April 1, 2021

via email

Christine Long
Registrar
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4
Registrar@oeb.ca

Dear Ms. Long

Re: Elexicon Energy Inc. Distribution System Plan

On December 20th, 2018 the Ontario Energy Board (OEB) approved an application (EB-2018-0236) to amalgamate Veridian Connections Inc. (Veridian) and Whitby Hydro Electric Corporation (Whitby Hydro). In that decision the OEB ordered that the merged entity shall file a consolidated Distribution System Plan (DSP) within 24 months of the closing date of the proposed transaction.

On April 1, 2019 Veridian and Whitby Hydro amalgamated and formed Elexicon Energy Inc. (Elexicon). In accordance with the OEB's Decision and Order and the Chapter 5 Filing Requirements for Electricity Distribution Rate Applications, Elexicon is pleased to submit its consolidated DSP for the 2021 bridge and 2022-2026 forecast period.

Do not hesitate to contact me should you have any questions or require further information in respect of this matter.

Sincerely,

Original signed by

Steve Zebrowski
Manager, Regulatory Policy
szebrowski@elexiconenergy.com

Elexicon Energy Inc.

Distribution System Plan

Historical Period: 2014 - 2021

Forecast Period: 2022 - 2026

1 April 2021

TABLE OF CONTENTS

LIST OF APPENDICES

LIST OF FIGURES

LIST OF TABLES

GLOSSARY

ACA - Asset Condition Assessment
ADMS - Advanced Distribution Management System
AHP - Analytical Hierarchy Process
AM - Asset Management
AMI - Advanced Metering Infrastructure
BRT - Bus Rapid Transit
CDM - Conservation and Demand Management
CEA - Canadian Electricity Association
CI - Customer Interruptions
CI - Customers Interrupted
CIA - Connection Impact Assessment
CIC - Customer Interruption Costs
CHI - Customer Hours Interrupted
CIS - Customer Information System
CMDB - Change Management Database
CMDB - Configuration Management Database
CPP - Capital Planning Process
DAI - Data Availability Index
DER - Distributed Energy Resources
DMS - Distribution Management System
DSC - Distribution System Code
DS – Distribution Station
DSP - Distribution System Plan
DW - Direct Worth
EAC - Equivalent Annual Cost
Elexicon - Elexicon Energy Inc.
ELT - Executive Leadership
ELT - Elexicon Leadership Team
EOL - End of Life
ESA - Electrical Safety Authority
EUSR - Electric Utility Safety Requirements
EUSR - Electric Utility Safety Rules
FCI - Faulted Circuit Indicators
FCI - Faulted Current Interrupters
FCR - First Contact Resolution
FESI - Feeders Experiencing Sustained Interruptions
GIS - Geographic Information Systems
HI – Health Index
HONI - Hydro One Networks Inc.
ICM - Incremental Capital Module
IESO - Independent Electricity System Operator
IR - Infrared
IRRP - Integrated Regional Resource Plan
IT - Information Technology
IT/OT - Information and Operational Technology
LIS - Load Interrupter Switch
LOS - Loss of Supply

LSP - Locate Service Provider's
MAADs - Mergers, Acquisitions, Amalgamations and Divestures
MED - Major Event Days
METSCO - METSCO Energy Solutions Inc.
MS – Municipal Station / Substations
NA - Needs Assessment
ODS - Operational Data Storage
OEB - Ontario Energy Board
OMS - Outage Management System
OPG - Ontario Power Generation
OT - Operational Technology
PEG - Pacific Economics Group
PSU - Process and Systems Upgrades
PtoK - Peterborough to Kingston
Regulator - Ontario Energy Board
RIP - Regional Infrastructure Plan
RRF - Renewed Regulatory Framework
SA - Scope Assessment
SAIFI - System Average Interruption Frequency Index
SERC - Standards Equipment Reliability and Compliance
SQR - Service Quality Requirements
the utility - Elexicon Energy Inc.
TIR - Technical Interconnection Requirements
TS - Transformer Station
TUL - Typical Useful Life
USF - Utilities Standards Forum
Veridian - Veridian Connections Inc.
Whitby Hydro - Whitby Hydro Electric Corporation
WPF - Worst Performing Feeders
WTP - Willingness to Pay

5.1 INTRODUCTION

5.1.1 OBJECTIVES & SCOPE OF WORK

Planning Context and Investment Magnitude

This Distribution System Plan (“DSP”) represents the first consolidated capital planning submission of Elexicon Energy Inc. (“Elexicon” or “the utility”) – the product of a 2019 merger of Whitby Hydro Electric Corporation (“Whitby Hydro”) and Veridian Connections Inc. (“Veridian”) approved by the Ontario Energy Board (“OEB” or “Regulator”) on December 20th, 2018.[1] In approving the transaction, the OEB mandated the new distributor to file a consolidated DSP within the first 24 months since the transaction which occurred on April 1, 2019.

In addition to being a response to the Regulator’s explicit direction, this DSP also represents an interim progress report on the merger activities impacting the capital work planning and execution processes, and the articulation of the utility’s investment plans for the five-year timeframe ahead. Table 5.1-1 provides a summary of the anticipated capital and System O&M expenditures underlying this DSP.

Table 5.1-1: Elexicon's Forecasted Capital and System O&M Costs

Category	Bridge ($000)	Forecast ($000)				
	2021	2022	2023	2024	2025	2026
System Access	44,681	27,473	28,271	26,673	14,853	19,053
System Renewal	19,667	23,441	21,490	19,879	18,037	17,756
System Service	1,418	42,805	1,348	1,353	1,053	1,053
General Plant	12,065	6,460	5,183	4,605	4,205	4,134
Subtotal Gross	**77,831**	**100,179**	**56,292**	**52,510**	**38,148**	**41,996**
Contributed Capital	32,475	15,175	20,461	16,485	5,475	6,735
Total Net	**45,356**	**85,004**	**35,831**	**36,025**	**32,673**	**35,261**
System O&M	16,591	16,923	17,261	17,606	17,959	18,318

Two years into its amalgamated existence, Elexicon is much more than a sum of its predecessors’ parts. It is a modern utility with a clearly articulated corporate identity, reflective of its shareholders’ and customers’ priorities, a focus on modern technology as an enabler of incremental value gains in service offerings, and an investment portfolio increasingly grounded in data-driven asset intervention decisions. As the following pages convey, Elexicon’s current approach to Asset Management (“AM”) is a work in transition – built on deep introspection of the status quo, extensive industry research on the emerging approaches to Asset Management as both a scientific and a managerial discipline, and decisive action on implementing more advanced tools and processes.

[1] Ontario Energy Board, EB-2018-0236, “Application for approval to amalgamate Veridian Connections Inc. and Whitby Hydro Electric Corporation and continue operations as a single electricity distribution company” - Decision and Order, December 20, 2018.

While new approaches are increasingly in use, more work lies ahead in piloting, deploying, stress-testing and further configuring the components of Elexicon's AM process based on ongoing operating insights and evolving priorities in what is an increasingly complex strategic and operating environment. Accordingly, and notwithstanding the progress demonstrated in this DSP, the utility's medium-term goal is to finalize most enhancements and refinements to its AM practices ahead of its first rebasing application anticipated for 2029. In doing so, Elexicon intends to ensure that the investment plan presented to the OEB, upon completion of its deferred rebasing period is grounded in extensively tested and well understood decision support systems that integrate objective evidence collected in the field and strategic judgment refined through ongoing analysis of outcomes targeted and delivered.

Ratemaking Considerations

Unlike most DSPs presented to the OEB, this document is not supporting a Cost-of-Service application, as the utility continues to find itself in the deferred rebasing period. As such, the 2022-2026 investments presented in this document are not associated with any *immediate* incremental rate increase asks, aside from formulaic adjustments consistent with the OEB's treatment of distribution rates during post-consolidation deferred rebasing periods. Accordingly, none of the Forecast Period years are referred to Test Years. It is important to note, however, that the magnitude of several investments contemplated in this DSP may make them eligible for incremental capital funding mechanisms available to Ontario' s distributors.

While the rationale underlying these investments and their expected timing are discussed in the pages that follow, any associated incremental capital rate increase requests would be addressed through a dedicated application later in 2021 consistent with the applicable OEB filing requirements. Elexicon notes, however, that the Customer Engagement efforts supporting this DSP explicitly articulated the scope and nature of investments that may be eligible for the Incremental Capital Module ("ICM") rate treatment and sought their customers' feedback on the rationale and anticipated rate impact of these investments. As discussed below, among other valuable inferences the customers' feedback led Elexicon to scope down the list of investments potentially considered for the ICM treatment.

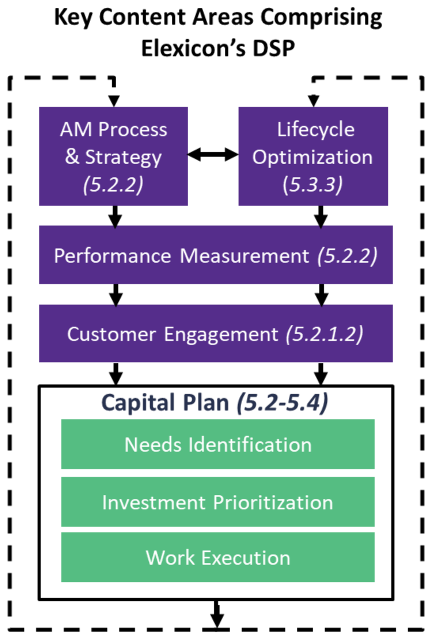
Scope of Work Covered in the Document

This DSP is prepared in accordance with the OEB's guidance articulated in Chapter 5 of the *Filing Requirements for Distribution System Applications*. The document covers the capital and system O&M expenditures planned over the 2021-2026 Forecast Period. Capital investments span the four categories defined in the OEB's Renewed Regulatory Framework ("RRF") report, namely *System Access, System Service, System Renewal,* and *General Plant*.

The document describes in detail Elexicon's transitional Asset Management process, including the range of planning inputs that are considered in the process of asset lifecycle management and capital planning processes. The DSP documents the practices, policies and processes that are both in place and under development to ensure that investment decisions support the desired outcomes in a cost-effective manner.

Figure 5.1-1 provides a high-level conceptual content map that outlines how the key content areas discussed in this document interact in articulating the overall process of defining and executing on the utility's capital investment decisions. The sections that follow contain more granular diagrams articulating the individual processes referred to in the figure to the left.

Figure 5.1-1: Major DSP Content Areas



Strategic Objectives Driving Investment Planning

This DSP also describes how the evidence collected through asset lifecycle management activities, forecasting and stakeholder engagement work is continuously guided and assessed against three complementary layers of strategic considerations, namely:

- The OEB's RRF Principles;
- Elexicon's Strategic Pillars; and
- Elexicon's Asset Management Objectives.

These strategic guiding principles described in more detail in Sections 0 and 5.3.1.1 help define investment outcomes with increasing granularity – to ensure that analytical insights gathered throughout the Asset Management Process reflect the utility's desired performance and accomplishments across various dimensions of its operations.

5.1.2 OUTLINE OF THE REPORT

As noted above, this plan has been structured to align with the OEB's expectations for DSP preparation articulated in Chapter 5 of the *Filing Requirements for Electricity Distribution Rate Applications*. Accordingly, the DSP consists of four major sections: 5.1 Introduction, 5.2 Distribution System Plan, 5.3 Asset Management Process, and 5.15.4 Capital Expenditure Plan. The following passages provide brief descriptions of each section.

Section 5.1: ***Introduction*** outlines the document's objectives and the utility's planning context, lays out the structure of this DSP, and briefly describes the utility's current state of operations. The description of the utility includes information such as its corporate values and goals, service area, customers, and system performance. This section also provides an overview of the capital investment programs and drivers within each investment category is provided.

Section 5.2: ***Distribution System Plan*** provides an overview of the document, covering its key dimensions such as customer preferences, investment horizons and information vintage, changes to the asset management process, and ongoing efforts to modernize Elexicon's grid. This section also summarizes the key consultation processes for coordinating the utility's planning efforts with organizations such as Hydro One Networks Inc. ("HONI"), Metrolinx, other local utilities, and the developer community (among others). A detailed analysis of the performance measures used to quantify and track Elexicon's performance over the historical period concludes the section.

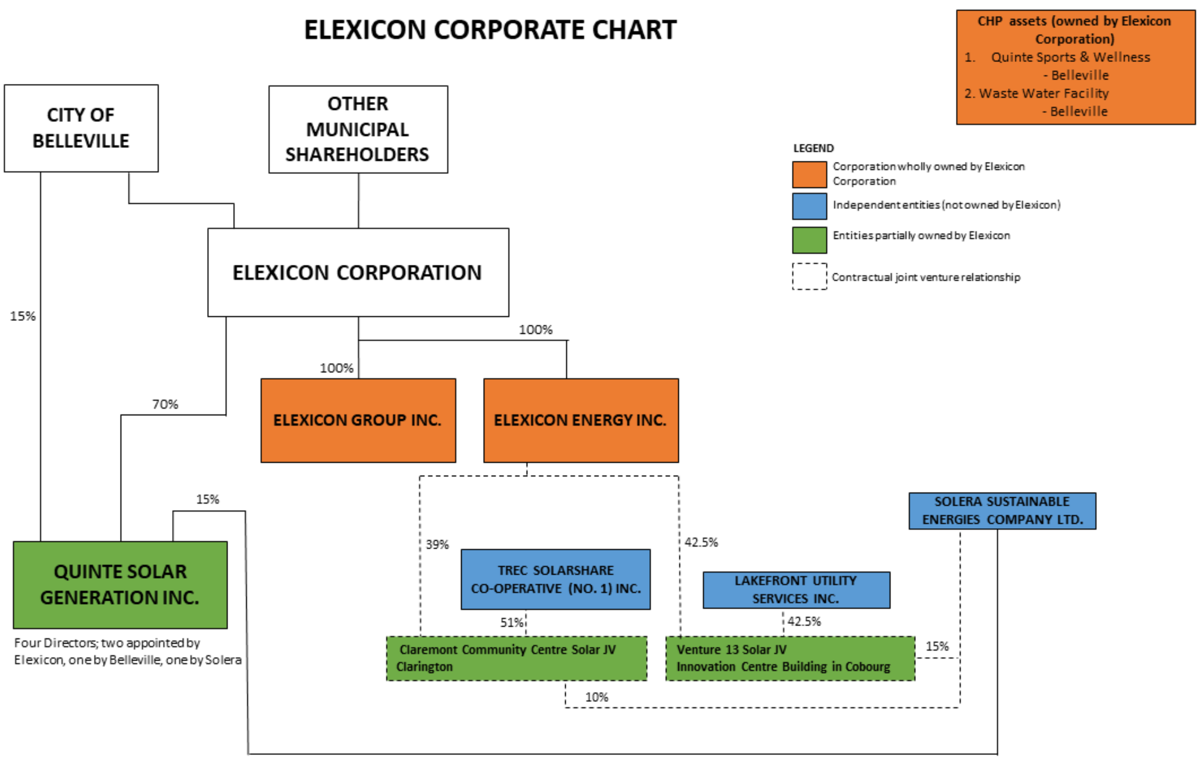
Section 5.3: ***Asset Management Process*** describes Elexicon's Asset Management process and strategy in their current, transitional form, and illustrates the component activities through which relevant asset information inputs are transformed into actionable work execution plans. The section also describes the Asset Management Objectives underlying Elexicon's asset intervention decisions, and the data-driven process through which the utility's Executive Leadership Team determined their relative prioritization. Also included in this section is the information on Elexicon's service territory characteristics and the elements of the utility's Asset Lifecycle Management practices. The section concludes with a summary of its most recent Asset Condition Assessment ("ACA") results, and the discussion on current system capacity availability across the service area.

Section 5.4: ***Capital Expenditure Plan*** describes the steps comprising the capital expenditure planning process, including information such as risk management practices, investment prioritization, and an overview of CDM programs. It also includes a historical variance analysis which describes the differences between planned and actual expenditures consolidated across both predecessor utilities. A comparison of historical and forecast expenditures at the investment category, driver, and program levels is also provided. In addition, the section details the impact of capital investments on System O&M costs and provides justification for material investments through business case documents.

5.1.3 Description of the Utility

Elexicon is a comparatively new distributor which formally commenced operations on April 1st, 2019 upon the merger of Whitby Hydro and Veridian Connections. The merger was driven by the predecessors' objectives of minimizing costs, improving customer experience and system reliability, and establishing more efficient operations. Elexicon is owned by Elexicon Corporation, which also owns Elexicon Group Inc. Figure 5.1-2 below presents Elexicon's shareholder structure, including all parent entities and subsidiaries. Elexicon is 100% owned by the municipalities it serves.

Figure 5.1-2: Elexicon Shareholder and Corporate Structure Overview



Elexicon is headquartered in Ajax, ON and serves a non-contiguous service area primarily located in the Region of Durham. Elexicon also provides power to towns and cities as far north as Gravenhurst and as far east as Belleville. The non-contiguous service territory covers a total area of 787 square kilometers, of which 639 were formerly within Veridian's service territory and 148 were previously served by Whitby Hydro. Figure 5.1-3 below depicts Elexicon's service territory, which consists of the following towns, cities, and municipalities. Detailed service area maps can be found in Section 5.3.2.2.

Elexicon's service area is very spread out with roughly 179Km between Gravenhurst and Belleville. This poses multiple challenges to Elexicon on an operational level including needing multiple operation centers and receiving energy from numerous Hydro One transformer stations in each area.

- Formerly Whitby Hydro Territory:
    - o The Town of Whitby

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

Figure 5.1-3: Elexicon Service Area Map

Table 5.1-2: Largest Population Centres

Population Centre[2]	Population (2016 Census)	Population (2011 Census)
Whitby	128,377	122,022
Ajax	119,677	109,600
Pickering	91,771	88,721
Belleville	67,666	66,331
Bowmanville	39,371	35,168
Port Hope	16,753	16,214
Gravenhurst	12,311	12,055

5.1.3.1 Corporate Mission, Vision, and Core Values

Elexicon's Mission, Vision, and Core Values reflect the principles which drive its planning activities, daily operations, and interaction with customers and shareholders. These fundamental corporate documents outline Elexicon's customer service philosophy and encompass considerations beyond business operations such as the broader community, company culture, and shareholder priorities.

The impact of these strategic principles is reflected in Elexicon's planned investments, performance tracking, and other operational areas. The mission, vision, and core values statements are provided below. Supplementing these expressions of the driving principles are Elexicon's Strategic Pillars, which align closely with the OEB's RRF principles, and in turn guide the more granular Asset Management Objectives discussed in Section 5.3.1. The Strategic Pillars are outlined in Table 5.1-3.

Mission Statement: *"To provide our customers with reliable, affordable energy services and to continuously improve to meet their needs, while ensuring the needs of our shareholders are met through sustainable growth."*

Vision Statement: *"To empower the communities we serve and help customers seize opportunities to ignite a better future."*

[2] Source: Statistics Canada, Census Profile, 2016 Census.

Table 5.1-3: Overview of Elexicon's Strategic Pillars

Strategic Pillar	Pillar Definition
Customer Centricity	**Customer Centricity is developing an agile operating mindset that prioritizes decisions to build and maintain a positive customer experience.** Regularly engaging with evolving customer perspectives to understand their demands and delivering on these, will develop customer-centricity on the outside while simultaneously fostering these behaviours internally – strengthening the Elexicon brand.
Operational Excellence	**Operational Excellence is the continuous improvement of the organization's people, processes, places, safety, and financial sustainability.** Operational Excellence looks to yield fundamental and incremental ways of working, rooted in data and innovation, to best serve stakeholders in an economical, safe, and reliable way.
Economic Development	**Economic Development is enabling the organization to be a trusted strategic partner and catalyst for growth by nurturing, developing, and managing relationships with our community shareholders and the stakeholders in the areas we serve**. Relationships are leveraged to create value-added services that align with customer needs, improve operations, enhance financial performance, and practice strong corporate, environmental, and social responsibility. Elexicon's corporate, environmental, and social responsibility plan is currently under development.
Strategic Investment	**Strategic Investment is the balancing and optimizing of capital investments while managing revenue requirements.** This means developing proactive approaches to future-proofing the organization by balancing the traditional 'poles & wires' business with adaptable, innovative opportunities, that show a deep understanding of recoverable and non-rate recoverable investments and engage the customers / communities Elexicon serves.

Corporate Values

Safety: *"We prioritize the safety of our team and customers, knowing this is the foundation of a healthy home and engaged workplace."*

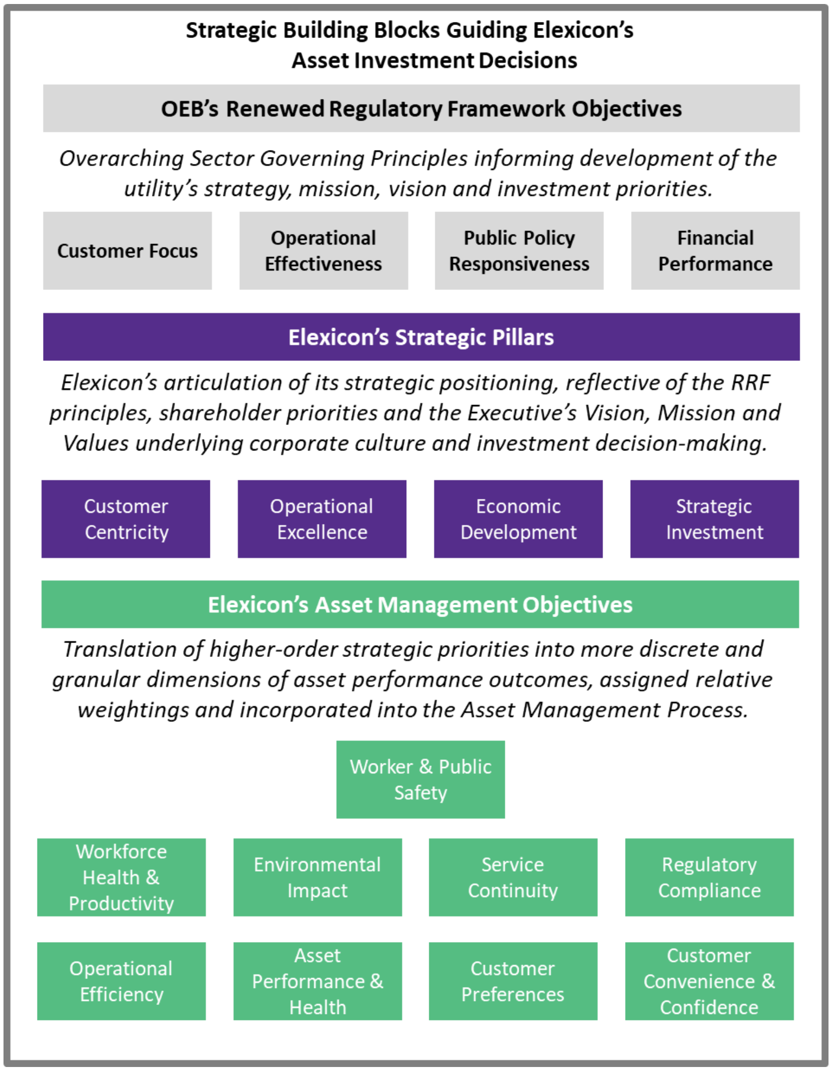
Kinship: *"We seek every opportunity to forge personal connections with our customers and employees, because we know genuine relationships are lasting ones."*

Responsiveness: *"We know our customers rely on electricity to successfully navigate their day. As a result, we go above and beyond to meet their needs by proactively addressing their questions and concerns, and continuously improving our services"*

Competence: ***"****"We understand that our customers' trust is built upon our knowledge, solutions, and ability to make – and keep – our promises."*

Mindfulness: *"We are mindful of our impact on the environment and make every effort to ensure we cause no undue harm during the delivery of our services."*

Figure 5.1-4: Strategic Objectives Hierarchy Underlying Investment Planning



As noted above, Elexicon's Strategic Pillars are broadly aligned with the OEB's RRF principles, while taking into the consideration the priorities of the utility's shareholders and the articulation of the corporate Mission, Vision and Values developed by the Executive Leadership Team and the Board of Directors. As illustrated in Figure 5.1-4, the Strategic Pillars in turn serve as the foundation for the utility's Asset Management Objectives that articulate the strategic priorities in a more granular fashion in a manner relevant to the performance outcomes expected from the asset base.

Section 5.3 describes how each AM Objective corresponds to a given Strategic Pillar and the OEB's RRF Outcome, and carries a relative weighting assigned by the Executive Leadership Team for use in the capital investment planning process. As the preceding figure illustrates, Elexicon's corporate-level strategic objectives exhibit clear alignment with the broader sector governing principles and the more discrete technical, operational, and financial considerations that drive day-to-day decision-making. In conducting their work, Elexicon employees channel the value systems articulated in the utility's Mission, Vision and Values.

5.1.3.2 Customers Served

As of 2019 year-end Elexicon served 167,563 customers across its service area. Prior to the merger, Veridian served 121,826 customers while Whitby Hydro served 42,906 customers (2018). Elexicon's service territory currently spans an area of 788 square kilometres, which covers 451 square kilometres of rural area and 337 square kilometres of urban area. Prior to the merger, Veridian Connections serviced a total area of 639 square kilometres which consisted of 386 squares kilometres of rural area and 253 square kilometres of urban area.

Whitby Hydro's service area was considerably smaller at 148 square kilometres, consisting of 64 square kilometres of rural area and 84 square kilometres of urban area. Elexicon is the fifth largest utility in Ontario in terms of the number of customers it serves, and seventh largest in terms of service area. Elexicon's customers are classified into five categories: *Residential*, *General Service < 50kW*, *General Service >= 50kW*, *Large User*, and *Sub Transmission*. Historical counts by customer class from 2015 to 2019 for Elexicon and its predecessor utilities are summarized in Table 5.1-4 below.

Table 5.1-4: Elexicon Customer Counts by Class

	Customer Class	2014	2015	2016	2017	2018	2019	Average Growth
Combined / Elexicon	Residential	146,537	147,753	149,071	150,220	151,914	154,711	1.09%
	General Service < 50kW	11,030	11,088	11,211	11,274	11,389	11,535	0.90%
	General Service > 50kW	1,413	1,435	1,426	1,458	1,425	1,403	-0.13%
	Large User	2	3	3	3	4	4	16.67%
	Sub Transmission	-	-	-	-	-	-	N/A
Veridian	Residential	107,574	108,502	109,483	110,330	111,642	**N/A**	
	General Service < 50kW	8,874	8,909	8,991	9,036	9,135		
	General Service > 50kW	1,044	1,067	1,056	1,088	1,045		
	Large User	2	3	3	3	4		
	Sub Transmission	-	-	-	-	-		
Whitby	Residential	38,963	39,251	39,588	39,890	40,272	**N/A**	
	General Service < 50kW	2,156	2,179	2,220	2,238	2,254		
	General Service > 50kW	369	368	370	370	380		
	Large User	-	-	-	-	-		
	Sub Transmission	-	-	-	-	-		

Note: the shaded area contains the summation of both predecessors' customers ahead of the merger to illustrate the continuity of customer growth.

Table 5.1-5 provides additional customer-related statistics and comparisons to the other 59 utilities in Ontario (as of 2019). In terms of statistics that reflect absolute size, Elexicon generally ranks amongst the top ten utilities in Ontario. The utility has a mid-tier ranking in terms of normalized size statistics such as Customer Density and Customers per km of Line, reflecting the non-contiguous nature of its system that includes both urban and rural areas. Elexicon also ranks mid-tier in terms of normalized demand statistics such as Average Monthly kWh Delivered per Customer and Average Peak kW per Customer. When examining the cost and revenue-related statistics normalized per customer, Elexicon ranks amongst the lowest in Ontario. This suggests that Elexicon and its predecessors have effectively managed their electricity distribution costs.

Table 5.1-5: Additional Customer Related Statistics

Measure	Value	Ranking
Total Customers	167,653	5th
Total Service Area	788	7th
KM of Line	3,823	6th
Customer Density	213	34th
Customers per KM of Line	44	30th
Average Monthly kWh Delivered per Customer	1,712	28th
Average Peak per Customer (kW)	3.19	33rd
Distribution Revenue per Customer ($)	344	56th
Average Cost of Power & Related Costs per Customer ($)	1,759	54th

5.1.3.3 System Demand and Efficiency

In 2019, Elexicon's system load was amongst the highest in Ontario. In comparison to other utilities, Elexicon ranked as the fifth highest in terms of summer peak load at 649 MW, winter peak load at 565 MW, and average peak load at 535 MW. The historical summer, winter, and average peak loads for Elexicon and its predecessor utilities are summarized in Table 5.1- below.

An analysis of Elexicon's system efficiency as measured through the System Losses performance measure is provided in Section System Losses. Improving its system loss performance is among the objectives underlying several investment categories – most notably the Voltage Conversion work.

Table 5.1-6: Elexicon Demand Statistics

Utility	Peak Type	2014	2015	2016	2017	2018	2019
Elexicon	Winter Peak (kW)	597,268	579,652	545,666	530,953	561,289	565,125
	Summer Peak (kW)	616,634	652,447	684,688	626,506	696,639	648,618
	Average Peak (kW)	553,300	544,886	561,442	513,334	561,023	534,745
Veridian	Winter Peak (kW)	445,077	432,644	405,512	394,989	418,330	N/A*
	Summer Peak (kW)	444,688	470,705	494,731	450,688	503,702	
	Average Peak (kW)	407,720	402,030	412,835	378,148	411,496	
Whitby	Winter Peak (kW)	152,191	147,008	140,154	135,964	142,959	N/A
	Summer Peak (kW)	171,946	181,742	189,957	175,818	192,937	
	Average Peak (kW)	145,580	142,856	148,607	135,186	149,527	

**"N/A" for predecessor numbers refers to the start of integrated operations where there are no longer predecessor-specific figures.*

5.1.4 BACKGROUND & DRIVERS

Elexicon's capital investments over the forecast period have been grouped across the four OEB-defined investment categories: System Access, System Renewal, System Service, and General Plant. Investment plans within these categories have been paced and prioritized to meet the objectives of the RRFE. Elexicon's capital planning process is detailed in Section 5.4.1b) and the pacing of investment programs is outlined in the Business Case documents contained in Appendix A. Table 5.1-7 provides an overview of the programs and drivers within each investment category.

Table 5.1-7: Overview of Investment Programs, Drivers, and Relevant Strategic Pillars

Investment Category	Program	Driver	Relevant Strategic Pillars
System Access	Connection of New Services	Customer Service Requests	Customer Centricity, Economic Development, Operational Excellence
	Customer Requested Work		
	Feeder Expansion		
	Road Relocations	Third Party Infrastructure Development Requirements	
	BRT Relocations		
	Metering	Mandated Service Obligations	
System Renewal	Renewal Programs – Distribution Transformers	Asset at the End of their Service Life	Customer Centricity, Operational Excellence
	Renewal Programs – Others		
	Renewal Programs – Rebuilds		
	Renewal Programs – Poles		
	Renewal Programs – Switches & Switchgears		
	Substation Renewal		
	Voltage Conversions – Reliability		
	Renewal Programs – Reactive	Asset Failure	
System Service	Feeder Enhancement	System Capacity	Customer Centricity, Operational Excellence, Strategic Investment
	Substations Growth & Expansion	System Operational Objectives: Reliability/Environmental Performance	
	System Reliability Improvement		
	Standard Equipment Reliability & Compliance		
	Substation Upgrades		
General Plant	Information Technology	Business Operations Efficiency	Operational Excellence, Strategic Investment
	Facilities	Non-system Physical Plant	
	Fleet	Capital Maintenance Support	
	Tools and Equipment		
	Intangibles		

The *System Access* investment category includes investments that enable Elexicon to fulfill its obligation to provide customers with access to electricity services through the distribution system (including modifications such as asset relocations). The primary drivers for this investment category are Customer Service Requests, Third Party Infrastructure Development Requests, and Mandated Service Obligations (e.g., as per the Distribution System Code).

The *System Renewal* investment category includes investments to replace or refurbish the distribution system assets to manage the risks associated with aged and deteriorated plant and maintain Elexicon's ability to provide customers with electricity services. Drivers for this investment category include Assets at the End of Their Service Life and Asset Failure. The former covers all proactive renewal programs whereas the latter corresponds to the Reactive Renewal program.

The *System Service* investment category includes investments which modify Elexicon's distribution system to ensure that it continues to meet its operational objectives while addressing anticipated future customer service requirements and enhancing and modernizing the system's operability. Drivers for this investment category include System Capacity, System Operational Objectives: Reliability, and System Operational Objectives: Environmental.

The *General Plant* investment category includes modifications, replacements, or additions to Elexicon's assets that are not part of its distribution system – this includes land and buildings, tools and equipment, rolling stock and electronic devices, and software used to support daily business and operations activities. Drivers for this investment category include Business Operations Efficiency, Non-Systems Physical Plant and Capital Maintenance Support.

5.2 DISTRIBUTION SYSTEM PLAN

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

5.2.1 a) Key Elements of the DSP

Key DSP Content Areas and their Interaction

Elexicon's DSP is a planning document that conveys the scope and nature of its capital and operating expenditure plans over the 2021-2026 Forecast Period and substantiates these plans by presenting the evidence available to support them. Being a recently formed utility, Elexicon's investment plans for the 2021-2026 DSP stem from the combination of planning outputs produced by the predecessor utilities and those developed since the merged operations commenced in 2019.

Accordingly, the key content elements of this DSP are those that:

- describe the current and anticipated state of Elexicon's asset base over the Forecast Period in terms of asset health, performance, and utilization levels;
- articulate the components of the Asset Management process that gradually translates the variety of data inputs into actionable lists of candidate investments for all types of assets;
- explain how the outputs of the Asset Management process influence the ongoing Asset Lifecycle Management practices and help formulate near/medium-term Investment Plans.

Figure 5.2-1: Key Content Elements of the DSP

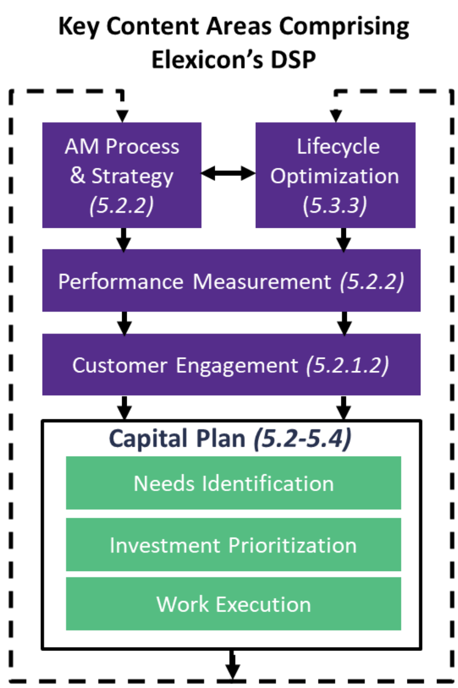


Figure 5.2-1 illustrates the major content elements of the DSP (along with the document section numbers describing them) and showcases in a simplified manner, how each of them fits into the overall process of preparing the DSP. The following passages briefly describe each element showcased.

The discussion of *Asset Management Process and Strategy* (Section 5.2.2) outlines Elexicon's AM objectives that articulate the expected service outcomes of the utility's investment work as defined by its ELT. It also lays out the multi-stage AM Process, which includes all data collection and analysis activities that yield analytical outputs used in investment planning and recommend adjustments to the ongoing asset lifecycle management activities.

The *Asset Lifecycle Optimization* content (Section 5.3.3) describes the practical approaches that Elexicon employs to ensure that it derives the expected value from the asset base it operates. The section discusses the nature and frequency of maintenance and inspection activities occurring at different stages of the assets' lifecycle, and the approaches to asset performance optimization or renewal (e.g., maintenance, vs. refurbishment, vs. replacement – as appropriate). As illustrated in the above diagram, the lifecycle management activities are closely related to the AM Process activities, as they provide it with inputs in the form of asset data and consume its analytical outputs that may suggest from time to time the incremental changes to how some asset types are managed.

The *Performance Measurement* content (Section 5.2.2) describes Elexicon's performance measurement framework and the most recent results across the combination of internal and external metrics, which themselves serve as potential indicators for near-term corrective action through operational or capital investments. Accordingly, the Performance Measurement work is positioned downstream from the AM Process and Lifecycle Management activities in the above diagram. As Elexicon continues its integrated operations, it expects to consider tracking additional types of measures and metrics based on the insights emerging from the AM process and/or the operational management of its Asset Lifecycle support activities.

The *Customer Engagement* content (Section 5.2.1.2) discusses the utility's efforts to convey to its customer base the nature of investment planning and execution trade-offs that the utility is facing, while collecting their feedback on the scope and nature of upcoming work, their preferences as to the manner in which certain projects can be executed, and the potential changes in how customers' use of new technologies can create new demands on the grid. The above diagram positions this category downstream from Performance Measurement and ahead of the capital planning work, as Customer Engagement work draws on both the outcomes of asset analytics and the objective performance data to explain to the customers the current planning context and gauge their needs and preferences as to the service levels and work execution plans.

The *Capital Plan* content (primarily addressed in Section 5.4) describes the process mechanics of the final stage where the inputs generated and tested through the preceding stages are ultimately combined in the form of concrete capital plans. By its nature, this stage involves the review of objective asset evidence in order to define, pace and prioritize the investments planned over the relevant horizon. As such, this stage exhibits significant overlap with the AM Process and Asset Lifecycle Management stages where much of these analytical insights are generated. For clarity, while the AM Process discusses all types of data gathering and analytical activities that Elexicon performs in a sequential manner, the Capital Planning content describes the logistics through which the utility generates the actual capital plans, by drawing on various reports that combine the insights generated through the AM process.

The arrows leading back from the bottom to the top of the Figure 5.2-1 are meant to illustrate the constant feedback loop underlying all asset management and capital planning activities. As such, the content of all key sections described in the diagram can be expected to evolve over time, as Elexicon continuously reviews the performance outcomes of its investment plans and the analytical insights from its AM activities. As many AM process enhancements remain underway, Elexicon expects the content of its future DSP filings to evolve materially as the new tools and processes are implemented.

Key Societal Trends Impacting Elexicon's Planning

Aside from the insights generated in the course of analysis of Elexicon's current asset base and its anticipated evolution over the relevant planning horizons, Elexicon's planners and ELT members are staying apace of the key societal trends that may have a bearing on the scope and nature of investments that the utility has to make in order to meet its customers' and shareholders' expectations. Two of the most notable of these trends impacting this DSP are Managing the Environmental Impact and Opportunities Presented by Innovation and Technology.

Managing the Environmental Impact

Elexicon is keenly aware that the energy sector's impact on the natural environment is increasingly important to people and organizations that it serves. Most notably, several municipalities have formally declared a Climate Emergency and established aggressive targets for greenhouse gas reductions and other environmental sustainability efforts. The Region of Durham, which includes the majority of municipalities served by Elexicon, has developed a Community Energy Plan which outlines these goals and associated targets. Some of these environmental objectives are outlined in Table 5.2- below.

Table 5.2-1: Environmental Targets Established by the Region of Durham

Target	Target Date
Increase Durham Region's energy self-sufficiency and resiliency by increasing local renewable energy sources to 35%	2030
Decrease carbon-based energy consumption by 15%	2035
Increase energy production from Durham community energy projects to a minimum of 50% of consumption.	2050

Communities outside of the Region of Durham served by Elexicon include the City of Belleville, the Town of Gravenhurst, and the Municipality of Port Hope. These municipalities have also indicated commitment to environmental sustainability through efforts such as the Green Task Force (Belleville), the Centre of Excellence for Environmental Sustainability Working Group (Port Hope), and the environmental guidelines presented in the Town of Gravenhurst's official plan.

Among the immediate actions that Elexicon took in response to this trend was to rank Environmental Impact as the third-highest ranked AM Objective out of nine. See Section 5.3.1 for further discussion of the AM Objectives setting process and the manner in which these Objectives impact the investment planning process.

Opportunities Presented by Innovation and Technology

The development of new technologies provides more resources and opportunities for improvement across all lines of business. Elexicon understands that new technologies have potential to change the manner in which its customers interact with the power grid, as adoption rates of electric vehicles and distributed generation sources continue to increase. At the same time, technology also presents opportunities to change the way the utility's staff perform their daily tasks – at once offering streamlining opportunities and creating new demands in terms of staffing competencies.

The impact of technological trends on this DSP is manyfold. For example, in developing its Customer Engagement materials, Elexicon explicitly asked its customers about their current and intended use of new technologies such as Electric Vehicles and Distributed Generation sources. In doing so, the utility sought to gather factual evidence gauging whether, how and when these technologies may warrant making additional investments into the grid stability and operability. Moreover, the DSP contains a number of critical Information Technology ("IT") and Operational Technology ("OT") investments that Elexicon is planning to implement to modernize and enhance the efficiency of its grid operations function. The most notable such investment is the Advanced Distribution Management System ("ADMS") discussed in Business Case P3 – IT/OT.

Key Managerial Objectives Impacting Elexicon's Planning

Aside from the societal trends and information regarding current and anticipated asset degradation and utilization levels, there are also key near/medium-term managerial objectives that impact the scope and nature of investments planned for the Forecast Period. Among these managerial objectives are the following:

<u>Understanding and Maintaining Customer Satisfaction</u>

Customer expectations are continually evolving, and Elexicon must adjust its objectives and priorities to ensure satisfaction. For example, Elexicon understands that its customers expect more than just system reliability – they also value responsiveness, digital access, and accurate information. In developing its Customer Engagement materials in support of this DSP, Elexicon sought to explore what aspects of its current service offerings matter to customers the most and how customers perceive the relative value propositions of different investment priorities. Understanding that customers value their time in interacting with the utility, Elexicon also asked its customers about the type and frequency of consultations that they would see as reasonable going forward.

Elexicon also understands that the complexity of its service territory likely means that members of the same customer classes located in different parts of the province may have some unique needs and perspectives on what the utility's investment priorities should be. To this end, the utility notes that the scope of its Customer Engagement work to date represents an early juncture in what it expects to be a more comprehensive and ongoing dialogue. In fostering a more collaborative relationship with all cohorts of its clients, Elexicon will continue exploring how different customer groups across its service territory see the value provided by the utility – to develop increasingly nuanced operating and capital investment plans for its diverse and dynamic service territory.

<u>Improving the Granularity of Reliability Tracking</u>

Over time, Elexicon aims to explore moving beyond the typical measures used to track and analyze system reliability (namely SAIDI and SAIFI) and enable reliability performance on a more nuanced – where economic and supported by ongoing customer engagement. The development of more nuanced reliability statistics can help the utility tailor its investment plans to different parts of its system and create opportunities for exploration of additional performance metrics. The first step on the path towards more advanced reliability statistics is the implementation of the new ADMS system – to integrate and standardize the system operation processes across the two legacy utilities and enable more efficient collection of operating data. Some of the custom DSP measures proposed for the Forecast Period will aid Elexicon in improving their reliability tracking.

<u>Enhancing Coordinated Planning across Business Lines</u>

As a result of the recent merger and the general continuous improvement activities, Elexicon actively seeks out and capitalizes on opportunities to streamline its operations. Elexicon aims to use the opportunity presented by the merger to re-think its processes and increase coordination across different lines of business to improve decision-making processes and operational efficiency. An important step in this process achieved to date was the integration of the Asset Management Objectives and the Business Planning process dynamics. The predecessors' articulations of AM Objectives were primarily relevant for the utility's electrical plant and required two separate Business Case formats. Starting in mid-2020, the utility implemented an integrated AM Objectives framework that defined the targeted outcomes in a way that makes them relevant for both Electrical and General Plant assets (See Section 5.3.1a). This important change enabled Elexicon to develop an integrated capital investment business case format that applies to all types of investments. In doing so, the utility took an important step towards making all of its investment decisions by using consistent evidence-based decision support tools that nevertheless provide requisite flexibility for different types of assets.

Helping Customers Continue their CDM Journeys

Notwithstanding the recent changes with delivery of the Conservation and Demand Management ("CDM") programs, Elexicon considers CDM as a valuable tool in its ongoing efforts to optimize the efficiency of design and operations across its system. To this end, Elexicon currently has several CDM programs in place that represent "wind-down" efforts stemming from the IESO's recent assumption of the CDM program delivery role. Three example programs are listed below with a brief description – the complete list of programs and additional details can be found in Section 5.4.1.1 - Rate-Funded Activities to Defer Distribution Infrastructure.

- *Audit Funding* – this program is intended to provide funding to businesses for energy audits which are the first step in the process of implementing CDM. Energy audits allow for the identification of opportunities to reduce energy and operating costs – this program provides funding for up to 50% of the cost of an energy audit.

- *Retrofit* – this program provides funding for businesses looking to upgrade their equipment or improve their operation. Eligible projects include those that provide sustainable, measurable, and verifiable reductions in peak electricity demand and electricity consumption (e.g., lighting and controls, HVAC, VFD).

- *Residential New Construction* – this program encourages residential home builders to include energy efficiency technologies and design features in new and substantially renovated homes. The level of funding provided depends on the sub-type of the project: performance, prescriptive, or custom.

Finding Innovative Solutions to Defer Capacity Upgrade Investments

Increasing system capacity is a long-term and capital-intensive effort. In the interest of efficiency and cost savings for customers, Elexicon sees new technology and/or utility-sponsored customer initiatives as potential means of deferring capital investments over the long term. Importantly, and as discussed in more detail below, the merger of Elexicon's predecessors has created an immediate opportunity to optimize the available station capacity across the former service territory boundaries. To enable part of the current load growth in the former Whitby Hydro service area, Elexicon is tapping into the available capacity in the former Veridian service area by way of six express distribution feeders, which is a more efficient solution compared to the alternative of additional transformation capacity.

As discussed in Section 5.4b, Elexicon is also integrating probabilistic analysis into its load forecasting work, by applying the probability modifiers to load forecasts from specific municipalities or developments – depending on the rate to which the historical forecasted volumes have translated into actual demand. These and other steps are helping Elexicon ensure that the scale and timing of system capacity investments provides the maximum value for the ratepayers.

<u>Managing the Impact of the COVID-19 Pandemic</u>

Along with the families and businesses across its service territory, the COVD-19 pandemic has affected Elexicon itself. The utility ensures that it complies with all relevant provincial, regional, and municipal restrictions on indoor and outdoor gatherings to ensure the safety of its employees and residents of its service territory. In light of these rapidly evolving requirements, the utility's ability to execute on some of its planned investment activities is affected as well. Many types of activities such as planning-related tasks are expected to continue without major challenges, as employees have successfully transitioned to remote work arrangements. However, Elexicon is experiencing delays in the completion of field work such as construction, asset inspections, and non-emergency asset replacements which can require the presence of multiple employees in close physical proximity.

While the utility is staying flexible in its work execution activities, the health and safety of its staff and local residents are of utmost importance. As a result, and subject to the future developments in the effort to curb the pandemic, Elexicon expects a temporary decrease in its capital and maintenance throughput performance, which may potentially have impact on its reliability performance, and consequently the DSP Implementation Progress and SAIDI/SAIFI metrics. A more detailed discussion of the impact of COVID-19 is provided in section 5.2.1.7 DSP Contingencies.

Nature and Volumes of Planned Investments

Table 5.2-2 provides a summary of historical actuals which include both predecessor utilities and forecast expenditures that Elexicon plans to execute over the Forecast Period.

Table 5.2-2: Historical and Forecast CAPEX and System O&M Expenditures

Category	Historical ($000)							Bridge	Forecast ($000)				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Access	17,199	17,206	14,032	12,289	15,355	25,214	25,041	44,681	27,473	28,271	26,673	14,853	19,053
System Renewal	9,206	14,560	20,917	17,840	17,878	27,660	13,555	19,667	23,441	21,490	19,879	18,037	17,756
System Service	3,911	1,803	858	483	497	1,126	1,983	1,418	42,805	1,348	1,353	1,053	1,053
General Plant	5,372	5,243	5,259	5,189	6,166	6,293	6,077	12,065	6,460	5,183	4,605	4,205	4,134
Subtotal Gross	**35,688**	**38,812**	**41,066**	**35,801**	**39,896**	**60,293**	**46,656**	**77,831**	**100,179**	**56,292**	**52,510**	**38,148**	**41,996**
Contributed Capital	7,347	11,228	8,358	4,337	8,131	16,807	16,341	32,475	15,175	20,461	16,485	5,475	6,735
Total Net	**28,341**	**27,584**	**32,708**	**31,464**	**31,765**	**43,486**	**30,315**	**45,356**	**85,004**	**35,831**	**36,025**	**32,673**	**35,261**
System O&M	13,884	14,465	14,986	15,025	15,970	12,111	14,262	16,591	16,923	17,261	17,606	17,959	18,318

The following subsections describe in more detail the types of investments comprising the 2022-2026 Forecast across the four main RRF Investment Categories.

System Access

System Access investments over the Forecast Period are driven by customer service requests, third party infrastructure development requirements, and other mandated service obligations. As a licensed electricity distributor in Ontario, Elexicon is required to complete these investments and has minimal discretion as to their timing. Projects within this investment category fall into one of five programs which are listed and described below.

- *Connection of New Services* – this program includes projects to fund the installation of new service connections driven by routine customer growth over the forecast period.

- *System Expansion* – this program supports the installation of new / expanded service connections or transformer capacity to accommodate new customers.

- *Facility Relocations* – this program funds asset relocations triggered by third-party projects such as road expansions, transit system modifications, and the installation of telecommunications infrastructure.

- *Customer Requested Work* – this program addresses customer requests that include such work as repairs due to third party damages, underground capital locates, customer-own equipment isolations, etc.

- *Metering* – this program funds installation or upgrades of metering units to maintain compliance with relevant regulatory standards and bring about incremental benefits of new functionalities.

Given the mandatory nature of these investments, the planning process for these types of electrical assets differs substantially from those applied to System Renewal and System Service Portfolios. However, Elexicon relies on its Load Forecast to estimate future connection requirements. The Load Forecast considers several inputs including municipal forecasts, development plans, municipal and regional plans, customer needs, and historical loading data.

There is some variability in the level of expenditure for the System Access investment category. Specifically, there is a notably high level of expenditures planned in 2021 and a relatively low level of expenditure in 2025. In 2021, the increase in spending results from increases in the Road Relocations and System Expansion programs. Elexicon expects to receive a higher-than-average volume of third-party infrastructure development related requests from Metrolinx. The planned increase in spending for the System Expansion program is expected to occur due to a material increase in customer growth in the Ajax-Pickering area. The decrease in total expenditures in 2025 results from an expected decrease in Feeder Expansion requirements subject to further planning and consultation activities and the manner in which the COVID-19 pandemic affects the expected pace of load growth and work execution.

Elexicon expects to receive customer contributions for a portion of the work completed within this program. The expected level of customer contribution varies depending on the purpose of the investment. For example, Elexicon expects to receive 100% contribution for nearly all Feeder Expansion work and Metrolinx-driven Facility Relocations projects and expects no contributions for the Metering program investments as they are driven by regulatory compliance requirements.

In addition, it is important to note that Elexicon plans to fund two System Expansion projects driven by the construction of the new Seaton Transformer Station ("TS") in 2022 through the ICM mechanism. The expected gross expenditure for these projects amounts to $5.05 million. A detailed analysis of the historical and forecast program-level expenditures is provided in Section 5.4.3.1.1.

System Renewal

System Renewal investments over the forecast period seek to replace or refurbish aged, deteriorated and/or functionally obsolete system assets, to maintain Elexicon's ability to provide customers with safe and reliable service. There are two primary drivers for programs within this category – assets determined to be at the end of their service life and asset failures. All System Renewal programs with the exception of the Renewal Programs – Reactive are categorized under the former driver, where engineering analysis and other relevant considerations determined that assets have reached their ends of life. While in many cases System Renewal work occurs on a like-for-like basis, some projects also involve upgrading the equipment's capacity or integrating newer performance capabilities. For example, when completing switches/switchgear replacements, Elexicon may consider installing TripSaver devices in place of standard reclosers to enable automatic service restoration after faults are cleared. The Switches/Switchgears Renewal program also supports the Alternatives to Capacity Upgrades objective as it maintains the operability of switches/switchgears assets used to complete switching operations. Switching operations are critical functions as they can be used to address overloading by re-routing load. Similarly, the Voltage Conversions – Reliability program supports the ongoing objective of finding solutions to defer capacity upgrades, as it increases feeder capacity, reduces system losses, and enables switching operations through the standardization of system voltage.

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

- Renewal Programs – Substation Renewal
- Renewal Programs – Poles
- Renewal Programs – Distribution Transformers
- Renewal Programs – Switches/Switchgears
- Renewal Programs – Others
- Renewal Programs – Rebuilds
- Renewal Programs – Reactive
- Voltage Conversions – Reliability

Elexicon's System Renewal investment planning leverages the analytical insights obtained through the Asset Management Process discussed in Section 5.3, including the ACA work, the Reliability Analysis data insights such as the Worst Performing Feeders ("WPF"). The level of investment over the forecast period is expected to vary to accommodate the expected fluctuations in the System Access portfolio where the utility has considerably less discretion as to the timing or volume of investments. Elexicon does not expect to receive any customer contributions for investments within this category as the underlying work involves renewing the existing asset base. It is important to note, however that Elexicon plans to request $800,000 in funding through the ICM mechanism in 2022 for switch/switchgear replacements necessitated by the development of the Bus Rapid Transit ("BRT") system. A detailed analysis of the historical and forecast program-level expenditures is provided in Section 5.4.3.1.1.

System Service

Investments within the System Service investment category are intended to increase system capacity and improve operational performance in areas such as reliability, safety, and system efficiency. As a result, there are two drivers for this program: System Capacity and System Operational Objectives. The five programs within this investment category are listed and described below:

- Substations Growth and Expansion – this program addresses system capacity through the upgrade of substation assets or the construction of new substations such as the planned Seaton TS project in 2022.

- Substation Upgrades – this program provides funding for upgrades at Elexicon substations which are expected to improve operational performance.

- Feeder Enhancement – this program enables capacity upgrades for existing feeders in the distribution system.

- Standards Equipment Reliability and Compliance ("SERC") – this program seeks to assess and improve Elexicon's equipment standards and operating practices, particularly those related to reliability.

- System Reliability Improvements – this program improves system reliability performance through efforts such as SCADA system upgrades and the deployment of assets such as Faulted Circuit Indicators ("FCI") and TripSaver automation devices.

System Service investment planning is based on Elexicon's Load Forecast, Reliability Analysis, and the outcomes of the Regional Planning Process, among other inputs described in Section 5.3. The load forecast allows Elexicon to understand whether and how its system demand is expected to evolve over the forecast period and optimize capital expenditures accordingly. The Reliability Analysis allows Elexicon to determine how system capacity and operability enhancements can help affect the reliability performance as well. The outcomes of the Regional Planning Process may also influence investments in this category by identifying opportunities for potential planning or execution synergies. As discussed in Section 5.3, Elexicon is also piloting a number of new tools and processes seeking to significantly enhance its reliance on risk-based asset intervention planning.

Forecast expenditures for this investment category are consistent for all years except for 2022 when expenditures will increase substantially to $41.4 million to accommodate the planned construction of the new Seaton TS – Elexicon plans to request funding for this initiative through a dedicated ICM filing.

A detailed analysis of the historical and forecast program-level expenditures is provided in Section 5.4.3.1.1. Over the forecast period, there are significant planned investments only in the Substations Growth and Expansion, SERC, and System Reliability Improvements programs.

General Plant

The General Plant investment category includes in upgrade or renewal of non-distribution system assets such as Elexicon's office and warehouse facilities, vehicles, tools, and IT hardware/software. There are three drivers within this investment category: non-system physical plant, capital/maintenance support, and business operations efficiency. This category includes five programs which are listed and described below.

- *Facilities* – this program is intended to maintain, renovate, or upgrade facilities assets such as buildings, furniture, and lighting systems.

- *Fleet* – this program allows Elexicon to maintain and procure vehicles used to perform routine and specialized work.

- *Information Technology* – this program funds the procurement or upgrades of IT software and hardware which is essential for the completion of back-office tasks such as planning, engineering analysis, and customer service.

- *Intangible Assets* – this program includes miscellaneous investments such as the purchase of land rights and capital contributions to other utilities.

- *Tools and Equipment* – this program allows Elexicon to maintain or procure the tools and equipment staff use to perform their work.

General Plant investment planning is based on individual assessments for the four sub-classes of General Plant Assets: IT, Tools and Equipment, Facilities, and Fleet. The IT assessment is based on consideration of operational needs, IT lifecycles, and anticipated growth. The Tools and Equipment assessment accounts for operational needs, Electric Utility Safety Rules ("EUSR"), and age and condition data. 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 facilities 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. See Sections 5.3.1 and 5.3.3 for additional information on Elexicon's General Plant asset lifecycle management and analytics activities.

Forecast expenditures for General Plant programs are relatively consistent after 2021. Over the first two years of the forecast period, there is an expected increase in expenditures due to a planned effort to consolidate and upgrade software systems as a result of the merger. There is also an increase in expenditures expected in 2023 as several fleet assets are expected to reach EOL and require replacement. Elexicon does not expect to receive any contributions for investments within this category. A detailed analysis of the historical and forecast program-level expenditures is provided in Section 5.4.3.1.1.

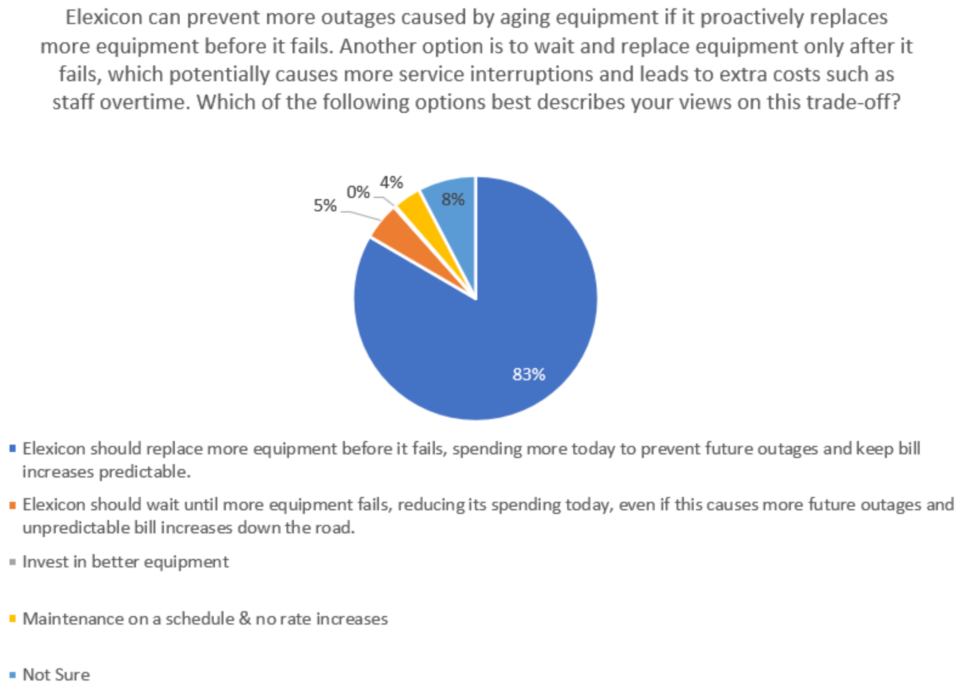
5.2.1 b) Overview Customer Preferences and Expectations

Elexicon had two methods for its customer engagement survey: online survey and phone survey. For the online self survey 262 customers responded. The online survey was conducted between October 26th and December 13th, 2020. The phone survey had 600 respondents of which 524 were residential, 70 were small business, and 6 were large business customers. The phone surveys were conducted between November 20th and December 4th, 2020.

Overall customers are satisfied with Elexicon. Most respondents stated they had no concerns; for those with concerns the most cited issues were reliability and service cost. Responses aside from reliability and cost cited concerns of outdated infrastructure and long customer service waits. Additionally, the majority of respondents found Elexicon's standard of reliability was satisfactory.

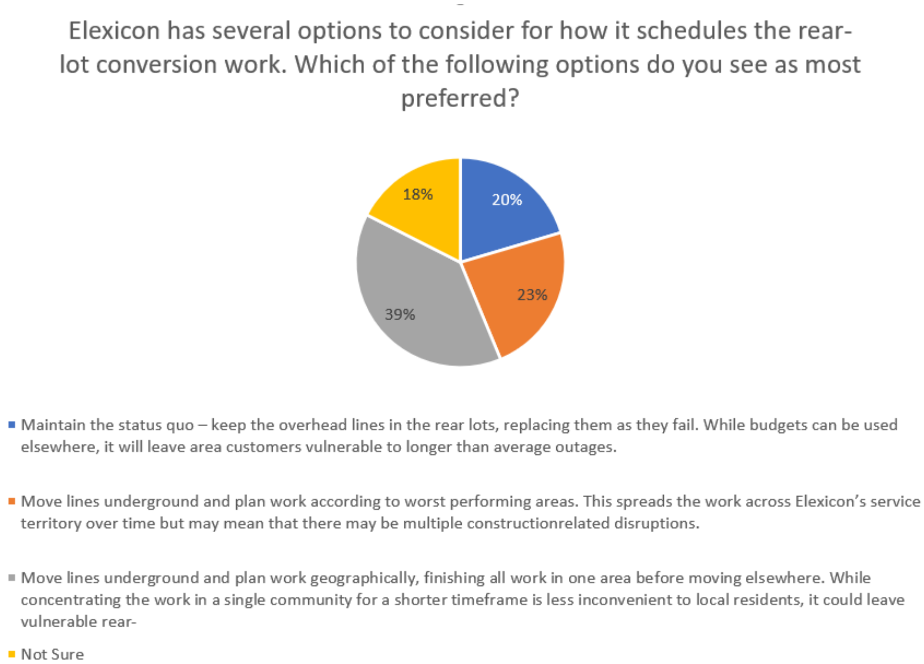
- Customers support the proposed plan for Seaton TS. Elexicon has considered this in their DSP under the System Access section, with the Seaton TS project.
- Customers support proposed Underground System Relocation in Pickering to enable Regional Bus Rapid Transit. Elexicon has considered this in their DSP under System Access, Road Relocation program.
- Customer's support "proactively [replacing] more equipment before it fails." Elexicon has accounted for this in their DSP by allocating more funds to System Renewal than in the historical period, with the majority of these funds budgeted towards proactively replacing Assets at the End of their Service Life as opposed to reactively responding to Asset Failures.

Figure 5.2-2: Customer Survey Response on Equipment Replacement



- Customer's support moving overhead power lines underground. Elexicon has considered this in the System Renewal portion of their DSP.

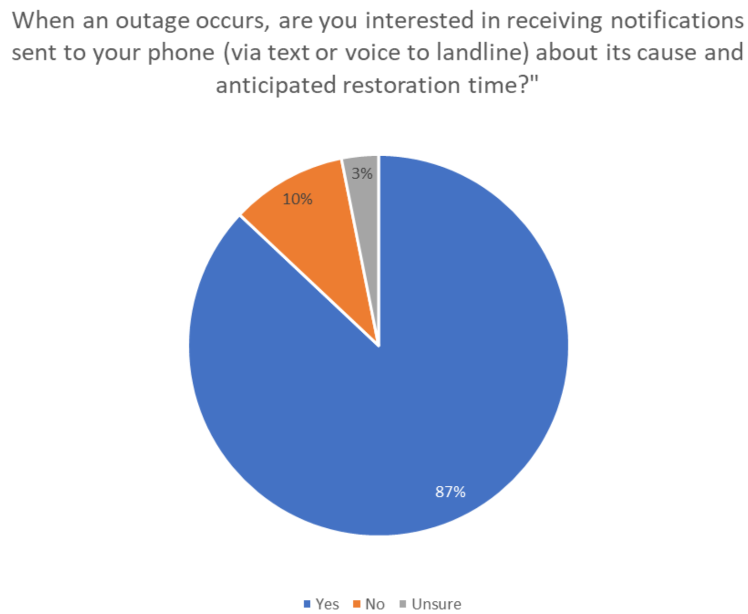
Figure 5.2-3: Customer Survey Response on Moving Lines Underground



- Customers are interested in "an outage notification system by text or voice." Elexicon has considered this in their DSP by allocating more funds to General Plant, specifically Information

Technology, in the upcoming period. Elexicon plans on updating their software as part of the merger.

Figure 5.2-4: Customer Survey Response on an Outage Notification System



- "In addition to keeping the system safe and accommodating new growth in the coming years" customers felt Elexicon should focus on "Improving the grid's resilience to major weather events, like storms, etc." Elexicon has considered this in their DSP by allocating more funds to General Plant, specifically Information Technology and Operation Technology, in the upcoming period.

Figure** 5.2-5**: Customer Survey Response on What Elexicon Should Focus On

Please choose two of the following objectives that you think Elexicon should focus its efforts on,in addition to keeping the system safe and accommodating new growth in the coming years.

	First mention	Second mention	Combined
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	31%	31%	31%
Preparing the grid for new types of uses, like electric vehicles and renewable generation	23%	11%	17%
Investing now in things that will help reduce rate increases after 2029	12%	20%	16%
Minimizing the impact of power outages	6%	20%	13%
Helping customers manage their electricity use	10%	9%	10%
Reducing the environmental impact of Elexicon's operations	11%	5%	8%
Improving power quality	4%	3%	4%
Addressing customer requests faster and more efficiently	2%	1%	2%

- Customer's support "investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage" and felt Elexicon should focus on "Preparing the grid for new types of uses, like EV's & renewable generation." Additionally, Elexicon found a little under half of the customers surveyed are considering purchasing an electric vehicle in the next 5 years. Elexicon has considered this in their DSP by allocating more funds to General Plant, specifically Information Technology and Operation Technology, in the upcoming period.

Figure 5.2-6: Customer Survey Response on Investing in EVs & Renewable Generation

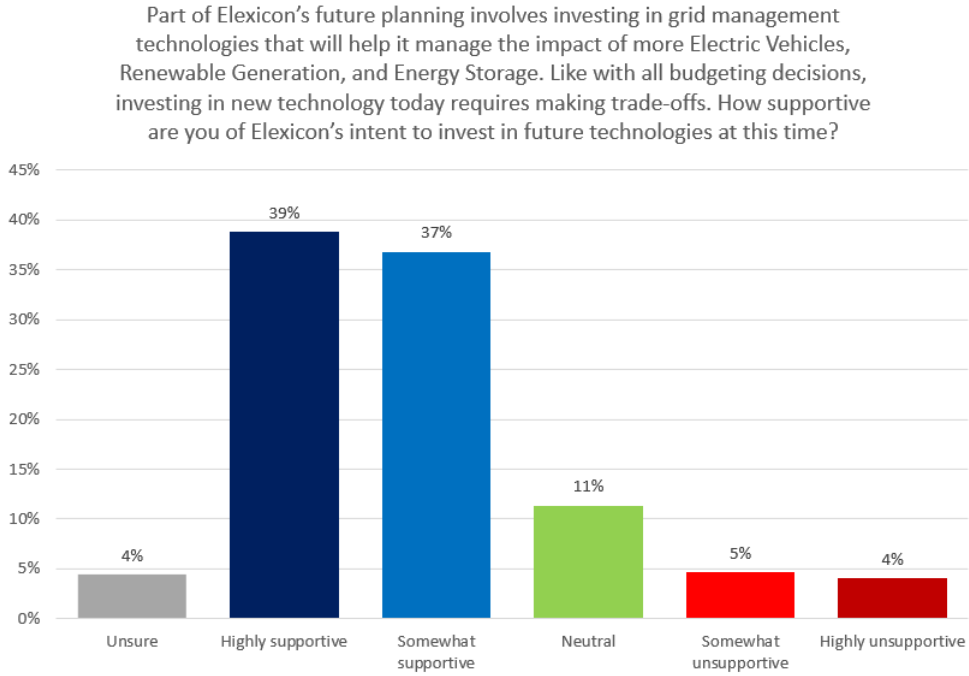
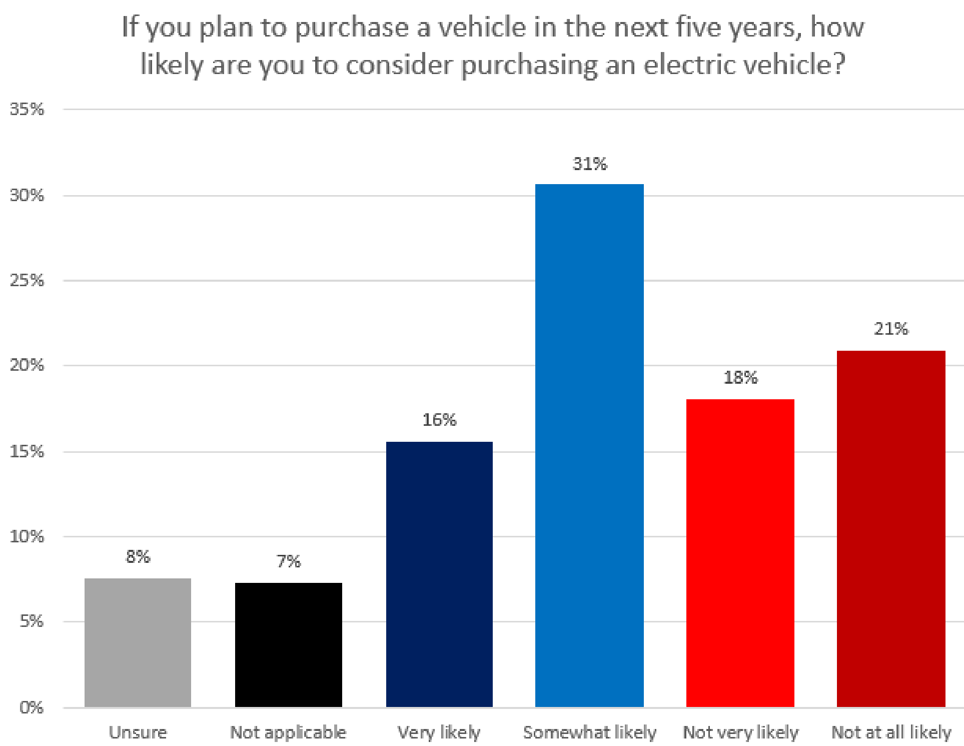


Figure** 5.2-7**: Customer Survey Response on Purchasing an EV



- Customers support the plan to Accommodate the Move of the Belleville Operations Centre. Elexicon has considered this in their DSP in the General Plant, Facilities planned capital expenditure.
- Over half of the customers were satisfied with the planned allocation of funds remaining from funds spent on customer growth. Elexicon has considered this in the DSP.
- When questioned on what objectives Elexicon should focus on (as seen in Figure 5.2-5) 54% of customers who are dissatisfied with reliability listed minimizing outage impacts in their top two priorities.
- Customers had more concerns over the duration of outages as compared to the frequency of outages. Elexicon has considered this in the DSP by updating a custom measure in the DSP that tracks SAIFI for only defective equipment cause codes, this can be seen in section 5.2.2.4 Custom DSP Measures. This has been updated to track SAIDI for only defective equipment cause codes.

Through Elexicon's customer engagement, certain factors such as reliability and cost have been identified as concerns at the residential and business levels. Most customers are satisfied with Elexicon's current level of reliability. Elexicon uses the information derived from customer engagement pieces to ensure its decisions are aligned with customer preferences and that its decisions are valid based on the customer feedback generally.

In addition to leveraging customer needs, priorities, and preferences from survey results to make capital planning decisions, Elexicon also took customer feedback into consideration when designing custom performance measures as part of this DSP. Originally, Elexicon created a performance measure tracking SAIFI due to defective equipment. Due to the finding that customers are more sensitive to the duration of outages, however, compared to the number of outages they experience, this measure was changed to cover defective equipment SAIDI instead.

5.2.1 c) Anticipated Sources of Cost Savings

Consistent with its Operational Excellence strategic pillar, Elexicon is committed to identifying and executing on opportunities for cost efficiencies across all facets of its operations. Having recently undergone a merger, the utility has been given an opportunity to compare the approaches used by its predecessors and define the course for merged operations – by either following one of the predecessors' strategies, integrating the elements of both, and/or adopting new practices identified through industry research.

Embedding operating and capital cost efficiency and effectiveness into the merged operations is among the key objectives underlying the ongoing consolidation efforts. However, when assessing potential synergies, Elexicon considers them on balance with other key considerations, such as maintaining or improving service quality, ensuring health, safety and wellness of its labour force, and delivering on other strategic commitments like economic development and operational sustainability. As such, decisions to pursue specific cost savings opportunities are made in the context of careful trade-off analysis, where financial performance is considered alongside other considerations that make Elexicon's corporate identity. The following passages provide an overview of the areas where operating synergies are expected to materialize over the Forecast Period.

<u>Merger-Driven Cost Synergies</u>

As disclosed in Whitby Hydro and Veridian's Mergers, Acquisitions, Amalgamations and Divestures ("MAADs") Application, the predecessors expected the merger to present opportunities for 10-year

OM&A savings of approximately $48.8 million.[3] At this juncture, the utility is in process of identifying and executing on the available synergies, with progress to date originating from the following areas:

- Office of the CEO and Executive Team;
- Asset Management;
- Corporate Services;
- Customer Experience;
- Finance;
- Information and Operational Technology ("IT/OT"); and
- Operations.

Sources of Operating Efficiencies

The majority of achieved and forecasted OM&A cost savings come in the form of avoided labour costs enabled by the merger. This includes the efficiencies stemming from streamlining the Executive Team, Board of Directors, and other duplicative positions, along with avoiding a material portion of third-party the regulatory application costs that would otherwise be required for both predecessors.

Other examples include the savings through optimization of the use of internal and field contractor labour. For example, while it has been determined that it is more efficient for the new entity to outsource all line patrol work, the available in-house former Veridian capabilities can absorb the meter and fleet maintenance activities that were formerly contracted by Whitby Hydro. Similarly, the utility expects to realize material efficiencies through a consolidated Vegetation Management contract that leverages the combined scale to yield lower unitized costs of tree trimming work. Additional savings are expected from expanded use of technology in operations, which is expected to reduce the manual effort and increase overall task throughput rates.

Other areas with OM&A savings potential include the Customer Experience and IT/OT, where consolidation of activities such as bill printing and notice issuances and streamlining of internal and customer-facing technology requirements are creating operating synergies through increased scale economies and reduced software and hardware maintenance requirements and licensing costs. Among the examples of IT/OT areas with opportunities for maintenance savings is the consolidation of the GIS and the vehicle communications capabilities, which are either being reconfigured for use of Veridian's existing systems or are planned to be replaced with net new technology procured for the merged utility. Customer facing software savings result from the avoidance of software upgrades and reduced licensing costs for applications such as the Customer Information System ("CIS") and the Operational Data Storage ("ODS").

Sources of Capital Efficiencies

Aside from the OM&A cost savings Elexicon is also identifying opportunities for multiples capital-related sources of savings. Chief among them is the deferral of station capacity expansion in the legacy Whitby Hydro area, by utilising the available transformation capacity in the nearby part of the legacy Veridian service territory. While tapping into the available capacity requires construction of new express feeders, the project nevertheless results in net cost savings, increases the utilization of previously built assets, reduces the overall station footprint, and enhances system operability through inter-area load transfer capabilities.

[3] Ontario

The integration of the predecessors' asset lifecycle management best practices is also creating opportunities for capital cost deferral through enhanced preventative maintenance work. One such example is the adoption of the legacy Veridian practice of underground cable testing and undertaking cable injections to repair the suitable candidates. Expanding this practice into the former Whitby Hydro service territory is expected to generate opportunities for underground asset lifecycle extension, and associated deferral of System Renewal investments.

Changes in IT/OT activities driven by the merger are another source of anticipated capital cost savings. These synergies stem from the reduction of planned SCADA upgrade investments made partially duplicative by the merger, and extension of more advanced capabilities previously available to one of the two predecessors over the new service territory. A related source of efficiencies stems from recent consolidation of the two former control rooms in a single facility that now oversees the entire service territory and is expected to increase its operational capabilities through targeted investments into smart technologies.

Anticipated Sources of Cost Efficiencies Unrelated to the Merger

Aside form the above-noted activities associated with the operational consolidation of the predecessor utilities, Elexicon expects to leverage several other important sources of cost efficiencies over the Forecast Period, including:

- *Mandated Work Synergies*: when Elexicon is required to relocate its existing overhead or underground infrastructure to enable the work undertaken by third parties (e.g., transit expansion), the utility typically replaces and/or upgrades the assets subject to relocation, provided they are not re-usable assets. In a similar manner, Elexicon attempts to align renewal programs with system growth programs. In both cases, Elexicon attempts to maximize the value of customer contributions to enhance the overall health and capacity of its system.

- *System Reliability Improvements*: a subset of Elexicon's planned capital investments targets improvement of system reliability through targeted deployment of technology, including upgrades to the SCADA infrastructure and implementing system automation to help identify and rectify the outages faster and more efficiently. These technologies are expected to help Elexicon reduce lost revenue through faster response/restoration, reduce the number and cost of truck rolls, and collect more nuanced operating data.

- *Incremental Benefits of Metering Fleet Renewal*: as Elexicon renews its Smart metering fleet to comply with the requisite Measurement Canada requirements, it expects to leverage some additional benefits inherent in newer technology. New metering units are expected to allow Elexicon to improve outage response time, as the last gasp functionality and fault/outage detection capabilities allow the utility to better understand the extent and origin of outages. Additional features such as remote disconnect, tamper detection, and voltage monitoring are also expected to help avoid certain labour expenditures, truck rolls and revenue losses.

- *Elimination of Obsolete / Legacy Infrastructure*: among the System Renewal programs planned for the Forecast Period are the feeder voltage conversion projects and continued conversion of rear-lot overhead infrastructure to front-lot underground services. Both programs target facilities built to legacy construction standards and collectively target multiple benefits beyond improving reliability. These include supply chain efficiencies through reduction of non-standard equipment, reduced distribution losses, and reduced potential for employee and public safety incidents associated with rear-lot feeders.

5.2.1 d) Period Covered by DSP

The historical period for this DSP covers the years 2014 to 2020. The year 2021 is the Bridge Year, while years 2022 to 2026 constitute the Forecast Period. As noted earlier, since this DSP is not being submitted in the context of a Cost-of-Service Application the Forecast Period years are not denoted as Test Years.

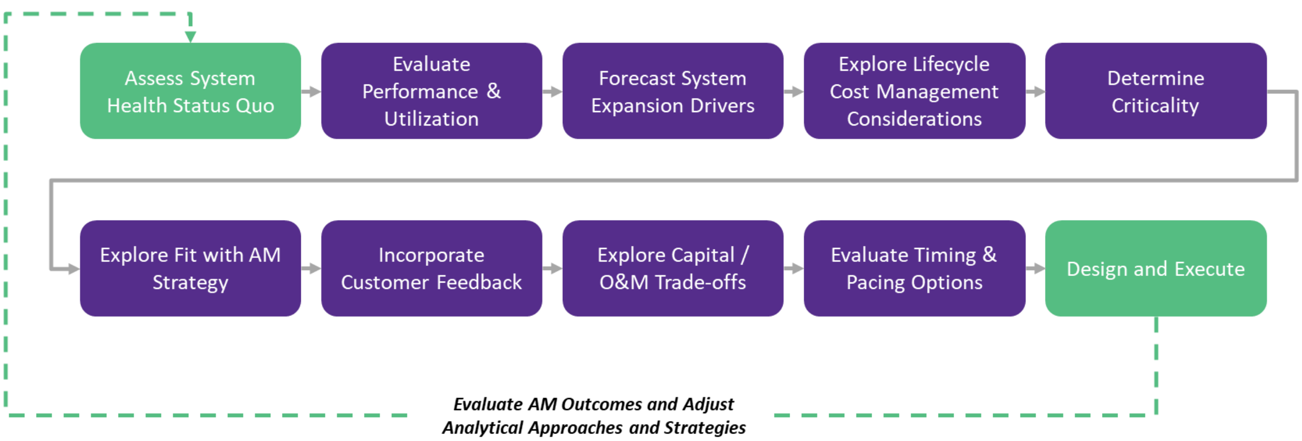
5.2.1 e) Vintage of the Information

The information presented in this DSP is considered current as of January 1st, 2021.

5.2.1 f) Important Changes to Asset Management Processes

This is the first DSP filed by Elexicon as a merged utility. As such, the identification of important changes to the AM Process is completed through a comparison to the predecessor utilities asset management processes. Elexicon's consolidated asset management process draws elements from both predecessor utilities. Given the relative recency of commencement of merged operations, much of the system investments made in the first two years drew extensively on the investment plans prepared by the predecessor utilities, as the new entity was required to maintain the service standards from the first day of its operation. While the need for many projects planned over the Forecast Period was also originally identified by Elexicon's predecessors, these investments have increasingly undergone evaluation using the new analytical and investment planning tools and processes that have been put into place over the past two years.

Figure 5.2-8: Elexicon's Asset Management Process



First and foremost, the utility has re-defined the scope and sequencing of activities that comprise the Asset Management process itself. Figure 5.2-8 captures the new definition of the AM Process comprised of 11 stages that capture how various data inputs related to current and anticipated state of the system and non-system assets are gradually transformed into actionable candidate projects that are ultimately executed in the field. The revised process and its component stages and activities are described in more detail in Section 5.1.3 and represent the product of a dedicated effort on the part of Elexicon's management to review the current state of its AM Processes relative to emerging industry practices and the objectives of the newly merged utility.

As a part of redefining its AM Process itself, Elexicon has taken multiple decisive steps to integrate and enhance its actual analytical capabilities supporting the asset management and capital planning work. These include the following initiatives in various stages of implementation:

Consolidated Asset Condition Assessment ("ACA") – a comprehensive ACA study completed by METSCO Energy Solutions Inc. ("METSCO") that provided Elexicon with the first consolidated view of its asset health using a consistent methodology, and outlined recommendations for additional data collection efforts, including approaches to prioritizing this work (See Appendix F). While both predecessors have performed ACA studies in the past, the integrated ACA provides a consistent reference point for work prioritization and further process refinements.

- A new corporate *Risk Management Policy* (currently under development), which will lay out Elexicon's strategy in identifying and addressing the variety of risks it may face. Once finalized and adopted, the new corporate Risk Management Policy will also enable further optimization of capital expenditure planning – through planned and currently piloted implementation of more specific risk-based asset management tools and processes, which must be grounded in and consistent with the overall Risk Management Policy.

- A new *AM Objectives Framework* that builds on Elexicon's Strategic Pillars and the OEB's RRF Outcomes Framework and explicitly defines and prioritizes among nine asset performance outcomes related to both electrical and general plant assets. In setting the AM Objectives, Elexicon's ELT relied on an objective Pair-Wise Comparison / Analytical Hierarchy Processes to limit the degree of assessment subjectivity and ensure that each objective is explicitly considered relative to others (See Section 5.3.1a)

- A consolidated *Capital Business Case* format specifically designed to apply to both distribution infrastructure and general plant assets, with an added emphasis on evidence-based decision-making. While the currently available amount of empirical / quantitative evidence supporting each program varies materially, the objective of the new format is to encourage the increasing reliance on quantifiable support of investment decisions and an approach to investment planning grounded in consideration of opportunity cost of capital.

- A new *System Load Forecasting* approach that integrates a "top-down" econometric and a "bottom-up" engineering analysis to establish the range of potential load growth projections, along with robust procedures to validate and enhance the underlying models based on ex-post variance analysis of actual outcomes relative to the forecasted growth.

- *Piloted Introduction of Risk-Based Planning and Connectivity Based Electrical Plant Prioritization* approaches that are consistent with industry-leading AM standards such as ISO-55000x group of standards. Among other initiatives, this work includes the derivation of asset-class specific failure probability curves based on the actual failure data collected by one of the predecessor utilities. While these initiatives (discussed in Section 5.3.1a) are still in the pilot / exploratory stages they constitute important steps forward towards a risk-based asset management process.

- *Integration of Asset Lifecycle Management Approaches* – Elexicon's predecessors relied on different types of asset lifecycle management activities associated with several asset classes. For instance, while Whitby Hydro replaced underground cables based on age and historical failure rates, Veridian undertook cable testing and life extension work through cable injection. Since Veridian's use of this refurbishment work generated positive results, Elexicon will adopt this practice across its service territory where doing so is economic. See Section 5.3.3 for other examples of changes to asset lifecycle management.

- *Consolidation of Asset Inspection Cycles* – as shown in Table 5.2-3, and discussed in more detail in section 5.3.3 Elexicon has consolidated the scope and frequency of inspection activities across all major distribution asset classes for consistency, better operational efficiency and asset data collection discipline.

Electrical Plant

Table 5.2-3: Summary of Changes to Asset Class Inspection Cycles for Electrical Plant

Asset Class	Legacy Veridian Cycle	Legacy Whitby Cycle	Elexicon Cycle
Wood Pole	8 years	3 years	3 years
Concrete Pole	None	3 years	3 years
Overhead Conductor	None	None	3 years
Pole-mounted TX	None	3 years	3 years
Pad-mounted TX	3 years	3 years	3 years
Overhead Switch (LIS Type)	3 years	3 years	3 years
Overhead Switch (non-LIS Type)	None	3 years	3 years
Distribution Switchgear	3 years	3 years	3 years
Underground Cable	None	None	None
Vault Transformer	3 years	None	3 years
Station Power Transformer	1.5 years	3 years	3 years
Station Circuit Breaker	1.5 years	3 years	3 years
Station Battery	1.5 years	3 years	3 years
Station Protective Relay	1.5 years	3 years	3 years
Building/Fence	None	None	None

General Plant

Moving to the General Plant assets, there are several changes to the Asset Management process related to IT/OT assets. Prior to the merger, Whitby Hydro and Veridian Connections employed contrasting approaches which are being merged to leverage the relative strengths of each predecessor utility. While Whitby Hydro outsourced a large portion of work related to IT/OT infrastructure, the former Veridian focused on maximizing its in-house development capabilities. Moving forward, Elexicon plans to make use of the in-house development infrastructure established by Veridian but will retain flexibility in decisions regarding the use of internal or external resources where most commercially and operationally advantageous.

Elexicon is in the process of consolidating the legacy software systems (e.g., implementation of a vendor neutral ADMS) and transitioning to digital processes where possible. Elexicon has commenced the implementation of a Configuration Management Database ("CMDB") which tracks information about software systems such as licensing, upgrades, and vendor support. Previously, IT software management was completed through a fluid and partially decentralized decision-making process, where procurements and upgrades were completed as required. Moving forward, the CMDB will allow Elexicon to transition to a more centralized and proactive approach as it will provide the utility with key information about software lifecycles. Elexicon also plans to integrate IT hardware assets into the CMDB in the future.

For other General Plant asset classes, and as noted earlier, the introduction of a consistent Business Case format that emphasises the objective, evidence-driven decision-making is expected to further drive the culture of operational data collection and analysis to further enhance the rigour underlying investment activities in these areas.

5.2.1 g) DSP Contingencies

Successful execution of the capital work program comprising the current DSP is contingent on a number of internal and external factors over which Elexicon has varying degrees of control. These factors are discussed in the passages below.

Weather / Climate Related Challenges

Among Elexicon's planned investment, there are multiple projects which involve the completion of outdoor field work such as asset replacements, new service connections, and other types of construction and maintenance projects. A subset of these projects also requires coordination with third parties such as road relocations, scheduled outages, and customer locates. Elexicon's ability to successfully complete these planned projects may be impacted by local, sub-regional or regional system constraints that may emerge due to extreme weather such as abnormally high levels of precipitation or atypical seasonal temperatures. Should prolonged and atypical heat waves or storm activity affect certain portions of Elexicon's fragmented and expansive distribution system, the utility may be required to reallocate expenditures to address high-priority needs. Elexicon has a budget prioritization process which allows it to objectively assess and prioritize projects and provide optimal value from the available budget.

Customer and Third-Party Request Variability

Elexicon's ability to complete the investment programs outlined within this document may be impacted by the volume of external requests it receives from current or prospective customers and third parties such as municipalities, the Region of Durham, and Metrolinx. These requests include work such as new service connections, asset relocations, and other customer requested work. The planned level of expenditures for programs which fund this work is significant and subject to variability. For example, Elexicon anticipates a significant increase in expenditures in its Road Relocations program in 2021 (from $5.61 million to $24.0 million) due to a high volume of Metrolinx-driven relocation projects.

Should new requests emerge over the Forecast period, Elexicon would be required to reallocate the available funding from other planned projects. Alternatively, should the anticipated timing and volumes of work change due to the circumstances outside of the utility's control, Elexicon would be required to identify and execute other planned projects. To manage the inherent variability associated with these types of investments, Elexicon will work with the requesting parties and other affected stakeholders to reasonably accommodate all requests as per the Distribution System Code ("DSC").

Regional Electricity Infrastructure Requirements

Elexicon participates in five regional planning groups to coordinate identification and addressing of regional infrastructure activities coordinated by Hydro One and the Independent Electricity System Operator ("IESO"). These consultations involve several stakeholders whose needs and planning assumptions inform the content of the regional planning processes and the final regional infrastructure plans. Elexicon's ability to complete the planned investment programs outlined in this document may be affected by the recommendations of regional infrastructure plans as some outcomes can have a significant impact on the capital expenditure plan.

For example, the future plans regarding Ontario Power Generation's ("OPG") Pickering Nuclear Generating Station may have implications for station capacity both upstream and within the Elexicon service area. As these and other developments materialize over time, Elexicon will work to re-prioritize its planned expenditures to the degree permissible by operational and financial constraints while considering all rate funding options at its disposal. It is expected the infrastructure planning in this region will be re-evaluated in 3-5 years.

Merger-Related Contingencies

The investment plan outlined in this DSP reflects Elexicon's current level of integration between the two predecessor utilities. Elexicon is diligently consolidating all legacy systems and practices to achieve a balance between operational and cost efficiency by optimizing the use of legacy resources. There is a portion of this integration effort which has yet to be completed and may impact the planned investment programs over the forecast period. Major considerations which are subject to change include anticipated cost savings, asset lifecycle optimization policies and practices, customer engagement program, and risks. As Elexicon continues its integration effort, it may discover additional efficiencies which may assist in the minimization of ongoing costs.

The predecessor utilities applied different asset lifecycle optimization policies and practices, and Elexicon is currently in the process of finalizing its consolidated approach. While no major changes in planned expenditures are expected as a result of this consolidation effort, there is potential for the introduction of new practices which could impact the forecasted budget.

In addition, the investment programs outlined in this DSP reflect Elexicon's current understanding of the technical, environmental, and safety issues inherent in the recently integrated distribution system. Should further analytical or operational activities identify any incremental risks that warrant mitigation through near-term capital investments, Elexicon may amend the currently forecasted mix of capital investments to accommodate the emerging needs as per its investment prioritization process.

Property Rights and Access-related Considerations

Certain construction and maintenance activities over the forecast period may require Elexicon to obtain access or easement rights with respect to public or privately owned lands. Should Elexicon be unable to secure these access rights within the timelines contemplated in the project plans it may adjust the project timelines or explore alternative locations or asset configurations as appropriate.

Impact of COVID-19

Given the ongoing circumstances of the COVID-19 pandemic, there is a degree of uncertainty surrounding Elexicon's ability to execute the planned investments and conduct certain types of planned O&M activities. Currently, the expected duration of restrictions imposed by the local and provincial authorities is unclear. As a result, the long-term impact of the pandemic is difficult to estimate accurately, and Elexicon continues monitoring the situation and the anticipated near-term impact.

The COVID-19 pandemic has had minimal impact on Elexicon's ability to perform indoor functions such as planning, engineering analysis, and customer service as these operations can be completed remotely. While additional General Plant investments were required to enable remote work, no major challenges arose to date or are expected in the near term. Among the incremental investments that Elexicon is required to make due to COVID-19, there are efforts to ensure the safety of staff that must be in the office such as control room operators. These investments completed in 2020 and planned for 2021 amounting to $0.45 million – example projects include laptop purchases and facility upgrades.

The pandemic has had more significant impact on completion of field work such as construction, asset inspections, and asset replacements which can require multiple employees working in close proximity.

Elexicon prioritizes the safety of the public and its employees and aims to comply with Federal and Provincial restrictions regarding indoor and outdoor gatherings.

Other Contingencies

Other contingencies that may affect Elexicon's execution of the current DSP include but are not limited to the following events that may affect its capital work planning or execution abilities or priorities:

- Government and OEB policy amendments;
- Changes to technical industry standards or planning assumptions as a result of ongoing analytical work or externally mandated changes; and
- Higher-than anticipated uptake in emerging technologies such as electric vehicles and storage, which could warrant additional expenditures to support system operability.

Elexicon understands these eventualities and will actively manage them through regular engagements with policymakers, industry organizations, employees, customers and the contractor community.

5.2.1 h) Grid Modernization, Energy Resource, and Climate Change Adaptation

Table 5.2-4 below identifies investment programs which support grid modernization, energy resources, or climate change adaptation.

Table 5.2-4: Summary of Grid Modernization Efforts

Category	Program	Description
System Access	Connection of New Services	The Connection of New Services program provides funding for the installation of new service connections. As new facilities (reflecting the latest construction standards and equipment features) are added to the system, the system's overall health and operational capabilities typically improve. As noted earlier, when planning for new customer connections and/or ensuing capacity enhancements, Elexicon ensures that the mandated work maximizes the benefits to the grid overall by considering potential upgrades or configuration modifications that could be economically accommodated in the scope of work.
	Metering	Installation of a new generation of Smart Meters provides additional functionalities such as remote disconnect, tamper detection, outage detection, and improved data collection. These new tools that come standard in newer models enable the utility to derive incremental insights regarding the system's performance, learn more about system reliability drivers, and leverage operating efficiencies.
System Renewal	All Programs	As aged and deteriorated assets are replaced with new equivalents or are refurbished to extend their lifespans, Elexicon's overall system becomes more modernized, as newer assets reflect the most recent construction standards, are manufactured from more durable materials, or include new or expanded functionalities.
System Service	SERC	Elexicon explores operational and system improvements through the SERC program. The utility analyzes historical data (e.g., reliability data, equipment failure data) and evaluates standards to facilitate continuous improvement. These improvements can support grid modernization, energy resources, and climate change adaptation. For example, the studies conducted in this program have helped improve the resiliency of distribution system assets to weather events through investment activities such as system hardening.

Category	Program	Description
	System Reliability Improvements	This program is intended to fund efforts to improve reliability performance and includes the installation of devices such as FCIs and TripSavers, which improve the utility's ability to identify the extent of outages and complete restorations quicker and more efficiently.
General Plant	Facilities	Environmental benefits are realized from any facilities projects geared towards energy efficiency. A decrease in emissions and wasted energy can be produced from further facility investments. Currently, Elexicon engages in energy efficiency initiatives to decrease the amount of energy consumption within facilities.
	Fleet	Newer vehicles have improved fuel efficiency compared to older and deteriorated vehicles. Where possible, Elexicon evaluates the opportunity to replace conventional vehicles with electric vehicles.
	Information Technology	The Information Technology program provides funding for the procurement or upgrade of software applications or hardware assets. These investments introduce new capabilities to Elexicon's operations and position the utility to improve its efficiency and service delivery. In addition, this program includes research and development projects through which Elexicon identifies potential investments based on emerging technologies that would improve operational performance, customer satisfaction, and cost efficiency. Certain investments in this category such as the ADMS project support grid modernization, energy resources, and climate change adaptation.

Note: The Long-Term Energy Plan is not currently active.

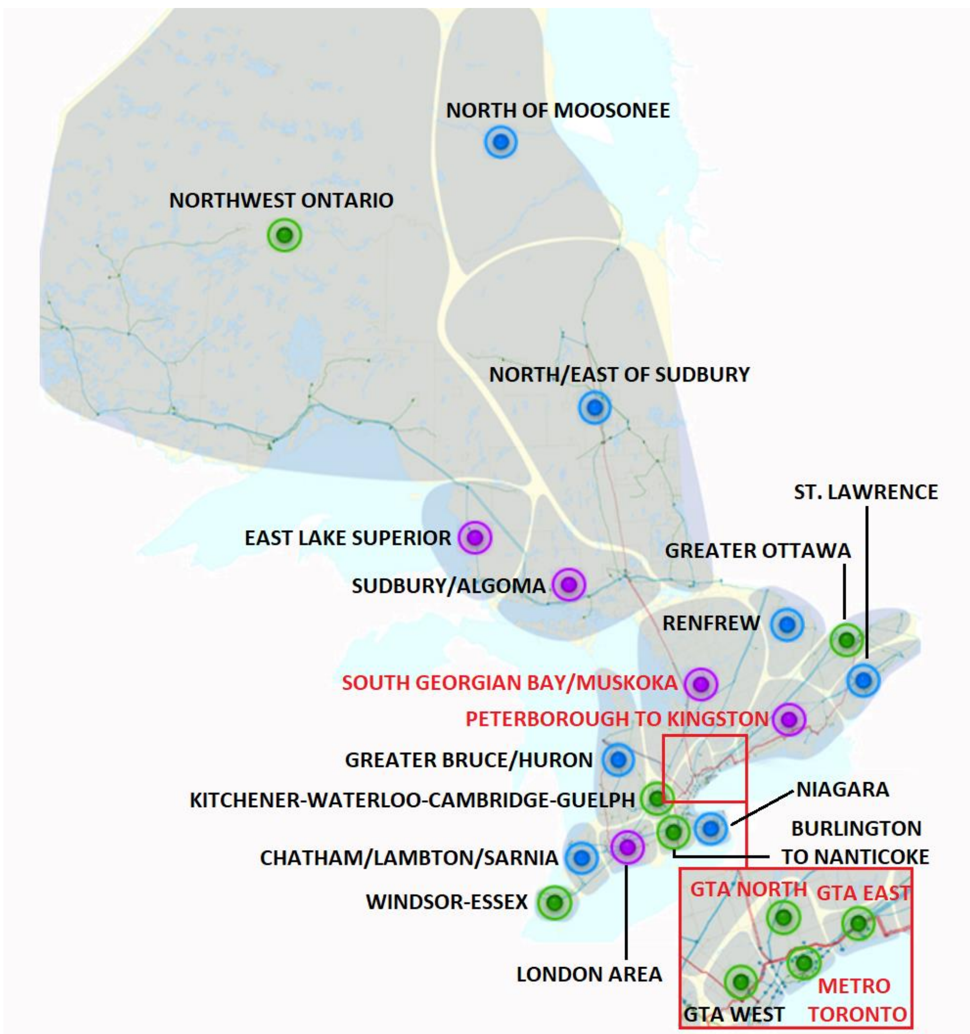
5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Regional Planning Process

The Regional Planning Process is a multi-phase cyclical coordination effort which can consist of the following phases: Needs Assessment ("NA"), Scope Assessment ("SA"), Regional Infrastructure Plan ("RIP"), and the Integrated Regional Resource Plan ("IRRP"). There are several regional planning zones which correspond to different areas in Ontario (see Figure 5.2-9) – each with an independent Regional Planning Process. Given that Elexicon has a widespread, non-contiguous service territory, it participates in the Regional Planning Process for five zones:

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

Figure 5.2-9: Overview of Regional Planning Zones in Ontario



The Regional Planning zones that Elexicon participates in have most recently completed the NA or RIP phase. Key information about these consultations such as the purpose, role of Elexicon, key inputs, and final deliverables is provided below. Additional details about the most recently completed phase for each planning zone are provided in the following subsections.

Needs Assessment

Purpose – The purpose of the NA phase is to identify new needs and/or reaffirm needs from the previous cycle. This is accomplished through discussion and technical assessments of system capacity, reliability, operation, and aging infrastructure. The participants review options for these needs, develop a preferred plan, and/or recommend which needs require further assessment or regional coordination.

Role of Elexicon – Elexicon provides key information which is used to identify needs and conduct technical assessments of system capacity, reliability, operation, and asset condition. The utility shares its perspective on the outcomes of technical assessments, discusses options for addressing needs, and provides recommendations regarding additional coordination efforts.

Key Inputs – The utility provides a substation level load forecast which is used in conjunction with the IESO's CDM and DG projections to create a net load forecast at the transmission station level. Participating LDCs also provide relevant information about system reliability, operational issues, and HV transmission equipment requiring replacement or refurbishment.

Final Deliverables – The final deliverable associated with the NA consultation is a NA report which summarizes key information such as background, assessment methodology, and needs. The report also provides recommendations for the optimal planning approach (e.g., RIP, IRRP, or Local Plan) to address needs.

Regional Infrastructure Plan

Purpose – The purpose of the RIP phase is to summarize needs and develop the associated wires plans, including new needs that may have emerged since the start of the planning cycle. This consultation identifies investments in transmission and/or distribution facilities that should be implemented on a coordinated basis to meet regional electricity infrastructure needs.

Role of Elexicon – Elexicon collaborates with other participants to finalize needs, develop alternatives, and provide recommendations. The utility shares new information which may lead to the identification of new needs and provides its perspective during the development of alternatives and recommendations.

Key Inputs – Given that the primary purpose of the RIP phase is to develop solutions to address needs identified in the NA phase, the key inputs are largely consistent with those described in the NA phase. However, the participants may provide updated version of the inputs (e.g., Load Forecast) to account for new needs that may have emerged since the beginning of the cycle.

Final Deliverables – The final deliverable associated with the RIP phase is a RIP report which summarizes key information about the process such as the final set of needs, alternative wires plans/solutions, and recommendations.

5.2.2.1.1 GTA East

Figure 5.2-10 below depicts the GTA East planning region. The participants completed the first cycle of the process in January 2017 with the publication of the RIP report. Hydro One initiated the second cycle with the NA phase and the participants subsequently pursued the RIP phase only. The RIP consultation is the most recently completed stage of the process as it concluded with the publication of the RIP report in February 2020. Table 5.2-5 below provides a summary of the needs discussed and resulting outcomes. Among these discussion points, the need for additional capacity in the Pickering-Ajax-Whitby sub region is the only one which has a material effect on Elexicon's DSP.

The Pickering-Ajax-Whitby sub region is supplied by Cherrywood TS at 44-kV and Whitby TS at 27.6-kV. There is a need for additional transformation capacity in this region as there is an expected load increase of 2.9% annually over the next 10 years. In addition, the development of a new residential and mixed-use commercial area in the Seaton region will increase load demand at 27.6-kV. These factors are expected to result in a shortage of transformation capacity at Whitby TS by 2021. The recommended solution involves Elexicon proceeding with the construction of a new Seaton MTS. Although this station was planned to be in service by Q1 2020, external factors have delayed the initiative – the construction is currently planned for 2022 and is categorized within Elexicon's Substation Growth and Expansion investment program. In addition, there are planned projects to support the construction of Seaton MTS in the Connection of New Services, Feeder Expansion, and Voltage Conversions – Reliability investment programs.

Figure 5.2-10: Overview of GTA East Regional Planning Zone

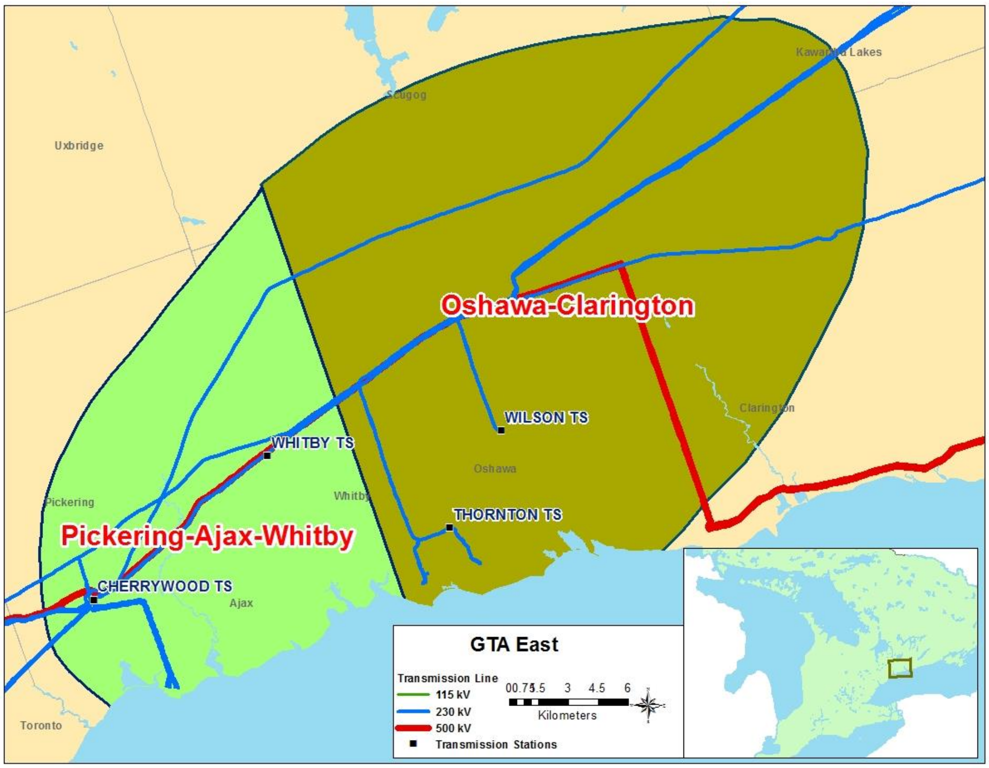


Table 5.2-5: Overview of GTA East RIP Needs and Outcomes

Need	Impact on Elexicon's DSP?	Outcome	Date
Increase of transformation capacity in the Pickering-Ajax-Whitby sub-region	Yes	Elexicon to proceed with the development of Seaton MTS. Hydro One to convert an existing single circuit 230-kV transmission line to a double circuit line to serve station.	2021
Cherrywood TS 230-kV & 500-kV Breaker Replacements	No	Proceed with EOL replacements as per the existing refurbishment plan for HV breakers at Cherrywood TS. Hydro One to coordinate execution with affected LDCs.	2027
Cherrywood TS – LV DESN Switchyard Refurbishment	No	Proceed with EOL replacements as per the existing plan for LV breakers at Cherrywood TS DESN. Hydro One to coordinate execution with affected LDCs.	2025
Wilson TS – T1, T2, and Switchyard Refurbishment	No	Proceed with EOL replacements as per the existing refurbishment plan for transformers at Wilson TS. Hydro One to coordinate execution with affected LDCs.	2022

5.2.2.1.2 GTA North

Figure 5.2-11 below depicts the GTA North region. The participants are currently in the second Regional Planning Process cycle as they completed first cycle with the publication of the RIP report in February 2016. Hydro One initiated the second cycle with the NA phase and the participants subsequently completed the IRRP stage in February 2020 and the RIP phase in October 2020. The latter is the most recently complete phase of the Regional Planning Process for the GTA North region.

Figure 5.2-11: Overview of GTA North Regional Planning Zone

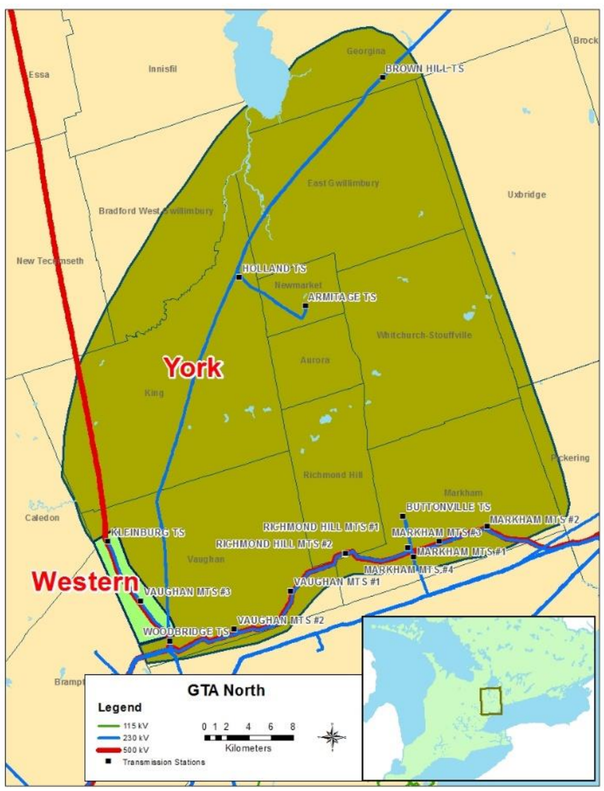


Table 5.2-6 provides a summary of the needs discussed during the consultation and the associated outcomes, none of which impact the current DSP. The study team identified that no actions are required to address needs related to high voltages on the M80B/M81B circuits and Vaughan step-down transformation capacity within this planning cycle. The remaining needs will be addressed by Hydro One in coordination with affected LDCs.

Table 5.2-6: Overview of GTA North NA Needs and Outcomes

Need	Impact on Elexicon's DSP?	Outcome	Date
Markham Area: Step-down Transformation Capacity	No	Build new Markham #5 MTS at the existing Buttonville TS and connect to P45/P46 circuits – 1.1 km section of line between Parkway TS and Markham MTS #4 Jct needs to be uprated. Hydro One and Alectra to coordinate construction of station and line tap connection.	2025
Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	No	Reconductor circuits P45/P46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS. It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying forecasted load.	2025
High voltages on 230kV circuit M80B/M81B	No	No action required. The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage for up to 30 minutes. This provides sufficient time for operators to manually adjust the system as required.	N/A
Northern York Area: Step-down Transformation Capacity	No	Build new Northern York Station – it is anticipated that the new station will be supplied by circuits B88H/B89H. Further discussions between Hydro One and affected LDCs are required.	2027
Woodbridge TS: End-of-life of transformer T5	No	Replace the end-of-life transformer T5 at Woodbridge TS with a new 75/125MVA 230/44-27.6 kV transformer to maintain reliable supply to the customers in the area. Hydro One to coordinate with affected LDCs.	2027
Vaughan Area: Step-down Transformation Capacity	No	Build new Vaughan #5 MTS – Alectra has sufficient space at Vaughan #4 MTS to accommodate another station, but additional transmission capacity is required. A plan to increase transformation capacity is required before a plan for the new station can be committed.	2030

5.2.2.1.3 Metro Toronto

Figure 5.2-12 below depicts the Metro Toronto planning region. The participants completed the first cycle of the regional planning process in January 2016. Hydro One initiated the second cycle with the NA phase which concluded with the publication of the NA report in October 2017. Subsequently, the SA (February 2018), IRRP (August 2019), and RIP (March 2020) phases were completed. The latter is the most recent in the consultation process.

Table 5.2-7 below summarizes the needs discussed and outcomes, none of which have an impact on Elexicon's current DSP. All planned projects are expected to be completed by Toronto Hydro or Hydro One, as nearly all of the Metro Toronto region falls under Toronto Hydro's service territory.

Figure 5.2-12: Overview of Metro Toronto Regional Planning Zone

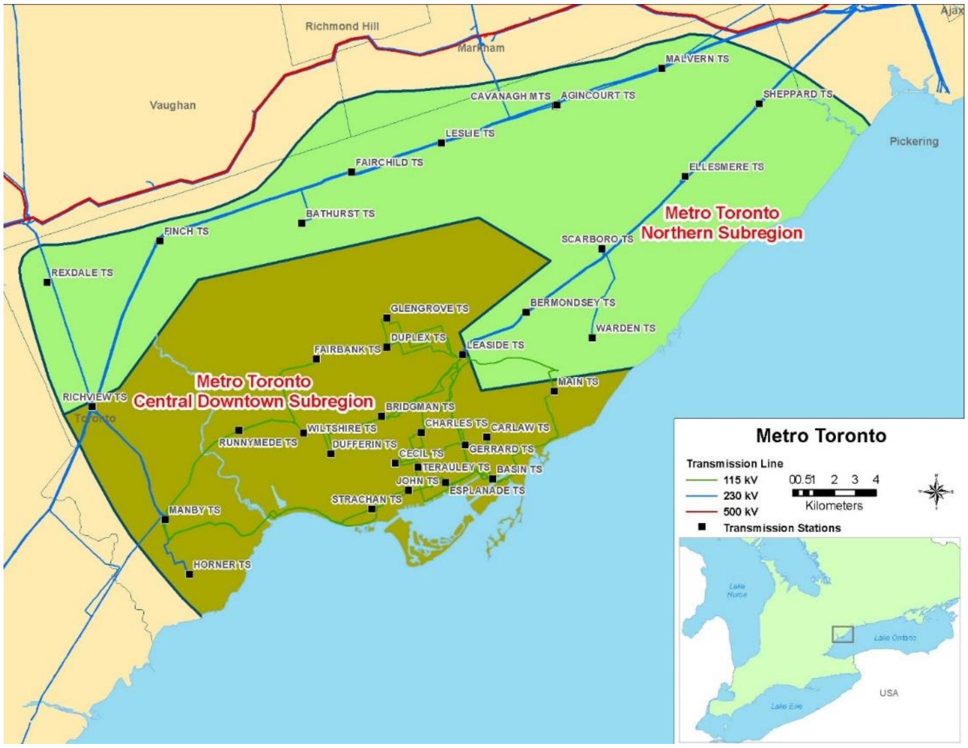


Table 5.2-7: Overview of Metro Toronto RIP Needs and Outcomes

Need	Impact on Elexicon's DSP?	Outcome	Date
Main TS: End-of-Life of transformers T3/T4	No	The study team recommended that Hydro One replace the end-of-life transformers with similar type/size equipment as per current standard to address EOL asset needs and maintain service reliability.	2021
H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	No	The study team recommended that Hydro One refurbish the end-of-life H1L/H3L/ H6LC/H8LC section. The conductor will be replaced with a larger size while the existing tower structures will be retained.	2023
L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	No	The study team recommended that Hydro One refurbish the end-of-life L9C/L12C section. The conductor will be replaced with a larger size while the existing tower structures will be retained.	2023
C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	No	The study team recommended that Hydro One replace the end-of-life C5E/C7E cables. As of the publication of the RIP, Hydro One was estimating and planning construction options.	2024
Richview TS to Manby TS 230-kV Corridor Reinforcement	No	The study team completed an evaluation of alternatives in the 2015 RIP. Hydro One is replacing existing idle 115-kV double circuit line with new 230-kV double circuit line between Richview TS and Manby TS.	2023
Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230-kV switchyard	No	The study team recommended that Hydro One replace the end-of-life transformers with similar type and size equipment as per current standard and refurbish/reconfigure the Manby TS 230-kV switchyard.	2025
Bermondsey TS: End-of-life of transformers T3/T4	No	The study team recommended that Hydro One replace the end-of-life transformers with similar type and size equipment as per current standard.	2025
John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115-kV breakers, and LV switchgear	No	The study team recommended that Hydro One completes replacements with similar type and size equipment as per current standard in coordination with Toronto Hydro.	2026

5.2.2.1.4 Peterborough to Kingston

Figure 5.2-13 below depicts this regional planning zone. The participants completed the first planning cycle in July 2016 with the publication of the RIP report. Hydro One initiated the second cycle with the NA phase which concluded in February 2020. This NA consultation is the most recently completed step of the process.

Table 5.2-8 below summarizes the needs discussed and relevant outcomes, none of which currently impact Elexicon's DSP. The participants outlined that further regional coordination is not required for EOL equipment replacement needs. These replacements will be completed by Hydro One and the affected LDCs, which may include Elexicon, but implementation plans have not been finalized. The participants recommended further regional coordination (IRRP/RIP) for all other needs – the outcomes of these subsequent phases may impact Elexicon's forecast investment plan.

Figure 5.2-13: Overview of Peterborough to Kingston Regional Planning Zone

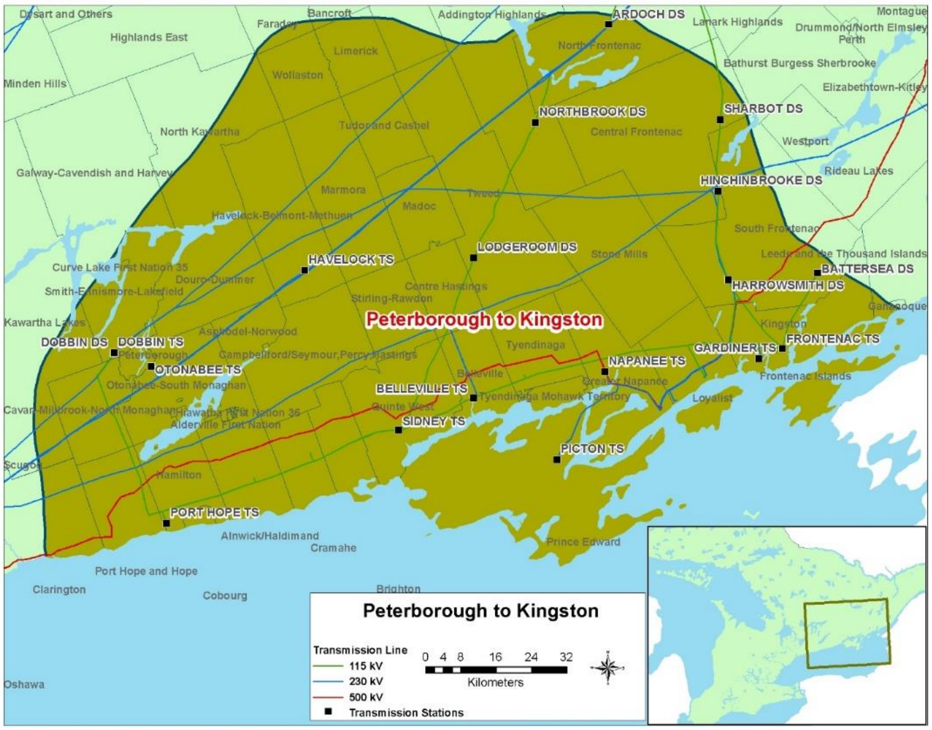


Table 5.2-8: Overview of Peterborough to Kingston NA Needs and Outcomes

Need	Impact on Elexicon's DSP?	Outcome
Transformation capacity relief at Gardiner TS DESN 1	No	This need was identified in a previous planning cycle. Hydro One transferred load from Gardiner DESN 1 to Gardiner DESN 2 to provide load relief.
Lennox TS – 230-kV & 500-kV Breaker Replacement (Bulk System)	No	Replacement of EOL equipment does not require further regional coordination. The implementation and execution plan for these needs will be coordinated by Hydro One and the affected LDCs.
Port Hope TS – Transformers Replacement (T3/T4 at EOL)	No	
Havelock TS – Transformers Replacement (T1/T2 at EOL)	No	
Belleville TS – Transformer Replacement (T2 at EOL)	No	
Frontenac TS Capacity	No	Overloading at Frontenac will be managed by Hydro One in coordination with Kingston Hydro through load transfers between Gardiner TS and Frontenac TS over the near term. Further regional coordination in the form of an IRRP or RIP is recommended.
Gardiner TS DESN 1 Capacity	No	Further regional coordination in the form of an IRRP or RIP is recommended.
Belleville TS Capacity	No	Further regional coordination in the form of an IRRP or RIP is recommended.

5.2.2.1.5 South Georgian Bay/Muskoka

Figure 5.2-14 below depicts this regional planning zone. The participants completed the first cycle of the process with the publication of the RIP report in August 2017. Hydro One initiated the second cycle of the process with the NA phase which was completed in April 2020. Table 5.2-9 below outlines the needs discussed and relevant outcomes, none of which currently impact Elexicon's DSP. Efforts to address some needs are already underway while others require further regional coordination. The outcomes of subsequent phases may impact Elexicon's planned expenditures, but wires plans/solutions have yet to de finalized.

Figure 5.2-14: Overview of South Georgian Bay/Muskoka Regional Planning Zone

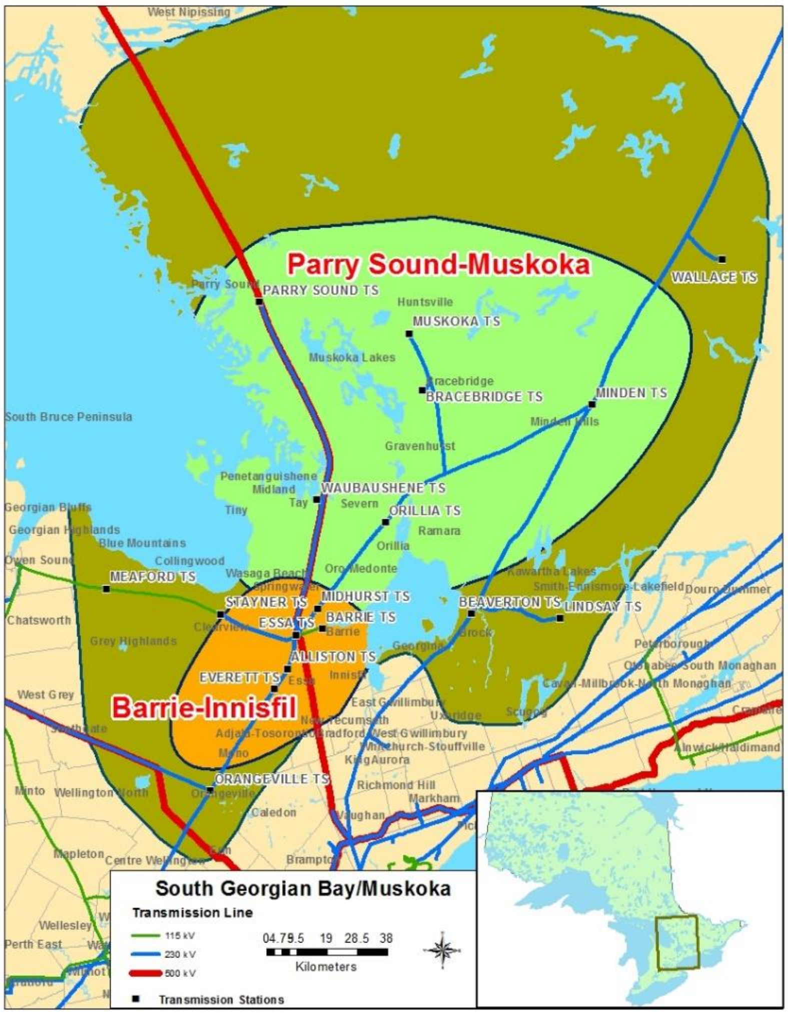


Table 5.2-9: Overview of South Georgian Bay/Muskoka NA Needs and Outcomes

Need	Impact on Elexicon's DSP?	Outcome
Barrie TS transformer supply capacity will be exceeded and the majority of equipment at Barrie TS 115-kV yard is at EOL.	No	This need was identified in the previous planning cycle. Hydro One's Barrie Area Transmission Reinforcement project to address these needs is underway. Scheduled to be in service for 2022.
Parry Sound TS supply capacity has been exceeded and transformers have also been assessed at being EOL.	No	This need was identified in the previous planning cycle. Hydro One will be installing new 230/44-kV 83MVA transformers to address both EOL and supply needs. Scheduled to be in service for 2024.
Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load	No	This need was identified in the previous planning cycle. Hydro One will be installing 230-kV motorized disconnect switches on the M6E and M7E circuits. Scheduled to be in service for 2024
Minden TS – 230/44-kV (T1/T2) transformers have been assessed as being at EOL.	No	This need was identified in the previous planning cycle. Replacement efforts are underway and scheduled to be in service for 2021.
Orangeville – 230/44/27.6-kV (T1/T2) transformers, 230/44-kV (T3/T4) transformers, LV switchyard equipment assessed at EOL.	No	This need was identified in the previous planning cycle. Replacement efforts are underway and scheduled to be in service for 2023.
Waubaushene TS is expected to exceed its normal supply capacity at the end of 2020 based on summer demand forecast. Transformers are also expected to be at EOL by 2030.	No	Hydro One to coordinate with the connected LDC to address immediate supply capacity constraints. Permanent solutions will require further regional coordination.
Everett TS – Load growth at this station is restricted due to a limiting component in the LV Yard.	No	Hydro One will initiate a project to modify CT ratio settings in collaboration with LDCs as soon as practical. Further regional coordination is not required.
Barrie TS is expected to exceed its normal summer and winter supply capacity in 2024/2026 based on existing transformers installed.	No	Will be addressed in part by the Barrie Area Transmission Upgrade project (planned in service 2022). The working group will continue to develop supply capacity solutions for Innisfil area load growth – further regional coordination is required.
Parry Sound TS is expected to exceed supply in 2020 based on winter demand forecast.	No	Station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro aims to expedite replacement to manage overloading risk to existing transformers. No further regional coordination is required.
EOL Replacement needs for sections of M6E/M7E (25km), E8V/E9V (56km), and D1M/D2M (62km).	No	Further regional coordination is required.
M6E/M7E thermal overloading	No	Further regional coordination is required.

5.2.2.2 Coordination with Utilities and Other Parties Outside the RPP

Outside of the Regional Infrastructure Planning Process, Elexicon collaborates with HONI, LDCs, and/or other parties on a number of ongoing and discrete individual issues. These consultations can occur for a variety of reasons including sharing best practices and experiences, discussing interconnection requirements, and identifying and addressing capacity issues. These consultations are typically organized by other organizations such as HONI, ESA, and Utilities Standards Forum ("USF") which invite LDCs such as Elexicon to participate. Examples of past consultations include:

- Electricity Distributors Association – Elexicon has representation on a variety of committees that undertake proactive and reactive work on the legislative regulatory and operational matters impacting Ontario's LDCs;

- Utilities Standards Forum – Consultation for LDCs to collaborate with industry stakeholders on best practices/experiences in priority areas and direct USF on future projects;

- HONI / LDC Distributed Energy Resources ("DER") – Discussion between HONI/LDCs related to DER planning, interconnection requirements, and Technical Interconnection Requirements ("TIR") report;

- Capacity Planning with HONI – Consultation with HONI to discuss capacity issues, such as recent discussion involving capacity in the Belleville area and relevant projects impacted (e.g., Quinte Health CHP); and

- Utility Advisory Committees – the ESA initiated discussion with utilities regarding issues relevant to the distribution system (e.g., a consultation was conducted to identify and eliminate #6 copper conductor from the distribution system based on the ESA's experience with this product).

Some of these consultations occur regularly, such as the USF which typically occurs 3-4 times per year, whereas others do not have an established frequency and occur as required. Depending on the nature of the meeting, Elexicon's role varies from a general participant to a key stakeholder and/or technical expert providing key data inputs or opinion on the range of feasible solutions.

The utility may provide relevant documentation such as load forecasts, REG plans, and interconnection reports. In some cases, these technical inputs are used to create final deliverables such as the TIR Report and implementation plans related to the outcomes of ESA discussions. Discussions which occur for the purpose of sharing best practices typically do not have a direct impact on the DSP, but the utility may apply the resulting planning or work execution standards/best practices. Other consultations, such as those organized by HONI, can have a tangible impact on the DSP – for example, Elexicon's planned Voltage Conversion projects in Belleville are driven in part by discussions with HONI regarding capacity issues.

5.2.2.3 Developer Meetings

This category of engagements covers any consultations between Elexicon and real estate developers which are primarily conducted to discuss new connection/expansion requirements for residential or commercial developments. These meetings are organized by the real estate developer, who invites relevant municipalities and LDCs to participate when discussion of electrical service connections is required. Examples of recent developer consultations include:

- The Dorsay Development – a consultation to discuss master planning stages of a new 4000 acres community in North-East Pickering

- Highmark Homes – a consultation with developers and Town of Whitby to review and submit a draft plan for the Highmark Homes residential development. This consultation occurred as part of a series of consultations where Elexicon responds to the needs of the Town and developers with its long-term planning and load forecasting

- Brooklin Developments – a consultation to discuss the master planning and servicing strategy for the forecasted new development in Brooklin in north Whitby

The utility is involved in ongoing consultations with several developers including the North Brooklin Developers and the Seaton Land Owners Group, which currently take place every two weeks. Elexicon's role in developer meetings is to plan for service connections to accommodate new construction and communicate work execution requirements to stakeholders such as municipalities.

The utility provides technical inputs (e.g., load forecasts) during these discussions as the pace of development depends in part on the utility's ability to install new connections and accommodate the required capacity. Key information is captured in scope documents and development plans which outline the volume of development, electrical service requirements, and timelines.

Scope documents are created at the beginning of the projects and are available immediately but may be subject to change for larger developments such as Seaton and Brooklin. These consultations have a significant effect on the DSP as they drive a large portion of work in the Connection of New Services and Feeder Expansions investment programs.

5.2.2.4 Meetings with Municipalities

Elexicon consults with municipal organizations to discuss issues relevant to the distribution system (e.g., reliability/capacity related) and to plan and coordinate mandated work such as new service connections and road relocations. These meetings are typically organized by municipalities who invite stakeholders such as Elexicon, telecommunications utilities, and regional organizations to participate. Municipal consultations were scheduled regularly in the past, but the frequency has largely changed to an as needed basis for most areas. However, certain public organizations still hold regular meetings (i.e., annually at minimum) such as the Town of Gravenhurst's Advisory Committee meetings and the Town of Whitby's Utility Coordination meetings.

Elexicon's role in these consultations is to provide relevant information that enables prudent planning, to collaborate with other participants to develop alternatives/solutions, and to complete relevant work (i.e., mandated service requirements such as road relocations). The utility provides the organizers with key technical information including assessments of its ability to complete new service connections, load forecasts, reliability analyses, REG plans, and schedules. Based on this material and other inputs, the participants collaborate to develop specific work plans which outline key information such as the scope of work, alternatives, recommended solutions, and timelines. Depending on the nature of the discussion, the final output may vary – for example, the deliverables associated with meetings intended to address reliability/capacity issues could include reliability analyses or load forecasts. Elexicon is also responsible for completing relevant work which results from these discussions. Therefore, municipal consultations can have a notable effect on the DSP as they drive work categorized in programs such as Road Relocations, Feeder Expansions, and Connection of New Services.

5.2.2.5 Meetings with Metrolinx

Metrolinx is a Government of Ontario agency that provides transportation services and continually seeks to improve its transportation system. Elexicon consults with Metrolinx to discuss ongoing or future project work which entails modifications to the electrical distribution system and to plan the associated work that Elexicon is mandated to complete. These Metrolinx projects can include road extensions/widening and the construction of new transportation stations or systems. These consultations are initiated by Metrolinx, who invites relevant stakeholders such as municipalities, telecommunications utilities, and LDCs such as Elexicon as required. The utility is currently engaged in regular consultations with Metrolinx which occur every two weeks.

Elexicon’s role in these discussions is to collaborate with the other participants to identify and plan work that is relevant to the distribution system to support Metrolinx projects. The working group identifies the volume of work to be completed, expected timelines, responsible parties, and requirements for completion – this information is captured in work execution plans. outcomes of Metrolinx consultations have a material effect on the DSP as there are several planned projects in the Road Relocation program to support Metrolinx initiatives – examples include Metrolinx – Squires Breach Rd LSE 134 (existing steel towers) and Metrolinx – Squires Beach Rd LSE 139 (wood pole crossing).

5.2.2.6 Coordination with the Region of Durham

Elexicon meets with the Region of Durham as required to discuss relevant project work planned by the region that involves Elexicon. Example projects include feeder upgrades for seasonal peak requirements, road relocations, and other projects related to public infrastructure such as the transportation system. Elexicon is typically invited to participate in these consultations by the Region but may choose to initiate a consultation to assess coordination between ongoing projects and the future needs of the municipality, region, or other utilities. Other participants can include design and resource management consultants such as NBM Engineering and PlanView, telecommunications utilities, natural gas utilities, and municipalities. Elexicon is currently involved in ongoing consultations for approximately eight different projects which require consultation with the Region. The projects are in different phases of their lifecycles and the estimated completion dates vary. However, there are upcoming deadlines for two BRT system related projects targeted for completion in 2021.

Elexicon’s role in these consultations is to collaborate with the Region and other participants to outline needs, develop design solutions, and plan work execution to support the Region’s projects. Elexicon’s role varies depending on the nature of the project, ranging from providing input on design solutions to completing work driven by these discussions. The outcomes of these consultations are summarized in design or work execution plans which outline key information such as needs, relevant methodologies, alternatives, recommended solutions, and the timing/scheduling of work. These deliverables are typically available one year after the project discussion. The outcomes of these discussions are expected to have an effect on the current DSP as Elexicon has planned projects related to the BRT initiative in the Road Relocations and Switches/Switchgears Renewal programs.

The utility may also participate in Region of Durham consultations that are not related to specific projects. A key example is the Region of Durham Climate Action Forum which is an initiative organized by the Region to ensure that infrastructure is resilient against extreme weather events resulting from climate change such as floods, earthquakes, and ice storms. This initiative was organized by the Region and included relevant service providers such as electricity, gas, and water utilities.

5.2.2.7 IESO Comment Letter (5.2.2d)

Elexicon submitted a request for a letter of comment (attached as Appendix E) to the IESO in October 2020. The IESO has reviewed the letter containing Elexicon's information on REG applications, planning and investments, and concluded that the request for a letter of comments is not needed as there are no REG investments over the DSP period 2021-2026. The IESO also confirms that Elexicon has been a participating member of the five regional planning groups within its service territory.

5.2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

Like every distribution utility, Elexicon is a complex organization with multiple activity systems that function collectively to provide customers with safe and reliable electrical service. Adding to this complexity in the near-term is the ongoing post-merger integration work that requires detailed analysis of the previous practices and definition of a clear path forward reflective of a new corporate identity. As the consolidation activities proceed, performance measurement serves as a key indicator of operating areas where more managerial focus or innovation can deliver additional value or address the emerging performance gaps.

Elexicon continually monitors and reports on these metrics to ensure that it performs optimally, continuously improves, and complies with regulatory requirements. The performance measures allow Elexicon to map the current state of its system and supporting processes. In doing so, the utility can identify areas of concern and adapt its plans to address current or anticipated operational deficiencies.

The core of Elexicon's performance measurement framework applicable in the context of the DSP is made up of the OEB's Distributor Scorecard measures that the utility is required to track and report on an annual basis. Figures Figure 5.2-15 through Figure 5.2-17 on the pages that follow provide the latest copies of the consolidated 2019 Elexicon Distributor Scorecard and the 2018 Scorecards for its predecessors. The sections that follow provide a discussion of performance on all Scorecard metrics, focussing on consolidated performance on a subset of the Scorecard Metrics that, in Elexicon's view, are most closely aligned with the three categories of measures and metrics discussed in the OEB's Chapter 5 guidance, namely:

- Customer-Oriented Performance;
- Cost Efficiency and Effectiveness; and
- Asset/System Operations Performance.

The discussion of Elexicon and its predecessors' performance on other Distributor Scorecard metrics not discussed within this document is available in the Scorecard MD&A documents published on the OEB's Utility Performance and Monitoring website.[4]

In addition to the standard Scorecard Metrics, Elexicon proposes to track several additional custom measures over the Forecast Period. Table 5.2-10 lists these custom measures, discussed in more detail in the sections that follow.

Table 5.2-10: Additional DSP Performance Measures

Customer-Oriented Performance	Asset and System Operations Performance	Cost Efficiency / Effectiveness in Delivering the Plan
Worst Performing Feeders: FESI-9	Defective Equipment SAIDI	Cable Replacement Value Deferred

[4] https://www.oeb.ca/utility-performance-and-monitoring/what-are-electricity-utility-scorecards/electricity-utility

Figure 5.2-15: Consolidated Elexicon Scorecard: 2015-2019

Scorecard - Elexicon Energy Inc.

10/21/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.00%	97.00%	98.00%	96.00%	96.40%	down	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	99.00%	99.74%	down	90.00%	
		Telephone Calls Answered On Time		79.00%	77.00%	82.00%	82.00%	76.01%	down	65.00%	
	Customer Satisfaction	First Contact Resolution		84%	87%	87%	88%	88.60%			
		Billing Accuracy		99.75%	99.84%	99.91%	99.93%	99.92%	up	98.00%	
		Customer Satisfaction Survey Results		90%	91%	92%	95%	95.00%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		81.00%	81.00%	83.00%	83.00%	84.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	1	1	2	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.300	0.273	0.535	0.000	flat		0.155
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.56	1.17	0.98	1.32	1.34	down		1.35
		Average Number of Times that Power to a Customer is Interrupted [2]		2.01	1.28	1.11	1.16	1.05	down		1.69
	Asset Management	Distribution System Plan Implementation Progress		89.95%	109.62%	94.84%	99.07%	104.00%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$603	$618	$605	$624	$648			
		Total Cost per Km of Line [3]		$28,988	$27,282	$26,361	$27,139	$28,396			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		13.00%	30.00%	64.00%	82.00%	89.00%			201.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%		100.00%			
		New Micro-embedded Generation Facilities Connected On Time		99.00%	88.00%	95.00%	100.00%	100.00%	up	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.37	1.50	1.33	0.81	1.04			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.10	1.12	1.05	1.05	0.91			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.43%	9.43%	9.43%	9.43%	9.43%			
			Achieved	9.58%	9.44%	9.09%	9.84%	7.61%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

Figure 5.2-16: Veridian Connections Scorecard: 2014-2018

Scorecard - Veridian Connections Inc.

9/30/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		96.00%	97.70%	98.10%	98.62%	95.70%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	99.56%	99.05%	↓	90.00%	
		Telephone Calls Answered On Time		64.30%	78.70%	76.20%	80.83%	80.87%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		78.1%	79.1%	82.7%	82.2%	83.7%			
		Billing Accuracy		99.70%	99.73%	99.85%	99.92%	99.93%	↑	98.00%	
		Customer Satisfaction Survey Results		91%	90%	91%	91%	95%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness			82.00%	82.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	1	1	1	↑		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.445	0.389	0.380	↑		0.117
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.97	1.62	1.24	1.07	1.55	↑		1.43
		Average Number of Times that Power to a Customer is Interrupted [2]		1.72	2.13	1.29	1.07	1.26	↓		1.81
	Asset Management	Distribution System Plan Implementation Progress		84.58%	88.45%	98.81%	93.96	99.19			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$560	$577	$593	$578	$603			
		Total Cost per Km of Line [3]		$25,720	$30,404	$27,593	$26,411	$27,737			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]			10.68%	24.26%	53.23%	77.00%			142.97 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%				
		New Micro-embedded Generation Facilities Connected On Time		93.33%	97.67%	97.37%	100.00%	100.00%	↑	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.44	1.34	1.62	1.49	0.77			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.39	1.31	1.34	1.25	1.26			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%			
			Achieved	10.61%	9.31%	9.28%	8.66%	9.21%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the 2015-2020 Conservation First Framework. 2018 results are based on the IESO's unverified savings values contained in the March 2019 Participation and Cost Report.

Legend: 5-year trend: ↑ up ↓ down → flat. Current year: target met; target not met

Figure 5.2-17: Whitby Hydro Scorecard: 2014-2018

Scorecard - Whitby Hydro Electric Corporation

9/30/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		96.10%	96.20%	95.10%	95.60%	98.81%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	99.60%	99.60%	99.46%	99.73%	↓	90.00%	
		Telephone Calls Answered On Time		73.80%	81.50%	80.60%	87.93%	87.36%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		99.86%	99.82%	99.59	99.74	99.82			
		Billing Accuracy		99.89%	99.83%	99.81%	99.88%	99.93%	↑	98.00%	
		Customer Satisfaction Survey Results		A	A	A	A	A			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness			78.90%	78.90%	83.60%	83.60%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	1	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.906	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.89	1.40	0.99	0.69	0.68	↓		1.14
		Average Number of Times that Power to a Customer is Interrupted [2]		2.32	1.65	1.23	1.23	0.86	↑		1.35
	Asset Management	Distribution System Plan Implementation Progress		94.9%	100.98%	97.95	95.14	98.76			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$628	$676	$689	$682	$681			
		Total Cost per Km of Line [3]		$24,275	$26,052	$26,552	$26,241	$25,745			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]			10.63%	29.22%	55.85%	72.00%			58.44 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%							
		New Micro-embedded Generation Facilities Connected On Time		92.86%	100.00%	78.95%	91.89%	100.00%	↑	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.48	1.45	1.24	1.04	0.92			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.69	0.67	0.66	0.63	0.59			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.66%			
			Achieved	13.89%	10.43%	9.94%	10.46%	11.84%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the 2015-2020 Conservation First Framework. 2018 results are based on the IESO's unverified savings values contained in the March 2019 Participation and Cost Report.

Legend: 5-year trend: ↑ up ↓ down → flat; Current year: target met; target not met

5.2.3.1 Scorecard Metrics: Customer-Oriented Performance

5.2.3.1.1 System Reliability

5.2.3.1.1 a) Methods and Measures

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's *Electricity Reporting & Record Keeping Requirements* dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in a year on average and is expressed as hours per customer per year. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average and is expressed as the number of interruptions per customer per year. The formulae below present the calculation of these system reliability measures. These indices only consider sustained outages, which are defined as service interruptions that last for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

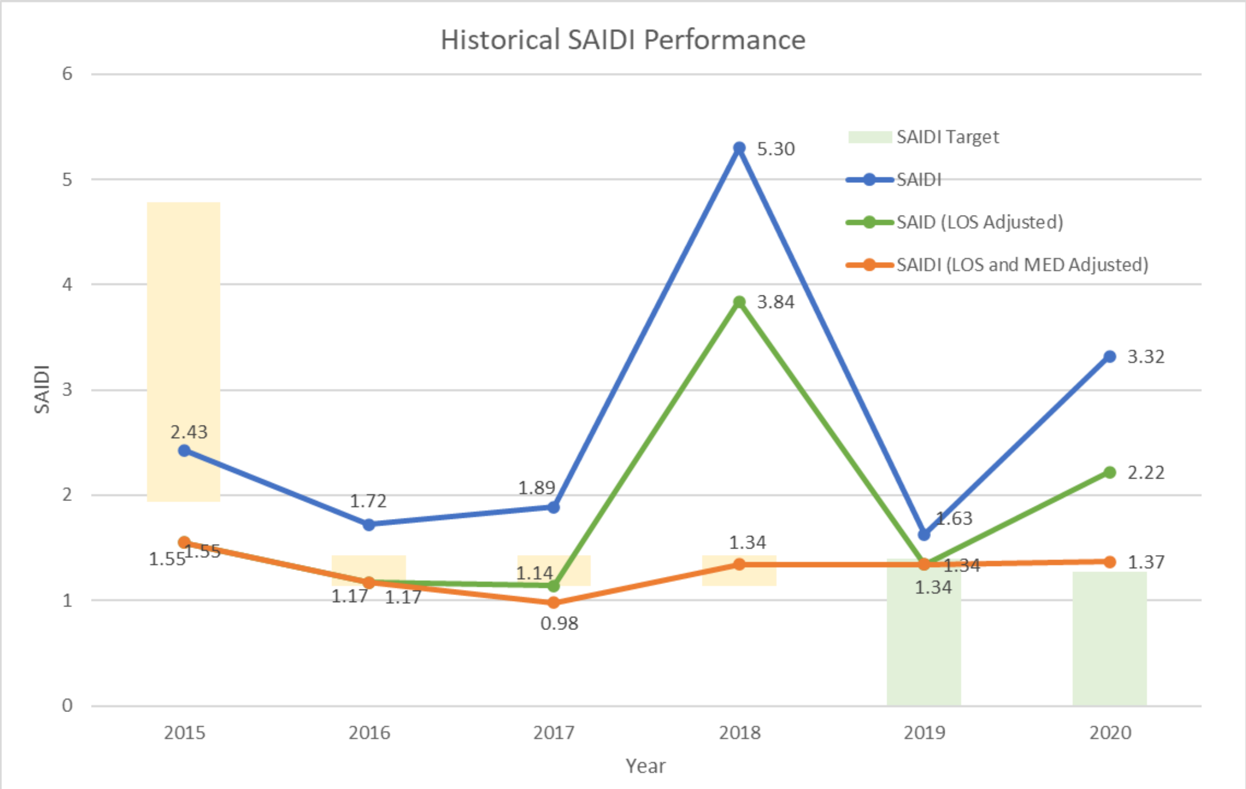
5.2.3.1.1 b) Historical Performance

Table 5.2-11 below presents Elexicon's and its predecessors consolidated historical performance for the SAIDI and SAIFI reliability measures, including adjustments for Loss of Supply ("LOS") events and Major Event Days ("MED"), which are typically outside the utility's control. According with the OEB guidance, Elexicon sets performance targets for the MED- and LOS- adjusted SAIDI and SAIFI measures on the basis of a 5-year rolling average performance. There are no targets for reliability performance that includes the factors outside of Elexicon's control (i.e., LOS and MED events). Figures Figure 5.2-18 and Figure 5.2-19 showcase the historical SAIDI and SAIFI measures in a graphic format.

Table 5.2-11: Summary of Historical SAIDI and SAIFI Performance

Metric	2014	2015	2016	2017	2018	2019	2020	Target*
System Averages: All Outages								
SAIDI	2.38	2.43	1.72	1.89	5.3	1.63	3.32	-
SAIFI	2.82	2.74	1.78	2.01	2.59	1.26	1.74	-
System Averages: Loss of Supply Adjusted								
SAIDI	1.94	1.55	1.17	1.14	3.84	1.34	2.22	-
SAIFI	1.85	2	1.28	1.5	1.57	1.05	1.17	-
System Averages: Loss of Supply and Major Event Day Adjusted								
SAIDI	1.94	1.56	1.17	0.98	1.32	1.34	1.37	**1.35**
SAIFI	1.85	2.01	1.28	1.11	1.16	1.05	1.01	**1.69**

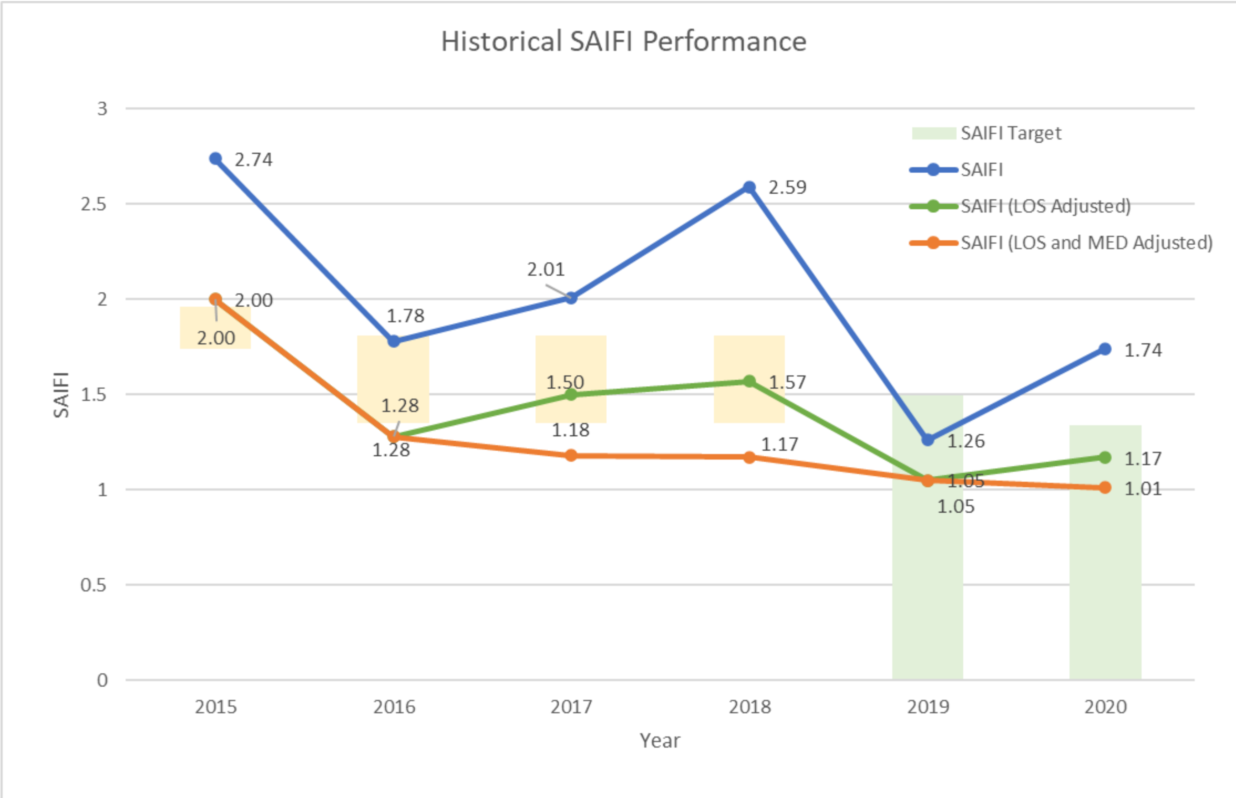
Figure 5.2-18: Historical SAIDI Performance



As the above figure indicates, when adjusted for impact of events largely outside of the utility's control, the consolidated SAIDI performance over the historical period showcases a declining trend through 2014-2017, with a marginal increase in the three most recent years. The 2020 Scorecard SAIDI metric does not meet the OEB's five-year rolling average target of 1.35. This is due to a higher-than-average number of customer hours interrupted under the Tree Contacts and Human Element cause codes.

The performance result in 2018 is an outlier as the SAIDI result was higher than all prior and subsequent years - measuring at 5.3 hours per customer prior to LOS and MED adjustments. The increase is the result of major weather activity, which also had a negative impact on the predecessors' upstream supply reliability.

Figure 5.2-19: Historical SAIFI Performance



The downward SAIFI performance trend exhibited in Figure 5.2-19 indicates that system reliability has generally improved or remain stable over the historical period. The predecessors' combined historical performance for SAIFI is relatively high prior to LOS and MED adjustments in 2015 and 2018. As mentioned above, Elexicon's predecessors experienced a relatively high volume of adverse weather in 2018 that triggered MED and LOS events. In 2015, Whitby Hydro and Veridian also experienced a higher-than-average volume of MEDs, nearly all of which were associated with LOS-related outages. The consolidated 2020 performance falls within the acceptable range after adjusting for MEDs and LOS events.

Table 5.2-12: Summary of Historical MED

#	Date	Cause Code	Customers Interrupted	Description of MED
1	2015-05-31	2	20,027	LOS event which was triggered by Hydro One to perform repairs.
2	2017-12-28	6	51,136	MED resulted from Adverse Weather conditions and only affected the Whitby service area.
3	2018-04-04	2/6	28,061	A severe windstorm resulted in several instances of falling trees causing damage to power lines which resulted in outages.
4	2018-04-16	6	9,265	An ice storm caused damage to distribution infrastructure such as overhead lines, underground cables, and poles.
5	2018-05-04	6	59,145	A severe windstorm resulted in damage to distribution assets such as overhead lines and underground cables directly and due to falling trees.

#	Date	Cause Code	Customers Interrupted	Description of MED
6	2018-05-05	6	4,571	A severe windstorm resulted in direct damage to distribution assets such as poles and switches.
7	2018-09-21	6	54,648	A severe windstorm resulted in several instances of falling trees causing damage to assets such as poles, overhead lines, and transformers which resulted in service interruptions.
8	2020-01-25	2	18,071	This LOS event was triggered by an outage at Belleville TS initiated by Hydro One.
9	2020-07-19	6	17,989	A severe windstorm resulted in several instances of falling trees causing damage to power lines which resulted in outages.
10	2020-10-23	6	2,614	A severe windstorm resulted in several instances of falling trees causing damage to power lines which resulted in outages.
11	2020-11-15	2/6	22,892	A severe windstorm resulted in several instances of falling trees causing damage to power lines which resulted in outages.

5.2.3.1.1 c) Effect on DSP

The historical system reliability performance on the part of Elexicon's predecessors and over the first year of merged operations suggests acceptable performance, as the results for both SAIDI and SAIFI generally fall within the acceptable range after adjusting for LOS and MED events. However, given that system reliability is a lagging indicator that requires consistent investments in the most vulnerable areas, Elexicon plans to continue investing into programs which benefit system reliability.

Moreover, while aggregated statistics suggests stable performance, there is nevertheless significant variability in the levels of service experienced by customers in different parts of its service territory and differing expectations of service levels across different customer classes. To this end, Elexicon aims to continuously improve its system reliability to enhance customer experience and allow the utility to achieve its corporate objectives. As it continues engaging its customers over the Forecast Period, the utility expects to explore a more nuanced approach to reliability planning and target setting across its various regions, should the customer feedback support such undertakings. Investment programs which benefit system reliability fall into the System Renewal or System Service investment categories. Additional details about these investment programs can be found in Section 5.4 which outlines capital expenditures.

Elexicon DSP includes several System Renewal programs which target replacements for different asset classes that are expected to improve the system condition and resilience. These programs are:

- Renewal Programs – Distribution Transformers
- Renewal Programs – Rebuilds
- Renewal Programs – Poles
- Renewal Programs – Reactive
- Renewal Programs – Switches & Switchgears
- Substation Renewal
- Voltage Conversions – Reliability

- Renewal Programs – Others (covers replacement of porcelain insulators and porcelain insulators and other expenses such as capitalized planning, operations and interest)

In addition, the DSP includes System Service programs which target enhancements to the distribution system through projects which facilitate growth and improve reliability. These programs are:

- System Reliability Improvement

Standard Equipment Reliability & Compliance

5.2.3.1.2 Customer Satisfaction

5.2.3.1.2 a) Methods and Measures

First Contact Resolution

At this juncture, specific First Contact Resolution ("FCR") measure or target have not been mandated for the industry at large, as the OEB has encouraged distributors to adopt approaches that are relevant for them. Elexicon has developed an internal tracking mechanism to measure FCR, which takes both customer phone calls and written correspondence into account. At the time of first contact, customer care representatives enter a call code to identify the type of inquiry a customer made. A report is then run against the call codes and customer accounts to determine whether and when the follow-up interaction occurs. Customers who make contact again on the same issue (as determined by call codes), within a thirty-day period are considered as not having had their issue resolved on the first instance of contact.

Customer Satisfaction Survey

The OEB provided distributors with a degree of discretion in determining how to conduct customer satisfaction surveys, provided the surveys adhere to the following principles:

1) Surveys must canvas satisfaction regarding power quality and reliability, price, billing and payment, communications, and the customer service experience; and

2) Surveys must follow good survey practices.

Elexicon's predecessors regularly conducted comprehensive customer satisfaction surveys to obtain feedback from their customers. Whitby Hydro and Veridian engaged the market research firm Utility-Pulse to complete these surveys on a biennial basis. Surveys were carried out by telephone and targeted a mix of residential and business customers from across the predecessor utilities' service areas. Survey questions covered a wide range of topics such as system reliability, customer service, billing, and corporate image. The predecessor utilities used survey results to help inform business planning processes. In addition, the market research firm conducted supplemental research to establish provincial and national benchmarks for comparison. Elexicon plans to adopt all legacy practices and aims to achieve a customer satisfaction survey score of 95%. The utility plans to administer the next customer satisfaction survey in late 2020 or early 2021.

5.2.3.1.2 b) Historical Performance

First Contact Resolution

Elexicon does not currently have an explicit performance target for the FCR measure. However, it expects the performance trend to remain stable or improve year over year. Elexicon's predecessors have performed comparatively well on the activities captured by this metric as their consolidated performance is consistently above 80% over the historical period and averages to 86.45%. In addition, the combined performance has improved over the historical period, increasing from 83.8% in 2014 to 88.6% in 2019. Elexicon does not believe that targeted responsive action is necessary for this measure as the overall performance trend is positive. However, given the unique challenges associated with COVID-19, the utility is closely monitoring the performance of its customer contact centre to ensure that service levels remain robust in the face of significant challenges faced by its customer base. FCR results for 2020 were not yet available at the time of filing.

Table 5.2-13: Historical Performance for FCR (Consolidated)

Target	2014	2015	2016	2017	2018	2019
N/A	83.8%	84.5%	87.1%	86.8%	87.9%	88.6%

Customer Satisfaction Survey

Historically, Whitby Hydro reported Customer Satisfaction Survey scores in the form of a letter grade, while Veridian reported scores as a percentage of customers that were either "very" or "fairly" satisfied with the utility's service. Whitby Hydro's historical target was an overall grade of A and Veridian's historical target was 90%. The surveys were conducted by telephone using a mix of residential and business customers. Both predecessor utilities successfully achieved their target scores for all years during the historical period. For the first year of merged operations and beyond, Elexicon adopted a percentage score, using the methodology consistent with that used by Veridian Connections prior to the merger. The score of 95% indicates a consistent performance from the last year prior to the merger. Customer Satisfaction Survey results for 2020 were not yet available at the time of filing.

Table 5.2-14: Historical Performance for Customer Satisfaction Survey

Measure	Target	2014	2015	2016	2017	2018	2019
Customer Satisfaction Survey: Whitby	A	A	A	A	A	A	-
Customer Satisfaction Survey: Veridian	90%	91.0%	90.0%	91.0%	91.0%	95.0%	-
Customer Satisfaction Survey: Elexicon	-	-	-	-	-	-	**95.0%**

5.2.3.1.2 c) Effect on DSP

First Contact Resolution

Elexicon's predecessors' performance for FCR is considered satisfactory, as they achieved an average consolidated score of 86.02% over the 2014-2018 period. The utility's performance score of 95% in the first year of merged operations suggests that customers have generally maintained their satisfaction levels with their distribution service provider since the time before ethe merger. While recent performance provides limited evidence to consider dedicated remedial, there are planned projects over the Forecast Period that are expected to enable Elexicon to maintain or improve current levels. The primary objective of the investments in question is to improve the quality of customer service, which will in turn benefit FCR performance. These projects are categorized under the Information Technology investment program. This program enables improved customer service performance through efforts such as Customer Information System ("CIS") consolidation, the procurement of office equipment which supports customer-facing processes (e.g., billing printers), and software upgrades for applications such as NorthStar.

Customer Satisfaction Survey
Elexicon's predecessors' Customer Satisfaction Survey results do not indicate a strong need for correction. However, maintaining customer satisfaction at the historical levels and attempting to reach the higher levels targeted by the new entity requires continued investments. The survey measures customers' satisfaction with various aspects of the company such as price, customer service, brand image, reliability/power quality, and operational efficiency. Programs that improve Elexicon's performance in any of these areas are expected to assist in maintaining or improving Customer Satisfaction Survey performance. Among these programs are:

- Information Technology – The Information Technology program includes projects that are expected to improve customer service performance such the CIS consolidation/upgrade, procurement of office equipment which supports customer-facing processes (e.g., billing printers), and software upgrades. This program also includes investments which should benefit Elexicon's operational efficiency and increase customer satisfaction. These planned projects include cybersecurity upgrades, data management systems, and software upgrades for engineering and asset management applications.

- Programs which target system reliability improvements in the System Renewal and System Service categories are listed below. These programs are expected to improve customer satisfaction by decreasing reliability risk, reducing unanticipated reactive costs, and increasing operational efficiency.

5.2.3.1.3 Service Quality

5.2.3.1.3 a) Methods and Measures
The *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Energy Competition Act, 1998*. As required by the OEB, Elexicon records and submits all performance measures, which are compared with the OEB's established targets to evaluate Elexicon's customer service quality. The performance measures are described below, as defined in the *Distribution System Code*.

<u>Telephone Accessibility:</u>
The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the thirty-second time period. As mandated by the OEB, this service quality requirement must be met at least 65% of the time on a yearly basis.

<u>Telephone Call Abandon Rate</u>
As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered is to be 10% or less on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the thirty-second time period has elapsed.

<u>Connection of New Services</u>
The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage (<750 V) service must be completed within five business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed by the customer and distributor.

- A connection for a new service request for a high voltage (>750 V) service must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

This service quality requirement must be met at least 90% of the time on a yearly basis, as mandated by the OEB.

Appointment Scheduling

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. If an appointment is requested by a customer or customer representative or if the distributor requires the customer or customer representative's presence, the distributor must:

- Offer to schedule the appointment during the distributor's regular hours of operation within a window of time no greater than 4 hours

- Arrive for the appointment within the scheduled timeframe

If the appointment does not require the presence of a customer or customer representative, the distributor shall arrive for the appointment on the day scheduled. This service quality requirement must be met at least 90% of the time on a yearly basis.

Appointments Met

When an appointment is either:

- requested by a customer or a representative of a customer; or

- required by a distributor with a customer or a representative of a customer.

The distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four hours. The distributor must then arrive for the appointment within the scheduled timeframe. If the customer fails to attend the appointment, the distributor may consider the appointment to have been met. This service quality requirement must be met at least 90%of the time on a yearly basis.

Rescheduling a Missed Appointment

When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and

- attempt to contact the customer within one business day to reschedule the appointment.

This requirement does not apply if the appointment is missed due to the failure of the customer or the customer representative to attend the meeting. This service quality requirement must be met 100% of the time on a yearly basis.

Written Responses to Enquiries

A written response to a qualified enquiry shall be sent by a distributor within ten business days and is subject to the following conditions:

- The 10 business days shall be counted from date on which any conditions associated with the enquiry have been satisfied or, if there are no such conditions, from the date of receipt of the enquiry

- A written response can be considered sent if the distributor sends a written acknowledgement of the receipt of the qualified enquiry and a specific date in which a complete response will be provided

- A written response shall be deemed to have been sent on the date on which it is faxed, mailed, or emailed by the distributor

This service quality requirement must be met at least 80% of the time on a yearly basis.

Emergency Response

Emergency calls (i.e., assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two hours in rural areas and within one hour in urban areas, where the definitions of “urban” and “rural” align with the municipality’s definition. The arrival of a qualified service person on site will constitute a response. This service quality requirement must be met at least 80% of the time on a yearly basis.

Reconnection Performance

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within 2 business days of the date on which the customer:

- Makes payment in full of the amount overdue for payment as specified in the disconnection notice; or

- Enters into an arrears payment agreement with the distributor

This service quality requirement must be met at least 85% of the time on a yearly basis.

Billing Accuracy

A distributor must issue an accurate bill to each of its customers, subject to the following conditions:

- A distributor should not include customer accounts that are unmetered accounts (e.g., street lighting and unmetered scattered loads) or power generation accounts when calculating percentage of accurate bills

- The percentage of billing accuracy shall be calculated using the following formula:

$$Billing\ Accuracy = \frac{Total\ Number\ of\ Bills\ Issued - Number\ of\ Inaccurate\ Bills}{Total\ Number\ of\ Bills\ Issued}$$

This service quality requirement must be met at least 98% of the time on a yearly basis.

5.2.3.1.3 b) Historical Performance

The historical performance results for the predecessor utilities and the consolidated performance results for Elexicon are summarized in Table 5.2-15 below. The following analysis of the historical performance for these Service Quality Requirements ("SQR") is based on the combined performance of the predecessor utilities. The 2020 metrics were unavailable at time of filing.

Table 5.2-15: Historical Performance for Service Quality Requirements

	Service Quality Measure		2014	2015	2016	2017	2018	2019	Target
Whitby Hydro	Telephone accessibility		73.8%	81.5%	80.6%	87.9%	87.4%		65%
	Telephone call abandon rate		1.80%	1.10%	1.10%	0.91%	1.02%		10%
	Connection of new services	Low Voltage	96.1%	96.2%	95.1%	95.6%	98.8%		90%
		High Voltage	100%	100%	100%	100%	100%		90%
	Appointments scheduling		98.4%	98.9%	98.9%	66.6%	96.0%		90%
	Appointments met		100%	99.6%	99.6%	99.5%	99.7%		90%
	Missed appointments rescheduling		N/A	0	0	50%	99.3%		100%
	Written response to enquiries		100%	99.1%	100%	100%	100%		80%
	Emergency response	Rural	100%	100%	100%	100%	100%		80%
		Urban	100%	100%	100%	100%	100%		80%
	Reconnection performance		100%	100%	99.5%	100%	99.6%		85%
	Billing Accuracy		99.89%	99.8%	99.8%	99.9%	99.9%		98%
Veridian	Telephone accessibility		64.3%	78.7%	76.2%	80.8%	80.9%		65%
	Telephone call abandon rate		8.70%	3.30%	2.40%	1.83%	2.52%		10%
	Connection of new services	Low Voltage	100%	97.7%	98.1%	98.6%	95.7%		90%
		High Voltage	100%	100%	100%	100%	100%		90%
	Appointments scheduling		93.7%	92.5%	93.4%	93.1%	97.1%		90%
	Appointments met		100%	100%	100%	99.6%	99.1%		90%
	Missed appointments rescheduling		N/A	N/A	N/A	100%	100%		100%
	Written response to enquiries		100%	99.8%	99.8%	99.95%	99.8%		80%
	Emergency response	Rural	100%	N/A	100%	100%	100%		80%
		Urban	95.1%	91.7%	96.3%	100%	89.3%		80%
	Reconnection performance		100%	100%	100%	100%	100%		85%
	Billing Accuracy		99.7%	99.7%	99.9%	99.9%	99.9%		98%
Elexicon / Combined Historical	Telephone accessibility		66.0%	79.2%	77.1%	82.5%	82.5%	**76.0%**	65%
	Telephone call abandon rate		8.7%	2.9%	2.1%	1.6%	2.1%	**1.8%**	10%
	Connection of new services	Low Voltage	99.4%	97.3%	97.2%	97.9%	96.4%	**96.4%**	90%
		High Voltage	100%	100%	100%	100%	100%	**100%**	90%
	Appointments scheduling		94.6%	92.8%	94.1%	86.5%	96.9%	**94.1%**	90%
	Appointments met		93.7%	99.9%	99.9%	99.5%	99.3%	**99.7%**	90%
	Missed appointments rescheduling		N/A	0%	0%	76.9%	99.3%	**96.9%**	100%
	Written response to enquiries		100%	99.7%	99.8%	100%	99.9%	**99.8%**	80%
	Emergency response	Rural	100%	100%	100%	100%	100%	**100%**	80%
		Urban	96.7%	96.5%	98.1%	100%	91.8%	**99.1%**	80%
	Reconnection performance		100%	100%	99.9%	100%	100%	**100%**	85%
	Billing Accuracy		99.8%	99.8%	99.8%	99.9%	99.9%	**99.9%**	98%

Telephone Accessibility:

The OEB requires a minimum standard of 65% for the Telephone Accessibility metric. Elexicon's predecessors' consolidated performance trended upwards over the historical period, increasing from 66% in 2014 to 76% in 2019 while peaking at 82.5% in 2017 and 2018. Although there has been a slight decrease in 2019, the performance still exceeds the required standard by 11%. Generally, the legacy utilities' combined performance against this metric is excellent as it exceeds the minimum OEB standard every year by an average of 12.2%. The combined performance is calculated by using the Sum of "Number of qualified incoming calls answered within 30 seconds" divided by the Sum of "Number of qualified incoming calls."

Telephone Call Abandon Rate

The OEB requirement for Telephone Call Abandon Rate is that the result should not exceed 10%. Elexicon's predecessors' poorest performance occurred at the beginning of the historical period in 2014, when the combined metric reached 8.7%. However, performance has improved significantly in subsequent years, consistently being below 3%. Whitby Hydro and Veridian's consolidated performance against this metric shows a positive trend as it sees a decrease from 8.7% in 2014 to 1.8% in 2019. The results do not indicate the need for remedial action as the legacy utilities exceeded the target by 6.8% on average. The combined performance is calculated by using the Sum of "Number of qualified incoming calls abandoned after 30 seconds" divided by the Sum of "Number of qualified incoming calls."

Connection of New Services

The OEB requires a minimum standard of 90% for the Connection of New Services within 5 to 10 business days (depending on low vs. high voltage). The combined performance is calculated by the Sum of "Number of new low voltage services connected within 5 or 10 days (depending on low vs. high voltage)" divided by the Sum of "Number of new low voltage services requested." Elexicon's predecessors' consolidated performance for low voltage connections has decreased slightly over the historical period from 99.4% in 2014 to 96.4% in 2019. The former is the best performance result, and the latter is the poorest. However, there is minimal cause for concern as Whitby Hydro and Veridian's combined performance exceeds the OEB standard by 7.4% every year on average. The legacy utilities had a perfect 100% performance result for high voltage connections for all years during the historical period.

Appointment Scheduling

The OEB requires a minimum standard of 90% for Appointment Scheduling within the required timeline of 5 business days. The legacy utilities' combined performance exceeds the minimum standard by an average of 4.5% every year, but they failed to meet to the target in 2017 with the result of 86.5%. In 2017, the performance fell short of the target due to a combination of adverse weather and the Locate Service Provider's ("LSP") unanticipated staffing issues. The resource constraint was due to an abnormal amount of rain that occurred in the spring of 2017, which caused major flooding, affecting the contractors' ability to perform timely locates. The problem compounded when the LSP did not ramp up their resources in time for the summer months, creating a backlog of appointments which was difficult to overcome. Elexicon's predecessors' combined performance improved after 2017 as they achieved a record high of 96.9% in 2018 and 94.1% in 2019. The combined performance is calculated using the Sum of "Number of appointments scheduled with customer or representative within 5 business days or on such later date as may be agreed upon by the customer and distributor" divided by the Sum of "Number of appointments requested by a customer or representative."

Appointments Met

The OEB requires a minimum standard of 90% for Appointments Met. Whitby Hydro and Veridian's consolidated performance against this metric improved over the historical period as it increased from

93.7% in 2014 to 99.7% in 2019. The former was the poorest performance year after which performance results were consistently above 99% and exceeded the OEB target by 8.7% on average. The combined performance metric is calculated by using the Sum of "Number of appointments completed as required" divided by the Sum of "Number of appointments scheduled with customer or representative."

Rescheduling a Missed Appointment

The OEB mandates a 100% target for Rescheduling a Missed Appointment. Elexicon's predecessors' combined performance was substantially below the target, averaging to 54.6% over the historical period. The legacy utilities' combined performance was well below the target during the early years of the historical period (2015-2017) but has improved in recent years (2018-2019) to levels marginally below the 100% target. It is important to consider that while performance levels were low during the early years of the historical period, there were very few instances of missed appointments in total. Therefore, if the legacy utilities failed to reschedule even one missed appointment, there was a significant impact on the performance result. In total, there were two missed appointments in 2015, three missed appointments in 2016, and three missed appointments in 2017. The root causes of these instances included human error during the creation of service orders, scheduling conflicts, and late arrivals. The predecessors' combined performance was marginally below the target in 2018 at 99.3%, but decreased to 96.9% in 2019. This occurred because staff performing locates were not correctly rescheduling missed appointments – the issue was identified early in 2020 and the appropriate procedures have since been corrected. The combined performance metric is calculated by using the Sum of "Number of appointments missed where there was an attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and an attempt to contact the customer within one business day to reschedule the appointment" divided by the Sum of "Number of appointments missed."

Written Responses to Enquiries

The OEB requires performance to be at least 80% and sets a target of 10 business days for completion. Whitby Hydro and Veridian's consolidated performance has been excellent over the historical period as it was consistently above 99% and exceeded the standard by 19.9% on average. The best performance result occurred in 2014 and 2017 at 100% and the poorest performance occurred in 2015 at 99.7%. The combined performance metric is calculated by using the Sum of "Written responses to qualified enquiries sent by the distributor within 10 business days" divided by the Sum of "Qualified enquiries."

Emergency Response

The OEB requires performance to be at least 80% and sets a target of 2 hours for rural areas and 1 hour for urban areas. The legacy utilities' combined performance in urban areas has improved over the historical period, increasing from 96.7% in 2014 to 99.1% in 2019. The best performance occurred in 2017 at 100% and the poorest performance occurred in 2018 at 91.8%. Generally, the performance levels were consistently above 96% and exceeded the target by 17% on average. Both predecessors achieved a result of 100% for rural areas over the entire historical period. The combined performance metric is calculated by using the Sum of "Emergency calls answered withing the specified times above" divided by the Sum of "Emergency calls."

Reconnection Performance

The OEB standard for Reconnection Performance is 85%. Elexicon's predecessors' consolidated performance has been excellent over the historical period at 100% for all years except 2016 where the result was 99.9%. The legacy utilities combined performance results have exceeded the OEB standard by 15% every year, on average.

<u>Billing Accuracy</u>

The OEB standard for Billing Accuracy is 98%. Whitby Hydro and Veridian's consolidated performance was consistently greater than 99.5% over the historical period. The best results occurred from 2017 to 2019 at 99.9% and the worst results occurred from 2014 to 2016 at 99.8%. Elexicon's predecessors have exceeded the minimum target by an average of 1.85% every year. The combined performance metric is calculated using the Sum of "Number of bills issued for the year " minus the Sum of "Number of inaccurate bills issued for the year" which is then divided by the Sum of "Number of bills issued for the year."

5.2.3.1.3 c) Effect on the DSP

The SQR performance measures listed above are key indicators of Elexicon's effectiveness at delivering quality customer service expected by its customers. Overall, the predecessors' consolidated performance and that of Elexicon in its first year of merged operations has met or exceeded targets for all years during the historical period. There were some cases where the legacy utilities failed to meet targets, but they quickly identified and rectified the root causes. While the combined historical performance does not indicate the need for strong corrective action, there are planned investments which are expected to help maintain or improve current performance levels.

The majority of investments supporting Elexicon's SQR performance are categorized under the Information Technology program. Connection of New Services and Reconnection Performance are the only measures which are not relevant to the Information Technology program. Programs which support these measures fall under the System Access category – examples include Connection of New Services, Customer Requested Work, and Road Relocations. Table 5.2-16 below provides examples of planned or completed projects which will benefit Elexicon's performance for the SQR measures listed above.

Table 5.2-16: Investment Programs Impacting SQRs

Service Quality Measure	Programs	Example Project
Telephone accessibility	Information Technology	Phone Hardware Upgrades
Telephone call abandon rate	Information Technology	Phone System Upgrade - IVR
Connection of new services	Connection of New Services, Customer Requested Work	New Load Forecast Methodology
Appointment's scheduling	Information Technology	Transition Customer Portal
Appointments met	Information Technology	CIS Merge Project
Missed appointments rescheduling	Information Technology	CIS Merge Project
Written response to enquiries	Information Technology	CIS Merge Project
Emergency response	Information Technology	Phone Hardware Upgrades
Reconnection performance	Connection of New Services, Customer Requested Work, Road Relocations	New Vintage Smart Meters Allowing Remote Disconnection / Reconnection
Billing Accuracy	Information Technology	Billing System Upgrade

5.2.3.2 Scorecard Metrics: Cost Efficiency and Effectiveness

5.2.3.2.1 Cost Control

5.2.3.2.1 a) Methods and Measures

<u>Total Cost Per Customer</u>

This metric reflects the total cost per customer and consists of two different components. The first is the operating and maintenance cost per customer. This metric is obtained by dividing the annual O&M expenditures by the number of customers. The second component is the capital cost per customer and is obtained by dividing the annual capital expenditures (as calculated in the Pacific Economics Group ("PEG") efficiency analysis) by the number of customers.

$$Total\ Cost\ per\ Customer = O\&M\ Cost\ Per\ Customer + Capital\ Cost\ Per\ Customer$$

<u>Total Cost Per KM of Line</u>

This metric reflects the total cost per kilometre of line and consists of two different components. The first is the operating and maintenance cost per kilometre of line. This metric is obtained by dividing the annual O&M expenditures by the kilometres of line. The second component is the capital cost per kilometre of line and is obtained by dividing the annual capital expenditures by the kilometres of line.

$$Total\ Cost\ per\ KM\ of\ Line = O\&M\ Cost\ Per\ KM\ of\ Line + Capital\ Cost\ Per\ KM\ of\ Line$$

5.2.3.2.1 b) Historical Performance

Table 5.2-17 below presents historical cost metrics data for Whitby Hydro and Veridian. It also includes consolidated data which reflects the combined performance of both legacy entities. Elexicon calculated the consolidated performance by completing a weighted average calculation based on relevant parameters as outlined below:

- Total Cost/Customer → based on the number of customers for each predecessor utility
- Total Cost/KM of Line → based on the kilometres of line for each predecessor utility

Table 5.2-17: Historical Performance for Cost Metrics

	Metric	2014	2015	2016	2017	2018	2019
Whitby	Total Cost/Customer	$628	$676	$689	$682	$681	-
	Total Cost/km of Line	$24,275	$26,052	$26,552	$26,241	$25,745	-
Veridian	Total Cost/Customer	$560	$577	$593	$578	$603	-
	Total Cost/km of Line	$25,720	$30,404	$27,593	$26,411	$27,737	-
Elexicon	Total Cost/Customer	$578	$603	$618	$605	$624	**$648**
	Total Cost/km of Line	$25,293	$28,988	$27,282	$26,361	$27,139	**$28,396**

Note: Consolidated Elexicon values found using the Sum of Total Cost / Sum of Customers or Sum of Km of Line respectively

Throughout 2017 and 2018 Elexicon's predecessors were engaged in merger discussions. In anticipation of the merger, the predecessors prudently identified initiatives that should be deferred until post-merger so that they could be undertaken more effectively on a combined basis in Elexicon. A significant contributor to lower historical OM&A costs were earlier than anticipated staff retirements and staff vacancies which were not backfilled in anticipation of the merger. Absent the planned merger, Elexicon estimates that operating costs per customer would have increased over this time. In 2019, Elexicon's operating costs were higher due to transition costs, such as legal and consulting, related to the Elexicon's merger. The 2020 metrics were unavailable at time of filing.

Over the last several years, capital costs have increased as Elexicon and its predecessor utilities have focused on the renewal and modernization of their distribution assets to enhance reliability for customers. Additionally, Elexicon has begun investments in system capacity to support major growth within the Pickering Seaton communities. Elexicon will continue asset replacement and rehabilitation in a managed timeframe and seek efficiencies in its spending.

5.2.3.2.1 c) Effect on the DSP

Cost Performance Metrics

Elexicon's goal is to continuously improve its cost performance as measured by both capital and O&M expenditures. There are several planned programs that are expected to help Elexicon pursue these objectives. The Information Technology program includes several projects which invest into operations, hardware, and software systems to improve business operations efficiency. This improved operational efficiency is expected to provide several benefits for Elexicon, one of most important being cost control. The projects in Information Technology that provide cost control benefits do so through improved monitoring, data management, and software upgrades – for example, planned projects include Capital Spend/Job Cost Reports, Records Management general – GIS, and GP/Reporting Enhancement.

O&M costs can also be controlled to a degree through investments into the System Renewal and System Service categories. Programs within these categories aim to improve the health of the distribution system and reduce the likelihood of unexpected asset failure. When assets fail unexpectedly (such as during adverse weather events), the utility must complete reactive asset replacements. The cost of reactive replacements is higher than the cost of proactive replacements as they are subject to more stringent time constraints and may require engaging contractors on short notice. The System Renewal and System Service investment categories include programs which are intended to improve the health of the distribution system assets, increase resilience to reactive failures, and reduce the risk of costly reactive repairs.

More generally, as Elexicon continues identifying and executing on merger-related synergies over the remainder of its Deferred Rebasing timeframe, it expects to make meaningful contributions towards keeping its cost performance stable.

5.2.3.2.2 DSP Implementation Progress

5.2.3.2.2 a) Methods and Measures

Distribution System Plan Implementation Progress

The OEB has permitted electricity distributors to use their discretion to develop and implement a measure that they feel most effectively reflects their performance in plan implementation. Elexicon plans to use the following formula to calculate DSP Implementation Progress:

$$DSP\ Implementation\ Progress = \frac{Total\ Annual\ Actual\ Capital\ Spend}{Approved\ Annual\ Capital\ Budget}$$

Neither the amount in the numerator nor in the denominator includes financial contribution made by outside parties (customers, developers, municipalities, etc.). Elexicon is very cognizant of the need to prudently manage its capital spend and ensure that it remains within the approved capital budget dollar envelope throughout the year. The utility aims to meet all planned schedules and complete the entirety of capital programs every year.

5.2.3.2.2 b) Historical Performance

Elexicon's predecessors' consolidated DSP Implementation Progress performance is summarized in Table 5.2-18 below. Elexicon has adopted the legacy Veridian minimum target of 90% for this performance measure. A performance result of 100% would mean that the actual capital expenditures were equal to the planned budget. The 90% target indicates that the maximum acceptable deviation from the ideal performance level is +/- 10%. The deviation results of this metric are also shown in Table 5.2-18 below.

The legacy utilities' combined performance has improved over the historical period as the amount of absolute deviation decreased from 12.4% in 2014 to 4% in 2019, before increasing in 2020 to 21.01%. 2020 was the poorest performance result during the historical period and the predecessors failed to meet the 90% target in 2014, 2015 and 2020. The best result occurred in 2018 at a deviation of only 0.93%. There is high variability in Whitby Hydro and Veridian's consolidated performance early in the historical period as the result in 2015 was 10.05% below 100% and the result in 2016 was 9.62% above 100%. This is a consequence of the fact that this measure reflects a utility's ability to complete planned projects, which at times is a function of circumstances outside of its control.

Elexicon's legacy entities were unable to complete all planned work in 2015, which was delayed until the following year. In 2017, the absolute deviation fell by nearly 50% as the result was only 5.16% below the target performance. In recent years, performance levels have improved as the result was only 0.93% below complete alignment in 2018 and 4% above in 2019. Although the average absolute deviation of 9% is notable, there is minimal cause for concern because the largest deviations occurred early in the historical period and have improved in recent years, excluding 2020 which experienced project delays due to COVID 19.

Table 5.2-18: Historical Performance for DSP Implementation Progress

	2014	2015	2016	2017	2018	2019	2020
Result	87.6%	89.95%	109.62%	94.84%	99.07%	104.00%	78.99%
Deviation	-12.4%	-10.05%	9.62%	-5.16%	-0.93%	4.00%	-21.01%

5.2.3.2.2 c) Effect on DSP

The legacy entities' combined performance has been satisfactory over the historical period and there are planned investments to maintain or improve current levels. Given the nature of this performance measure, all planned investments play a role in achieving 100% alignment between planned and actual expenditures. However, there is a subset of projects which target improvements in operational efficiency and are expected to have a significant impact on this performance measure. These projects generally fall under one of three programs: Information Technology, Fleet, or Tools and Equipment.

In addition, and as discussed in the subsequent sections, Elexicon is in the process of substantially enhancing its tools and processes comprising and supporting the Asset Management program. As these enhancements take effect over the Forecast Period, the utility expects them to add further rigour, efficiency and flexibility across all stages of the work planning and execution value chain.

5.2.3.2.3 PEG Efficiency Assessment

5.2.3.2.3 a) Methods and Measures

<u>Efficiency Assessment</u>
The OEB's consultant PEG has developed an econometric model to predict total costs for electricity distributors. This model enables benchmarking and subsequent stretch factor assignment, separating all utilities into five Efficiency Cohorts. The efficiency measure compares PEG's calculation of total actual costs with those the model predicts for a utility with Elexicon's size, load and customer mix. PEG calculates total costs by reviewing annual data submissions provided by utilities which include both Capital and OM&A costs and assigns all utilities across five Cohorts from most to least efficient.

5.2.3.2.3 b) Historical Performance

The results of the PEG efficiency assessment for both predecessor utilities are shown in Table 5.2-19 below. Both Whitby Hydro and Veridian ranked in Cohort 3 – corresponding to actual total costs within +/- 10% from the PEG Model-predicted efficient cost levels. The PEG efficacy assessment results for 2020 were not yet available at the time of filing.

Table 5.2-19: Historical Performance for PEG Efficiency Assessment

	2014	2015	2016	2017	2018	2019
Efficiency Assessment - Whitby	3	3	3	3	3	N/A
Efficiency Assessment - Veridian	3	3	3	3	3	N/A
Efficiency Assessment - Elexicon	N/A					3

In 2019, Elexicon's actual total costs were below the predicted costs by 1.0%. This represents a slight increase from Veridian's 2016- 2018 average total costs which were 3.1% below the total predicted costs and Whitby Hydro's 2016-2018 average total costs which were 3.9% below the total predicted costs. The increase in costs for 2019 is partly due to the merger transition, which is typical for a company to experience in the initial years of a merger. Elexicon expects such transition costs to decrease in 2020 as the organization starts to realize further cost savings as efficiencies are leveraged following the initial investments and/or transition cost expenditures. The 2020 metric was unavailable at time of filing.

5.2.3.2.3 c) Effect on DSP

Among other uses, the PEG Efficiency Assessment performance metric measures a utility's ability to manage its system expenditures. Elexicon's DSP includes investments which are intended to help monitor and control its costs. The Information Technology program includes efforts driven by the goal of increasing business operations efficiency such as improved monitoring, data management, and software upgrades.

For example, the planned projects include Capital Spend/Job Cost Reports, Records Management general – GIS, and GP/Reporting Enhancements. Asset renewal programs are also expected to assist in managing overall costs as they reduce the risk of asset failure which would result in reduced operational efficiency and require costly reactive replacements. A detailed description of the anticipated cost savings which would benefit this performance measure is provided in section 5.2.1.3.

In addition, the ongoing enhancement of Elexicon's Asset Management capabilities discussed throughout this plan is driven in part by the objective of improving the overall planning effectiveness efficiency – to ensure that the available capital and operating funds target the most pressing needs and the most valuable operational improvement projects.

5.2.3.3 Scorecard Metrics: Asset/ System Operations Performance

5.2.3.3.1 Safety

5.2.3.3.1 a) Methods and Measures

Maintaining a high level of employee safety, health & wellness, and public safety are key corporate objectives. The safety measure is generated by the ESA and includes three components:

- Component A – Public Awareness of Electrical Safety
- Component B – Compliance with Ontario Regulation 22/04
- Component C – Serious Electrical Incident Index

<u>Component A – Public Awareness of Electrical Safety</u>

Elexicon's predecessors' scores for the Public Safety Awareness Index were obtained by surveying members of the general public 18 years of age or older in their licensed service areas. The surveys followed the requirements of a detailed guide that was published by the OEB on November 25th, 2015. The guide requires that the survey be conducted at least once every two years. This survey measured the effect of the legacy utilities' ongoing safety awareness efforts which included:

- School Safety Awareness Presentation Program
- Co-promotion of Electrical Safety Authority ("ESA") safety awareness campaigns
- Customer Newsletters
- Website Communications
- Social Media
- Hazard Specific Campaigns

<u>Component B – Compliance with Ontario Regulation 22/04</u>

Ontario Regulation 22/04 establishes objective-based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. There is annual refresher training for all staff involved with Ontario Regulation 22/04 and compliance is maintained through ongoing reinforcement and education.

Component C – Serious Electrical Incident Index

This metric details the number and rate of serious electrical incidents occurring on the legacy entities' distribution systems. The rate of serious electrical incident occurrence is normalized per 1000km of line. A "serious electrical incident" would appear as part of this composite index if it has been determined that a member of the public was involved in the incident and that the result of the incident either caused a death or a critical injury or had the potential to cause a death or a critical injury as defined by the ESA.

5.2.3.3.1 b) Historical Performance

Table 5.2-20: Historical Performance for all Safety Performance Metrics

	Measure	Target	2014	2015	2016	2017	2018	2019	2020
Whitby	Level of Public Awareness	N/A	N/A	78.90%	78.90%	83.6%	83.6%	N/A	N/A
	Level of Compliance with *O. Reg. 22/04**	C	C	C	C	C	C		
	Serious Electrical Incident Index	0	0	0	0	0	1		
	Serious Electrical Incident Index per 10, 100, 1000km	0	0	0	0	0	0.906		
Veridian	Level of Public Awareness	N/A	N/A	82.00%	82.00%	83.0%	83.0%	N/A	N/A
	Level of Compliance with *O. Reg. 22/04**	C	C	C	C	C	C		
	Serious Electrical Incident Index	0	0	0	1	1	1		
	Serious Electrical Incident Index per 10, 100, 1000km	0	0	0	0.445	0.389	0.38		
Elexicon	Level of Public Awareness	N/A	N/A	81%	83%	83%	84%	84%	84%
	Level of Compliance with *O. Reg. 22/04**	C	C	C	C	C	C	C	C
	Serious Electrical Incident Index	0	0	0	1	1	2	0	0
	Serious Electrical Incident Index per 10, 100, 1000km	0	0	0	0.273	0.268	0.528	0	0

**Compliance Assessment grades: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).*

Level of Public Awareness

The predecessor utilities conducted surveys that measured the Level of Public Awareness every two years. As shown in Table 5.2-20 above, scores are repeated in 2016, 2018, and 2020. Elexicon has not set a target for this performance measure. However, Elexicon's predecessors' consolidated performance results for this metric are satisfactory as they are consistently above 80% and show improvement between cycles. Therefore, significant remedial actions are not required to address this metric, but Elexicon plans to make investments which will assist in maintaining or improving current performance levels.

Level of Compliance with O. Reg. 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998 which covers various aspects of Electrical Distribution Safety including asset ownership, safety standards, and compliance. There are three possible outcomes for this performance metric: Compliant (denoted as “C”), Needs Improvement (denoted as “NI”), and Non-Compliant (denoted as “NC”). Whitby Hydro and Veridian’s performance against this metric is excellent as both predecessor utilities achieved compliance for all years during the historical period.

Serious Electrical Incident Index

Elexicon’s target is to have zero serious electrical incidents, and the utility places safety above all other objectives. However, the predecessor utilities experienced a total of four serious electric incidents during the historical period. Veridian experienced three incidents in total which occurred in 2016, 2017, and 2018. Whitby Hydro’s performance amounted to one incident recorded in late December 2017. This incident was triggered by adverse weather due to extreme cold temperatures and was considered part of a major weather-related event.

5.2.3.3.1 d) Effect on the DSP

The legacy utilities’ performance is satisfactory for the Level of Public Awareness and Level of Compliance with O. Reg. 22/04 metrics. While the historical period included several electrical safety incidents, the most recent performance since the beginning of merged operations suggests a concerted effort to prevent any incidents through operating and capital renewal initiatives.

Elexicon plans to make investments that will help improve the distribution system’s safety and assist in maintaining or improving the current performance levels. This is primarily accomplished by investments in the System Renewal and System Service categories, which include programs that target removal of aged and deteriorated plant and enable faster identification and resolution of incidents.

5.2.3.3.2 System Losses

5.2.3.3.2 a) Methods and Measures

The System Losses metric measures the distribution system’s efficiency in delivering power to customers. It is calculated by dividing the total distribution losses by the total kWh purchased, as presented in the formula below. Elexicon does not have an established target for this performance measure.

$$System\ Losses = \frac{Total\ Distribution\ Losses}{Total\ kWh\ purchased}$$

5.2.3.3.2 b) Historical Performance

Elexicon’s predecessors’ consolidated performance has been consistent over the historical period, ranging from 3.5% to 4.5% and averaging to 4%. Although there is no established target, the performance trend is positive as it shows an improvement over the historical period. Elexicon has planned investments that will assist in further improving performance. In 2019 there was an increase in loses due to new loads in Ajax, Pickering, and Whitby which are far away from sources as well as General Service loads reducing due to COVID 19. The 2020 metrics were unavailable at time of filing.

Table 5.2-21: Historical Performance for System Losses

	Metric	2014	2015	2016	2017	2018	2019
Whitby	Total Distribution Losses (GWh)	36.1	32.2	33.3	32.3	32.7	

	Metric	2014	2015	2016	2017	2018	2019
	Total GWh Delivered (excluding losses)	859.1	860.5	871.7	823.4	870.9	
	Total GWh Purchased	895.2	892.7	905.0	855.7	903.6	
	System Losses	4.03%	3.61%	3.67%	3.78%	3.62%	
Veridian	Total Distribution Losses (GWh)	103.0	124.4	107.2	105.3	105.7	
	Total GWh Delivered (excluding losses)	2557.7	2545.1	2581.1	2508.2	2641.5	
	Total GWh Purchased	2660.7	2669.6	2688.3	2613.4	2747.2	
	System Losses	3.87%	4.66%	3.99%	4.03%	3.85%	
Elexicon	Total Distribution Losses (GWh)	139.1	156.6	140.5	137.6	138.4	150.4
	Total GWh Delivered (excluding losses)	3416.8	3405.6	3452.8	3331.6	3512.4	3443.5
	Total GWh Purchased	3555.9	3562.3	3593.3	3469.1	3650.8	3593.9
	System Losses	3.91%	4.40%	3.91%	3.97%	3.79%	4.19%

Note: Consolidated values for Total Distribution Losses, Total GWh Delivered & Total GWh Purchased are the sum of Whitby & Veridian values. Consolidated System Losses is them calculated using the above formula.

5.2.3.3.2 c) Effect on the DSP

System Losses can be caused by aging assets which lose their ability to efficiently perform their function (e.g., transformers, overhead conductors, and underground cables) and legacy lower-voltage distribution feeders prone to higher losses. There are several planned renewal and upgrade programs which aim to improve the condition of these aging assets through replacement or refurbishment. In addition, there are some voltage conversion projects planned over the forecast period which will increase the voltage capacity of some assets. Voltage conversion work is expected to reduce the current in the system, help reduce the pace of asset deterioration, and result in decreased system losses. These programs are categorized under the System Service and System Renewal investment categories.

5.2.3.3.3 Power Quality

5.2.3.3.3 a) Methods and Measures

MAIFI or Momentary Average Interruption Frequency Index is a measure of the frequency of momentary outages, which are defined as service interruptions with a duration of one minute or less. These outages are less significant than sustained outages which can last for several hours and often require work crews to perform repairs. However, momentary outages have a considerable impact for some customers who rely on a continuous supply of power, such as commercial customers who operate industrial machinery or other sensitive equipment. MAIFI is calculated using the formula presented below. Elexicon sets performance targets for MAIFI by calculating the average performance over the last five years.

$$MAIFI = \frac{Total\ momentary\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

5.2.3.3.3 b) Historical Performance

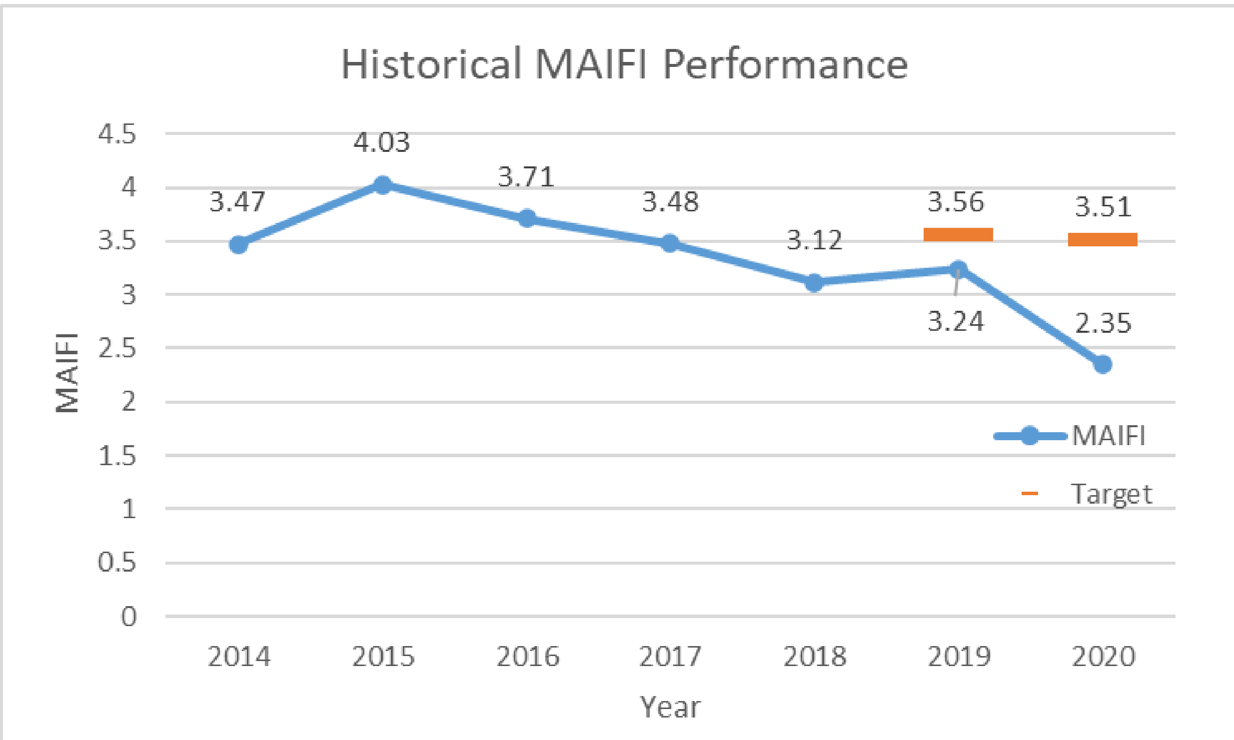
Table 5.2-22 and Figure 5.2-20 below show the consolidated historical MAIFI performance for Elexicon's predecessors. Historical targets are not available because this is a new measure which

Elexicon plans to adopt moving forward. As outlined above, historical outage data is available as far back as 2014 for both predecessors – therefore, historical targets from 2014 to 2018 cannot be calculated. In 2019, the MAIFI result of 3.24 interruptions per customer met the performance target of 3.56 interruptions per customer. The worst performance was recorded in 2015 with a MAIFI value of 4.03 interruptions per customer. A cause code analysis reveals that this occurred because the distribution system experienced more outages triggered by Adverse Weather or Unknown cause codes. Since 2015, the legacy utilities combined MAIFI performance has improved as it displays a decreasing trend over the historical period. The current MAIFI target is 3.51 interruptions per customer.

Table 5.2-22: Summary of Historical MAIFI Performance

	2014	2015	2016	2017	2018	2019	2020
MAIFI	3.47	4.03	3.71	3.47	3.12	3.24	2.35
Target	N/A	N/A	N/A	N/A	N/A	3.56	3.51

Figure 5.2-20: Historical MAIFI Performance



5.2.3.3.3 c) Effect on DSP

Elexicon's predecessors' performance for MAIFI displays a clear decreasing trend over the historical period. The performance results do not suggest the need for dedicated remedial action. However, several of the planned investment programs are expected to help maintain or improve the current trend. Given that momentary outages are also a subset of reliability performance, the programs relevant to improving SAIDI and SAIFI also contribute to MAIFI improvements. These programs fall under the System Renewal or System Service investment categories and are summarized below. Additional information about these programs can be found in Section 5.4.

System Renewal

- Renewal Programs – Distribution Transformers
- Renewal Programs – Rebuilds
- Renewal Programs – Poles
- Renewal Programs – Reactive
- Renewal Programs – Switches & Switchgears
- Substation Renewal
- Voltage Conversions – Reliability
- Renewal Programs – Others (covers porcelain insulator replacement and other uncategorized investments)

System Service

- Substations Growth & Expansion
- System Reliability Improvement
- Standard Equipment Reliability & Compliance

5.2.3.4 Custom DSP Measures

In addition to tracking its performance using the measures comprising the Distributor Scorecard, Elexicon proposes to deploy and report on three additional custom DSP metrics over the Forecast Period. Elexicon expects that tracking these metrics will help it obtain increasingly nuanced insights as to the impact of its asset intervention decisions on the operational performance and lifecycle economics of its asset base.

5.2.3.4.1 OEB Guidance on Custom DSP Measures

As per the OEB's Chapter 5 Filing Requirements direction, in addition to the unit cost metrics comprising Appendix 5-A (discussed in Section 5.2.3.2.1) utilities are expected to provide measures and metrics that address the following areas:

- Customer Oriented Performance;
- Cost Efficiency and Effectiveness of Planning Quality and DSP Implementation; and
- Asset ad/or System Operations Performance.

For each of the metric, distributors are expected to provide an explanation of how historical performance has affected the DSP and how it has been used to continuously improve the asset management and capital expenditure planning process.

5.2.3.4.2 Custom Measures Proposed for the Forecast Period

Table 5.2-23: displays the three custom DSP measures that Elexicon plans on tracking in addition to the core Distributor Scorecard measures. The utility selected these measures given their alignment with the expected scope of enhancements to the AM tools and processes that it expects to undertake over the coming years. The passages that follow provide the background information associated with each of these measures and articulate their relevance to the DSP and the processes underlying it.

Table 5.2-23: Custom DSP Performance Measures

Customer-Oriented Performance	Asset and System Operations Performance	Cost Efficiency / Effectiveness in Delivering the Plan
Worst Performing Feeders: FESI-9	Defective Equipment SAIDI	Cable Replacement Value Deferred

5.2.3.4.2(a) Customer-Oriented Performance: Worst Performing Feeders: FESI-9

Background: Elexicon closely monitors the reliability performance of all of its feeders throughout the year, generating and analysing monthly reliability reports, which include detailed analysis of all outage, and identification of a subset of WPF, which are assessed for potential near-term asset intervention opportunities (e.g., preventative maintenance, replacement, or refurbishment). While the feeders on the WPF list may vary from month to month, Elexicon is exploring ways of gradually improving the consistency of reliability performance across its system. To this end, the utility will track the Feeders Experiencing Sustained Interruptions measure ("FESI") to monitor and attempt to reduce over time the number of sustained outages experienced across Elexicon's circuits.

Definition: The FESI-9 measure will track and report the number of feeders experiencing 9 or more sustained interruptions (1 minute or longer in length) over a rolling 365-day period. The threshold of 9 has been determined by way of analysis of Elexicon's and its predecessors' historical reliability data, which suggests that outages on feeders with 9 or more sustained interruptions in the year correspond to 25% of all Customer Interruptions ("CI") experienced in the past. Given the size of Elexicon's service territory and the variability in feeder lengths, distance from service centres and number of customers per feeder, at this juncture the utility elected to focus this metric on a subset of feeders with the greatest potential for proactive outage mitigation relative to the cost of doing so. Accordingly, the proposed measure will only focus on the top 50% of Elexicon's feeders by customer count under normal operating conditions. To focus on issues where it has the greatest degree of control, this measure will also exclude the Major Events Days, Loss of Supply outages, and Planned Outages.

Importantly, the utility recognizes that customers served by the most distant / least loaded feeders may be affected by poor reliability to a significant degree as well. Once it gains experience with tracking and operationalizing the insights gained from this measure, Elexicon will consider devising similar measures targeting the particularly vulnerable or otherwise notable portions of its system.

Recent Performance Trend: The following table captures the historical performance data for Elexicon and its predecessors on the FESI-9 measure as defined above. While the underlying data is available, the utility notes that it has not previously analyzed its reliability using this approach. As such, no proactive or corrective actions have bene taken to manage performance according to this metric. Feeders that frequently make the FESI-9 list become candidates for focused investment in renewal and reliability investments. 2020 metrics were unavailable at time of filing.

Table 5.2-24: Historical FESI-9 Performance

Measure	2015	2016	2017	2018	2019
FESI-9 (Top 50% of Feeders)	22	21	19	23	24

Table 5.2-25: Feeders on the FESI-9 List for Three or More Years

Years on FESI-9 List	Feeders
5	BAYRF1, MONAF4, JAMSF1, PICBF6
4	DOWTF4, SPRYF2, PICBF5, NOTIF2, GRAVF1, SANDF1, SANDF2, EDGEF2
3	MONAF2, GRAVF3, FAIRF1, PICBF2, 11F4

Relevance to the Plan: Rather than tracking the frequency and duration of outages, the measure focuses strictly on the number of sustained interruptions (1 minute and longer) occurring on a given feeder. Unlike the system average measures like SAIDI and SAIFI, FESI-9 represents a move towards a more customer-oriented reliability measure in that it focuses on performance of a specific subset of feeders (and the customers they serve) that experience comparatively more outage occurrences in a given year. By reviewing the outage data underlying this metric's results, Elexicon expects to derive additional insights as to the predominant drivers of these issues and develop both near- and longer-term plans to address these issues across the service territory. While Elexicon is not committing to a specific target for this new measure, its overall expectation is to gradually reduce the number of feeders that meet the FESI-9 threshold.

5.2.3.4.2(b) Asset and System Operations Performance: Defective Equipment SAIDI

Background: Given that outages caused by in-field equipment failures or malfunctions are considered among the most controllable of the outage cause codes tracked by utilities, Elexicon elected to separately measure SAIDI separately for this category of power outages. Survey results from 2020 (Appendix B) indicate that customers are more sensitive to the duration of outages than the frequency; hence, defective equipment SAIDI is tracked as opposed to SAIFI.

Definition: the measure will be calculated and reported in the same manner and format as the standard SAIDI metric and showcase the total duration of sustained interruptions caused by Defective Equipment experience by an average Elexicon customer in a year. However, unlike the full SAIDI metric, the basis for this measure will be made up of only those outages classified as having been caused by the Defective Equipment Cause Code.

Recent Performance Trend: The following table showcases Elexicon's and its corporate predecessors' combined results on this measure.

Table 5.2-26: Historical Defective Equipment SAIDI Performance

Measure	2015	2016	2017	2018	2019	2020
Defective Equipment SAIDI	0.74	0.50	0.27	0.51	0.36	0.30

Relevance to the Plan: Replacement and/or refurbishment of aged and deteriorated assets makes up a major portion of Elexicon's projected DSP spend over the Forecast Period. The Defective Equipment SAIDI measure will help the utility monitor whether and to what extent its ongoing system capital renewal spend is generating positive reliability performance outcomes over the longer term. Should the measure indicate concerning performance trends, Elexicon staff would conduct the requisite follow-up investigations and devise the appropriate response strategies.

5.2.3.4.2(c) Cost Efficiency and Effectiveness in Delivering the Plan: Cable Replacement Value Deferred

Background: as noted at several junctures in this document, Elexicon has adopted a life extension approach for underground cables previously utilized by Veridian. This approach entails injecting suitable cable segments (identified via past outage analysis and cable testing) with a sealant solution, designed to reinforce the cables outside coating to prevent further outages. While Veridian's past experience points at the efficacy of this approach as a means of extending the cables' lifecycle, Elexicon is interested in further exploring the underlying economics of this technique.

Definition: this measure will track the cumulative replacement value of all cable segments subjected to cable injection over the Forecast Period. The replacement value deferred will be calculated by multiplying the appropriate cable replacement unit cost by the number of meters of length of each segment injected, less the cost of testing and injection. The unit cost value applied to each segment will be drawn from Elexicon's planning cost database, using the unit cost appropriate for the type of each cable segment subjected to life extension (e.g., PILC, XLPE, etc.) in the year in which the job was executed. The cost of testing and injection subtracted from the replacement value deferred will be sourced from the contractor final cost data in each year. The resulting net replacement value deferred through life extension will be summed up over the Forecast Period. In other words, the value reported in each successive Plan Year will represent a cumulative total to date.

Recent Performance Trend: Elexicon or its predecessors have not previously tracked this new measure. As such, the historical performance information is not available.

Relevance to the Plan: given their installation and reactive maintenance logistics, underground cables represent one of the most capital-intensive elements of any distributor's line infrastructure. By tracking the proposed measure, Elexicon intends to showcase the economic value add represented by life extension activities that defer the need for cable replacement. By tracking the reliability performance of cables subjected to injection over time, Elexicon also intends to enhance its understanding of the expected length of life extension time that injection provides on average. By analyzing the underlying data (e.g., type / age or number of past failures of a cable having been injected) the utility can also enhance its understanding of the characteristics of candidate cable segments that present the most promising life extension opportunities

5.2.4 Realized Efficiencies due to Smart Meters

The deployment of Smart Meters as mandated by the Ontario Government starting in mid-late 2000's has arguably been an example of the single largest digital transformation project impacting distribution utility operations. Aside from obviating the need for manual meter readings, the transition to Advanced Metering Infrastructure ("AMI") enabled distributors to perform a number of additional functions and collect data useful in both system planning and asset management.

While Smart Meter initiative implementation cost records could be traced back to the associated recovery applications for Elexicon's predecessor utilities, neither Whitby Hydro nor Veridian tracked the quantifiable benefits associated with efficiencies enabled by Smart Meters. As such, Elexicon is unable to quantify these efficiencies as the logistics of creating even a directionally accurate estimate would be impractical and inconsistent with the utility's ongoing efforts to realize integration-related O&M efficiencies. Therefor there are no quantitative descriptions are available. However, the following passages describe in a qualitative manner the types of operational benefits that the Smart Meters and the associated infrastructure have enabled.

<u>Control Room and Service Improvements from Last Gasp & Pinging</u>

Last Gasp Technology: Whitby Hydro's system featured real-time outage identification for residential customers via integration of AMI infrastructure with the former utility's GIS and OMS systems. When a residential smart meter loses power, it sends out a 'last gasp' signal that appears on the OMS screen in the control room in real time. Depending on the magnitude of the number of meters out of service, Whitby Hydro's control room would be able to determine the severity of the outage. An understanding of the severity of the outage would in turn allow the utility to send the adequate number of resources to respond and better estimate the requisite restoration time.

For the former Veridian service territory, only 30 to 40% of meters featured last gasp technology given the earlier vintage of units and the communication issues in the parts of its service territory. Moving forward, Elexicon will replace legacy Veridian meters that lack last gasp functionality once the meter seal expires to provide this benefit for the entirety of the service territory.

Pinging Technology: when a customer calls Elexicon to report an outage, Elexicon can use AMI pinging capabilities to verify if power has been interrupted. This reduces the need to manually check for outages and eliminates the needs for additional truck rolls. By pinging a variety of meters within a selected area for outages, this can help reduce and identify the device that has been tripped.

<u>Net Revenue Lag Reductions</u>

As has been documented through numerous Lead-Lag Studies submitted by utilities in the course of their past rate applications, the introduction of Smart Meters has significantly reduced the Net Revenue Lag associated with distribution operations. As the time of meter data collection has been shortened significantly, it has had the commensurate impact on the length of time that it took utilities to collect its revenues since the date of meter reading. With the reduction of Net Revenue Lag, the Working Capital Allowance required by utilities has also significantly declined, thereby reducing the overall Revenue Requirement underlying the distribution rates. Both Whitby and Veridian customers have benefitted from these reductions over time.

<u>Distribution Planning and Asset Management utilizing Smart Meters</u>

Transformer Loading Data: Elexicon utilizes Smart Meters to monitor the loading of distribution transformers serving customers. Data that can be captured include the consumption and demand for varying time intervals. This data is important for providing the engineering, planning and asset management departments with knowledge of the state and condition of assets.

The planning department utilizes the data collected from Smart Meters for system load flow studies, and other exploratory projects. In addition, transformers can be sized using knowledge of existing customer meter data when a new connected customer is like an older customer. The analysis and review of similar customer profiles allows Elexicon to optimize asset investments. Load Forecasting, and Load Shape studies are also performed using Smart Meter data. Renewal of transformers, upgrades to service, and any other activities can be planned with analysis of historical loading data.

Operational Efficiency for Operations and Fleet Departments

Smart Meter implementation has afforded operational efficiencies to operational departments like Lines, Stations, and Metering. Due to the ability of Control Room to identify the severity of outages, the amount of personnel needed to respond to a call is reduced. Furthermore, an understanding of how the grid has been affected with respect to the locations of smart meters allows operators and field staff to identify where a specific issue has occurred. In parallel with staff efficiencies, the fleet department also experiences efficiencies from Smart Meter data. As the number of staffing resources are more accurately identified for calls, less vehicles from fleet will be required. This assists in preventing unnecessary wear and deterioration on existing fleet assets. As smart meters provide location-based information, choosing the required fleet vehicles also becomes easier.

Customer Service Efficiencies through Smart Meter Data Access

As Smart Meter data is easily accessible by the Customer Service and Billing department, this creates material efficiencies for data extraction purposes to enable faster and more efficient customer service. While older analog meters required manual trips to collect and/or verify the data, Elexicon’s Customer Service Representatives can access this data on demand to facilitate client inquiries or coordinate any meter disputes. Moreover, Smart Meters allow the utility to remotely disconnect meters for accounts which no longer require service.

5.3 ASSET MANAGEMENT PROCESS

5.3.1 ASSET MANAGEMENT PROCESS OVERVIEW

Balancing the Near-Term and Longer-Term AM Priorities: A Transitional Approach

As a recently formed utility, Elexicon views the merger as an opportunity to define and progressively build on a new and expanded set of Asset Management ("AM") capabilities, grounded in objective assessment of current needs, evidence-based exploration of emerging risks, and economic optimization of available resources

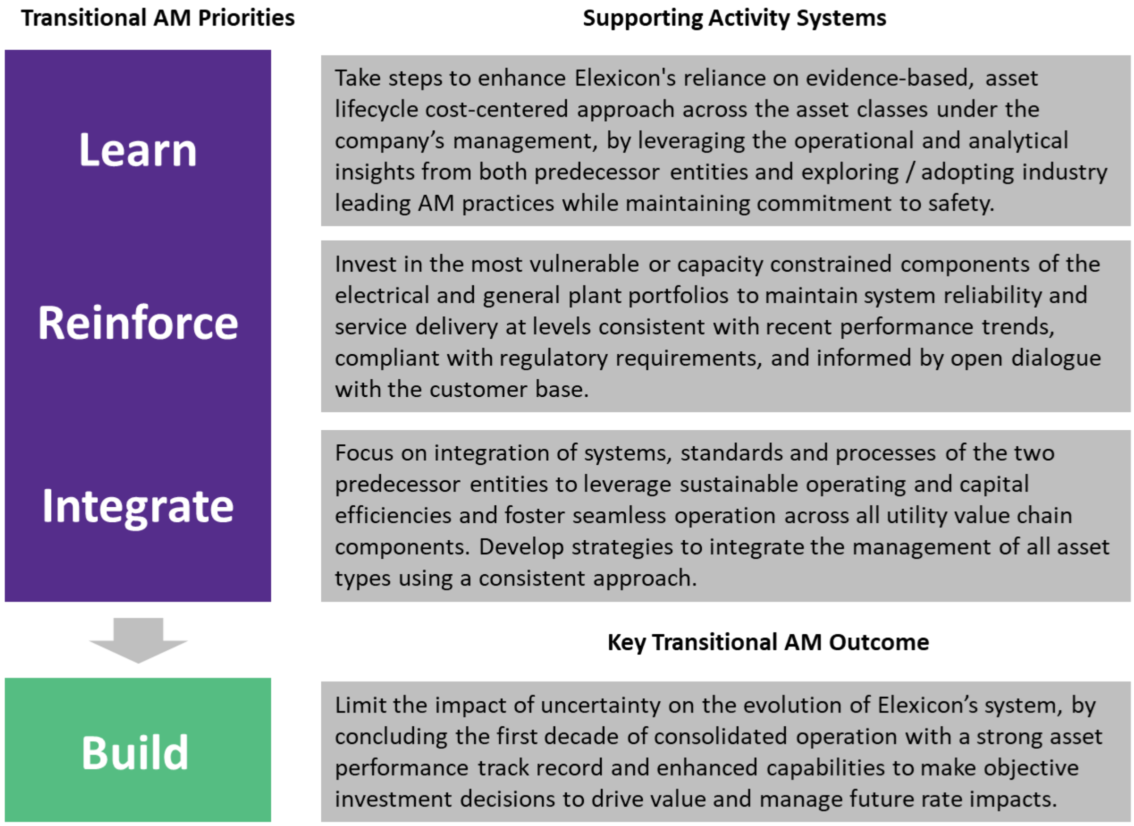
Elexicon understands that Asset Management Excellence is a multi-year journey of continuous improvement that requires managerial dedication and clarity of focus at every step of the way. Over the first 20 months of its merged operations, Elexicon's overarching focus in the AM subject area has been on *consolidation* and *continuity*:

- analyzing the predecessors' AM practices and latest available near-term plans;
- integrating legacy practices into practical and consistent AM approaches;
- identifying and addressing the most pressing medium-term asset intervention needs;
- ensuring ongoing service continuity across the merged service territory; and
- outlining the continuous improvement path towards future AM enhancements.

The utility's longer-term goal in the AM subject area is to continue developing a framework of tools and processes that are aligned with and informed by the industry-leading AM approaches such as the ISO 55000x group of standards. In fashioning a modern and flexible AM framework, Elexicon's goal is to integrate the best aspects of its predecessors' AM strategies with the emerging body of research and practical approaches from across the broader industry. Looking ahead at its first rebasing application as a merged utility in 2029, Elexicon plans to dedicate the coming years to enhancing and refining its AM analytics capabilities to deliver a clear, focussed, and analytically robust investment plan that reflects Elexicon's corporate identity, strategic priorities and empirical performance from data gathered over the first decade of its integrated operations.

To balance the near-term consolidation and service continuity objectives with the medium/longer term goals of targeting AM excellence through progressive enhancements of its tools and processes, Elexicon outlined a set of overarching Transitional AM priorities captured in the Figure 5.3-1 below.

Figure 5.3-1: Transitional AM Priorities 2019-2029



As the above diagram indicates, Elexicon's overarching priority as a recently merged asset management organization is to maintain (and where possible, improve) the performance of its growing and complex system that features a wide variety of asset types that stretch across urban areas with high load density, and rural landscape with challenging natural terrain. To attain this objective in the near-term, Elexicon is leveraging the analysis and near-term plans available from its predecessors, noting the areas where the two legacy utilities adopted materially different approaches to enable further refinement over time.

As it learns more about its system and the opportunities it presents, the utility is also thinking ahead and taking important steps to integrate the legacy processes into a unified and consistent asset lifecycle management and investment planning value chain, identifying opportunities for gradual adoption of more advanced AM analytics approaches. The following sections highlight practical examples of this transitional approach to date, which include a number of important recent enhancements, such as the consolidation of investment planning and justification processes across the electrical and general plant asset classes into a single business case format, adoption of utility-wide AM Objectives, and early steps towards introduction of probabilistic analysis as a component of asset lifecycle management and investment planning.

5.3.1 a) Asset Management Objectives

Purpose of AM Objectives

Elexicon understands that at the basis of any AM Process must lie a clearly articulated and balanced expression of corporate values, grounded in exploration of relative trade-offs across multiple desired outcomes. While typically qualitative in its nature, the overarching AM value framework serves as a key input into assumptions used in quantitative investment planning and prioritization tools and processes. To clearly articulate the set of corporate values that guide its AM process, in the summer of 2020 Elexicon's Executive Leadership ("ELT") undertook a comprehensive planning exercise that defined a consistent set of utility-wide AM Objectives that capture corporate values most relevant to asset management in the form of outcome-oriented statements supported by relative weightings.

2020 AM Objectives Setting Process Details

To make the objective-setting explicitly tied to the utility's operational circumstances, Elexicon developed a set of practical examples, representative of impact of asset failures or malfunctions corresponding to each objective. Each set of impacts of asset failure / malfunction included examples across five increasing severity categories, calibrated to keep the magnitude of economic impact as consistent as possible across each severity band. To ensure that impact examples were equally relevant to both electrical and general plant assets, the definition of each objective attempted to incorporate both types of asset failures, while all relevant impact category definitions identified two complementing sets of impacts –stemming from electrical and general plant failures.

Using this framework of overall objectives supported by specific examples of negative impacts, Elexicon's ELT assigned relative weightings to each objective using the Analytical Hierarchy Process ("AHP") Pair-Wise assessment model. Similar in its process flow to the optometric corrective vision lens selection where a patient is repeatedly asked to select the better option across a number of corrective lenses, the AHP worksheet for AM objectives asked individual ELT members to rank each objective relative to all others using a consistent scale, and subsequently amalgamated the results across the entire ELT. The exercise's final output was the relative weighting (expressed in percentages) across the nine AM objectives previously selected.

Elexicon's Current AM Objectives and Relative Weightings

Table 5.3- provides the final results of the AM Objectives Definition and Prioritization Process, showcasing the definitions of each objective, the relative weighting assigned, and the relevant RRF outcomes associated with each. This framework will serve as a key input into the investment planning and prioritization work.

Table 5.3-1: Summary of Elexicon's AM Objectives

AM Objective	RRF Outcomes	Related Corporate Values	Description	Weight
Service Continuity	Customer Focus, Operational Effectiveness	Competence, Responsiveness	Risk of sustained interruptions to material segments of customer load (system projects) or those associated with non-electrical equipment that facilitates core utility operations (general plant projects).	8.4%
Customer Convenience/Confidence	Customer Focus	Kinship, Responsiveness, Competence	Risk of underinvestment in utility plant and general plant (e.g., customer care and metering) that causes material inconvenience to the customers' interaction with the utility and its assets.	5.8%
Customer Preferences	Customer Focus, Financial Performance	Kinship, Responsiveness	Risk of material customer dissatisfaction resulting from a failure to consider customer preferences when planning investments.	3.7%
Worker/Public Safety	Customer Focus, Operational Effectiveness, Public Policy Responsiveness	Safety	Risk of safety incidents sustained by Elexicon's staff, contractors, or general public living, working, or in transit in the vicinity of the utility's equipment.	32.0%
Asset Performance and Health	Operational Effectiveness	Competence	Risk of asset deterioration through normal wear and tear up to the point where replacement is the most economical intervention option.	5.1%
Workforce Health and Productivity	Operational Effectiveness	Safety	Risk of restrictions to safe and efficient operation of staff or core utility functions due to spatial constraints or access restrictions caused by major facilities systems outages.	17.7%
Operational Efficiency	Operational Effectiveness, Financial Performance	Competence	Risk of lost opportunities for efficiency improvements through investment in labour-saving capital equipment.	5.4%
Environmental Impact	Public Policy Responsiveness	Mindfulness	Risk of unplanned and uncontrolled release of a hazardous substance required in normal operation of Elexicon's equipment into the natural environment.	11.4%
Regulatory Compliance	Public Policy Responsiveness	Competence	Risk of non-compliance with regulatory and legislative requirements to ensure that its system meets relevant standards.	10.5%

Current AM Objectives Framework in the Transitional Context

While each of Elexicon's predecessors had previously employed versions of AM objectives that captured their relative weighting, these legacy frameworks were largely applicable to the electrical plant, lacked clearly defined and sequential impact threshold categorization, and left more room for subjective interpretation on the part of individual planners conducting assessments. The 2020 Objective Definition exercise, on the other hand, took important steps towards unifying the assessment criteria for both electrical and general plant projects, clearly defined impact thresholds and examples for each successive severity category, and used a data-driven process to produce consensus weighting to each individual objective.

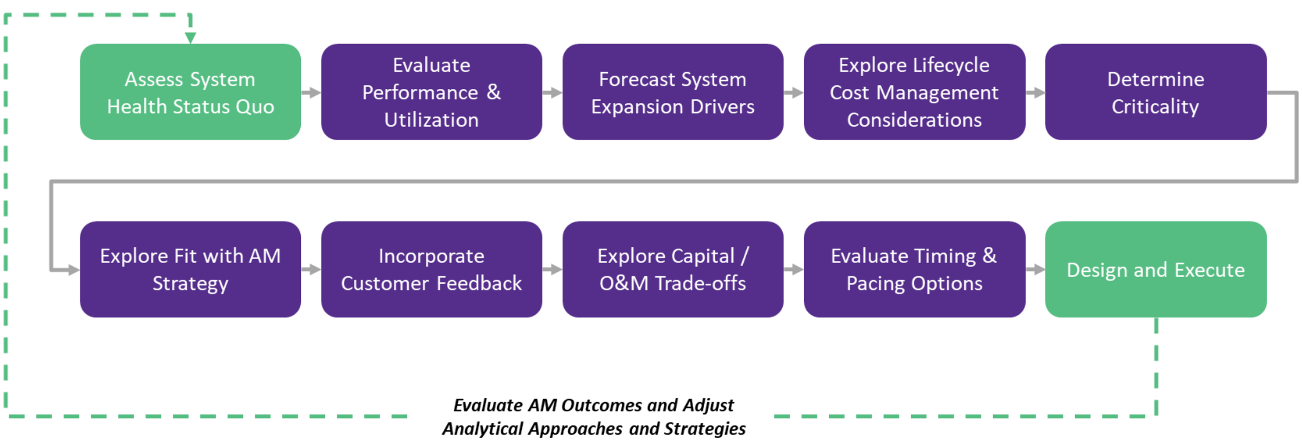
The timing of the most recent AM Objectives setting exercise did not permit Elexicon to incorporate its results into the project planning for the 2020/2021 work program, which was largely defined earlier to ensure sufficient time for planning and design. Nevertheless, Elexicon's planners have tested the application of the resulting prioritization schemes on a subset of projects planned for this timeframe and confirmed their directional consistency with the new approach. As Elexicon's AM planning and prioritization tools and processes continue to mature, the definitions and weightings of the AM objectives defined through the 2020 exercise (or its potential updates in later years) can be incorporated into a variety of underlying assumptions of tools used in Elexicon's AM Process. Doing so will ensure that nuanced quantitative analysis is guided by the ELT's expression of key outcomes of asset investments that Elexicon makes on behalf of its customers and shareholders.

5.3.1 b) Components of the Asset Management Process

The Fundamental Purpose of the Asset Management Process

One of Elexicon's overarching priorities is ensuring that its customers and shareholders derive the optimal value from assets installed, operated, and disposed on their behalf. Operating a diverse and growing portfolio of asset classes, types, vintages, and configurations, Elexicon and its staff make asset management decisions every day – ensuring that the asset portfolio in service at any given moment brings about the desired service outcomes by operating as intended. Figure 5.3-2 presents a graphical overview of the key components Elexicon's AM Process.

Figure 5.3-2: Overview of AM Process



Despite the variety of assets in its care, the fundamental elements of the AM Process apply to all four major asset types defined in the OEB's RRF. Also consistent across all asset types is the understanding that the AM Process entails a constant feedback loop, where the service outcomes of today inform the scope, nature, and timing of future asset intervention decisions. Each component is discussed in more detail in the sections that follow.

While the form and function of specific activities at each step of the AM Process may differ across the various asset types, a common element is the expectation of continuous improvement through increased reliance on objective, data-driven analysis that considers the opportunity cost of capital. In other words, Elexicon's asset managers in every part of the utility are expected to gradually increase the analytical rigour they apply to developing investment work programs – to ensure that available capital resources (which are invariably lower than the sum of potential asset needs in any given year) bring about the optimal value to the utility – by mitigating risks and bringing about desired benefits.

It is important to note at the outset of the AM process discussion that the above diagram presents the key analytical dimensions emphasized by the utility – which do not necessarily correspond to the form and function of specific deliverables that are generated throughout the AM work cycle. For instance, multiple phases outlined above are often captured in a single work product (e.g., System Fleet Utilization Reports). As such, the stages of the AM process described above represent an overall conceptual framework that captures all types of considerations that shape the utility's achievement of AM outcomes. As the AM transition work continues, activities comprising each AM Process phase described below can be expected to be further refined and enhanced, while other priority areas may be identified and integrated as well.

Asset Management Process Components

1. <u>Assess System Health Status Quo</u>

The first component of the AM Process seeks to capture the current state of health of the utility's existing asset portfolio. Asset health is one of the leading indicators of impeding Asset End of Life ("EOL") and serves as a key input into the subsequent analytical decisions that determine the scope and nature of Elexicon's investment program. Since asset deterioration is a continuous process that starts when an asset is placed into service, asset health information gathering is also a continuing endeavour that takes many forms depending on the type of asset.

Elexicon's asset managers collect several major types of asset health information using processes that vary in their frequency, extent of formalization, and types of information collected:

- *System ACA*: formal quantitative (e.g., testing) and qualitative (e.g., visual inspection) assessments of major electrical system assets that are integrated in asset class Health Indices. See Section 5.3.2.3 for the results of Elexicon's latest ACA study.

- *IT Asset Lifecycle Stage Assessments*: periodic evaluation of the state of vendor support and continual functional adequacy of the utility's hardware and software systems relative to the evolving user needs. See Section 5.3.3 for the discussion of Elexicon's efforts to establish a formal IT lifecycle management approach.

- *Fleet Assets Inspection Results*: evaluation of mechanical wear and tear of the utility's vehicles, trailers and other mobile equipment and machinery performed by qualified technical personnel as a part of regular inspections or reactive maintenance. For more information, see fleet equipment asset lifecycle management discussion in Section 0

- *Facilities Assets Inspection Results*: results of visual assessments and empirical testing of Elexicon's buildings, warehouses, workshops, fleet yards and key support systems (e.g., HVAC), which aim to capture the degree of physical degradation and/or other signs of impending failure and malfunction. See facilities asset lifecycle discussion in Section 5.3.3 for further information.

- *Metering Asset Inspection Results*: periodic testing and verification as mandated by regulatory bodies and/or requested from time to time by customers to establish that metering assets and supporting equipment functions as intended.

The insights gathered in the course of these activities inform a variety of asset class- or function-specific Needs Assessment documents that form the basis of further analysis to determine the scope and volume of asset intervention activities (such as replacement, refurbishment, or maintenance). Depending on the type and severity of asset health concerns identified and the manner in which they are identified (e.g., by way of a cyclical inspection vs. a reactive call), some health deficiencies may be addressed sooner than others.

A major recent enhancement to Elexicon's asset health data storage capabilities was the consolidation of the two predecessors' Geographic Information Systems ("GIS") into a single platform. Since Elexicon will be using its GIS as the Asset Registry for the electrical system assets, the consolidation effort included establishment of a detailed Asset Data Hierarchy and Validation Rules, designed to ensure that all requisite information regarding current health (or its predictors such as age or make) is captured in the Asset Registry for easier retrieval and analysis.

2. <u>Evaluate Performance and Utilization</u>

Asset health is not the only type of empirical information from the field that Elexicon relies on to inform its asset intervention decision-making. Another critical source of diverse empirical information that helps Elexicon identify emerging risks and/or correct concerning performance trends is the information on performance and usage of its assets.

By examining asset performance information alongside asset health data, asset managers can prioritize the assets or areas that warrant more immediate attention. Over the longer term, integration of health and performance data can also help planners identify statistical relationships that can assist in preventative maintenance and risk-based replacement planning. Elexicon gathers and analyzes system performance and utilization data through a variety of activities:

- *System Reliability Analysis*: outage data collected by the control room staff and field response crews is aggregated and analyzed by the Planning Team in the form of periodic Reliability Reports. Reliability analysis explores the individual outage causes and emerging trends across Canadian Electricity Association ("CEA") outage cause codes and provides opportunities to explore reliability trends along equipment types, feeders, and geographical areas. Reliability reports also identify Worst Performing Feeders and explore MED thresholds where applicable.

- *Feeder / Station Loading and Line Loss Monitoring*: using AMI and SCADA data capturing capabilities, Elexicon staff capture and monitor the loading of its station and feeder assets that serves as a predictive input as to the extent of asset deterioration and identifies the areas where load transfer or capacity upgrade projects may be required in the future. Similarly, AMI data enables Elexicon to track distribution losses across its system, identifying candidates for future voltage conversion and other upgrade work.

- *Environmental Incident Monitoring*: given the focus of its shareholder municipalities on environmental performance improvement, Environment is one of the major AM Objectives for Elexicon itself. Given this focus, and to ensure compliance with relevant legislation and regulations, the utility diligently follows all required environmental reporting and rectification guidelines and identifies any emerging trends with equipment performance, for further evaluation during the investment planning process.

- *SQI Performance Measurement Data*: OEB-mandated Service Quality Indicator data collected and reported to the regulator is another source of operating insights that may serve as a leading indicator of underlying issues associated with Elexicon's equipment or systems.

- *Safety Incident Monitoring*: employee and public safety is the highest-weighted Elexicon AM Objective. To ensure exceptional safety performance, Elexicon tracks all information related to safety incidents, near misses and/or impending safety concerns identified in the process of inspections. While specific safety risks identified through inspections are usually rectified without delay, the overall information collected is a source of broader planning data and it can point to any emerging trends in specific areas or equipment configurations. For example, the Rear-Lot Feeders are a notable priority area both in terms of safety and reliability performance, and Elexicon plans to systematically reconfigure these legacy installations over the coming years.

- *General Plant Performance Monitoring*: as a part of consolidating its merger operations, Elexicon is turning its attention to monitoring the performance of General Plant assets as another input into asset intervention planning. For example, the IT department is in the process of establishing a framework whereby the individual service requests and/or systems outages information are periodically analyzed to identify common performance issues that would serve as a performance-based planning input. Similarly, various vehicle classes reaching a certain utilization (mileage) threshold serve as a signal for inspections that serve as an input for future replacement needs.

- *Customer and Partner Input*: Elexicon periodically receives information from its customers or key partners (such as municipalities, developers, other utilities in the area) regarding potential performance issues such as Power Quality, or impending safety / reliability concerns associated with its equipment. Whether it arrives by way of Customer Contact Centre calls or specific comments shared through regular customer engagement activities, this information also serves as a key input into the scope of future planning activities.

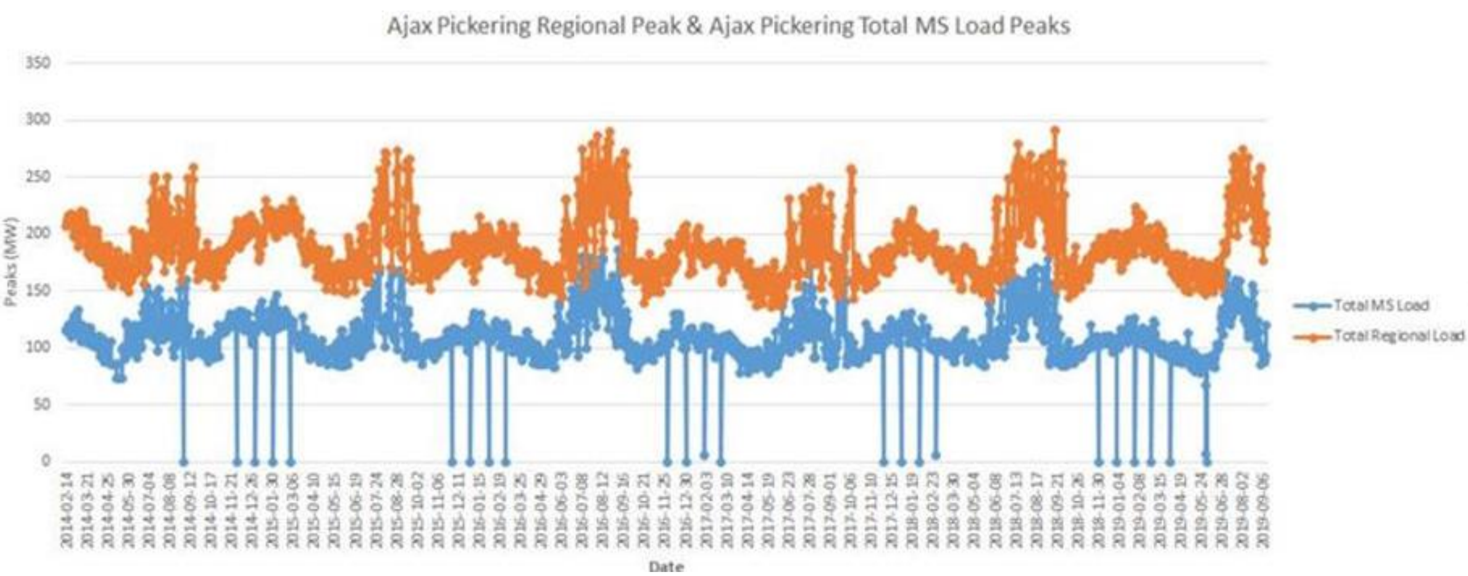
Combined with asset health information, asset performance and utilization data provide an important source of information regarding existing or emerging performance trends that may warrant intervention through a variety of maintenance or capital renewal activities. While Elexicon is in the relatively earlier stages of leveraging some of these information sources as explicit inputs into AM decision-making, the new integrated Business Case format now in use across the utility has established ongoing performance data monitoring as a key empirical input into future investment analysis and justification. As such, the utility's line departments and the central Planning function will continue developing tools and processes to collect and incorporate this data into planning with greater rigour and regularity.

3. <u>Forecast System Expansion Drivers</u>

Planning input generation work associated with this stage of Elexicon's AM process involves integration of information related to the current levels of system capacity and utilization with a variety of forward-looking information indicative of potential changes to the size and configuration of the system stemming primarily from externally oriented engagement activities. Along with reliability analysis discussed above, the activities of this phase are particularly impactful on the scope and nature of System Access and System Service portfolios. The specific activities captured in this stage of the AM process include:

- *Load Forecasting Work*: while the amount of recent historical load growth differs substantially across Elexicon's diverse service territory, the utility takes a comprehensive and methodical approach to load forecasting across its entire system. The most recent load forecast completed in collaboration with METSCO (see Appendix H) uses a two-phased approach, with a "top-down" econometric forecast. The econometric approach leveraged third-party forecasts of statistically significant load predictors such as Housing Starts to develop an overall load growth prediction. Conversely, the "bottom-up" station-by-station forecast relied on historical peak load and known upcoming development information in the area to produce more localized forecasts that were then aggregated. When incorporating developer or municipality-specific information the analysis assigned probability values to each using historical information on the rate at which forecasted load growth materialized in the past. In both cases, the historical load information underwent extensive data cleansing and weather normalization effort to align with industry best practices in technical load forecasting. The combination of top-down and bottom-up forecasting information establishes a range of potential load growth that Elexicon can expect to materialize in the near/medium-term. The utility expects to repeat this analysis annually and enhance the underlying analytical and data collection rigour as it gains more experience.

Figure 5.3-3: Sample extract from the latest Load Forecast showcasing two approaches



- *Customer Connection Process*: aside from system-wide load forecasting, Elexicon also undertakes more site- or- subsystem-specific analysis of available capacity and connection or relocation costs in the course of the Customer Interconnection Process. Formal applications and preliminary conversations regarding potential for load or generation interconnection or facility relocation work, along with earlier stage feasibility discussions with potential customers or municipal and regional authorities lead to a variety of interconnection studies and relocation feasibility assessment and planning work, which form the core of Elexicon's System Access investment portfolio.

- *Regional Planning Work*: With assets in four separate IESO Regional Planning Zones, Elexicon is constantly involved in regional planning activities. Since certain components of the Regional Planning process involve exploration of non-wires alternatives where they may be feasible, the analysis generated in preparing them can serve as important system planning input with the potential to balance the investments suggested by the forecasted load growth. Even when non-wire alternatives or other means of investment deferral analysis do not yield feasible options, the conclusions of this analysis serve as an explicit input to confirm the anticipated customer / load growth enabling investments.

- *Customer and Third-Party Engagement Work*: as a part of the Customer Engagement effort supporting this DSP, Elexicon asked its customers several specific questions to gauge their general attitudes and specific intentions in relation to new technology that can impact its system over time, such as Electric Vehicles and Distributed Generation. Moreover, ongoing discussions with municipal and regional governments, large customers and other entities, provide critical planning insights that influence the future configuration and capacity of Elexicon's system.

- *Facilities, Fleet and IT Capacity Expansion Needs*: ongoing capacity analysis of available office / warehouse space, IT server capacity and fleet vehicles may identify expansion needs in these areas.

4. <u>Explore Lifecycle Cost Management Considerations</u>

The preceding three stages of Elexicon's AM Process focus on generating a diverse and comprehensive set of inputs – related to the current and anticipated state of the system based on the natural wear and tear, and incorporation of external system expansion drivers. The purpose of the next four phases is to "transform" the raw inputs into intermediate analysis outputs through the use of various AM analysis tools and processes, along with other critical sources of input like congruence with strategy and consistency with the feedback received from customers.

Asset Lifecycle Cost Management Analysis is the first of these elements, which primarily applies to System Renewal and General Plant investment planning work by way of multiple potential assessment techniques. In its simplest form, Asset lifecycle cost analysis amounts to integrating the available evidence collected to determine the following (as applicable):

(a) which assets within a population are more likely to reach their End of Life over the relevant planning horizon based on their health data;

(b) whether the economic impact of reaching EOL while in service is significant enough to warrant replacing them proactively before their failure;

(c) whether performance of any assets warrants considering earlier replacement or other form of intervention (e.g., refurbishment or extra maintenance for Worst Performing Feeders); and

(d) whether expected system growth in specific areas creates opportunities for synergies between renewal and expansion work that could lower the aggregate asset lifecycle cost.

While in general, an organization derives the full value from an installed asset only when it fails beyond reasonable repair and replacement, the added considerations of avoided economic impact of costly in-service failure, continued underperformance, or potential synergies that sacrifice some remaining life to attain broader economic synergies, comprise the subject matter of Asset Lifecycle Costing.

Aside from subject matter-specific technical considerations, these broader AM economic principles apply to both electrical and general plant assets.

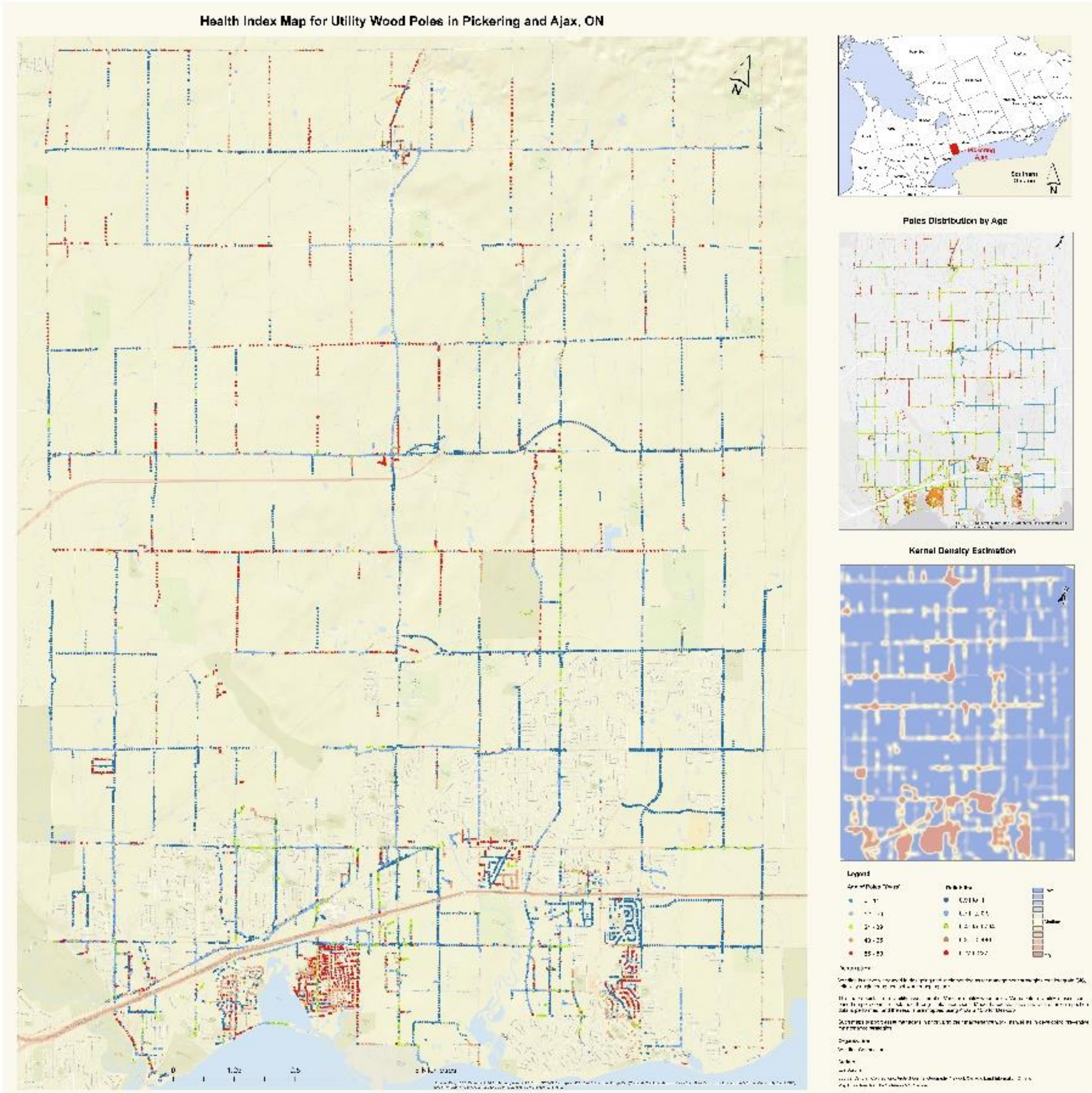
Electrical Plant Lifecycle Cost Analysis

In the past, both Whitby Hydro and Veridian Connections assessed these considerations through business case analysis, relying to a large degree on the results of the ACA that identified the individual units in worst condition across electrical asset class populations.

As shown in Figure 5.3-4 below, predecessor utilities used GIS data visualization and other modelling tools to combine ACA results and past reliability statistics to identify the areas of convergence that warranted more detailed examination by planners. Aside from identifying specific areas of volumes of assets by class, other elements of asset lifecycle costing analysis performed by Elexicon's predecessors included additional considerations, including:

- manufacturer or regulator recommendations or expectations of asset replacement or refurbishment timelines (e.g., Smart Meter re-seal periods);
- discretionary obsolescence – when a given type of equipment is no longer deemed safe or beneficial to the system and replaced as a matter of policy (e.g., porcelain insulators);
- non-discretionary obsolescence – when spare parts are not available to ensure continued upkeep (e.g., certain types of older electromechanical relays); and
- construction economics – such as when fixed costs of major station component replacements (e.g., power transformers) warrant earlier replacement of smaller adjacent station equipment.

Figure 5.3-4: Asset HI and Reliability Visualization Analysis



Given the relative recency of the merger, elements of this approach underlie the selection of System Renewal work program presented in this DSP. Elexicon is confident in the outputs of these analytical methodologies that underwent further review by way of an integrated Business Case and project scope development and prioritization (See Chapter 4).

Consistent with the values of Continuous Improvement, the utility is taking important steps to further enhance its electrical asset lifecycle analysis capabilities. Among the capability enhancements and refinements pursued are achieving additional accuracy in forecasting the asset failure timing, and the ability to forecast the volumes of asset failures over the longer timeframe than what is possible by using static ACA methodologies. To this end, Elexicon is developing several additional capabilities, which are also reflected in select Business Cases underlying the Forecast Period work program.

Failure Curve Development and Calibration – working with METSCO, Elexicon planners are developing a framework of time-based asset class probability curves using the Weibull distribution methodology accepted in the industry. Elexicon possesses sufficient data records of asset in-service failures or inspection-identified replacements by age and type that enable construction of service area-specific failure curves for certain asset classes. The utility will continue collecting this data to expand this analysis to other asset classes and with time, derive analytical insights that could enable further granularity by area, types, etc.

Figure 5.3-5: Wood Pole Failure Curve - Veridian Data

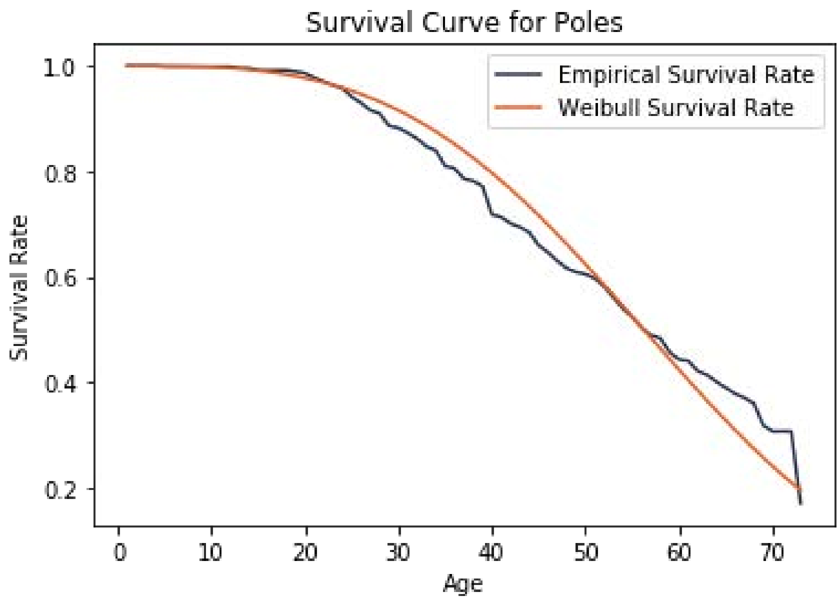


Figure 5.3-5 showcases an example of a wood pole failure curve derived by leveraging one of the predecessors' past investments into tracking the age of asset failures. For other asset classes, Elexicon will initially rely on industry failure curves calibrated by METSCO, which can be verified or supplemented over time by empirical information from the field. The primary purpose of the failure curve development is to enable Risk-Based Asset Intervention Planning where potential intervention candidates are prioritized on the basis of asset risk – a function of Failure Probability (expressed as a percentage) and Failure Impact (expressed in dollars). This is a methodology underlying advanced AM analytics platforms that Elexicon is currently exploring. See Section 5,3,3b for further information.

System Condition Forecasting: asset failure curves are an input into another system asset lifecycle management product that Elexicon is currently testing – namely the medium-term System Condition Forecast. Using the failure curve information that serves as a proxy for the pace of asset degradation throughout their useful lives, Elexicon and METSCO are developing a predictive model that will enable the utility to conduct sensitivity analysis on the volume (in units or replacement value dollars) of assets in each Health Index band – depending on the volume and asset class allocation of expenditures over the forecast period. As this model undergoes further testing and refinement in the coming years (provided that Elexicon chooses to formally implement it or a similar product), it is expected to provide the utility with additional ability to explore investment pacing and lay the foundation for development of reliability forecasting approaches.

General Plant Asset Lifecycle Cost Analysis

While the same economic asset intervention principles generally apply to the General Plant assets (Fleet, Facilities and IT), Elexicon understands that risked-based planning methodologies for these assets are significantly less common in the Ontario distribution sector and elsewhere in the industry. As the means of performing asset lifecycle cost analysis for these types of assets, Elexicon generally relies on a variety of objective thresholds and third-party recommendations to assess equipment lifecycle decisions. These include:

- *IT Software and Hardware warranty / extended support thresholds* – upon expiration of which the utility's experts must decide whether keeping the systems or hardware components in service will be beneficial and economical given the increasing complexity of upkeep (e.g., custom patches), integration issues with newer products. and higher failure propensity.

- *Fleet Vehicle Years in Service and Mileage Thresholds* – Elexicon's Fleet Management policies define specific runtime thresholds for vehicles of various tonnage beyond which they must undergo detailed inspection to confirm their suitability for remaining service. Damage or deterioration to major systems such as the engine or the drivetrain established during the ensuing inspections can lead to the vehicles being removed from the fleet.

- *Expert Assessments of Facilities and Building Systems* – using internal or third-party technical assessments, Elexicon's facilities asset managers may determine that certain building systems, structures or implements have reached or are nearing the end of their lifecycles and are advisable for replacement and/or refurbishment.

As it continues refining its analytical approaches ahead of its first rebasing application, Elexicon will continue exploring additional approaches to asset lifecycle analysis for General Plant assets. A major step towards encouraging greater reliance on objective evidence for all types of asset intervention planning has been taken through the introduction of a single Business Case format for all capital programs. Putting a significant emphasis on objective data evidence, the new business case structure can be expected to challenge Elexicon's asset managers to identify and explore additional ways to generate new evidence in support of asset lifecycle decision-making. For additional information, see Section 5.3.3b.

5. <u>Determine Criticality</u>

The lifecycle cost analysis provides Elexicon with the scope of assets potentially warranting some form of near-to-medium-term intervention. However, the amount of available capital funding in any given year is unlikely to be sufficient to address all the identified asset intervention needs proactively. Moreover, for assets with comparatively lower anticipated impact of failure (e.g., due to quick restoration times, low likelihood of catastrophic failures, minimal customer inconvenience, etc.) proactive replacement may be less economically efficient, as it could result in sacrificing more residual economic value available from the existing than optimal.

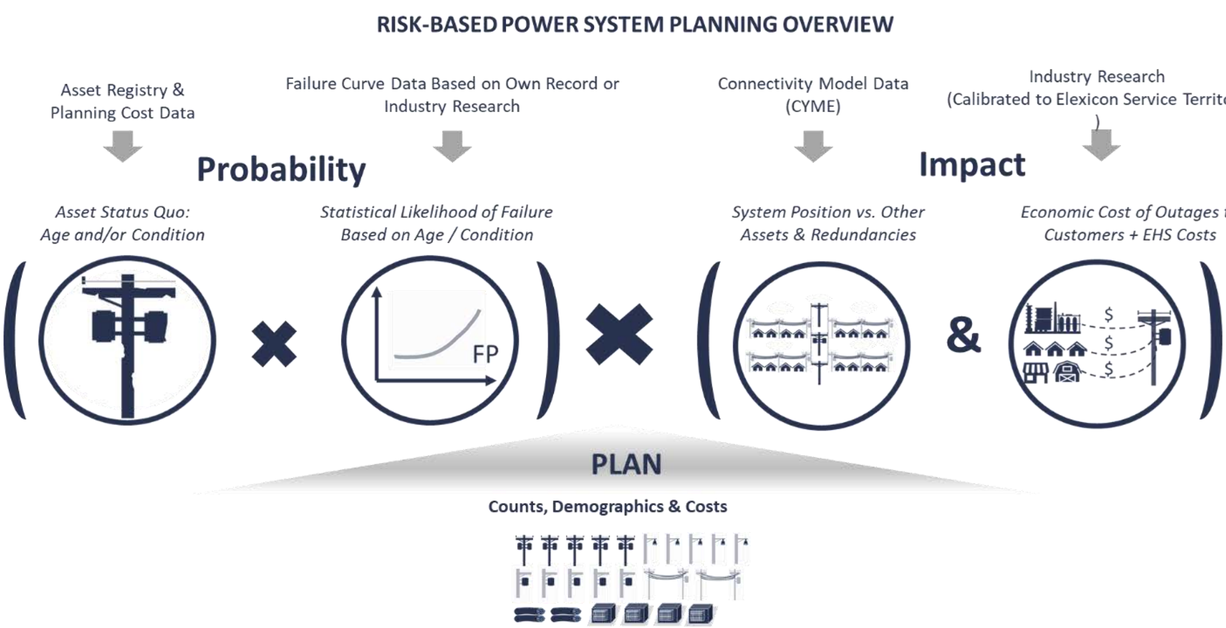
To address these budgetary and economic considerations, in this stage of the AM Process, Elexicon examines potential investment candidates on the basis of their relative criticality – to determine one of the dimensions over which potential investments can be prioritized for inclusion into the capital work program. There are several dimensions of criticality analysis applicable to different types of assets or intervention rationales identified in the earlier stages:

- *Potential Impact on Safety*: tools, vehicles or electric system equipment identified as having potential employee or public concerns through the previous stages of the AM process are invariably determined to be of highest criticality, with rectification work proceeding as soon as practicable.

- *Connectivity-Based Criticality*: when determining criticality among otherwise similar electrical system assets (e.g., wood poles) an asset or group of assets will be assigned a relatively higher criticality to other similar assets in the same condition category if:
    - a feeder, individual equipment, or a protection region supports substantially higher load, more customers, or larger / more sensitive customers than other candidates of the comparable asset health and/or performance results;
    - a feeder or protection region lacks redundancies (backup supply paths) relative to other comparable intervention candidates; and
    - an individual asset is located higher upstream on a radial feeder without redundancies (i.e., backup feeds) relative to other similar assets on a feeder.

In short, connectivity-based criticality attempts to prioritize equipment with otherwise similar performance characteristics or residual lives that could have higher overall economic impact in the event of in-service failure. Provided that all assets have comparable probabilities of failure or other rationale for potential intervention, applying connectivity-based criticality principles reduces the overall dollar value of system risk posed by Elexicon's current system condition and configuration. To conduct this analysis, the utility relies on data available in its CYME connectivity / load flow analysis system, which is in the process of being integrated with the GIS platform to further simplify the data transfer between the two.

Figure 5.3-6: Risk-Based Power System Planning Overview (METSCO Illustration)



Going forward, Elexicon intends to transition to a risk-based system asset planning, where prioritization would occur on the basis of quantified asset risk – the product of probability of asset failure (estimated through failure curves) and impact of failure – estimated costs of failure to the utility and its end customers, supported by connectivity analysis. Figure 5.3-6 provides a sample illustration of the Risk-Based planning process. See section 5.3.3b for additional description of Elexicon's efforts to implement a risk-based AM analytics capability.

- *Compliance-based criticality*: mandatory activities prescribed by the terms of Elexicon's OEB Distribution License or other relevant legislative or regulatory provisions automatically go to the top of the planning priority queue. Examples include System Access investments to connect new customers or relocate the infrastructure to enable third-party transportation projects.

6. <u>Explore Fit with AM Strategy</u>

Confirming Congruence with AM Objectives

As discussed at the outset of the AM Process section, Elexicon's ELT has recently adopted a new set of AM Objectives that outlines the key desired outcomes expected of the utility's AM decisions. The ELT members have also assigned relative prioritization weightings to each AM objective, using a structured and data driven evaluation approach designed to control for individual biases and provide consistent evaluation across each objective considered.

This stage of the AM Process involves another dimension of potential investment project prioritization, whereby candidate investments undergo evaluation based on their congruence with Elexicon's AM Objectives. The prioritization process is completed in the course of preparing Program Business Cases or Individual Project Scopes (as applicable). Depending on the results of the prioritization work, certain candidate projects may be "promoted" or "demoted" in their relative standing based on previous analytical steps.

As noted earlier, the timing of the AM Objectives Adoption did not permit for the work program comprising this DSP to formally undergo the prioritization process using the AM Objectives. However, a number of individual Business Cases incorporate this analysis. In the future, and subject to further deliberations, the AM Objectives Congruence assessment may also help Elexicon prioritize among certain investments from across different RRF categories by exploring their relative fit with AM Objectives. As such, it has the potential of supplementing the risk-based planning and prioritization intended for the electrical plant by providing a broader, cross-category assessment dimension.

Incorporating Mission-Critical Strategic Projects

Elexicon continues its post-merger consolidation activities, while simultaneously charting the course for its forward-looking strategy. Attaining its broader corporate strategy goals requires allocating a portion of its capital and operating budgets towards projects that drive the strategy execution. Among such specific initiatives included in the 2021-2025 work program are a number of technology projects aimed at positioning Elexicon to meet the demands of the rapidly changing grid, such as the Advanced Distribution Management System ("ADMS"). While the ADMS and other strategic projects are critically important for the utility to realize its longer-term strategic vision, it cannot reasonably be expected to undergo the same AM process evaluation as the core system or general plant assets. To this end, the Strategy Fit component of the AM process provides an opportunity to integrate into the investment planning pipeline the projects that carry significant strategic benefits to the utility and its customers.

Elexicon notes that its Business Case requirements apply to both normal-course and strategic investment projects. the scope and nature of evidence describe in the latter can be expected to put more emphasis on the utility's vision and steps of attaining it rather than the current state of the system and/or risk mitigation potential benefits.

7. Incorporate Customer Feedback

Customer Centricity is a core pillar of Elexicon's corporate strategy. Accordingly, ensuring that the utility's Asset Management decisions reflect the feedback received through a variety of customer engagement efforts is an important component of the overall AM Process.

In designing its first Customer Engagement Survey associated with this DSP, Elexicon attempted to convey the nature of investment trade-off decisions that it faces in managing its system and invited its customers to share their perspectives on the optimal way of addressing these trade-offs. The utility also asked its customers several questions regarding their plans with respect to adoption of emerging technologies like Electric Vehicles and micro-embedded Distributed Generation sources that may impact its distribution grid.

The insights gained through Customer Engagement activities can be of value to the overall AM Process in multiple ways:

- Confirming the degree of directional alignment between the scope, nature and allocation of Elexicon's capital investment plans across the broader investment categories;
- Gauging the customers' perspectives on the current levels of service they are receiving from the utility in terms of reliability, service quality, or access to customer service tools;
- Exploring the customers' attitudes and / or specific intentions with respect to adoption of new technologies that may have an impact on Elexicon's investment priorities;
- Exploring customers' preferences as to certain modes of work staging and execution where the utility has multiple options to consider;
- Exploring customers' views on value of asset lifecycle management trade-offs – such as the asset refurbishment work that prolongs service lives but would result in incremental costs that only postpone the eventual need for replacement; and
- Receiving feedback on levels of support for specific material projects and the resulting rate increases, such as the anticipated ICM projects.

Although the COVID-19 pandemic affected the scope and timing of Elexicon's customer engagement work ahead of this DSP's finalization, it provided a number of important insights that will inform the utility's AM analytical and execution work going forward. See Section 5.4a for additional information on the outcomes of the Customer Engagement work.

8. Explore Capital / O&M Trade-Offs.

The previous seven phases of the AM process cover the data input generation and analysis work to determine the relative value of potential investment projects. The purpose of the remaining phases of the AM Process is to define and optimize the scope, nature and timing of the projects deemed to be most valuable based on preceding analysis. The first such phase involves exploration of relative merits of addressing the identified asset needs through either capital investments or O&M activities.

General Considerations in O&M vs. Capital Trade-Offs in the Distribution Utility Sector

Where feasible options exist, a decision between a capital expenditure (e.g., asset replacement) and O&M activities (e.g., testing, or minor upkeep) is a trade-off in volume and timing of expenditures incurred over an asset's lifecycle. In other words, the volume and cost of O&M work performed over an asset's lifetime have a direct bearing on the net value provided by that asset over the time it spends in service. Where the aggregate cost of preventative or predictive O&M work is equal to or lower than the asset life extension benefits that this O&M work helps realize, incremental maintenance can be justifiable. At the same time, keeping assets in service longer invariably increases their probability of failure which often involves substantial reactive maintenance costs.

The Capital-O&M value trade-off equation gains further complexity when considering the ratemaking implications of O&M vs. capital dollars, since the two types of expenditures have materially different near-term impact on customer rates. The trade-off discussion becomes more complex still depending on whether and how the costs and benefits of asset lifecycle management incorporate the economic impact of failures (or their avoidance) on the utility's customers or the broader society – where the environmental impact, economic development, or public safety are considered. Finally, Elexicon understands that historical data records available across the industry today often lack sufficient detail to firmly establish empirical links between O&M work and asset life extension benefits it brings about.

One area where the capital vs. maintenance trade-off considerations are arguably clearer is the potential impact of O&M cost avoidance by way of investments in labour-saving technology. By increasing the degree of its system's automation, remote sensing, and operation capabilities as a part of its overall strategy, Elexicon expects to deliver significant cost avoidance benefits to its customers. The ADMS implementation project and next-generation Smart Meter upgrades that feature expanded capabilities are among these types of OT projects included in this DSP. While these investments carry significant operational and strategic value beyond O&M cost management, their potential impact in this area form an important part of the overall value proposition.

Elexicon's Current Approach to Capital vs. O&M Planning in Asset Lifecycle Management

Recognizing the complexity underlying this subject area, Elexicon is taking important steps to bolster its analytical capabilities in order to drive economically optimal decisions. As noted previously, the utility is in the process of developing and calibrating a set of asset failure curves to be used in risk-based planning approaches that combine engineering and economic considerations. Among other applications asset risk-based planning models can enable the utility to perform a variety of sensitivity exercises that model and gradually verify the impact of incremental maintenance or refurbishment activities on asset failure propensity. While this work remains in relatively early stages, Elexicon recognizes its importance and expects to expand its understanding of this area in the coming years.

In the interim, the more immediate focus area for Elexicon has been the analysis and integration of its predecessor utilities' existing asset inspection and maintenance approaches to establish a common operating strategy for the years ahead. While the predecessors' regular cyclical O&M activities largely were consistent across most asset classes, there were several notable differences. For example, while Veridian conducted wood pole testing on a nine-year cycle to account for the size and non-contiguous nature of its service territory, Whitby Hydro (whose assets occupied a far more compact area) utilized a three-year cycle for the same pole testing activities. Going forward, Elexicon intends to complete this work on a three-year cycle in recognition on preventative value of more frequent O&M work on this critical asset class.

Another major asset class with materially different approaches to O&M work between the predecessors are the underground cables. Whereas Veridian conducted DC Polarization /

Depolarization testing work to determine condition of underground cables and explore their suitability for refurbishment through cable injection, Whitby Hydro did not historically conduct any cable testing activities, opting for replacement of adjacent cable segments through larger renewal projects targeting specific subdivisions. Going forward, Elexicon is targeting the adoption of Veridian's testing and injection approach in an effort to prolong the lifecycle of these capital-intensive assets. See Section 0 for additional details on the differences between the predecessors' lifecycle management practices and the approach targeted by Elexicon.

In the area of General Plant, the predecessors' approaches to maintenance work were largely similar, with cyclical or operational threshold-based inspection and testing activities being a common standard approach. Going forward, the utility's staff plan to collect additional operating performance and cost evidence (such as the number and type of IT service calls) to enable exploration of other potential managerial approaches and enhance reliance on objective evidence when contemplating incremental operating or capital investments.

9. Evaluate Timing and Pacing Options

In formulating program expenditure plans and developing individual project scopes, Elexicon seeks to align the execution timing of its investments as closely as possible to the time when the underlying need materializes.

In the context of *System Access* projects driven by customer requests, Elexicon requires its proponents to meet a number of financial (deposit) and technical (designs and approvals) milestones to signify their readiness to benefit from the requested work and manage the financial risk of assets that may be placed in service sooner than optimal. As noted earlier, Elexicon's staff regularly engage the municipal and regional government officials and the developer community to ensure continued alignment as to the scope and timing of planned construction activities. Moreover, given the inherent volatility of this investment portfolio, Elexicon monitors the in-year pace of budgeted System Access expenditures and may reallocate the available funds towards other investment portfolios if the budgeted amounts appear to exceed the actual requirements.

When planning *System Service* projects that expand capacity or enhance the technical capabilities of its system, Elexicon initially explores a number of options that could forego and/or defer the underlying investment need. When station or feeder capacity upgrades are planned, the utility examines the viability of interim or permanent alternatives, such as load transfers. As noted earlier in this DSP, among the capital efficiencies enabled by the merger is the ability to meet the growing load demand in the Whitby area by leveraging spare transformer capacity in the neighbouring Veridian areas through construction of six express feeders. The cost and physical footprint of these feeders are expected to be lower than those of the station capacity that would otherwise be required.

When planning for load growth accommodation investments, Elexicon is also beginning to leverage probabilistic analysis tools. When preparing the latest load forecast underlying this plan, Elexicon and METSCO attempted to adjust the volumes of load growth projected by the municipalities and the developer communities by exploring the historical load materialization patterns relative to previous forecasts. Where there was evidence that earlier forecasts consistently overestimated the actual load growth, planners applied an adjustment factor to reduce the expected load growth accordingly. Although the historical information of this nature was sporadic, Elexicon intends to collect and track the requisite load materialization evidence to further refine its approaches. Elexicon notes that this probabilistic planning approach can also be applied to the System Access investment planning, subject to further exploration.

Since a material portion of its distribution plant is advanced in age and increasingly approaches Poor / Very Poor condition, proactive *System Renewal* investment programs typically maintain consistent volumes from year to year. The annual volumes for these programs are currently established through the combination of ACA recommendations and reliability analysis tools (among others). To enhance its ability of targeting the highest-risk assets for proactive intervention, Elexicon is taking steps to explore more advanced risk-based planning AM analytics described in earlier stages. A critical benefit of a risk-based approach to asset intervention planning is the ability to estimate with increasing clarity the opportunity cost of deferring a given investment project for another year or longer.

To extract the maximum value from asset classes the failure impact of which is not expected to cause major outages or require extensive rectification work, Elexicon manages a number of its overhead and underground system assets on a run-to-failure basis (See Section 0 for additional details). As with proactive renewal, ongoing enhancements to risk-based planning frameworks are expected to yield incremental benefits to the precision of reactive investment planning as well.

For *General Plant* Fleet and Facilities assets, the timing of renewal and upgrade work is largely dictated by the results of cyclical and operating threshold-based inspections. Where these inspections determine that assets are in an adequate state to remain in service longer, replacement or refurbishment can be delayed. Moreover, investment can be deferred due to re-prioritization within a single investment portfolio, should evidence emerge to suggest that projects other than those originally planned warrant attention in the near term. In the case of IT projects, major system replacement upgrade, or integration projects typically occur over the span of months, with rigorous business case requirements at the earlier stages dedicated to evaluating all feasible alternatives, including deferral.

10. Design and Execute

This phase of the AM Process involves actual preparation and execution of capital and O&M projects. While the planning, design procurement and implementation / construction processes vary significantly depending on the type of investments, the overarching focus at this stage is placed on safety, accuracy, efficiency, and compliance with all internal and external policies and regulations. While most design, procurement and construction activities typically follow standard process flows, their accuracy and efficiency are in many ways tied to the products of data collection and analysis completed in the preceding stages of the AM process.

Depending on the nature of a given execution task, Elexicon relies on the combination of in-house and contractor labour to complete the work. For example, larger, more complex and infrequent projects such as station asset renewal are typically undertaken by third-party contractors who specialize in this type of design and construction work. The more typical maintenance and construction renewal work (such as overhead system renewal) is more commonly performed by in-house crews. Importantly, Elexicon monitors the underlying costs and benefits of internal vs. external work execution to ensure that approaches in place continue providing the expected value relative to alternatives. For example, an ongoing GIS – CYME systems integration project was originally slated for execution by a third-party contractor but was determined to be more beneficial if performed by internal staff.

11. Evaluate AM Outcomes and Adjust Analytical Approaches and Strategies

This final phase of the AM Process entails the collection and consideration of qualitative and quantitative feedback aimed at learning and adjustment – both in terms of technical and broader organizational outcomes of past investment work. This critical stage frames the AM Process as a continuous loop, where evaluation of past successes and oversights is treated with the same regard and focus as any of the preceding analysis stages. At this continuous stage, Elexicon is targeting acquisition of a variety of learning insights:

- Reconciliation of planning and design cost estimates with final project costs with the aim of potential adjustments to the estimation frameworks;

- Comparison of forecasted vs. actual reactive asset failure volumes to refine the forecasting methodologies and explore any emerging trends by equipment type, area or cause;

- Review of assumptions underlying System Access and System Service investment planning (e.g., the extent to which the forecasted load or customer connections materialize and whether the evidence suggests potential refinements to the modelling approaches);

- The performance of external contractors on a number of key dimensions, such as health and safety, environmental, and overall throughput, among others; and

- Empirical evidence suggestive of potential adjustments to the assumptions underlying asset lifecycle management approaches (e.g., more/less preventative maintenance or inspection data collection, adjustments to failure curves based on "post-mortem" asset analysis, etc.).

As stated at the outset of the AM Process discussion, Elexicon's major priorities in the first years of integrated operations have been those of *consolidation* and *continuity* – facilitating the establishment of coordinated and consistent processes that leverage predecessor best practices, while ensuring consistently safe and reliable system performance and accommodation of economic growth drivers. As the consolidation work nears completion across most areas, Elexicon is increasingly turning its full attention towards the ongoing enhancements and refinements of its AM analytics, planning and implementation work. Objective and consistent review of its past results focussed on identifying and leveraging future improvement opportunities is expected to form a major part of this continuous improvement work.

5.3.2 Overview of Assets Managed

5.3.2 a) Description of the Service Area

The majority of Elexicon's service territory and customer base is located in the Region of Durham. However, Elexicon also provides power to other several towns and cities as far north as Gravenhurst and as far east as Belleville. The non-contiguous service territory covers a total area of 787 square kilometers, of which 639 were formerly within Veridian Connections' service area and 148 correspond to the former Whitby Hydro territory. Elexicon expects significant load growth over the forecast period due to major residential developments such as Seaton, West Whitby, North Pickering, and Port Whitby. More detail on growth and its effect on the DSP can be found in section 5.4 b) **System** Development over the Forecast Period

The service area consists of 451 square kilometers of rural area (57.2%) and 337 square kilometers of urban area (42.8%). The utility's overhead system consists of 1,949 km of circuit line (51.5% of total) and 1,836 km of underground circuit line (48.5%). Elexicon serves a total of 164,732 customers in the following towns, cities, and municipalities:

- Formerly Whitby Hydro Territory (42,906 customers):
  - The Town of Whitby
- Formerly Veridian Connections Territory (121,826 customers):
  - The City of Pickering;
  - The City of Ajax;
  - The City of Belleville;

- o The Township of Brock (Beaverton, Cannington, and Sunderland);
- o The Municipality of Clarington (Bowmanville, Newcastle, and Orono);
- o The Town of Gravenhurst;
- o The Municipality of Port Hope;
- o The Township of Scugog (Port Perry); and
- o The Township of Uxbridge

Figure 5.3-7: Elexicon Service Area Map

As the above map indicates, the Whitby-Pickering-Ajax area where the majority of Elexicon's customers are concentrated is geographically continuous and similar in terms of customer density and mix of economic activities. This area is heavily developed for residential, commercial, and industrial activities with the exception of several protected natural habitats such as the Greenwood Conservation Area and Herber Down Conservation Areas.

While the Whitby-Pickering-Ajax area is home to the majority of Elexicon's customers, a portion of customers also resides in the Township of Brock including Beaverton, Cannington, Sunderland, Scugog/Port Perry and Uxbridge. The area has a greater presence of natural features and is located relatively close to large bodies of water such as Lake Scugog and Lake Simcoe.

The Town of Gravenhurst is the least urbanized municipality in Elexicon's service territory with the highest concentration of natural features such water bodies, densely forested areas. Elexicon's easternmost territory, Belleville, has an even mix of urban and natural areas. Weather characteristics of three key areas in Elexicon's service territory are provided in Table 5.3-. 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 in Table 5.3- below are average values based on ten years of historical data.

Table 5.3-2: Summary of Weather Characteristics for Key Areas in Elexicon's Service Territory

Weather Characteristic		Whitby-Pickering-Ajax Area	Belleville Area	Gravenhurst Area
Temperature	Summer	19.6	20.9	18.0
	Winter	-4.5	-4.7	-7.3
Precipitation	Summer	71.0	78.8	72.8
	Winter	42.8	58.5	42.1
CDD (Summer)		64	95	39
HDD (Winter)		636	620	711

5.3.2 b) Summary of System Configuration

Ajax-Pickering

The Ajax-Pickering sub-region is a high growth urban area which encompasses a significant portion of Elexicon's customers. The utility's headquarters in Ajax also serves as an operations centre for this area. Ajax-Pickering receives power at 44-kV and 27.6-kV from TS's owned by Hydro One. There are eight 44-kV feeders emanating from Cherrywood TS, three 44-kV feeders and six 27.6-kV feeders from Whitby TS, two 27.6-kV feeders egressing from Sheppard TS, and one 27.6-kV feeder egressing from Malvern TS. These feeders supply 15 municipal stations ("MS") in the area which step down power to 13.8-kV – the locations of these stations are depicted below in Figure 5.3-8 and Table 5.3- outlines the capacity and voltage of each station. All substations operate at 13.8-kV except for Greenwood, Green River, and Greenwood North in northern Pickering which operate at 8.32-kV. Table 5.3- below outlines the length of overhead and underground circuit in the area by voltage level. There is an approximately even split between the length of underground and overhead systems in the area. The majority of circuit line is rated at 13.8-kV (49%) or 27.6-kV (35%) and a smaller fraction of feeders operate at the 44-kV and 8.32-kV levels.

The utility has planned capital investments which will impact the system configuration in the Ajax-Pickering area. As outlined above, all distribution stations except for Green River, Greenwood, and Greenwood North operate at 13.8-kV. Elexicon has planned voltage conversion projects which are intended to standardize the system voltage to 13.8-kV to enable switching operations, accommodate growth, and improve reliability/safety.

The utility has also a planned a major investment into a new Seaton TS which will provide load relief at other high voltage stations and accommodate new developments. There are also several supporting projects related to this initiative which are expected to result in changes to the system configuration such as those intended to fund the addition of new feeders. The system configuration may also evolve as a result of road relocations projects which address changes due to transportation infrastructure development and road modifications.

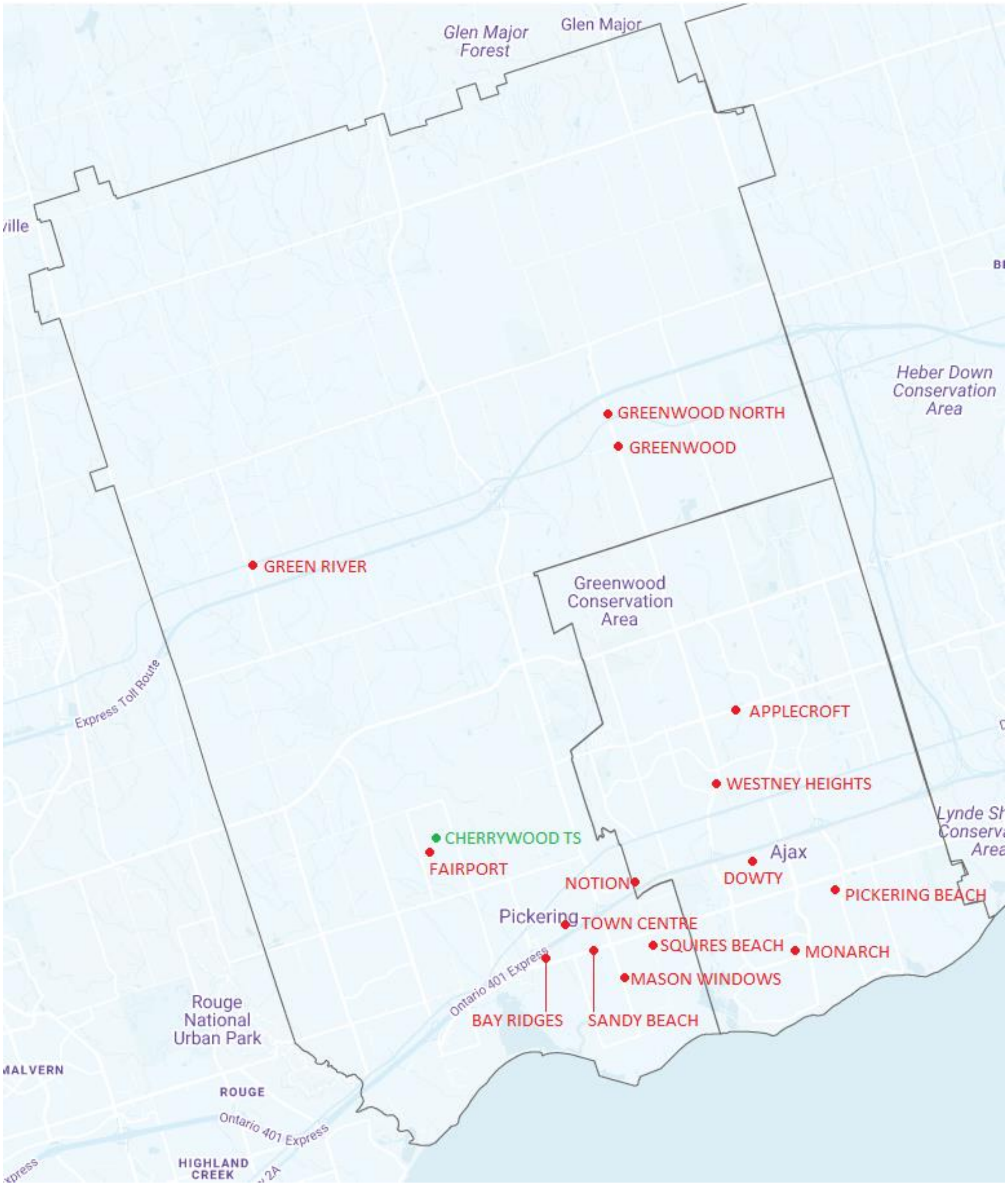
Table 5.3-3: Ajax-Pickering Municipal Stations Voltage and Capacity

Region	Station	Voltage (kV)	Capacity (MVA)
Ajax	Applecroft	13.8	25
	Dowty	13.8	22
	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	30
	Squires Beach	13.8	20
	Town Centre	13.8	22
	Green River	8.32	1.5
	Greenwood	8.32	5
	Greenwood North	8.32	5

Table 5.3-4: Ajax-Pickering Overhead and Underground Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total (km)
4.16-kV	0	0	0
8.32-kV	120	8	128
12.47-kV	0	0	0
13.8-kV	257	497	754
27.6-kV	240	300	539
44-kV	127	5	132
Total	743	810	1553

Figure 5.3-8: Municipal Stations in the Ajax-Pickering Area



Whitby Area

The Whitby sub region 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 customer reside in the southern urban core, there is a significant portion of non-urban land in the northern half of this area. It receives power at 44-kV from nine feeders egressing from Whitby TS and four feeders egressing from Thornton TS. These feeders supply power to 11 MS in the area – Figure 5.3-9 depicts the locations of these stations and Table 5.3- outlines their voltage and capacity. All stations within the Whitby sub region operate at 13.8-kV. Table 5.3- 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 substation in Seaton and road relocations may impact the system configuration in the future.

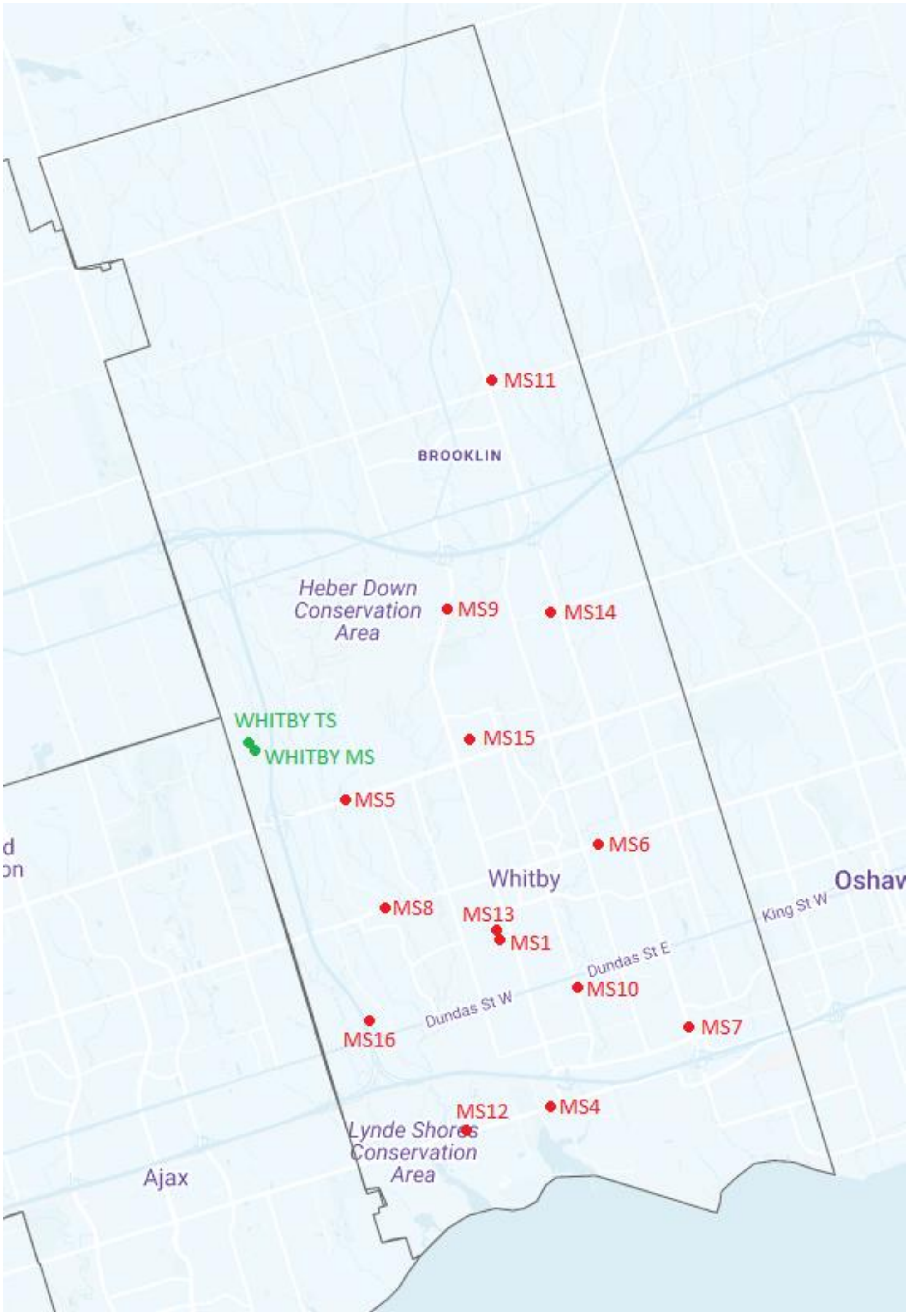
Table 5.3-5: Whitby Municipal Stations Voltage and Capacity

Station	Voltage (kV)	Capacity (MVA)
MS5	13.8	18
MS6	13.8	24
MS7	13.8	24
MS8	13.8	12
MS9	13.8	12
MS10	13.8	32
MS11	13.8	20
MS12	13.8	12
MS13	13.8	12
MS14	13.8	18
MS15	13.8	18

Table 5.3-6: Whitby Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total (km)
4.16-kV	2	0	2
8.32-kV	0	0	0
12.47-kV	0	0	0
13.8-kV	352	573	925
27.6-kV	0	0	0
44-kV	144	3	148
Total	499	576	1075

Figure 5.3-9: Municipal Stations in the Whitby Area



Belleville Area

While the vast majority of the City of Belleville consists of non-urban land, Elexicon's service territory is limited to the downtown core and surrounding area. Belleville's regional characteristics are comparable to Ajax-Pickering and Whitby as it has a similar weather profile and contains a notable population of customers. The utility has a satellite-operations centre in the area given its distance from the headquarters in Ajax. It receives power at 44-kV from five feeders egressing from the Hydro One owned Belleville TS. These feeders supply eleven Municipal Substations – Figure 5.3-10 depicts the location of these stations and Table 5.3- outlines key aspects such as voltage and capacity. The municipal stations within the area are rated at either 4.16-kV or 13.8-kV – the only exception is Edgehill MS which includes one transformer at each voltage level. Table 5.3- below outlines the overhead and underground circuit length by voltage level. The majority of the circuit length in Belleville is overhead (64%) and rated at 13.8-kV (61%). There is a significant population of line at 4.16-kV (25%) with aged assets – for example, the average age of 4.16-kV power transformers is 51.5 years. The utility aims to complete voltage conversion projects to standardize voltage to 13.8-kV in order to enable switching operations, improve asset condition, and increase reliability/safety.

Table 5.3-7: Belleville Municipal Stations Voltage and Capacity

Station	Voltage (kV)	Capacity (MVA)
Bell	13.8	20
Cascade	4.16	7.5
Church	4.16	5
Catherine	4.16	7.5
Edgehill	4.16/13.8	25
Harder	13.8	10
Herchimer	4.16	7.5
Jones	4.16	7.5
Reid	13.8	20
Riverside	4.16	7.5
Sidney	13.8	20

Table 5.3-8: Belleville Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total (km)
4.16-kV	62	14	76
8.32-kV	0	0	0
12.4-7kV	0	0	0
13.8-kV	89	94	183
27.6-kV	0	0	0
44-kV	41	1	42
Total	192	109	301

Figure 5.3-10: Municipal Stations in the Belleville Area

Brock Area

The Brock operational area encompasses the communities of Beaverton, Cannington, Scugog/Port Perry, Sunderland, and Uxbridge. These areas have similar characteristics as they are all relatively small and have 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 transmission station connections are outlined below.

- Beaverton is served via two 44-kV feeders 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 one 44-kV feeder egressing from Hydro One owned Wilson TS.
- Sunderland is served via one 44-kV feeder egressing from Hydro One owned Beaverton TS.
- Uxbridge is served via two 44-kV feeders egressing from Hydro One owned Armitrage 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 5.3- outlines key information about voltage and capacity of each station. Table 5.3- below outlines the overhead and underground circuit length by voltage level in the Brock area. The majority of the circuit line in

Brock is overhead (70%) and operates at the 4.16-kV level (88%). There are no planned voltage conversions or road relocations projects within the Brock area that would impact the system configuration.

Table 5.3-9: Brock Municipal Stations Voltage and Capacity

Municipality	Station	Voltage (kV)	Capacity (MVA)
Beaverton	Beaverton Main	4.16	5
	Beaverton West	4.16	5
	William Gillespie	4.16	5
Cannington	Laidlaw	4.16	5
Scugog/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 5.3-10: Brock Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total (km)
4.16-kV	65	27	92
8.32-kV	5	4	9
12.47-kV	0	0	0
13.8-kV	0	0	0
27.6-kV	0	0	0
44-kV	4	0	4
Total	74	31	105

Clarington Area

The Clarington operational 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 are relatively small with 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 transmission connections for each municipality are outlined below.

- Bowmanville is served from 44-kV feeders egressing from Hydro One owned Wilson TS.
- Newcastle is served from 44-kV feeders egressing from Hydro One owned Wilson TS.
- Orono is served directly at 8.32-kV from Hydro One owned Orono Distribution Station ("DS").
- Port Hope is served from 44-kV feeders egressing from Hydro One owned Port Hope TS.

Elexicon owns a total of twelve municipal stations within the area – the locations of these stations are depicted in the figures below and Table 5.3- 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 5.3- 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. The majority of feeders operate at the 13.8-kV level (60%), but there are material segments at the 4.16-kV (15%) and 27.6-kV (13%) levels as well. Elexicon has planned voltage conversions projects in Port Hope and Cavan South 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. A key challenge within the Clarington area is the presence of Hydro One owned long feeders with a lack of SCADA telemetry. This entails difficulty in operations such as fault identification, but Elexicon plans to install FCI capabilities in this area to address this issue.

Table 5.3-11: Clarington Municipal Stations Voltage and Capacity

Municipality	Station	Voltage (kV)	Capacity (MVA)
Bowmanville	Bradshaw	13.8	10
	Liberty North	13.8	15
	Scugog	4.16	1.5
	Spry	13.8	25
Newcastle	Toronto	13.8	10
	Wilmot	13.8	10
Port Hope	Cavan North	4.16	7.5
	Cavan South	4.16	6
	Howard Walker	4.16	5
	James D. Collins	27.6	10
	Peacock	4.16	5
	Shuter	27.6	10

Table 5.3-12: Clarington Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total (km)
4.16-kV	38	19	57
8.32-kV	7	0	7
12.47-kV	0	0	0
13.8-kV	79	148	227
27.6-kV	33	17	50
44-kV	37	0	37
Total	193	184	378

Figure 5.3-11: Municipal Stations in the Bowmanville Area

Figure 5.3-12: Municipal Stations in the Newcastle Area

Figure 5.3-13: Stations in the Orono Area

Figure 5.3-14: Municipal Stations in the Port Hope Area

Gravenhurst Area

Gravenhurst is similar to several other areas within Elexicon's service territory in that it serves a relatively small population and does not experience significant 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, and materially different weather characteristics. A 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 Muskoka TS and Orillia TS.

From the Muskoka TS supply point, Elexicon customers are served directly at 44-kV and at 12.47-kV by feeders egressing from three Hydro One owned DS: Jones DS, Muskoka Falls DS, and Walkers Point DS. From the Orillia TS supply point, customers are served directly at 44-kV and at 12.47-kV via feeders egressing from the Hydro One owned Gravenhurst DS. Alternatively, customers are served at either 12.47-kV or 4.16-kV from Elexicon owned municipal stations. The locations of Hydro One owned DS and Elexicon owned MS are presented in Figure 5.3-15. Table 5.3- provides additional information about the Elexicon owned MS in Gravenhurst which operate at either 4.16-kV or 12.47-kV. Table 5.3- provides an overview of the overhead and underground circuit length by voltage level. The vast majority of circuit line is overhead (79%) and operates at the 12.47-kV level (84%).

Elexicon has some planned projects within the area that have implications for the system configuration. There are voltage conversion targeting 4.16-kV feeders and First substation which are intended to increase capacity to 12.47-kV. Similarly, to Clarington, this area also has long Hydro One owned feeders with a lack of SCADA telemetry – the utility has planned projects to introduce FCIs into the system to address this issue. There are currently no planned road relocations which would impact system configuration in the area.

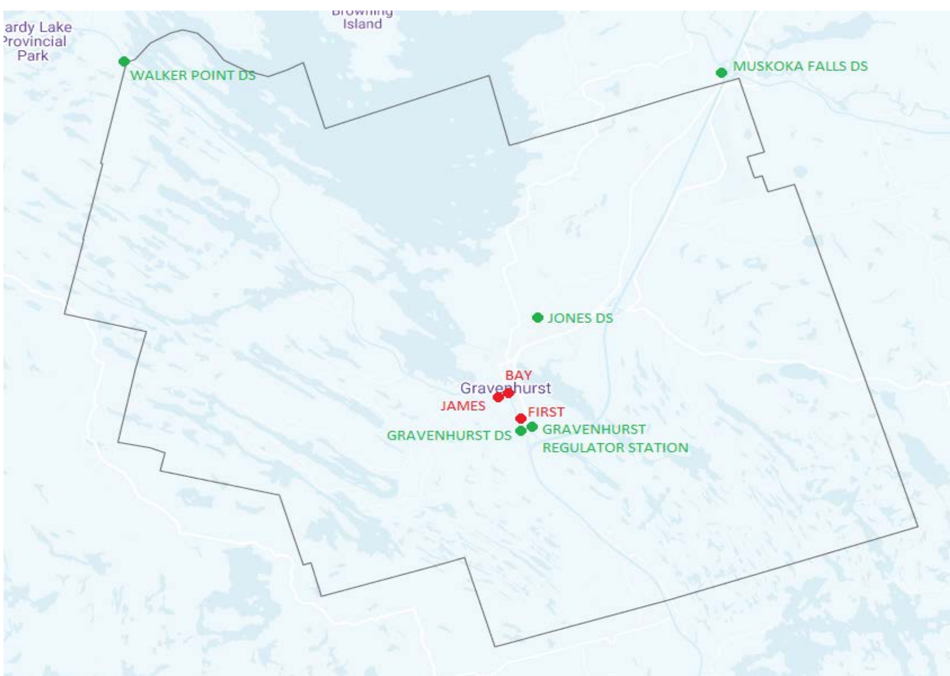
Table 5.3-13: Gravenhurst Municipal Stations Voltage and Capacity

Station	Voltage (kV)	Capacity (MVA)
Bay	4.16	6
James	12.47	7.5
First	4.16	6

Table 5.3-14: Gravenhurst Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total (km)
4.16-kV	24	12	36
8.32-kV	0	0	0
12.47-kV	197	49	247
13.8-kV	0	0	0
27.6-kV	0	0	0
44-kV	10	0	11
Total	232	62	293

Figure 5.3-15: Stations in the Gravenhurst Area



Other Challenging System Features: Rear-Lot Distribution Lines

A notable system configuration-related challenge facing Elexicon across a number of its communities is the presence of rear-lot lines located in laneways of older residential subdivisions in multiple communities, with most being in Pickering. These rear-lot lines carry both primary and secondary distribution circuits and show extensive signs of deterioration as they have been in service for several decades.

These installations are a source of hazard during severe weather, due to their proximity to trees, residential buildings, and backyard facilities like pools or sheds. Damage to rear-lot poles from lightning strikes can also potentially create a greater than normal safety risk for residents. Importantly, rear-lot power outages are typically long and expensive to rectify, as accessing the sites is difficult due to narrow laneways, dense vegetation and other obstacles.

Most Ontario utilities with rear-lot powerline feeders are gradually converting them to front-lot (street side) overhead or underground services. While converting to underground lines costs substantially more than keeping the transferred lines overhead, underground lines are less susceptible to most types of weather events and are more aesthetically pleasing.

5.3.2 c) Results of Asset Condition Assessment

The ACA allows the utility to understand the condition of its distribution assets and plan system renewal capital investments. Elexicon completed its first ACA as a merged utility in December 2019 and plans to conduct this analysis annually moving forward. This section presents the ACA results for several key asset classes which assess the health of underground, overhead, and substation infrastructure, as listed below.

The complete ACA report is provided in Appendix F. In some cases, sufficient data for the calculation of a Health Index ("HI") score was not available, resulting in asset not being assigned a Valid Health Index. The utility plans to prioritize data collection efforts for these assets in order to include them in the next annual ACA update.

The Data Availability Index ("DAI") discussed in the subsections below is a measure of the availability of the input data use to calculate an HI score. It is presented as a percentage and accounts for the relative weighting of the input condition parameters. For example, a condition parameter with a high weighting in the HI calculation would have a more significant impact on the DAI. The utility plans to increase DAI over the ongoing maintenance cycle as a merged utility

The following passages provide ACA results for the following asset classes:

- Wood Poles
- Underground Cable
- Overhead Conductor
- Pole-mounted Transformers
- Pad-mounted Transformers
- Station Power Transformers
- Station Circuit Breakers

Wood Poles

There are currently 34,111 wood poles in deployment in Elexicon's distribution system. The condition of wood poles is assessed based on the following parameters:

- Service Age
- Defects/Overall Condition
- Wood Rot
- Remaining Strength
- Out of Plumb

Figure 5.3-16 and Figure 5.3-17 below depict the HI results and age demographics for wood poles, respectively. The average DAI across all wood poles is relatively high at 88% - as shown below, approximately 12% of wood poles did not have sufficient data for the calculation of an HI score. Given that approximately 4% of wood poles fall into the Poor/Very Poor condition categories, the majority of assets are in Fair Condition or better.

Figure 5.3-16: Health Index Results for Wood Poles

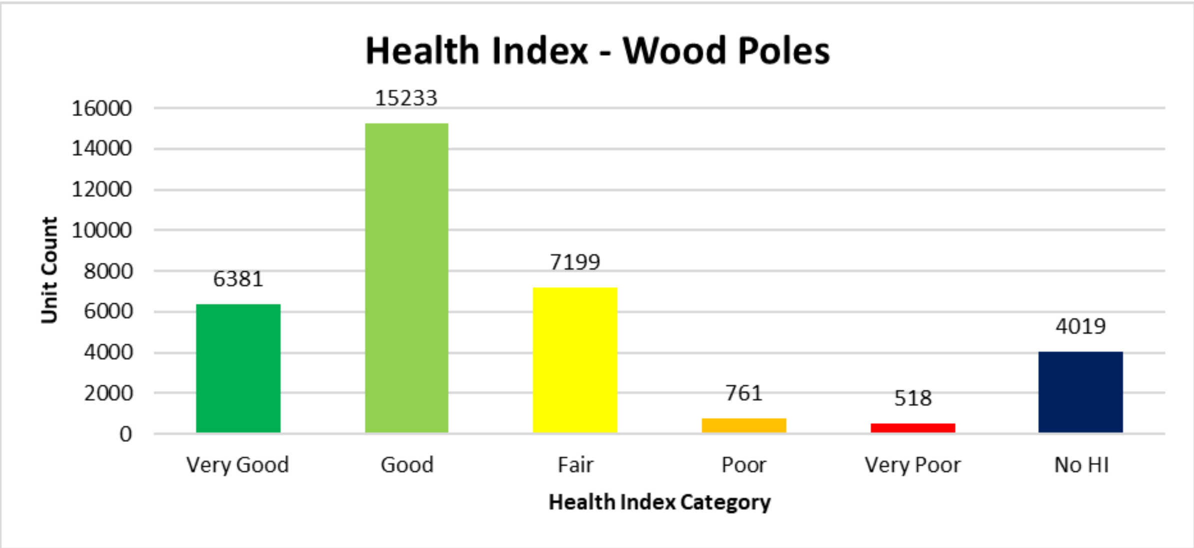
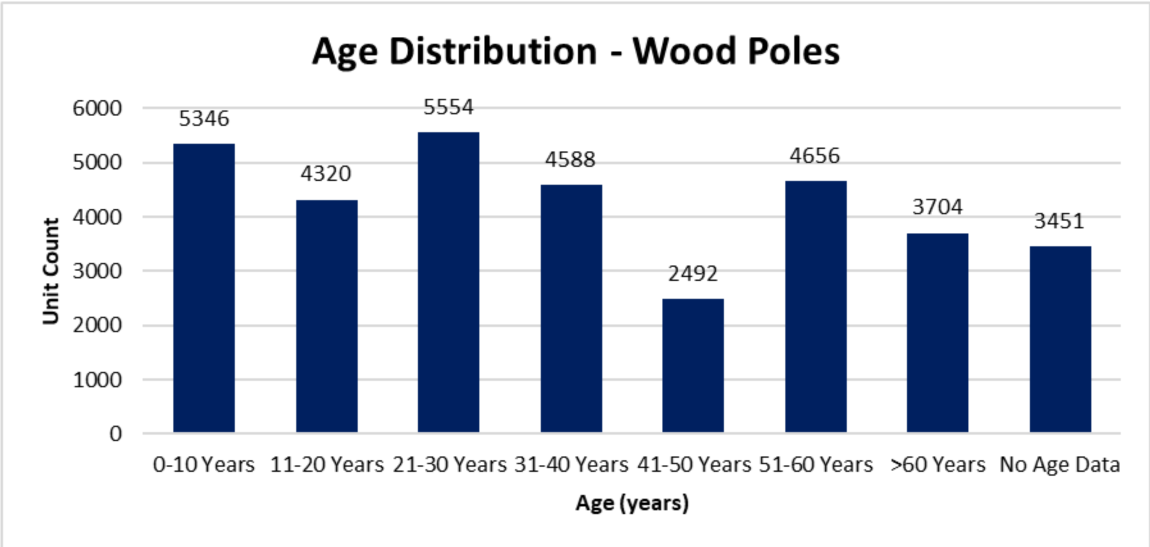


Figure 5.3-17: Age Demographics for Wood Poles



Underground Cable

Elexicon's distribution system contains approximately 2,336km of underground cable operating at voltages between 2.4-kV and 44-kV. Underground cables' condition assessment is completed on the basis of service age and the presence of cable splices. This data was readily available for most segments of underground cable as the average DAI is very high at 94%. As shown in Figure 5.3-18 the majority of Elexicon's underground cables are in Fair condition or better as only 9% of the population (by length) falls into the Poor or Very Poor categories. The age distribution for underground cables is depicted in Figure 5.3-19.

Figure 5.3-18: Health Index Results for Underground Cable

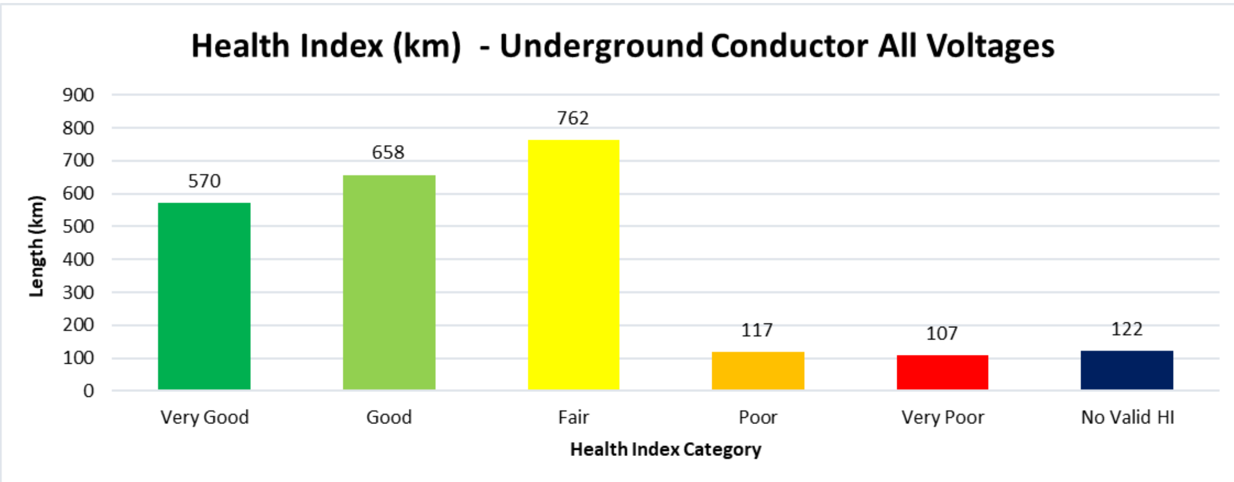
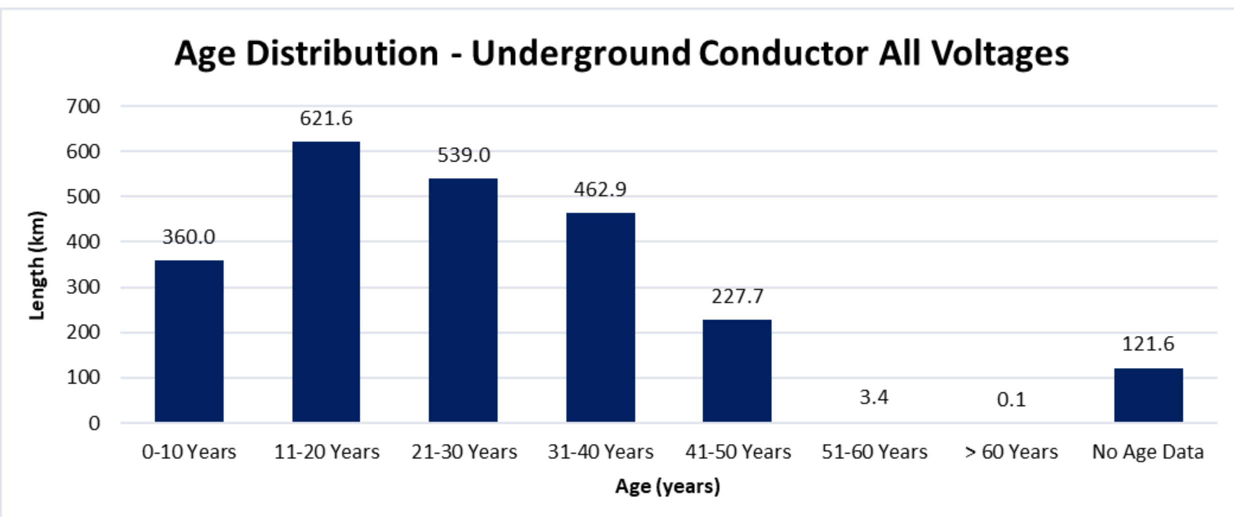


Figure 5.3-19: Age Demographics for Underground Cable



Overhead Conductor

Elexicon's distribution system contains approximately 4,300 km of overhead conductor. However, only 3,800km are present in the GIS system and only a small fraction of these has age data available. Given these circumstances, an HI score was not calculated for this asset class. Overhead conductors do not have their own replacement programs and are typically renewed during pole replacements or rebuilds. The demographics for small and large conductor types are presented separately as there is a tendency for small copper conductors to deteriorate at an accelerated rate. The age demographics for the large and small conductor types are shown in Figure 5.3-20 and Figure 5.3-21, respectively. Elexicon is working on addressing this and other pertinent asset data gaps.

Figure 5.3-20: Age Demographics for Large OH Conductor

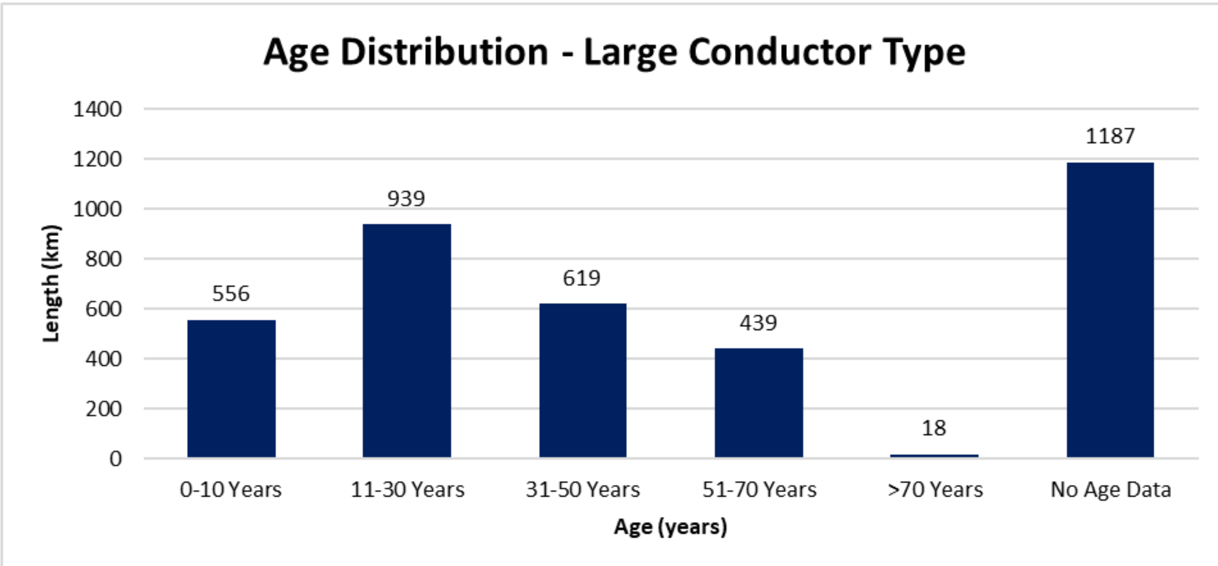
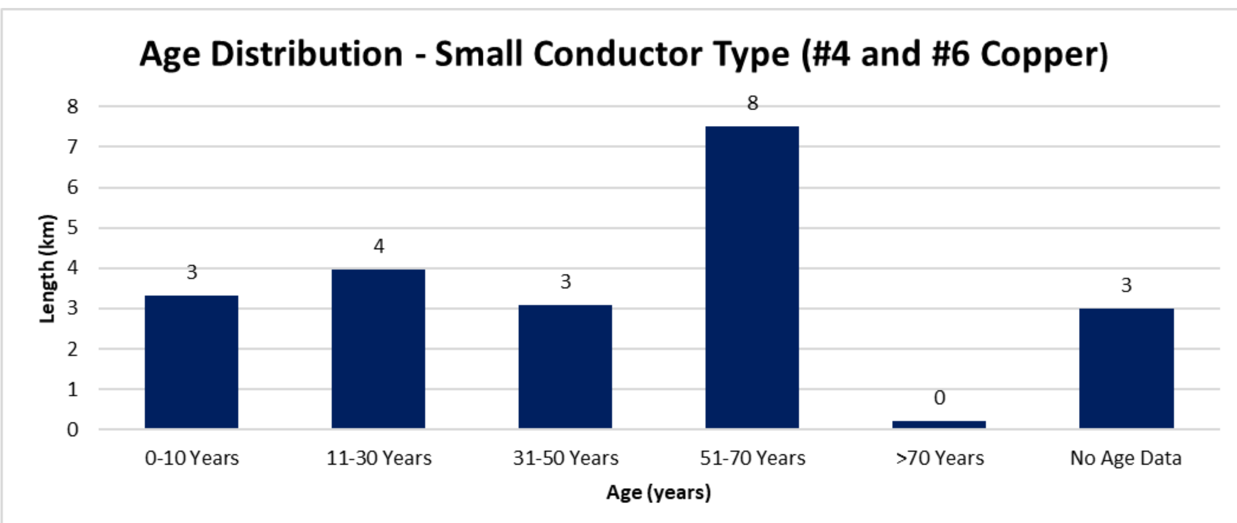


Figure 5.3-21: Age Demographics for Small OH Conductor



Pole Mounted Transformer

Elexicon's distribution system includes 7,232 pole mounted transformers, of which 1,465 in the legacy Whitby area have visual inspections data. There is no recorded condition data for the legacy Veridian pole mounted transformers, but transformer degradation was noted on an exception basis in the routine inspection process. The average DAI for pole mounted transformers is relatively low at 30%, but this is primarily due to the legacy Veridian inspections practice. A health index was calculated for legacy Whitby pole mounted transformers only and the results for single and three phase units are presented below in Figure 5.3-22 and Figure 5.3-23 respectively. This health index calculation is based on age and overall condition data. The majority of these pole mounted transformers are in Fair condition or better as approximately 2% fall into the Poor or Very Poor category. The age demographics for single and three phase pole mounted transformers are shown in Figure 5.3-24 and Figure 5.3-25, respectively.

Figure 5.3-22: Health Index Results for Legacy Whitby Single Phase Pole Mounted TX

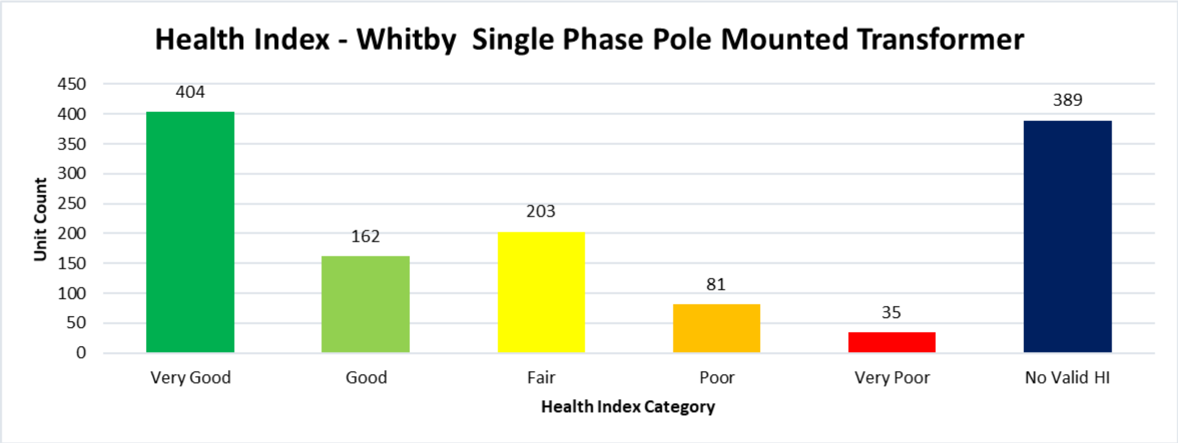


Figure 5.3-23: Health Index Results for Legacy Whitby Three Phase Pole Mounted TX

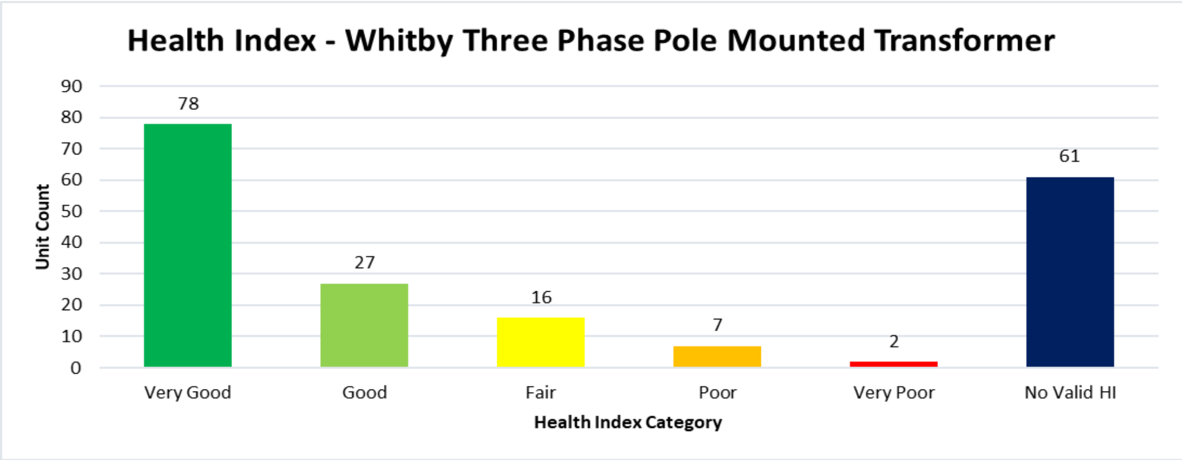


Figure 5.3-24: Age Demographics for Single Phase Pole Mounted TX

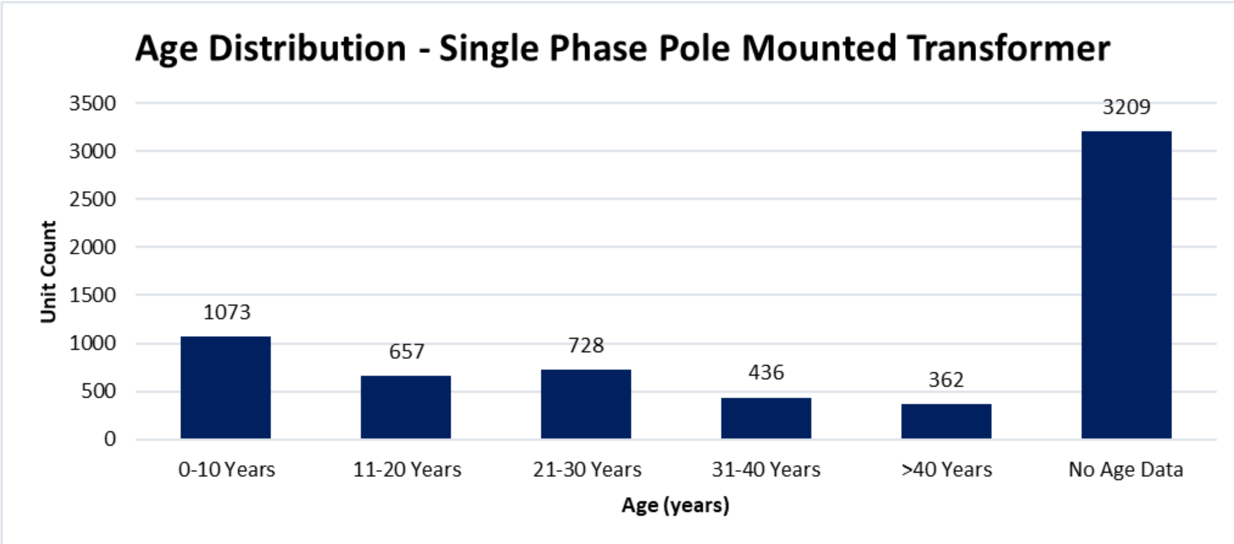
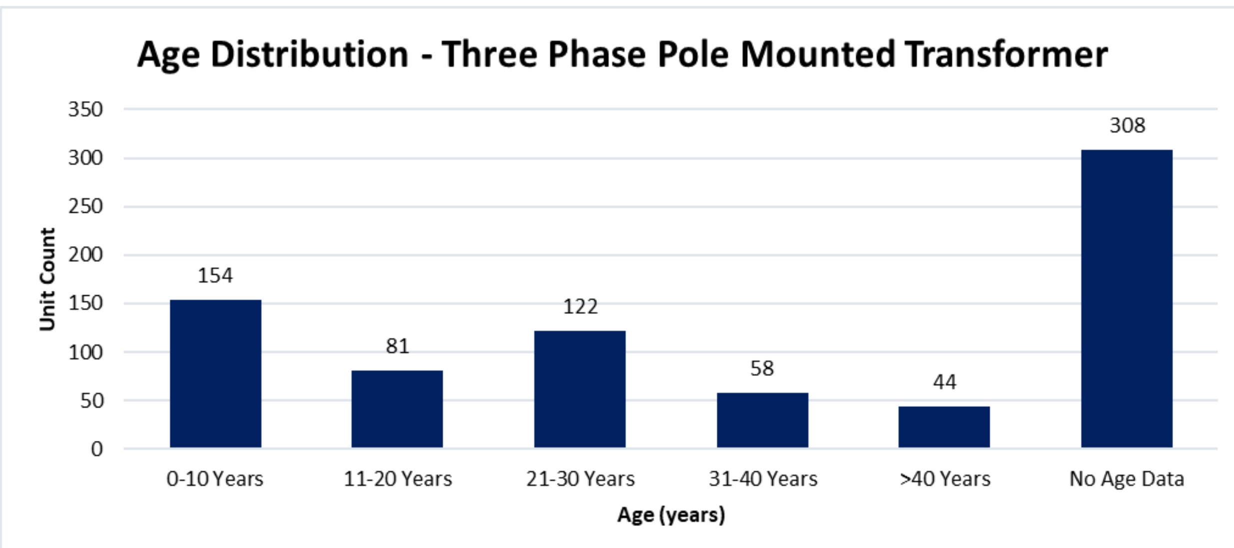


Figure 5.3-25: Age Demographics for Three Phase Pole Mounted TX



Pad Mounted Transformer

Elexicon's distribution system contains approximately 12,002 single phase and 1,587 three phase pad mounted transformers. The average DAI for this asset class is very high at 95% and allows for the calculation of an HI score for nearly all pad mounted transformers. The HI calculation is based on available service data and overall condition data from visual inspection records. The results of the HI assessment for single and three phase pad mounted transformers are presented below in Figure ***5.3-26*** and Figure 5.3-27, respectively. The majority of both single and three phase pad mounted transformers are in Fair condition or better and only 4% of single-phase units and 1.5% of three phase units are in Poor or Very Poor condition. The age demographics for both single and three phase pad mounted transformers are also provided below in Figure 5.3-28 and Figure 5.3-29, respectively.

Figure* 5.3-26*: Health Index Results for Single Phase Pad Mounted Transformers

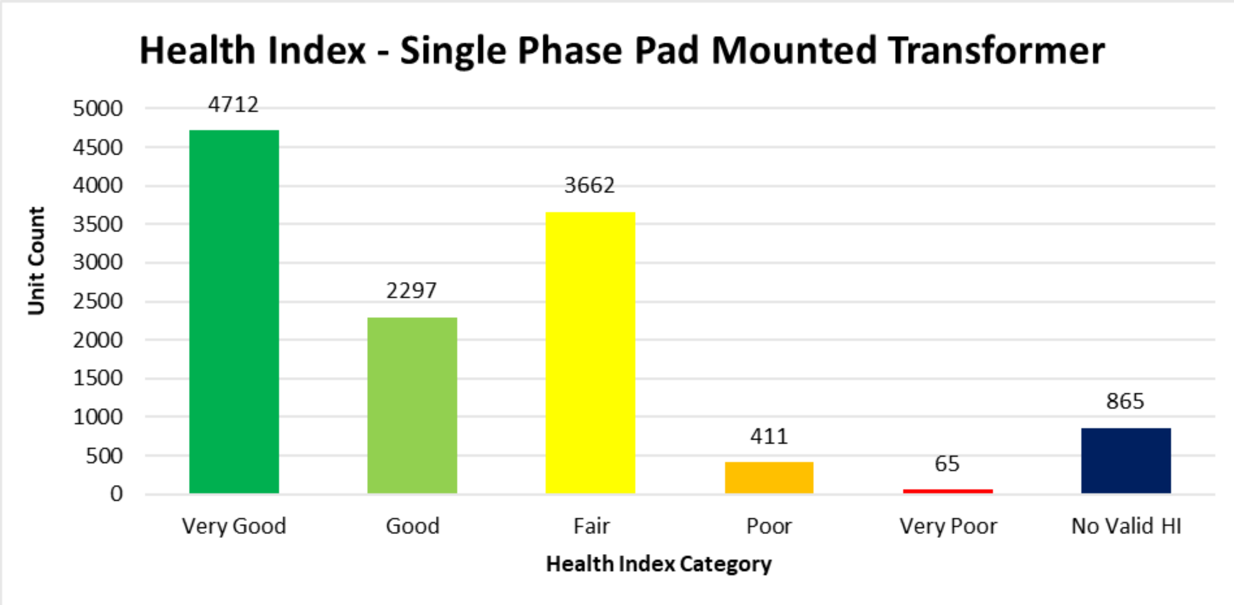


Figure 5.3-27: Health Index Results for Three Phase Pad Mounted Transformers

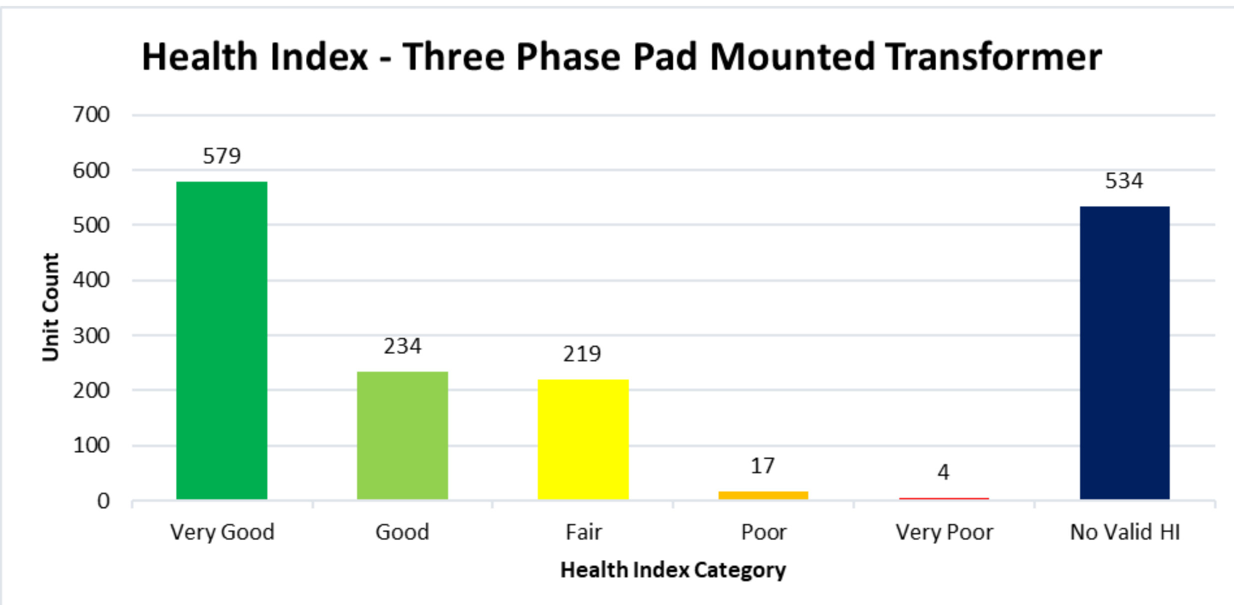


Figure 5.3-28: Age Demographics for Single Phase Pad Mounted Transformers

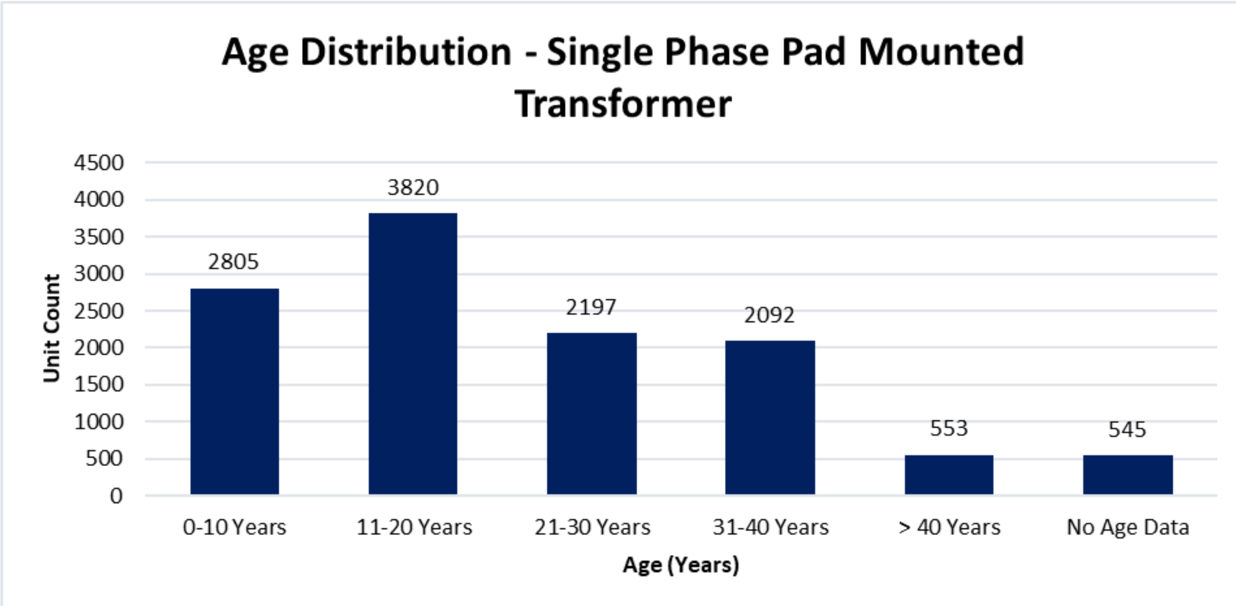
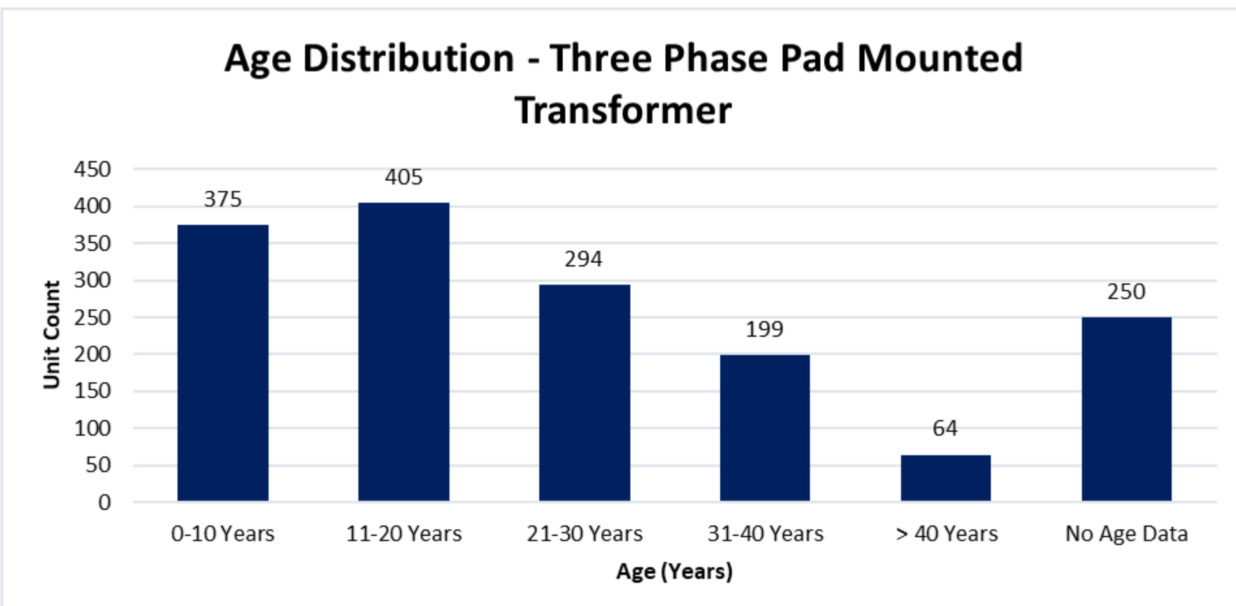


Figure 5.3-29: Age Demographics for Three Phase Pad Mounted Transformers



Station Transformers

Elexicon's distribution system includes 96 station transformers, including a spare unit, and customer owned units at two customer locations. This asset class has a high average DAI at 99% - the condition parameters used to conduct the health index assessment are listed below:

- Dissolved Gas Analysis
- Insulation Power Factor
- Oil Quality

- Service Age
- Overall Condition
- Bushing Condition
- Cooling Equipment
- Grounding Condition
- Gasket Condition
- Connections Condition
- Oil Leaks

As shown in Figure 5.3-30 below, the majority of station transformers are in Fair condition or better. In addition, only 7% are in Poor condition and there are no transformers in very poor condition. Age demographics for this asset class are provided below in Figure 5.3-31.

Figure 5.3-30: Health Index Results for Station Transformers

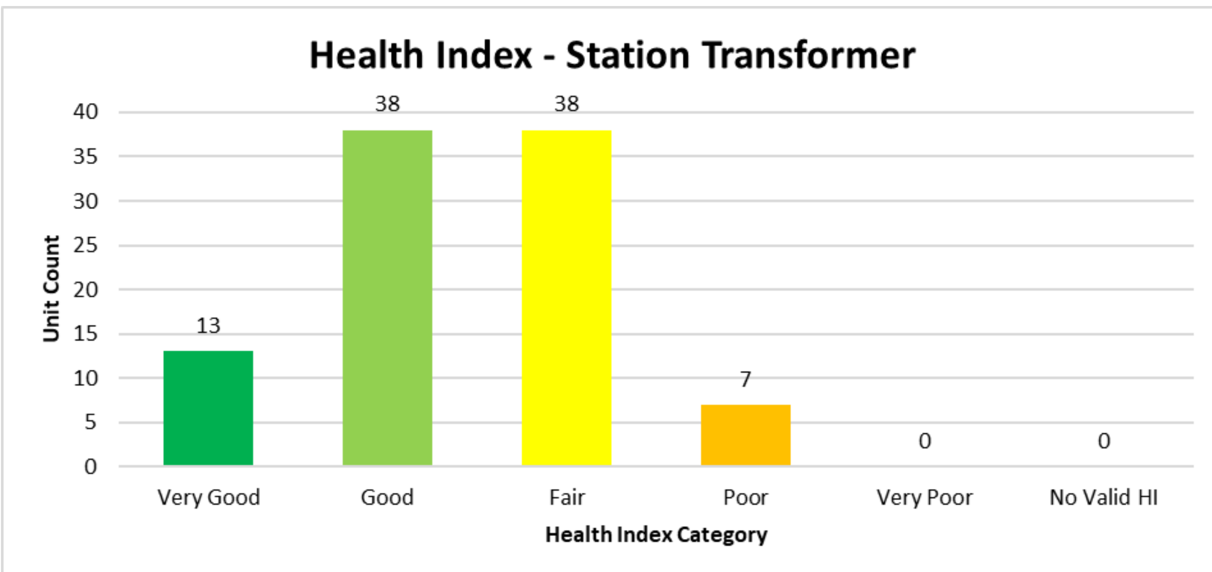
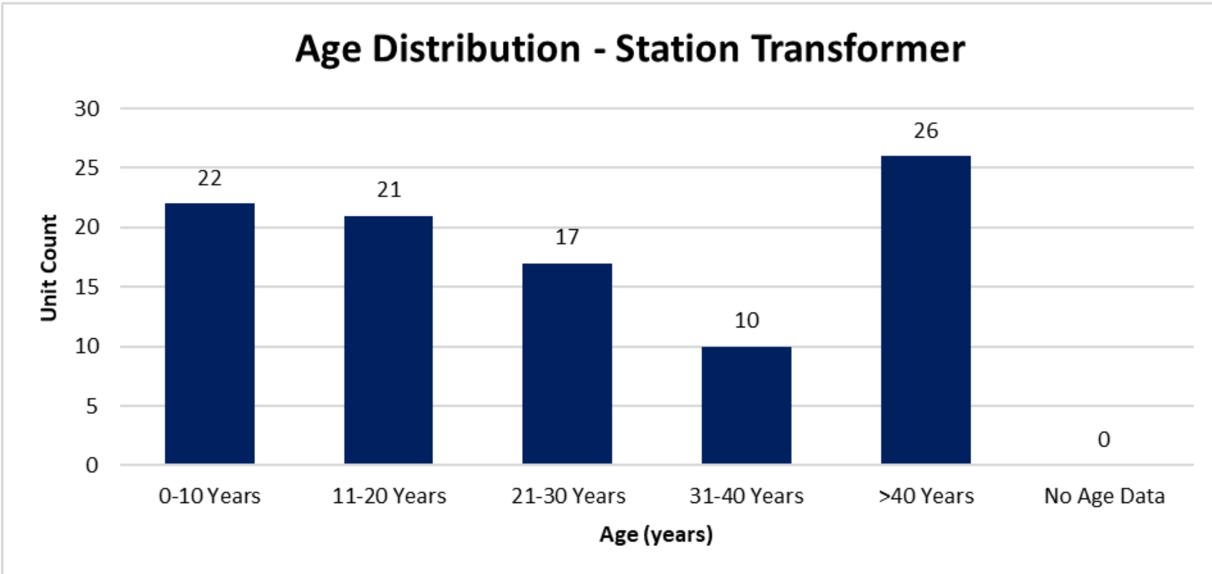


Figure 5.3-31: Age Demographics for Station Transformers



Station Circuit Breakers

Elexicon's distribution system has 178 circuit breakers which are assessed based on service age, test results, and visual inspections. The average DAI for this asset class is very high at 97% and the results of the HI assessment, shown in Figure 5.3-32 below, indicate that this asset class is in excellent condition. The majority of Elexicon's circuit breakers are in Fair condition or better and only 7% are in Poor or Very Poor condition. The age demographics for this asset class are shown below in Figure 5.3-33.

Figure 5.3-32: Health Index Results for Station Circuit Breakers

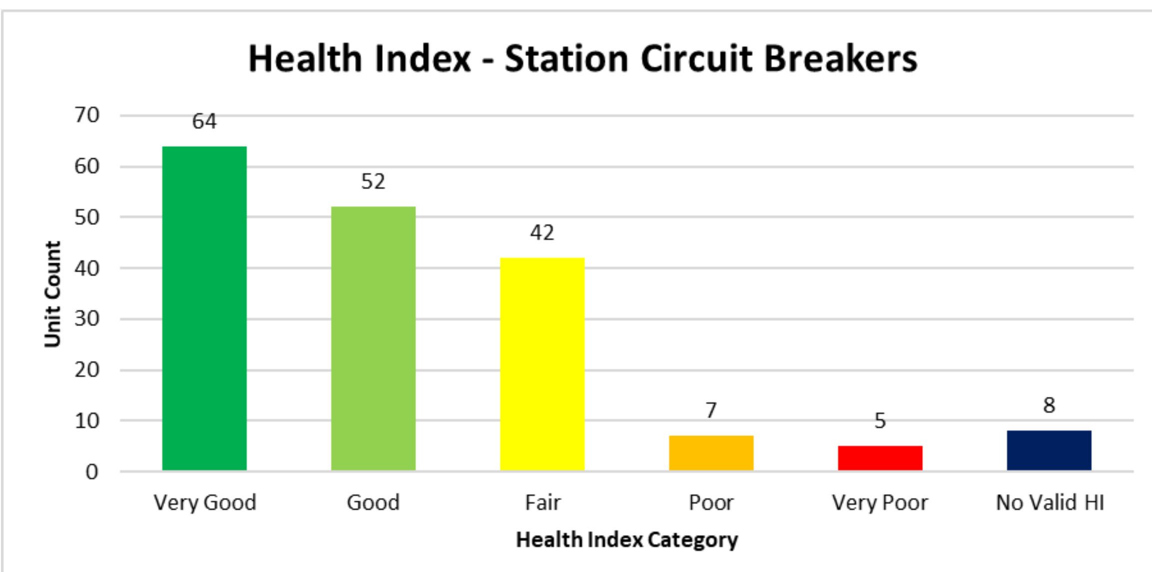
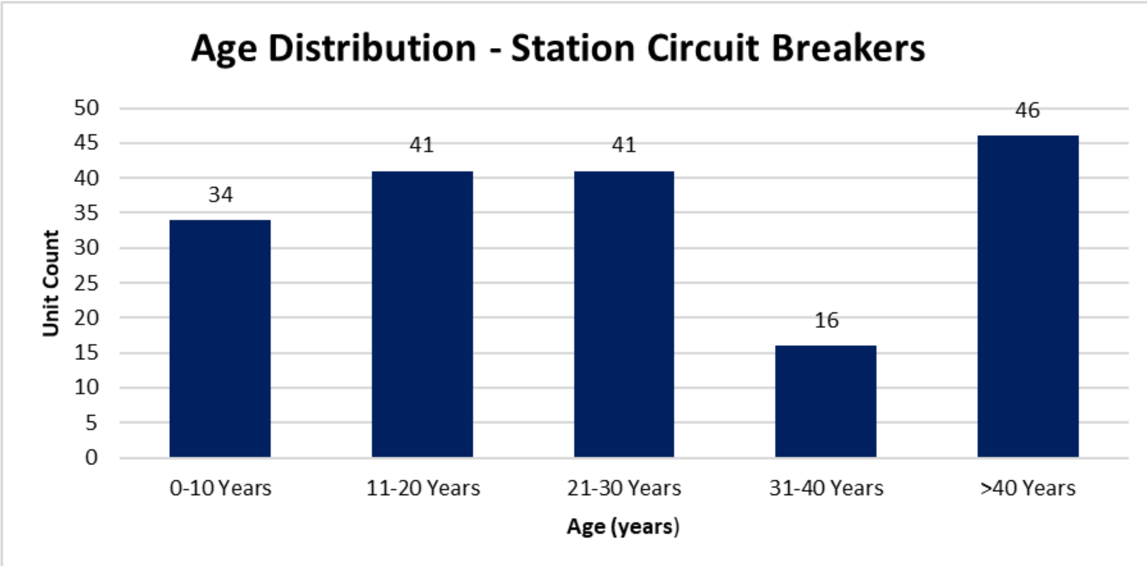


Figure 5.3-33: Age Demographics for Station Circuit Breakers



5.3.2 d) System Utilization

Elexicon collects system loading data on an hourly basis through meters installed at customer sites. This allows the utility to understand the loading profile at the customer, feeder, and station levels. Elexicon assesses capacity by calculating the non-coincident peak load which represents the maximum load regardless of the time of occurrence. This section outlines key aspects of the current loading profile of the system at the station and the feeder levels.

Station Capacity

Elexicon assesses station capacity using average utilization over the last five years. The non-coincident peak load of a given year is divided by the capacity of the station transformer and the results are averaged. Table 5.3- below provides a summary of the average capacity of station utilization by voltage level. Stations with an average utilization that exceeds 100% of ONAN rating are presented in Table 5.3-.

Table 5.3-15: Summary of Average Utilization by Station Voltage

Voltage Rating (kV)	Average Capacity (MW)	Average Utilization
4.16	5.9	48.4%
4.16/13.8	25.0	52.0%
8.32	5.0	35.4%
12.47	7.5	62.8%
13.8	19.1	72.6%
27.6	10.0	43.8%

Table 5.3-16: Stations Exceeding 100% Utilization

Service Area	Station	Voltage (kV)	Capacity (MVA)	2015	2016	2017	2018	2019	Average Utilization
AJAX	NOTION RD	13.8	15	15.88	19.13	11.69	16.54	13.63	102.49%
PICKERING	FAIRPORT	13.8	20	20.21	26.94	17.8	21.77	20.98	107.70%
BOWMANVILLE	BRADSHAW	13.8	10	9.23	11.08	12.09	9.16	11.53	106.18%
WHITBY	MS 8	13.8	12	12.88	16.63	14.95	16.63	7.53	114.37%
WHITBY	MS 11	13.8	20	22.07	20.58	21.41	20.58	18.5	103.14%

Loading beyond the station components' capacities results in increased deterioration through mechanisms such as thermal degradation. If station components are loaded beyond their intended capacity for significant periods of time, the risk of asset failure and service interruptions increases. Elexicon continually monitors the loading profiles of its system assets to ensure that they meet demand requirements. The vast majority of stations have not experienced loading over 100% ONAN capacity. While the stations listed above have an average utilization greater than 100%, Elexicon does not expect that they will experience capacity or performance related issues.

As outlined above, the calculation of average utilization is completed using the non-coincident peak load. It is important to consider that the non-coincident peak load represents the maximum load experienced by the system regardless of the time of occurrence. The non-coincident peak load does not reflect the practical loading profile and is only considered to encourage a proactive assessment of system capacity. In addition, further analysis reveals that the duration of the overage is minimal and is not expected to cause significant degradation. However, Elexicon plans to proactively make investments to minimize the risk of capacity related issues – these investments are described in section 5.3.2.4.3 below.

Feeder Capacity

Feeder capacity is assessed using average utilization over the previous year. Elexicon evaluates feeder capacity based on full standard feeder size of 556Al at 300A, while the maximum technical feeder capacity at 600A. This practice allows the utility to retain load transfer capability between feeders in case of emergencies and to provide reliability to customers during outage events. The maximum non-coincident current over the previous year is divided by the feeder ampacity. Table 5.3- below outlines the average ampacity and utilization for all feeders by voltage level. There are nine feeders with a per cent utilization greater than 100% - these feeders are presented in Table 5.3- below.

Table 5.3-17: Summary of Average Feeder Utilization by Voltage

Voltage (kV)	Average Ampacity	Average Utilization
4.16	384	48.6%
8.32	450	38.3%
12.47	390	14.0%
13.8	494	48.8%
27.6	465	39.8%

Table 5.3-18: Feeders Exceeding 100% Utilization

Feeder	Voltage (kV)	Ampacity (A)	Max Current (A)	% Utilization
11F2	13.8	640	811	127%
LIBN F1	13.8	465	800	172%
JAME F2	27.6	465	500	108%
BIGE F1	4.16	300	381	127%
BIGE F2	4.16	300	303	101%
BIGE F3	4.16	300	454	151%
MABL F1	4.16	300	510	170%
MABL F2	4.16	300	459	153%
FIRS-F3	4.16	390	452	116%

As outlined above, loading beyond intended capacity results in increased deterioration (via thermal degradation) and can increase the risk of asset failure and reliability issues. Elexicon monitors the loading profiles of feeders to ensure that they are equipped to meet demand. While the feeders listed above have exceeded their loading capacity at some point over the past year, there is minimal cause for concern. As outlined above, the non-coincident peak load used for this calculation does not reflect the practical system loading profile as it considers the peak load regardless of the time of occurrence. In addition, the duration of the overage is minimal and infrequent which means that significant deterioration is not expected. However, Elexicon plans to make investments to proactively address potential capacity issues. These investments are described in section 5.3.2.4.3 below.

Conclusion

As outlined above, Elexicon collects loading data on an hourly basis and produces monthly loading profile reports. The loading profiles of Elexicon's stations and feeders are analyzed for potential capacity issues. While there are stations and feeders which have exceeded loading capacity in the past, the duration, frequency, and nature of these overages does not necessitate significant remedial action. However, there are measures in place to ensure that the distribution system does not experience significant capacity or performance issues. Elexicon's operations staff responds to overages by completing switching operations which minimize their duration and assist in relieving load where required. In addition, Elexicon has planned investments over the forecast period which will assist in proactively addressing capacity constraints. There are two investments which contribute to this goal: the development of the Seaton TS and voltage conversion projects.

The construction of Seaton TS was an outcome of the Regional Planning Process intended to address growth in the northern Pickering area. Seaton TS will also provide load relief for Elexicon stations as it will be owned and operated by the utility and integrated into its system. This allows Elexicon the opportunity to further optimize its load distribution as it can reallocate load from existing stations and feeders which may be experiencing load growth. In addition, Elexicon has also planned voltage conversions in its Voltage Conversions – Reliability program which will provide several benefits. The conversion of existing feeders to higher voltages provides greater capacity and opportunity to renew the condition of system assets. Voltage conversions are also intended to standardize the voltage across Elexicon's distribution system, which will allow for greater flexibility for switching operations which can serve as an effective method of load transfers.

In conclusion, while some stations and feeders in Elexicon's distribution system have exceeded capacity over the historical period, the duration and frequency of these overages is minimal. In addition, the calculation is completed through consideration of the non-coincident peak load which acts as a safety factor. There are no significant capacity related risks to Elexicon's system at this time. However, growth within the service territory is expected over the forecast period and the planned investments described above (Seaton TS and voltage conversions) will ensure that capacity risk is further reduced or maintained at the current level.

5.3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

5.3.3 a) Asset Lifecycle Optimization Policies and Practices

Elexicon has implemented various asset lifecycle optimization policies and practices in order to achieve a balance between safety, reliability, cost control, and customer preferences. These practices vary depending on the asset class and often draw elements from the approaches of the predecessor utilities. Elexicon gathers and analyzes information about the condition of individual assets through inspections or existing GIS data. This information is used to assess the current state of distribution system assets, review intervention options, and select an approach which best fits Elexicon's corporate goals, customers preferences, and available budget. Typically, Elexicon selects between asset refurbishment and replacement. The latter is an effective but costly approach for improving asset health whereas the former is less expensive but has a limited effect on the useful life of an asset. This section outlines Elexicon's inspection, maintenance, refurbishment, and replacement practices for several distribution and general plant asset classes.

The subsections below describe Elexicon's asset replacement and refurbishment policies to optimize renewal spending, routine system O&M activities, and maintenance planning criteria and assumptions for each asset class. In addition to this asset-specific information, a description of how all investments – including asset replacements – are prioritized and scheduled to align within budget envelopes is provided in Section 5.4.1(b), which includes criteria to assess impacts on system O&M expenditures. Section 5.3.19b) also provides a description on how system O&M and capital expenditures are optimized within Elexicon's asset management process.

Distribution Line Assets

Table 5.3-19 summarizes Elexicon's asset lifecycle optimization policies and practices (i.e., replacement and refurbishment policies, O&M activities, and maintenance planning criteria and assumptions for distribution line assets. Details descriptions for each asset class are provided below the table.

Table 5.3-19: Summary of Elexicon's Asset Lifecycle Optimization Policies and Practices

Asset Class	Inspection Activities	Maintenance / Testing Activities	Refurbishment Activities	Current Replacement
Wood Poles	Visual Inspections on a 3-year cycle.	Predictive Maintenance via Wood Rot and Remaining Strength Testing on a 3-year cycle.	None.	Condition-based proactive replacement. High risk "danger" poles replaced immediately.
Concrete Poles	Visual Inspections on a 3-year cycle.	None.	None.	Condition-based proactive replacements with wood poles.
Overhead Conductor	Visual Inspections on a 3-year cycle.	Predictive Maintenance via IR Scanning on a 3-year cycle. Repairs as needed.	None.	Proactive replacements completed during line rebuilds.
Pole Mounted Transformers	Visual Inspections on a 3-year cycle.	Predictive Maintenance via IR Scanning on a 3-year cycle. Repairs as needed.	In field repairs limited to units less than 15 years of age.	Proactive replacements completed based on condition or overloading.

Asset Class	Inspection Activities	Maintenance / Testing Activities	Refurbishment Activities	Current Replacement
Overhead Switches (non-LIS)	Visual Inspections and mechanical operation check on a 3-year cycle.	Predictive Maintenance via IR Scanning on a 3-year cycle. Repairs as needed.	Repairs completed in field as required.	Condition-based proactive replacements completed.
Overhead Switches (LIS)	Visual Inspections and mechanical operation check on a 3-year cycle.	Predictive Maintenance via IR Scanning on a 3-year cycle. Repairs as needed.	Repairs completed in field as required.	Proactive replacements based on condition.
Distribution Switchgear	Visual Inspections on a 3-year cycle.	Predictive Maintenance via IR Scanning on a 3-year cycle for all units. Live front units are also cleaned with CO2 on a 3-year cycle. Repairs are completed as required.	None. Refurbished units currently in field are being replaced with new units.	Proactive replacements based on condition.
Underground Cable	None.	DC Polarization / Depolarization cable testing based on age and number of failures	Cable injections and cable splicing based on testing results (where feasible).	Proactive replacements based on condition or as part of sectional rebuilds.
Vault Transformers	Visual Inspections on a 3-year cycle.	None.	Repairs performed as needed on units under 15 years old.	Units are allowed to run to failure. The site is evaluated to check if the unit can be moved outside or must be replaced as is.
Pad Mounted Transformers	Visual Inspections on a 3-year cycle.	Repainting based on customer request only.	Repairs performed on units under 15 years old.	Proactive replacements based on condition or overloading.

<u>Wood Poles</u>

Both predecessors regularly completed visual inspections and predictive maintenance (i.e., wood rot testing and remaining strength testing). However, Veridian's legacy inspection cycle was longer to account for a larger population spread over a significantly larger and segmented service area. The inspections cycle spanned an eight to nine-year period, in general alignment for the DSC requirements for rural line patrols. In comparison, Whitby Hydro completed these activities on a three-year cycle which concluded prior to the merger. Neither legacy utility completed additional maintenance or refurbishment, but both performed proactive replacements prioritized by condition. The predecessors also replaced high risk poles identified during visual inspections immediately or within the year (depending on severity).

Given that there are several similarities between the legacy approaches, Elexicon intends to adopt most of these activities moving forward. Elexicon plans to adopt a three-year cycle for visual inspection, wood rot testing, and remaining strength testing. This translates to approximately 10,000 poles/year subject to applicable operational constraints. While it leads to higher annual expenditures, shorter inspection cycle helps identify and rectify any impending reliability and safety issues, enhance the currency of asset condition databases, and identify any emerging or persistent vegetation-related issues (e.g., suggesting areas for emergency trimming, or capturing information that helps monitor the efficacy of current vegetation clearing cycles). The current strategy does not include any additional maintenance or refurbishment and entails proactive replacements prioritized by condition. Similarly, to the predecessors, the utility expects to replace high-risk poles identified during visual inspections immediately or within the year.

Figure 5.3-34: Example of a Pole with Signs of Deterioration (1)

Figure 5.3-35: Example of Pole with Signs of Deterioration (2)

Concrete Poles

Whitby Hydro visually inspected concrete poles on a three-year cycle and typically completed like-for-like replacements reactively. The legacy utility only completed proactive replacements if visual inspections identified a high-risk pole. In comparison, Veridian did not inspect concrete poles and only completed replacements with wood poles upon failure. Neither predecessor performed any maintenance or refurbishment activities. Elexicon plans to visually inspect assets on a three-year cycle and complete proactive replacements with wood poles based on age and inspection results. The current strategy does not include any refurbishment or maintenance efforts. Going forward, Elexicon has determined that it will not be constructing new concrete poles and replacing the existing ones with wooden equivalents once their ends of life – unless specifically requested and paid for by a customer. In doing so, the utility plans to gradually phase out this asset class to improve the consistency of its installed asset base and help streamline the supply chain and warehousing function by reducing the number and variability of items required for ordering and stocking.

Overhead Conductor

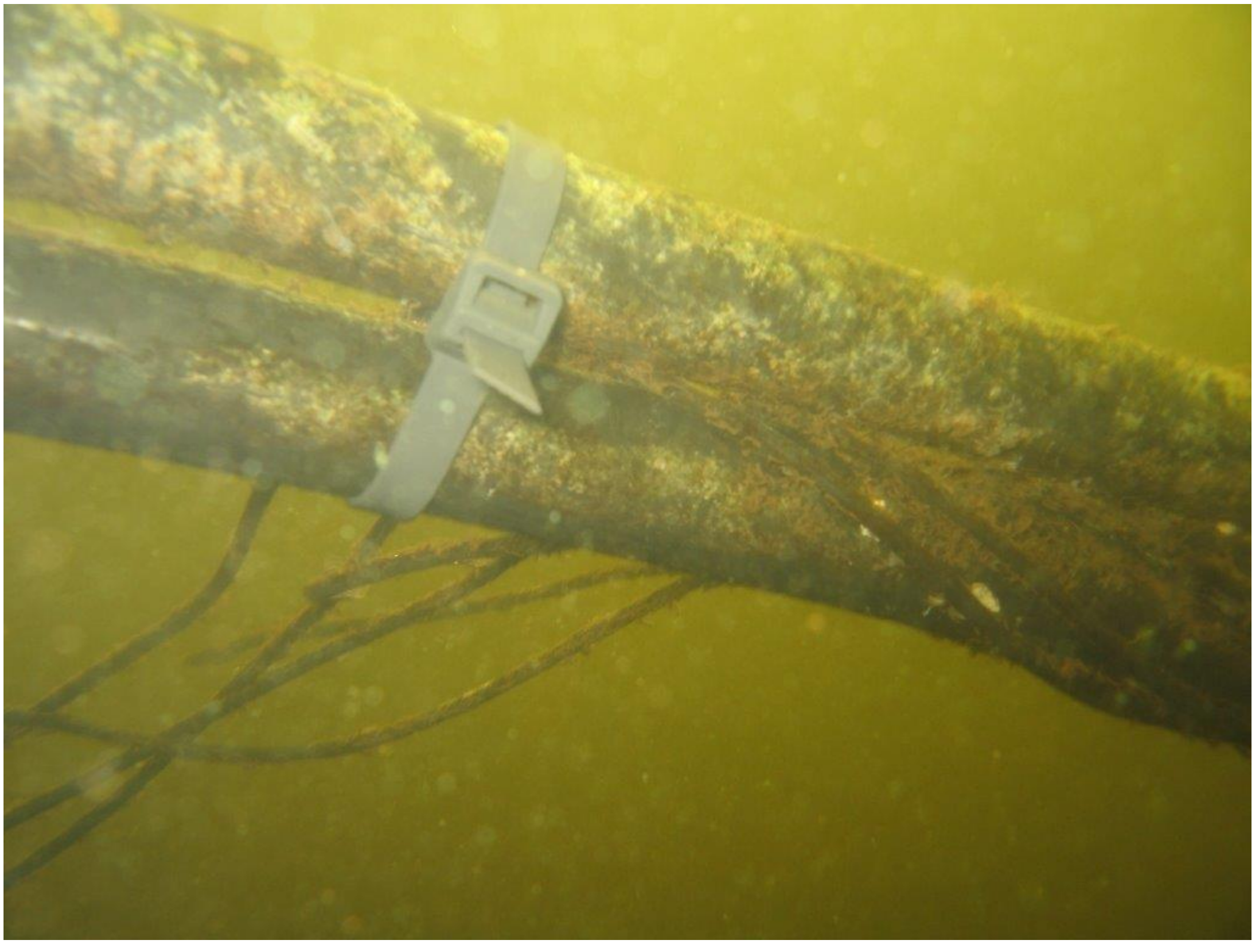
Both legacy utilities had annual Infrared ("IR") scanning programs for overhead lines assets which indicated deficiencies requiring maintenance or repairs. However, only Whitby Hydro completed visual inspections and additional refurbishment in the form of in-field repairs/splices. Veridian did not complete any refurbishment activities and performed like-for-like replacements reactively. In comparison, Whitby Hydro completed proactive replacements through line rebuilds based on visual inspection results. Elexicon plans to visually inspect all overhead conductor on a three-year cycle and continue the annual IR scanning program – the latter is expected to target all three-phase line segments and portions of the single-phase system. The utility intends to complete maintenance or repairs based on scanning and inspection results but does not expect to perform additional refurbishment. The current plan includes proactive replacements through line rebuild projects prioritized by condition.

Underground Cable

Elexicon's predecessors used differing approaches to identifying and rectifying the issues related to health of underground cables. Veridian tested cables based on age and the number of failures to identify opportunities for refurbishment through splices or cable injection. Veridian completed proactive replacements prioritized by age and testing results. Whitby Hydro's underground cable asset management strategy did not include cable testing, but the utility refurbished certain segments through cable splicing, prioritizing replacement and refurbishment candidates based on failure history and number of splices. Whitby Hydro targeted proactive replacements for a sub-division sized section of cable annually based on age and the condition of other underground distribution assets. Elexicon plans to adopt the legacy Veridian cable testing approach to identify suitable candidates for refurbishment via splices and cable injections. The current strategy targets proactive replacements based on age and testing results. The utility may also consider completing rebuilds if it discovers areas with a high concentration of deteriorated assets.

Figure 5.3-36: Work Crew Completing a Cable Splice

Figure 5.3-37: Submarine Cable with Signs of Deterioration



Pole Mounted Transformers

The predecessor utilities completed visual inspections and IR scanning for pole-mounted transformers on a three-year cycle. Based on these efforts, they identified and completed maintenance/repairs as required. Both predecessors completed additional refurbishment in the form of in field repairs, but Veridian's efforts were limited to units below 15 years of age. While both legacy entities largely completed reactive replacements, Whitby Hydro also completed proactive replacements if severe deficiencies were discovered through IR scanning or visual inspections. Prior to the merger, Veridian also started completing proactive replacements driven by overloading or capacity issues only. Elexicon intends to continue completing IR scanning and visual inspections on a three-year cycle. The utility expects to complete maintenance/repairs based on these programs and intends to perform additional in-field repairs for units less than 15 years in age. Elexicon plans to adopt a proactive replacement strategy which prioritizes assets based on condition and overloading/capacity issues.

Pad Mounted Transformers

Elexicon's predecessors completed visual inspections for pad mounted transformers on a three-year cycle. While both predecessors completed transformer repainting as a form of maintenance, the triggers for this activity varied. Whitby Hydro repainted units with rust but no holes whereas Veridian repainted units upon customer request only. Whitby Hydro's refurbishment strategy was limited to minor in-field repairs and Veridian's refurbishment efforts only targeted units less than 15 years in age.

Both legacy utilities typically completed reactive replacements for these assets. Whitby Hydro only completed proactive replacements if severe deficiencies were discovered through inspections. Veridian performed proactive replacements to address overloading or capacity issues only.

Elexicon's planned strategy includes completing visual inspections on a three-year cycle and maintenance in the form repainting. The current approach involves repainting based on customer request, but the utility intends to transition to a reactive approach based on inspection results. Elexicon expects to adopt the legacy Veridian refurbishment practice which targeted in-field repairs for units less than 15 years of age only. The utility plans to complete proactive replacements based either on condition or overloading/capacity issues.

Figure 5.3-38: Example of Pad Mounted TX with Signs of Deterioration (1)

Figure 5.3-39: Example of Pad Mounted TX with Signs of Deterioration (2)

Figure 5.3-40: Example of Leaking Oil Valve in Pad-Mounted Transformer

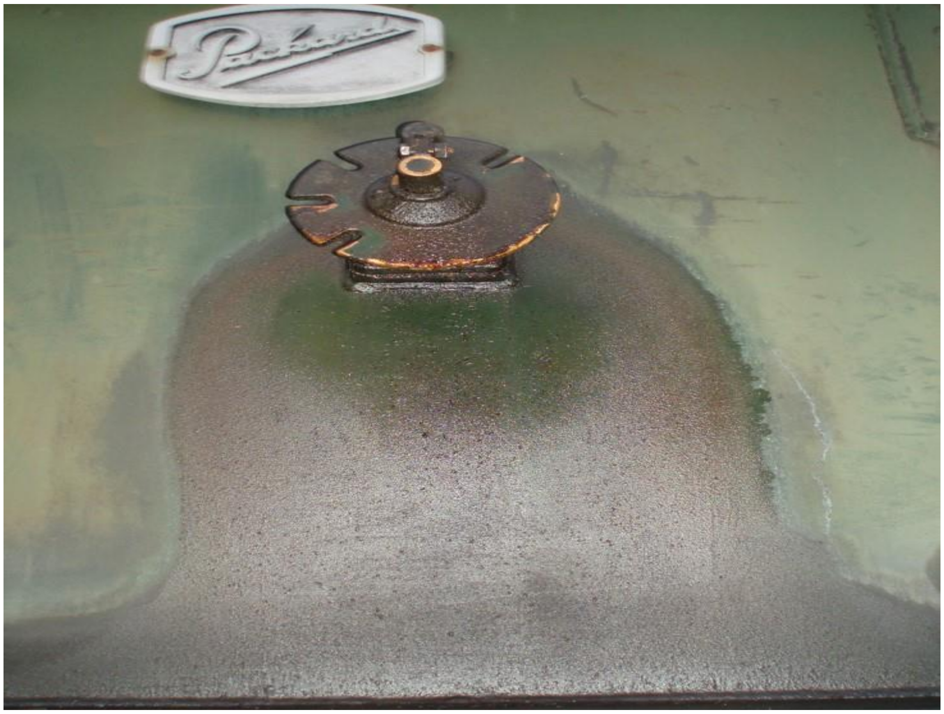
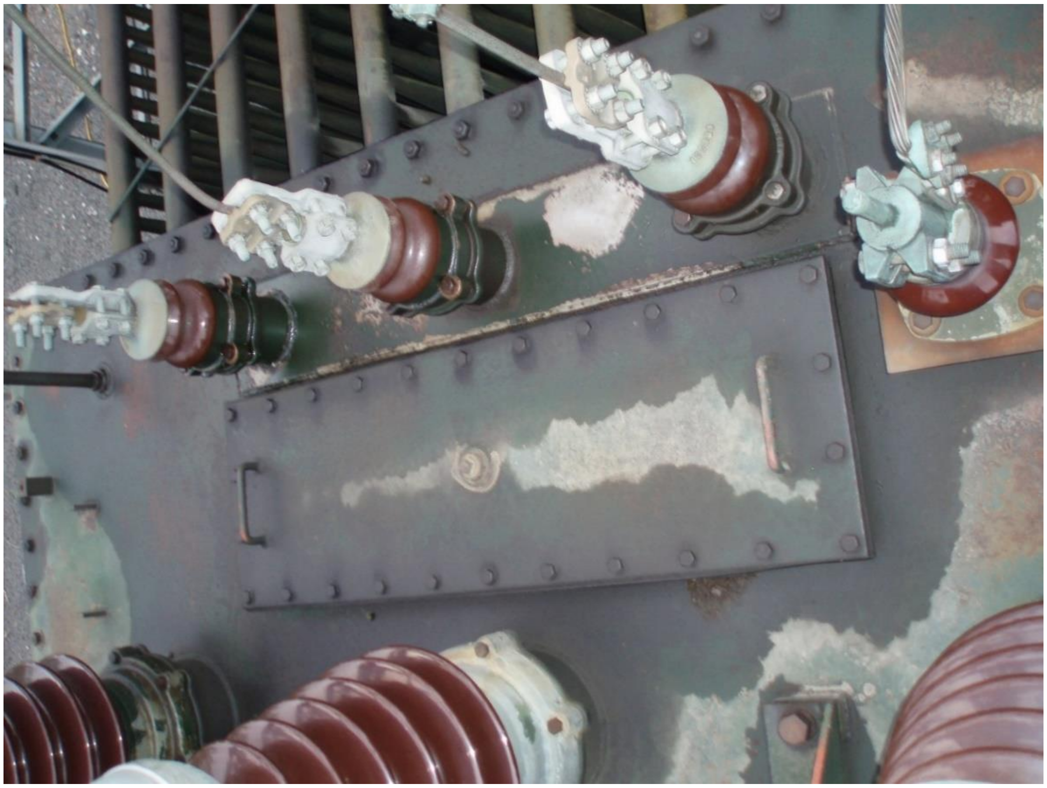


Figure 5.3-41: Example of Deteriorated Secondary Bushing inside Pad-mounted Transformer



Overhead Switches

The predecessor utilities' overhead switch lifecycle optimization practices varied depending on the type of unit. Specifically, LIS type switches and non-LIS type switches had different asset management strategies. While only Whitby Hydro completed visual inspections for non-LIS type switches (on a three-year cycle), both legacy entities included them their overhead lines IR scanning programs. They used the results of the scanning programs to identify deficiencies and plan maintenance activities such as repairs. Veridian did not complete any additional refurbishment, but Whitby Hydro performed minor in-field repairs if required. The legacy utilities employed a reactive replacement approach, but Whitby Hydro completed proactive replacements for high-risk units discovered during visual inspections.

Both predecessors visually inspected LIS type switches on a three-year cycle, but only Whitby Hydro conducted IR scanning and maintenance repairs if needed. Veridian did not complete additional refurbishment and Whitby Hydro's refurbishment efforts were limited to minor in field repairs. Veridian completed proactive replacements based on age, whereas Whitby Hydro primarily adopted a reactive replacement approach. However, similarly to non-LIS switches, the legacy utility performed proactive replacements if visual inspections or IR scans identified high risk assets.

Elexicon plans to complete visual inspections and mechanical check on a three-year cycle for both LIS and non-LIS type units. The utility plans to continue performing IR scans to identify deficiencies and perform repairs for all switches. In addition, the forecasted strategy includes additional refurbishment in the form of in-field repairs. Elexicon intends to adopt a proactive condition-based replacement approach for LIS type and non-LIS type switches.

Distribution Switchgear

The legacy utilities' inspection practices included visual inspections and assessments of the condition of enclosure and internal components on a three-year cycle. Distribution switchgear were also included in both predecessors' annual IR scanning programs. The predecessors planned maintenance and repairs based on the results of these programs. Whitby Hydro also completed additional maintenance through annual CO_2 cleaning. The legacy entities' refurbishment efforts were limited to minor repairs as required and both completed proactive condition-based replacements. Elexicon intends to retain the majority of these practices moving forward. The current plan targets visual inspections and IR scanning on a three-year cycle for all units – it also includes CO_2 cleaning for live front switchgears on the same cycle. The utility plans to complete maintenance and repairs based on inspections/IR scan results, but no additional refurbishment will be targeted. Elexicon plans to complete proactive condition-based replacements and target existing refurbished units in service.

Figure 5.3-42: Example of a Failed Switchgear

Vault Transformers

Elexicon's vault transformer population is small in comparison to all other asset classes. Since Whitby Hydro only managed three vault transformers, they were subject to the same asset management practices as other major asset classes. In comparison, the legacy Veridian system included 151 units which were visually inspected on a three-year cycle. While Veridian refurbished units which were less than 15 years in age on a case-by-case basis, there were no established maintenance or replacement practices. Both predecessors replaced vault transformers reactively when significant deterioration was identified during inspection. Elexicon plans to visually inspect all vault transformers on a three-year cycle and perform maintenance repairs as required. Additional refurbishment efforts are expected to target units less than 15 years in age only. The utility expects to complete reactive replacements and plans to assess the feasibility of relocating the units to above the surface when replacements are due. In the interim, should work crews identify units with severe deficiencies, the utility may plan to implement a proactive replacement program instead.

Distribution Stations Assets

Table 5.3-20 summarizes Elexicon's asset lifecycle optimization policies and practices (i.e., replacement and refurbishment policies, O&M activities, and maintenance planning criteria and assumptions for distribution station assets. Details descriptions for each asset class are provided below the table.

Table 5.3-20: Summary of Lifecycle Optimization Practices for Key Stations Assets

Asset Class	Inspection Activities	Maintenance / Testing Activities	Refurbishment Activities	Current Replacement
Station Power Transformers	All Station assets are visually inspected monthly.	Predictive maintenance completed includes oil sampling for all transformers annually and electrical testing on a 3-year cycle. Regular maintenance includes minor repairs.	Refurbishments completed by third parties where testing data suggests need and feasibility.	Proactive replacements based on condition or to address capacity issues.
Station Circuit Breakers		Predictive maintenance via electrical testing completed on 3-year cycle.	Refurbishments completed according to electrical testing results.	Proactive replacements completed based on condition of assets or current capacity.
Station Batteries		Predictive maintenance via electrical testing completed on 3-year cycle.	Refurbishments completed for chargers only according to electrical testing.	Proactive replacements completed based on condition.
Station Protective Relays		Predictive maintenance via electrical testing completed on 3-year cycle.	None.	Proactive replacements completed based on condition or functional obsolescence.
Station Building and Fences		Repairs as required according to visual inspections.	Refurbishments of minor deficiencies as required according to visual inspections data.	Fence may be replaced if large section is in poor condition.

<u>Station Power Transformers</u>

Elexicon plans to complete visual inspections for power transformers and all other stations assets on a monthly basis and perform advanced testing such as oil sampling (e.g., dissolved gas analysis and oil quality) and electrical testing (e.g., insulated power factor testing) as a form of predictive maintenance. The utility expects to complete oil sampling for all power transformers annually and electrical testing on a 3-year cycle. The current plan includes regular maintenance during monthly inspections to address minor issues such as broken gauges. Elexicon expects predictive maintenance testing to identify significant refurbishment needs and plans to engage specialized contractors such as ABB or GE to complete this work.

The utility's replacement approach targets proactive replacements based on condition or anticipated capacity/overloading issues. The predecessor utilities' lifecycle optimization policies and practices were consistent with Elexicon's, aside from the fact that Whitby Hydro completed predictive maintenance testing on a shorter 18-month cycle as it had a smaller population of assets.

Figure 5.3-43: Example of Power Transformer Conservator Valve with Signs of Leaking

<u>Station Circuit Breakers</u>

Elexicon plans to complete visual inspections for station circuit breakers and all other stations assets each month and perform electrical testing as a form of predictive maintenance. The utility intends to complete predictive maintenance testing for all circuit breakers on a three-year cycle. Refurbishments/repairs may be completed if issues are discovered through visual inspections or electrical testing. Elexicon plans to complete proactive replacements for circuit breakers prioritized by condition. The utility may also complete replacements if the current capacity of the circuit breaker is less than the expected fault current. The predecessor utilities' lifecycle optimization policies and practices were identical to Elexicon's except for the fact that Whitby Hydro completed electrical testing on an 18-month cycle as it had a smaller population of assets.

<u>Station Batteries</u>

Elexicon completes visual inspections for station batteries and all other station assets on a monthly basis and performs electrical testing as a form of predictive maintenance on a 3-year cycle. Regular maintenance is not completed for station batteries and refurbishment is limited to battery chargers. Station batteries replacements are prioritized according to condition. The lifecycle optimization policies and practices implemented by the predecessor utilities were identical to Elexicon's except for the fact that Whitby Hydro completed electrical testing on an 18-month cycle as it had a smaller population of assets.

Station Protective Relays

Elexicon plans to visually inspect station protective relays and all other station assets on a monthly basis and perform electrical testing as a form of predictive maintenance on a three-year cycle. There are limited applications of other forms of maintenance or refurbishment strategies for this asset class that is increasingly comprised of digital (rather than electromechanical) assets. The current replacement strategy consists of a proactive approach driven by poor condition, age, or functional obsolescence. The predecessor utilities' lifecycle optimization policies and practices were identical to Elexicon's except for the fact that Whitby Hydro completed electrical testing on an 18-month cycle as it had a smaller population of assets.

Station Fences and Buildings

Station fences and buildings are a unique asset class due to the fact that they do not directly perform any functions related to the distribution of electricity. The utility monitors the condition of these assets through monthly station visual inspections which indicate if repairs or refurbishment efforts are required to address deterioration. Replacements are typically not applicable to these assets, but Elexicon may choose to replace large sections of the fence if extensive damage is found during monthly visual inspections. The predecessors' lifecycle optimization policies and practices were identical to Elexicon's.

General Plant Asset Lifecycle Management Activities

Facilities

The facilities category includes real-estate assets such as land and buildings that serve as Elexicon's offices or operations centres and supporting infrastructure. The utility has established seven sub classes within this category for which the lifecycle optimization practices vary. Table 5.3- below provides an overview of these sub classes and the associated practices.

Table 5.3-21: Summary of Lifecycle Optimization Practices for Facilities Assets

Sub Class	Inspection Activities	Maintenance / Testing Activities	Refurbishment Activities	Current Replacement
HVAC	Visual inspections conducted monthly.	Maintenance completed four times per year.	Repairs and refurbishment completed as required.	Proactive replacements completed based on visual inspections.
Generator Systems	Visual inspections conducted monthly.	System performance is tested every two weeks. Maintenance is completed four times per year.	Repairs and refurbishment completed as required.	Proactive replacements completed based on visual inspections and testing results.
Furniture	No inspections completed.	No maintenance completed.	No refurbishment completed.	Reactive replacements completed as assets reach EOL.
Security Systems	Visual inspections conducted monthly.	No maintenance completed.	No refurbishment completed.	Proactive replacements completed based on visual inspections.

Sub Class	Inspection Activities	Maintenance / Testing Activities	Refurbishment Activities	Current Replacement
Fire Systems	Visual inspections conducted monthly.	Alarm tests are completed on a monthly basis. Extinguisher recertification, sprinkler tests, and hydrant tests are completed annually.	Repairs and refurbishment completed as required.	Proactive replacements completed based on visual inspections and testing results.
Roof Structures	Inspections and condition assessments completed by contractors.	Minor maintenance is completed internally. Additional maintenance is completed by contractors.	No refurbishment completed.	Proactive replacements completed based on condition assessments completed by contractors.
Driveways and Parking Lots	No inspections completed.	No maintenance completed.	No refurbishment completed.	Reactive replacements completed as assets reach EOL.

Elexicon plans to complete visual inspections for all sub classes except for furniture and driveways/parking lots as the utility intends to allow these assets to run-to-failure. In addition, the roof structure sub class is unique due to the fact that the utility engages contractors with the required licenses, expertise, and equipment to complete visual inspections. Elexicon expects to complete maintenance for all sub classes as per the frequency outlined in Table 5.3-. The roof structures sub class maintenance efforts include minor maintenance performed by internal staff and major maintenance performed by contractors. Planned maintenance practices involve predictive maintenance testing for generator systems and fire systems. The utility intends to complete refurbishment for HVAC, generator systems, and fire systems only. The current asset management strategy entails proactive replacement for all sub classes except furniture and driveways/parking lots prioritized by visual inspection and testing results.

IT Asset Management Lifecycle and Steps

Elexicon's IT group consists of two technology departments: OT and IT. The OT function is responsible for operational software such as SCADA, OMS, and Distribution Management System ("DMS") which is used for operation of the grid. The IT function is responsible for other types of technology infrastructure that allows employees to perform a variety of tasks to support Elexicon's operations.

This IT/OT sub-category of General Plant assets is unique in that it includes both physical hardware assets and intangible assets such as software applications. Since inspections are not a viable means of assessing the health and continued usability of most types of technology infrastructure, Elexicon deploys has a dedicated IT/OT asset management process to pace, prioritize and otherwise optimize its investments in technology.

Whereas its predecessors largely employed a reactive IT asset management approach where consideration of system replacement or upgrades was considered closer to the time of them reaching end of life, Elexicon plans to adopt to a more balanced strategy that incorporates more forward-looking elements. The envisioned approach entails proactive consideration of functional requirements, capacity needs and changing patterns in energy use over the medium and longer-terms, a more centralized approach to planning the evolution of the overall system architecture, paired with focussed analysis of the marketplace to determine the optimal solutions for the investment needs upcoming in the near term.

One example of this balanced approach is the planned procurement of the ADMS system that contemplates a gradual expansion of functionalities from a foundational platform featuring core functionalities required in the near term, but also capable of being expanded to include more advanced features that Elexicon anticipates requiring in the medium term. Another recent example includes a high-level “Asset Management fitness check assessment” – to evaluate whether and how its current IT applications and the anticipated near-term upgrades and integrations aligned with Elexicon’s plans to continuously expand its asset management capabilities.

Recently, the utility completed two major initiatives to support this transition:

- Implementation of a Change Management Database (“CMDB”) to centrally track key information such as IT/OT asset lifecycles, functionalities and performance data; and

- The Help Desk to resolve user issues and help track the user experience and/or system issues that may suggest the need for potential intervention, enhanced user support etc.

The CMDB currently tracks all hardware assets, while the software applications are expected to be integrated in the future.

Asset Lifecycle Management for IT/OT Hardware Systems

The current IT/OT asset management and lifecycle optimization process consists of five steps listed and described below.

At this stage of its transition, Elexicon evaluates existing hardware systems as their approach the ends of their lifecycles – typically determined by vendor specification and/or upcoming expiration of vendor support. Opportunities for improvement such as higher processing power or hardware capabilities are considered. Over the course of the Forecast period, core enterprise hardware assets will be consolidated in a single data centre, and investment planning will proceed on a consolidated basis. Hardware Lifecycles have been implemented into Elexicon’s new Change Management database.

Inputs to IT/OT Investment Projects

In the past, Veridian and Whitby did not have a formally recorded process for managing IT assets. In February of 2020, Elexicon implemented a CMDB and Help Desk which will help track the software and hardware assets. The CMDB will track lifecycles and end of life aspects of hardware components. Software components have not yet been imported into the database but are expected to be integrated over the course of the Forecast Period.

There are several inputs that Elexicon collects and analyzes in order understand the current state of the system and effectively plan capital investments. These inputs include IT/OT Lifecycles, Operational Needs, Growth, Industry Trends, Compliance Requirements, and Data Analyses and are summarized in Table 5.3- below.

Table 5.3-22: Summary of Inputs to IT Asset Management Process

Input	Description
IT/OT Lifecycles	All IT/OT software and hardware assets have an expected lifecycle which is determined through factors such as user experience, vendor support/availability of licensing, and other constraints. Elexicon evaluates all IT/OT assets after the completion of a lifecycle to determine if they should be renewed or replaced with new technologies. There are currently two sub-processes for the replacement of IT assets: Project Evergreen and the Emergency Process. The former provides funding for routine IT replacements whereas the latter addresses unexpected failures.
Operational Needs	As the distribution system evolves due to external factors such as regulator decisions or the emergence of new technologies, the utility may complete investments to address new operational needs. These needs are typically identified by stakeholders across the company in consultation with the IT group.
Growth	As Elexicon's customer population grows, it may need to expand in order to meet evolving expectations, conditions, and requirements. This growth may result in the addition of new employees, facilities, and infrastructure which could translate to increased IT/OT requirements.
Compliance Considerations	Elexicon is mandated to complete certain IT/OT investments such as those driven by the OEB's Cybersecurity Compliance requirements. The utility submits a cybersecurity vulnerability report which identifies gaps that must be addressed.
Industry Trends	Elexicon monitors industry trends when planning technology investments – these trends are typically identified through research, studies, or discussions with various utility working groups. Elexicon evaluates the potential benefit that the proposed technologies could provide to its operations and makes investments accordingly. Examples of past industry-trend driven investments include electric vehicle, microgrid, and solar penetration infrastructure.
Data Analysis	Elexicon completes a variety of analyses based on collected data to identify opportunities for improvement and plan IT/OT investments accordingly. Examples of collected inputs include failure, reliability, and performance data. The utility also completes an annual analysis and review of paper-based processes which could be transitioned to a digital format to realize increased efficiency.

The above input categories are translated into actionable projects through the following six planning and implementation process steps:

1. IT Needs Assessment

An overall IT assessment is conducted on a rolling basis to evaluate the input data generated over time, to identify the emerging needs of the IT/OT assessment category in terms of analytical functionalities, processing capabilities, capacity, or integration across tools and databases. Need drivers are recorded compiled, and where possible, supported with objective (e.g., numerical) analysis to provide evidence to IT/OT assessment requirements. A list of the required IT/OT needs is compiled across all programs to be evaluated.

2. Alternatives Analysis

Alternatives analysis is performed for the needs identified in the IT Needs Assessment, and can include considerations such as vendors, versions, in-house vs. outsourced development, pacing and timing, scope of functionalities and others. In all cases status quo is considered as a default approach. Based on this information, relative merits and viability of potential approaches are evaluated using appropriate frameworks, available external evidence and cost benefits analysis, among others.

3. Project Identification

Based on the results of the options analysis, the IT/OT staff develop initiate a project scope development process, consisting of multiple technical and business analysis elements appropriate for a given project type. An internal project business case is also prepared for projects / programs over certain materiality thresholds. This step typically involves consultations with a variety of stakeholders, industry research to verify costing and functionality assumptions, and may involve discussions with peer utilities that have recently implemented similar initiatives or exploratory conversations with industry experts.

4. Prioritization of Projects

The projects within the program are weighted and compared to each other to identify their relative priority of investments using a set of objective criteria. Elexicon attempts to continuously review and enhance its internal IT/OT project prioritization approaches to ensure they meet the evolving needs of the utility and its customers, while supporting Elexicon's overall drive towards evidence-based asset management and investment decision-making.

5. Actions

There are currently three priority project execution dimensions underway at Elexicon related to technology investments. These include consolidation of existing systems from the two former utilities, performing updates or new purchases of new systems, and removing existing IT assets our of service.

5.1- Consolidation of existing systems (Post Merger)

As a newly merged company, Elexicon is proactively assessing the systems they have currently to evaluate opportunities for Consolidation. For example, NorthStar CIS mergers are planned for September 2020 which will merge the existing NorthStar CIS systems of the two former utilities. Other consolidation of systems includes GIS which is crucial in recording and applying geographical analysis and data to the Elexicon distribution network. Many of the existing systems are to be consolidated moving forward.

5.2- Action: Perform Updates or new purchases

Depending on the current operating state, levels of vendor support, available capabilities and needs of the company, Elexicon can choose to perform updates on existing technology, maintain the technology or pursue new purchases to replace technology assets deemed insufficient for work. These actions are intended to address when assets are no longer deemed sufficient for work purposes.

5.3- Remove IT assets out of service

Once the needs of a current technology asset have been identified as not needed and obsolete, it is removed out of service. If a new asset will be introduced to replace the legacy asset, IT will ensure that a smooth transition shall be held where the older asset is maintained until the new asset may replace it entirely. IT will ensure that training and experience with the IT asset has been provided prior to fully removing the legacy IT asset out of service. All data that is essential from the older IT asset shall be transferred to the new replacement.

6. Records Management of Technology Assets

After the investment has been made, IT and OT professionals will enter the details of the new system into the CMDB. This will allow for tracking of the lifecycle, and documentation of the current capabilities of the new investment.

Tools and Equipment Asset Lifecycle Management

Elexicon's lifecycle optimization practices for tools and equipment are limited to inspections and replacement – these assets do not undergo maintenance or refurbishment. Elexicon visually inspects tools and equipment prior to use to ensure that they do not exhibit deterioration that could impact the staff's ability to perform work safely or effectively. In addition, the utility retests all tools and equipment assets as per the frequency dictated by legislation and the Electric Utility Safety Requirements ("EUSR"). If assets fail to pass visual inspections or meet safety standards, they are replaced as soon as possible. The utility plans to adopts a reactive replacement approach for all other tools and equipment assets.

Fleet Asset Lifecycle Management

Elexicon's lifecycle optimization practices for Fleet assets consist of inspections, maintenance, refurbishment, and replacement. There are several sub-categories of Fleet assets which reflect different vehicles classes, as summarized in Table 5.3- below.

Table 5.3-23: Summary of Vehicle Classes at Elexicon

Vehicle Class	Description
Large	Large Fleet Vehicles are predominantly Bucket Trucks used for overhead and lines work.
Medium	Medium-sized fleet assets are found in this category which corresponds to vans.
Other	Other miscellaneous fleet assets are found in this investment category.
Small	Smaller Fleet vehicles include passenger vehicles. These vehicles are used to inspect and manage work.
Specialized	These vehicles are used for more specialized tasks such as pole digging, traversing through the snow with snowmobiles, and pulling cable.
Substations	These fleet assets are specifically designated for the Substations department at Elexicon.
Trailers/Trucks	Trailers and Trucks are used to transport the more heavy-duty assets to locations. These trailers are designated specifically to transport cable reels, poles, transformers, and various other distribution equipment that cannot be housed on the normal vehicles.

Inspection practices include pre-deployment visual inspections and annual mechanical assessments. Work crews perform pre-deployment visual inspections using logbooks equipped to each vehicle and bring any defects to the attention of supervisors. Elexicon mechanics complete annual mechanical assessments for all vehicles which exceed either the age or mileage criteria outlined in Table 5.3- below. These mechanical assessments include an evaluation of the following components of the vehicle:

- Engine
- Drive Train
- Chassis
- Tires
- Body
- Paint
- Condition of Aerial Device
- Hydraulic System Controls & Hoses
- General Appearance

The mechanical assessment assigns a letter grade – A, B, or C – to each vehicle which reflect its condition and investment priority, as outlined in Table 5.3-. The utility considers capital investment based on the results of the mechanical assessment. Specifically, grade A and B vehicles are candidates for refurbishment or replacement. Elexicon staff also complete preventative maintenance for vehicles based on the engine hours and odometer.

Table 5.3-24: Age and Mileage Thresholds for Mechanical Assessment

Vehicle Category		Threshold	
		Age (years)	Mileage (km)
Vehicles, Large		>10	200,000
Vehicles, Light	Cars	> 5	150,000
	Others		150,000
Trailers		>12	n/a
Special Purpose		>15	n/a

Table 5.3-25: Investment Priority Categories

Category	Status	Assessment
A	High Investment Priority	The vehicle is in deteriorating condition, and planned replacement or refurbishment is critical for the coming calendar year.
B	Medium Investment Priority	The vehicle is mechanically and structurally sound at present, but the condition is at risk of deterioration during the coming calendar year.
C	Low Investment Priority	The vehicle is mechanically and structurally sound. Planned replacement or refurbishment is not necessary for the coming calendar year.

Vegetation Management

Elexicon routinely performs maintenance to manage the vegetation surrounding its distribution assets and reduce the likelihood of interference and reliability issues. There are three components to Elexicon's vegetation management practices:

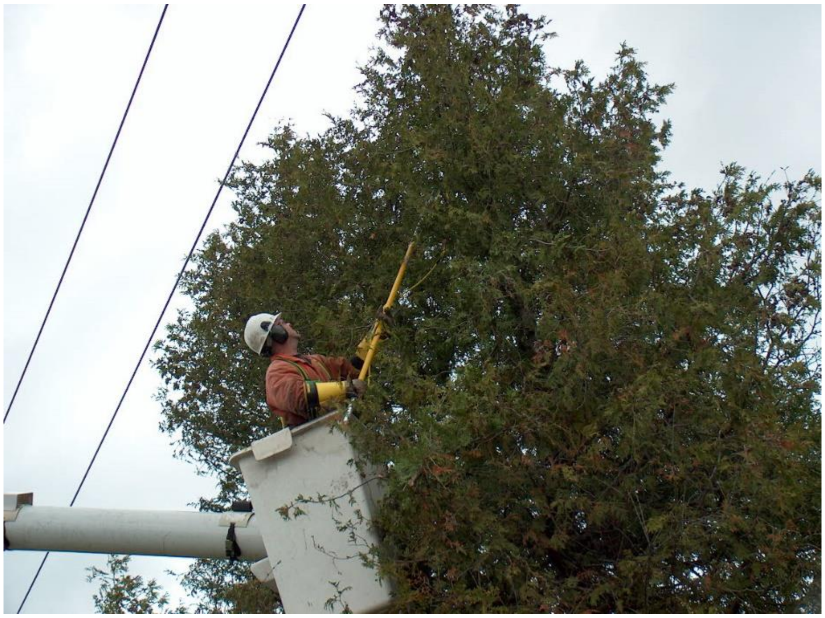
- Cycle Line Clearing (Planned)
- Spot Clearing (Unplanned)
- Stations Clearing

Cycle line clearing refers to Elexicon's routine vegetation removal/trimming practices. The utility completes this maintenance effort for all areas on a three-year cycle. Each district consists of three sub regions which the utility uses to plan work – Figure 5.3-44 below shows an example of the sub-regions within the Ajax and Whitby districts.

Figure 5.3-44: Sub Regions within the Ajax and Whitby Districts

Elexicon plans to complete clearing for one sub region within each district annually to avoid excessive growth within a single district. Spot clearing refers to unplanned vegetation removal/trimming efforts to address unexpected circumstances. Examples of these circumstances include weather-induced interference or unexpected growth which poses a high risk of system interference. The utility also routine completes stations vegetation clearing which includes tree trimming and the removal of weeds and other undesirable elements in the station yard. Elexicon employs contractors to complete all vegetation management related activities. However, the utility may rely on internal resources if there are unplanned spot clearing requirements which can be safely and effectively addressed by the crews.

Figure 5.3-45: Example of Work Crews Performing Tree Trimming



5.3.3 b) Asset Lifecycle Risk Management Policies and Practices

Having completed the definition of its corporate strategy, Elexicon is currently in the process of developing its Enterprise Risk Management Policy and the associated supporting tools and processes. This corporate-wide initiative aims to ensure that all potential internal and external developments that may pose a threat to business continuity, execution of corporate strategy, achievement of financial objectives, the well-being of its customers or priorities of its partners and shareholders are identified, tracked and mitigated in a timely and effective manner. This ongoing work is expected to culminate in the adoption of several planning and tracking tools and processes that will collect inputs and disseminate appropriate insights and/or directions across all utility functions.

While the corporate risk management tools that are currently under development are expected to define the overall approach to risk management for the utility, Elexicon also deploys several more granular decision support tools that help planners determine and manage the risks associated with its asset base. Among these tools are both well-understood approaches that have been in place for a number of years, and newer risk-based planning enhancements that are currently being piloted. Once the overall corporate risk management tools are finalized Elexicon will ensure full alignment of its more asset class- and system-specific risk management approaches, undertaking any requisite adjustments and developing consistent reporting tools.

- Among the system- and asset-class specific lifecycle risk management tools are the following tools described in more detail in the subsequent sections: Reliability Analysis
- Asset Condition Assessment
- Failure Curve Development
- System Risk Assessment

<u>Reliability Analysis</u>

Elexicon conducts reliability analysis on an ongoing basis using the outage statistics recorded in the field and through centralized outage management software applications. The assessment entails granular review of the utility's SAIDI/SAIFI performance, outages by cause code, MED, and WPF. While all components have an impact on capital investments, the cause code analysis and the WPF analysis assist in the identification of system risk presented by the current assets. This analysis allows Elexicon to identify the root causes of outages and feeders experiencing frequent or particularly impactful interruptions.

As discussed is Section 5.3.1b, the insights of reliability analysis are considered at several stages of Elexicon's Asset Management Process, namely Stage 2 – "Evaluate Performance and Utilization" where reliability reports are reviewed alongside other system-wide performance data in and Stage 4 – " Explore Lifecycle Cost Management Considerations" where reliability and health index data is integrated together through visualization tools to help determine candidate areas for intervention work. The cause code analysis performed by Elexicon outlines the number of outages, the number of customers interrupted ("CI"), and the number of customer hours interrupted ("CHI") by cause code. Elexicon relies on standard CEA Cause Codes, which are listed below for reference:

- Cause Code 0 – Unknown Outages
- Cause Code 1 – Scheduled Outages
- Cause Code 2 – Loss of Supply Outages
- Cause Code 3 – Tree Contacts Outages
- Cause Code 4 – Lightning Related Outages
- Cause Code 5 – Defective Equipment Outages
- Cause Code 6 – Adverse Weather Outages
- Cause Code 7 – Adverse Environment Outages
- Cause Code 8 – Human Element Outages
- Cause Code 9 – Foreign Interference Outages

The cause code analysis allows the utility to understand the nature and volume of service interruptions, identify key system risks, and respond accordingly. In addition, Elexicon tracks sub-cause codes for each of these items which provide useful insights when planning capital investments. Cause Code 5 – Defective equipment is particularly useful when planning System Renewal investments. In the case of Cause Code 5, the sub cause codes reflect the type of asset experiencing failure or malfunction that causes the outage, and allows the utility to identify the most significant contributors to outage frequency and duration.

Similarly, the WPF analysis allows Elexicon to identify feeders and areas which frequently experience outages and represent the candidates for additional near-term maintenance work, System Renewal investments or circuit reconfigurations (as may be applicable).

Asset Condition Assessment

The ACA is an integral component of Elexicon's Asset Management Process and a key input into multiple stages of the process, including the system risk assessment work. The ACA development process involves collecting and assessing data related to key condition parameters associated with degradation of assets as they interact with the natural environment and/or undergo various forms of technical loading. Each asset receives a score for each parameter which is used in conjunction with the parameter weighting to calculate a HI score.

This HI score reflects the overall health of the asset and categorizes it into one of five HI categories which describe its condition. The purpose of a numerical HI score is to indicate an approximate percentage of useful life remaining within a given asset, which in turn provides the grounds for simple and intuitive prioritization of planned work and can serve as an input into more advanced prioritization frameworks. The basic HI category definition guidelines are summarized below in Table 5.3-. The results of the ACA can be used to identify aged and deteriorated assets which pose a comparatively greater system failure risk and target investments accordingly. The complete ACA performed by METSCO can be found in Appendix F.

Table 5.3-26: HI Scores and Associated Categories

HI Score	HI Category
>85%	Very Good
70% to 85%	Good
50% to 70%	Fair
30% to 50%	Poor
0% to 30%	Very Poor

Ahead of the merger, both predecessor utilities relied on ACA results to identify the candidate assets for near-to-medium term replacement or refurbishment, giving prioritization assets in Poor and Very Poor condition categories and integrating them with insights from other types of analysis (such as reliability performance). Going forward, and as described below, Elexicon expects to utilize asset HI results as inputs into more advanced frameworks to help it attain both more granular (e.g., statistical failure probability) and/or longer-term investment planning insights. Over the Forecast Period, Elexicon may also consider the value proposition of potential enhancements to the scope and number of asset health parameters collected for its core asset classes.

Failure Curve Development

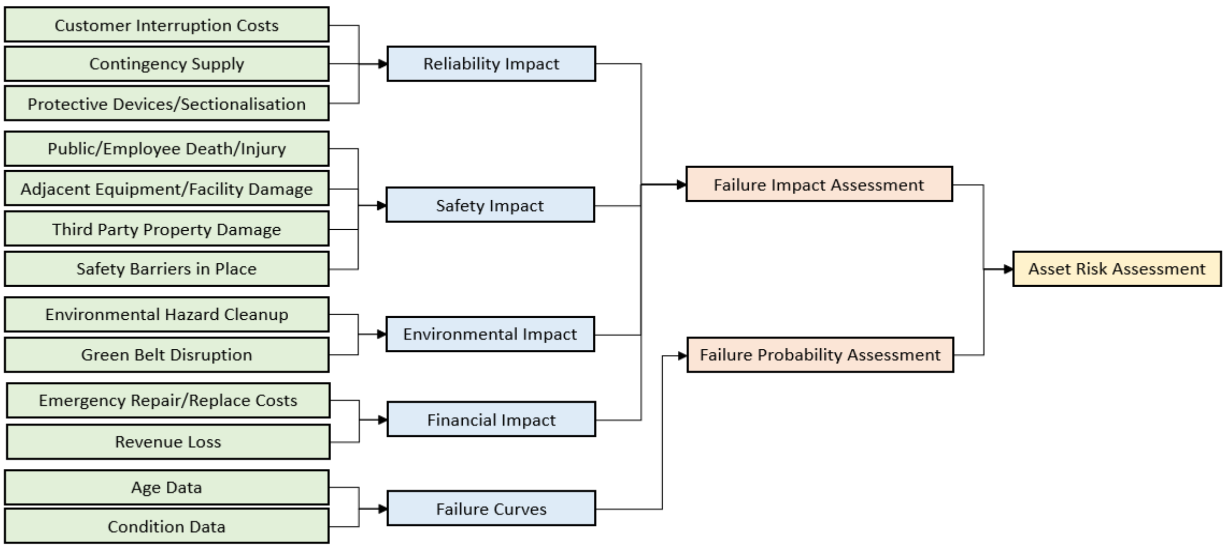
The development of asset-class specific failure curves represents an important facet of the next frontier of Elexicon's continuous improvement journey in Asset Management. By collecting objective information associated with asset failure (such as age and/or condition score of assets when they either failed in service or were deemed to have reached End of Life by way of testing or inspection), utilities are able to develop statistical probability distributions regarding the percentage of assets expected to survive up to a certain age (Survival Rate), or an asset's probability of failing in the next year based on its current age and/or condition (Hazard Rate). By tying asset failures to objective parameters such as age or condition scores, and tracking the actual failures experienced against the predicted failure volumes, utilities are able to derive increasingly detailed planning insights and consequently improve their ability to mitigate the most impactful system risks. In doing so, they are also better positioned to allocate their available capital resources in a manner that increases the value to customers and shareholders.

Failure curves can be developed based on the industry standard Typical Useful Life ("TUL") of an asset class (configuring the curve parameters using the available information on assets currently in service) or by using in-field failure data. If empirical failure data is available, the utility can apply curve fitting techniques to apply a standard Weibull distribution to the data and estimate the failure rates. Using the information collected by its predecessors, Elexicon was able to construct an empirical failure curve for its population of wood poles, which is shown in Figure 5.3-5 above. Elexicon understands that it is among very few Ontario distributors who currently possess sufficient data to define their own empirical failure curves for any major asset class. The utility is also in the process of reviewing the information available regarding the underground cable performance that may enable it to develop specific failure curves for this important asset class as well. While data collection for failure data on other key asset classes is being initiated, Elexicon will be relying on industry TUL values calibrated to its current experience in the interim.

Failure Curve Application: Longer Term Vision

As noted above, and discussed in more detail in Section 5.3.1b, failure curve data can be used to develop advanced risk-based asset intervention optimization models, where the data on assets' current age / health and the anticipated failure probability can be integrated with the utility's connectivity model and assumptions regarding the cost of failure incurred by different types of customers – to develop a comprehensive investment prioritization model that also prioritizes assets according to their criticality, consistent with advanced industry practices and leading AM standards. The following figure illustrates a conceptual risk-based asset prioritization framework that also includes analysis of safety and environmental costs associated with equipment failure.

Figure 5.3-46: Overview of System Risk Assessment Process



The following passages discuss the key elements of such an approach, which represents the current longer-term vision of Elexicon's AM analytics evolution, subject to insights of ongoing pilot work, future regulatory guidance, and/or the relative value proposition of other investment priority areas.

Failure Impact Calculation

The reliability impact assessment quantifies the cost associated with a service interruption due to asset failure. These Customer Interruption Costs ("CIC") vary depending on the customer class. The reliability impact assessment uses Willingness to Pay ("WTP") parameters to quantify the impact for Residential customers – WTP parameters represent the cost a customer is willing to pay to avoid an outage. For commercial and industrial customers, the analysis considers the direct financial loss due to the loss of electrical service, also known as Direct Worth ("DW") cost. DW costs consist of short- and long-term costs. Short term DW costs include damaged equipment, incomplete/scrapped product, loss of productivity, and impacted profits. Long term DW costs typically include the affect on contracts and customer satisfaction affecting the business. While Residential customers typically comprise the majority of customer interruptions, commercial/industrial customers typically incur a greater portion of total interruption costs.

Safety Impact Calculation

The safety impact assessment quantifies the cost associated with injury, death, and collateral damage resulting from asset failure. Collateral damages are costs associated with catastrophic failure events that introduce safety hazards to the public/employees or power deviations due to asset failure. These costs vary depending on the asset class and its associated catastrophic failure impacts – example failure modes include the collapse of a wood pole, pole fires, and transformer fires. Safety costs typically consist of payouts from claims filed against the utility for damages related to asset failure and the associated legal fees. There are also costs associated with public or employee injury or fatality and claims made by other impacted third parties. The assessment relies on research and historical data to estimate these costs.

Environmental Impact Calculation

The environmental impact assessment calculates the cost associated with environmental impacts occurring due to asset failure. It considers the cost of environmental cleanup as well as indirect environmental damages resulting from catastrophic asset failure. These environmental damages typically occur due to oil spills and entail costs such as those associated with cleanup, related remediation costs for harmful chemicals (e.g., oil, PCBs, asbestos, lead), as well as indirect costs associated with irreparable contamination. Environmental costs vary depending on the size of the spill and specific costs include crew dispatch (hazard cleanup crew/contractor), transportation, material/chemicals used, and the degree of cleanup required. Environmental impacts also typically include the social costs of environmental damage which are often incurred through fines and levies imposed by governing bodies, particularly those associated with environmentally sensitive areas.

Financial Impact Calculation

The financial impact considers the direct tangible costs that are incurred by the utility during and after the interruption of electrical service. This includes repair/replacement costs such as the cost of labour, material costs for replacements, and incremental labour costs for emergency repairs. The assessment also accounts for the revenue lost as a result of the outage. However, the revenue loss is typically negligible in comparison to the labour and material costs associated with performing repairs or replacements.

Bringing It All Together: Risk-Based Asset Intervention Prioritization:

Combining the above elements yields a framework that assigns economic cost to various types of impact associated with electrical asset failure or malfunctions, including the impact on the utility itself, different types of customers and the society at large. The statistical analysis of likelihood of such events occurring based on the current asset health and demographics helps determine the likelihood of this impact being experience across the system. The connectivity analysis, which involves capturing the relationships between assets and between assets and specific numbers and types of customers, provides a key prioritization variable which helps determine which of potential asset replacement is more critical to the ongoing system's proper functioning.

While Elexicon expects its AM capabilities to evolve in the direction of this risk-based planning approach, the immediate next frontier (and the juncture for failure curve application) is the pilot development of a 10-year system condition forecast, where the failure curve information will be calibrated to represent a proxy of asset condition degradation over time – to help the utility assess the mix and volumes of work that can be anticipated over the longer timeframe.

System Condition Forecast

As discussed above, the System Condition forecasting pilot work is under development as a part of a broader exploration of risk-based asset management and is expected to provide Elexicon with the ability to perform longer-term forecasts and sensitivity analysis as to the expected condition of its asset classes depending on investment volumes and allocation across programs. The core inputs into the forecasting tool are the failure curve data and the most recent ACA results. When completed, this piloted exercise would represent a step forward towards a full risk-based asset intervention planning model.

5.3.4 System Capability Assessment for REG

5.3.4 a) Applications for Renewable Generators over 10 kW

Elexicon currently has a total of sixteen applications for renewable generators over 10kW. These applications are summarized in Table 5.3- below. Elexicon has six pending battery energy storage systems connections, summing up to 18.94 MW. Elexicon also has an engine driven synchronous generator connection in the Whitby service area that has a generation capacity of 800 kW. Elexicon also has six pending contracts for solar generation connections, totaling a generation capacity of 1390 kW. Finally, Elexicon also has three combined heat and power generator connections, all three having a combined generation capacity of 1715 kW.

Table 5.3-27: Summary of Applications for Renewable Generators

Type	Capacity
Battery Energy Storage System	1,200kW
Battery Energy Storage System	1,100kW
Battery Energy Storage System	4 x 2500kW (10MW)
Battery Energy Storage System	2.4MW
Battery Energy Storage System	2.434MW
Battery Energy Storage System	4MW
Engine Driven Synchronous Generator	800kW
Solar	2 x 100kW (200kW)
Solar	100kW
Solar	800kW
Solar	135kW
Solar	35kW
Solar	4 x 15kW (60kW)
Combined Heat and Power	3 x 65kW (195kW)
Combined Heat and Power	570kW
Combined Heat and Power	950kW

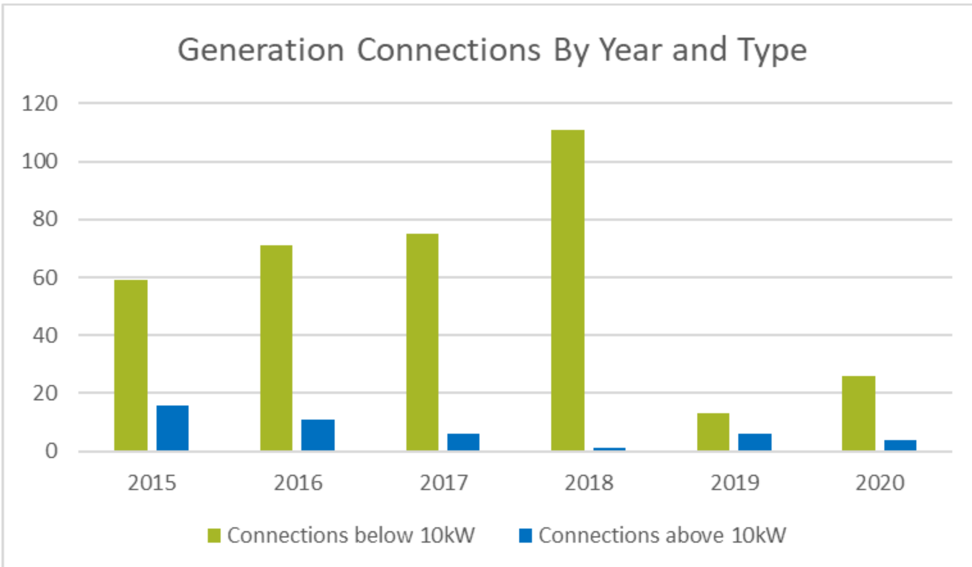
5.3.4 b) Forecast of REG Connections

Elexicon serves twelve non-contiguous regions within its service area:

1. Gravenhurst;
2. Beaverton;
3. Cannington;
4. Sunderland;
5. Uxbridge;
6. Scugog;
7. Whitby, Ajax, and Picking;
8. Orono;
9. Bowmanville;
10. Newcastle;
11. Port Hope; and
12. Belleville.

Elexicon currently has 57 connections in the areas of Ajax, Belleville, Brock, Clarington, Port Hope, Gravenhurst over 10KW and 532 connections that are 10KW or below. Based on the number of new connections in recent years, it is expected that there will be slight increases in the number of connections in the coming years.

Figure 5.3-47: Distribution of Generation Connections



The number of micro-generation connections has been accelerating in recent years through 2019. This is due to the fact that micro-FIT projects were cancelled, and this resulted in a sharp increase in 2018. This year, Elexicon is expecting the previous trend to continue based on the volume of recent connections until it reaches a stabilized increase per year. The number of new normal generation connections has been steady throughout recent years and it is expected that this trend will continue. The tables below show the forecasted number of new connections per year as well as the expected increase in the generation capacity.

Table 5.3-28: Historical Number of New Generation Connections by Region

	2015		2016		2017		2018		2019		2020	
Region	Connections (#)	Capacity (MW)	Connections (#)	Capacity (MW)	Connections (#)	Capacity (MW)	Connections (#)	Capacity (MW)	Connections (#)	Capacity (MW)	Connections (#)	Capacity (MW)
Whitby	31	1.45	38	0.37	38	0.28	33	0.24	1	0.00	0	0.00
Belleville	8	0.08	13	0.77	3	0.37	3	0.03	8	1.82	4	0.19
Bowmanville	9	0.33	5	0.05	8	0.06	8	0.06	2	0.02	1	0.8
Port Hope	2	0.02	0	0.00	9	0.11	7	0.05	0	0.00	3	0.03
Pickering	8	0.86	4	0.04	13	0.13	11	0.09	3	0.02	1	0.2
Ajax	12	1.40	19	0.66	6	0.53	38	0.34	4	0.76	17	1.48
Gravenhurst	2	0.32	3	0.29	1	0.01	6	0.05	1	0.01	1	0.1
Newcastle	0	0.00	0	0.00	3	0.03	1	0.02	0	0.00	13	0.10
Sunderland	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Cannington	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Uxbridge	1	0.01	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00
Port Perry	1	0.01	0	0.00	0	0.00	2	0.02	1	0.01	0	0.00
Beaverton	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00
Orono	0	0.00	0	0.00	0	0.00	2	0.01	0	0.00	0	0.00
Total	**75**	**4.48**	**82**	**2.17**	**82**	**1.53**	**112**	**0.92**	**20**	**2.65**	**40**	**2.90**

Table 5.3-29: Predicted REG connections and connection capacity by region based on 2019/2020 distribution

Total	Relative Percentage - 2019-2020	
Region	Connections (%)	Capacity (%)
Whitby	1.7%	0.1%
Belleville	20.0%	36.3%
Bowmanville	5.0%	14.8%
Port Hope	5.0%	0.5%
Pickering	6.7%	3.9%
Ajax	35.0%	40.4%
Gravenhurst	3.3%	2.0%
Newcastle	21.7%	1.8%
Sunderland	0.0%	0.0%
Cannington	0.0%	0.0%
Uxbridge	0.0%	0.0%
Port Perry	1.7%	0.2%
Beaverton	0.0%	0.0%
Orono	0.0%	0.0%

Table 5.3-30: Forecasted Number of New Generation Connections

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	20	20	20	20	20
Net Metering >10 kW	8	8	8	8	8
Net Metering ≤10 kW	1	1	1	1	1

Table 5.3-31: Forecasted Increases of Generation Capacity (in kW)

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	0.164	0.164	0.164	0.164	0.164
Net Metering > 10kW	2.264	2.264	2.264	2.264	2.264
Net Metering <10kW	0.044	0.044	0.044	0.044	0.044

5.3.4 c) Capacity Available

Elexicon's *REG Investment Plan* (Appendix D) includes a detailed REG capacity analysis by feeder. There are currently no constraints on Elexicon's system that would prevent the connection of new REG. There are, however, constraints on the upstream transmission system that prevent downstream connection of new REG on certain Elexicon feeders. Hydro One's Cherrywood Transformer Station T7/T8 has reached its short circuit capacity limits and no new downstream generation connections can be added.

5.3.4 d) Constraints – Distribution and Upstream

Elexicon evaluates the safety and viability of connecting a new generator to a feeder based on multiple criteria to minimize the risk associated with new additions. The inclusion of a new generation connection affects the flow along the feeder and voltage profile, which makes it essential to study the effects of any proposed generation as part of the connection impact assessment (aside for microgeneration applications). The equipment on the distribution system must be assessed to ensure it can handle the stresses during normal operation (thermal constraints) and short-circuit conditions. For larger connection requests, Elexicon must also follow Hydro One's transmission interconnection requirements which mandate a completion of a Connection Impact Assessment ("CIA") to ensure that any potential impact on the upstream system is within the planning parameters.

The defining constraint that ensures that generation connections are operating safely is that the sum of the generation capacity tied to a single feeder cannot exceed minimum load on the feeder. The load capacity on the feeder is used as a proxy to monitor REG connection capacity relative to the minimum load. When the total generation capacity tied to a feeder exceeds a quarter of the feeder's load, the feeder is flagged and is monitored. The total connected REG capacity should not exceed half of the feeder's capacity to serve load.

Elexicon also takes into consideration the thermal capacity limits of the system under normal and contingency operating conditions when assessing the viability of adding a new connection. Adding a new connection affects the current flow on the system; therefore, equipment thermal limits may be exceeded. By performing this check during the connection impact assessment, Elexicon reduces the risk of losing its assets to damages resulting from overheating, which preserves the safety and reliability of the system.

New generation connections also impact the voltage profile of the feeder. Elexicon has an obligation to provide electricity to customers at an acceptable quality with limited voltage excursions during normal and switching operations. The connection impact assessment checks for voltage issues along the feeder due to the addition of a new generator.

New generators contribute short-circuit current to the feeder. Excessive short-circuit current above a piece of equipment’s rated short-circuit capacity can lead to a catastrophic failure. The connection impact assessment checks that equipment short-circuit limits are not exceeded due to the addition of a new generator.

Since the defining factor limiting new REG connections on the distribution system is typically the minimum load threshold of the feeder. There are currently no constraints on Elexicon’s system that would prevent the connection of new REG. There are, however, constraints on the upstream transmission system that prevent downstream connection of new REG on certain Elexicon feeders. Hydro One’s Cherrywood Transformer Station has reached its generation connection capacity, and no new downstream generation connections can be added during the current status quo. Elexicon will continue to work with Hydro One through the RPP and various consultations outside of the RPP to eliminate upstream constraints that prevent new REG connections to Elexicon’s distribution system.

5.3.4 e) Constraints – Embedded Distributor

Elexicon currently has one embedded supply point within the Alectra Utilities service territory where it serves a single large customer. There are no REG plans associated with this customer or the part of the system serving them.

5.4 CAPITAL EXPENDITURE PLAN

5.4 a) Customer Engagement Program Information

Elexicon had two methods for its customer engagement survey: online survey and phone survey. For the online self survey 262 customers responded. The online survey was conducted between October 26th and December 13th, 2020. The phone survey had 600 respondents of which 524 were residential, 70 were small business and 6 were large business customers. The phone surveys were conducted between November 20th and December 4th, 2020.

Overall customers are satisfied with Elexicon. Most respondents stated they had no concerns; for those with concerns the most cited issues were reliability and service cost. Responses aside from reliability and cost cited concerns of outdated infrastructure and long customer service waits. Additionally, the majority of respondents found Elexicon's standard of reliability was satisfactory.

Over half of the customers surveyed supported the overall planned allocation of funds. The following Capital Investment programs were included on the survey. All were supported by the majority of customers.

System Access

- A1 Road Relocations: Customers support proposed Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit.
- A2 - Connection of New Services: Customers were informed that Elexicon will spend a portion of their five-year budget to support customer growth.
- A3 - Feeder Expansion: Customers support the proposed plan for the New Pickering Area Transformer Station, Seaton TS.
- A4 – Metering: Customer's support "investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage."
- A5 - Customer Requested Work: The fewest number of respondents indicated they felt Elexicon should focus on addressing customer requests faster and more efficiently.

System Renewal

- R1 - Substation Renewal: Customer's support "proactively [replacing] more equipment before it fails."
- R2 - Renewal Programs-Rebuilds: Customer's support "proactively [replacing] more equipment before it fails."
- R3 - Renewal Programs-Poles: Customer's support "proactively [replacing] more equipment before it fails."
- R4 - Renewal Programs-Distribution Transformers: Customer's support "proactively [replacing] more equipment before it fails."
- R5 - Renewal Programs-Switches & Switchgears: Customer's support "proactively [replacing] more equipment before it fails."
- R6 - Renewal Programs-Others: Customer's support "proactively [replacing] more equipment before it fails."
- R7 - Renewal Programs-Reactive: Customer's support "proactively [replacing] more equipment before it fails." Customers believe that the duration and frequency of outages that have occurred are the most inconvenient aspects when power outages occur.
- R8 - Voltage Conversion-Reliability: One of the largest customer concerns was reliability.

System Service

- S1 - Substation Growth & Expansion: Customers support the proposed plan for the New Pickering Area Transformer Station, Seaton TS.
- S3 - Standard Equipment Reliability & Compliance: The majority of customers are very satisfied or somewhat satisfied with the service reliability and are satisfied with the planned allocation of investment.
- S5 - System Reliability Improvement: One of the largest customer concerns was reliability, specifically length of outages.

General Plant

- P1 – Facilities: Customers support the plan to Accommodate the Move of the Belleville Operations Centre.
- P2 – Fleet: Customer's support "proactively [replacing] more equipment before it fails."
- P3 - Information Technology: Customers are interested in "an outage notification system by text or voice." Customers felt Elexicon should focus on "Improving the grid's resilience to major weather events, like storms, etc." Customer's support "investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage."
- P4 - Tools & Equipment: Customer's support "proactively [replacing] more equipment before it fails."

5.4 b) System Development over the Forecast Period

Load and Customer Growth

Load and Customer Growth projections are driven by the Region of Durham's semi-annual regional household forecasts and long-term household forecasts produced by Port Hope, Muskoka (Gravenhurst) and Belleville. In addition, the projections take development plans and other residential growth forecasts from the Belleville, Gravenhurst, and Port Hope municipalities into account. The utility also considers the difference between past estimates and actual development when forecasting load growth. Key projection plans are listed below:

1) Regional Municipality of Durham Household Forecast – Monitoring of Growth Trends
2) City of Pickering 20 Year Report
3) City of Belleville, 2018 Municipal Review of Urban Serviced Area
4) 2019 Development Charges Background – Port Hope
5) 2019 Growth Strategy: The District Municipality of Muskoka

Over the past five years, Elexicon has not experienced major growth in the General Service or Large User classes. The number of customers within these categories has remained stable as per Table 5.4-1. The 2020 year-end total customer counts and additions are not available at the time of filing. In comparison, the Residential customer population has consistently grown due to development within the service territory.

Table 5.4-1: Historical Customer Demographics

Year	Residential	General Service < 50KW	General Service > 50KW	Large User >5 MW
2014	146,537	11,030	1,413	2
2015	147,753	11,088	1,435	3
2016	149,071	11,211	1,426	3
2017	150,220	11,274	1,458	3
2018	151,914	11,389	1,425	4
2019	154,711	11,535	1,403	4

Table 5.4- below provides the historical number of new service connections by voltage level. The majority of Elexicon's new service connections are low voltage (99.34%).

Table 5.4-2: Historical New Service Connections Volume

Connection of New Services	2015	2016	2017	2018	2019
Low Voltage (<750 Volts)	1627	1859	1736	2180	3306
High Voltage (>750 Volts)	22	16	22	8	3

Figure 5.4-1 below provides a residential customer forecast is based on the projection plans listed above. Over the forecast period, Elexicon expects to experience a large increase in residential customers. Table 5.4-3 below provides a breakdown of residential customer growth by district – the utility anticipates the most significant growth in the Ajax-Pickering and Whitby areas.

Figure 5.4-1: Residential Customer Growth Forecast

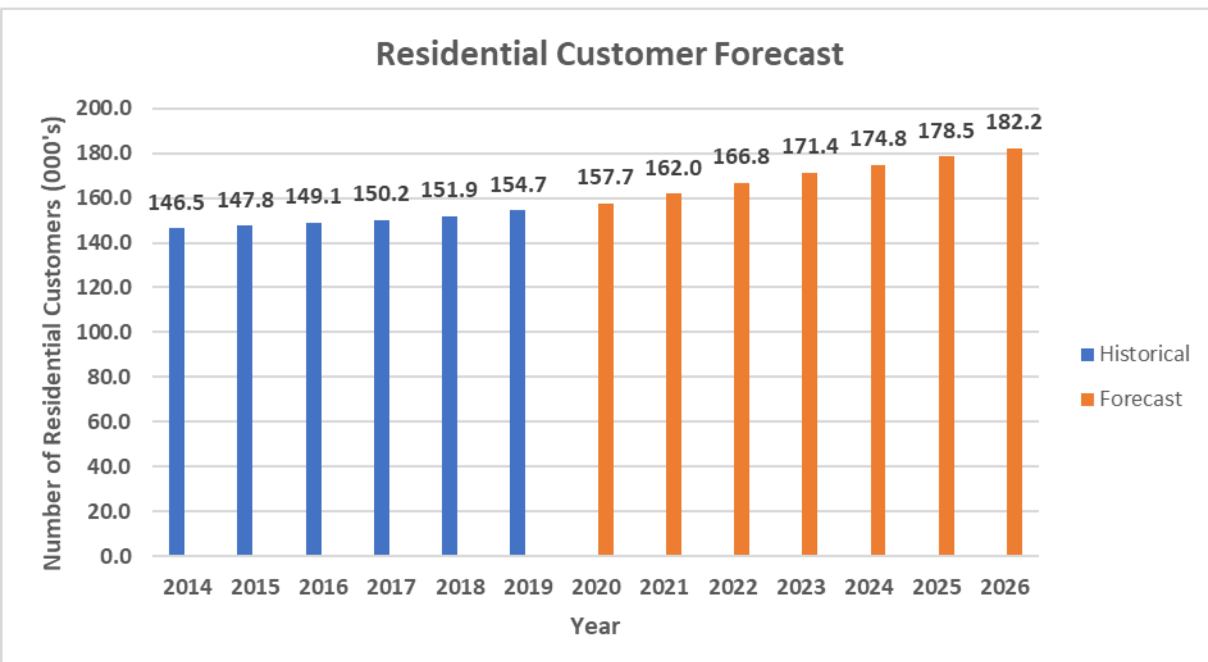


Table 5.4-3: Annual Forecast of Year-End Customer Additions

District	2020	2021	2022	2023	2024	2025	2026
Ajax-Pickering	1,468	2,730	3,209	2,997	1,750	2,023	2,110
Whitby	746	862	880	879	895	914	931
Belleville	198	199	141	210	177	177	178
Clarington	316	312	325	301	306	312	319
Brock	87	79	63	61	70	71	72
Port Hope	95	95	95	94	95	95	95
Gravenhurst	72	72	72	71	72	72	72
Total	**2,982**	**4,349**	**4,785**	**4,613**	**3,365**	**3,664**	**3,777**

Elexicon expects significant load growth over the forecast period due to major residential developments such as Seaton, West Whitby, North Pickering, and Port Whitby. The utility engaged a third-party consultation firm to complete a load forecast which applied a combination of engineering analysis and econometric modelling. Figure 5.4- below provides the anticipated summer peaks over the forecast period. As outlined above, the Ajax-Pickering and Whitby areas account for the majority of growth while all other areas' forecasts are relatively stable. Table 5.4- below summarizes the historical peak loads and

Table 5.4- provides the results of the engineering and econometric load forecasts. The P10, P50, and P90 levels represent different confidence levels – for example, P10 indicates that there is a 10% chance that the actual load is higher than the listed value. The "WN" values represent the expected load at typical weather conditions.

Figure 5.4-2: System Load Forecast

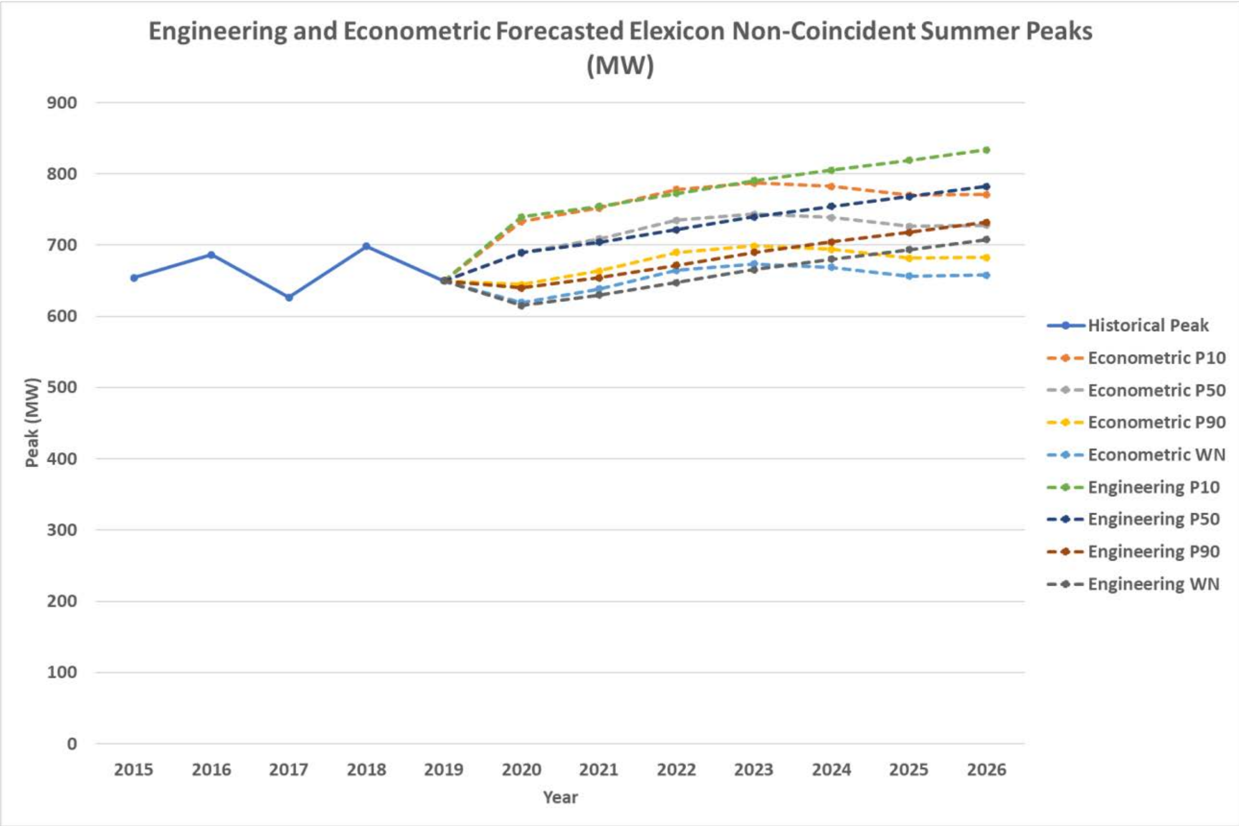


Table 5.4-4: Historical Peak Load

Year	2015	2016	2017	2018	2019
Peak	654.05	686.48	626.56	698.40	649.82

Table 5.4-5: Forecast Peak Loads

Peak Load Forecast	2020	2021	2022	2023	2024	2025	2026
Econometric P10	733.07	751.96	778.08	786.92	782.28	769.79	771.13
Econometric P50	689.62	708.51	734.63	743.46	738.82	726.33	727.68
Econometric P90	644.66	663.55	689.67	698.51	693.87	681.38	682.73
Econometric WN	619.58	638.47	664.59	673.43	668.79	656.30	657.65
Engineering P10	739.71	754.53	772.38	790.35	805.31	819.04	833.46
Engineering P50	689.31	704.01	721.73	739.57	754.39	768.01	782.29
Engineering P90	639.63	654.22	671.84	689.58	704.33	717.81	732.00
Engineering WN	615.31	629.91	647.53	665.27	680.02	693.51	707.69

Climate Change Adaptation

Elexicon applies a proactive approach to address climate change adaptation through various system hardening efforts and the Standards Equipment Reliability and Compliance program. One example of a system hardening effort is the application of CSA Heavy Loading standards in place of CSA Medium

Loading B standards. The utility plans to complete Grade 2 or Grade 1 construction in the future instead of Grade 3. These design and construction changes are expected to address the CEA environmental notice regarding increases in wind and loading. In addition, there is an increase in new approval for standardized heavy-duty designs – for example, cross-arm load capacity per wire has increased from 6,000lbs to 10,000lbs. The utility also updates software applications, such as those used for non-linear guying analysis, with the latest CSA standards which have stringent requirements for weather loading and built-in safety factors. Elexicon also evaluates alternatives to SF6 gases and limits their usage to cases where the fault current limits of air-insulated or solid-dielectric units are not sufficient. The utility has experienced an increase in lightning events which it addresses through the implementation of lightning arrestor standards every 10 poles. Elexicon has initiated an effort to install enhanced ground plates at every distribution pole to reduce equipment failures through a multi-grounded system neutral.

Elexicon also has a Standards and Equipment Reliability Committee that continuously evaluates existing standards to manage the risk of climate change effects. The utility frequently conducts equipment failure, trending, investigation, and system related analyses. In the past, these analyses have revealed opportunities for improvement relevant to climate change such as. cable replacements/injection, porcelain replacement, and FCI deployment. The committee considers the CEA guidelines for Risk Management for Utilities when planning improvements to standards. In terms of efforts related to substations, the utility has verified that current specifications are appropriate for the temperature profiles and plans to consider drainage in the future. Elexicon also analyzes historical loading information to understand the impact of climate change on the substation-level loading profile. For the station's portfolio, the specifications to current substations have been verified and are appropriate for temperature profiles. Drainage and accumulation of water could be considered into the future. Historical Loading information is also considered with respect to climate to understand the behavior of load on Elexicon substations.

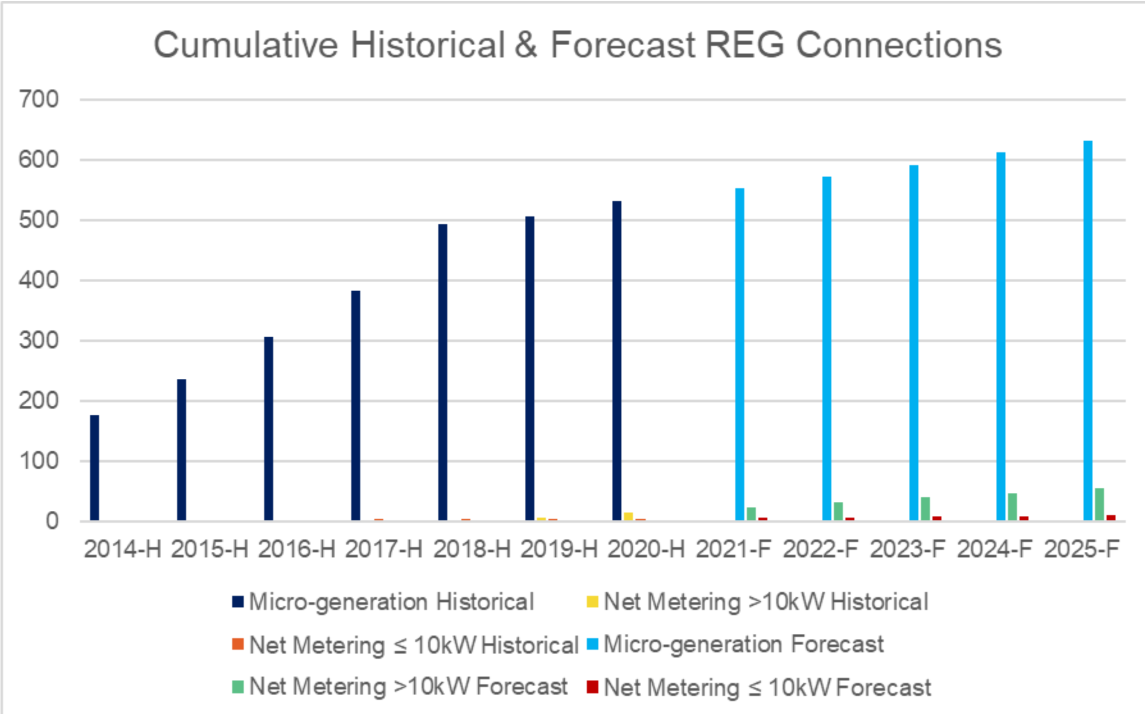
Grid Modernization

Elexicon plans to complete several grid modernization projects over the forecast period including efforts related to the System Reliability Improvements program, Smart Meters, microgrids, electric vehicles, and IT/OT infrastructure. The System Reliability Improvements program includes projects for the installation of Smart FCIs and TripSavers on worst performing feeders and areas with frequent reliability issues. In addition, the utility plans to upgrade legacy electromechanical relays at substations. The Metering program includes initiatives to install Smart Meters with additional communication capabilities that can be used in conjunction with the ADMS.

Historically, Veridian completed electric vehicle infrastructure related projects. For example, the legacy utility installed a solar powered carport canopy with electric vehicle charging infrastructure in 2016. As Distributed Energy Resources and Electric Vehicle infrastructure continues to develop, Elexicon plans to prepare by ensuring that IT/OT software enhancements can incorporate innovative modules. The planned ADMS capabilities are being defined without a specific vendor in mind (a vendor-neutral approach focussing on capabilities required now and over time). There are additional planned innovation projects in the Information Technology program related to IT/OT infrastructure such as electric vehicles and distributed energy resources. The group has an annual budget to address grid advancement innovation and innovative technology. Elexicon plans to use legacy infrastructure to automate SCADA and operational activities. The utility applies a variety of analyses to identify opportunities for increased efficiency through the introduction of new technology.

Accommodation of Forecasted REG Projects

Figure 5.4-3: Cumulative Historical and Forecast REG Connections



Elexicon expects steady growth in REG investments over the forecast period which do not pose significant capacity risk at the distribution station level. The utility performs a CIA for all new REG projects which outlines the expected impact on the distribution system. Section 5.3.4 provides additional details about REG investments including the system capability assessment for renewable generation. As summarized in Table 5.4-6, the utility expects twenty micro-generation, eight net metering (>10kW), and one net metering (<10kW) every year over the forecast period.

Table 5.4-6: Forecast REG Connections by Type

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	20	20	20	20	20
Net Metering >10 kW	8	8	8	8	8
Net Metering ≤10 kW	1	1	1	1	1

5.4.1 Capital Expenditure Planning Process Overview

5.4.1 a) Risk Management Tools and Methods

Current Tools Subject to Updates: Risk Registers and Risk Matrix

As described in Section 5.3.3 b) Asset Lifecycle Risk Management Policies and PracticesElexicon is currently in the process of developing a new corporate Risk Management Policy and the associated tools and processes. As this work is still ongoing, the following passages reflect the framework that is currently in place and is subject to upcoming modifications.

Elexicon's existing Risk Management Policy establishes its risk management strategy by outlining the objectives, principles, and processes used to address risks associated with its distribution assets. The overarching objective of Elexicon's Risk Management Policy is to ensure sustainable business growth and promote a proactive approach to reporting, evaluating, and resolving risks. The specific objectives of the Risk Management Policy are listed below:

- To enable compliance with appropriate regulations, wherever applicable, through the adoption of best practices.
- To ensure systematic and uniform assessment of risks and related operational responsibilities.
- To ensure business growth with financial stability.
- To establish a framework for Elexicon's risk management process and to ensure companywide implementation.
- To identify, assess, quantify, and appropriately mitigate/manage all the current and future material risk exposures.

The Risk Management Policy outlines the Risk Registers which describes and evaluates various risks using a combination of quantitative and qualitative methods. The key components of the Risk Registers are shown below in Table 5.4-– the utility identifies this information for each asset class. Elexicon completes the Quantification of Risk (item number 5) at the asset level and consolidates results across the asset class.

Table 5.4-7: Key Components of the Risk Registers

Item		Description
1	Name of Risk	Short description by which the risk may be referred to
2	Scope of Risk	Qualitative measurement indicating the size, type, number of the risk events and their related dependencies
3	Nature of Risk	Strategic/Business/Operational
4	Stakeholders	List of stakeholders affected and impact on their expectations Public/Business /Internal
5	Quantification of Risk and Risk Tolerance	Cost impact if risk materializes. Loss potential and financial impact of risk on the business or public. Probability of occurrence and size of potential losses.
6	Risk Treatment and Control Mechanism	Main method by which the risk is currently being managed
7	Potential Action for Improvement	Recommendation, if any, to reduce the occurrence and/or level of adverse impact of the risk. This is derived from the Asset Management Plan.
8	Strategy and Policy Developments	Identification of function responsible for developing the strategy and policy for monitoring, control and mitigation of the risk.

Elexicon's Risk Management Policy outlines its strategy for addressing different levels of risk and planning risk mitigation measures. For very high- and high-risk levels, Elexicon may employ a strategy of risk avoidance which entails not performing activities which carry this risk and effectively eliminates the risk. However, with this strategy, Elexicon also loses out on potential gains that retaining the risk may have allowed.

Elexicon may choose to employ a strategy of risk transfer for moderate risk which involves having another party assume responsibility for the risk through contract or other alternatives. Risk reduction is a viable strategy for low risk level assets and involves employing methods/solution that reduce the severity of the loss (e.g., shotcrete for preventing slippages adjacent to pole lines). For cases of very low to no risk, Elexicon may choose to retain the risk entirely and accept losses when they occur. Depending on the risk strategy that Elexicon chooses to employ, there is a range of viable risk mitigation measures which includes: removal of the asset, replacement of the asset, increased maintenance, and increased inspections.

Capital projects are influenced by certain risk mitigation measures – only asset removal or replacement efforts will be addressed through capital spending. Decisions on whether a replacement or increased maintenance is the preferred alternative are made using several criteria which are related to location, risk level, and asset type. Project selection is based on geographic location as there are often several assets in a given area which were installed at the same time and will require intervention at roughly the same time. In order to qualify for replacement, an individual asset must be assigned a Very High risk level. High risk level assets may also be selected for replacement if they form an immediate geographic cluster with one or more Very High risk level assets. The Planning Department may choose to replace Medium and Low risk level transformer assets within a qualified project cluster if more than 70% of the same asset class within the cluster is being replaced. The Planning Department may also choose to replace Medium or Low risk level non-transformer assets within a qualified project cluster if the ERL is less than 20%. Pole replacements are unique as they are treated as a separate project and are not associated with a specific geographic location.

System Risk Assessment

The System Risk Assessment is used to quantify the risk associated with Elexicon's assets. It involves quantifying the probability and impact of failure. The probability of failure is calculated using the failure curves described above. The failure impact assessment estimates the cost of failure and is comprised of four sub-assessments: reliability impact assessment, safety impact assessment, environmental impact assessment, and financial impact assessment. Each of these sub-assessments quantify relevant costs associated with asset failure as described below:

- Reliability Impact Assessment – A quantification of the costs associated with outages due to asset failure through WTP parameters for residential customers and lost revenue or DW for commercial/industrial customers.

- Safety Impact Assessment – A quantification of the costs associated with injury, death, and collateral damage resulting from an asset failure. These collateral damage costs typically consist of payouts, legal fees, and claims made by third parties.

- Environmental Impact Assessment – A quantification of the costs associated with environmental damage resulting from asset failure. This includes costs such as labour costs for hazard cleanup crews, materials/chemicals used, transportation costs, and fines/levies.

- Financial Impact Assessment – A quantification of the direct tangible costs that are incurred by the utility during service interruptions. This includes material and labour costs associated with repairs/replacements and the loss of revenue during the interruption.

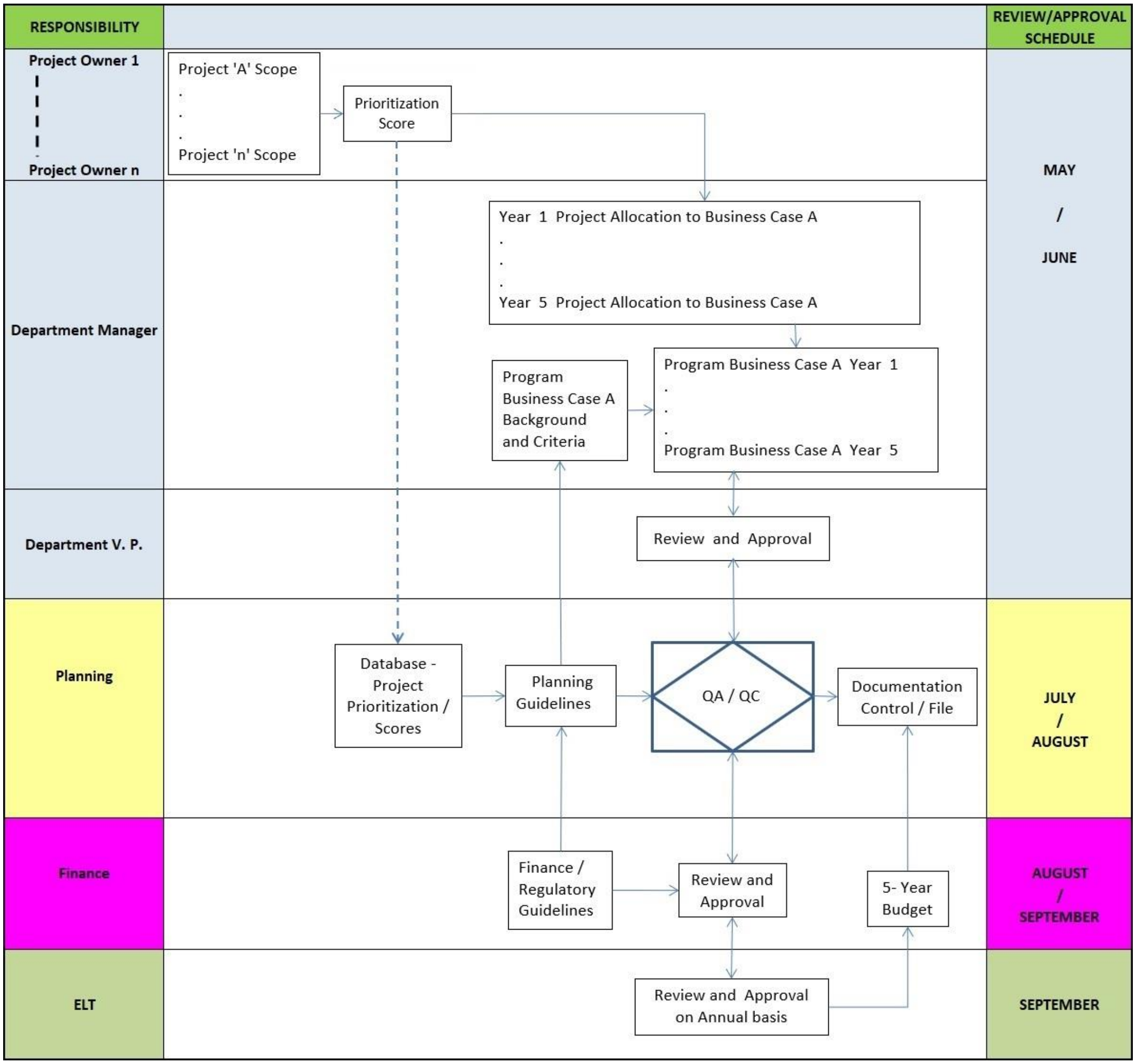
The asset risk assessment allows Elexicon to plan, prioritize, and optimize capital expenditures. The risk cost of an existing asset is calculated as the product of the total cost and the failure probability. The total cost is calculated as the sum of the reliability, safety, environmental, and financial costs and the failure probability is derived from the failure curve as outlined above. Next, the total lifecycle costs of the new asset to be installed are calculated through an analysis of its lifecycle risk, maintenance, and capital costs.

These costs are annualized and used to identify the minimum lifecycle cost of the new asset, otherwise known as the equivalent annual cost ("EAC"). The risk cost for the existing asset is compared to the EAC in order to determine the economic end of life or the optimal intervention time for the existing asset. If the risk cost of the existing asset exceeds the EAC, replacement is deemed to be the most economical option. However, Elexicon considers other EOL options for some assets such as refurbishment, increased inspections/maintenance, and reconfiguration in order to further optimize capital expenditures.

5.4.1 b) Capital Planning Tools, Processes, and Methods

Elexicon's AM Process, as described in section 5.3.1, concludes with the development of alternatives and recommendations by the Planning Department to address the needs identified. After the conclusion of the AM Process, the utility initiates the Capital Planning Process ("CPP") depicted in Figure 5.4- below. The capital planning process begins with the creation of project scope documents, which outline key information such as drivers, scope of work, costs, benefits, alternatives, and priority. The priority score is a key consideration during the capital planning process and is an output of the Budget Prioritization Process. The budget prioritization process is a multi-phase, multi-criteria approach which objectively and consistently ranks budget items using quantitative and qualitative methods. It allows Elexicon to assess the risk associated with projects, ensure alignment with corporate goals (as defined by AM objectives), and optimize capital expenditures. The utility completes this process annually and makes adjustments throughout the year as its needs evolve. Additional details about the Budget Prioritization Process are provide in APPENDIX I: Project Prioritization Process.

Figure 5.4-4: Capital Planning Process Overview



After scope documents have been created, department managers organize projects into programs and create the associated business case documents. Business cases are program-level documents which outline key information such as the basis for action, program alternatives, merged operations planning and insights, and the scope documents for the projects within the program. The department manager considers guidelines created by the Planning and Finance departments when creating business cases. These business cases provide a justification of capital expenditures and are a key component of the DSP.

The department manager submits completed business cases to the Department VP who is responsible for reviewing and approving them. Once approved, the Planning department creates a tentative budget and completes a QA check. The Planning department also reviews prioritization scores, adjusts planning guidelines accordingly, and ensures that the budget aligns with planning guidelines. Next, the Finance department reviews and approves the budget after ensuring that it aligns with Finance/Regulatory guidelines. The final step of the capital planning process involves Elexicon's executive team, also known as the Elexicon Leadership Team ("ELT"), which is comprised of the individuals listed in Table 5.4-8. The ELT completes a final review and approval for the budget and the Planning and Finance departments update the documented budget accordingly.

Table 5.4-8: List of ELT Members

Member	Role
Lesley Gallinger	Chief Executive Officer
Falguni Shah	Vice President, Technology and Innovation
Kevin Whitehead	Vice President, Asset Management
Kristine Chandler	General Counsel and Corporate Secretary
Lucy Lombardi	Chief Financial Officer, Vice President, Regulatory Affairs
Moranne McDonnell	Vice President, Distribution Operations
Rob Scarffe	Vice President, Customer Experience
Stacia Boss	Vice President, Human Resources and Corporate Services

5.4.1 c) Method and Criteria used to Prioritize REG Investments

The investment prioritization process for REG investments is the same as described in section 5.4.1b), with the exception of one key difference. When considering alternatives for REG investments, Elexicon will explore options for the customers to contribute to REG enabling investments through cost sharing of the REG enabling investment between the customer and Elexicon.

5.4.1 d) Assessment of Non-Distribution System Alternatives

Elexicon's approach to assessing non-distribution system alternatives for relieving system capacity includes consideration of switching operations, distributed generation, and the outcomes of the Regional Planning Process. The most readily available solution for relieving capacity is the use of switching operations. For example, Elexicon's monthly loading reports can indicate that there are capacity issues related to distribution assets such as conductor or transformers in a certain region. Elexicon analyzes its distribution system configuration to identify alternative feeders to provide electrical service and effectively relieve load constraints. While this is typically a short-term solution, it provides substantial benefits with respect to the deferral of capital investments intended to upgrade capacity or relieve load constraints. If capacity issues are discovered, Distributed generation is another method through which Elexicon can relieve load on its system. Elexicon works with its customers to facilitate the implementation of distribution generation infrastructure which reduces customer load and relieves system demand. This is an effective solution for commercial customers, who often account for large portions of load and have the ability to implement measures such as renewable generation and energy storage systems.

The Regional Planning Process impacts Elexicon's system load as it provides an opportunity for the utility, transmitters, and other LDCs to collaborate and optimize the distribution system at a large scale. The outcomes of this consultation process can result in Elexicon making capital investments to relieve load. For example, the previous Regional Planning Process cycle for the GTA East region entailed the construction of Seaton TS to provide electrical service to customers in the new Seaton development. While this requires investment from Elexicon, the construction of the Seaton TS enables switching operations and provides Elexicon with an opportunity to relieve load at existing stations.

5.4.1 e) Grid Modernization Investments Planning

Elexicon strategically plans modernization investments by completing analyses in order to predict the future state of the distribution system, electricity distribution industry, and customer needs. Elexicon avoids completing modernization investments on the sole basis of industry trends and instead considers relevant trends that will provide the most value to its system and operations. The IT group is responsible for completing modernization investment planning. There are three types of modernization investments which Elexicon considers – these investments vary in the driving factor which justifies their necessity. These three types of investments are: data-driven investments, trend-driven investments, and non-discretionary investments.

Data-Driven Investments
These investments arise from the results of various data analyses that indicate deficiencies in the distribution system or operational performance that could be resolved through modernization efforts. These data analyses range in complexity – for example, the analysis could consist of a simple evaluation of historical data (e.g., outages) or a more complex modelling analysis involving advanced techniques such as machine learning. Examples of past data-driven modernization investments include the installation of smart FCI devices in areas with a high outage volume and TripSaver devices which reduce the number of momentary faults and increase operational efficiency. These investments typically follow a traditional business case format as they are based on quantifiable trends and benefits.

Trend-Driven Investments
These expenditures arise from consideration of industry, innovation, or customer-focused trends relevant to Elexicon's distribution system or operations. For example, Elexicon has considered external trends such as the increase in customer utilization of electric vehicles, upgrades to fibre-optic communication infrastructure, and increases in renewable energy generation/distributed generation. Examples of trend investments include projects intended to fund the development of microgrids and infrastructure for electric vehicles. Elexicon often makes assumptions to complete the forecasting analyses that drive these types of modernization investments and, as a result, the associated benefits are more difficult to quantify.

Non-Discretionary Investments
These investments arise from external factors such as OEB requirements or government regulations which mandate changes in an LDC's distribution system or operating practices. These investments are the simplest to address as the underlying process consists of developing the optimal solution and does not require the same level of justification as data or trend-driven investments. Examples of non-discretionary modernization investments include the Cybersecurity project which is intended to address cybersecurity gaps identified in the OEB Cybersecurity Framework.

Other Investments
Apart from these investments, Elexicon completes other investments in support of modernization. Relevant examples include projects intended to provide funding for research and development or proof of concept for emerging technologies. Specific examples include the Innovation Project, Technology and Innovation, and the Grid Advancement Project. In addition, Elexicon evaluates capital investments in other investment categories to understand if there is potential for efficiency in regards to future modernization efforts. The utility's ideology is that if it is making a capital investment to address a certain aspect of the distribution system, it may be beneficial to invest additional capital in order to accommodate future modernization investments. For example, if Elexicon is completing pole replacements as part of the Poles Renewal Program, it may consider replacement with a larger pole to accommodate future anticipated communication infrastructure.

Customer Access to Consumption Data and Behind-the-Meter Services
As part of the CIS merger project, Elexicon is merging the existing customer portals into a single site where all Elexicon customers can view their bills and manage their account details. This initiative is thoroughly documented in the P3 business cases for IT/OT investments (see Appendix A).

Facilitating Integration of Distributed Generation, DERs, and Complex Loads
Elexicon's planned implementation of an ADMS will help facilitate the integration of distributed generation, DERs, and more complex load. This initiative is thoroughly documented in the P3 business cases for IT/OT investments (see Appendix A).

Technology-Enabling Opportunities and Innovation
Elexicon invest in new technology to increase operational efficiencies, improve asset management, and enhance services to customers alongside the adoption of innovative processes, services, business models, and technologies as prudent and supported by its investment plan. Most of these investments fall under the S3 – System Reliability Improvements and P3 – IT/OT investment categories. On the system service side, Elexicon invests in single-phase line reclosers ("Tripsavers"), three-phase "SCADA Mate" and "IntelliRupter" switches, standard and smart Faulted Circuit Indicators, and other SCADA improvements.

On the IT/OT side, Elexicon has employed microgrid pilot projects to understand its effect on the distribution network and operations. Other innovative projects levy the expertise found within the technology division at Elexicon by performing data analytics across the grid and in the organization. These projects evaluate and seek opportunities where the utility can become more operationally efficient. The relevant business cases in Appendix A document these investment programs.

5.4.1 f) Overview of CDM Programs

Prior to the merger of Whitby Hydro and Veridian, the only CDM programs in place were those driven by IESO. In March 2019, shortly before the merger of the predecessor utilities, the IESO made the decision to take responsibility for CDM programs. Prior to this decision, the IESO designed CDM programs and LDCs delivered them to customers. The decision meant that IESO would work directly with the customer to coordinate CDM efforts. However, the IESO allowed utilities to complete any ongoing CDM programs – Elexicon's "wind down" CDM efforts are listed below and described in greater detail in the following section.

- Retrofit
- Process and Systems
- Residential New Construction
- Audit Funding
- High Performance New Construction

5.4.1.1 Rate-Funded Activities to Defer Distribution Infrastructure

As outlined in section 5.4.1f), the only CDM programs that Elexicon has in place are the "wind down" efforts that were in place prior to the IESO's decision to work directly with customers for CDM efforts. These programs are system-wide and do not target local constraints or specific areas of the distribution system. However, these programs reduce the load on Elexicon's distribution system as they are intended to improve energy efficiency and reduce demand. As a result, it is expected that these programs may assist in the deferral of capital investments related to system capacity to the degree that customers participate. Table 5.4-9 below provides a description of each of these programs. These descriptions are current as of March 2019 and reflect Elexicon's approach. However, new applications for these programs are overseen by the IESO and the program scopes may be subject to change.

Table 5.4-9: Description of CDM Programs

Program Name	Description
Audit Funding	An energy audit is the first step in identifying opportunities to reduce energy use and operating costs. This program provides funding for up to 50% of the cost of three types of energy audits undertaken to identify opportunities to reduce electricity consumption at industrial, commercial, institutional, and multi-family residential buildings. Participant incentives are available for the following types of energy audits: Electricity Survey and Analysis, Building Systems Audit, Detailed Analysis of Capital-Intensive Modifications.
Retrofit	This program provides incentives for businesses looking to upgrade their equipment or improve their operations. Eligible projects under the Retrofit program include those that provide sustainable, measurable, and verifiable reductions in peak electricity demand and electricity consumption (e.g., lighting and controls, HVAC, VFD, compressed air systems, fans, pumps, motors, unitary AC). There were two tracks available for applicants: prescriptive and custom. The former is a quick-application process with pre-set incentive amounts whereas the latter is intended for more comprehensive upgrades and involves incentives based on before-and-after energy savings.
Process and Systems Upgrades (“PSU”)	This program provides financial incentives for the implementation of Energy Efficiency and Generation Projects that are capital intensive. The PSU program also provides funding for an Engineering Feasibility Study which supports the PSU program by identifying and developing potential project opportunities.
Residential New Construction	This program encourages residential home builders to include energy efficiency technologies and design in new and substantially renovated homes. There are three tracks available for this program: performance, prescriptive, and custom. The performance track provides incentives up to $1,000; the prescriptive track provides an incentive per measure (e.g., lighting fixtures, timers, sensors, and more), and the custom track covers incentives for construction that goes above and beyond Ontario Building codes.
High Performance New Construction	This program provides financial incentives/support for building energy efficiency into construction plans. It applies to new buildings as well as existing buildings undergoing a major renovation. It includes two tracks: engineering projects and custom projects. The former includes interior/exterior lighting and unitary air conditioners with incentives set based on pre-set energy savings calculations. The latter includes chiller systems, insulation, and more with incentives set based on modelled energy performance – it also includes modelling incentives up to $10,000 or 100% of simulation costs.
Certified Energy Manager	Certified Energy Mangers work with large power consumers help them achieve energy and demand savings. They work directly with the company’s operations team, vendors, and service providers to implement an energy management strategy. Companies can apply directly to the IESO to participate in the Energy Manager program.

Elexicon also has planned efforts to improve energy efficiency and reduce losses within its distribution system. This primarily occurs through the Information Technology and Voltage Conversions – Reliability programs. The Information Technology program includes the Volt-Var Control at LV Level project which is expected to inject reactive power to reduce energy loss. The Voltage Conversions – Reliability and Feeder Enhancements programs include projects to standardize the voltage rating of feeders in the distribution system through upgrades.

5.4.2 CAPITAL EXPENDITURE SUMMARY

Table 5.4-11 provides a summary of Elexicon's historical and forecast capital and O&M expenditures. It shows the variance between planned and actual expenditures across the four investment categories. There are no expenditures for non-distribution activities in the budget. This section provides detailed explanations about the sources of discrepancy. It is important to consider that Elexicon intends to fund two efforts in 2022 through the ICM mechanism. Table 5.4-10 below provides a summary of these ICM projects. Elexicon initially planned to request ICM funding for three initiatives – the construction of Seaton TS, Bus Rapid Transit System, and the Belleville Office Relocation. However, the utility applied managerial discretion and created a strategy to fund the Belleville Office Relocation projects through base rates.

Table 5.4-10: Summary of ICM Projects

Investment Category	Program	Project Name	Gross Budget	Net Budget
System Access	Road Relocations	BRT Highway 2	$5,299,000	$3,379,000
System Access Subtotal			**$5,299,000**	**$3,379,000**
System Service	Substations Growth & Expansion	Seaton TS	$40,762,000	$40,762,000
System Service Subtotal			**$40,762,000**	**$40,762,000**
Total			**$46,061,000**	**$44,141,000**

For capital projects that have a project life cycle greater than one year, project costs are tracked as Construction Work in Progress. Once the capital project is completed (i.e., the assets are used and useful) the costs are moved from Construction Work in Progress into the rate base.

Table 5.4-11: Historical and Forecast Capital and O&M Expenditures

Category	Historical																	
	2014			2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.
	$000		%	$000		%	$000		%	$ 000		%	$ 000		%	$ 000		%
System Access	40,138	17,199	-57%	21,801	17,206	-21%	22,537	14,032	-38%	17,351	12,289	-29%	40,948	15,355	-63%	43,167	25,214	-42%
System Renewal	17,479	9,206	-47%	17,685	14,560	-18%	15,957	20,917	31%	18,321	17,840	-3%	17,464	17,878	2%	13,160	27,660	101%
System Service	2,441	3,911	60%	1,547	1,803	17%	864	858	-1%	1,889	483	-74%	2,840	497	-83%	506	1,126	122%
General Plant	5,020	5,372	7%	5,465	5,243	-4%	4,930	5,259	7%	3,973	5,189	31%	5,774	6,166	7%	4,360	6,293	44%
Total (Gross)	65,078	35,688	-45%	46,498	38,812	-17%	44,288	41,066	-7%	41,534	35,801	-14%	67,026	39,896	-40%	61,193	60,293	-1%
Contributed Capital	26,946	7,347	-73%	10,611	11,228	6%	7,663	8,358	9%	7,080	4,337	-39%	7,724	8,131	5%	19,510	16,807	-14%
Total (Net)	38,132	28,341	-26%	35,887	27,584	-23%	36,625	32,708	-11%	34,454	31,464	-9%	59,302	31,765	-46%	41,683	43,486	4%
System O&M	15,240	13,884	-9%	14,188	14,465	2%	14,320	14,986	5%	14,870	15,025	1%	15,841	15,970	1%	16,315	12,111	-26%

Category	Historical						Forecast				
	2020 Plan	2020 Actual	2020 Variance	2021 Plan	2021 Actual	2021 Variance	2022	2023	2024	2025	2026
	$000	$000	%	$000	$000	%	$000	$000	$000	$000	$000
System Access	21,947	25,041	14%	44,681		N/A	27,473	28,271	26,673	14,853	19,053
System Renewal	13,163	13,555	3%	19,667		N/A	23,441	21,490	19,879	18,037	17,756
System Service	1,320	1,983	50%	1,418		N/A	42,805	1,348	1,353	1,053	1,053
General Plant	6,164	6,077	-1%	12,065		N/A	6,460	5,183	4,605	4,205	4,134
Total (Gross)	42,594	46,656	10%	77,831		N/A	100,179	56,292	52,510	38,148	41,996
Contributed Capital	13,502	16,341	21%	32,475		N/A	15,175	20,461	16,485	5,475	6,735
Total (Net)	29,092	30,315	4%	45,356		N/A	85,004	35,831	36,025	32,673	35,261
System O&M	16,873	14,262	-15%	16,591		N/A	16,923	17,261	17,606	17,959	18,318

5.4.2.1 Variances in Capital Expenditures

This section presents the variance analysis for Elexicon and the predecessor utilities. The predecessor utilities had merged by the end of Q1 2019 and tracked capital expenditures as a merged utility from this point onwards. All expenditures for 2019 onwards are presented together in this section. Note that the presented planned and actual expenditures were based on the investment categories and programs from the two previous utilities. The planned and actual expenditures in this variance analysis are equal to the planned and actual expenditures of Table 5.4-11. This table can also be found in App.2-AB.

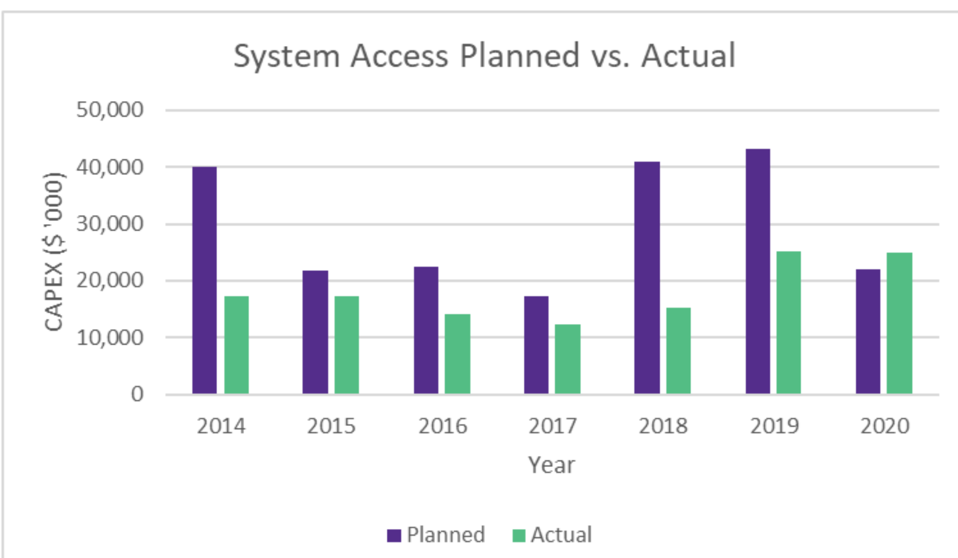
System Access

Table 5.4-12 presents the planned and actual capital expenditures in the System Access investment category for Elexicon and its predecessor utilities – this information is also presented in Figure 5.4-. As these investments are initiated by third parties, there are notable variances each historical year.

Table 5.4-12: Variance Analysis Summary for System Access Expenditures

Year	Whitby Hydro $ (‘000)		Veridian $ (‘000)		Combined / Elexicon Energy $ (‘000)			%
	Planned	Actual	Planned	Actual	Planned	Actual	Difference	Variance
2014	12,880	4,611	27,258	12,588	40,138	17,199	-22,939	-57.2%
2015	8,486	5,874	13,315	11,332	21,801	17,206	-4,595	-21.1%
2016	6,668	3,958	15,869	10,074	22,537	14,032	-8,505	-37.7%
2017	6,028	2,131	11,323	10,159	17,351	12,289	-5,062	-29.2%
2018	6,930	2,132	34,018	13,223	40,948	15,355	-25,593	-62.5%
2019					43,167	25,214	-17,953	-41.6%
2020					21,947	25,041	3,094	14.1%
Total					**207,888**	**126,336**	**-81,552**	**-39.2%**

Figure 5.4-5: Elexicon Variance Analysis Summary for System Access



2014

Overall, actual expenditures were 57.2% less than planned spending at Elexicon in 2014. Both former Whitby Hydro and Veridian Connections did not spend as much as the two utilities had planned.

In 2014, Whitby Hydro's underspending was due to the Road Relocations program. About $12.4M was forecasted to be spent on these projects, but only $3.8M of actual expenditures were spent on these projects. Projects related to the MTO, Region of Durham and Town of Whitby projects did not materialize as expected due to delays and cancellations from project owners. An additional $0.725 million was added on for Subdivision projects which was not planned.

In 2014, Veridian Connection's underspending resulted from the Road Relocations program and was significantly less than that of the planned values. 2014 planned numbers were higher than typical due to expected spending of the extension of Highway 407. Project delays relating to the 407 decreased the actual spending on road relocations for the 2014 year. $11M of Road Relocation related projects were planned for Highway 407 and Highway 2 but actual expenditures only totalled to $1.4M for these projects. Other system access projects were also invested less than planned across the portfolio.

2015

Whitby Hydro's System Access underspending by 21.1% in 2015 results primarily from the Road Relocations program. This program included several projects which were completed under budget or delayed due to external circumstances such as construction delays and cancellations from the project owners. The majority of these projects were related to work driven by the MTO at various points on the 407, but there was also significant underspending related to work driven by the Region of Durham. In total, the Road Relocations program accounts for $3.30M of underspending. This figure is offset by overspending in the Connection of New Services program which amounted to $0.69M and was driven by a higher volume of commercial secondary service connections than anticipated.

Veridian Connections' System Access underspending in 2015 primarily results from the Connection of New Services and Road Relocations programs. There are two projects which account for the majority of underspending in this category as they collectively amount to $3.0M of expenditures below budget. The first project was a generic new service connections project intended to provide funding for new service connections across the legacy Veridian Connections service territory. This project had a budget amount of $2.49 million, but none of the projects were completed within the year. The second project was intended to fund new service connections for Audley Developments (Subdivision Phase 6) in Ajax and had a budget of $0.51M but was also not completed within the year.

The majority of Road Relocation's underspending occurred due to several projects intended to fund relocations along the highway 407. The remainder of the underspending amount comes from incomplete road relocations projects in Ajax, Pickering, Brock, and Clarington.

2016

In 2016, actual expenditures in the System Access investment category are below the planned budget by 37.7%. Whitby Hydro's Road Relocations program accounts for underspending amounting to $3.26 million, but this figure is offset by overspending in the Connection of New Services program amounting to $0.554 million. There is one project within the Connection of New Services program which accounts for the majority of the overspending in the program. This project was intended to fund secondary service connections for commercial customers – actual expenditures exceeded the budgeted amount due to a higher volume of connections than anticipated.

The majority underspending in the Road Relocations program occurred due to MTO-driven projects intended to relocate assets along the 407 due to construction. This underspending resulted from external factors such as scope changes and delays related to project design, coordination, construction, and customer feedback. Region of Durham driven Road Relocations projects accounted also accounted for underspending. This discrepancy resulted from delays such as construction, pending third party transfers, and last-minute design changes. Town of Whitby driven Road Relocations projects were rescheduled, cancelled, or reallocated to other categories in the following year.

2017

In 2017, the actual System Access expenditures were 29.2% below the planned budget. The difference between Whitby Hydro's planned and actual expenditures results from underspending in the Road Relocations program and overspending in the Connection of New Services program amounting. Similar to previous years, the Connection of New Services program entailed expenditures greater than the budgeted amount due to a higher volume of secondary service connections for commercial customers than anticipated. The majority of the underspending in the Road Relocations program is related to work on the 407 driven by the MTO. There were several projects intended to fund the relocation of assets due to expansions and construction at various points on the 407. The actual expenditures for all of these projects were significantly lower than planned due external circumstances.

There were three Region of Durham driven projects which accounted for the majority of underspending: road relocations at Brock St. (Manning – Rossland), expansions at Victoria St E (South Blair to Thickson Rd.), and relocations at Victoria St E (South Blair to Thickson Rd.). All of these projects were delayed due to construction challenges or changes in scope by the Region. Town of Whitby driven Road Relocations projects resulted in underspending amounting to $0.553 million. This is primarily driven by one project for relocation at the McQuay/DGN intersection that was under budget due to delays in drafting agreements and the final design. There were other projects driven by the Town of Whitby that were below budget due to additional contributions or cancellations.

Key projects contributing to this variance include new service connections at Workman's Circle Condo, Audley Developments (Phase 7), Mattamy – Seaton Taunton Ridge (Phase 1), Averton-Bowmanville, Duffins Village (Phase 2), Lakebreeze (Port Darlington West), and Sunderland Meadows (Phase 2). The Road Relocations program accounts for $0.447 million in underspending which results from incomplete or delayed road relocations projects such as Westney Road (Rossland x Williamson), Rossland Road (Clearside x Southcott), and SL26 (Taunton vs Whitevale).

2018

In 2018 actual System Access expenditures were 62.5% lower than the budget. The difference between planned and actual expenditures for Whitby Hydro resulted primarily from the Road Relocations program. MTO driven relocations work along the 407 accounted for the underspending – this discrepancy occurred due to delays in construction work, pole delivery, agreement negotiations, and approvals and other actions from the MTO (such as road closures and feeder isolations). Relocation work driven by the Region of Durham, including several Metrolinx projects, accounted for $2.09 million and resulted from scope changes and delays in design, construction, and pole delivery. Town of Whitby driven relocations work accounted for $1.58 million – this resulted from additional contributions and delays in construction, engineering analysis work, and contractor action.

The difference between planned and actual expenditures for Veridian Connections' System Access investments amounts to $8.31 million of underspending. This difference can be attributed to the

Connection of New Services program which accounted for actual expenditures below budget amounting to $8.70 million – this figure is offset by expenditures over the planned budget in other programs. There are some key projects which individually account for a large portion of the variance – this includes projects intended to fund new service connections across the legacy Veridian service territory and projects for developments in specific areas. Generic new service connections projects account for $6.10 million of underspending. Development-specific projects were primarily in the Ajax-Pickering area and accounted for $3.97 million of underspending. Examples of development- specific projects include DG Lands A10, Mattamy – Seaton Taunton Ridge (Phase2), and Duffins Village (Phase 2). These figures indicate that the actual underspending amount is higher than that figure listed above. The actual underspending for this program amounts to $12.63 million, but this figure is offset by overspending for some projects amounting to $4.15 million.

2019

Actual expenditures in 2019 were 41.6% below the planned budget. Higher levels of System Access were forecasted due to major Road Relocation projects such as the BRT and Metrolinx. Higher Residential Development was forecasted in addition to the purchasing of Seaton MTS land. Feeder construction in the Seaton and Durham Live was also expected in 2019. Whitby Hydro's Q1 expenditures account for $2.45 million of capital expenditures below budget, which resulted from the Road Relocations program. Specifically, Region of Durham driven road relocations work accounted for $1.39 million, Metrolinx driven road relocations work accounted for $0.477 million, and Town of Whitby driven road relocations accounted for $0.251 million. The Connection of New Services program also contributed to this underspending as it accounts for a relatively small $0.315 million of underspending.

All remaining expenditures in the System Access investment category account for $4.39 million of underspending. This primarily results from the Road Relocations program, which accounts for $6.50 million, and Customer Requested Work program, which accounts for $0.582 million. The average underspending within the Road Relocations program amounts to approximately $340,000. There are a few projects which contribute significantly to underspending within this program. This includes projects intended to fund relocations at Rossland Road to Taunton Road, Rossland Road – Lakeridge to Des Newman, Brock Street (Manning – Rossland), Cornation Road (Taunton to Rossland), and Rossland Road (DNB to McQuay). Underspending in the Customer Requested Work program results from a few key projects such as Westney & Bayly – DL Intersection Improvements, Kellino & Church – DL Intersection Improvements, and Marquis Towns Relocation of Existing Plant.

These figures are offset by overspending of $3.08 million in the Connection of New Services program. There are several projects which contribute to overspending with the Connection of New Services program – this overspending collectively amounts to $12.04 million. There are also projects within the Connection of New Service program which offset this figure as they account for underspending amounting to $8.96 million. Key projects which contribute to overspending include Residential Subdivision Costs, Mattamy-Seaton Taunton Ridge (Phase 2), Workman's Circle Condo, Lakebreeze – Port Darlington West, Seven Meadows (Phase 1), Madison Liverpool, and Main Street – Seaton (Phase 2). Key projects which contribute to underspending include several general new service connections projects, New Commercial Services, and projects for new service connections along Rossland Road.

2020

Expenditures in 2020 were 14.1% over the planned budget. The majority of this results from Road Relocations, which accounts for $0.851 million, and Feeder Expansion, which accounts for $0.63

million. Key projects that contribute to under spending include Brock St & Rossland Ph2 – 1511 and DND-Rossland to Dundas.

These figures are offset by Connection of New Services which went $3.3 million over budget. Key projects which contribute to overspending include Seven Meadows (Phase 2), Lebovic South Seaton – 1133373 and DG Lands A10 Oak Ridges.

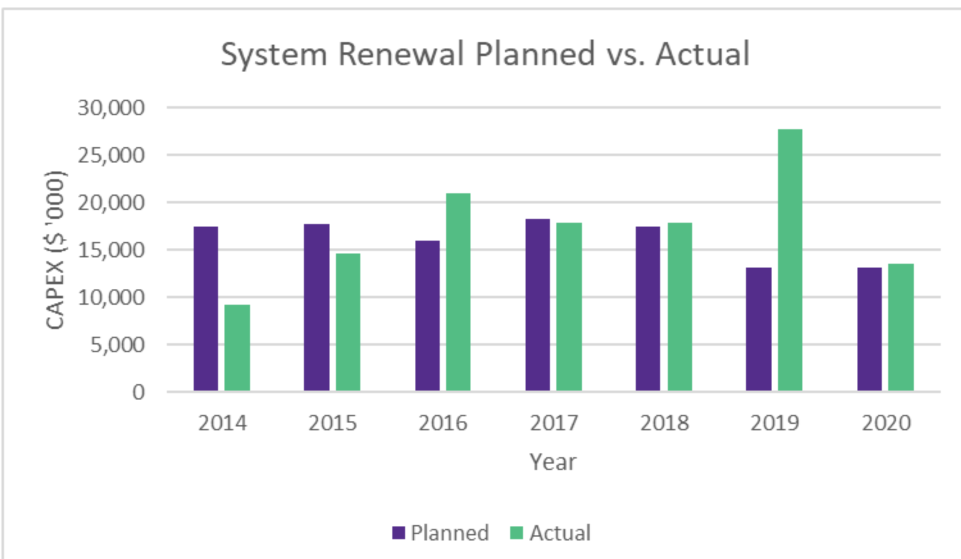
System Renewal

Table 5.4-13 presents the planned and actual capital expenditures by investment category for Elexicon and its predecessor utilities – this information is also presented in Figure 5.4-6.

Table 5.4-13: Variance Analysis Summary for System Renewal Expenditures

Year	Whitby Hydro $ ('000)		Veridian $ ('000)		Combined / Elexicon Energy $ ('000)			%
	Planned	Actual	Planned	Actual	Planned	Actual	Difference	Variance
2014	3,359	3,338	14,120	5,868	17,479	9,206	-8,273	-47.3%
2015	3,313	3,365	14,372	11,195	17,685	14,560	-3,125	-17.7%
2016	4,516	4,463	11,441	16,454	15,957	20,917	4,961	31.1%
2017	5,794	6,114	12,527	11,727	18,321	17,840	-481	-2.6%
2018	7,347	7,032	10,117	10,846	17,464	17,878	414	2.4%
2019					13,160	27,660	14,501	110.2%
2020					13,163	13,555	392	3.0%
Total					**113,229**	**121,618**	**-3,416**	**7.4%**

Figure 5.4-6: Elexicon Variance Analysis Summary for System Renewal



2014

Actual expenditures by Elexicon in 2014 were 47.3% lower than that of planned investments. The year 2014 was the first that Veridian System Renewal investments incorporated Asset Condition Assessment results which contributed to the higher planned value. Overall, across the board for

System Renewal investments, former Veridian did not spend as much on renewal projects as intended. For instance, the total substation planned replacement investments for Transformers, Breakers and Reclosers was about $4.65M. Only $0.62M of substation renewal related investments were actual expenditures representing a $4.03M difference. Other asset-related projects followed a similar pattern as being below planned spending.

2015

System Renewal expenditures in 2015 were below the planned budget by 17.7%. Of the 2015 year, Veridian projects such as the Sunderland recloser upgrade, 44-kV feeder expansion/renewal and spare substation transformers did not transpire which were major contributors to the underspending. Distribution Transformer Replacements and other Annual programs also underspent contributing to the overall underspending of this program.

2016

System Renewal expenditures in 2016 exceeded the planned budget by 31.1%. There are several programs which contribute to the total variance, but the most significant are the Poles Renewal, Reactive Renewal, Rebuilds, and Substation Renewal as these programs collectively account for $2.3M of expenditures over budget. These additional expenditures resulted from more significant asset deterioration being discovered than initially planned. The remaining expenditures over budget resulted from renewal work related to Distribution Transformers, Switches/Switchgears, and Feeders (i.e., Rebuilds Program).

2017

System Renewal expenditures in 2017 were under planned budget by 2.6%. Underspending results from a variety of programs such as Poles Renewal, Rebuilds, Distribution Transformers Renewal, Switches/Switchgears Renewal, and Reactive Renewal. Three programs account for most of the overspending. Distribution Transformers Renewal accounts for $0.95 million, Switch/Switchgear Renewal accounts for $1.07 million, and Substation Renewal accounts for $1.63 million. The remaining overspending is attributed to other renewal programs or projects which were historically classified under System Renewal but have since been allocated to programs in other investment categories.

2018

In 2019, actual expenditures in the System Renewal investment category were 2.4% over the planned budget. Additional spending in the Porcelain Insulator program, Westney Heights Substation Fencing, Cable Testing and FCI Deployment contributed to the overspending of this year.

2019

In 2019 actual expenditures in the System Renewal investment category were 110.2% over the planned budget. Overall, the Substations Renewal program accounted for most of the overspending with major projects such as the Dowty Station Rebuild, Planned Transformer Sustainment for Gillespie SS, MS9 Rebuild, Substations Sustainment – Unplanned, and MS10 T1 Gantry and Circuit Breaker. Additionally, many stations were also corrected for any substation deficiencies leading to higher actual expenditures. Only Dowty SS and Gillespie SS were forecasted as station renewal projects of up to $2.7 million but $7.3 million was spent on the whole station portfolio. Other renewal projects within the renewal portfolio such as rebuilds, cable testing and rejuvenation, like for like pole replacements also contributed to the higher actual expenditures for 2019. For example, actual expenditures for the pole renewal program were $6.15M but forecasted initially at $1.47 million.

2020

In 2020 expenditures were 3% over the allocated budget. This can be attributed mostly to Rebuilds and Substation Renewal. The projects that contribute the most to underspending include MS-5 Secondary Backup Feed and Ashburn Rd (Townline to Brawl). This is offset by underspending in other categories.

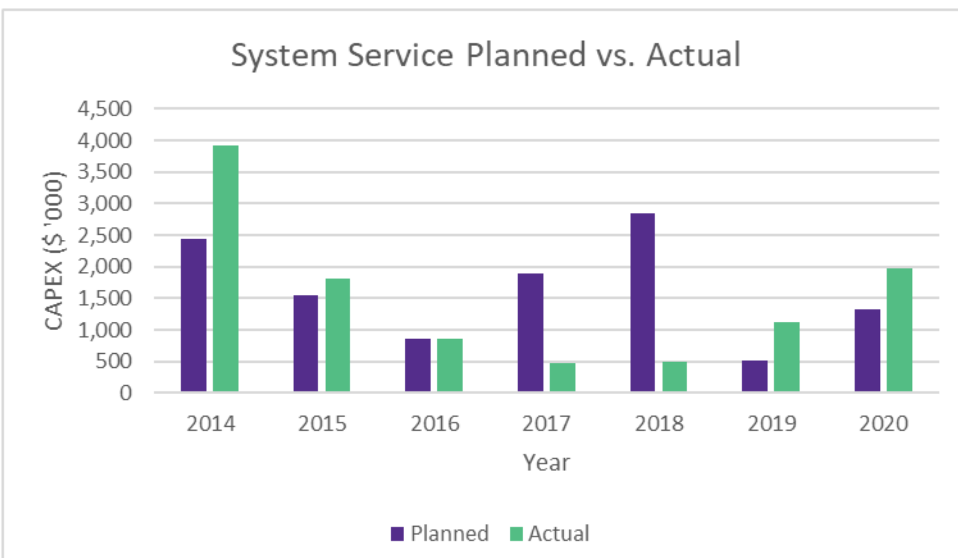
System Service

Table 5.4-14 presents the planned and actual capital expenditures in the System Service investment category for Elexicon and its predecessor utilities – this information is also presented in Figure 5.4-7.

Table 5.4-14: Variance Analysis Summary for System Service Expenditures

Year	Whitby Hydro		Veridian		Combined / Elexicon Energy			
	$ ('000)		$ ('000)		$ ('000)			%
	Planned	Actual	Planned	Actual	Planned	Actual	Difference	Variance
2014	818	481	1623	3,429	2,441	3,911	1,470	60.2%
2015	1,484	1,631	63	171	1,547	1,803	256	16.5%
2016	589	696	275	163	864	858	-5	-0.00%
2017	876	483	1,013	-	1889	483	-1,406	-74.4%
2018	2,840	466	-	31	2,860	497	-2,343	-82.5%
2019					506	1,126	620	122.4%
2020					1,320	1,983	663	50.2%
Total					**11,407**	**10,661**	**-746**	**-6.5%**

Figure 5.4-7: Elexicon Variance Analysis Summary for System Service



2014

For System Service expenditures in 2014, actual spending from Elexicon was 60.2% higher than that of the planned estimates for this program. Comparatively, Veridian Connections spent much more than their planned amount whereas Whitby Hydro spent less than budgeted. Originally, three projects were budgeted whereas eighteen projects were invested in. Major projects such as SCADA-related initiatives and upgrades, new system reliability improvements of FCIs and Trip Savers, and the Wilmot Substation Upgrade contributed to the higher spending. The year 2014 was peak historical spending for System Service expenditures.

2015

In 2015 the actual System Service expenditures were 16.5% higher than planned. This is mainly due to cost overages on a voltage conversion project in Whitby due to unforeseen complexities with the rear-lot construction.

2016

There were no significant variances in the System Service program in 2016.

2017

In 2017 the actual System Service expenditures were 74.4% lower than planned. This is due to one project – a 44-kV feeder tie – which was started late in the year and only the new pole line was installed in 2017. The removals of the old line were deferred until 2018.

2018

The 2018 System Service spending was 82.5% below the planned budget, almost completely attributed to the legacy Whitby Hydro. Whitby Hydro's actual expenditures were below the planned budget by $2.37 million. This difference primarily results from two projects – one Feeder Expansion and one Substation Expansion. These projects pertain to an expansion for a 44-kV feeder from MS16 between Dundas and Rossland and a substation expansion at MS16 to accommodate load and customer growth in the area. As the system and customer needs changed, the program was reclassified under the System Access program to align with other Expansions.

2019

In 2019 the actual System Service expenditures were 122.4% higher than planned. This is due to the increase and completion of System Reliability improvement projects such as the implementation of S&C Smart Intellirupter Switches, Trip Savers, and Smart/Standard FCIs.

2020

In 2020 the expenditures were 50.2% over budget. This is mostly due to increases in Substation Growth and Expansion and Standards Equipment Reliability and Compliance.

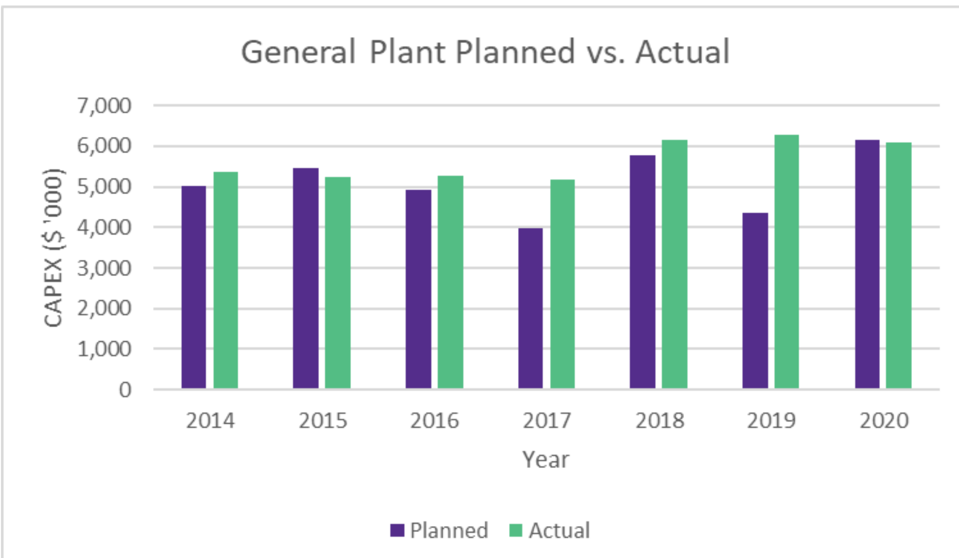
General Plant

Table 5.4-15 below presents the planned and actual capital expenditures in the General Plant investment category for Elexicon and its predecessor utilities. Expenditures in this category are relatively consistent year-over-year. The year 2017 had the most significant negative variance.

Table 5.4-15: Variance Analysis Summary for General Plant Expenditures

Year	Whitby Hydro		Veridian		Combined / Elexicon Energy			
	$ ('000)		$ ('000)		$ ('000)			%
	Planned	Actual	Planned	Actual	Planned	Actual	Difference	Variance
2014	1,996	1,588	3,024	3,784	5,020	5,372	352	7.0%
2015	950	721	4,515	4,522	5,466	5,243	-223	-4.1%
2016	1,254	720	3,676	4,539	4,930	5,259	329	6.7%
2017	1,030	528	2,943	4,661	3,973	5,189	1,216	30.6%
2018	3,124	1,309	2,650	4,857	5,774	6,166	392	6.8%
2019					4,360	6,293	1,932	44.3%
2020					6,164	6,077	-87	-1.4%
Total					**35,686**	**39,598**	**3,912**	**11.0%**

Figure 5.4-8: Elexicon Variance Analysis Summary for General Plant



<u>2014</u>

In 2014, Elexicon's actual expenditures were 7.0% higher than that of planned expenditures. This is primarily due to Veridian's spending about $0.76M more than planned for actual General Plant expenditures. The quantity and range of investments into Information Technology contributed to this higher variance which included GIS Records Management/Enhancements, Billing Improvements, Mobile Computing and Data server and Disk Space additions.

<u>2015</u>

In 2015, actual General Plant expenditures were 4.1% less than planned. Key contributors include deferred investments into communication platform upgrades, deferred Great Plains (financial tracking system) upgrades, and less spending on office/computer equipment.

2016

In 2016, actual General Plant expenditures were 6.7% more than planned. Legacy Whitby Hydro expenditures were much lower than planned and legacy Veridian Connections expenditures were slightly higher than planned. The negative variance is mainly attributed to less spending on computer/office equipment and a deferred Combine Heat and Power pilot project with the Town of Whitby.

2017

In 2017, actual General Plant expenditures were 30.6% more than planned. Key contributors include less spending on metering (Whitby Hydro previously categorized metering under the General Plant category), less spending on office/computer equipment, and deferred investments into land purchases.

2018

In 2018, actual General Plant expenditures were 6.8% more than planned. Whitby Hydro spending was significantly below budget and Veridian Connections spending was significantly above budget. On the Veridian side, there were several unbudgeted projects for Belleville SCADA equipment relocation, purchases of new large fleet vehicles, and wholesale meter point modems. Whitby Hydro made significantly less investments into office/computer equipment, SCADA communication systems, tools and equipment, and fleet in anticipation of the prospective merger. Whitby Hydro also deferred a planned land purchase.

2019

In 2019, actual General Plant expenditures were 44.3% more than planned. Key contributors include additional spending on an IT data capture project for corporate services (fleet, facilities, etc.), unbudgeted replacement of a plotter/scanner, and additional spending on major tools.

2020

In 2020 expenditures were 1.4% lower than budgeted. Key contributors include decreased spending on Information Technology, Fleet and Facilities projects.

5.4.3 JUSTIFYING CAPITAL EXPENDITURES

5.4.3.1 Overall Plan

5.4.3.1.1 Comparative Expenditures over the Historical Period

After the merger of Veridian Connections and Whitby Hydro in 2019, Elexicon reclassified several projects into new programs which impacted the spending allocation across the four investment categories. Therefore, two datasets are presented in this section. The first dataset compares Elexicon's forecast capital expenditures to the historical capital expenditures according to the original allocation. This budget sees notable differences between the historical and forecast expenditures which can be attributed to the reallocation of projects into new programs. The second dataset compares the forecasted capital expenditures to the historical capital expenditures adjusted to the current project/program allocation. This dataset better reflects the evolution of Elexicon's capital expenditures whereas the first demonstrates alignment with the forecasted budget outlined in previous DSPs. Figure 5.4-9 below compares the original and adjusted allocations for expenditures across the four investment categories – this information is also captured in Table 5.4-16. The reallocated expenditures match that of App.2-AA where the breakdown of actual CAPEX has been reassigned to the program breakdown as defined by Elexicon. Note that the 2021 numbers are planned expenditures and actuals have not been recorded as of this time.

Figure 5.4-9: Comparison of Original Historical and Reallocated Historical Budget

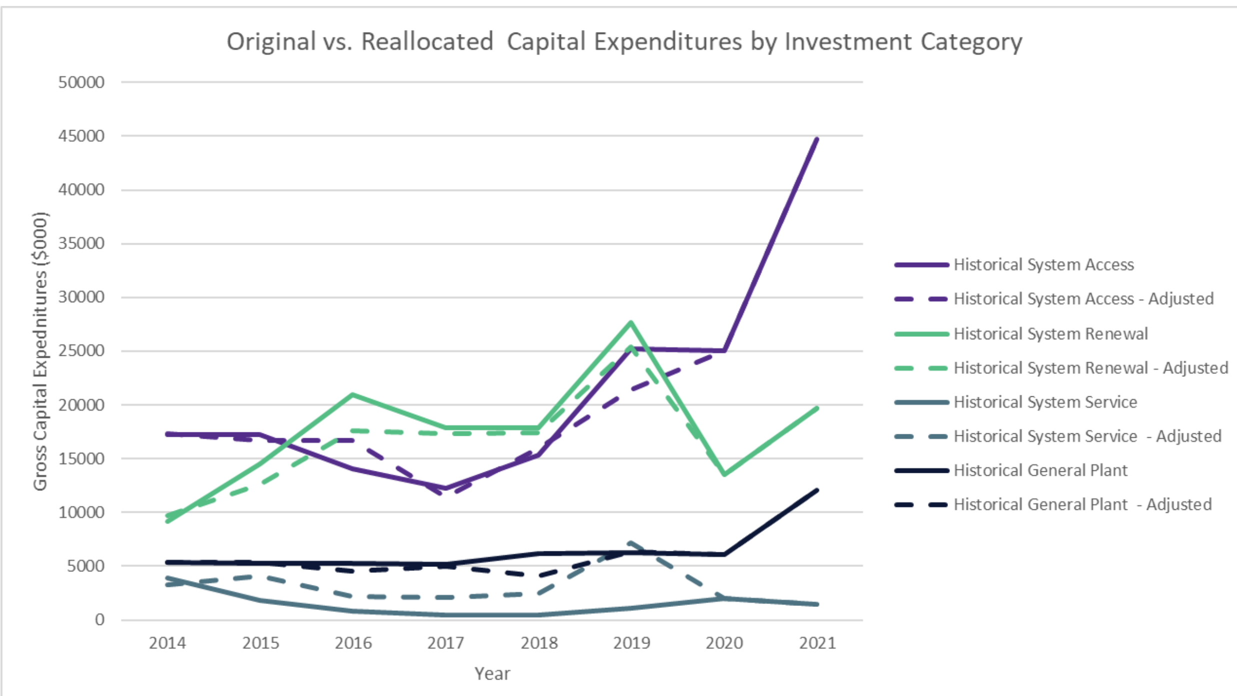


Table 5.4-16: Comparison of Original Historical and Reallocated Historical Budgets

	Investment Category	2014	2015	2016	2017	2018	2019	2020	2021
Original Allocation	System Access	17,199	17,206	14,032	12,289	15,355	25,214	25,041	44,681
	System Renewal	9,206	14,560	20,917	17,840	17,878	27,660	13,555	19,667
	System Service	3,911	1,803	858	483	497	1,126	1,983	1,418
	General Plant	5,372	5,243	5,259	5,189	6,166	6,310	6,077	12,065
	Total	35,688	38,812	41,066	35,801	39,896	60,293	46,566	77,803
Adjusted Allocation	System Access	17,332	16,724	16,721	11,392	15,966	21,433	25,041	44,681
	System Renewal	9,702	12,623	17,568	17,365	17,427	25,043	13,555	19,667
	System Service	3,265	4,131	2,219	2,076	2,425	7,147	1,983	1,418
	General Plant	5,389	5,335	4,559	4,968	4,077	6,310	6,077	12,065
	Total	35,688	38,812	41,067	35,801	39,896	60,293	46,566	77,803

System Access

Figure 5.4-10 below shows Elexicon's capital expenditures over the historical and forecast periods. It includes the reallocated budget as well as the original budget for comparison. However, the former is the focus of this section as it provides a more accurate depiction of the evolution of Elexicon's capital expenditures. Table 5.4-17 shows the historical and forecast program level expenditures for this investment category.

Figure 5.4-10: Historical and Forecast System Access Expenditures

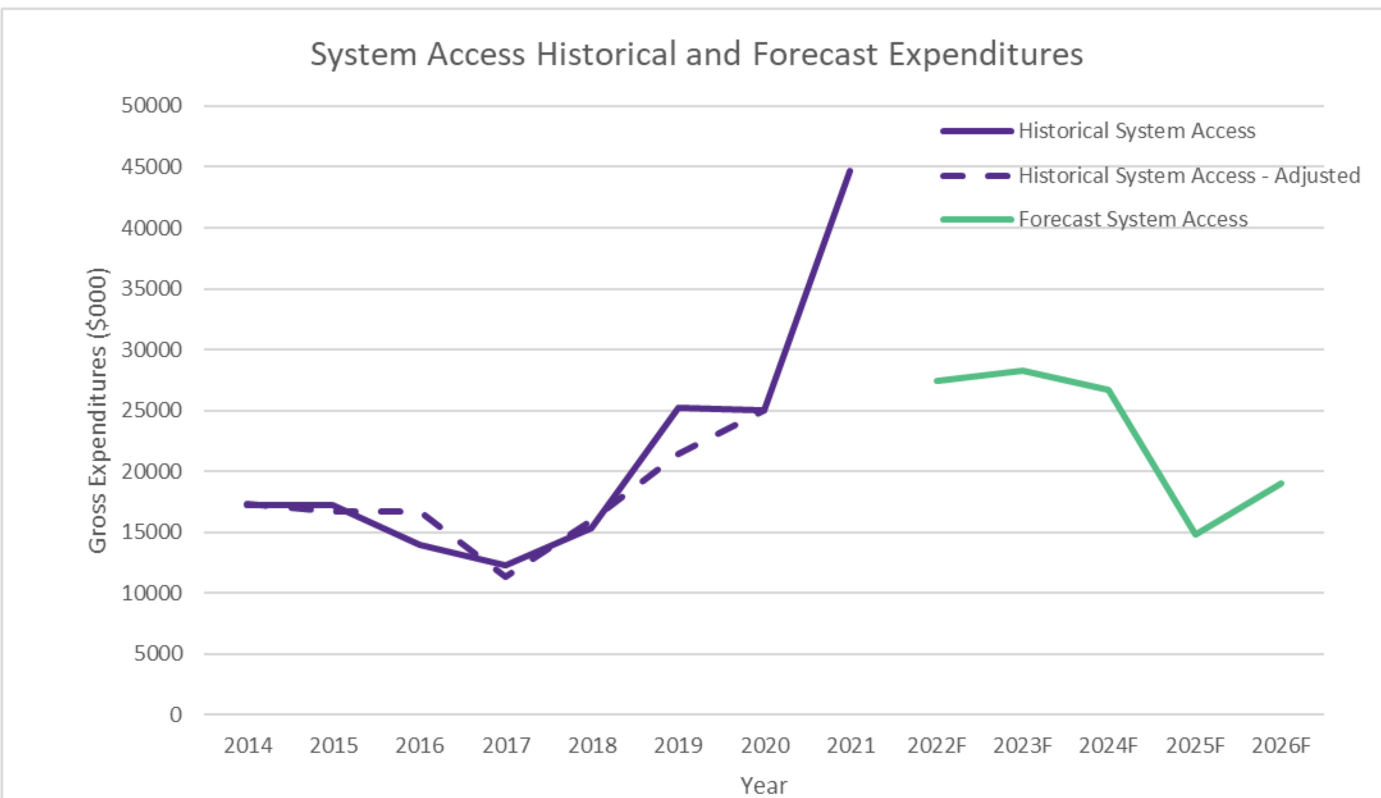


Table 5.4-17: Comparison of Historical (Reallocated) and Forecast System Access Gross Expenditures ($000)

Program	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Road Relocations	5,813	11,872	5,861	2,901	4,803	3,642	4,752	23,053	5,543	1,800	2,800	2,000	6,200
Region of Durham BRT Road Relocation	-	-	-	-	-	-	-	-	5,299	-	-	-	-
Feeder Expansions	2,644	288	2,396	485	695	534	2,683	8,845	2,320	13,734	11,020	-	-
Connection of New Services	6,020	3,749	6,882	6,668	8,850	15,773	14,949	8,943	12,878	11,333	11,449	11,449	11,449
Customer Requested Work	20	87	380	280	649	510	1,419	2,001	101	101	101	101	101
Metering	2,834	727	1,202	1,058	969	974	1,238	1,839	1,331	1,303	1,303	1,303	1,303
Total	17,332	16,724	16,721	11,392	15,966	21,433	25,041	44,681	27,472	28,271	26,673	14,853	19,053

The historical average for this investment category is $17.8 million and there is minimal variability over the historical period. Historical expenditures for all years except for 2017, 2019 and 2020 deviate marginally from the historical average. There was a decrease in expenditures in 2017 which resulted from a low volume of Road Relocations projects. In 2019 and 2020, there was an increase in expenditures due to an increase in the volume of Connection of New Services projects. This increase was driven by several new real-estate developments in the Ajax, Pickering, and Whitby areas.

The forecasted planned expenditures of $44.7 million for 2021 contribute to an increase in the forecasted average investment across 2021 to 2026. As shown in Table 5.4-17 above, this increase occurs in the Road Relocations and Feeder Expansions programs. An outcome of the Regional Planning Process for the GTA East planning region was the construction of a new transmission station, Seaton TS, to resolve capacity issues at Whitby TS which would arise due to the development of the new Seaton subdivision. The construction of the new Seaton TS involves changes to the current feeder configuration which are completed through projects in the Feeder Expansions program. Elexicon also has a high volume of Road Relocations planned projects in 2021 due to several Metrolinx and municipal projects planned during these years.

Without the outlier year 2021, the average forecast expenditure is still higher than the historical average of $17.8 million at $23.3 million. The increase between the average historical and forecast expenditures is driven by several new real-estate developments in high-growth areas such as Ajax, Pickering, and Whitby. There is minimal variability in forecast expenditures if the outlier year 2021 is excluded. All other forecast years except 2024 and 2025 deviate marginally from the average expenditure. In 2024, there is an expected increase in expenditures as there is a planned effort to complete several Feeder Expansions projects. This effort is expected to result in a decrease in expenditures in the following year, 2025, as Feeder Expansion requirements are likely to decrease.

The forecast expenditure amount for 2022 is approximately $27.5 million and this figure includes one ICM funded project. The Region of Durham BRT Road Relocation accounts for the entire $5.3 million ICM budget.

System Renewal

Figure 5.4-11 below shows Elexicon's capital expenditures over the historical and forecast periods. It includes the reallocated budget as well as the original budget for comparison. However, the former is the focus of this section as it provides a more accurate depiction of the evolution of Elexicon's capital expenditures. Table 5.4-18 shows the historical and forecast program level expenditures for this investment category.

Figure 5.4-11: Historical and Forecast System Renewal Expenditures

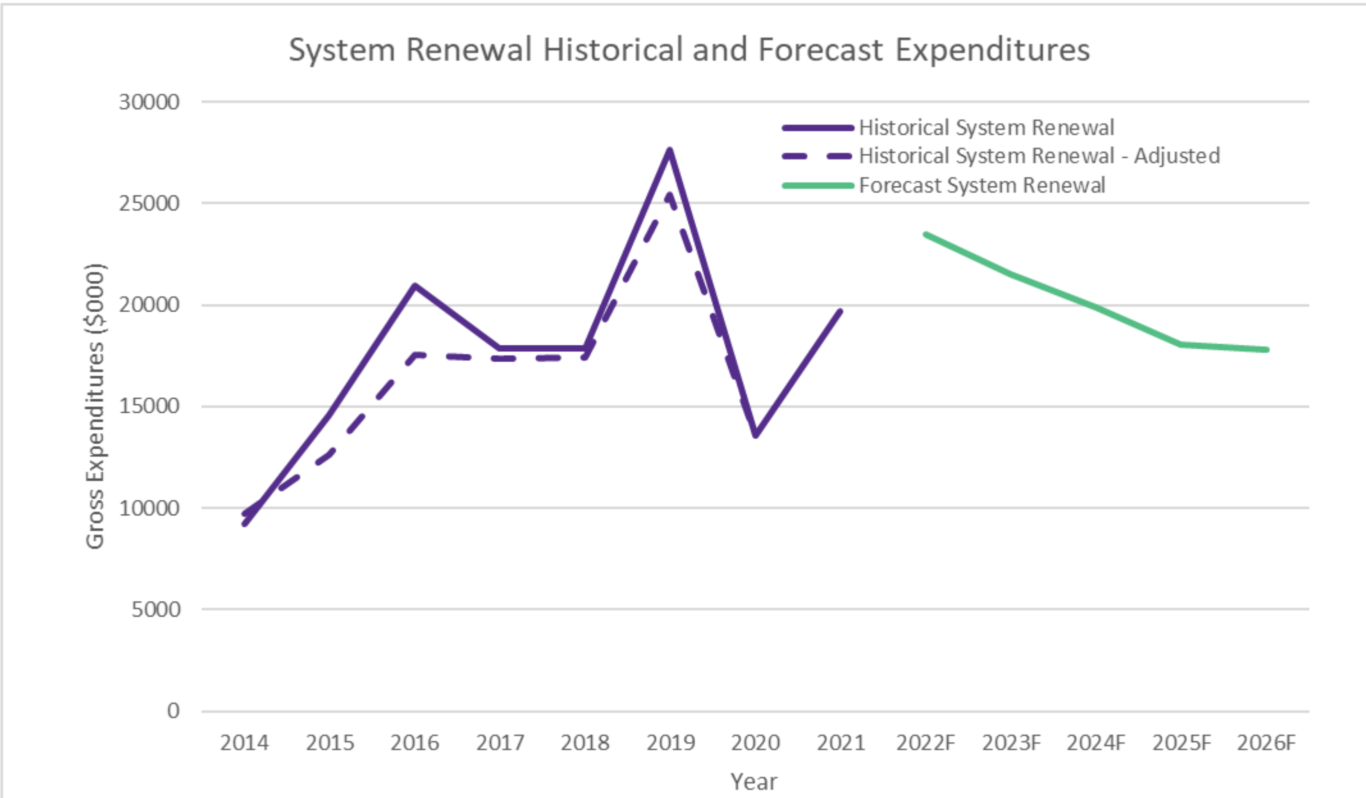


Table 5.4-18: Comparison of Historical (Reallocated) and Forecast System Renewal Gross Expenditures ($000)

Program	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Substation Renewal	1,009	2,179	3,748	3,902	3,441	7,518	2,970	7,079	9,404	2,644	860	3,460	810
Voltage Conversions - Reliability	394	788	-	8	-	426	685	531	900	2,329	3,318	2,781	4,300
Renewal Programs - Poles	937	1,290	2,028	1,945	1,907	6,484	1,565	1,200	2,400	2,200	2,096	2,390	4,640
Renewal Programs - Distribution Transformers	476	448	532	1,016	2,059	849	475	1,078	1,302	1,870	1,741	1,741	1,741
Renewal Programs - Switches/Switchgears	1,339	1,840	1,556	1,740	1,651	1,924	1,796	1,317	1,525	1,595	2,125	2,125	2,125
Renewal Programs - Others	0	40	744	596	670	447	1,133	951	771	741	991	991	991
Renewal Programs - Rebuilds	2,731	3,279	5,416	5,551	5,282	5,475	2,598	5,645	5,296	8,297	6,928	2,729	1,329
Renewal Programs - Reactive	2,817	2,759	3,544	2,606	2,417	2,281	2,333	1,865	1,842	1,813	1,820	1,820	1,820
Total	9,702	12,623	17,568	17,365	17,427	25,043	13,555	19,667	23,441	21,490	19,878	18,037	17,756

The average historical expenditure for System Renewal investments is $16.2 million. Investments in this category are intended to improve the health of distribution system assets. Given that there are several asset classes which vary in their typical useful lives and current condition, Elexicon's level of investment varies year over year. Expenditures in 2015, 2019 and 2020 deviated notably from the average historical expenditure. Historical expenditures were at a minimum in 2015 at $12.6 million as the majority of distribution system assets were in good condition. In 2016, expenditures increased to average levels at $17.6 million due to increases in spending in the Substation Renewal, Poles Renewal, Reactive Renewal, and Rebuilds programs. The legacy utilities maintained this level of expenditure in the following year, 2017, as the total expenditures amounted to $17.4 million and the allocation of expenditures across programs remained consistent. This level of expenditure continues in 2018 at $17.4 million, but the allocation of expenditures across programs shifted. There was a notable increase in the Distribution Transformers Renewal program and decreases in the Substation Renewal, Poles Renewal, Reactive Renewal, and Rebuilds programs. A sharp increase in expenditures in 2019 at $26.1 million influences the average historical expenditure. In comparison, the average expenditure for all years prior to 2019 is $16.2 million. This increased spending resulted from additional efforts in the Substation Renewal and Poles Renewal programs. Expenditure dropped in 2020 to $13.3 million due to the high level of expenditure in 2019. Planned expenditures increase to $19.6 million in 2021 due to increases in expenditures for all programs except Voltage Conversions – Reliability, Others Renewal, and Reactive Renewal.

Elexicon's planned expenditures are expected to be higher than the historical average as the forecast average is $20.04 million. There is significant variability in forecast expenditures due to anticipated renewal requirements. As shown in Table 5.4-18, the most notable planned increase occurs in the Substation Renewal program. Total expenditures are expected to increase in 2022 to $23.4 million due to additional spending in several renewal programs including Substation Renewal, Voltage

Conversions – Reliability, Switches/Switchgears Renewal, and Poles Renewal. In addition, ICM expenditures amount to $0.8 million in 2022 – the ICM funded project is intended to complete switchgear replacements as part of the BRT expansion. Expenditures are expected to decrease to $21.5 million in 2023, primarily due to decreases in Substation Renewal and Poles Renewal spending. There is a planned decrease in 2024 to $19.9 million which is driven by reduced expenditures in the Substation Renewal and Rebuilds programs. The utility forecasts a decrease in expenditures to $18.0 million in 2025 due to the Voltage Conversions – Reliability and Rebuild programs. In the final year of the forecast period, 2026, expenditures are expected to decrease to $17.8 million due to reduced expenditures in the Substation Renewal and Rebuilds programs.

System Service

Figure 5.4-12 below shows Elexicon's capital expenditures over the historical and forecast periods. It includes the reallocated budget as well as the original budget for comparison. However, the former is the focus of this section as it provides a more accurate depiction of the evolution of Elexicon's capital expenditures. Table 5.4-19 shows the historical and forecast program level expenditures for this investment category.

Figure 5.4-12: Historical and Forecast System Service Expenditures

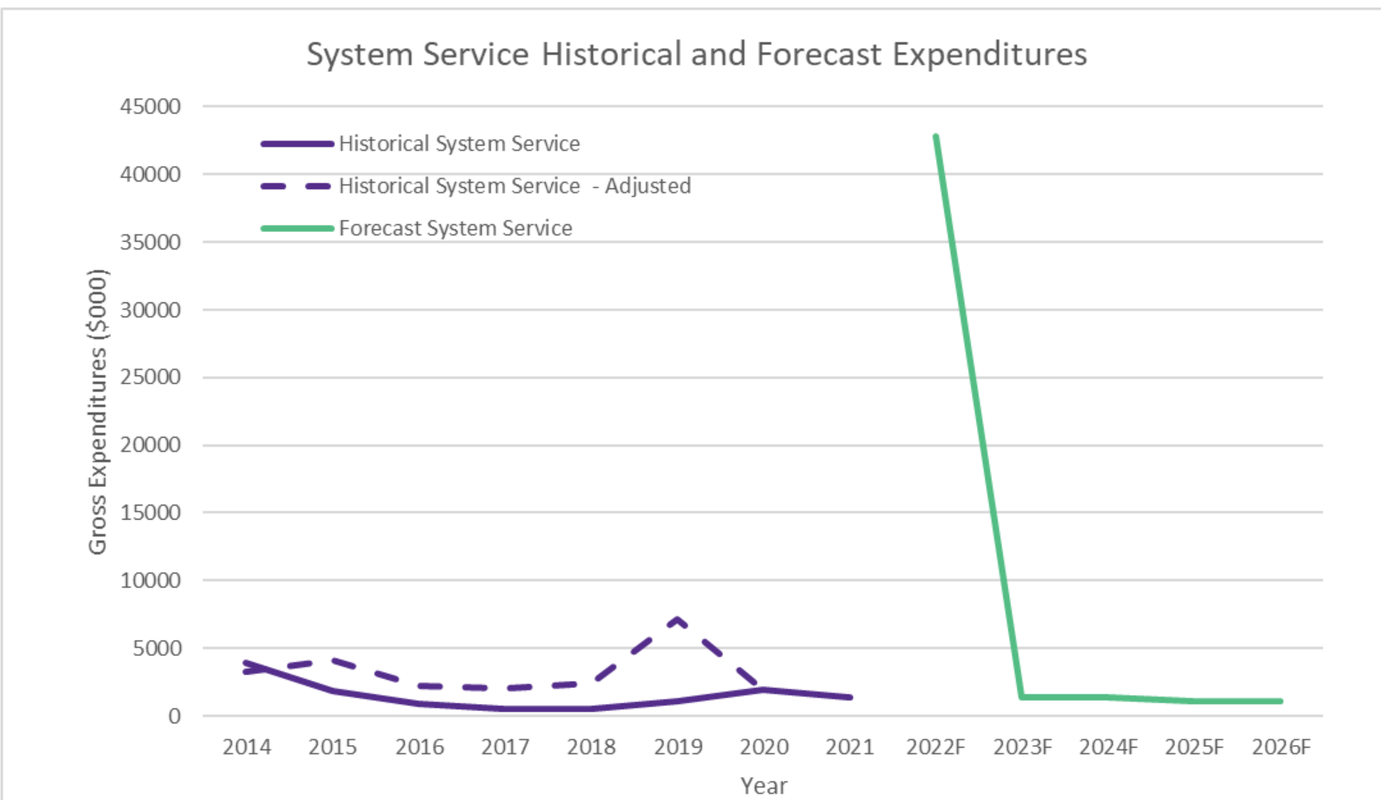


Table 5.4-19: Comparison of Historical (Reallocated) and Forecast System Service Gross Expenditures ($000)

Program	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Substations Growth and Expansion	4	9	-	4	122	5,646	641	-	40,762	-	-	-	-
Feeder Enhancement	0	2,245	71	561	-3	57	-	-	-	-	-	-	-
Standards Equipment Reliability and Compliance	261	360	368	275	271	275	327	300	300	300	300	300	300
Substation Upgrades	2041	562	486	580	800	157	-	-	-	-	-	-	-
System Reliability Improvements	959	954	1,295	656	1,234	1,011	1,015	1,118	1,743	1,048	1,053	753	753
Total	3,265	4,131	2,219	2,076	2,425	7,147	1,983	1,418	42,805	1,348	1,353	1,053	1,053

The average historical expenditure for this investment category is $3.32 million and there is minimal variability year over year. It is important to consider that there is a sharp increase in spending in 2019 at $7.1 million which influences this figure. All other historical expenditures are marginally above or below the historical average. Expenditures were slightly higher than average in 2015 at $4.1 million – this was driven by high levels of spending in the Feeder Enhancement program – specifically due to enhancement efforts along Liverpool Road, James Street, and Taunton Road. Expenditures were consistently between $2.0 million and $2.5 million from 2016 to 2018. However, as outlined above, there was a notable increase in expenditures to $7.1 million in 2019. This increase resulted from the Substations Growth and Expansion program – specifically due to the legacy Whitby Hydro MS16 substation rebuild project. If the outlier year 2019 is excluded, the average historical expenditure amounts to $2.69 million.

The average forecast expenditure for this investment category is significantly higher than the historical average at $8.17 million. However, this occurs due to a sharp increase in planned expenditures in 2022 at $42.8 million. If this outlier year is excluded, the average forecast expenditure amounts to $1.3 million, which is significantly less than the average historical expenditure. In addition, there is minimal variability in forecast expenditures with the exception of the outlier year 2022. The sharp increase in spending in 2022 results from the Substations Growth and Expansion program. There are five projects within this program which account for this increase. The utility intends to seek ICM funding for these projects which are all related to the construction of Seaton TS.

General Plant

Figure 5.4-13 below shows Elexicon's capital expenditures over the historical and forecast periods. It includes the reallocated budget as well as the original budget for comparison. However, the former is the focus of this section as it provides a more accurate depiction of the evolution of Elexicon's capital expenditures. Table 5.4-20 shows the historical and forecast program level expenditures for this investment category.

Figure 5.4-13: Historical and Forecast General Plant Expenditures

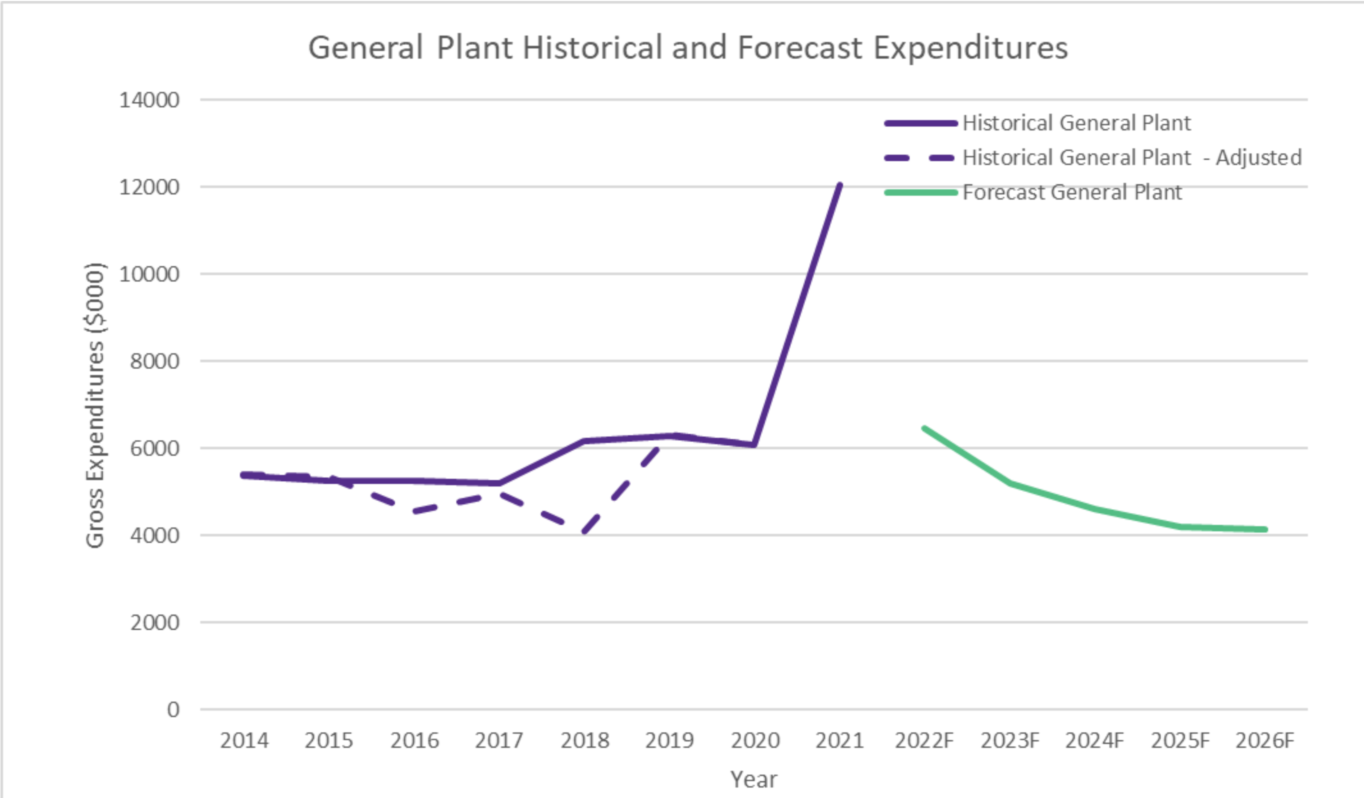


Table 5.4-20: Comparison of Historical (Reallocated) and Forecast General Plant Gross Expenditures ($000)

Program	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Facilities	1,159	719	1,053	352	923	1,116	786	3,580	740	600	240	240	240
Fleet	722	1,298	549	1,768	715	2,098	800	1,860	1,410	1,410	1,410	1,410	810
Information Technology	2,998	2,726	2,640	2,626	1,569	1,947	4,307	6,464	4,162	3,038	2,819	2,419	2,949
Intangible Assets	365	260	-	-	-	654	23	-	-	-	-	-	-
Tools and Equipment	145	333	317	222	871	495	163	160	147	135	135	135	135
Total	5,389	5,335	4,559	4,968	4,077	6,310	6,078	12,064	6,460	5,183	4,604	4,204	4,134

The average historical expenditure for this investment category amounts to $5.3 million. There is minimal variability as the expenditures for the majority of the historical period do not deviate significantly from the average. The most significant deviation occurs in 2018 where expenditures were at a minimum of $4.08 million and in 2021 where expenditures were at a maximum of $12.1 million. The relatively low level of expenditures in 2018 occurred due to a lack of fleet renewal investments. The historical high in 2019 occurred as a result of increased investment in Information Technology. Elexicon expects high levels of spending early in the forecast period as the planned expenditure is $12.1 million in 2021. In 2021, the high level of planned expenditures results from a continuation of the effort to upgrade and merger software/hardware systems. In addition, the Facilities program also contributes to the historical high expenditures in 2021 as Elexicon plans to complete the Belleville Office Relocation during this year.

The average forecast expenditure is consistent with the average historical expenditure as it is higher at 6.11 million. Expenditures are forecasted to decrease from 2022 onwards as the merger-related software consolidation effort and the Belleville Office Relocation are expected to be completed.

5.4.3.1.2 Forecast Impact of Capital Expenditures on System O&M Costs

The impact of capital projects on system O&M costs varies depending on the purpose of the project. The System Access investment category consists of the following programs: Connection of New Services, Road Relocations, Feeder Expansions, Customer Requested Work, and Metering. Customer Requested Work is the only program which is not expected to impact system O&M costs. In comparison, the utility forecasts that the Connection of New Services and Feeder Expansions programs may increase O&M costs and the Road Relocations and Metering programs may reduce O&M costs. The Connection of New Services and Feeder Expansions programs could result in increased system O&M costs as they involve the installation of new distribution infrastructure. This additional infrastructure would be subject to ongoing O&M activities such as maintenance, testing, and repairs. The impact of these investments would impact the utility's O&M costs after the new distribution assets begin to operate.

The Road Relocations program is expected to result in a potential decrease in system O&M costs. It is intended to relocate the existing distribution infrastructure and typically does not entail the installation of additional assets. As the condition of assets improves, the risk of asset failure decreases and maintenance requirements become less stringent, resulting in reduced system O&M costs. The O&M cost savings associated with the Road Relocations program are expected to be realized upon completion of asset replacements.

The Metering program is intended to provide funding for the replacement and upgrade of metering units located at customer sites and is expected to decrease system O&M costs. This program includes projects which involve the installation of smart meters with additional functionality such as automated usage reporting, remote disconnect, and tamper/theft detection. These additional capabilities would eliminate the need for labour required to manually complete these tasks and result in decreased O&M expenditures through improvements in operational efficiency. New meters can also reduce O&M costs as they typically have longer service lives which entail decreased testing requirements. The benefits afforded by the Metering program would be realized immediately upon installation of new smart meters.

The System Renewal investment category consists of several programs which target replacements and/or refurbishments for several asset classes. The impact on system O&M costs depends on the nature of the project (replacement vs. refurbishment) and the asset class targeted. These impacts are summarized in Table 5.4-21 below. Typically, System Renewal programs are expected to decrease system O&M costs as they improve the condition of distribution system assets and reduce maintenance, testing, and repairs requirements.

Table 5.4-21: Summary of the Impact of System Renewal Investments on System O&M

Asset Class	Impact	Timing	Details
Wood Poles	Decrease	Immediately – new wood poles are not tested for 10 years.	Wood poles are subject to ongoing inspection and testing costs. New poles require the same inspection frequency but testing is deferred for 10 years, saving O&M costs compared to the old asset that was replaced.
Concrete Poles	Increase	After 10 years	Concrete poles are subject to ongoing inspection costs only as Elexicon plans to remove them from the system and replace them with Wood Poles. This strategy would result in an increase in system O&M costs as Wood Poles have additional testing requirements.
Underground Cable	None	N/A	The replacement of underground cables is not expected to impact system O&M costs. Underground cable segments are tested to determine if they are suitable candidates for cable injection/splicing, but these testing and refurbishment efforts are completed through capital projects.
Overhead Conductor	Decrease	Immediately	These overhead lines assets are subject to similar system O&M costs as they are visually inspected and tested together. Elexicon has an IR scanning program in place for these overhead asset classes which allows the utility to identify issues and perform repairs (e.g., repairing of loose connections and addressing overheating). Deteriorated assets carry a higher risk of these issues and asset replacement reduces the likelihood of their occurrence – as a result, the associated replacement programs are expected to result in a reduction in ongoing repair costs.
Pad-Mounted Transformer	Decrease	Immediately	Pad-mounted transformers are subject to ongoing costs such as visual inspections, repairs, and refurbishment (typically via repainting). The replacement of pad mounted transformers would result in decreased system O&M costs as repair and refurbishment requirements decrease.
Vault Transformer	None	N/A	Vault transformers are subject to ongoing visual inspection costs only. Asset replacement would not impact system O&M costs as Elexicon regularly visually inspects all units.
Pad Mounted Distribution Switchgear	Decrease	Immediately	Pad mounted distribution switchgears are subject to system O&M costs such as visual inspections, IR scanning, and repairs. Asset replacement would not affect costs associated with visual inspections or IR scanning as these are routine. However, asset replacement improves asset condition and would reduce O&M costs as the likelihood of issues requiring repair decreases.
Station Transformers	Decrease	Immediately	Stations assets are subject to system O&M costs such as visual inspections, predictive maintenance testing (e.g., oil sampling, electrical testing), and repairs. Asset replacement would not impact system O&M costs associated with visual inspections or predictive maintenance as these are routine activities. However, there is an expected decrease in repair costs as issues are less likely to occur with new units.
Station Fences	Decrease	Immediately	Station fences are subject to ongoing costs such as visual inspections and repairs. Elexicon only completes replacements for station fences if a large section of fence is found to be in poor condition. These replacements have no impact on visual inspection costs, but they would be expected to result in reduced repair costs.

The System Service investment category consists of the following programs: Substations Growth and Expansion, Feeder Enhancement, SERC, Substation Upgrades, and System Reliability Improvements. These programs vary in the impact they have on system O&M costs. The Substations Growth and Expansion, Feeder Enhancement, and Substation Upgrades projects would be expected to increase O&M costs whereas the SERC and System Reliability Improvements programs would decrease O&M costs.

Substations Growth and Expansion, Feeder Enhancement, and Substation Upgrades projects involve upgrades to current system assets or the installation of additional distribution infrastructure. Asset upgrades typically do not impact system O&M costs, but the addition of distribution system assets would be expected to result in an immediate increase in ongoing costs. All distribution assets must be visually inspected and maintained on a regular basis. The addition of new distribution assets (not replacements) increases the total number of assets managed my Elexicon, which translates to an increase in the volume of regular maintenance activities (such as inspections) the utility must complete and system O&M costs. For example, Seaton TS will require ongoing maintenance once. While this fact applies to all three programs, it is important to consider that the utility has virtually no planned expenditures in the Feeder Enhancement or Substation Upgrades programs.

The SERC program only includes projects for the development of safety and/or work execution standards, which would not directly impact O&M costs, but may result in long-term decreases due to improved operational efficiency. The System Reliability Improvements program includes projects which are intended to reduce the likelihood of service interruptions. This would result in a decrease in O&M costs as reactive repairs for service restoration would become less likely. Elexicon expects that the cost benefits associated with this program would be realized over time after the implementation of improved practices.

The General Plant investment category consists of the following programs: Facilities, Fleet, Information Technology, Intangible Assets, and Tools and Equipment. These programs vary in the impact that they have on System O&M costs. The utility expects that the Facilities and Information Technology programs would increase O&M costs, the Fleet and Tools and Equipment programs would decrease O&M costs, and the Intangible Assets program would have no impact on O&M costs.

The Facilities program is intended to provide funding for the procurement of new offices, buildings, and other assets such as furniture. The projects within this program would result in an immediate increase in system O&M expenditures as they entail the procurement of new assets which must regularly inspected and maintained. Similarly, the Information Technology program involves the procurement of software applications/systems, upgrades, and other technological additions. These procurements and upgrades are budgeted through capital projects, but ongoing costs such as licensing would contribute to an increase in O&M costs upon deployment of new asset.

The Fleet program involves the procurement of new vehicles to replace aging assets and would be expected to decrease O&M costs. Deteriorated vehicle assets are subject to high maintenance and repair costs which can be reduced through asset replacement. The Tools and Equipment program involves projects for the procurement of new tools and equipment required to complete work. Testing is completed regularly for all tools and equipment and therefore the procurement of new tools would not directly reduce ongoing O&M costs. However, there is an expected decrease in O&M costs due to the fact that new tools with additional capabilities can improve operational efficiency and reduce the effort required to complete work.

5.4.3.1.3 Historical Trends and Expected Evolution of Drivers

Table 5.4-22 below shows the drivers within each investment category as well as performance measures that could track the benefits of capital expenditures. In addition to the performance measures listed in the table below, there are several performance measures which apply to all investment categories such as DSP Implementation Progress, Total Cost/Customer, Total Cost/Km of Line, and Customer Satisfaction Survey Results.

Table 5.4-22: Overview of Drivers and Performance Measures

<table>
<tr><th>Category</th><th>Driver</th><th>Performance Measures</th></tr>
<tr><td rowspan="3">System Access</td><td>Customer Service Requests</td><td rowspan="3">Service Quality Requirements</td></tr>
<tr><td>Third Party Infrastructure Development</td></tr>
<tr><td>Mandated Service Obligations</td></tr>
<tr><td rowspan="7">System Renewal</td><td rowspan="7">Assets at the End of their Service Life; Asset Failure</td><td>Volume of Cause Code 5 - Defective Equipment Outage</td></tr>
<tr><td>% of Assets in Poor/Very Poor Condition</td></tr>
<tr><td>Reliability Measures - SAIDI/SAIFI/MAIFI</td></tr>
<tr><td>MAIFI</td></tr>
<tr><td>Number of Voltage Issues at Customer Meter</td></tr>
<tr><td>Serious Electrical Incident Index</td></tr>
<tr><td>Level of Compliance with ON Reg 22/04</td></tr>
<tr><td rowspan="5">System Service</td><td>System Capacity</td><td>SAIDI/SAIFI</td></tr>
<tr><td rowspan="3">System Operational Objectives: Reliability</td><td>SAIDI</td></tr>
<tr><td>SAIFI</td></tr>
<tr><td>MAIFI</td></tr>
<tr><td>System Operational Objectives: Environmental Performance</td><td>None</td></tr>
<tr><td rowspan="3">General Plant</td><td>Non-system Physical Plant</td><td rowspan="3">Service Quality Requirements</td></tr>
<tr><td>Capital/Maintenance Support</td></tr>
<tr><td>Business Operations Efficiency</td></tr>
</table>

System Access

Figure 5.4-14: Historical and Forecast System Access Expenditures by DriverFigure 5.4-14 and Table 5.4-23 below present the historical and forecast System Access expenditures by driver. Additional details about the allocation of spending across drivers in this category can be found below.

Figure 5.4-14: Historical and Forecast System Access Expenditures by Driver

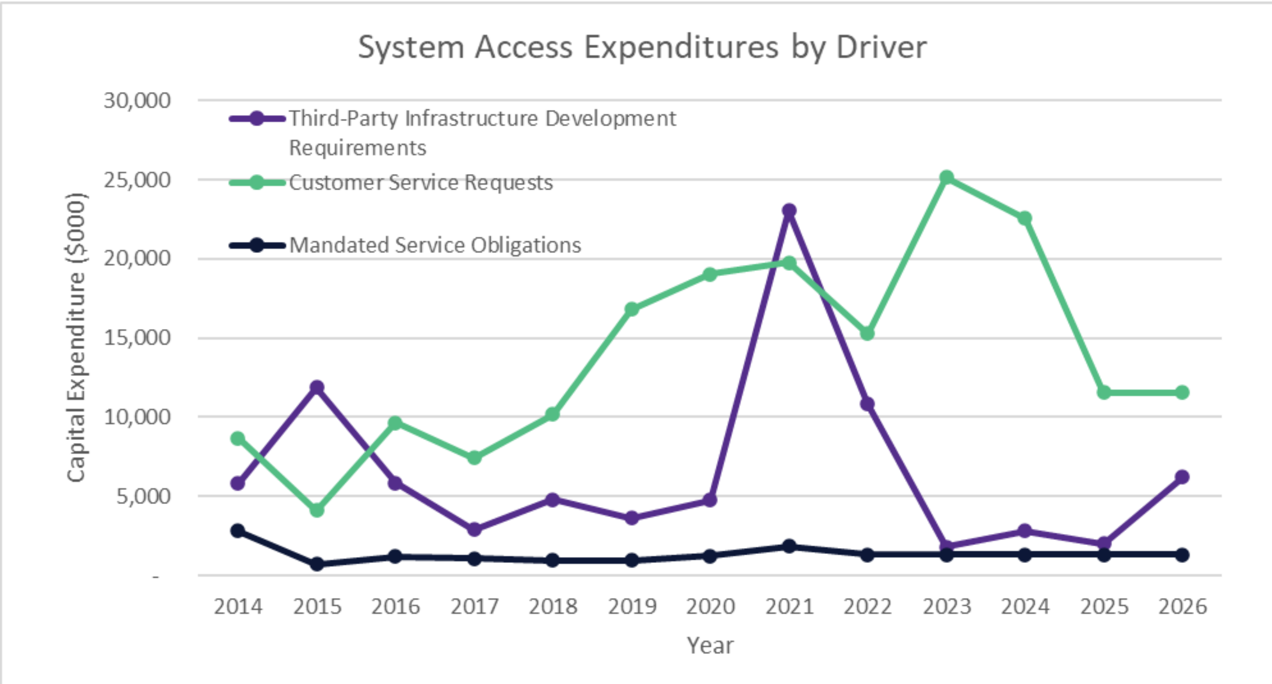


Table 5.4-23: Historical and Forecast Gross Expenditures for System Access Drivers ($000)

Driver	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Third-Party Infrastructure Development Requirements	5,813	11,872	5,861	2,901	4,803	3,642	4,752	23,053	10,842	1,800	2,800	2,000	6,200
Customer Service Requests	8,685	4,124	9,657	7,433	10,195	16,816	19,050	19,789	15,299	25,168	22,570	11,550	11,550
Mandated Service Obligations	2,834	727	1,202	1,058	969	974	1,238	1,839	1,331	1,303	1,303	1,303	1,303
Total	17,332	16,724	16,721	11,392	15,966	21,433	25,041	44,681	27,473	28,271	26,673	14,853	19,053

Third Party Infrastructure Development Requirements

This driver consists of only the Road Relocations programs, including the Region of Durham BRT Road Relocation program, for which the level of spending depends on the volume of external work requests. The average historical expenditure for this driver is $7.84 million. There is a notably high level of spending at the start of the historical period in 2015 as both predecessor utilities received a high volume of road relocation requests. This higher historical average is due in part to sharp increases in spending in 2021 at $23.0 million as part of various road relocation projects with municipal stakeholders and Metrolinx projects such as the BRT> Expenditures over the remainder of the historical period varied depending on the volume of external requests received by the legacy utilities. The average forecast expenditure is lower than the historical average as it amounts to $4.72 million. 2022 also expects higher than normal expenditures on Road Relocation projects that are related to the 2021 projects and new road relocations. Expenditures for the following four years are significantly lower as they average to $3.2 million. The utility expects a spending increase to $6.2 million at the end of the forecast period in 2026. This increase is driven by several road relocations projects in the Ajax service area.

Customer Service Requests

This driver consists of three programs related to customer work: Connection of New Services, Customer Requested Work, and Feeder Expansions. The average historical expenditure for this driver is $11.97 million and it displays an increasing trend over the historical period. This pattern can be attributed to growth within Elexicon's service territory as key areas such as Whitby, Pickering, and Ajax experienced consistent growth. There is a notably high level of expenditure in 2019 and 2020, at $16.8 million and $19.1 million respectively, which was driven by the Connection of New Services program. Specifically, there were several new real-estate developments in the Ajax, Pickering, and Whitby areas. The average forecast expenditure is $17.3 million, which is significantly higher than the historical average. However, this figure is heavily influenced by high levels of spending in 2023 at $25.2 million and in 2024 at $22.6 million. These increases are driven by a high volume of Feeder Expansion projects in the Ajax-Pickering service area. Forecast expenditures display and increasing trend until 2024 after which expenditures are expected to decrease to $11.6 million.

Mandated Service Obligations

This driver consists of only the Metering program. The average historical spending is $1.36 million, and expenditures display a high degree of consistency year over year except for 2014. In 2014, metering expenditures peaked at around $2.8 million. A significant amount of residential type meter investment was spent in comparison to the original estimate. Historical expenditures were at a minimum in 2015 at $0.725 million after which they increased to approximately $1.0 million for the remainder of the historical period. Forecast expenditures do not deviate significantly from historical expenditures as they average to $1.31 million.

System Renewal

Figure 5.4-15 and Table 5.4-24 show the historical and forecast expenditures for System Renewal drivers. Additional details about the allocation of spending across drivers in this category can be found below.

Figure 5.4-15: Historical and Forecast System Renewal Expenditures by Driver

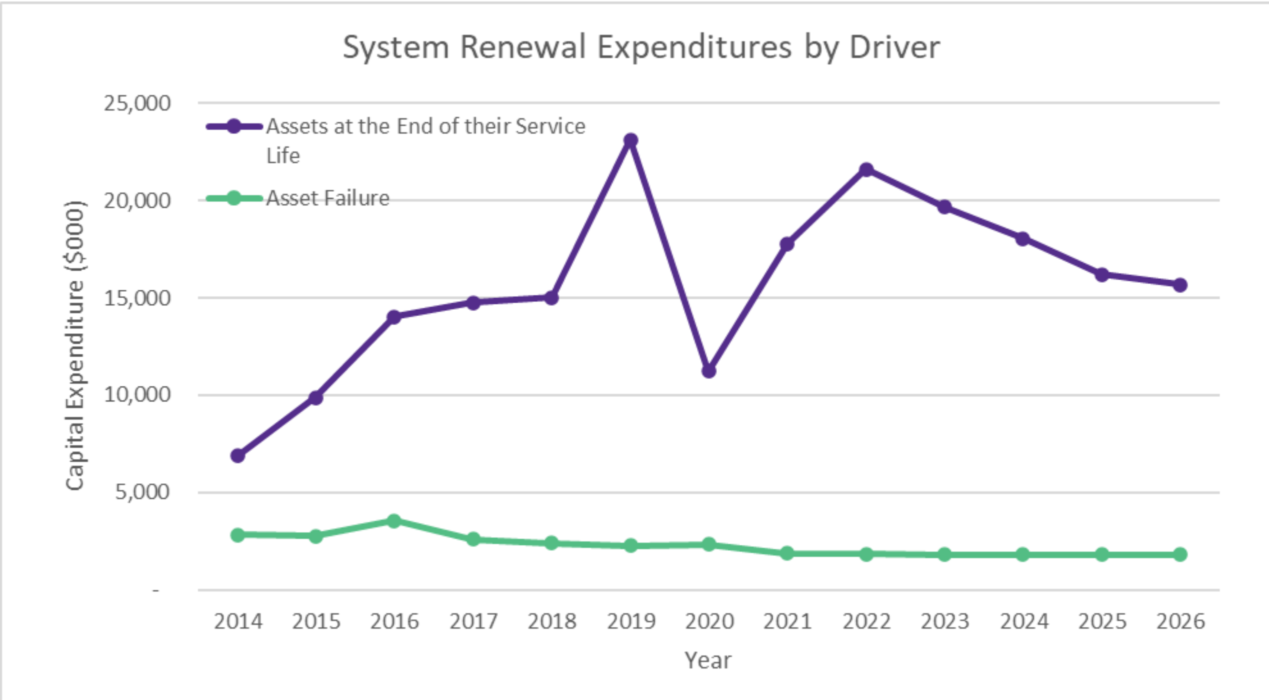


Table 5.4-24: Historical and Forecast Gross Expenditures for System Renewal Drivers ($000)

Driver	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Assets at the End of their Service Life	6,885	9,864	14,024	14,759	15,010	23,123	11,222	17,802	22,399	19,677	18,059	16,217	15,686
Asset Failure	2,817	2,759	3,544	2,606	2,417	2,281	2,333	1,865	1,842	1,813	1,820	1,820	1,820
Total	9,702	12,623	17,568	17,365	17,427	25,404	13,555	19,667	24,241	21,490	19,879	18,037	17,506

Assets at the End of their Service Life

This driver includes all renewal programs except for Reactive Renewal. Given the differences in condition and typical useful life for different asset classes, there is a high degree of variability in expenditures year over year. The average historical expenditure is $14.1 million and expenditures for all years except 2015 and 2019 do not deviate significantly from this value. Expenditures were at a minimum in 2015 at $9.86 million due to low levels of spending across all programs. In 2019, there was a significant increase in expenditures to $23.8 million which was driven by the Poles Renewal and Substations Renewal programs. Forecast expenditures average to $18.2 million and significantly vary year over year. Expenditures are at a forecast minimum of $18.2 million at the end of the forecast period in 2026. Expenditures are expected to increase until 2022 where they peak at $24.2 million. The utility intends to maintain this level of expenditure in the following year before returning to average levels in 2024. Spending is anticipated to decrease every year to 2026. Table 5.4-25 outlines the asset classes targeted year over year.

Table 5.4-25: Summary of Asset Classes Targeted by System Renewal Investments

Year	Asset Classes
2015	Rebuilds, Substation Assets, Switches/Switchgears
2016	Rebuilds, Substation Assets, Poles, Switches/Switchgears
2017	Rebuilds, Substation Assets, Switches/Switchgears, Poles
2018	Rebuilds, Substation Assets, Distribution Transformers, Poles
2019	Substation Assets, Rebuilds, Poles
2020	Rebuilds, Substation Assets
2021	Rebuilds, Substation Assets
2022	Substation Assets, Poles, Switches/Switchgears, Rebuilds
2023	Substation Assets, Voltage Conversions, Poles, Rebuilds
2024	Voltage Conversions, Poles, Switches/Switchgears, Rebuilds
2025	Substation Renewal, Voltage Conversions, Poles
2026	Voltage Conversions, Poles, Switches/Switchgears

Asset Failure

This driver consists of only the Reactive Renewal program. Elexicon and both of its predecessor utilities dedicated a certain portion of the System Renewal budget for reactive replacements annually, resulting in minimal variability over the historical and forecast periods. The average historical expenditure is $2.58 million, and the average forecast expenditure is $1.82 million. The decrease between historical and forecast expenditures is driven by a system-wide improvement in asset condition and a reduction in expected reactive renewal needs.

System Service

Figure 5.4-16 and Table 5.4-26 show the historical and forecast expenditures for System Service drivers. Additional details about the allocation of spending across drivers in this category can be found below.

Figure 5.4-16: Historical and Forecast System Service Expenditures by Driver

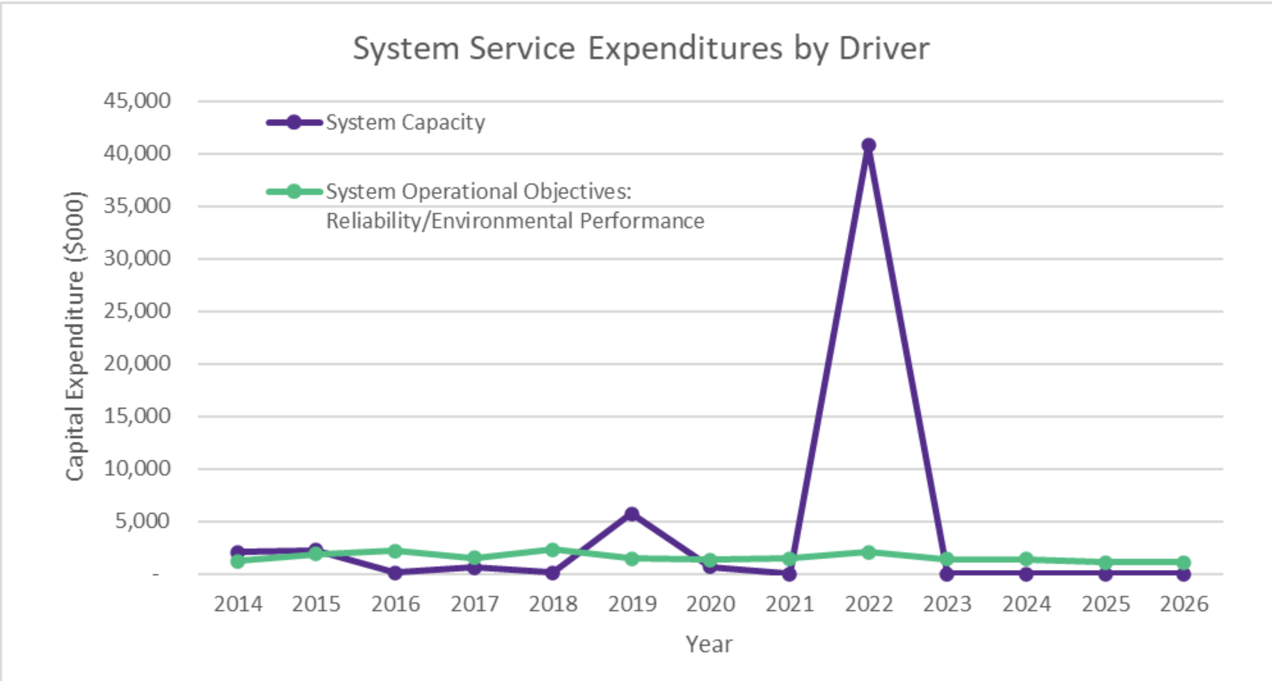


Table 5.4-26: Historical and Forecast Gross Expenditures for System Service Drivers ($000)

Driver	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Capacity	2,046	2,254	71	565	120	5,704	641	-	40,762	-	-	-	-
System Operational Objectives: Reliability/Environmental Performance	1,219	1,876	2,149	1,511	2,305	1,443	1,342	1,418	2,043	1,348	1,353	1,053	1,053
Total	3,265	4,131	2,219	2,076	2,425	7,147	1,983	1,418	42,805	1,348	1,353	1,053	1,053

System Capacity

This driver consists of two programs: Substations Growth and Expansion and Feeder Enhancement. The historical expenditures for this driver average to $1.42 million and vary significantly. There were notably high levels of expenditure in 2015, 2019 and 2020. In 2015, the majority expenditures occurred in Feeder Enhancement program which included several projects to address capacity needs. Expenditures decreased to relatively low levels until 2019, where they peaked at $5.70 million. The increase in 2019 and the high expenditures in 2020 occurred in the Substations Growth and Expansion program – specifically, the increase was driven by the MS16 Substation Rebuild project. The average forecast expenditure for this driver is significantly higher than the historical average at $8.15 million. However, this difference is driven by an extremely high level of expenditure in 2022 at $40.7 million as all other forecast years have no planned expenditures. This increase results from the planned construction of Seaton TS which in 2022 and is expected to be funded through the ICM mechanism.

System Operational Objectives: Reliability/Environmental Performance

System Operational Objectives: Reliability and System Operational Objectives: Environmental Performance are two separate drivers, but they are presented together because there is overlap between the programs they include. The programs included in these drivers are SERC, Substation Upgrades, and System Reliability Improvements. The historical expenditures for these drivers average to $1.66 million and there is minimal variability. Forecast expenditures are expected to decrease as they average to $1.37 million. All years except for 2022 are consistent with the average forecast expenditure. In 2022, expenditures are higher than average due to additional spending in the System Reliability Improvements program. Specifically, this increase occurs as a result of SCADA upgrade projects and an increased effort to install FCI devices.

General Plant

Figure 5.4-17 and Table 5.4-27 show the historical and forecast expenditures for General Plant drivers. Additional details about the allocation of spending across drivers in this category can be found below.

Figure 5.4-17: Historical and Forecast General Plant Expenditures by Driver

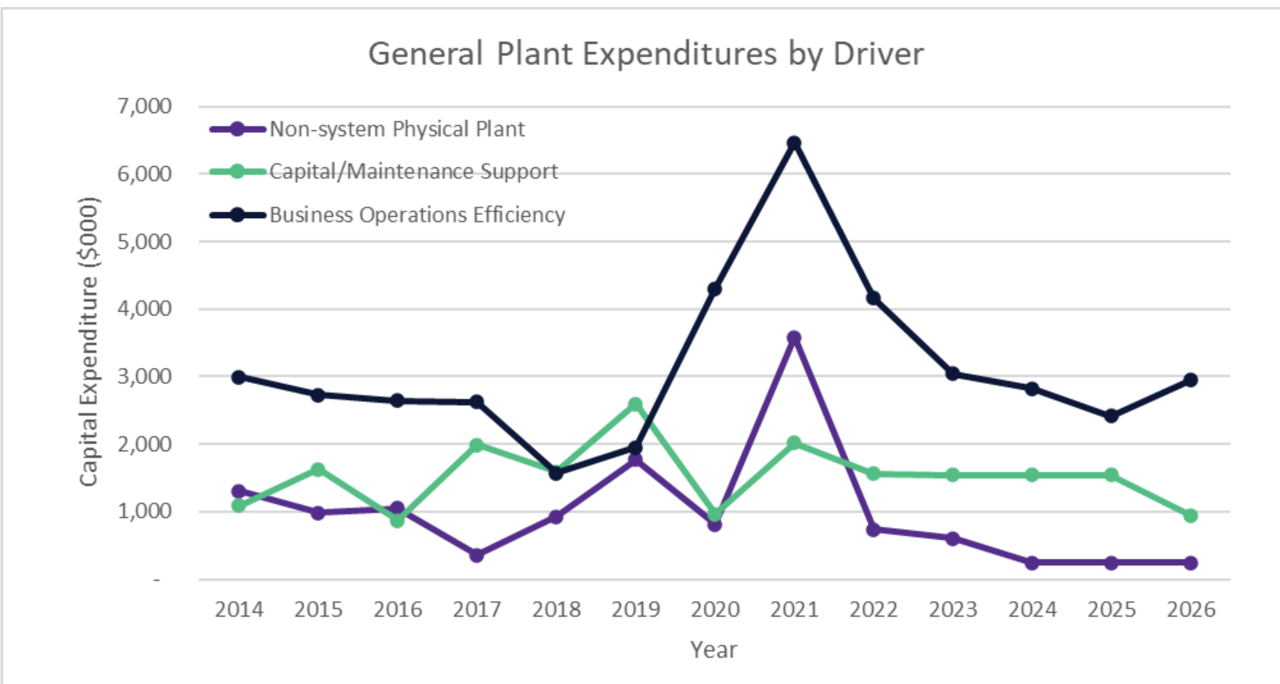


Table 5.4-27: Historical and Forecast Gross Expenditures for General Plant Drivers ($000)

Drivers	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Non-system Physical Plant	1,304	979	1,053	352	923	1,770	808	3,580	740	600	240	240	240
Capital/Maintenance Support	1,087	1,630	867	1,990	1,586	2,593	962	2,020	1,558	1,545	1,545	1,545	945
Business Operations Efficiency	2,998	2,726	2,640	2,626	1,569	1,947	4,307	6,465	4,162	3,038	2,820	2,420	2,950
Total	5,389	5,335	4,559	4,968	4,077	6,310	6,077	12,065	6,460	5,183	4,605	4,205	4,135

Non-System Physical Plant

This driver includes the Facilities program only. The average historical expenditure for this driver is $1.346 million. Compared to other years, there were high levels of expenditures in 2016 at $1.05 million and in 2019 at $1.12 million. The high level of expenditure in 2016 resulted from several facilities improvement projects in Ajax. In 2019, the above-average spending resulted from numerous facilities improvement initiatives as the majority of projects did not individually account for a large portion of the expenditure – the only exception is paving projects which accounted for approximately $0.40 million. There is significant variability in planned expenditures, particularly due to increased expenditure in 2021 at $3.58 million. This increase in Non-System Physical Plant spending is driven by the Belleville Office Relocation project. Forecast expenditures are expected to be lower as they average to about $0.41 million every year.

Capital/Maintenance Support

This driver includes two programs: Fleet and Tools and Equipment. The average historical expenditure for this driver is $1.59 million and there is some variability as expenditures were significantly lower than average in 2016 at $0.867 million and 2020 at $0.96 million, and significantly higher than in 2019 at $2.59 million. In 2016, Elexicon's predecessor utilities did not have significant investment requirements for their fleet assets, which resulted in historically low expenditures. In 2019, the increase was driven by additional spending in the Fleet program as several vehicles reached EOL and required replacement. In 2020 there was significantly lower spending on Tools and Equipment. 2021 spending is notably higher at $2.02 million with increased investment in the Fleet program. The average forecast expenditure for this driver is $1.43 million and there is significant variability in spending year-over-year. Planned expenditures do not deviate significantly from the average from 2022 to 2025. However, there is an expected decrease in 2026 to $0.94 million which occurs due to a lack of investment in the Fleet program.

Business Operations Efficiency

This driver includes the Information Technology program only. The average historical expenditure for this driver is $3.16 million and there was minimal variability over the historical period until 2020. Expenditures for all years except for 2018 did not deviate significantly from the average expenditure. In 2018, the expenditure for this driver was $1.57 million – this decrease resulted from a lack of Information Technology requirements. In 2020, the expenditure increased greatly to $4.3 million, this increase is due to an increase in spending in Information Technology as a result of the merger. There are high levels of historical expenditure in 2021 at $6.46 million. This increase occurs because Elexicon has a planned effort to upgrade and consolidate software/hardware systems as a result of the merger. Forecast expenditures for this driver average to $4.92 million and display a decreasing trend over the forecast period. The utility expects expenditures are expected to return to average levels for the next two years, 2022 and 2023, after which there is a decrease to sub-average levels for the remainder of the forecast period.

5.4.3.1.4 System Capability Assessment

Elexicon tracks loading data on an hourly basis and analyzes system capacity in monthly reports. Meters at customer sites enable system capacity analyses at the customer, feeder, and station levels. For the purposes of assessing system capacity, Elexicon calculates the average utilization of stations and feeders over the past five years as a percentage of their maximum capacity. There are several feeders and stations which have an average utilization greater than 100%, as listed below.

- Stations with average utilization >100%
    - Notion Road SS
    - Fairport SS
    - Cascade SS
    - Jones SS
    - Bradshaw SS
    - Liberty North SS
    - Wilmot SS
- Feeders with average utilization >100%
    - 11F2
    - LIBN F1
    - JAME F2
    - BIGE F1
    - BIGE F2
    - BIGE F3
    - MABL F1
    - MABL F2
    - FIRS F3

Loading beyond capacity is not optimal for feeders and stations as this can reduce the performance of distribution assets through various forms of deterioration such as thermal degradation. Elexicon frequently monitors its assets and analyzes loading data to ensure that there are no significant risks to system performance and reliability. While the stations and feeders listed above have an average utilization greater than 100%, it is important to consider that this calculation is based on the maximum non-coincident load (maximum load, regardless of the time of occurrence). However, Elexicon is prudent in ensuring that system capacity is addressed proactively. Even though there are no significant capacity risks to Elexicon's system based on current utilization, Elexicon has planned investments in the System Service category which will increase the capacity in targeted areas of the system in response to growth plans driven by new residential and commercial developments within Elexicon's service area. Specifically, capacity upgrades are planned through the Substations Growth and Expansions and voltage conversion program. Elexicon also addresses capacity related issues through programs in the System Renewal category. When completing asset replacements for certain asset classes, Elexicon evaluates historical loading data to assess if the asset should be upgraded or if a like-for-like replacement is the optimal approach.

5.4.3.2 Material Investments

Elexicon creates Business Case documents for each investment program which outline key information such as the basis for action, alternatives considered, planning and execution processes, and forecast expenditures. These business cases only include details about material projects above the net expenditure threshold of $300,000. Table 5.4-28 below shows the total net expenditures at the program level and includes all projects under the program. These business cases – in response to Section 5.4.3.2 of the Filing Requirements – are attached in Appendix A.

Elexicon's applicable materiality threshold is defined as 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. Section 2.0.8 – Materiality Thresholds of the OEB's *Filing Requirements for Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications - Chapter 2 Cost of Service* ("Chapter 2 Filing Requirements") states that the materiality threshold relates to the revenue requirement impact of the expenditure.

Table 5.4-28: Summary of Forecast Net Expenditures in 2021 & 2022

Investment Category	Total Category Net Expenditure 2021	Total Category Net Expenditure 2022	Program	Material 2021 Net Capital Expenditures	Material 2022 Net Capital Expenditures
System Access	$12,205,643	$12,298,110	A1 - Road Relocation	$3,874,837	$210,000
			A2 - Connection of New Services	$5,507,000	$7,286,350
			A3 - Feeder Expansion	$893,566	$0
			A4 - Metering	$1,839,240	$1,331,460
			A5 - Customer Requested Work	$91,000	$91,000
			BRT Relocations	$0	$3,379,300
System Renewal	$19,667,064	$23,440,839	R1 - Substation Renewal	$7,079,000	$9,404,000
			R2 - Renewal Programs-Rebuilds	$5,645,000	$5,296,345
			R3 - Renewal Programs-Poles	$1,200,000	$2,400,000
			R4 - Renewal Programs-Distribution Transformers	$1,078,200	$1,302,400
			R5 - Renewal Programs-Switches & Switchgears	$1,317,000	$1,525,000
			R6 - Renewal Programs-Others	$951,000	$771,000
			R7 - Renewal Programs-Reactive	$1,865,364	$1,842,094
			R8 - Voltage Conversion-Reliability	$531,500	$900,000
System Service	$1,418,000	$42,805,000	S1 - Substation Growth & Expansion	$0	$40,762,000
			S2 - Substation Upgrades	$0	$0
			S3 - Standard Equipment Reliability & Compliance	$300,000	$300,000
			S4 - Feeder Enhancement	$0	$0
			S5 - System Reliability Improvement	$1,118,000	$1,743,000
General Plant	$12,064,500	$6,460,000	P1 - Facilities	$3,580,000	$740,000
			P2 - Fleet	$1,860,000	$1,410,000
			P3 - Information Technology	$6,464,500	$4,162,400
			P4 - Tools & Equipment	$160,000	$147,600

APPENDIX A: Capital Program Narratives

Budget Category	Road Relocations
OEB Investment Category	System Access
Primary Driver	Third-Party Infrastructure Requirements
Secondary Driver(s)	Mandated Service Obligations

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$5.82M	**$6.90M**

1. Executive Summary

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

Elexicon "Road Relocation" projects are driven from third-party infrastructure requirements to relocate existing overhead or underground infrastructure from one road allowance to another. It is mandatory to comply with these initiated changes to public roads as based upon the *Public Service Works on Highways Act* ("*PSWHA*"). Additionally, changing infrastructure requirements and increased loading from new electrification projects influenced and pursued by Metrolinx require Road Relocation projects. Initiatives from major transportation projects, and various transportation master plans drive Road Relocation projects that Elexicon must partake in.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	5.82	4.75	23.05	5.54	1.80	2.80	2.00	6.20
Contributions	3.41	2.44	19.18	5.33	0.47	0.77	0.53	1.79
Net Program Expenditures	2.40	2.32	3.87	0.20	1.33	2.03	1.48	4.42

There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

A variety of transportation plans produce the amount and complexity of road relocation projects within the Elexicon territory. These plans include *The Region of Durham Transportation Master Plan*, *Northumberland Transportation Master Plan*, *Belleville Transportation Plan*, *Muskoka Transportation Plan*, and *Metrolinx Transportation* plan. The common objectives between each of these plans include future planning of transportation infrastructure, sustainable travel, and road enhancements. Furthermore, major transportation projects such as the GO Electrification and the Metrolinx Bowmanville Go Extension will produce significant road relocation efforts. These projects span multiple towns, cities, and municipalities within Elexicon's service territory with significant financial investment. Major growth in population and employment is expected throughout the region which promotes further road work. Road Relocation projects affect infrastructures such as bridges, roads, highways, sidewalks, and tracks. Due to the nature of Road Relocations and projects being driven by Road Authorities, Elexicon budgets for the projects accordingly as they are introduced and developed. Recently, the Ontario Government approved the Building Transit Faster Act, which could impact major road relocation projects under Elexicon across the DSP period. The Act's purpose is to 'expedite the delivery of transit projects of provincial significance by removing barriers and streamlining processes that may result in delays to the timely completion of these projects, while enhancing coordination and engagement with and being fair to public and private sector stakeholders.' Major projects that would fall under this act would be the variety of Road Relocation projects initiated by Metrolinx.

Elexicon will engage in Road Relocation projects efficiently and safely while achieving project deadlines. Transportation projects and road relocations have a large impact on customer service, public perception, and the reliability of the grid. System Access projects such as Road Relocations are prioritized as mandatory investments to serve customers and service obligations. In completing these projects, Elexicon maintains close contact with Road Relocations stakeholders.

Road Relocation projects will set the benchmark for many of Elexicon's collaborated efforts. The combined expertise of field and office workers will provide potential improvements to road relocations. The consolidated staffing will especially help in the major transportation projects that span multiple towns, cities, and municipalities within Durham. The insights between both predecessors will be beneficial in determining how to approach road relocation projects into the future.

2. Basis for Action

2.1 Performance Trends:

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project

Road Relocation projects are driven by Road Authorities who are defined as bodies having jurisdiction and control of a highway (or road). Any major developments in transportation or road improvements have an impact on Elexicon infrastructure. The major drivers of road relocation projects stem from transportation plans and major cross-regional transportation projects. Stakeholders involved in road relocation projects include transportation authorities like Metrolinx and the road authorities of MTO alongside individual towns, cities, municipalities, and the regions. Individual cities and regions may initiate civil works in addressing their road infrastructure which affects the Elexicon assets situated around the road. The complexities of Road Relocation projects can differ from one another and affect multiple parties. In these cases, coordination with an assortment of parties is required to relocate assets affecting roads.

1. **Transportation Plans**

Transportation planning defines the future, policies, investments, and designs for the ability to move people and goods within a select region. Elexicon Energy is made up of different towns, cities and municipalities with the majority based in Durham, and other regions such as Quinte West, Muskoka, and Northumberland. A major contributor to Road Relocation projects has been the Region of Durham especially considering its development efforts.

Region of Durham Master Transportation Plan

The *2017 Durham Transportation Master Plan* produces the basis of many transportation-related projects that necessitate Elexicon Road Relocation projects. Many of Elexicon's Road Relocation projects will take place in Durham considering that the Towns, cities and municipalities of Ajax, Pickering, Whitby, Brock, and Clarington are all within the Elexicon territory. 'Based on Durham's *Regional Official Plan* forecasts, the Region's population and employment will grow by 49% and 55%, respectively, resulting in corresponding increases in travel demand.' The forecasted growth period is from the year 2006 to 2031. The seven facets of the plan that relate to Road Relocation projects are to:

- Strengthen the bond between land use and transportation;
- Elevate the role of integrated public transit including Rapid Transit;
- Make walking and cycling more practical and attractive;
- Optimize Road infrastructure and operation;
- Promote sustainable travel choices;
- Improve good movement to support economic development; and
- Invest strategically in the transportation system.

Within the proposed 2017 Durham Master Transportation Plan, the region had proposed 53 road expansion projects of differing complexities for the recommended phasing of 2017 to 2021, and 2022 to 2026. Some of these projects have been completed in the 2015 to 2019 period. Other remaining and upcoming work will be completed across the future DSP period.

Northumberland Transportation Plan

The *2017 Northumberland Transportation Master Plan* outlines strategic directions to Port Hope's transportation plans. Due to recent news of Bowmanville GO's expansion by Metrolinx, Port Hope and Northumberland as a county has shown interest in extending Metrolinx capabilities to the area. 80% of the expected population and employment is expected to occur in Port Hope and five other Northumberland areas. The seven objectives in the *Northumberland Transportation Master Plan* are to:

- Create a long-range transportation planning document;
- Prioritize future multi-modal transportation networks and infrastructure;
- Develop a sustainable program of system expansion over multi-year horizons;
- Identify funding strategies;
- Analyze safety and operations at key intersections;
- Conduct a road rationalization assessment; and
- Review transportation-related policies.

Belleville Transportation Plan

The City of Belleville Transportation Master Plan was produced in 2014 and outlines the city's future vision for transportation. Belleville's population is expected to grow by 24% from 2014 to 2031, while employment is expected to increase by 32% over the same period.

Muskoka Transportation Plan

The *Muskoka Transportation Plan* went public in an RFP stage in 2019 but has not been produced. Elexicon will evaluate the *Muskoka Transportation Plan* when it is produced and update its investment plans accordingly. Any ongoing road authority projects are communicated with Elexicon. Gravenhurst has engaged in an age-friendly active transportation plan in 2017. The purpose of the plan is to:

- Support the community and placemaking;
- Support economic activity;
- Maximize transportation choice;
- Integrate with the natural setting and built form (Built form refers to the function, shape, and configuration of buildings as well as their relationship to streets and open spaces.);
- Emphasize walking and cycling as fundamental community options; and
- Create harmony with other transportation networks.

Metrolinx 2041 Regional Transportation Plan

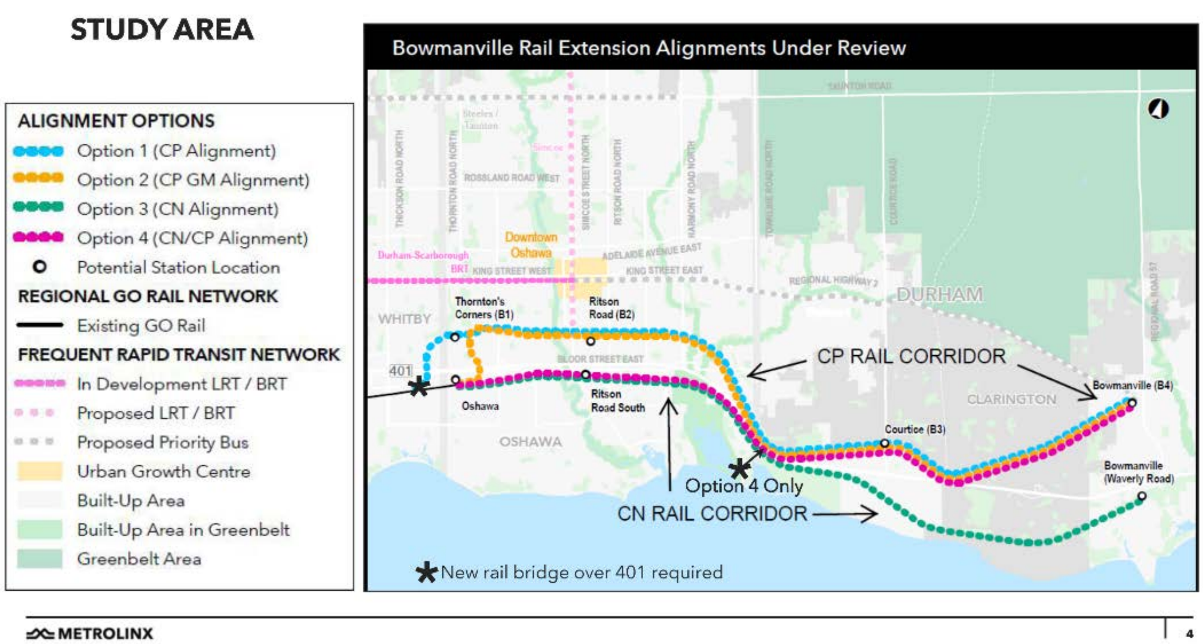
The *Metrolinx 2041 Regional Transportation Plan* outlines projects expected to enhance transportation around the Greater Toronto and Hamilton Area. Elexicon stakeholders such as the Region of Durham, City of Pickering, and the City of Clarington were involved in the peer review of the report. Three major transportation projects that are highlighted in the report include the Lakeshore Go East Rail extension to Bowmanville Go, GO Electrification, and the BRT project from Durham to Scarborough. The BRT project is covered in a separate business case. These projects are expected to contribute to a significant amount of road relocation work.

2. Large Road Relocation Projects

Large relocation projects that are expected to take place during the Elexicon forecast period from 2021 to 2026 include the Lakeshore GO East Rail Extension, and Metrolinx Electrification efforts. Considerable road relocation will take place within the Elexicon territory as these projects span multiple towns, cities, and municipalities.

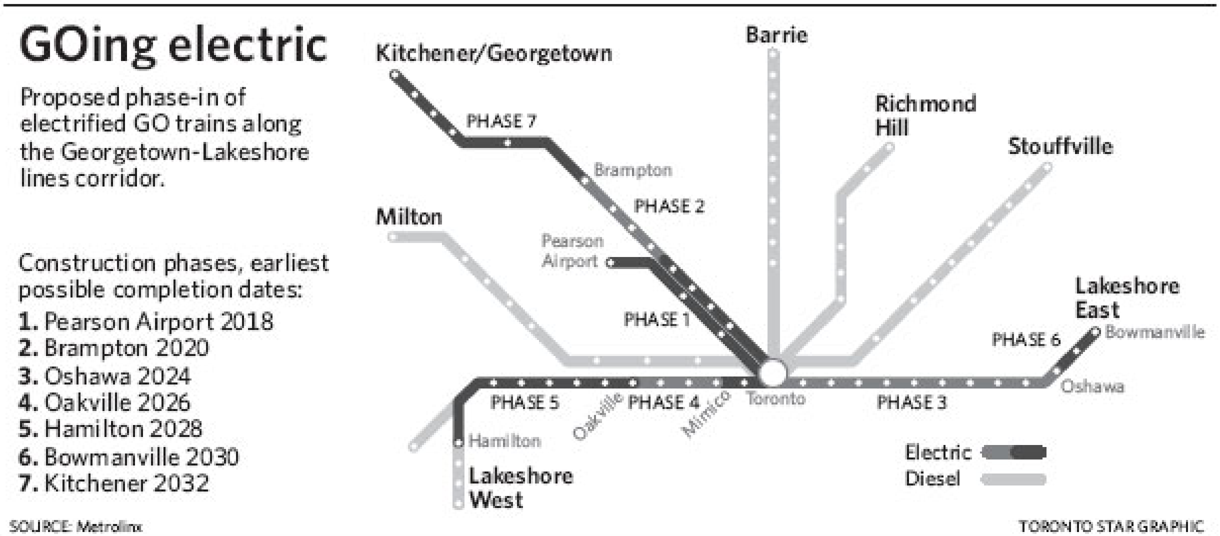
On February 20, 2020, The Metrolinx board of directors endorsed Option 2 for the GO East Rail Extension through Oshawa to Bowmanville along the Canadian Pacific mainline north of Highway 401. Bowmanville Go planned station in 2024. A Possible Courtice Go station could be added depending on the preferred route. As seen in the proposed options for Bowmanville Go in Figure 1, a significant amount of road relocation work will take place in the Clarington area. The planning and design of the new Go Station at Courtice Road in Clarington is currently underway. Improvements will be made along the Lakeshore East line to deliver the extension. The service levels for Metrolinx were determined based on years of rigorous study including factors of influence such as population density and feasibility of development. Elexicon will monitor the progress of the Bowmanville Rail Extension; currently, no contact has been established yet between the two parties.

Figure 1: Lakeshore Go East Rail Extension



As shown in Figure 3, Metrolinx is intending to perform electrification on many of its GO train-related infrastructure in Ontario. Elexicon has experienced road relocations stemming from the need to move assets due to the initiative set forth by Metrolinx. The Lakeshore Go East Expansion by Metrolinx plans to electrify the full length of the Lakeshore East corridor which would provide riders with quicker trains, no localized emissions for communities, and quieter trains. Considerable work was built previously such as new tracks, stations, grade separations, pedestrian bridges, underpasses, and bridge expansions which influenced the road relocation efforts of Elexicon.

Figure 2: Metrolinx Electrification Plan



Historical Road Relocation Projects

Elexicon has experienced a consistent amount of road relocation projects year over year across all categories from Towns, Cities and Municipalities, the MTO, and Metrolinx. The year 2018 exhibited a spike in road relocation projects as seen in Figure 4. However, the magnitude of projects in terms of dollar value has increased due to the larger Metrolinx projects materializing into the next DSP period. It is expected that the number of road relocation projects will drop into the future. Table 2 highlights the number of Road Relocation projects historically undertaken.

Figure 3: Historical Elexicon Road Relocation Projects

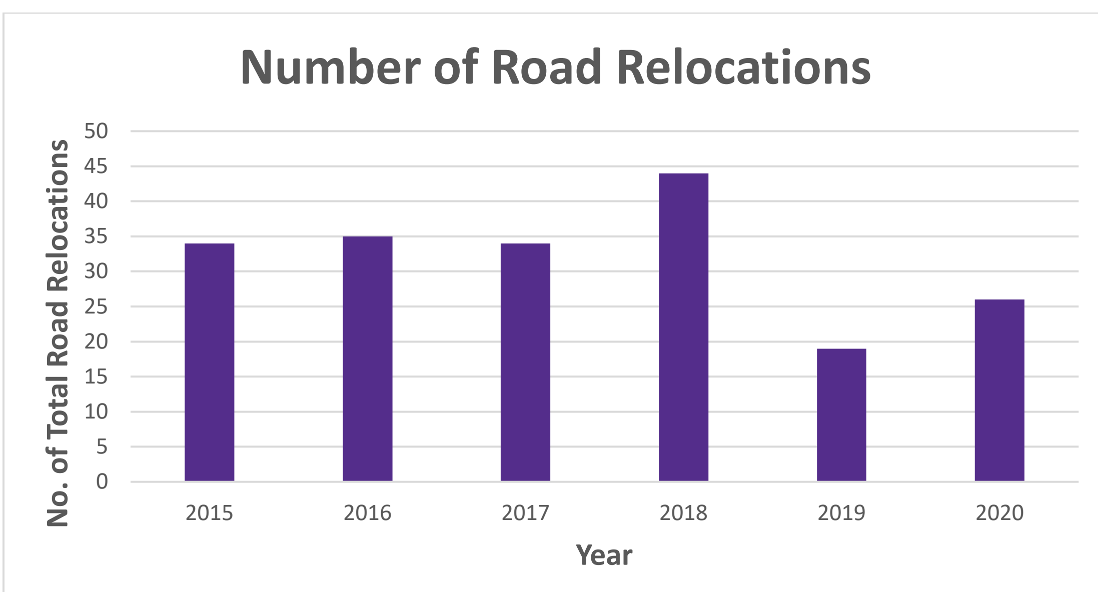


Table 2: Road Relocation Projects Year over Year

Year	2015	2016	2017	2018	2019	2020
Number of Road Relocation Projects	34	35	34	44	19	26

Historical Metrolinx Road Relocation Projects

As shown in the historical road relocation projects related to Metrolinx, Elexicon is experiencing an increase in Metrolinx projects in the year 2021 as compared to the 2015 to 2019 years. As shown in the planned capital spending, Elexicon will match with historical Metrolinx projects in 2020 but will be investing significantly in road relocations in 2021. This is due to many of the Metrolinx initiated projects \ and Electrification efforts coming into fruition in 2021.

Figure 4: Historical Metrolinx Road Relocation Projects

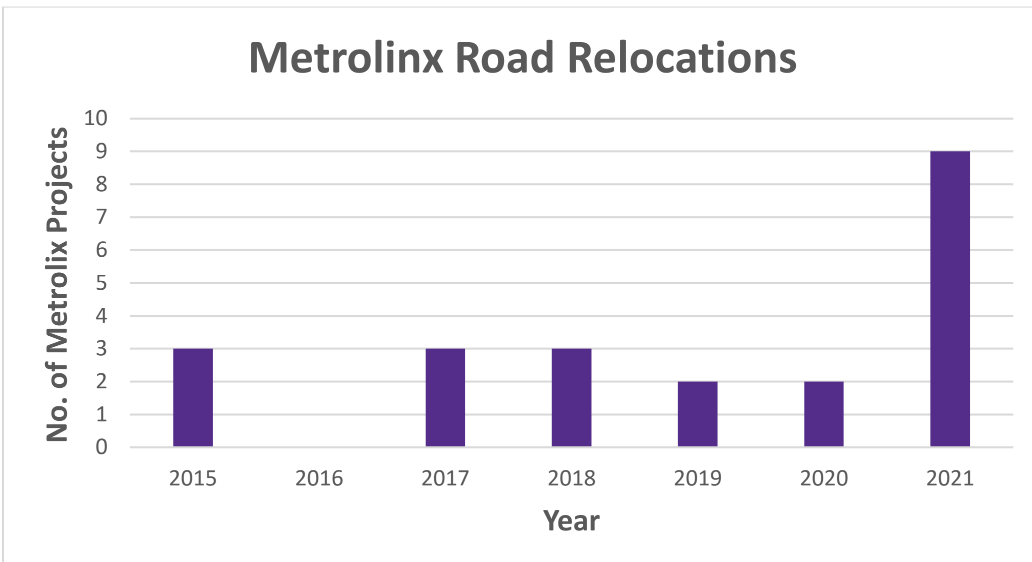


Table 3: Metrolinx Road Relocation Projects Year over Year

Year	2015	2016	2017	2018	2019	2020	2021
Number of Metrolinx Projects	3	0	3	3	2	2	9

2.2 Current-State Analysis:

Planned Road Relocation Projects by Service Area for Elexicon

Many of the road relocation projects are centered around the Ajax-Pickering and Whitby area under Elexicon. Transportation-related initiatives such as GO electrification, and extensions are driving the projects in these three areas. It is expected that these road relocations will continue within the area into the future. Furthermore, due to the initiatives in transportation from the Region of Durham, many of the road relocation projects will take place within the region. Areas such as Port Hope, Gravenhurst, and Belleville that are outside of the Durham territory are not expected to produce many Road Relocation projects if any. As a contingency, Elexicon has set up a general Road Relocation budget annually for any unexpected new Road Relocation projects from 2023 and onwards.

Figure 5: Planned Elexicon Road Relocation Projects by Service Area

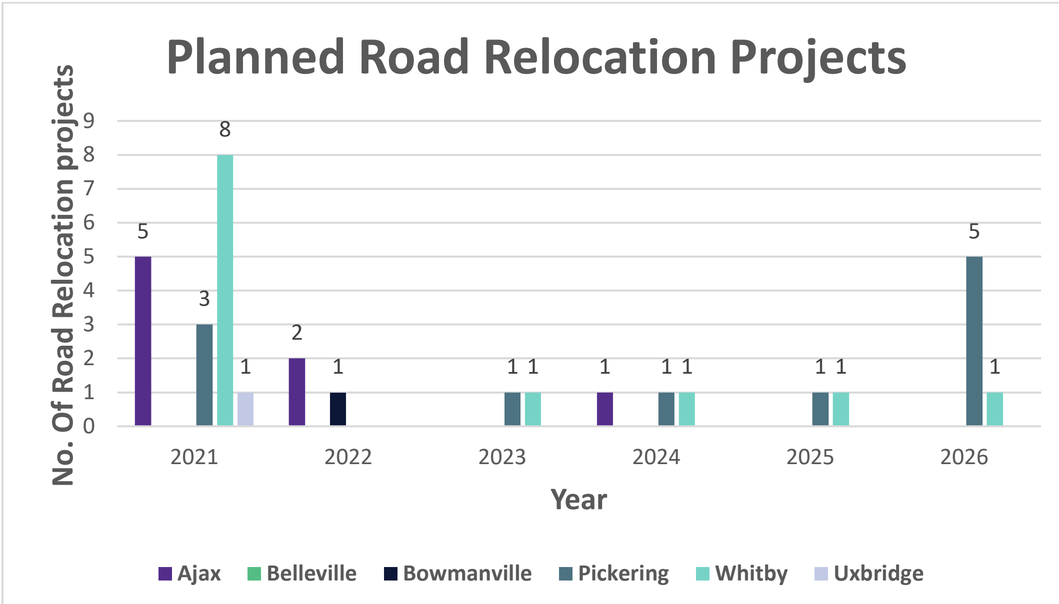


Table 4: Road Relocation projects by Service Area

Year	2021	2022	2023	2024	2025	2026	Grand Total
Ajax	5	2	0	1	0	0	8
Belleville	0	0	0	0	0	0	0
Bowmanville	0	1	0	0	0	0	1
Pickering	3	0	1	1	1	5	11
Whitby	8	0	1	1	1	1	12
General	1	0	0	0	0	0	1

The current system cannot meet customer needs as road relocation projects are taking place to introduce transportation infrastructure upgrades to the area. In the cases of road widenings, existing overhead or underground infrastructure needs to be moved to attribute for the new design. Much of the planned road relocations are found in the areas of Pickering, Ajax, and Whitby due to the transportation-related infrastructure changes in the area. The other service areas such as Port Hope, Gravenhurst, and Brock are not expected to experience significant road relocations across the DSP period. Clarington will experience road relocation efforts as the details to the Lakeshore East Go extension are finalized. Depending on the location, new assets may be required to facilitate the distribution of electricity around the updated location. By relocating assets, Elexicon can also renew the assets that exist within the road relocation area. Thus, both the current system can be updated to meet the needs of the new infrastructure and Elexicon's system can also realize renewed benefits in parallel.

New In-Service Assets from Road Relocations

Across the DSP period, Elexicon is anticipating introducing 1420 poles, 76 pad-mount transformers, 209 pole-mount transformers, and 5 switchgear through Road Relocation projects. These assets can function as an asset renewal as they replace older assets. The following tables shall break down the assets by Service Area. Across the next DSP period, Ajax-Pickering Road Relocations shall introduce the most distribution assets. Whitby Road Relocations shall introduce new assets from 2020 to 2022 whereas Road Relocation projects in Belleville and Bowmanville shall introduce new assets up to 2021.

Figure 6: New Assets introduced through Road Relocations

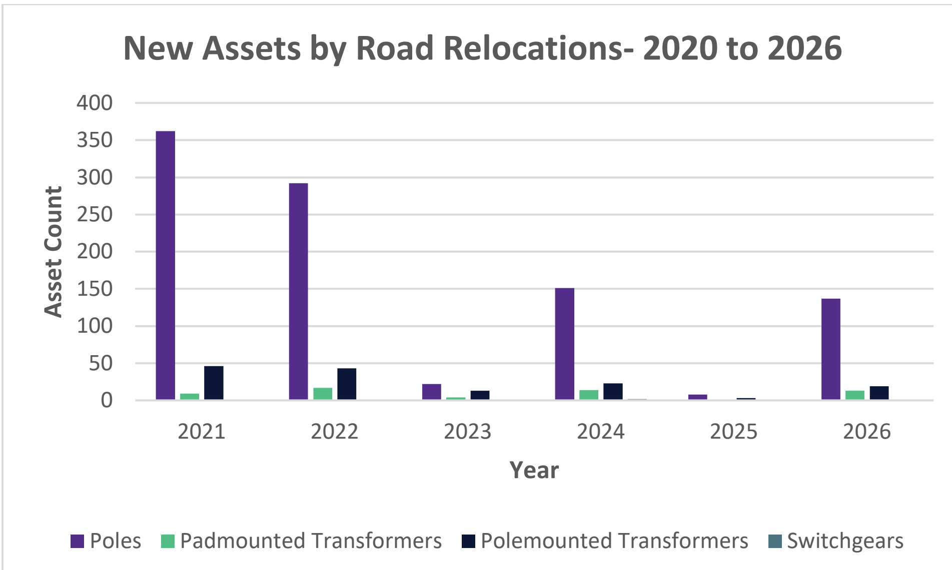


Table 5: Distribution Assets to Road Relocation Projects

Distribution Asset	2021	2022	2023	2024	2025	2026
Poles	362	292	22	151	8	137
Pad-mounted Transformers	9	17	4	14	0	13
Pole-mounted Transformers	46	43	13	23	3	19
Switchgears	0	1	0	2	0	0

Figure 7: New Pole Introductions by Service Area

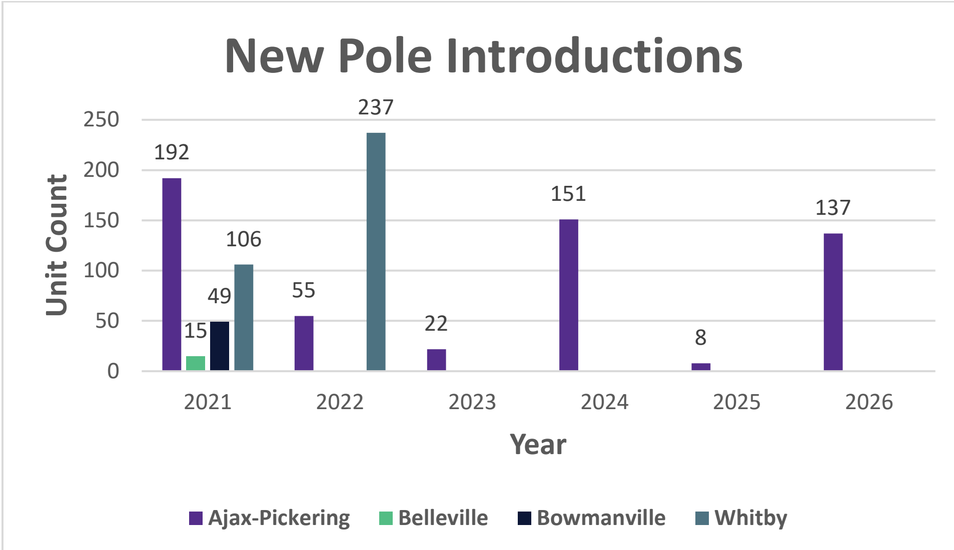


Table 6: Count of New Poles by Service Area and Year

Service Area	2021	2022	2023	2024	2025	2026
Ajax-Pickering	192	55	22	151	8	137
Belleville	15	0	0	0	0	0
Bowmanville	49	0	0	0	0	0
Whitby	106	237	0	0	0	0

Figure 8: New Pad-mount Transformer Introductions by Service Area

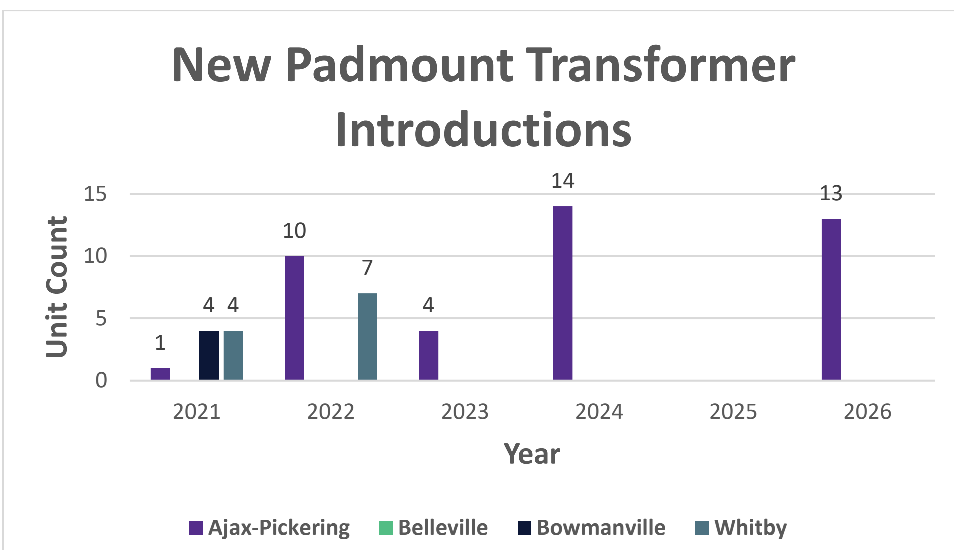


Table 7: Count of New Pad-mount Transformers by Service Area and Year

Service Area	2021	2022	2023	2024	2025	2026
Ajax-Pickering	1	10	4	14	0	13
Belleville	0	0	0	0	0	0
Bowmanville	4	0	0	0	0	0
Whitby	4	7	0	0	0	0

Figure 9: New Pole-mount Transformer Introductions by Service Area

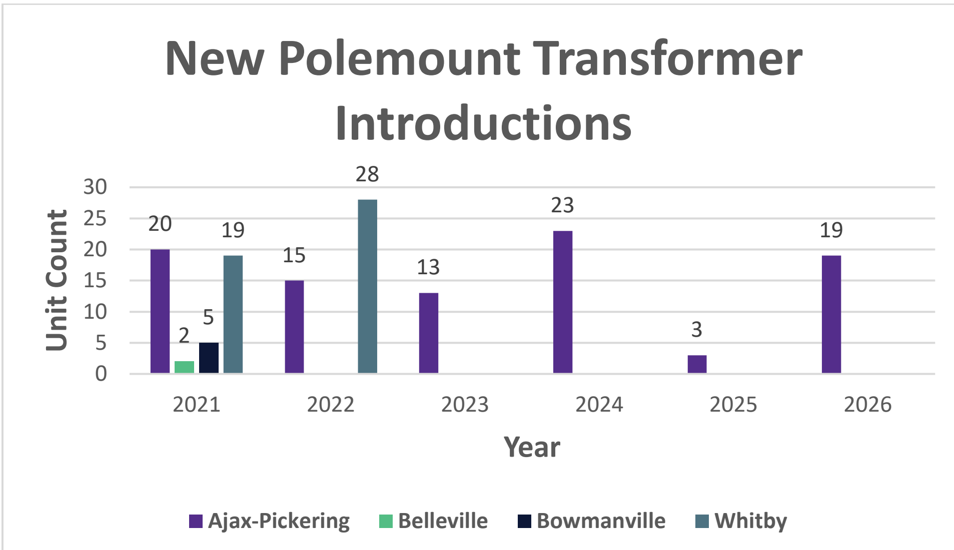


Table 8: Count of New Pole-mount Transformers by Service Area and Year

Service Area	2021	2022	2023	2024	2025	2026
Ajax-Pickering	20	15	13	23	3	19
Belleville	2	0	0	0	0	0
Bowmanville	5	0	0	0	0	0
Whitby	19	28	0	0	0	0

Figure 10: New Switchgear Introductions by Service Area

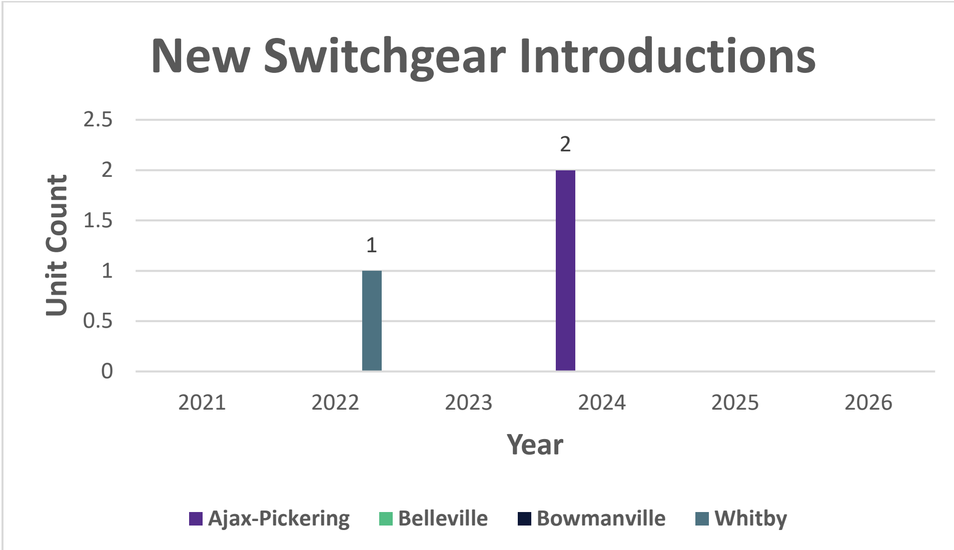


Table 9: Count of New Switchgears by Service Area and Year

Service Area	2021	2022	2023	2024	2025	2026
Ajax-Pickering	0	0	0	2	0	0
Belleville	0	0	0	0	0	0
Bowmanville	0	0	0	0	0	0
Whitby	0	1	0	0	0	0

When assets are relocated, they are usually replaced with like for like assets. The useful life of distribution assets is provided in Table 10. By reinvesting and placing new assets as replacements in road relocations, the lifespan of the area is extended with the third party contributing the amount. In that case, Elexicon benefits from the financial contributions of third parties by renewing asset lifecycles from completing road relocation projects. If a nearby Elexicon capital improvement or access project is around the same area, road relocations could be upgraded. This option is provided but the decision is ultimately up to the Customer if they are willing to pay for such services. These occurrences are not common as lower contribution amounts are preferred by the customer.

Table 10: Typical Useful Life of Distribution Assets

Distribution Asset	Useful Life
Wood Pole	45
Pole-mounted Transformer	40
Pad-Mounted Transformer	40
Overhead Conductor	60
Underground Cable	40
Ducts	50
Concrete Encased Ducts	55

Pad-mount Switchgear	40

For the Metrolinx electrification projects, the electrification will cross the 401 and are south of the highway. Feeders will need to be moved to cross the 401 with the 15kV feeders assisting in providing capacity to Go Trains. The Bowmanville Go Extension is to be expected in 2024 and a budget will be initiated when discussions with Metrolinx and associated stakeholders take place.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

Road Relocation projects must follow the *PSWHA*, wherein the "road authority" (i.e., MTO, municipal corporation, or other entity with control and construction of a highway) can provide notice to Elexicon to remove or change or works placed on the highway.

With Ontario's approval of the 'Building Transit Faster Act', Elexicon will comply and ensure the successful delivery of transit projects in its service area. The act's purpose will expedite the delivery of transit projects of provincial significance. Currently, a variety of Metrolinx and major transit projects are expected in the future DSP period under the Road Relocations program. Elexicon will follow and ensure that road relocation projects are delivered as per the outlines of this act.

All new infrastructure projects need to follow the Electrical Safety Authority guidelines and compliances. Installations and design of road relocations need to follow O, Reg 22/04, 'Electrical Distribution Safety' and sections to note include Section 4: for safety, Section 5: where safety standards are met, Section 6: Approval of electrical equipment, Section 7: approval of plans, drawings, and specifications for installation work and section 8: Inspection and approval of construction. Any new road relocation work that impacts the distribution system needs to follow the full list of compliances under O'Reg 22/04.

When performing work, Elexicon will ensure the safety of its workers. Any potential accidents from Road Relocations work could affect the Serious Electrical Index. Public awareness of electrical safety will also be applied for road relocation projects as these investments impact the public considerably as corridors and areas of transportation use.

Lastly, Road relocation projects need to follow the Distribution System Code while engaging in road authority projects. Section 3.1.1 suggests: Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that asset, except to the extent recovery is limited under law.

Leave to Construct approval is not required for road relocations projects.

2.4 *Consequences of Inaction*

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service: Residents feel the impacts of not having road relocations. Road widenings provide a significant impact on citizens and enforce existing system connections to adjust to new configurations. Furthermore, as road authorities are direct customers, Elexicon must uphold customer service standards in delivering projects. Residents will enjoy more efficient and safer travel routes, and additional travel options through initiatives such as road widenings, and GO electrification. The ongoing improvement of transportation resulting from road relocation projects in the service area will benefit the daily lives of customers.

Operational Effectiveness: Not completing the Road relocation projects in time or without correct planning can lead to decreases in operational effectiveness. Further resource utilization would be expected if road relocations are not finished near deadlines, and operations may need to work around suboptimal planned road relocations if projects are not of high quality.

Public Policy responsiveness: Towns, Cities and Municipalities and Road Authorities are engaging in transportation initiatives for the public across the Elexicon Territory. Elexicon should be responding to these projects as they are influenced by public policies to help Ontarians with transportation. If Elexicon does not respond to road relocation requests, they face compliance problems with the PSWHA and its obligation to road authorities as customers. Within the PSWHA, clauses (3) and (4) specify the minimum time interval or additional time as agreed upon by the road authority and the operating corporation, Elexicon. For transportation groups such as Metrolinx who are not part of the PSWHA, Elexicon is required to perform road relocation work. As Metrolinx projects span across multiple towns, cities and municipalities and are to enable greater transportation for the public, it is up to Elexicon to assist in these projects.

Financial Performance: Road relocation work provides an opportunity to rebuild and provide asset renewal naturally. By investing in newer assets at specific road relocations, the utility will benefit from financial investments into the future. Lastly, as road relocation projects are funded to some percentage by road authorities, Elexicon can prolong asset life in the area with funding from other parties from completing these projects.

2.5 Merger-Related Objectives:

With the consolidation of resources of the two utilities, more resources can be placed into road relocation projects in terms of labor and expertise. Furthermore, as certain larger transportation projects span Durham and into both the former Whitby and Veridian territories, it provides benefits in that work is no longer separate and can be combined under a singular entity.

The status quo for road relocations is to complete the projects on time, as efficiently as possible, and safely. Road Relocation projects provide high value for service continuity as it is a system access project and is mandated by legislative or regulatory requirements. During Road Relocations, older assets are replaced due to the modifications to the makeup of the distribution system. Newer assets such as poles, feeders, and duct banks are implemented which provides high-value renewal in addition to complying with road authority projects. A high value of utility integration is provided as it improves the throughput of planning, design, construction, operations, and back-office capabilities relative to both predecessors.

3. Program Alternatives

-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

3.1 Alternative Descriptions and Comparative Analysis

Number	1	2	3
Scenario Description	Current planned Road Relocations Investments	Heavier Storm Design	Combine a System Renewal Project with Road Relocation
Annual Program Scope	Elexicon will complete Road Relocation projects as budgeted across the DSP period.	Elexicon can invest in storm hardened equipment as new road relocation assets as a value-added addition to the system.	Elexicon will invest in a whole system renewal of an area in conjunction with the Road Relocation project.
Annual Gross CAPEX	$7.00M	$10.50M	$14.00M
Annual Net CAPEX	$2.57M	$3.86M	$5.14M
Annual Program Benefits	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, reliability, operational effectiveness and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, reliability, operational effectiveness and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, reliability, operational effectiveness and public policy responsiveness.
Program Economics	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.
Customer Feedback	Survey results below are represented by the 600 customers surveyed by phone and 262 surveyed online.	Survey results below are represented by the 600 customers surveyed by phone and 262 surveyed online. In addition to	Survey results below are represented by the 600 customers surveyed by phone and 262 surveyed online. Customers, in

		keeping the system safe and accommodating new growth, 61% of surveyed customers (530 of the 862) believed that improving the grids resilience to major weather events should be the first or second choice of additional investment objectives for Elexicon.	general, support investments in system renewal work involving equipment replacements by spending more today to prevent future outages and keeping future bill increase predictable. 83.4% of surveyed customers (719 of the 862) believed that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.
Other Constraining Factors	The only constraining factor is that Road Relocation projects are a mandatory obligation and must be completed. Overhead infrastructure for primary roadways is the only option of construction at Elexicon.	Storm Hardened Equipment will add additional costs that the Third-party may not agree with. The system will be able to handle the changing climate. Additional Hardening equipment could also extend installation time than standard equipment.	Adding another system renewal component for the area around the Road Relocation project is costly. Additionally, Elexicon will need to ensure assets around the area are not affected by the Road Relocation warrant renewal.
Preferred Alternative	**X**		

As Road Relocation projects are System Access, there is a mandatory obligation to relocate assets and distribution infrastructure. Commonly, the Utility will perform a like for like replacement with changes. However, if a capital project is within the area, renewal and road relocation could be done in parallel. In these situations, there are opportunities to enhance the service alongside the road relocations. This situation is not common and is dependent on the existence of another Elexicon capital project.

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Reliability is improved as the road relocation project is completed but at a slower pace. New transportation infrastructure or road configurations are now applicable to the current distribution system.

Grid Resiliency: Grid Resiliency increases as new distribution infrastructure is relocated although at a slower pace. New system loading and configurations are more optimal in providing resiliency than the current configuration.

Operational Efficiency and Cost Effectiveness: Operational Efficiency is more flexible as resources are not tied to a specific road relocation project. However, slower project pacing from Elexicon does run the risk of not being as efficient as possible in completing a project. Delays on projects could impact the public and cost-effectiveness.

Safety: Safety is improved with project work still being pursued by Elexicon. However, a slower pace could result in a larger opportunity and potential for safety problems during the construction of road relocation.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: Relationships will be maintained but may not be as strong as before with Elexicon and Road Authorities. Delays in projects from pacing investment into the road authority project could prove problematic due to the amount of coordination and interoperability required with third parties.

Conservation and Demand Management: N/A

Net Customer Benefits: Customers will experience the benefits of improved transportation plans or projects that aim to help ease transportation for civilians in the Elexicon territory. However, customers may note the delays of road relocation projects as Elexicon will complete these projects at a slower pace or use fewer resources to complete the project.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

If a Road Relocation project found in System Access has not materialized, budgeting could be used for other system projects in renewal, and service. System Access projects are non-discretionary however and thus will need to be completed. However, due to the scattered nature of System Access projects, a foundational budget should be held year over year in case of any new System Access developments. Current projects for either customers or renewal programs are evaluated based upon criteria of reliability, operational effectiveness, and safety. These projects are evaluated against one another using the same criteria. Any System access project budgets that do not materialize could be placed into the general project criteria and scope budgets for other projects.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

In the planning process, a review of the current distribution system configuration at the road location is performed. Previously, for road authority projects that spanned various territories, third parties needed to communicate with both Veridian Connections and Whitby Hydro. Third parties now only communicate with Elexicon and provide the scope of the road project. For example, a request for road widening prompts Elexicon to analyze how and where assets can be moved. A bill of materials and design is prepared internally by Elexicon to identify the new distribution network around the road. Previously, a set of distribution standards for both Veridian and Whitby were used for their associated territories. Elexicon has consolidated new standards to service the whole territory taking the best practices of both former utilities.

Elexicon will purchase new assets such as poles, conductors, and implement or extend ductwork or line extensions to complete road relocations. In this case, Elexicon benefits as the distribution system are renewed and improved in reliability from asset renewal from the road relocation. There are no major differences between the two former utilities; however, the merger has provided a benefit in providing a higher-level view for projects that span multiple territories of the two former utilities.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Standard construction at Elexicon is to utilize overhead wooden poles on public roadways and underground for new residential developments. If a Road Authority wishes to relocate existing Elexicon overhead assets to underground, the cost-sharing portion of the relocation will be as if the system was an overhead rebuild and the cost difference between overhead and underground systems. For relocations, not part of the road (e.g., due to installation of sidewalks, multi-use paths), Road Authority will pay the full cost of relocation of Elexicon Assets. External Inspectors are used to evaluating the work required to complete relocation projects. Depending on the location of the project, legacy equipment or connections may be present within the area. Elexicon will assess the distribution equipment and the network in ensuring that the configuration is understood by the two former utilities and applicable to the current system. Previously, the two utilities had their own specific set of standards in terms of overhead and underground design. Consolidated standards from the two utilities have been completed and are used for road relocation projects into the future within the Elexicon territory. Road relocation design is completed with a mix of internal employees and external contractors. For Road relocation projects that are more complicated, Elexicon will enlist external contractors to perform the design.

4.3 Scale Increase Considerations

In lieu of Regional plans for Durham for transportation projects, coordination between the selected towns, cities and municipalities will be easier. Past operations required communication between Whitby Hydro and Veridian Connections for projects that spanned across the two jurisdictions.

As Elexicon is a merged utility, work carried out between the two utilities will be easier and the purchasing power of the two former utilities will be combined. As projects are more efficient in coordination within the one utility, it allows for greater purchasing power to be used in contracting or using more financial resources towards road relocation projects. Capital savings and combined budgets from the two former utilities due to the merger will create an availability of financial resources that can be used within this program or another in the company. There are merger related savings that can be realized through this program.

Road Relocation projects are initially provided a timeline for design deadlines and construction but can be adjusted based upon the Region or Road Authorities decisions. Some projects are initiated in advance of a longer deadline whereas other projects require faster action. At times, the road authority or transportation authority may discover other conflicts while engaging further into projects which could affect the timeline.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Road Relocation projects are mandated investments by Elexicon. Decreased or increased pacing of projects depends entirely on parties external to Elexicon as Elexicon provides options of designs to the stakeholders. Delays are often experienced organically due to the nature of construction projects.

The consolidation of operations for road relocation projects will be beneficial as a merged utility. High-level transportation projects such as the Bowmanville Go Extension is an example of project that crosses over the two former utilities (Veridian Connections and Whitby Hydro) territory. Having knowledge of the project and coordinating internally could realize numerous benefits from the consolidation period. For instance, operations between the two utilities will understand the project scopes and work being done. Elexicon could realize savings from having the two former utilities work together in accomplishing and completing larger road relocation projects. Designers from both former utilities can work together in accomplishing designs that are approved by one utility and not two designs that may or may not work together. Overall, the merger between Whitby Hydro and Veridian Connections will provide benefits financially and operationally to Elexicon and its customers with regards to Road Relocations.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Table 11 presents a list of material projects in 2021. The project summary scope documents are attached in Section 5.2.

Table 11: Material Projects in 2021

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
W2019-0507A	Victoria St W (South Blair to Thickson) - Relocation (Service to Metrolinx) ph 1 of 2	2021	0.62	Mandatory
W2019-0507B	Victoria St W (South Blair to Thickson) - Relocation (Service to Metrolinx) ph 2 of 2	2021	1.24	Mandatory
W2019-5501	Metrolinx Jack and bore for CN crossing at Thickson (West side)	2021	0.56	Mandatory
2020-0512	Rossland (Church x Westney) RR	2021	0.75	Mandatory

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-C.a.3 (SA) Factors affecting the final cost of the project
-C.a.8 (SA) Where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.a.6 (SA) Whether other project design and/or implementation options were considered and if not, why not
-C.a.4 (SA) How controllable costs have been minimized
-C.a.8 (SA) Where applicable, the results of the final economic evaluation carried out as per section 3.2 of the DSC

-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.a.5 (SA) Whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why

Project name	Victoria St W (South Blair to Thickson)-Relocation (Service to Metrolinx) ph 1 of 2				
Project numbers	W2019-0507A				
Job numbers	W17226				
Project District	Whitby				
Project Location	Whitby				
Investment Category	System Access				
Budget Category	A1 - Road Relocation				
Project Driver	Road Authority request to relocate the pole line				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 DEC 31				
Scope of Work	Relocating OH system due to realignment of Victoria St W from South Blair St to Thickson Rd. 2-44kV circuits and 2-13.8kV circuits. Major intersection work at Thickson and Victoria Street. 17 line poles (70', 75' and 80') and 2 span guy poles (45', 50'), 2 sets of 44kV in line switches (total 6), 1 set of 44kV lighting arresters (total 3), 1-25kVA pole mount TX, and 3x25kVA pole TX bank.				
Preliminary Estimate: Total Capital Cost	Gross: $919,791	Contribution: $301,000	Net: $618,791		
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$82,781	$91,979	$156,364	$588,666
Rationale for Intervention	Road Authority request to relocate the assets				
Criteria Score	Not Applicable.				
Impacted Customers and Entities	Not Applicable.				
Intervention Options	There is no alternative option to the project. Elexicon is required to relocate the pole line due to road authority request.				
Effect on System O&M Costs	Not Applicable.				
Targeted Outcomes	The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.				
Cost Benchmarks	Average cost based on historical projects for each pole is $20,000.				
Value-Added Approach	Not Applicable.				

Project name	Victoria St W (South Blair to Thickson)-Relocation (Service to Metrolinx) ph 2 of 2				
Project numbers	W2019-0507B				
Job numbers	W17226B				
Project District	Whitby				
Project Location	Whitby				
Investment Category	System Access				
Budget Category	A1 - Road Relocation				
Project Driver	Road Authority request to relocate the pole line				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 DEC 31				
Scope of Work	Relocating OH system due to realignment of Victoria St W from South Blair St to Thickson Rd. 2-44kV circuits and 2-13.8kV circuits. 30-75' line poles, 10-50' span guy poles, 2-25kVA pole mount TX, 4 sets of 44kV inline switches (total 12), 2 sets of 13.8kV inline switches (total 6), 3 sets of 44kV lighting arresters (total 9), 4 sets of 44kV load break switches (total 12), 26m underground road crossing secondary duck bank and 20m underground secondary trench, 150m underground 2-44kV circuit duct bank under Hydro One ROW.				
Preliminary Estimate: Total Capital Cost	Gross: $1,617,176	Contribution: $372,379	Net: $1,244,796		
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$145,546	$161,718	$274,920	$1,034,993
Rationale for Intervention	Road Authority request to relocate the assets				
Criteria Score	Not Applicable.				
Impacted Customers and Entities	Not Applicable.				
Intervention Options	There is no alternative option to the project. Elexicon is required to relocate the pole line due to road authority request.				
Effect on System O&M Costs	Not Applicable.				
Targeted Outcomes	The project is non-discretionary and is required to meet obligations under law or Code.				
Cost Benchmarks	The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.				
Value-Added Approach	Not Applicable.				

<table>
<tr><td>Project name</td><td colspan="5">Metrolinx Jack and bore for CN crossing at Thickson (West side)</td></tr>
<tr><td>Project numbers</td><td colspan="5">W2019-5501</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">Whitby</td></tr>
<tr><td>Project Location</td><td colspan="5">Thickson Rd (CN crossing) Whitby</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><td>Budget Category</td><td colspan="5">A1 - Road Relocation</td></tr>
<tr><td>Project Driver</td><td colspan="5"></td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 APR 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 AUG 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Install one 44kV and one 13.8kV underground feeders in duct bank under the CN crossing bridge on Thickson Rd (West side)</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="5">Gross: $557,000 | Contribution: $0 | Net: $557,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$50,130</td><td>$55,700</td><td>$94,690</td><td>$356,480</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon has designed new loop system for suppling the industrial customers in Wentworth St area. The project is part of the loop.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">Elexicon new loop system that supplies industrial customer passes through the Metrolinx Electrification project. Considering the difficulties to keep clearances from the Metrolinx track, Elexicon opted for underground design which will be done along with Region of Durham’s improvements on Thickson Rd.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project is part of loop system that supplies industrial customers and will reduce the cost of O&M by providing the options for better system operation and maintenance.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Average cost for cable replacement using directional boring: $500. Cost will go up significantly if trenching is needed.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">New riser poles will be installed in project area to accommodate the underground crossing of the CN tracks.</td></tr>
</table>

<table>
<tr><td>Project name</td><td colspan="5">Rossland (Church x Westney) RR</td></tr>
<tr><td>Project numbers</td><td colspan="5">2020-0512 (ARR.20.0102)</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">Ajax</td></tr>
<tr><td>Project Location</td><td colspan="5">Rossland Rd West from Church St N x Westney Rd N</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><td>Budget Category</td><td colspan="5">A1 - Road Relocation</td></tr>
<tr><td>Project Driver</td><td colspan="5">Relocation request from road authority.</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">This project entails relocating an overhead system involving 46 pole removals and installation of 46 new poles, removal of seven overhead transformers and installation of seven new transformers, removal of one 44kV LIS and installation of a new 44kV LIS.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $1,225,900</td><td colspan="2">Contribution: $472,650</td><td>Net: $753,250</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$110,331</td><td>$122,590</td><td>$208,403</td><td>$784,576</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon Energy received a plant relocation request from Town of Ajax to move its distribution equipment to permit the widening of Rossland Rd W from Church St N to Westney Rd N. This project will improve access/capacity for existing customers and eliminate conflict between the roads and the distribution system.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable. Non-discretionary; project must be undertaken to comply with legal and/or regulatory requirements in the current period.</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative option to the project. Elexicon is required to relocate the overhead system due to road authority request.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project is non-discretionary and is required to meet obligations under law or Code. The project also addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The average cost of the project is based on historical projects for each pole and LIS switch which are $20,000 and $100,000 respectively.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable.</td></tr>
</table>

Budget Category	Connection of New Services
OEB Investment Category	System Access
Primary Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$7.99M	**$11.25M**

1. Executive Summary

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

Connection of New Services projects are System Access investments for new customers that require electrical connections to Elexicon's distribution system. Over the next few years, it is forecasted that a large amount of new residential customers will require service as a result of the major housing developments within the Elexicon territory. Elexicon utilizes municipal and regional household forecasts and regional forecasts alongside development plans and consultations with third-party developers to estimate the number of new customers in the future. Significant developments in Ajax-Pickering and Whitby are expected whereas smaller development is expected in Belleville, Gravenhurst, Port Hope, Clarington, and Brock.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	7.99	14.95	8.94	12.88	11.33	11.45	11.45	11.45
Contributions	4.54	9.58	3.44	5.60	4.63	4.69	4.69	4.69
Net Program Expenditures	3.45	3.45	5.51	7.29	6.71	6.76	6.76	6.76

There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Throughout the historical period, Elexicon experienced an average 1.16% growth in residential customers year over year. For the years of 2018 and 2019, an increase in customers was experienced citing the recent developments within the area. Elexicon's territory is currently experiencing major developments such as Seaton, Brooklin, West Whitby, and others across the area. Durham's position as a region is expected to grow economically and in terms of households. The major development center in the Elexicon territory will be found in Whitby and the Ajax-Pickering area. In particular, the Pickering area is expected to experience the largest growth in the next forecast period.

The consolidated staff and expertise will enable the combination of two experienced workforces and processes. Standards will be consolidated that will benefit both former territories. This will ensure an increase in residential developments being connected in a timely and safe manner. Additionally, operations work will be efficiently resourced within these three regions.

Primarily, the new residential service connections will be installed underground. Elexicon will proceed with overhead service connections in situations where ground conditions or terrain make underground installations technically unreasonable. Additionally, where feasible and economically viable, Elexicon will proceed with overhead connections provided pre-existing overhead infrastructure exists. However, these instances are subject to municipal approval and Elexicon's sole discretion. Elexicon always strives to connect new residential connections within five days of the initiated work. Elexicon will follow the principles as outlined in its conditions of service and ensure a safe connection compliant to *O. Reg 22/04* and its distribution standards.

2. Basis for Action

2.1 Performance Trends:

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project

The data/inputs that Elexicon considers when addressing the connections of new services are from several sources.

1) Household Projections

Household projections from the Region of Durham, Belleville, Gravenhurst, and Port Hope drive Elexicon's projections of the amount of expected new connections for Elexicon. In the current DSP period, Elexicon anticipates the growth of Ajax, Pickering, and Whitby will be considerable as compared to that of the other municipalities. Pickering is expected to experience the highest household growth of all service areas.

2) Development Plans

Development plans from the municipalities and developers help Elexicon understand the amount of expected new service connections within the area. As these development plans are initiated by the region or municipality, they are reflective of the long-term outlook of housing within the area. These development plans also detail expected economic development within the area.

3) Contacts with developers and customers

Ultimately, when a connection is required, the developer or customer will contact Elexicon. In which case, the developer and Elexicon will discuss the development in terms of expected number of houses to be built and occupied. Each lot that is assumed to be of a similar dwelling is expected to produce similar electrical demand in the area. Elexicon will then estimate and create plans for distribution loading and infrastructure in the area. Elexicon will provide an offer to connect the customer to the distribution system within its area. Larger Commercial and Industrial Customers proactively contact Elexicon to discuss expected service requirements and demand. Standard procedures in the Conditions of Service and *Distribution System Code* shall be followed for each customer class.

These inputs contribute to the overall residential forecast that Elexicon uses to prepare for new residential customers entering the Elexicon territory.

1 – Municipal Household Projections

The Regional Municipality of Durham Semi-Annual Monitoring of Growth Trends

The regional municipality of Durham produces household projections on a semi-annual basis for every municipality as shown in Figure 1. The areas served by Elexicon that the region has produced projections for include Ajax, Brock, Uxbridge, Scugog, Clarington, Pickering, Uxbridge, and Whitby. Pickering is expected to experience the most growth of all Durham territories under Elexicon. From the projections set forth by the region, the total number of households in Pickering are expected to pass Clarington in 2021 and Ajax in 2023. The areas of Whitby, Ajax, and Clarington are also expected to produce impactful household completion numbers. Of the service areas that Elexicon designates, Ajax-Pickering shall experience 11,970 housing completions in the next four years which is about 60% of the total household completions within Elexicon's service area.

Figure 1: Household Projections-The Regional Municipality of Durham

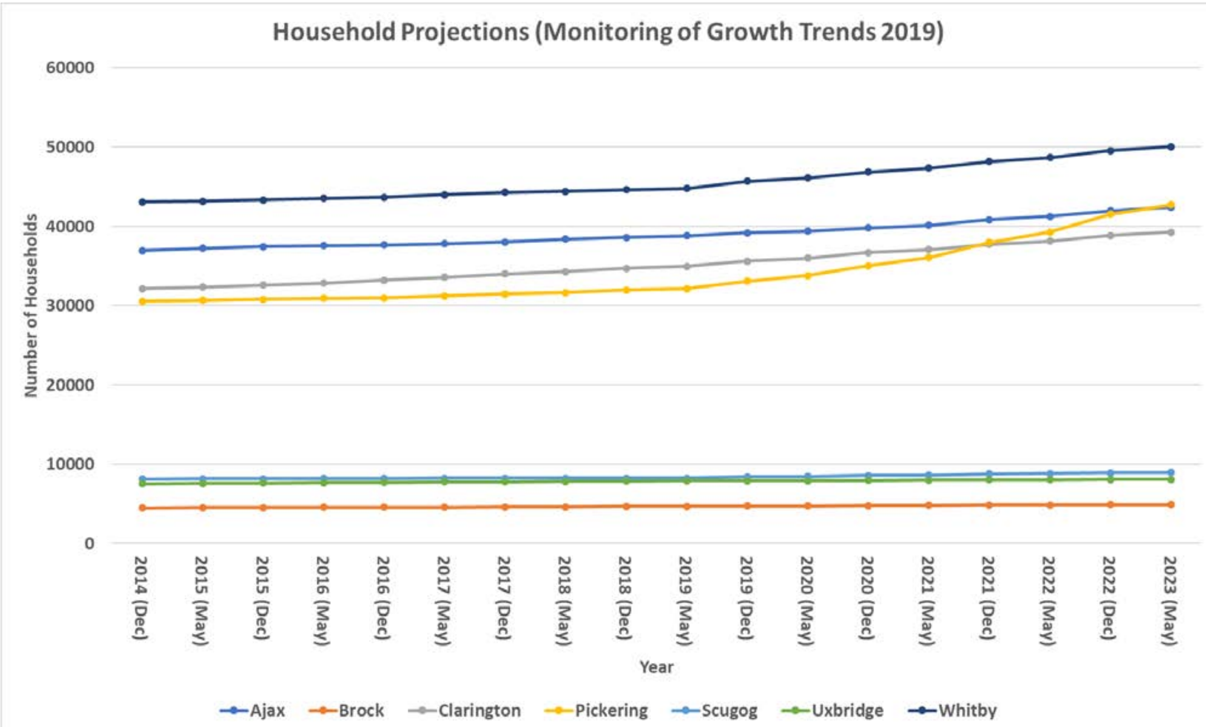


Table 2: Forecasted Households by Durham Constituent

Year	2020 (May)	2020 (Dec)	2021 (May)	2021 (Dec)	2022 (May)	2022 (Dec)	2023 (May)	Total Household Change
Ajax	39,410	39,790	40,160	40,830	41,250	41,980	42,440	3,030
Brock	4,740	4,780	4,800	4,830	4,840	4,870	4,890	150
Clarington	36,000	36,680	37,060	37,750	38,150	38,870	39,260	3,260
Pickering	33,780	35,020	36,090	37,990	39,260	41,530	42,720	8,940
Scugog	8,460	8,580	8,640	8,770	8,820	8,910	8,950	490
Uxbridge	7,930	7,970	7,990	8,020	8,040	8,080	8,090	160
Whitby	46,120	46,870	47,350	48,200	48,690	49,570	50,070	3,950
Total	**176,440**	**179,690**	**182,090**	**186,390**	**189,050**	**193,810**	**196,420**	**19,980**

City of Belleville: 2018 Municipal Comprehensive Review of Urban Serviced Area

The City of Belleville enlists external consultants to produce a comprehensive review of the urban serviced area within the City. Projections for households are produced in five-year increments into the future, as shown in Figure 2. The report aims to "provide a long-term assessment of future urban growth and associated urban land needs to inform and support the City's new Official Plan".

Figure 2: Belleville Household Projections by Municipal Review

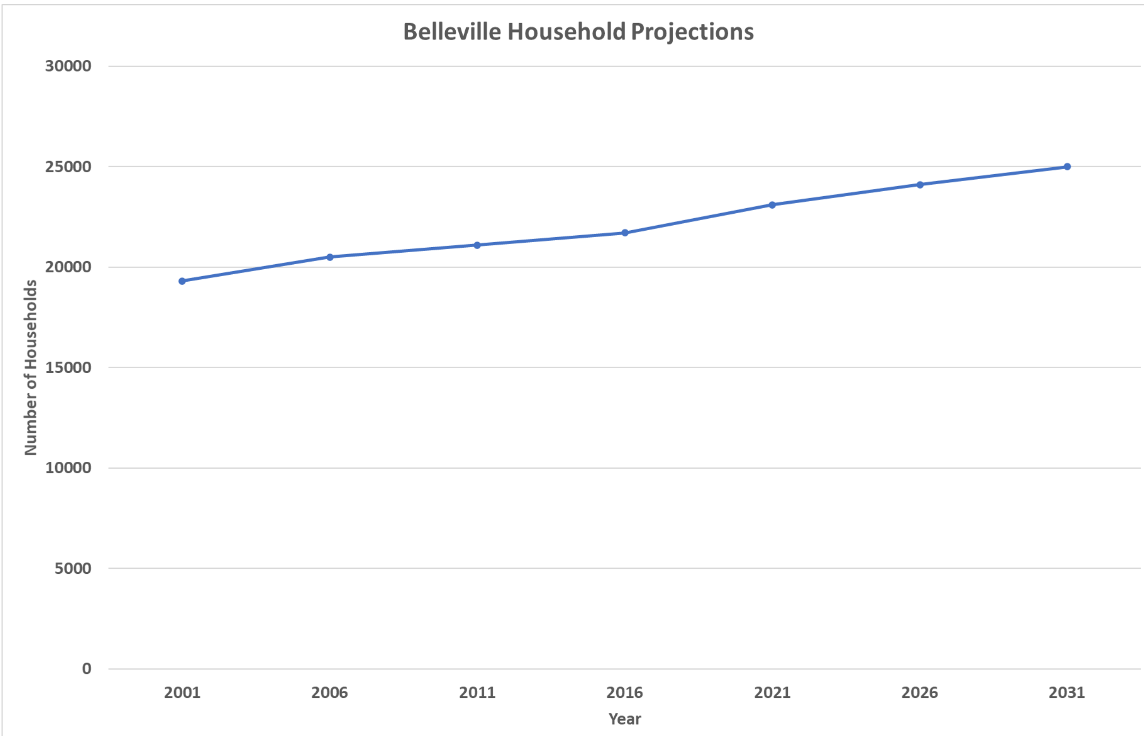


Table 3: Household Projections - Five-year increments

Year	2001	2006	2011	2016	2021	2026	2031
Belleville	19,300	20,500	21,100	21,700	23,100	24,100	25,000

2019 Growth Strategy: The District Municipality of Muskoka, Forecast & Growth Allocation Report

The District of Muskoka produced a *2019 Growth Strategy Report* outlining Gravenhurst's projections into 2026 and 2036 with the help of external consultants. The forecasts help “guide the development of policies related to planning and growth management, urban land needs, and municipal finance at the District and Area Municipal levels”.

Figure 3: Household Projections for Gravenhurst-Growth Strategy

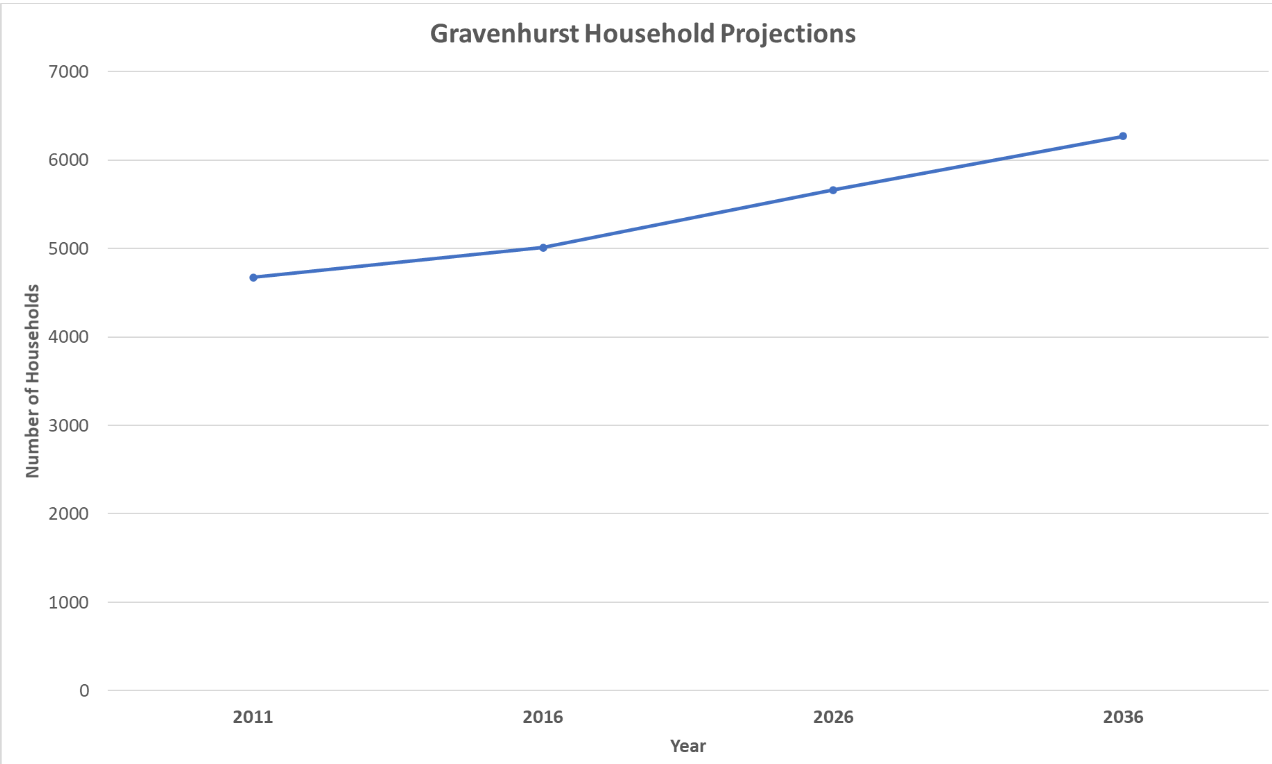


Table 4: Gravenhurst Growth Projections for Households

Year	2011	2016	2026	2036
Gravenhurst	4,675	5,010	5,660	6,270

2019 Development Charges Background Study: Municipality of Port Hope

The Municipality of Port Hope produced a *2019 Development Charges Report* outlining Port Hope's household projections for 2019 and 2029 with the help of external consultants. The study was prepared to meet the requirements of the Ontario *Development Charges Act, 1997*. A household forecast is prepared that summarizes the anticipated growth for the Municipality and describes the basis for the forecast.

Figure 4: Port Hope Household Projections- Growth Strategy

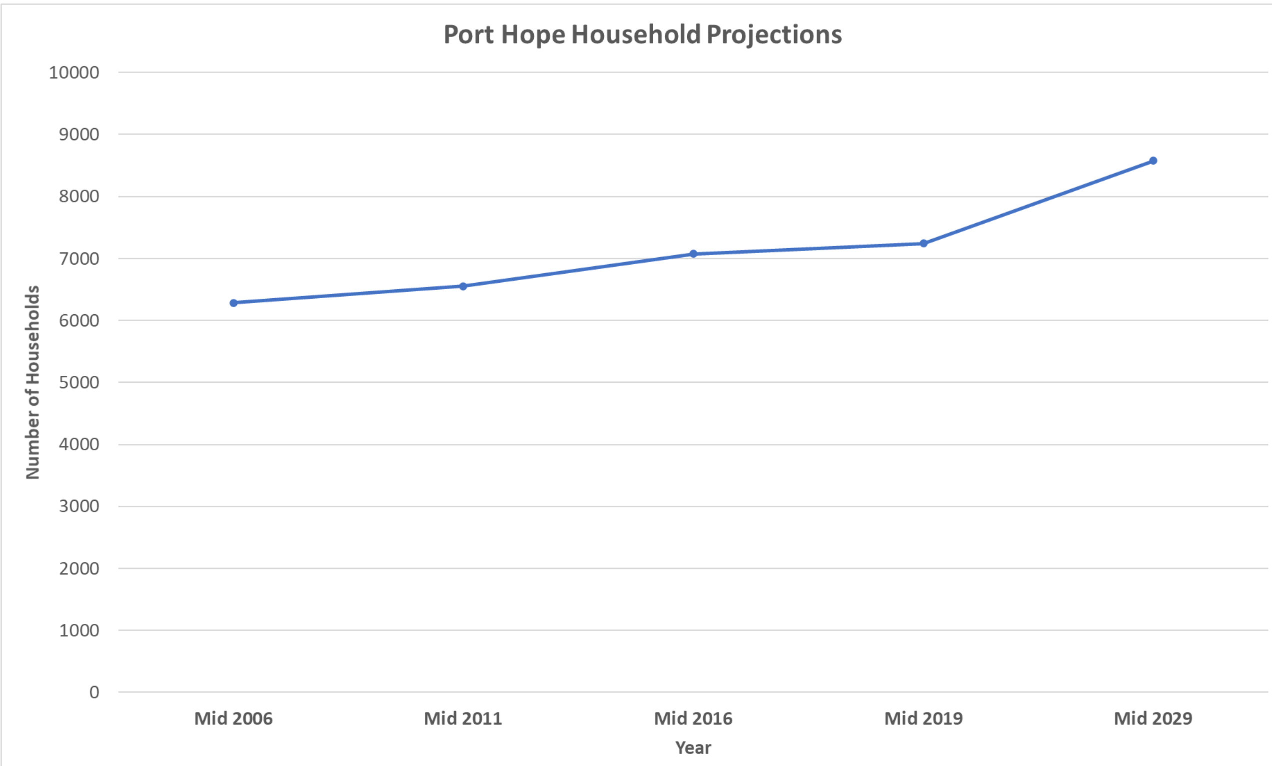


Table 5: Growth Projections for Port Hope

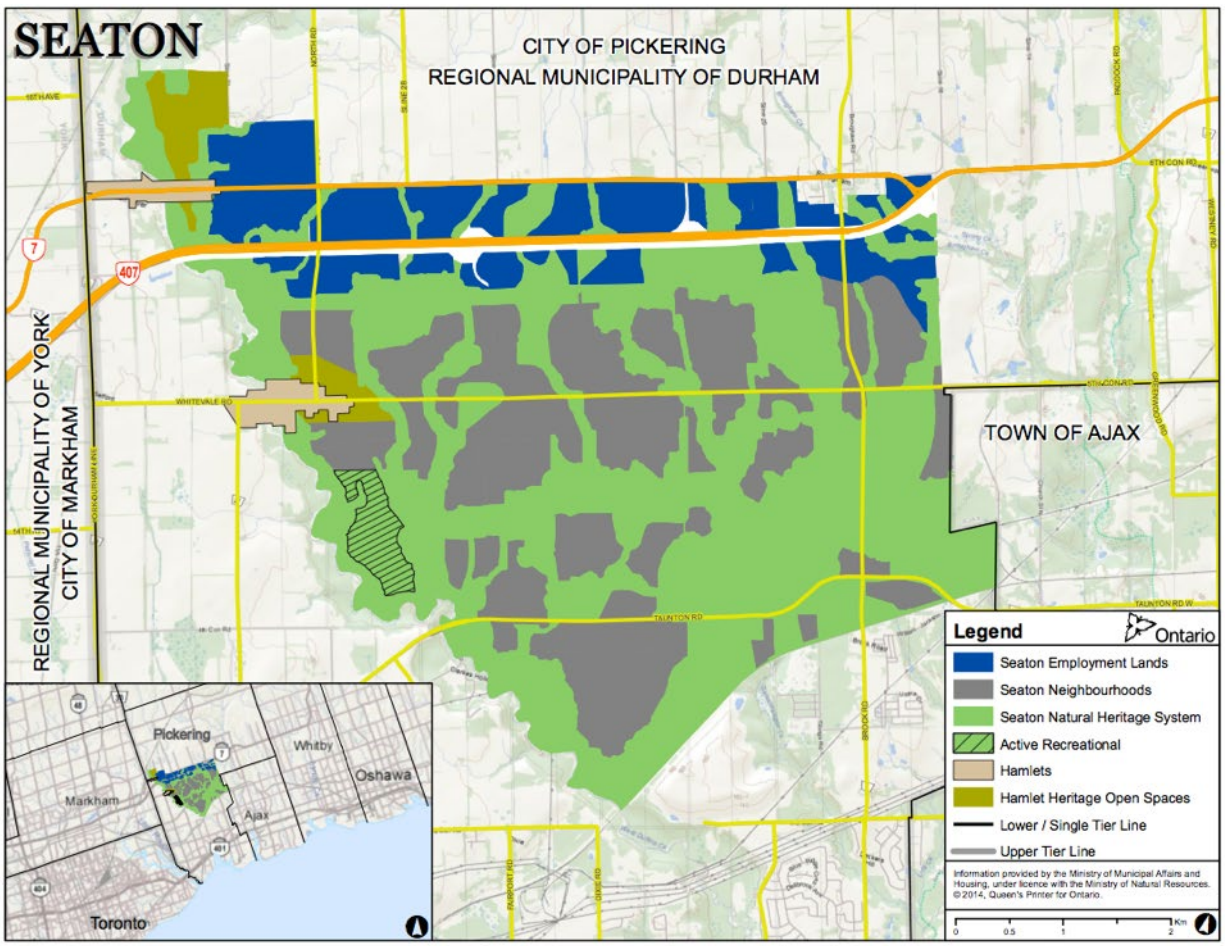
Year	Mid 2006	Mid 2011	Mid 2016	Mid 2019	Mid 2029
Port Hope	6,285	6,552	7,075	7,240	8,575

2- Examples of Major Residential Developments

There are major residential developments within the Elexicon territory which will bring a large influx of connections of new services throughout the next DSP Period. These developments include Seaton in Pickering, and Port Whitby, West Whitby, and Brooklin in Whitby. These development areas are the main causes of the major residential household growth as evidenced by the Regional Municipality of Durham's household forecasts.

One of the major developments in the Elexicon territory that is driving a large portion of the connection of new services investments is Seaton, a new development located in Pickering. Seaton was conceptualized in the early 1970s by the Ontario Provincial government for a community development northeast of Toronto. The ultimate population of Seaton is 70,000 people and six neighbourhoods of ranging housing types and densities. The current development of Seaton has undergone but is expected to continue as there is a range of civil and development work still required.

Figure 5: Seaton Development Lands by the Ontario Government



Port Whitby

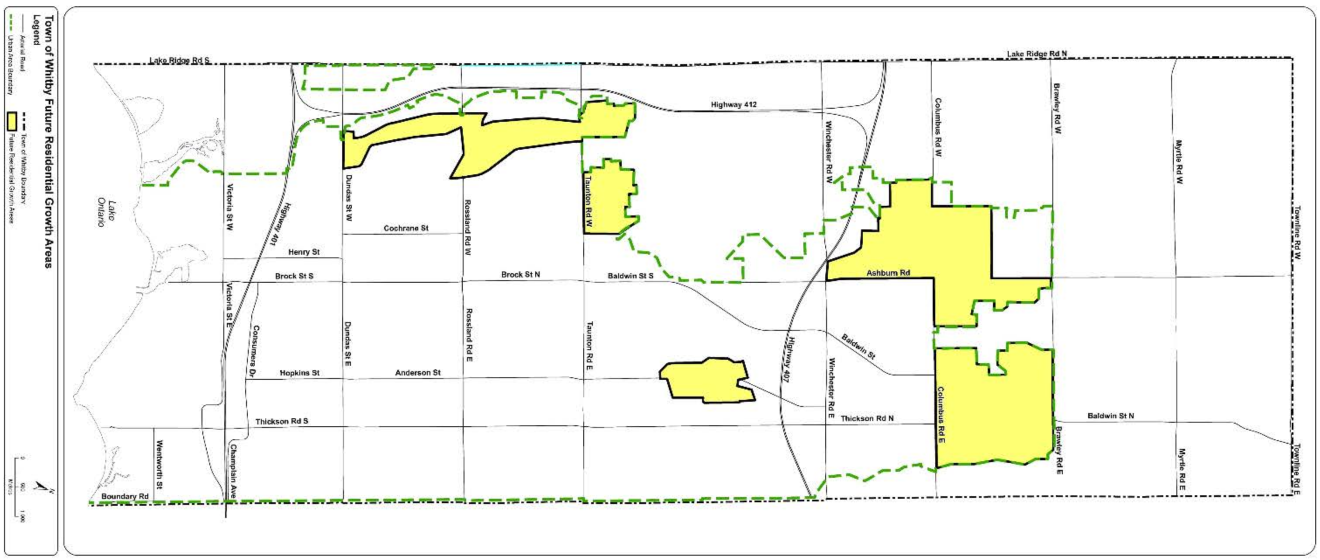
Port Whitby has been identified by the Town of Whitby as an area with major future development. Two prominent neighbourhoods are planned: one containing 1,111 condominium units and 132 townhouses; and the other containing 349 residential units, an eighteen-story tower, and five low-rise buildings.

Figure 6: Port Whitby Development

West Whitby and Brooklin

West Whitby has a major development of 552 single-detached units and 143 townhomes/apartments planned. Based on the growth plans, it is estimated that 21,000 to 26,000 people will move into west Whitby. Brooklin will expand by around 56,000 people over the next two decades. Consistent growth has been identified in the Brooklin and West Whitby areas as highlighted in Figure 7.

Figure 7: West Whitby and Brooklin Development Lands



Historical Year-to-Date Connection of New Services

For the years 2015 to 2017, the total number of connections of new services annually was relatively constant year over year. In 2018, Elexicon experience a noticeable higher number of customer connection requests and for the year 2019, Elexicon connected a substantial high of 3,310 new connections. These numbers detail the increasing developments found within Elexicon's service area. With larger developments such as Seaton, West Whitby, and Brooklin planned, Elexicon is expecting an increasing number of connections to new services.

Figure 8: Historical Connections of New Services

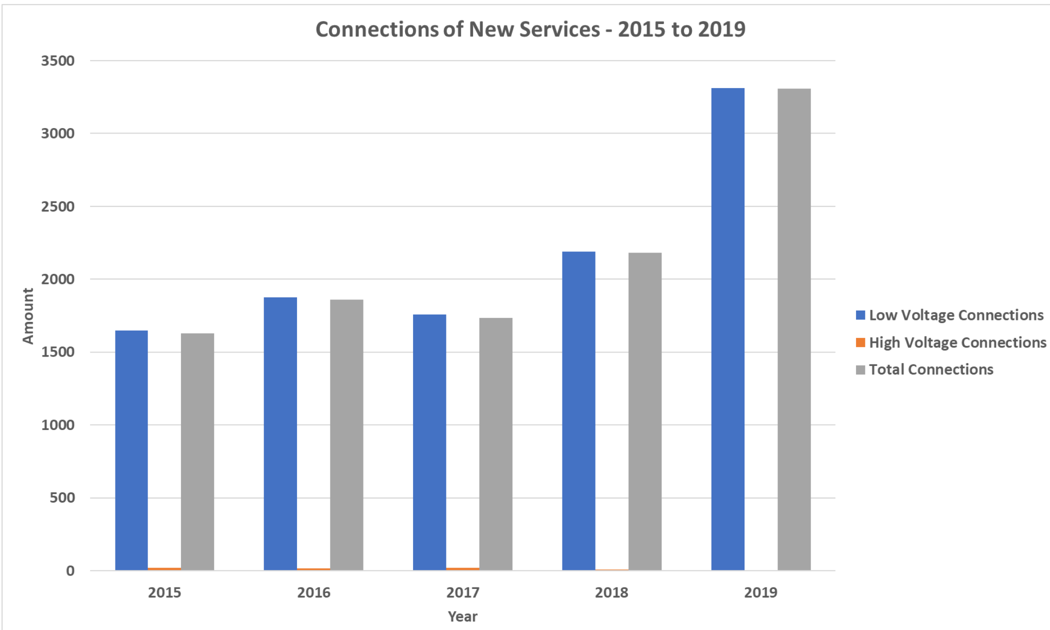


Table 6: Historical Low and High Voltage Connections Year to Date

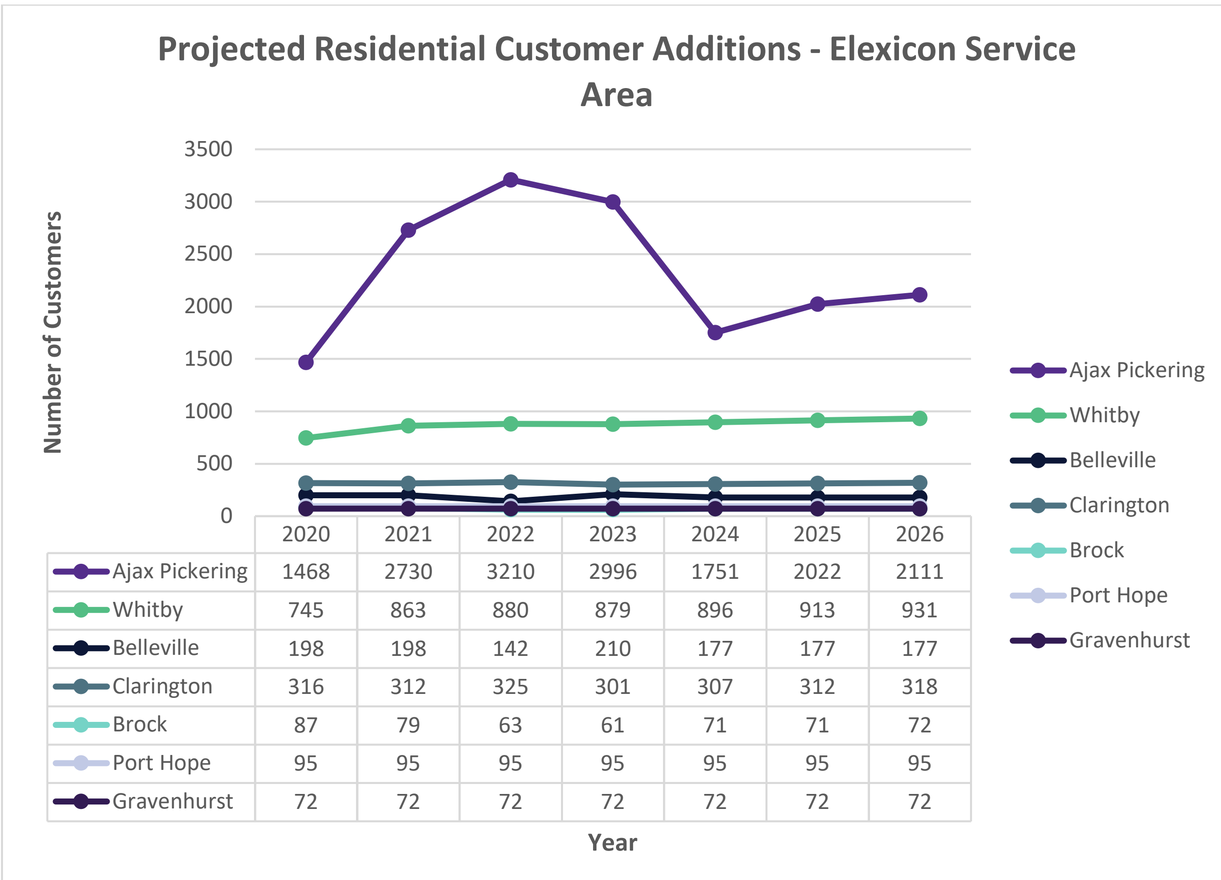
Year	2015	2016	2017	2018	2019
Whitby Low Voltage (<750 V)	424	549	432	505	1,271
Veridian Low Voltage (<750 V)	1,203	1,310	1,304	1,675	2,035
Whitby High Voltage (>750 V)	6	4	4	4	1
Veridian High Voltage (>750 V)	16	12	18	4	2
Total Elexicon Connections	**1,649**	**1,875**	**1,758**	**2,188**	**3,309**

<u>2.2 Current-State Analysis:</u>

Year-End Residential Customer Forecast for the DSP Period – Elexicon

Throughout the DSP period, it is forecasted that Elexicon may experience an increase of 27,535 residential customers over the next five years. Due to the increase in households that produce greater residential customer numbers, Elexicon will increase further investments into the connection of new services.

Figure 9: Total Annual Year-End Residential Customer Historical and Forecasted



Elexicon designates annual budgets for a variety of general connections of new services projects across the future DSP period. These investments are listed in Table 7.

Table 7: Annual Elexicon Projects and Durations

Annual Elexicon Project Name	Duration
New Residential Development- Non-Seaton	2020 to 2026
New Residential Development-Seaton	2020 to 2023
O/H New Residential Services	2020 to 2026
Temporary Services with w/o TX's	2020 to 2026
Transformers -General Services	2020 to 2026
U/G New Residential Services	2020 to 2026

The new Seaton TS found in the System Service-Substation Growth and Expansion portfolio will serve the new Seaton development by adding capacity around the area. New housing developments are ongoing in the Elexicon territory and being constructed in the area. In some areas, the current system cannot connect an entirely new neighbourhood from large developments. Elexicon will construct neighbourhood circuits and the necessary electrical distribution systems to connect these residential customers. Examples of assets required to connect new customers include overhead assets such as poles, transformers, conductors, switches, and pole line hardware for overhead systems and underground assets include transformers, cable ducts, conductors, and switches for underground systems. The figure below demonstrates the current developments planned within Seaton and the magnitude of the number of connections of new services that will be influenced by the one location. As the feeder expansions are created within the area, the connections for the new households will follow. Elexicon prefers to connect customers via an underground service as described in its Conditions of Service.

Altona Towns MicroGrid Project

In 2020, Elexicon completed two projects with connections of a Community Microgrid to the Elexicon network. Elexicon installed new connections and a recloser designated for the community. In partnership with the developer and consultant, any power from the microgrid will be returned to offset the costs of electricity. This marks a major implementation of a community microgrid in the territory and will be key to the dynamics of the future customer. Elexicon will be proactive in monitoring and ensuring the stability of the system for the community.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

Distribution System Code

New connections will follow the *Distribution System Code* (DSC) and specifically sections 3.1 for *Connections* and Section 7 *Service Quality Requirements*. As defined in the DSC, a connection is the process of installing and activating connection assets to distribute electricity. Section 3.1 outlines the requirements for the connection policy and obligations to new connections for utilities.

Section 2, *Conditions of Service*, of the DSC is also relevant since Elexicon needs to oblige to its Conditions of Service set forth to the customer and to itself. Elexicon is obligated by the OEB to maintain and publish its Conditions of Service that outlines the details to connections of new customers within its service territory.

Ontario Energy Board Performance Measures

The OEB's *Reporting and Record-keeping Requirements* ("RRR") require all electricity distributors in Ontario to track Service Quality Requirements, including targets for connecting customers on time. Unless the customer requests a later date, the utility must connect a new service for the customer within five business days at least 90% of the time. With an increase in connections within the territory, Elexicon has budgeted further investments into the connections of new services to ensure performance does not drop for New Residential Services Connected on Time.

O. Reg. 22/04 (Electrical Distribution Safety)

When constructing or updating new electrical distribution infrastructure, Elexicon must follow O. Reg. 22/04 (*Electrical Distribution Safety*). In compliance with O. Reg. 22/04, Elexicon ensures its distribution system is safe and poses no undue hazard to the public. These requirements apply to customer connections, including the distribution transformers, secondary service, and meter.

OEB Act, Section 92:

Leave to Construct approval is not required for these investments.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service:

According to the RRR, at least of 90% of new residential/small business services need to be connected within five days. This metric is evaluated annually and reported to the OEB. If Elexicon fails to connect a customer within five days, or a later date if requested by the customer, then Elexicon's service-quality performance would deteriorate. Additionally, Elexicon has a responsibility to its customers to connect new services on time to establish the utility and customer relationship. Delays to connections could damage Elexicon's relationship with its customers and its brand image. With an increase in residential developments in the Elexicon territory, the utility must spend more resources than historically to continue providing customers with the expected level of customer service. Elexicon Customers expect excellent and consistent electrical service for their purposes when connecting to the grid. Establishing new connections of services that are applicable and suitable are crucial to customers and their daily lives.

Operational Effectiveness:

By ensuring new connections are on time and addressing them on an efficient basis, Elexicon as a company will be more operationally effective. Any lingering work may delay the rest of the investment portfolio for Elexicon; the high volume of new residential connections requires that Elexicon be diligent in being operationally effective.

Public Policy Responsiveness:

Connections of new services should follow Electrical Distribution Safety regulations that are outlined in O. Reg. 22/04. All aspects of Elexicon's plant shall comply with the regulation including installation, design, inspection, and materials. Elexicon uses standard designs for customer services and its Conditions of Service lays out the fundamental processes and commitments that Elexicon follows when connecting new customers. Unless otherwise proven to be difficult, new connections are made through underground systems.

Financial Performance:

Elexicon needs to make the best use of financial resources and planning for the new connections and developments within the territory. Failure to capture the value of new assets and provide value-backed investments into new connections can affect Elexicon's Financial performance.

2.5 Merger-Related Objectives:

The amalgamation of Whitby and Veridian to Elexicon provides a consolidation of design and construction services to new connections. The two former utilities can consolidate expertise and experience with connections of new customers to benefit the larger Elexicon territory. Due to the volume of new residential developments and customers in the upcoming years, the consolidation of resources will prove vital to ensuring service continuity and customer service. Elexicon will however have a plan for or invest further financially into the connection of new services investment projects. Other programs may have decreased contributions because of the growth of new customers. All new services must be installed at underground standards. However, in cases where overhead distribution standards are more prevalent, or instances are more reasonable, overhead standards will be used. Overhead distribution is subject to municipal approval and Elexicon's discretion as outlined in its Conditions of Service.

Connections of new services investments provide high value to service continuity as it is a System Access project and is mandated by legislative or regulatory requirements. It also provides high value to utility integration as it improves the throughout of planning, design, construction, operations, and back-office capabilities relative to both predecessors.

3. Program Alternatives

-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

3.1 Alternative Descriptions and Comparative Analysis

Number	**1**	**2**	**3**
Scenario Description	Status Quo: Current Budgeted Connections of New Services Investments	Only perform Connections of Overhead Services for connections of new services	Increased Storm Hardening with regards to connections of new services work
Annual Program Scope	In the currently planned investments, overhead and underground connections of new services are performed. For areas where overhead infrastructure is already present or the only feasible option, Overhead designs are used. Otherwise, Underground Connections shall be utilized for all other situations.	The client may be satisfied with cheaper construction costs, but reliability may be worse for an overhead system. Elexicon prefers underground connections to ensure reliable service to customers.	The client may be satisfied with a more hardened system for connections of new services. With hardening, the program will also cost more due to the material needing to be more resilient to outside climates.
Annual Gross CAPEX	$11.25M	$3.71M	$16.88M
Annual Net CAPEX	$6.63M	$2.19M	$9.95M
Annual Program Benefits	The mandatory projects belonging to this program generally address the objectives of improving customer focus, final performance,	The mandatory projects belonging to this program generally address the objectives of improving customer focus, final performance,	The mandatory projects belonging to this program generally address the objectives of improving customer focus, final performance,

	operational effectiveness and public policy responsiveness.	operational effectiveness and public policy responsiveness.	operational effectiveness and public policy responsiveness.
Program Economics	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.
Customer Feedback	Elexicon Customers (262 that were online-surveyed and 600 that were telephone-surveyed) were informed that Elexicon will spend a portion of their five-year budget to support customer growth in addition to keeping the system safe. Customers were then asked to select two other potential objectives that Elexicon should focus on.	Elexicon Customers (262 that were online-surveyed and 600 that were telephone-surveyed) were asked about underground conversions or underground systems related to current rear lot lines. About 20.4% (176 of the 862 surveyed customers) of customers support maintaining status quo i.e., keeping the overhead lines in the rear lots and replacing them as they fail. 62% of customers were in favour of underground systems.	About 61.5% (374 of the 600 telephone-surveyed and 156 of the 262 online-surveyed) of customers selected that improving grid resilience to major storm events should be the first or second choice of objectives in addition to Elexicon making investments for new growth and system safety.
Other Constraining Factors	One constraining factor with this budget is if more connection of new services is required in the future DSP period. If further projects are to be produced, Elexicon will have contingencies in place to shift the budget such that all mandatory connections are made.	The costs of the connection would be cheaper. However, Elexicon is dedicated to using underground where applicable as it is a more reliable system than that of overhead.	Additional costs will be incorporated such that the design of the system will be more hardened. The customer may not want to pay the extra costs.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: In terms of reliability, underground systems are less prone to outages due to external factors such as weather.

Grid Resiliency: Overhead Services are less resilient to extreme weather as it is exposed to the outside environment. Underground services do not experience the effects of weather as it is shielded from such exposure.

Operational Efficiency and Cost Effectiveness: Overhead service connections are more cost-effective than underground service connections. Prudent investment and execution of new connections are required for the company to be operationally efficient and cost-effective. Delays in connections from Elexicon's side would affect operations throughout the company and increase costs.

Safety: Overhead services have a safety risk in terms of downed lines in situations where weather or external factors bring down overhead services. Underground systems are less exposed to the public, but carry a risk of dig-ins. Through participation in the Ontario One Call program, the risk of dig-ins is mitigated. New Connections are safely implemented in compliance with the Electrical Distribution Safety requirements.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Customers will benefit from Elexicon investing the requisite resources to ensure timely customer connections. By planning new connections underground where feasible, reliable and aesthetic services are provided to customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

Generally, since all access projects are mandatory, it can be assumed that connection projects will positively get materialized as planned. Any additional budget and resources will be shifted to other renewal projects as needed. Although system access projects are planned ahead of time, in few cases, construction delays and/or other external factors may significantly contribute to access projects' delays. The budget will, however, be set to ensure that the connections of new services shall still be completed on time when a connection is initiated.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Previously, customer forecasts from the residential side were driven directly by reports for the Region of Durham and assumptions made on smaller growth in other areas of Elexicon. Currently, an adjusted household forecast is produced using the semi-annual forecasts provided by the Region of Durham. Household projections from Belleville, Gravenhurst, and Port Hope are also taken into place. These individual forecasts from the separate areas allow Elexicon to plan for new residential customers to be expected within each geographic region. This allows a more granular level of understanding in terms of where new residential customers are expected to be using the specified municipal forecasts of each region. The household forecasts of each region are adjusted based upon historical accuracy and extrapolated into the future based on the trendline, such that historical data can be used to evaluate the actual household totals and the forecasted household totals. This forecast paints a picture of the potential expected number of new customers in each region.

Each legacy utility had a distinct Conditions of Service detailing the procedures related to each service connection. Elexicon has consolidated the best practices of both utilities into a singular Conditions of Service for Elexicon into the future. All new residential subdivisions are planned to be underground unless circumstances call for overhead connections.

4.2 Legacy Work Execution Approaches vs. Combined Operations

All electrical systems on customer premises and within buildings are subject to electrical inspection by the ESA. Elexicon will not connect any service until applicable installation and wiring are inspected and approved by the ESA. All new residential subdivisions shall be serviced underground unless it is not feasible to install. For instance, if existing infrastructure is overhead and a new customer requests an overhead connection, then its feasibility will be addressed.

Material differences between the two legacy utilities have been consolidated in the combined distribution standards at Elexicon. Some customers are served via overhead systems; however, underground systems are generally preferred. When an overhead system is the only option, Elexicon will have to go through municipal approval procedures under its sole discretion. Elexicon is responsible for the design standard, outlying the requirements for connection, inspection after construction, and constructing any infrastructure as defined in the Conditions of Service.

Service Voltage Offerings have been unchanged from the two voltage offerings of the former utilities. A conscious effort has been planned by Elexicon to perform voltage conversions for 8.32 and 4.16 kV systems in the service area. This is detailed further in the System Renewal – Voltage Conversion Business Case. A list of primary voltages and secondary voltage offerings are listed below in Table 8.

Table 8: Service Voltage Offerings- Primary and Secondary

Primary Voltage	Secondary Voltage
4.16/2.4 kV grounded wye, three-phase, 4 wire	240/208/600V, single-phase, 3-wire
8.32/4.8 kV grounded wye, three-phase, 4 wire	240/208/600V, three-phase, 4-wire
12.48/7.2 kV grounded wye, three-phase, 4-wire	347/600V, three-phase, 4-wire
13.8/8k kV grounded wye, three-phase, 4-wire	
27.6/16kV grounded wye, three-phase, 4-wire	
44KV effectively grounded wye, three-phase, 3-wire	

4.3 Scale Increase Considerations

The consolidation of operations and internal staff assists in completing residential connections in a scheduled manner. The joint pool of increased resources collectively brings together the knowledge and skills of the two former utilities. Resources can be pulled from other projects if available.

With the merger, Elexicon has sufficient budget and resources to address connection projects and high purchasing power. The operational efficiencies should provide financial savings as one entity is handling connections from the two former areas.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

With regards to the Connections of New Services, Elexicon must complete the work as it is a mandatory obligation to connect customers to the distribution system. Elexicon always provides economic options applicable to the customer. If underground systems cannot be built, overhead systems will be installed to connect new customers. As most of the new connections of services are expected in Ajax, Pickering, and Whitby, cost savings or efficiencies may be discovered by coordinating discussions and internal holdings in parallel. The combined staffing resources may also assist in finishing work more efficiently.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2017-0641	1956 Altona Road- Community Micro Grid (28 lots) – Recloser	2021	0.32	Mandatory
2021-0601	New Residential Development- Non-Seaton	2021	1.45	Mandatory
2021-0603	O/H New Residential Services	2021	0.72	Mandatory
2021-0604	U/G New Residential Services	2021	0.73	Mandatory
2021-0606	New Residential Development-Seaton	2021	0.73	Mandatory

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-C.a.3 (SA) Factors affecting the final cost of the project
-C.a.8 (SA) Where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.a.6 (SA) Whether other project design and/or implementation options were considered and if not, why not
-C.a.4 (SA) How controllable costs have been minimized
-C.a.8 (SA) Where applicable, the results of the final economic evaluation carried out as per section 3.2 of the DSC
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.a.5 (SA) Whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why

<table>
<tr><td>Project name</td><td colspan="5">1956 Altona Road - Community Micro Grid (28 lots) - Recloser</td></tr>
<tr><td>Project numbers</td><td colspan="5">2017-0641</td></tr>
<tr><td>Job numbers</td><td colspan="5">ACA190152</td></tr>
<tr><td>Project District</td><td colspan="5">Ajax</td></tr>
<tr><td>Project Location</td><td colspan="5">1956 Altona Road Ajax</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Access</td></tr>
<tr><td>Budget Category</td><td colspan="5">A2 - Connection of New Services</td></tr>
<tr><td>Project Driver</td><td colspan="5">Pilot project for Community Micro Grid</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project is part of Community Micro Grid project at 1956 Altona Road. The scope is to install an OH recloser and other distribution assets to service 28 townhouses.

The project consists of a 333kVA/666kWh battery energy storage system, public Level 2 electric vehicle charging station, innovative smart metering system for community use, 5kW/13kWh powerwall, 25kW of roof top solar panels and an integrated distribution energy service platform to control and coordinate the components of the microgrid.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $315,000</td><td colspan="2">Contribution: $0</td><td>Net: $315,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$28,350</td><td>$31,500</td><td>$53,550</td><td>$201,600</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">This project serves as the ideal opportunity for Elexicon to further highlight and enhance the integration of renewables with microgrid operation into Ontario’s energy landscape for customers. It’s also the important step in developing a system that will allow community microgrids to be added to utility distribution grid that will improve the quality of life for customers.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">28 Customers</td></tr>
<tr><td>Intervention Options</td><td colspan="5">The project is part of Community Micro Grid project.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.

<u>Project benefits</u>
<u>Grid benefits</u>
• Greater ability to integrate and manage renewable generation and electric vehicles.
• Improved grid reliability and resiliency
• Ability to identify and learn customer behaviour with an integrated microgrid and create a framework for utilities to deploy microgrid solutions.</td></tr>
</table>

	• Energy demand management and peak shaving • Providing voltage and frequency regulation **Community benefits** • Reliability of service for customer during grid contingencies or planned maintenance of grid supply. • Enabling customers to access to abundant information including advanced metering, data analytics, energy consumption, generation and storage. • Electric vehicle charging station for customers within the community. • Platform for developers for sustainable development • GHG reduction through renewable energy generation and energy storage
Cost Benchmarks	Not Applicable. The project is funded by the Ontario's Ministry of Energy, Northern Development and Mines 'Smart Grid' and IESO's 'Grid Innovation' programs.
Value-Added Approach	Not Applicable

<table>
<tr><td>Project name</td><td colspan="5">New Res Development-Non Seaton</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-0601</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><td>Budget Category</td><td colspan="5">A2 - Connection of New Services</td></tr>
<tr><td>Project Driver</td><td colspan="5">New customer connections request</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">A forecasted number of new residential connections is developed based on historical data and planning information from Regions, Municipalities, Towns and Cities.
For 2021, the number of new lots to be serviced in subdivisions is estimated to be 1000 lots at $2,900 per lot. This quantity of lots is for all Elexicon Energy service areas other than in the Seaton Development in Pickering.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $2,900,000</td><td colspan="2">Contribution: $1,450,000</td><td>Net: $1,450,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$261,000</td><td>$290,000</td><td>$493,000</td><td>$1,856,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The project is service new residential developments and is required to comply with legal and/or regulatory requirements.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to project. Projects are driven by statutory and regulatory obligations on the part of the distributor to provide customers with access to the distribution system.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">An economic evaluation is carried out to determine Elexicon's share of the costs. The upstream capital cost contribution has been removed from the estimates. The estimated cost per lot ($2900) is based on historical spending levels per lot that are reviewed regularly, typically on an annual basis. The costs not supported by the economic evaluation are recovered from the developers/customers.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

<table>
<tr><td>Project name</td><td colspan="5">Transformers - General Services</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-0602</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><td>Budget Category</td><td colspan="5">A2 - Connection of New Services</td></tr>
<tr><td>Project Driver</td><td colspan="5">Requests from commercial and industrial customers</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project scope is to reconfigure, upgrade or install three phase transformers for commercial and industrial customers.
This budget is for customer requests to accommodate new loads or upgrade to existing load and it’s 100% paid for by the requester.
Based on 2019 and 2020 numbers, an average of 53 units are addressed within Elexicon territory.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $2,551,000</td><td colspan="2">Contribution: $1,151,000</td><td>Net: $1,400,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$180,000</td><td>$200,000</td><td>$340,000</td><td>$1,280,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The project is initiated by customer requests and is required to comply with legal and/or regulatory requirements.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to project. Project is driven by statutory and regulatory obligations on the part of the distributor to provide customers with access to the distribution system.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Included project-associated O&M costs.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5"></td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Project name	OH New Residential Services				
Project numbers	2021-0603				
Job numbers	Several				
Project District	General				
Project Location	General				
Investment Category	SYSTEM ACCESS				
Budget Category	A2 - Connection of New Services				
Project Driver	Connection Request from customer/developer				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 DEC 31				
Scope of Work	The project scope would include one of the following items depending on type of the request from customer. • New or Upgraded Service Connection: Requests for new or upgraded electrical service connection for an existing house, semi-detached or townhouse. • Existing OH Residential service removal. • Triplex relocations where necessary (aerial trespassing) • Upgrade with equipment change or replacement: Applies when equipment is worn and requires replacement <u>or</u> after hours trouble call requires the replacement or upgrade •				
Preliminary Estimate: Total Capital Cost	Gross: $722,000	Contribution: $0	Net: $722,000		
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$64,980	$72,200	$122,740	$462,080
Rationale for Intervention	The project is service OH New Residential Services and is required to comply with legal and/or regulatory requirements.				
Criteria Score	Not Applicable				
Impacted Customers and Entities	Not Applicable				
Intervention Options	There is no alternative to project. Project is driven by statutory and regulatory obligations on the part of the distributor to provide customers with access to the distribution system.				
Effect on System O&M Costs	Not Applicable				
Targeted Outcomes	The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.				
Cost Benchmarks					
Value-Added Approach	Not Applicable				

<table>
<tr><td>Project name</td><td colspan="5">UG New Residential Services</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-0604</td></tr>
<tr><td>Job numbers</td><td colspan="5">several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><td>Budget Category</td><td colspan="5">A2 - Connection of New Services</td></tr>
<tr><td>Project Driver</td><td colspan="5">Connection Request from customer/developer</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project scope would include one of the following items depending on type of the request from customer.
• New or Upgraded Service Connection: Requests for new or upgraded electrical service connection for an existing house, semi-detached or townhouse.
• Upgrade with equipment change or replacement - Applies when equipment is worn and requires replacement <u>or</u> after hours trouble call requires the replacement/upgrade
• Service removal</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $726,000</td><td colspan="2">Contribution: $0</td><td>Net: $726,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$65,340</td><td>$72,600</td><td>$123,420</td><td>$464,640</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The project is service OH New Residential Services and is required to comply with legal and/or regulatory requirements.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to project. Project is driven by statutory and regulatory obligations on the part of the distributor to provide customers with access to the distribution system.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5"></td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

<table>
<tr><th>Project name</th><td colspan="5">New Res Development Seaton</td></tr>
<tr><th>Project numbers</th><td colspan="5">2021-0606</td></tr>
<tr><th>Job numbers</th><td colspan="5">several</td></tr>
<tr><th>Project District</th><td colspan="5">General</td></tr>
<tr><th>Project Location</th><td colspan="5">General</td></tr>
<tr><th>Investment Category</th><td colspan="5">SYSTEM ACCESS</td></tr>
<tr><th>Budget Category</th><td colspan="5">A2 - Connection of New Services</td></tr>
<tr><th>Project Driver</th><td colspan="5">New customer connections request</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021 JAN 01</td></tr>
<tr><th>Required In-Service Date</th><td colspan="5">2021 DEC 31</td></tr>
<tr><th>Scope of Work</th><td colspan="5">A forecasted number of new residential connections is developed based on historical data and planning information from Regions, Municipalities, Towns and Cities.
For 2020, the number of new lots to be serviced in Seaton Development in Pickering is estimated to be 500 lots at $2,900 per lot.</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td>Gross: $1,450,000</td><td colspan="2">Contribution: $725,000</td><td colspan="2">Net: $725,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$130,500</td><td>$145,000</td><td>$246,500</td><td>$928,000</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">The project is service new residential developments and is required to comply with legal and/or regulatory requirements.</td></tr>
<tr><th>Criteria Score</th><td colspan="5">Not Applicable</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">Not Applicable</td></tr>
<tr><th>Intervention Options</th><td colspan="5">There is no alternative to project. Projects are driven by statutory and regulatory obligations on the part of the distributor to provide customers with access to the distribution system.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">Not Applicable</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">An economic evaluation is carried out to determine Elexicon’s share of the costs. The upstream capital cost contribution has been removed from the estimates. The estimated cost per lot ($2900) is based on historical spending levels per lot that are reviewed regularly, typically on an annual basis. The costs not supported by the economic evaluation are recovered from the developers/customers.</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	Feeder Expansion
OEB Investment Category	System Access
Primary Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations; Reliability

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$1.17M	**$5.99M**

1. Executive Summary

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

Feeder Expansion investments are System Access projects related to the expansion and construction of new feeders within the Elexicon territory. Feeder expansion projects are driven by load growth within Elexicon as a modification to the distribution system to connect new customers to the distribution system. It is forecasted throughout the DSP period that Elexicon will experience large load growth stemming from the housing developments within the territory. Whitby North and Pickering – specifically the areas of Seaton, South Pickering, and the City Centre will experience the most growth of all the service areas under Elexicon. Household projections from the region of Durham, Belleville, Port Hope, and Gravenhurst all suggest increasing load growth into the future with significant contributions by Durham region, but no feeder expansion projects are expected in Belleville, Port Hope, and Gravenhurst. Most of the feeder expansion projects will be found in Pickering where new neighbourhoods will require further expansions of feeders to provide services to customers.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	1.17	2.68	8.85	2.32	13.73	11.02	0.00	0.00
Contribution	0.42	2.91	7.95	2.32	13.73	11.02	0.00	0.00
Net Program Expenditures	0.76	-0.23	0.89	0.00	0.00	0.00	0.00	0.00

The proposed feeder expansion projects are expected to occur in Pickering and Ajax. The forecast gross expenditures are significantly higher than the historical expendituresInvestments are projected between now and 2024, with the highest level of investment expected in 2023 and 2024. Contributions from the developer make it such that the overall cost of feeder expansions from 2021 onwards will offset the gross. This consequential jump is due to the new Pickering developments expected in the area. The Seaton neighbourhood is projected to bring a population of about 70,000 people to the area once the development is finished. Household projections of Pickering are expected to pass Ajax and Clarington over the forecast period.

Feeder expansion projects are critical in ensuring there is sufficient infrastructure in the locations where customers need to be served. As the Seaton development was proposed with the provincial and municipal government alongside developers, it highlights an important part of the future of the city of Pickering. Failing to expand feeders to respective communities seem unfavourable as this will result in new developments not being able to connect and this can potentially damage the trust that customers would have with Elexicon. Elexicon is obligated in the Distribution System Code to ensure the expansions of networks are adequately planned and designed.

With the merger between Whitby and Veridian to Elexicon Energy, feeder expansion projects will benefit from a merged workforce in both operations and design. For instance, as many of the feeder expansion projects are in Pickering and Whitby, staff will work on projects that are of close geographic proximity. More resources will be available to assist in completing and managing new feeder expansion projects, especially with the growth in expansion projects over the DSP period. Staff will be able to utilize experiences from the two former utilities to complete optimal and successful feeder expansion projects for Elexicon. In other words, with Elexicon now owning all the Whitby TS feeders, a coordination is underway to move load around and accommodate both Pickering and Whitby areas accordingly.

2. Basis for Action

2.1 Performance Trends

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project

Feeder Expansion projects are driven by dedicated new household developments within the Elexicon territory. As new households are built, feeder expansions are required for new households to connect to Elexicon's distribution system where existing infrastructure either does not exist or lacks capacity to serve new load. Similar to the inputs to the Connections of New Services, Feeder Expansions are driven by the same inputs which include household forecasts and development plans alongside third-party consultations with developers.

1) Household Projections from the City/Region

The household projections demonstrate the long-term vision of municipalities as to the amount of development they envision in the future. Projections also demonstrate the evolving work or increase of development in the region or city if present.

2) Specific Developments arising within the Region

The cities and region will have specific developments identified and as part of their long-term development goals for their respective areas. For example, Seaton has been highlighted by the City of Pickering as a major development area. The City of Whitby highlights certain areas like Brooklin where intense development is expected.

3) Contacts with developers over the new developments

Elexicon is presently in contact with developers over feeder expansion projects as these are system access projects. Developers will engage with Elexicon when connecting new households which will require feeder expansions. As determined by the nature of the projects, third-party developers will contribute entirely to the expansion work, hence the net project cost for Elexicon is zero.

Across the territory, feeder expansion projects are centred around the Ajax-Pickering and Whitby area. These areas are expecting new and large developments whereas the rest of the regions do not demonstrate major growth or large development plans or initiatives.

City of Pickering 20-Year Population Forecast

The City of Pickering produces a 20-year population forecast for distinct neighbourhoods within the city. These are separated into three categories such as South Urban Pickering, Seaton Urban Area, and Rural Pickering. Elexicon reviews the information provided in the 20-year population forecast to review cumulative units forecasted alongside the population forecast.

The Regional Municipality of Durham Household Projections – Monitoring of Growth Trends

The Region of Durham produces household projections each year on a semi-annual basis. As seen in the graph below, Pickering is forecast to surpass Ajax and Clarington in total households respectively over the next few years. This major inrush of development is due to the Seaton neighbourhood and other Pickering developments. Most feeder expansion investments are expected to occur in the Pickering area. The feeders need to be expanded to the respective communities and the circuits need to be built to connect new customers to Elexicon's distribution system. Other municipalities such as Brock, Scugog, and Uxbridge are not expected to grow considerably.

Figure 1: Region of Durham Household Projections

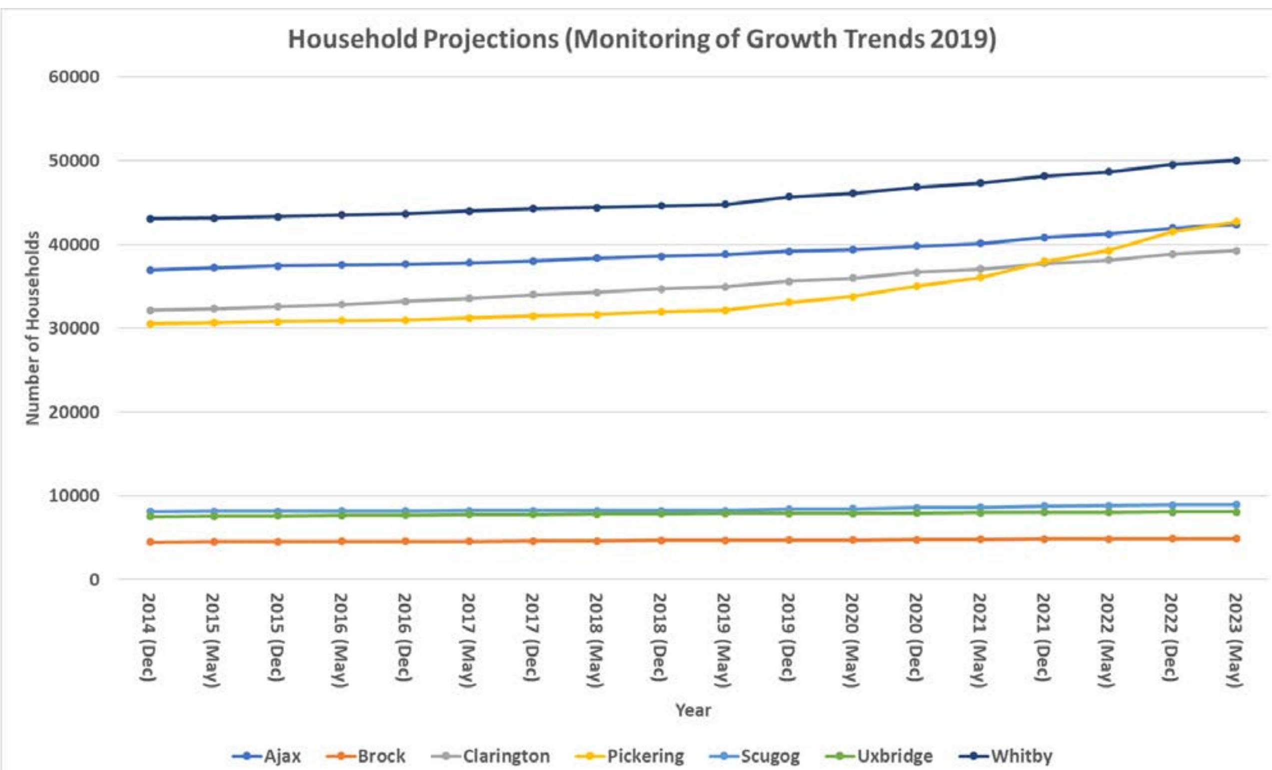


Table 2: Forecasted Households by Durham Municipality

Year	2020 (May)	2020 (Dec)	2021 (May)	2021 (Dec)	2022 (May)	2022 (Dec)	2023 (May)
Ajax	39,410	39,790	40,160	40,830	41,250	41,980	42,440
Brock	4,740	4,780	4,800	4,830	4,840	4,870	4,890
Clarington	36,000	36,680	37,060	37,750	38,150	38,870	39,260
Pickering	33,780	35,020	36,090	37,990	39,260	41,530	42,720
Scugog	8,460	8,580	8,640	8,770	8,820	8,910	8,950
Uxbridge	7,930	7,970	7,990	8,020	8,040	8,080	8,090
Whitby	46,120	46,870	47,350	48,200	48,690	49,570	50,070

Historical Feeder Expansions Year over Year

Over the historical period from the past five years, Elexicon has seen an increase in feeder expansion projects. During the historical years of 2015 to 2017, there were very few feeder expansion projects. However, from 2018 to 2019, eleven feeder expansion projects were completed which is almost three times the amount of the past three years. Elexicon has experienced growth within its service territory with more development on the way across the DSP period. Feeder expansion projects are predominantly driven when a specific area does not have the necessary infrastructure yet to support new developments or a large customer requires an expansion of the feeder. Corresponding to the previous statement, Seaton will have a new transformer station, Seaton TS, built to serve the new community. Feeder expansions will then be implemented from the new station into the neighbourhood.

Figure 2: Historical Feeder Expansion Projects

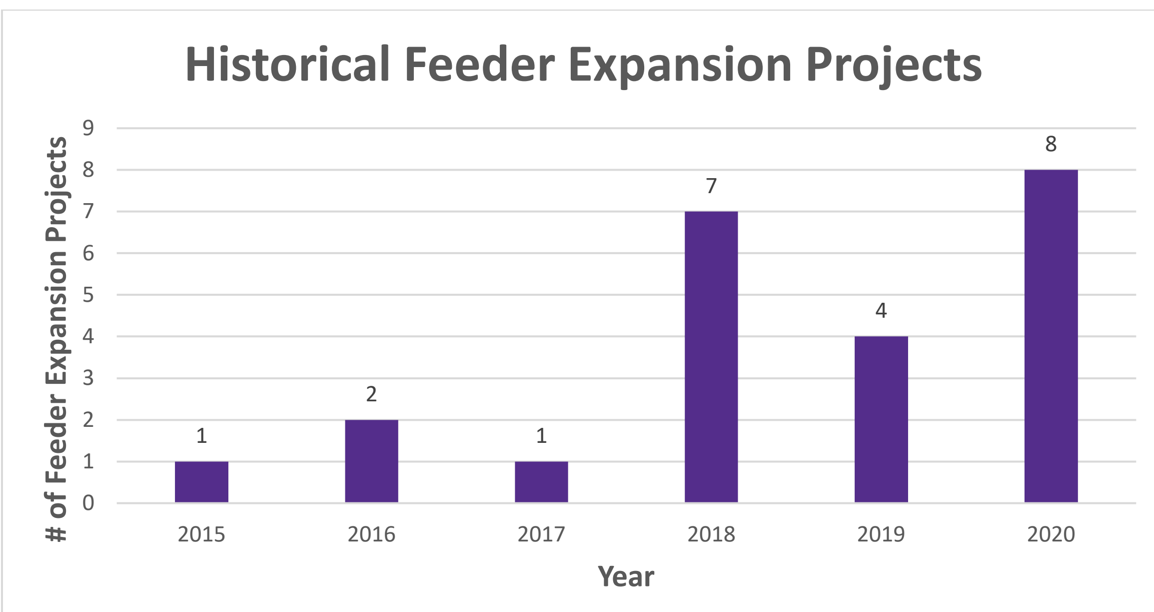


Table 3: Project Counts of Feeder Expansions Historically

Year	2015	2016	2017	2018	2019	2020
Feeder Expansions	1	2	1	7	4	8

2.2 Current-State Analysis:

Planned Feeder Expansion projects for years 2020 to 2026

Currently, 54 feeder expansion projects have been identified in the upcoming DSP period. With larger developments in the forecast, these will require several expansion projects. Most of the planned projects are needed in the Pickering area, whereas the second highest count is Whitby.

Figure 3: Planned Project Counts for Feeder Expansions by Service Area and Year

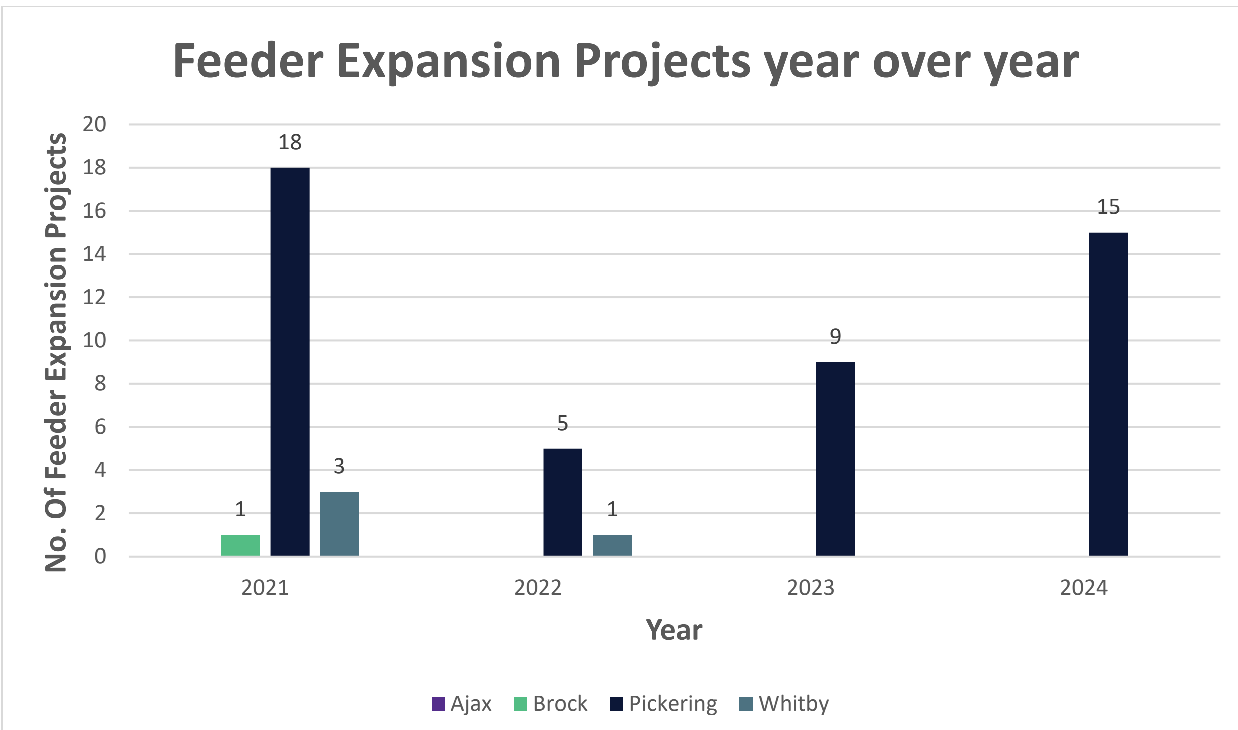


Table 4: Project Counts by Service Area and Year

Service Area	2021	2022	2023	2024	2025	2026
Brock	1	0	0	0	0	0
Pickering	18	5	9	15	0	0
Whitby	3	1	0	0	0	0
Other Regions	0	0	0	0	0	0

A current state view of three distinct areas within Pickering which are producing feeder expansion projects for Elexicon is detailed below. These include Seaton, South Pickering, and Pickering City Centre.

Seaton

The *Central Pickering Development Plan* outlines the Seaton development which will house 70,000 people and introduce 35,000 jobs on approximately 3,100 acres of land. Six neighbourhoods of various housing types and densities will be provided; these areas will drive many of the feeder expansion projects for Elexicon throughout the future DSP period. On April 17th, 2003, the government signed an order under the *Ontario Planning and Development Act, 1994* establishing a development planning area covering the Seaton lands. The final planning and design work is still being done for Seaton, including the completion of several studies.

Many of these development areas do not currently have distribution infrastructure which means that feeder expansions will be required to connect the new household customers. The planned substation of Seaton TS is also expected to be built in the DSP period many of its feeders will be expanded out into the various Seaton neighbourhoods. The existing neighbourhoods are currently being fed by Whitby TS but new demand from Seaton has influenced the decision to build Seaton TS. Twelve 27.6-kV Feeder Expansions are to be constructed from Seaton TS into the development area.

Figure 5: Seaton Development Land by the Ontario Government

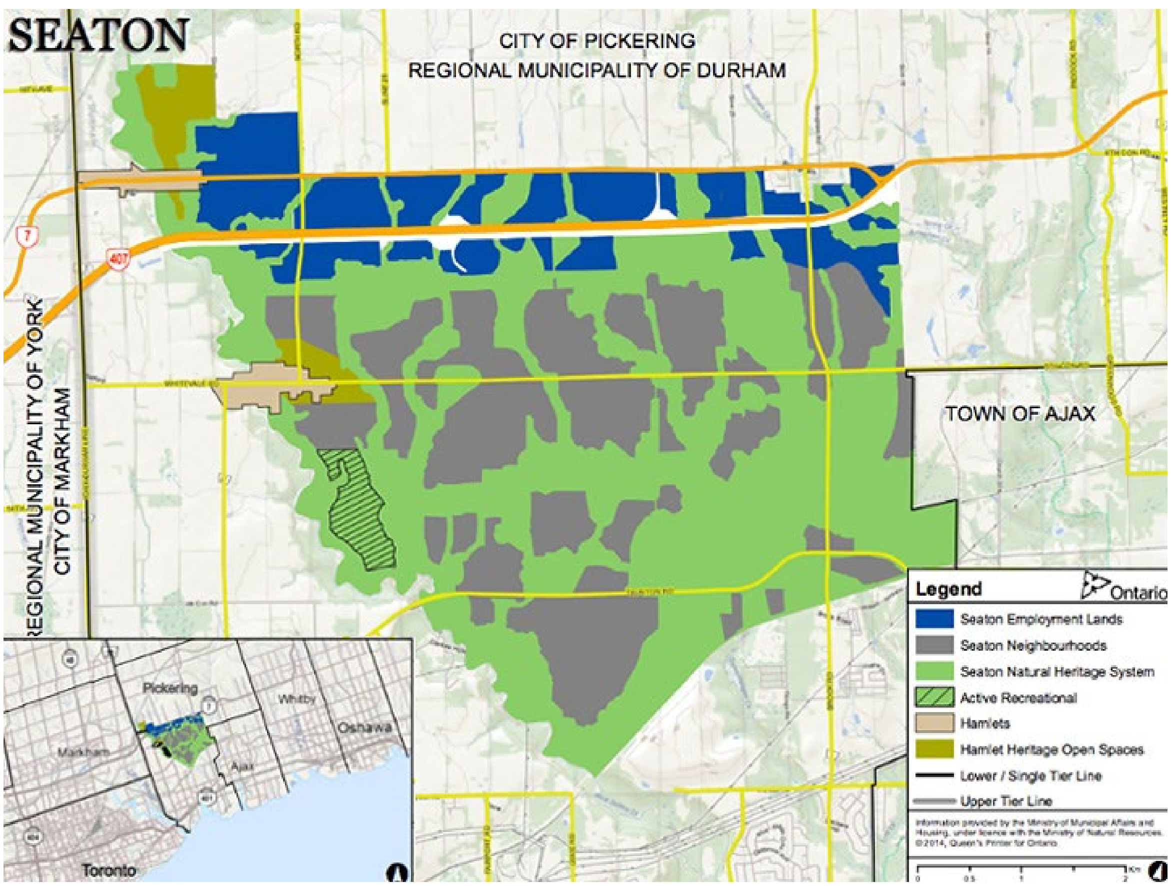


Figure 6 demonstrates the planned feeder expansions moving into Seaton from the proposed TS while Figure 7 illustrates typical expansion work influenced by Seaton TS in the future. Sections of the existing circuit will be removed and expanded further. Seaton is expected to contribute to a majority of the future feeder expansion projects into the future.

Figure 6: Referenced Feeder Expansions in Seaton

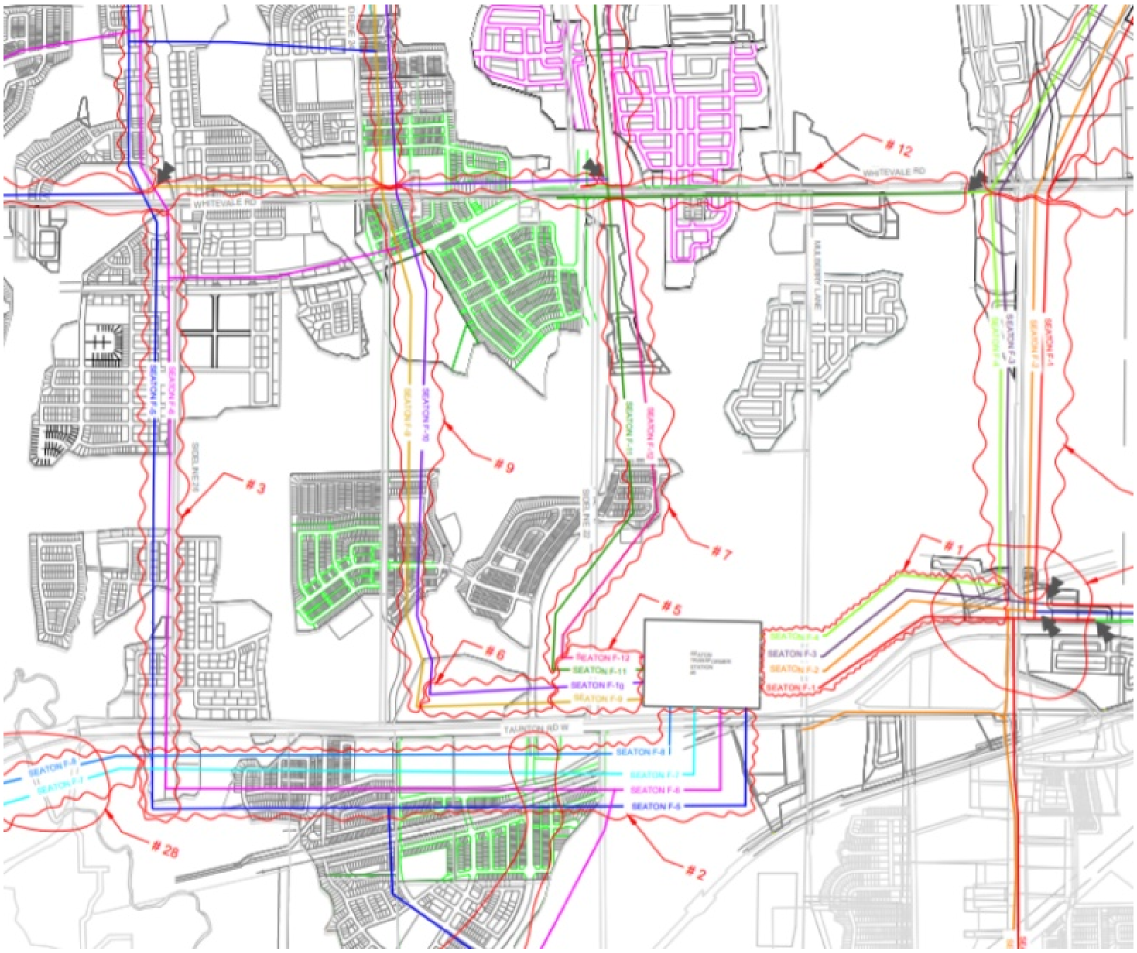
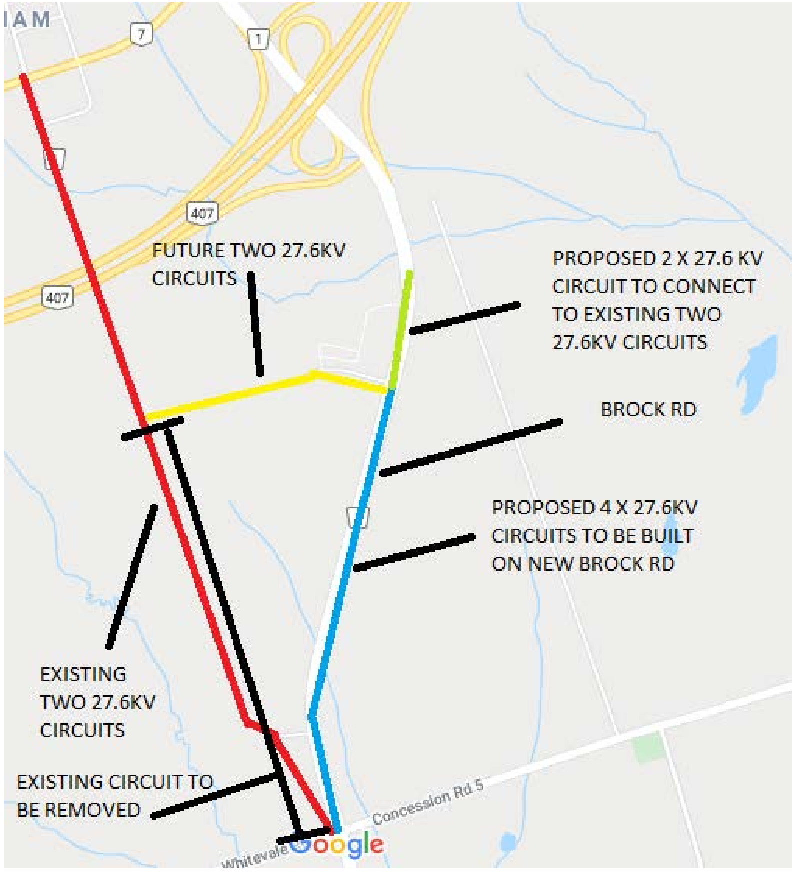


Figure 7: Typical Feeder Expansion Project Details



South Pickering

South Pickering has also been identified as part of a detailed study by the City of Pickering as a development area. The current Kingston Road corridor is designated as a mixed-used area and mixed corridor in the Pickering official plan. Four distinct precincts have been identified in the area. The City of Pickering constructed this scenario with inputs such as the visions, goals, and objectives of the area, key assumptions across intensification scenarios, identification of sites with redevelopment potential, and feedback through workshops, meetings with the public and agencies. The potential mixed-use of the four development precincts in South Pickering is shown in Table 5.

Table 5: South Pickering Development Details

Development Precinct	Potential Mix Use (Residents, Jobs)
Rougemont	1,991 Residents, 236 jobs
Whites	7,622 Residents, 2,546 jobs
Dunbarton/Liverpool	6,036 Residents, 1,274 Jobs
Brock	6,208 Residents, 3,580 jobs

Figure 8: South Pickering Land Use Map

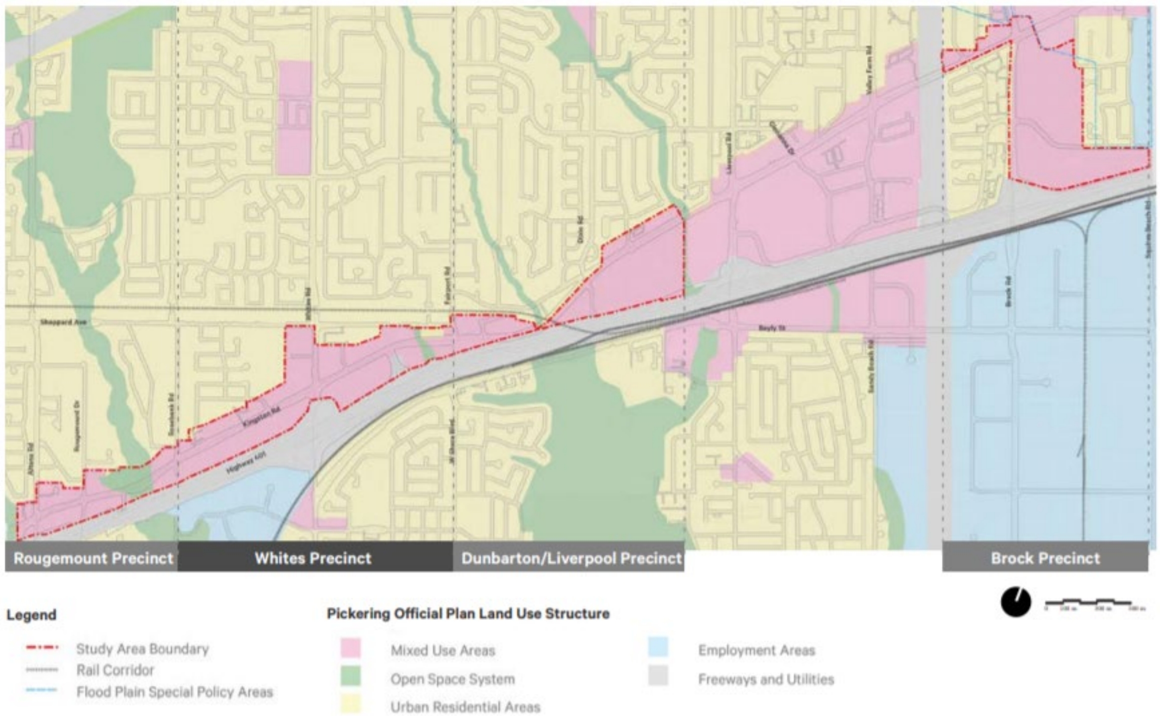
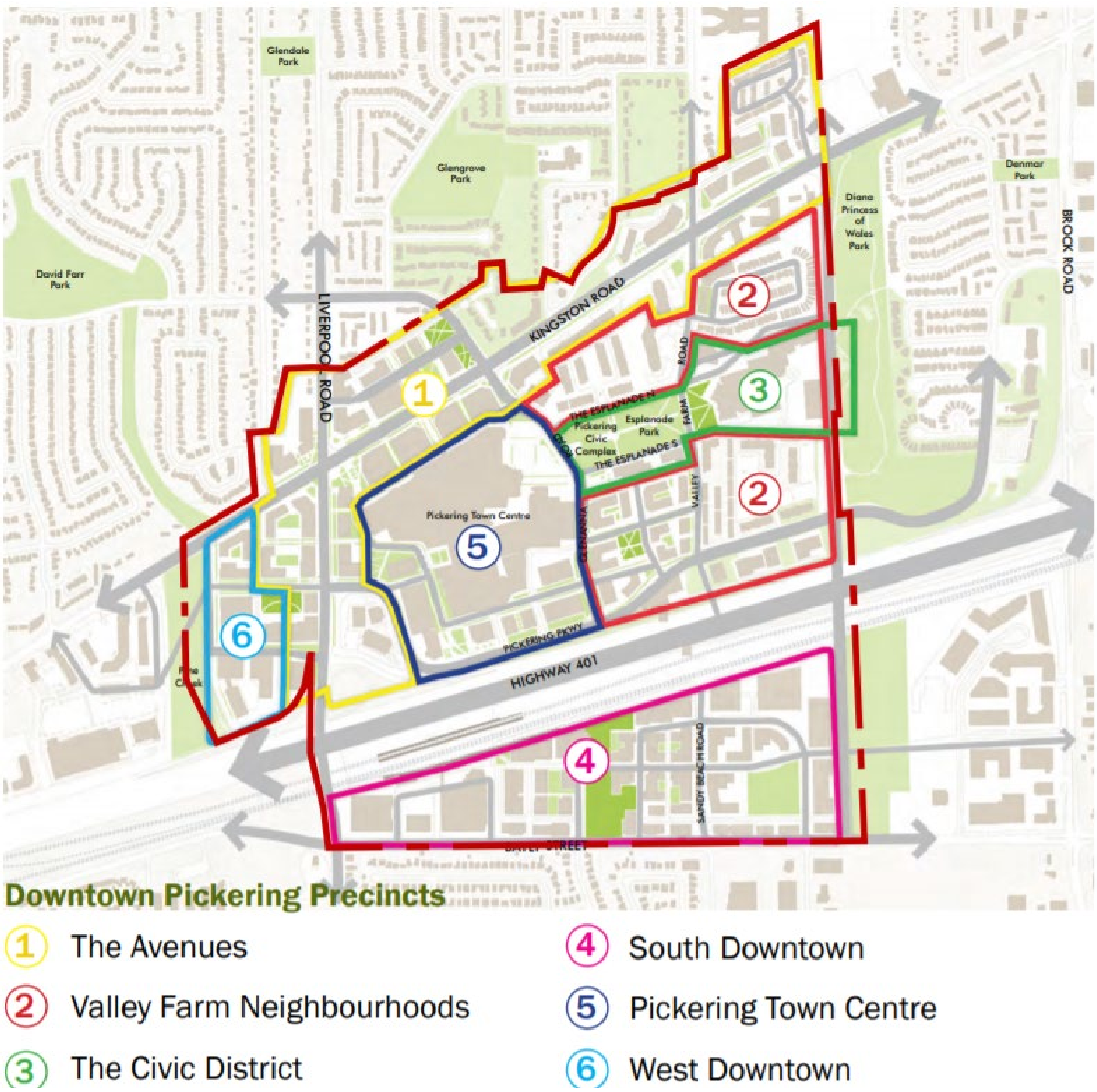


Figure 5. Official Plan Land Use

Pickering Town Centre

The downtown core of Pickering is also expecting development within the area, and the City has identified six precincts for distinctive use. Downtown Pickering is expected to grow by 8,300 people and 8,700 jobs by 2031 to achieve the greater golden Horseshoe target of 200 combined people and jobs per hectare. This greater golden horseshoe target was set by the Ontario Government as it identified downtown pickering as an urban growth centre in it's "Growth Plan for the Greater Golden Horseshoe".

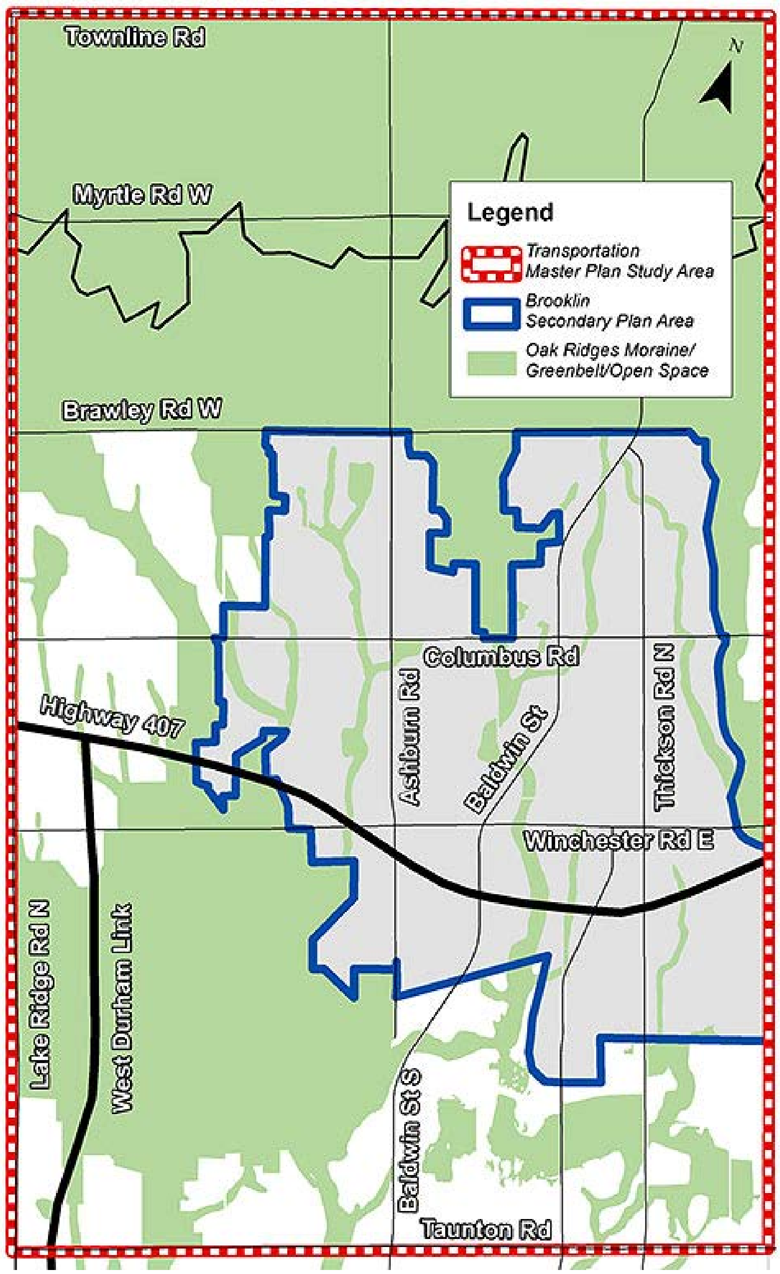
Figure 9: Pickering Town Centre Intensification



Brooklin

The existing Brooklin neighbourhood is expected to expand by around 56,000 people over the next two decades as determined by growth plans. Residential, commercial, and industrial developments will be built on the reserved land. Elexicon has budgeted and split feeder expansion projects in Brooklin to Southern and Northern sections. It was identified that Brooklin has the capacity for approximately 80,000 people. The Town of Whitby has a plan to target 50 people and jobs per hectare in the greenfield development.

Figure 10: Brooklin Development Area



New Asset Introduction from Feeder Expansion Projects

Over the forecast period, an assortment of new distribution assets shall be introduced onto the system as a result of these Feeder Expansion projects, namely switchgears, pad-mounted transformers, pole-mounted transformers, and poles. Figure 11 and Table 6 show the total number of asset additions. These assets will require ongoing inspection, maintenance, and capital upkeep by Elexicon in the future.

Figure 11: Holistic Asset Introduction by Feeder Expansion Project

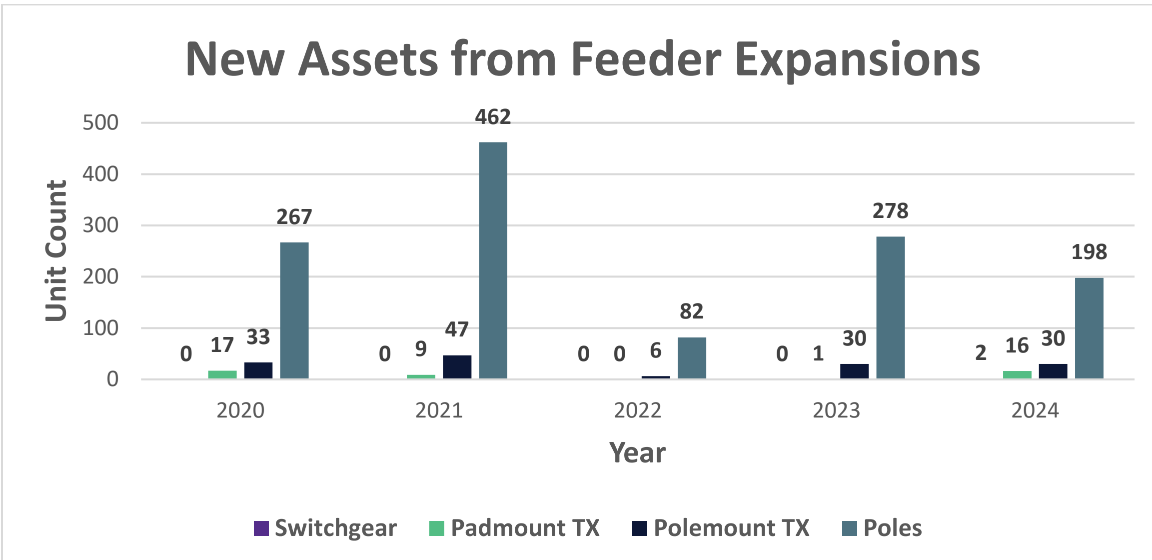


Table 6: Total Asset Introduction Count by Year

Distribution Asset	2020	2021	2022	2023	2024	Total
Switchgear	0	0	0	0	2	**2**
Pad-mounted Transformers	17	9	0	1	16	**43**
Pole-mounted Transformers	33	47	6	30	30	**146**
Poles	267	462	82	278	198	**1,287**

Additional analysis of the asset introduction per service area is provided in the following figures and tables. As represented in the forecasted developments and the planning of feeder expansions, most new projects and new assets will take place in Pickering.

Figure 12: New Pole Introductions by Service Area

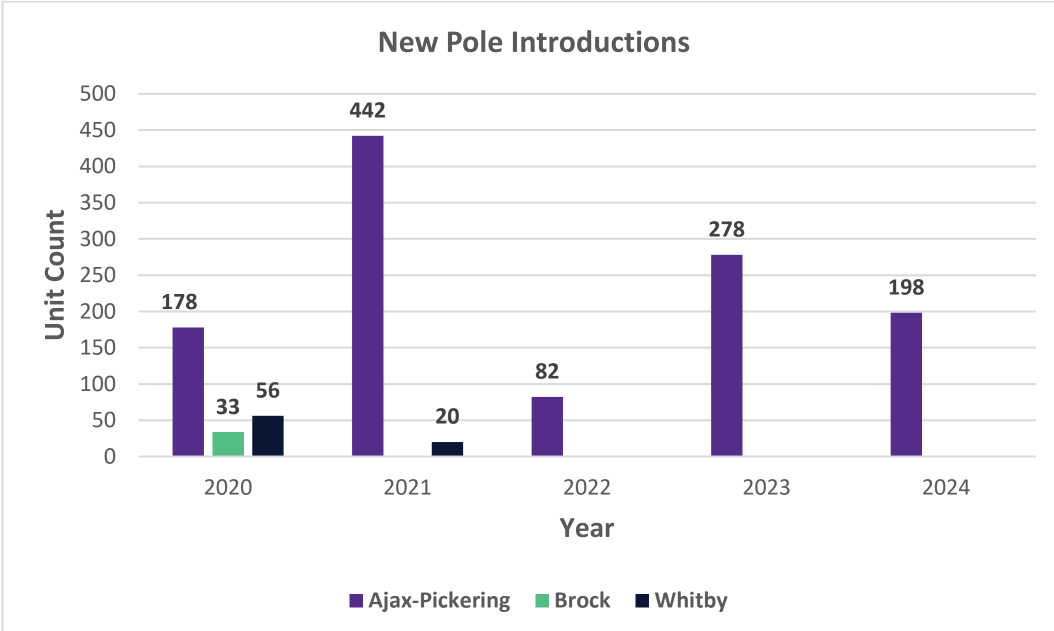


Table 7: New Pole Introduction Count by Service Area

Service Area	2020	2021	2022	2023	2024	Total
Ajax-Pickering	178	442	82	278	198	**1,178**
Brock	33	0	0	0	0	**33**
Whitby	56	20	0	0	0	**76**

Figure 13: New Pole-mounted Transformer Introductions by Service Area

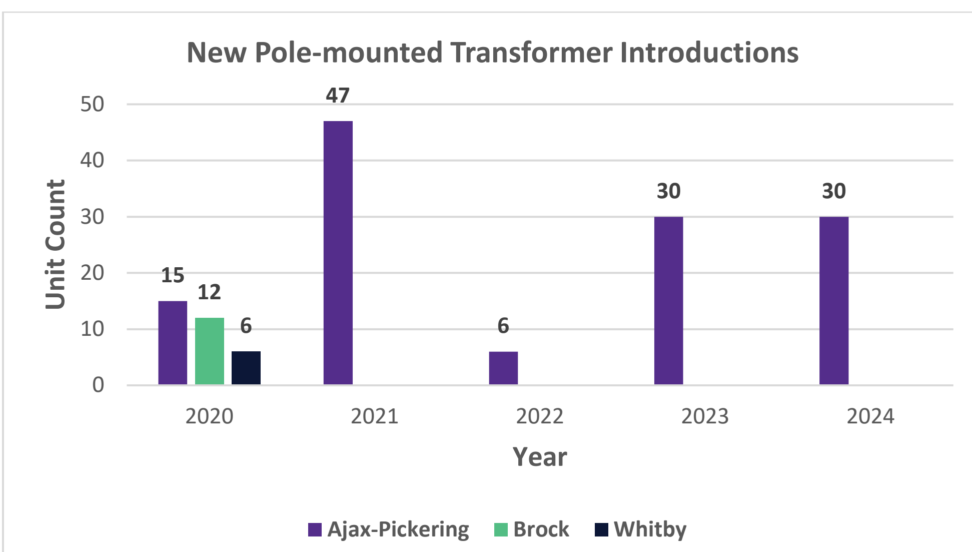


Table 8: New Pole-mounted Transformer Introduction Count by Service Area

Service Area	2020	2021	2022	2023	2024	Total
Ajax-Pickering	15	47	6	30	30	**128**
Brock	12	0	0	0	0	**12**
Whitby	6	0	0	0	0	**6**

Figure 1: New Pad-mounted Transformer Introductions by Service Area

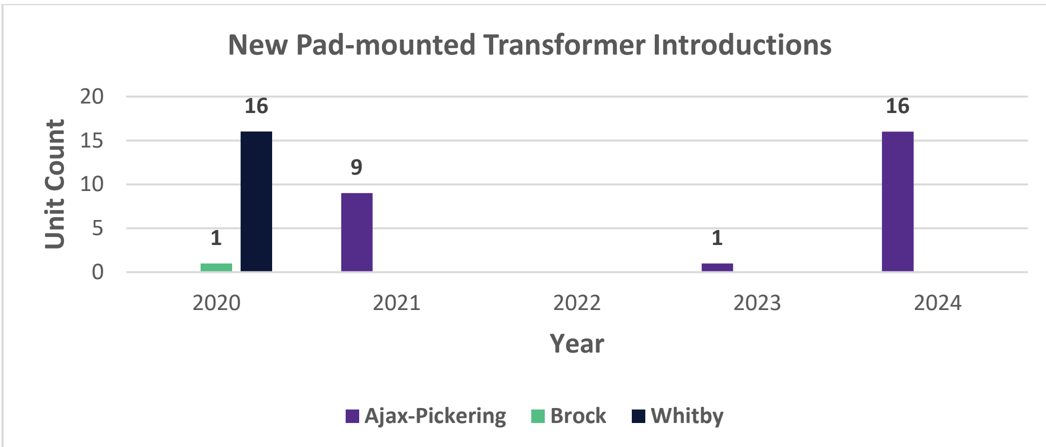


Table 9: New Pad-mounted Transformer Introduction Count by Service Area

Service Area	2020	2021	2022	2023	2024	Total
Ajax-Pickering	0	9	0	1	16	**26**
Brock	1	0	0	0	0	**1**
Whitby	16	0	0	0	0	**16**

Figure 15: New Switchgear Introduction by Service Area

Table 10: New Switchgear Introduction Count by Service Area

Service Area	2020	2021	2022	2023	2024	Total
Ajax-Pickering	0	0	0	0	2	**2**
Brock	0	0	0	0	0	**0**
Whitby	0	0	0	0	0	**0**

The typical useful life of distribution assets is provided below.

Table 11: Typical Useful Life of Distribution Assets

Distribution Asset	Useful Life
Wood Pole	45
Pole-mounted Transformer	40
Pad-mounted Transformers	40
Overhead Conductors	60
Underground Cable	40
Ducts	50
Concrete Encased Ducts	55
Pad-Mounted Switchgears	30

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

Distribution System Code, Section 3.2: Expansions

Feeder expansions must comply with the requirements of Section 3.2 of the *Distribution System Code*. The section covers the expectations for the distributor and customers when engaging in expansion projects. An expansion as defined in the Distribution System Code as a modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made, for example, by increasing the length of the main distribution system and includes the modifications or additions to the main distribution system.

Distribution System Code, Section 2.4: Conditions of Service

A distributor must document in its Conditions of Service the operating practices and connections policies of the distributor as stated in Section 2.4 of the Distribution System Code. Elexicon's Conditions of Service is compliant with the Distribution System Code.

O. Reg. 22/04: Electrical Distribution Safety

Elexicon is obligated to ensure the safety of workers and the public when engaging in feeder expansion projects. Any new installation, design, and inspection of feeder expansion projects must comply with O. Reg. 22/04, *Electrical Distribution Safety*, when connected to the grid. O. Reg. 22/04 provides the safety standards, compliances, and measures that should be followed in Ontario concerning the Electrical Distribution System.

Reporting and Record-keeping Requirements: Service Quality Requirements

Feeder Expansions create the infrastructure necessary for Elexicon to connect customers. Connections of low voltage (<750 Volts) Service is required to be completed within five business days or any later date agreed with the customer. This requirement must be met at least 90% of the time. Similarly, High Voltage Connections must also be completed but within 10 service days or any later date agreed with the customer about 90% of the time. Thus, feeder expansion investments must be completed as efficiently as possible to ensure the Service Quality Requirements are met.

OEB Act, Section 92:

Leave to Construct approval is not required for these investments.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.*

Customer Service: Customer Service can be affected greatly if feeder investment projects are not done adequately and efficiently. At a minimum, 90% of new connections must be connected on time. If Elexicon does not complete expansion projects optimally or efficiently, it may result in damage to the Elexicon brand. Customers may harbor a negative outlook if Elexicon cannot connect neighbourhoods or communities on time. Elexicon Customers expect excellent and consistent electrical service by connecting to the grid. Feeder Expansion projects allow for customers to connect to the grid by expanding infrastructure for connection and providing the sufficient capacity or power for customers to use electricity for their purposes and daily lives.

Operational Effectiveness: Suboptimal timing or planning of feeder expansion projects decrease the operational efficiencies of Elexicon. If new feeders are built too early, then they will not be needed immediately after construction. If new feeders are built too late, then expensive, temporary solutions will be required to serve new customers. Feeder expansions are planned such that they are built as-needed.

Public Policy Responsiveness: Public policy established by municipalities relate to the development plans in their respective territories. Feeder expansion projects support new development within Elexicon's service area, which supports economic and public development.

Financial Performance: Ensuring that feeder expansion projects are completed efficiently and on time, will reduce the risk of additional financial resources applied to the project. The Conditions of Service set by Elexicon also address the contributions that new connections will play to have expansions of feeders for new connections.

2.5 Merger-Related Objectives:

The commitments to services and the coordination of consistent operations for feeder expansion projects will improve for the merged organization compared to the separate legacy entities. Following the merger, the collective expertise of staff and resources is available for feeder expansion projects. As major developments occur within the Durham territory – specifically in Ajax-Pickering and Whitby – the combined resoureces will prove important in expanding feeders to the new developments. An increased amount of staff within the Durham area will also provide greater operational efficiencies for new developments. Durham is expected to grow considerably in the future and improved consolidation among utilities serving the Region is beneficial for customers.

3. Program Alternatives

-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

3.1 Alternative Descriptions and Comparative Analysis

Number	1	2	3	4
Scenario Description	Status Quo: Currently planned Feeder Expansion investments	Additional storm hardening on Feeder Expansions	Only perform Underground construction of Feeders	Expand and upgrade current existing feeders; no construction of new feeders
Annual Program Scope	Current planned feeder expansions take note of the developments in the Elexicon service area. Most of the dedicated feeder expansions over the DSP period are targeted for the new Seaton development.	Additional storm hardening design and construction shall be added onto the feeder expansion.	Underground feeder expansions would only be performed by Elexicon. This could ensure further reliability due to the lack of exposure to outside elements but be much more expensive.	No new feeders would be expanded. Current existing feeders would be expanded further into neighbourhoods. Additional capacity may also need to be added to the current station.
Annual Gross CAPEX	$5.99M	$9.47M	$12.06M	$14.63M
Annual Net CAPEX	$0.15M	$0.24M	$0.30M	$0.37M
Annual Program Benefits	The mandatory projects belonging to this program broadly address the objectives of improving customer focus, operational effectiveness,	The mandatory projects belonging to this program broadly address the objectives of improving customer focus, operational effectiveness,	The mandatory projects belonging to this program broadly address the objectives of improving customer focus, operational effectiveness,	The mandatory projects belonging to this program broadly address the objectives of improving customer focus, operational effectiveness,

	public policy responsiveness and economic development.	public policy responsiveness and economic development.	public policy responsiveness and economic development.	public policy responsiveness and economic development.
Program Economics	Enabling land development, placing of significant public or private infrastructure and simultaneous job creation.	Enabling land development, placing of significant public or private infrastructure and simultaneous job creation.	Enabling land development, placing of significant public or private infrastructure and simultaneous job creation.	Enabling land development, placing of significant public or private infrastructure and simultaneous job creation.
Customer Feedback	262 Customers were surveyed online and 600 customers were surveyed by phone. 71% of Customers (613 of the 862 surveyed) support the proposed plan for the New Pickering Area Transformer Station(Seaton TS). 77.4% (or 6668 of the 862 surveyed) had no additional comments of the investment. After construction of the Transformer Station, feeders emanating from the station will be expaneded to allow for new residential customers expected from the major development in the area.	About 61.5% (374 of the 600 telephone-surveyed and 156 of the 262 online-surveyed) of customers selected that improving grid resilience to major storm events should be the first or second choice of objectives in addition to Elexicon making investments for new growth and system safety.	Customers are aware of the possible relocation of existing underground infrastructure to enable the construction of dedicated RT bus lanes in Pickering. Elexicon Customers (262 that were online-surveyed and 600 that were telephone-surveyed) were asked about underground conversions or underground systems related to current rear lot lines. About 20.4% (176 of the 862 surveyed customers) of customers support maintaining status quo i.e., keeping the overhead	Customers generally support moving lines underground and finishing all work in one area before moving elsewhere. 62% of customers were in favour of underground systems.

			lines in the rear lots and replacing them as they fail. 62% of customers were in favour of underground systems.	
Other Constraining Factors	Currently planned investments are made to prepare for future neighbourhoods and developments in the Elexicon area. If more areas of development are produced during the DSP period, Elexicon shall ensure budgets can be shifted to account for the increase of unplanned work.	Additional storm hardening will cost customers more and would provide further time dedication to the design and construction of feeder expansion projects in the area.	The complexity of constructing underground feeders is one constraining factor. In addition, the costs would be much more than currently panned. The customer would prefer to choose a more economical option.	By only upgrading and expanding current feeders, significant amounts of studies will need to be performed to assess the reliability of such an option. Additionally, capacities of certain stations may need to be upgraded in order to expand only current feeders.
Preferred Alternative	**X**			

Generally, new feeders constructed in the are overhead as this tends to be the most economically viable alternative, whereas new subdivisions and customer connections (under different investment programs) tend to be underground construction. Underground feeder construction costs about three to ten times more than an overhead feeder. There is no "Do Nothing" alternative for this program, since it facilitates customer connections.

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Overhead feeders will generally experience more outages than underground feeders due to a higher exposure to external factors such as weather and traffic. Additional storm hardening would improve reliability of the system. Both options – building underground feeders and increased storm hardening – results in substantially higher costs.

Grid Resiliency: Underground and storm-hardened construction both support a grid that is more resilient; however, at a higher a cost.

Operational Efficiency and Cost Effectiveness: The preferred option is the most operationally efficient and cost effective, per the financials.

Safety: There is no substantial difference in safety between the program options. All construction by Elexicon is safe and poses no undue hazard to the public.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Expansions ensure that customers are adequately connected to an optimal distribution system. If projects are sub-optimal or not done on time, the customer will not experience benefits. The preferred program alternative provides service to customers in the most operationally efficient and cost-effective manner, which benefits customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

System Access projects are dependent on the developments and the construction and in-service dates of new households as produced by the developments. In general, new feeders are constructed as needed to serve customers in the area. In particular, the expansions of Seaton community feeders will be dependent on the time of construction of Seaton TS – planned for completion in 2022. Elexicon will carefully evaluate and ensure optimal efficiency and timing of Seaton community feeders along with all feeder expansions.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

As per Elexicon's Conditions of Service, the Economic Evaluation is performed by Elexicon to determine Customer share, if any, of equipment, labor, material, and on-going maintenance costs of the expansion ("The Expansion Costs"). Elexicon will make an offer to connect based upon the results of the Economic Evaluation that outline the charges, costs, and work needed to build the expansion to connect the customer(s). Elexicon is obligated to finish System Access projects such as Feeder Expansions to ensure new customers can be connected to the distribution system. Elexicon will continue to provide options to the developer regarding underground and overhead feeder expansions.

To plan for future feeder expansions, an analysis of the inputs of developments, housing forecasts, and development contacts will continue. In locations where developments are built, Elexicon will assess the current feeder configurations to determine if it shall require expansion.

Moving forward, Elexicon will continue to evaluate feeder expansion projects when required. As Seaton TS is being built, feeder expansions will be implemented from the new station into the neighbourhood. Throughout the DSP forecast period, most of the expansion projects will come from the Seaton area. The new development has been the major driver of this program.

4.2 Legacy Work Execution Approaches vs. Combined Operations

A mix of internal and external resources is utilized when performing design and installation work; however, project management and supervision of work for feeder expansion projects are completed by internal Elexicon resources. Like Ajax and Pickering, Whitby also has 13.8-kV stations and systems within the area. As standards between the two utilities were shared in the past and had similar staff, there are no major differences in the physical makeup or electrical configuration.

4.3 Scale Increase Considerations

With the merger, more resources are realized from the combination of staff of the two former utilities. The internal design staff and operations members can bring to light the workflows and experience in completing feeder expansions. Since Whitby is located close to Pickering and Ajax, it would be beneficial to have a larger workforce that can account for the feeder expansions in both areas especially in light that future expansion projects are in Whitby and Pickering. The consolidation of operations and project work is feasible due to the geographic proximity of the two regions. If any future new major developments are planned in the future, Elexicon will be ready to address them with the experience of feeder expansions in different areas. For instance, Durham is expected to continue to grow into the future, and Elexicon as a combined utility will be able to serve the region more effectively.

Another benefit to the scale increase is the new experiences Elexicon will have with feeder expansions of the new Seaton TS. As both former utilities are now combined, staff will be able to experience and partake in the new design, installation, and maintenance of a 27.6-kV distributor-owned station. Feeder expansions from the station will also be a new territory for the utility to explore which will benefit the skillsets of the current workforce.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Regarding the rate freeze, Elexicon will continue to build and provide options to developers and customers with regards to Feeder Expansion projects. As Feeder Expansions are in System Access and establish new connections of services to the distribution system, Elexicon must complete these investments as a mandatory obligation to customers. There is no pacing to these investments as it is a requirement that Elexicon must fulfill. Expansion investments are decided by evaluating the current state of the system, expected growth, and communication with developers over new built areas. As the planned feeder expansions are expected to take place in Ajax, Pickering and Whitby, cost savings and efficiencies could be discovered by completing the work in parallel or in conjunction with each other. The three service areas are where the majority of developments are located are close to one another.

5. Individual Projects Comprising the Program

5.1 Overview of Material Projects

There are no material projects within the Feeder Expansions program in 2021.

5.2 Individual Material Project Scopes

There are no material projects within the Feeder Expansions program in 2021.

Budget Category	Metering
OEB Investment Category	System Access
Primary Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests

Average Annual Program Spend – Historical	Average Program Spend – Forecasted
$1.29M	**$1.40M**

1. Executive Summary

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

Metering investments are System Access projects by Elexicon that are primarily driven by Mandatory Service Obligations to new customers and for meter replacements of current customers. Customer projections from the Engineering department suggest a major increase in total residential customers within the Elexicon territory which require new metered connections. These projections are made from information regarding development plans, forecasts, and third-party consultations similar to the 'connections of new services' program. Projected expenditures are produced based upon an internal customer forecast that is generated.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	1.29	1.24	1.84	1.33	1.30	1.30	1.30	1.30
Contributions	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	1.27	1.24	1.84	1.33	1.30	1.30	1.30	1.30

There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Metering investments are primarily driven by the growth in customers within the Elexicon territory. As new customers require connections, further investment into new meters will be required. Much of the customer growth within the Elexicon territory is driven by residential customer growth. Other types of metering investments are provided for General Services < 50 kW, General Services > 50K, and Large Users. Each customer class elicits specific metering standards and procedures set by Elexicon. Furthermore, as older meters approach end-of-life or experience issues (such as measurement accuracy), Elexicon identifies these defected meters or metering equipment for replacement. These two situations are the primary drivers to meter expenditures in the future years.

Metering Investments are required to follow a variety of requirements and standards such as Measurement Canada requirements, OEB Market Rules, O. Reg. 22/04, and the *Distribution System Code*. Every project is carried out with due diligence to these compliance measures. As the grid incorporates new developments such as renewable generation, and electrical vehicle infrastructure, smart meters will allow for monitoring and further data collection for these technologies. Utilities are encouraged to plan for the smart grid of the future in which smart meters are fundamentally critical to these networks. Upgrades and new communication infrastructure centred around metering are also required for cyber-security.

Looking forward to the future, Elexicon will be replacing legacy meters like the Rex1 with newer meters such as the Rex2 and RexU. These newer meters provide additional functionality to the control room and can result in cost savings and operational efficiencies. Currently, there are two AMI solutions that require two sets of different meters for each customer class. Elexicon will continue to utilize the two AMI solutions at hand. Elexicon will perform studies to evaluate how assigning a smart meter to a distribution transformer that serves multiple customers can assist the utility. Smart Meters will also be utilized for new DER and innovation projects at Elexicon. It is expected that the Veridian AMI alongside Smart Meters will be used to analyze and study the effects of islanding. Smart Meters will continue to be critical to Elexicon's planning for the grid of the future. Other studies include the Sensus Tower upgrade in trying to capture efficiencies in rural areas under Elexicon.

2. Basis for Action

2.1 Performance Trends:

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project *-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:* *o The distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3) [Continued in Section 2.2]*

Household Projections

Household projections are produced by the Region of Durham for cities and towns under its jurisdiction. On a semi-annual basis, the Region of Durham produces household estimates and forecasts. Elexicon evaluates these municipal driven forecasts to plan for new household connections. Inevitably, these households will require a variety of System Access investments which include metering.

Household projections from the other service areas of Gravenhurst, Port Hope, and Belleville are also utilized to determine the number of new households expected across the DSP period. Planned meter investments are made based upon these forecasts.

Across the service areas of Elexicon, it is expected that household growth will be greater than usual historical numbers. Elexicon takes notes of these numbers to produce metering investment quantities looking forward.

For the Region of Durham, consistent household growth is expected in most service areas. However, as noticed through the number of capital projects in Ajax and Pickering, these two service areas are expecting an increased number of households. Pickering especially has been identified as a large growth area as based upon capital projects received, large housing developments, the city development plans, and household forecasts. Whitby is also expecting larger household growth in the area. The three service areas of Ajax, Pickering, and Whitby shall contribute to most new metering connections and growth within the area. Clarington is also expected to grow.

Figure 1: Region of Durham Municipal Household Forecasts

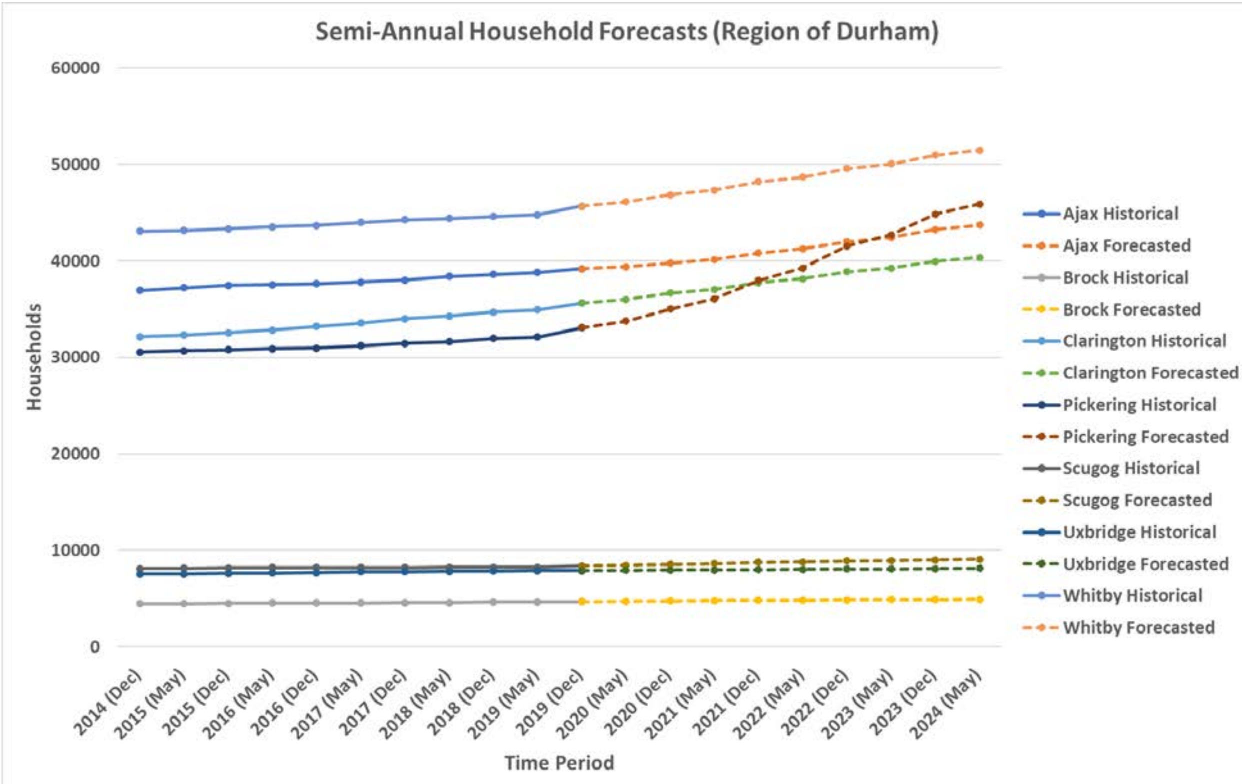


Table 2: Household Forecasts by Durham Municipality

Region	2015 (May)	2016 (May)	2017 (May)	2018 (May)	2019 (May)	2020 (May)	2021 (May)	2022 (May)	2023 (May)	2024 (May)
Ajax	37,225	37,550	37,815	38,400	38,825	39,410	40,160	41,250	42,440	43,720
Brock	4,500	4,545	4,555	4,605	4,675	4,740	4,800	4,840	4,890	4,930
Clarington	32,335	32,840	33,570	34,290	34,955	36,000	37,060	38,150	39,260	40,370
Pickering	30,685	30,920	31,220	31,630	32,130	33,780	36,090	39,260	42,720	45,880
Scugog	8,150	8,220	8,230	8,240	8,245	8,460	8,640	8,820	8,950	9,080
Uxbridge	7,565	7,665	7,795	7,850	7,905	7,930	7,990	8,040	8,090	8,160
Whitby	43,175	43,530	44,005	44,395	44,780	46,120	47,350	48,690	50,070	51,480

It is expected that Belleville Household growth will be greater than historically experienced across the forecast period. From 2006 to 2016, it was estimated that 1,200 new households were built in Belleville. The forecast suggests that from 2016 to 2026, about 2,400 new households will be built which is two times more than the decade previously.

Figure 2: Belleville Household Forecast (5-year increment)

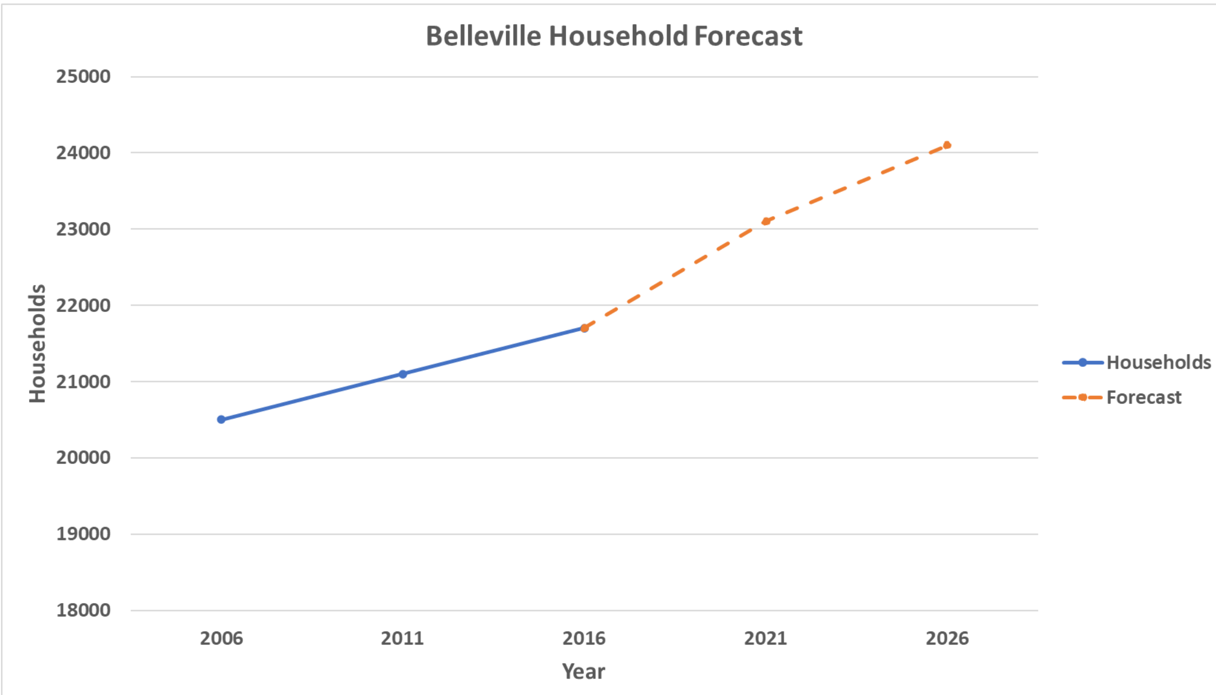


Table 3: Belleville Household Forecast

Year	2006	2011	2016	2021	2026
Households	20,500	21,100	21,700	23,100	24,100

Port Hope is expecting household development that is larger than historically across the DSP period. From 2006 to 2016, Port Hope was estimated to have added 790 new households. From 2016 to 2029, it is expected that 1,500 new households will be added.

Figure 3: Port Hope Household Forecast (to 2029)

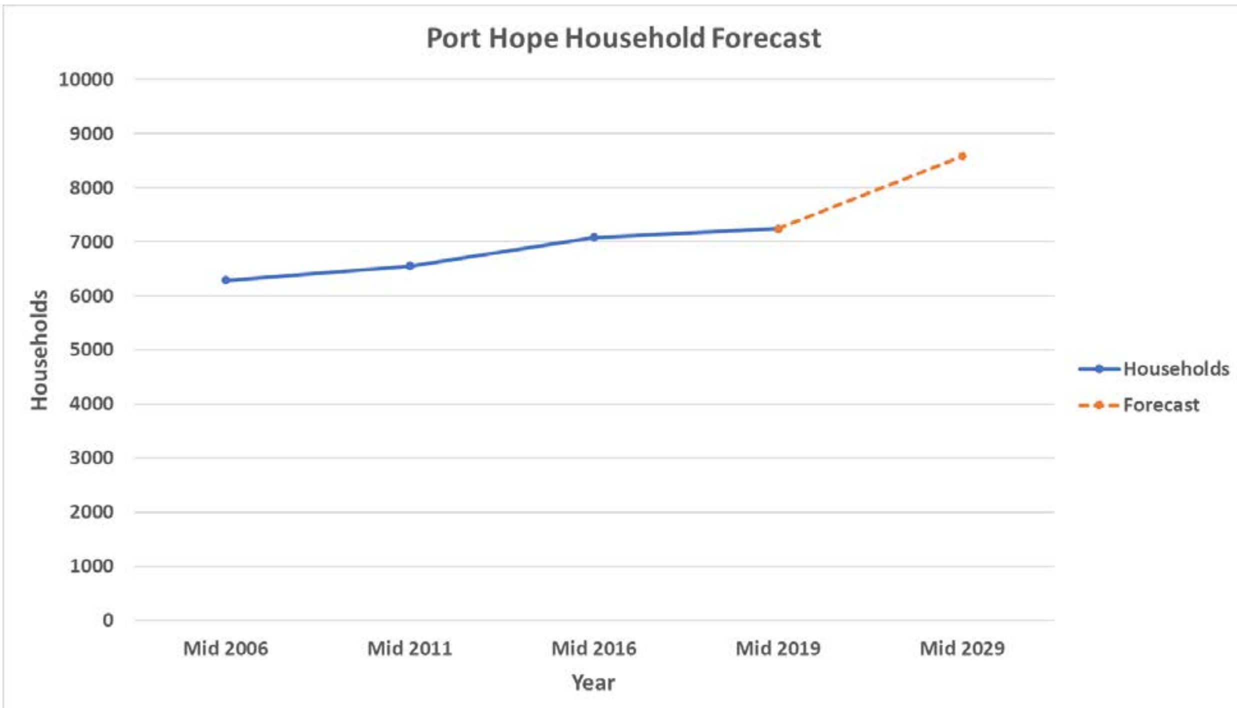


Table 4: Port Hope Household Forecasts (to 2029)

Year	Mid 2006	Mid 2011	Mid 2016	Mid 2019	Mid 2029
Households	6,285	6,552	7,075	7,240	8,575

Gravenhurst looks to achieve household growth that is close to historical numbers. From 2006 to 2016, It was estimated that 590 new households were constructed in Gravenhurst. It is expected that from 2016 to 2026, 650 new households will be constructed.

Figure 4: Gravenhurst Household Forecast (up to 2026)

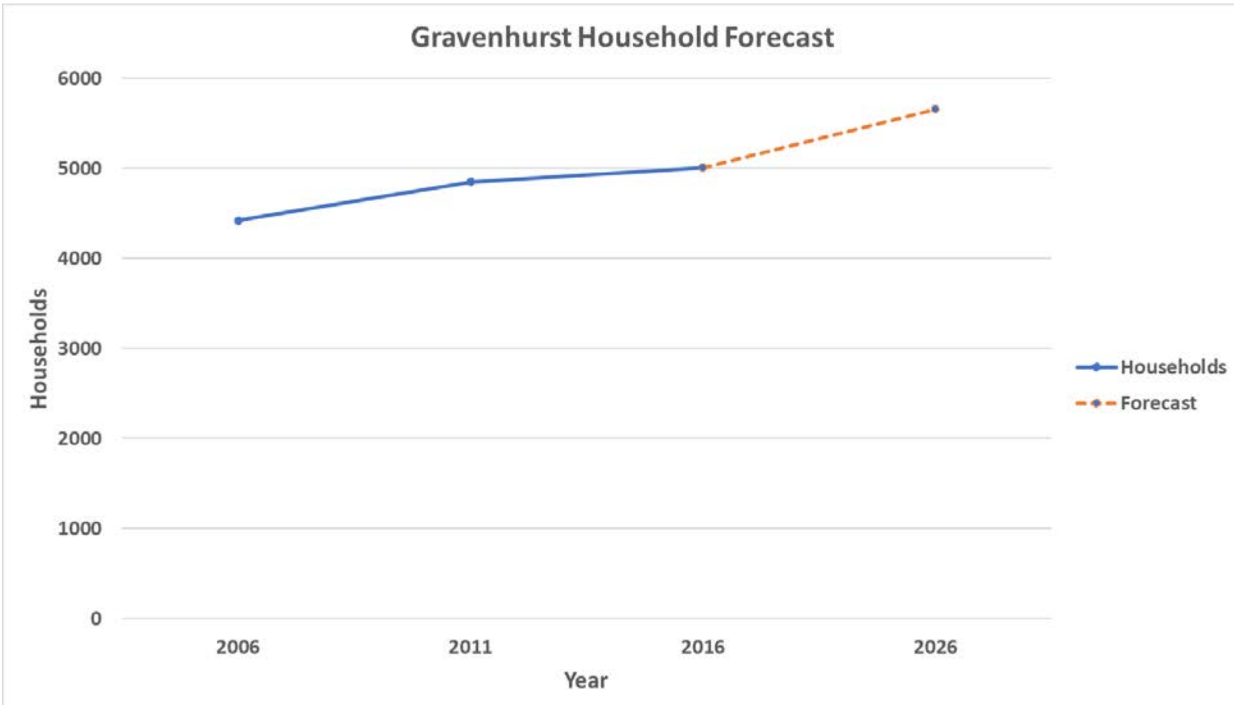


Table 5: Gravenhurst Household Forecasts

Year	2006	2011	2016	2026
Households	4,420	4,850	5,010	5,660

Historical Customer Growth and Total

Over the past five years, Elexicon has experienced consistent total customer growth influenced by the influx of housing and residential developments. As more households and people move towards the Elexicon territory, customer connections and required meters will continue to accumulate and grow.

Most of the customer growth within the Elexicon territory is coming from new Residential Customers. Elexicon's investments in the metering portfolio are heavily geared towards residential meters as shown in the amount planned. Within the General Service class, customers less than 50KW have shown growth year over year. In contrast, General Service Customers that require more than 50 KW have fluctuated historically with increases and decreases. Large Users have doubled from 2014 to 2019 with a large user added to the system in 2015 and 2018.

Figure 5: Elexicon YTD Customer Totals (2014 to 2019)

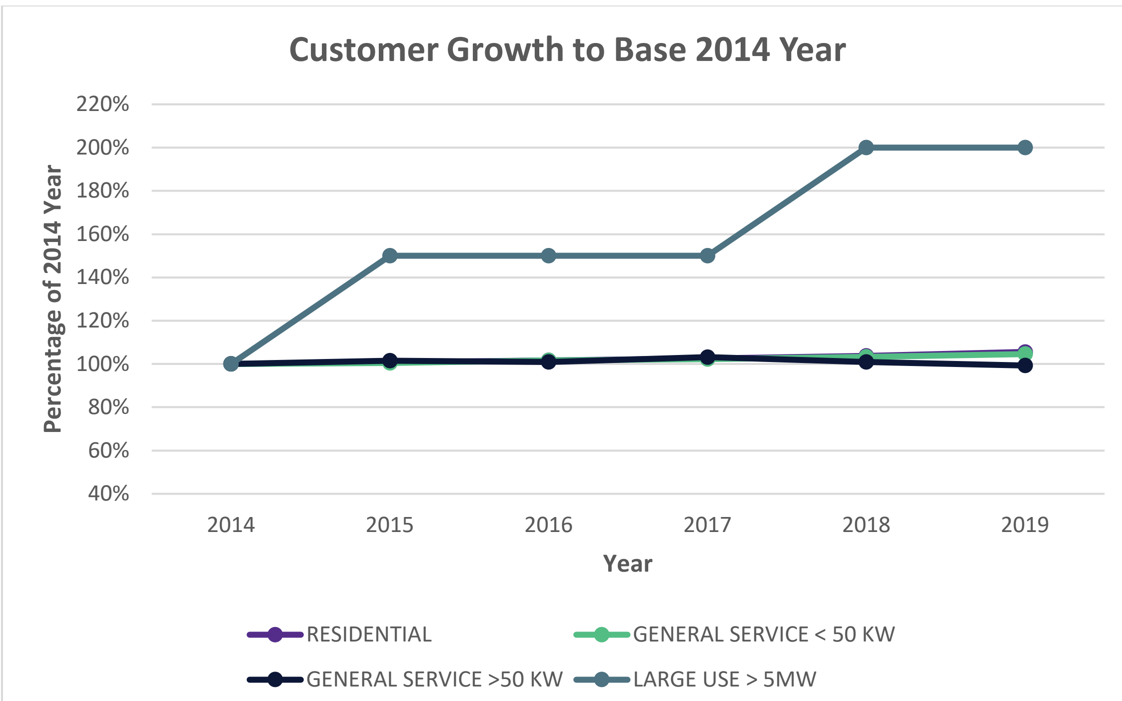


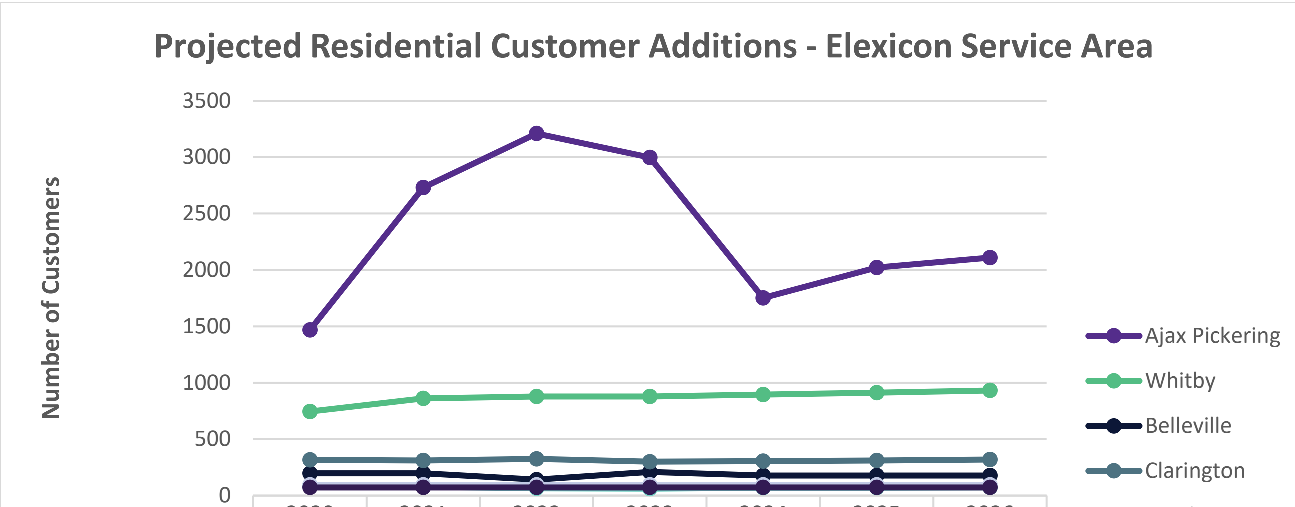
Table 6: Elexicon Customer Total by Customer Type

Year	2014	2015	2016	2017	2018	2019
Residential	146,537	147,753	149,071	150,220	151,914	154,711
General Service < 50 kW	11,030	11,088	11,211	11,274	11,389	11,535
General Service >50 kW	1,413	1,435	1,426	1,458	1,425	1,403
Large Use > 5 MW	2	3	3	3	4	4
Total Customers	**158,982**	**160,279**	**161,711**	**162,955**	**164,732**	**167,653**

Residential Customer Forecast (New Customer Connections)

Residential Customer projections drive the recommended number of meters required across the upcoming year. As a result of the new housing developments, a significant number of residential customers will be expected to be connected to Elexicon. Recent housing developments such as Seaton within Ajax-Pickering will drive a major percentage of the new residential customer connections. The number of residential connections dictates the recommended number of residential meters required for the year.

Figure 6: Elexicon Residential Customer Forecast



	2020	2021	2022	2023	2024	2025	2026
Ajax Pickering	1468	2730	3210	2996	1751	2022	2111
Whitby	745	863	880	879	896	913	931
Belleville	198	198	142	210	177	177	177
Clarington	316	312	325	301	307	312	318
Brock	87	79	63	61	71	71	72
Port Hope	95	95	95	95	95	95	95
Gravenhurst	72	72	72	72	72	72	72

2.2 Current-State Analysis:

Elexicon has obligations to connect and establish metering for customer connections to meet customer needs. The current process is to ensure that all new customer connections have the appropriate meter and interface. Currently, Elexicon has two AMI solutions in place within the company. Two types of meters for customer classes need to be stocked due to the proprietary head ends for the different AMI solutions. A significant portion (about 93%) of the customer accounts within the Elexicon territory are Residential Customer Counts. As such, most of the meter testing and meter replacements will be driven by the residential customer class.

Figure 7: Elexicon 2019 Customer Makeup

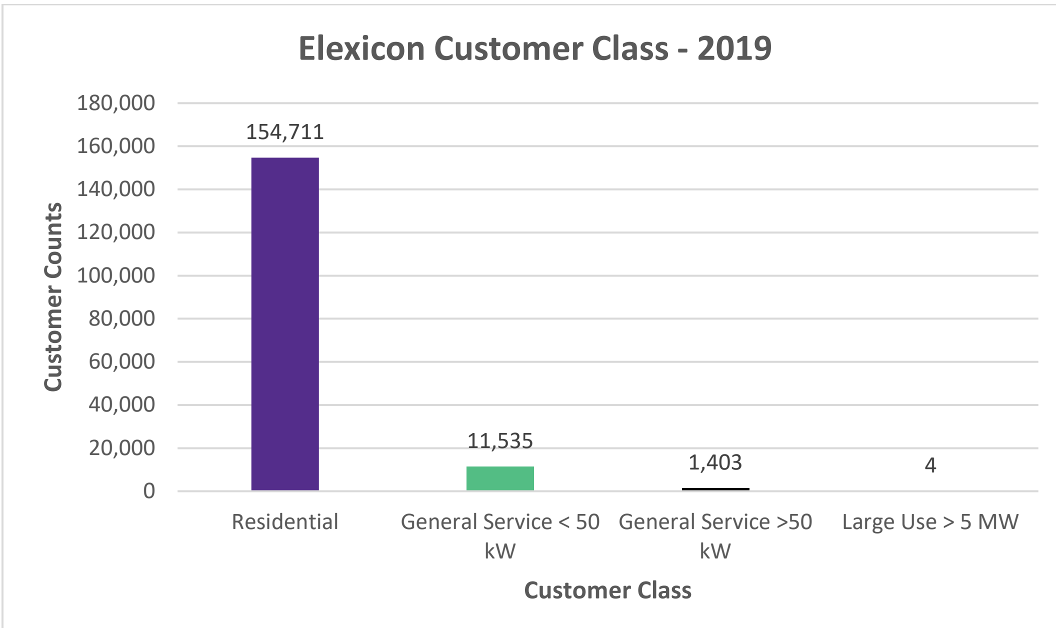
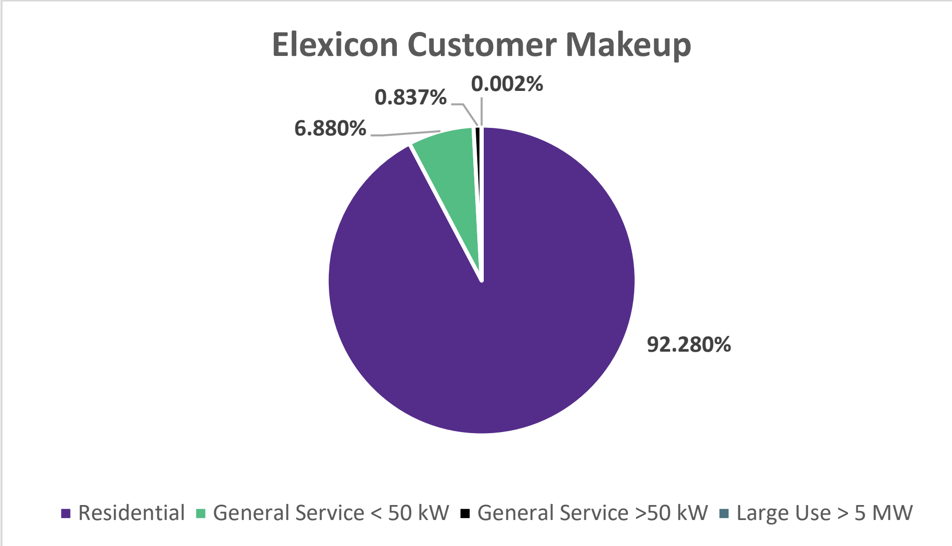


Table 7: Elexicon Customer Total by Customer Class

Customer Class	Number of Accounts
Residential	154,711
General Service < 50 kW	11,535
General Service >50 kW	1,403
Large Use > 5 MW	4
Total	**167,653**

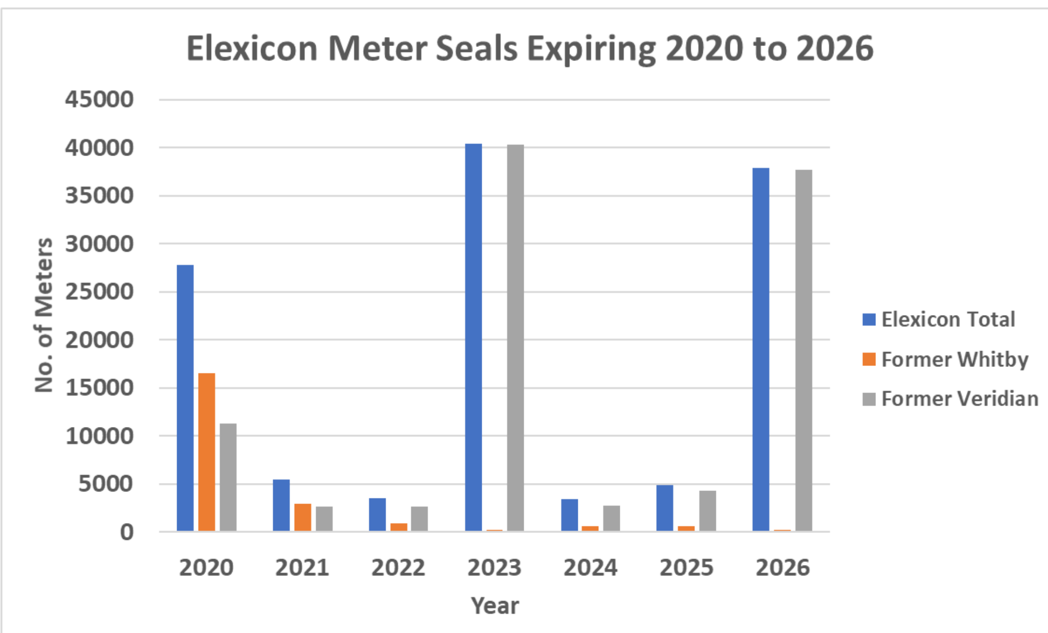
Figure 8: Percentage Customer makeup by Customer Class



Forecasted Meter Seal Expiry

The table below illustrates the number of meters that will have expired seals within the future DSP period.

Figure 9: Meter Seal expirations year over year



Using the information produced from Elexicon's consolidated Customer Information System ("CIS"), the expected expired metered seals across the DSP period are produced. Whitby expired seals are expected to peak around the year 2020 with expired seals for Veridian increasing to larger amounts every three years. To determine the number of meter seals to be replaced or refurbished, a sample of the meters is taken around a territory. Once evaluated with standard Measurement Canada testing, the meter lots can be taken into consideration and an in-service lot of meters can be extended in the re-certification period.

Table 8: Meter expiry by former territories

Territory	2020	2021	2022	2023	2024	2025	2026
Former Veridian	11,289	2,600	2,634	40,268	2,745	4,248	37,680
Former Whitby	16,500	2,877	839	167	624	626	199
Elexicon Total	**27,789**	**5,477**	**3,473**	**40,435**	**3,369**	**4,874**	**37,879**

Meter Capabilities at Elexicon

If a meter is expired and needs to be replaced, Elexicon shall replace the existing meter with a meter that can provide Elexicon's control room with outage signaling capabilities. Previous generations of meters such as the REX1 did not have last gasp capabilities. If the legacy meters are removed due to sample testing or service upgrades, they are not put back into service. Elexicon currently does not have plans to replace all REX1 meters until expiry or conditions deem it necessary. Newer generations of meters such as the REX2 and REXU provide the Control room with last gasp abilities thus increasing the awareness of the Control Room for the understanding of the location and magnitude of outages.

Last Gasp functionality has not been fully implemented in the Veridian AMI; the IP gatekeepers only send data back to the Operational Data Store. Whitby AMI outages were integrated into the GIS and OMS. Pinging functionality is operationally controlled by the Veridian AMI.

Future Analysis and Considerations

Elexicon Control Room and Metering is currently undergoing an investigation into attaching a smart meter to distribution transformers that serve multiple customers. This would provide Elexicon with increased intelligence and an ability to further understand the magnitude of the outage. These plans are currently for the former Veridian territory and will be revisited later during the DSP period.

The Veridian AMI will also be utilized to understand islanding and load control for new DER projects that Elexicon will proceed with.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

Measurement Canada: New Meters purchased and installed must be Measurement Canada approved and certified. Certain regulations such as the Electricity and Gas Inspection Act, and Weights and measures act are dictated and upheld by Measurement Canada. Provisional specifications of meters and notices of approvals are available on the Measurement Canada website.

IESO Market Rules: Metering investments also need to follow IESO Market Rules. Specifically, the Wholesale Residential Metering standard dictates that the standard should be observed by metered-market participants and by metered service providers in the IESO-administered market. Chapter 6 of the IESO Market Rules outlines 'a framework for revenue metering in the wholesale electricity marketplace, specifying the obligations of the metered market participant, the metering service provider and the IESO.

Distribution System Code: The Distribution System Code set by the OEB "sets out the minimum obligations that a licensed electricity distributor must meet in carrying out its obligations to distribute electricity within its service area under its license". Section 5 summarizes the metering obligations in which an LDC must provide to the customer. 5.1.1. illustrates that a distributor is fully responsible for the meter installation to retail settlement and billing for all customers connected to the distribution system. Other sub-sections within chapter 5 outline the distributor's requirements in handling metering data. The responsibilities as a metering service provider are to register the metering installation, maintain the installation, respond to meter trouble reports and investigate metering issues, provide edited metering data, and providing correction factors when necessary. When acting as a metered market participant, Elexicon must provide and is responsible for the metering installation, responsible for the accuracy of the metering data, and providing the name and contact info of the Metering Service Provider.

Electrical Distribution Safety - O'Reg 22/04: All metering installations and designs shall follow O'Reg 22/04. This is to ensure electrical safety for operational staff and the public.

O'Reg 389/10 Energy Consumer Protection Act : All General Services >50 kW are required to have a MIST Meter by March 21st, 2020 as per the Distribution System Code.

OEB Act, Section 92: Leave to Construct approval is not required for these investments.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.*

Customer Service: To ensure customer service to new connections, metering installations at the customer location must be performed on time. Metering is essential to customer service as it provides the customer with accurate billing, metered data, consumption, and demand statistics. Opportunities for customers to identify their usage and reduce their billing are made possible through smart metering. TOU pricing is adjusted based upon the duration of the day from the Smart Meter and it promotes customers to have more energy-efficient devices or use more electricity during off-peak times. Metering infrastructure also notifies Elexicon if there is a fault or issue within the meter to assist the customer. Customer engagement is handled by Asset Services for new connections whereas Operations and Maintenance are handled by the metering clerk and metering technician for the specified task.

Operational Effectiveness: Metering installations connected to the AMI reduce the need for meter readers and automates the billing and reading of metering data. As remote data is collected and remote connections and fault detection is provided by certain generations of meters, Elexicon becomes more operationally efficient.

Public Policy Responsiveness: It is mandated that Smart Meters need to be implemented and connected to all new Customer connections as set by the OEB's Smart Meter Implementation plan. Additionally, metering to Renewable Generation and Microgrids is required. All meters connected to customers must obey a variety of compliances and standards set by Measurement Canada, the OEB, and the DSC.

Financial Performance: Metering is key to Elexicon's revenue stream as customer consumption is billed. Elexicon also must provide adequate metering accuracy so that customers are accurately billed for what they are consuming.

2.5 Merger-Related Objectives:

The status quo is optimal from the merger as metering requirements are dictated by the growth in the area. Elexicon benefits from the merger as metering operations from the two former utilities are now combined. Expertise from the two utilities in terms of metering knowledge is combined and facilitates consistent operations into the future. Opportunities to evaluate best metering practices and the metering standards from the two utilities will prove beneficial for Elexicon in the future. Metering Investments provide high value to service continuity as it is a system access project that is mandated by a variety of organizations.

3. Program Alternatives

-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

3.1 Alternative Descriptions and Comparative Analysis

Number	1	2	3
Scenario Description	Status Quo: Current Budgeted Metering Plan	Replace with like for like meter; no new generation improvements	No Resealing of Meters
Annual Program Scope	In this annual scope, the resealing of meters is performed, and next-generation meters are used as replacements for expired meters. New Residential Type meters are also procured and installed for new connections.	No Replacement of meters to new generations. Like for like replacements of meters only.	Accuracy of expired seals to not be tested. Thus, resealing is not to be done but rather all meters will need to be replaced.
Annual Gross CAPEX	$1.40M	$1.17M	$2.34M
Annual Net CAPEX	$1.40M	$1.17M	$2.34M
Annual Program Benefits	The mandatory projects belonging to this program specifically address the objectives of improving customer focus and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus and public policy responsiveness.
Program Economics	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.

Customer Feedback	83.4% (619 of the 862) of customers support investments into equipment and replacing before failure. Customers were also told of Elexicon's two investment priorities in growth and system safety. In conjunction with other technology, Meters maintain reliability of the grid by signalling and allowing Elexicon to identify which portions of customers are out. Customers support investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage.		
Other Constraining Factors	If further developments than anticipated are produced in the Elexicon territory, Elexicon will need to invest in larger numbers of meters to ensure stock and installation numbers. Elexicon must perform this work as it is a mandatory obligation; adjustments to budgets shall be made to incorporate this constraint.	By not upgrading meters to newer generations, Elexicon may not improve in SAIDI and SAIFI and increased the functionality of new generation meters. Continuous Improvement of response to outages with Smart Meters is achieved using new generation smart meters.	Not resealing and testing metes would increase the expenditures required of the metering group. It is recommended to test for accuracy in groups to be more efficient with meter investments.
Preferred Alternative	X		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Reliability of service can stay stagnant if metering replacements are not made or new generations of meters are not needed. New Meters will have greater capabilities than legacy equipment. Continued investments and connectivity of meters for pinging and last gasp to control room would increase reliability. The reliability of the grid can be improved by the smart outage and fault detection of meters. New Metered connections help control room, and operations identify sections of the grid that are out of power. There is a possible reduction of outage duration.

Grid Resiliency: N/A

Operational Efficiency and Cost Effectiveness: Metering can identify where certain locations have outages and do not require workers to manually read meters as data is collected via the network interface. AMI automates other metering functions like service connection and disconnection, tamper and theft detection, fault and outage identification, and voltage monitoring. Elexicon can also be more cost-effective in asset investments through customer metered data. If a new customer fits a certain profile of a current customer, Elexicon can size the transformer or service using metering data.

Safety: N/A

Cyber-Security/Privacy: Replacement of Modem, Gatekeepers, smart meter implementation are to be incorporated as new investments. ION Meters provide better cybersecurity than older legacy standards. The privacy of Metering data is critical and is required to protect customer data.

Environmental Benefits: N/A

Coordination/Interoperability: IESO meter demand management and repository are mandatory for all local distribution companies within Ontario. Ensuring metering data is validated and secure in conjunction with usage of IESO MDM/R promotes greater coordination and interoperability. Metering of select customers or sections within the grid provides better insights especially to interconnections and support to nearby local distribution companies and the transmitter.

Conservation and Demand Management: Metering data provides customers with knowledge of their demand and consumption. If a customer increases understanding of their habits to the usage of electricity, it could influence the customer to seek CDM changes.

Net Customer Benefits: Advanced Metering Infrastructure and physical developments provide customers with better connectivity and access to metered data and billing. Customers need to be accurately metered whether they are older or new connections. Meters connected to AMI enable utilities to identify opportunities in reducing peak demand and energy consumption. DER technology can also be assessed using meters for load control and understanding of the behavior of DER on the grid. As the Customer becomes more dynamic, Smart Meters will provide utilities with knowledge and capabilities to prepare.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

Larger than typical Household growth within Elexicon's service areas is expected. This growth will drive the increase in residential customers as well as potential growth in industrial and commercial customers. Thus, an adequate supply and stock of meters whether it be polyphase, interval, residential type, or smart will be required. If developments increase or slow down, investments into meter installation projects will be adjusted. The new Seaton development within Pickering is expected to bring a substantial number of customers that will require new metered connections.

To ensure the modernization of meters, Elexicon will replace legacy meters with new generation meters that have added capabilities. This is expected to provide the control room and Elexicon with numerous operational efficiencies and cost savings. Elexicon will perform a study of the cost savings and efficiencies realized of these replacements.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

With current and historical practices, Customers are to provide site plans, single line diagrams, proposed usage, service, and required energization date before a new connection. Customers must contact Elexicon to use approved metering equipment and for an acceptable location as approved by Elexicon.

Meter replacements are to be performed when the accuracy of the meter is jeopardized, the seal has been broken, deterioration of performance, damage, or upgrades to services. Residential customers and small General Service meters, not presently billed on a demand basis, will be provided with a Smart Meter. Meters are changed according to Measurement Canada standards and policies. Whitby Hydro shall have access to the Customer's property. Customers shall permit, provide, and maintain access to metering equipment for Whitby Hydro's use.

A propagation study of the current Sensus Tower system will be used to determine the installation of new Sensus technology for commercial accounts in the 50-200KW customer subclass. The Sensus testing would help with the efficiencies of contiguous and more rural areas under Elexicon. Elexicon is also currently working on smart grid projects related to battery storage where the installation of internal disconnect meters is utilized to control loads for EV charging.

Looking forward, Elexicon will also evaluate opportunities to replace the REX1 meter. The first generation of Smart Meters could not transmit power outage capabilities. Options to install a new meter at every distribution transformer is evaluated as it could help Elexicon operations.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Elexicon has combined the best practices from both former utilities in creating a consolidated Conditions of Service. Installation of metering equipment must be made in consent with Elexicon practices. Inspections must follow before construction procedures and after construction has finished. With regards to the different service connections, Whitby and Veridian had laid out the requirements for metering associated with each connection such as meters and associated metering equipment. Elexicon has now updated provisions to the required meters and metering equipment like old processes. Elexicon will supply, own, install, and maintain all meters, instrument transformers, ancillary devices, and secondary wiring for revenue metering purposes. With regards to embedded generation, all customers must pay for metering compliance and installation of generation facilities. Elexicon will assume ownership and maintenance to internal requirements and standards. Work execution of metering practices has not changed from the former utilities to Elexicon. Typical Metering Requirements in Elexicon's territory are provided in the following chart below found in Section 2.3.7.2 Typical Metering Requirements of Elexicon's Conditions of Service.

Table 9: Typical Metering Requirements from Elexicon

Type of Service Entrance	Voltage of Service	Size of Service	Type of Meter Base
Main Switch	120/240V	200A Max,	Four Jaw Meter Base
Main Switch	120/240V	400A Max.	Transformer Type Five Jaw Meter Base
Main Switch	120/208V	200A Max.	Five Jaw Meter Base
Main Switch	120/208V	200A Max.	Seven Jaw Meter Base
Main Switch	120/208V	Over 200A	48” x 48” x 12” Meter Cabinet
Main Switch	347/600V	200A Max.	Seven Jaw Meter Base
Main Switch	347/600V	Over 200A	48” x 48” x 12” Meter Cabinet
Switchgear	All Voltages	All Service Sizes	36” x 36” x 12” Meter Cabinet

4.3 Scale Increase Considerations

There are a variety of Scale Increase improvements to the metering portfolio because of the merger. Higher purchasing power as a combined utility enables further investments into new metering technology or developments. There are numerous opportunities to consolidate metering operations and the combined skillsets of metering operations and design are consolidated into the future.

It remains to be seen how metering services can be combined on the software side and whether one single AMI solution can be finalized instead of two. Investigations into efficiencies from metering communications will be taken. However, Elexicon will continue to utilize the two AMI solutions for the time being. As investments into an ADMS are expected; metering software and operations will be impacted by the integration into the vendor-neutral platform. Elexicon will also be reviewing Sensus Technology to evaluate if there can be efficiencies gained in rural territories which are now contiguous. As the older smart meters are replaced with improved meters with advanced functionality, Elexicon will receive operational efficiencies. Elexicon will perform a study in the future to take notes of these efficiencies.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

With regards to the rate freeze, Elexicon is expecting an annual reduction of $20,000 in capital spending from the reduction in contractor services for complex meter services. As metering investments are mandatory obligations, Elexicon must perform these projects for new and existing customers. Elexicon will continue to seek benefits with new metering investments with regards to service continuity and integration into existing IT/OT systems. Elexicon has also considered consolidating AMI systems that interact with metering, but no opportunities have arisen. Into the future DSP period, two AMI systems will be kept in place due to the meters currently being used in all service areas. Efficiencies will arise from the utility pooling resources such as metering staff and meter requirements across the company.

5. Individual Projects Comprising the Program

5.1 Overview of Material Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2021-6001	Residential Type Meters	2021	1.06	Mandatory

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-C.a.3 (SA) Factors affecting the final cost of the project
-C.a.8 (SA) Where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.a.6 (SA) Whether other project design and/or implementation options were considered and if not, why not
-C.a.4 (SA) How controllable costs have been minimized
-C.a.8 (SA) Where applicable, the results of the final economic evaluation carried out as per section 3.2 of the DSC
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.a.5 (SA) Whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why

<table>
<tr><td>Project name</td><td colspan="5">Residential Type Meters</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-6001</td></tr>
<tr><td>Job numbers</td><td colspan="5"></td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Access</td></tr>
<tr><td>Budget Category</td><td colspan="5">A4 - Metering</td></tr>
<tr><td>Project Driver</td><td colspan="5">New residential connections
Meter failures
Meter sample testing as per Measurement Canada guidelines.</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Supply and install appropriate single-phase meters for new residential connections and addressing meter failures. Metering department is to ensure there are meters available to perform meter sample testing as per Measurement Canada guidelines.
1500 metering units are forecasted to be installed in 2021, at a cost of $706 installed.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $ 1,059,240</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $ 1,059,240</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$95,332</td><td>$105,924</td><td>$180,071</td><td>$677,914</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Residential meters are used by both Lines and Metering and as such stock must be available at all of Elexicon's service depots. In addition, since Elexicon Energy has deployed 2 separate AMI solutions we need to stock 2 different types of the same residential meters. Elexicon Energy must ensure that all meter sealing is within the Measurement Canada guidelines.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There are no alternative solutions as it relates to the smart meter.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, and customer focus.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5"></td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	Customer Requested Work
OEB Investment Category	System Access
Primary Driver	Customer Service Requests
Secondary Driver(s)	Mandatory Service Obligations

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.32M	**$0.42M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Customer Requested Work investments are System Access projects which are initiated when a customer specifically comes to Elexicon requesting that work be performed on the distribution system around them. Examples of these include customer station isolations, pole relocations/rebuilds, and underground cable locations. These projects are mandatory as they are System Access. They are not easily forecasted as these projects appear on a per needs basis when the customer demands it. Common customer requests such as customer station isolations, primary and secondary isolations at the meter, joint use, and underground cable locates are provided with an annual budget as they are expected year over year.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.32	1.42	2.00	0.10	0.10	0.10	0.10	0.10
Contributions	0.17	1.31	1.91	0.01	0.01	0.01	0.01	0.01
Net Program Expenditures	0.15	0.11	0.09	0.09	0.09	0.09	0.09	0.09

There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Customer-Requested work is mandatory for Elexicon as the customer is requesting services from the utility company. In these cases, an economic evaluation shall be conducted for the specific request. Annual projects such as Customer Station Isolations and Capital Cable locates are provided for free during regular working hours with specific limits associated. When customers are requesting these services, they usually are upgrading or performing routine maintenance on the customers end of the equipment. Close coordination with Elexicon is held to identify the scope of the request and to communicate when project work is initiated, being performed, and finished.

As a merged company, Elexicon will have more resources that can be assigned to customer requested work. The collective experiences of staff from the two former utilities will be beneficial in performing the work. Customer Isolations that are held within the territory of Ajax, Pickering, and Whitby could potentially be coordinated internally. Plant relocations initiated by Customers shall follow O. Reg. 22/04. Elexicon will ensure that communication and contact with customers shall be prompt to address customer satisfaction metrics the OEB has set in place. Failure to respond to customer inquiries and requests could cause customer dissatisfaction and damage the Elexicon brand.

2. Basis for Action

2.1 Performance Trends:

Customer Requested Work is easily forecasted other than for annual requested work such as isolations and cable locates. Unlike the other System Access projects, developments within the territory do not provide a picture of expected customer requested work into the future. Similarly, customer requested work can differ from one another depending on the complexity of the customer's request. As these projects are initiated depending on the individual customer, Elexicon will budget and address the project when requested. Elexicon has an obligation to its customers and will ensure appropriate and safe work is provided when the request is initiated. Customer Growth may however provide opportunities for more customer requested work to appear in the future due to the increase in total customer counts.

Figure 1: Historical Customer Requested Work

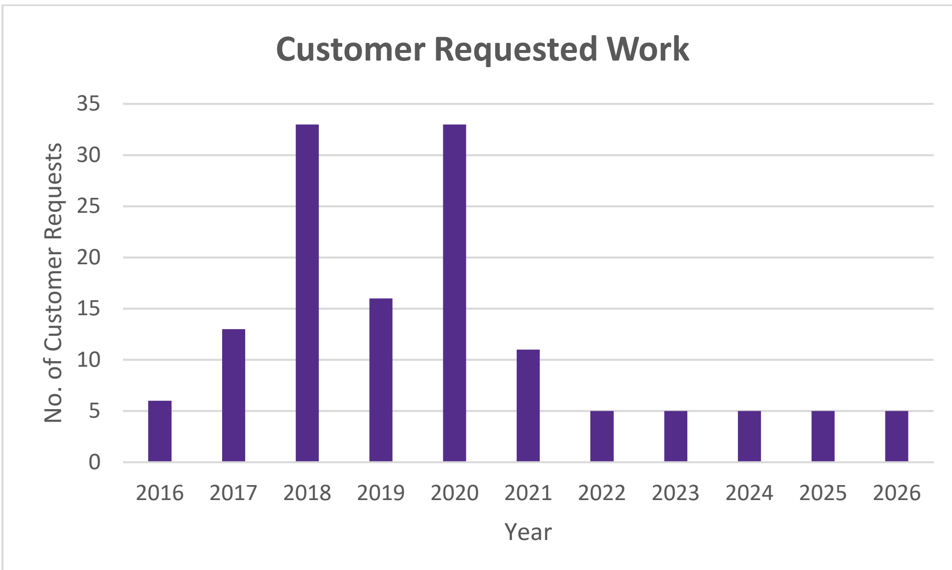
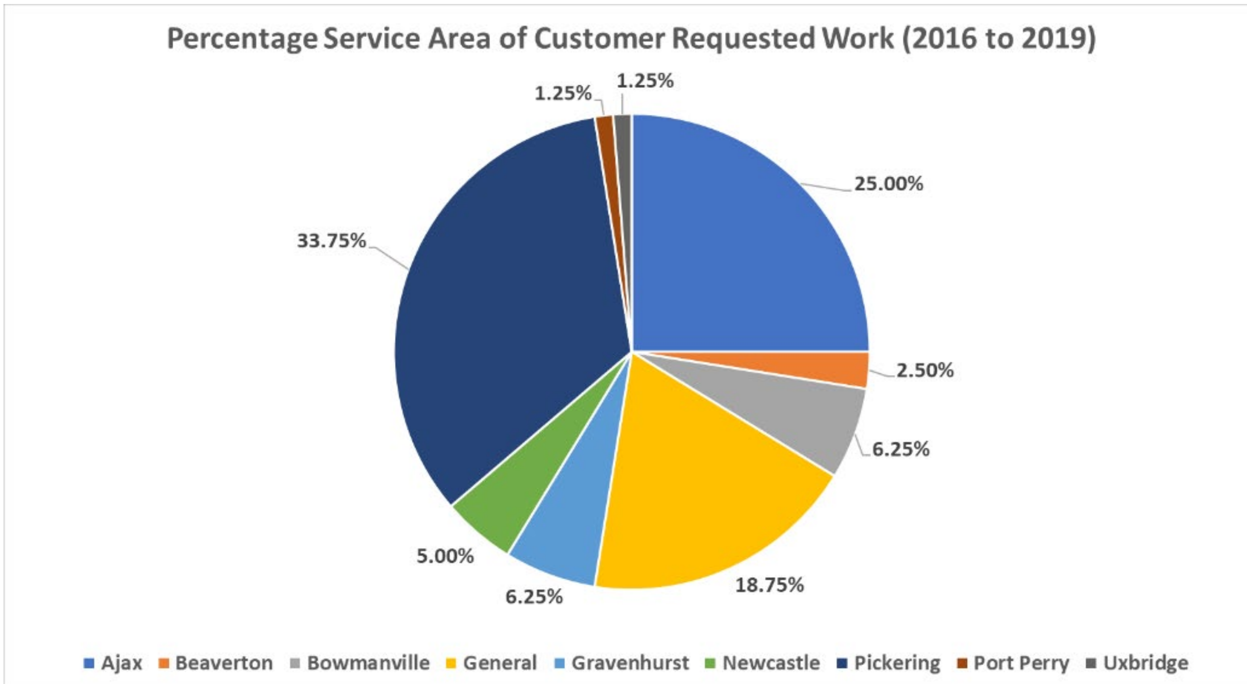


Table 2: Planned and Historical Customer Requested Work Projects

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Number of Projects	6	13	33	16	33	11	5	5	5	5	5

Typically, Elexicon has engaged with a steady stream of customer requested work across the past four years. In 2020, it was determined that twelve planned projects for customer requested work will transpire. 2018 was an outlier year as Elexicon experienced a large amount of customer requested work. Customer Requested Work appears on a per needs basis depending on the number of customers year over year who have designated requests. The 5 annual forecasted customer requested-work projects are found in Table 2. These projects are expected annually where customers will typically request one of the five requests as outlined in the table.

Figure 2: Percentage Makeup of Customer Requested Work to Service Area



The Service Area makeup of Customer Requested Work is provided in Figure 2. About 78% of the customer requested work that was carried out in the past originated in the Ajax, Pickering, and General Service Area. Much of the urban development found within Elexicon will be located in the Ajax-Pickering Service Area.

Historical Generation Connections

Customer Requested Work at Elexicon also pertains to generation connections and connection impact assessments that customers request for. Historically, generation connections have been steady until the end of 2018. This was due in part to the cancellation of the FIT project. It is expected that net metering and larger generation projects will be the major generation connections in the future. This is presented in the REG forecast as part of the DSP. Below is the outline of historical connections of generation as found in Figure 3 and Table 3.

Figure 3: Historical Generation Connections

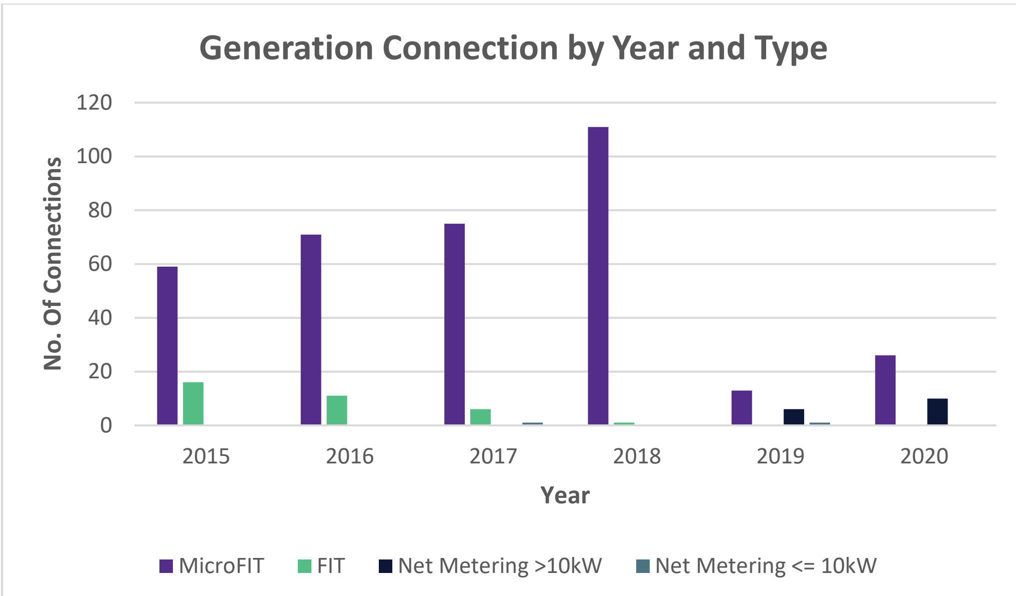


Table 3: Historical Generation Connection Types Yearly

Historical Connections	2015	2016	2017	2018	2019	2020
Generation > 10 kW	59	71	75	111	13	26
Generation ≤ 10 kW	16	11	6	1	0	0
Net Metering >10 kW	0	0	0	0	6	10
Net Metering ≤ 10kW	0	0	1	0	1	0

2.2 Current-State Analysis:

Currently, Elexicon budgets for annual customer requested work found in Table 3 such as Underground Cable Locates, Customer Station isolations, Primary and Secondary isolations at the meter, and joint use. The current system meets the customer's needs but the customer may want to perform upgrades of services or maintenance on their property. Additionally, any third-party damages and make-ready work are addressed in customer requested work. Generation Connections are the last annual project budgeted in Customer Requested work.

Table 4: Annual Customer Requested Work Project Budgets

Annual Customer Requested Work Budget	DSP Years
Generation Connections	2020 to 2026
Customer Station Isolations	2020 to 2026
3rd Party Damages	2020 to 2026
Third Party Make Ready Work	2020 to 2026
U/G Capital Cable Locates	2020 to 2026

These Services are expanded further in Elexicon's Conditions of Service. Customer Station Isolations can also be requested and are the right of Elexicon Customers. If the electrical services on their premises need to be disconnected for modification, upgrade, and maintenance, Customers shall request Elexicon with advanced notice. Residential Customers all have one free interruption throughout each annual year for normal working hours. Specifics to Primary Serviced and Secondary Serviced Customers are described in 4.2 where work execution of the program is described.

Third-party make-ready work and damages are also incorporated in the Customer Requested Work program. In these projects, the third party is the major contributor and catalyst. For instance, where damages are found on third party equipment, Elexicon will assist in repairing and ensuring operatable and safe equipment.

Customers may also request Elexicon to relocate plant or convert to underground distribution. When a customer requests for relocation, Elexicon will receive contributions from the customer as it was not initiated by the utility. Any customer-initiated projects that are implemented within the field can initiate renewal of asset lifecycles. A chart of common equipment found in customer requested work is found below with the typical lifecycles listed in Table 5.

Table 5: Distribution Asset Typical Useful Life

Distribution Asset	Typical Useful Life
Wood Poles	45
Underground Cable	40
OH Conductor	60
Pad mount Transformer	40

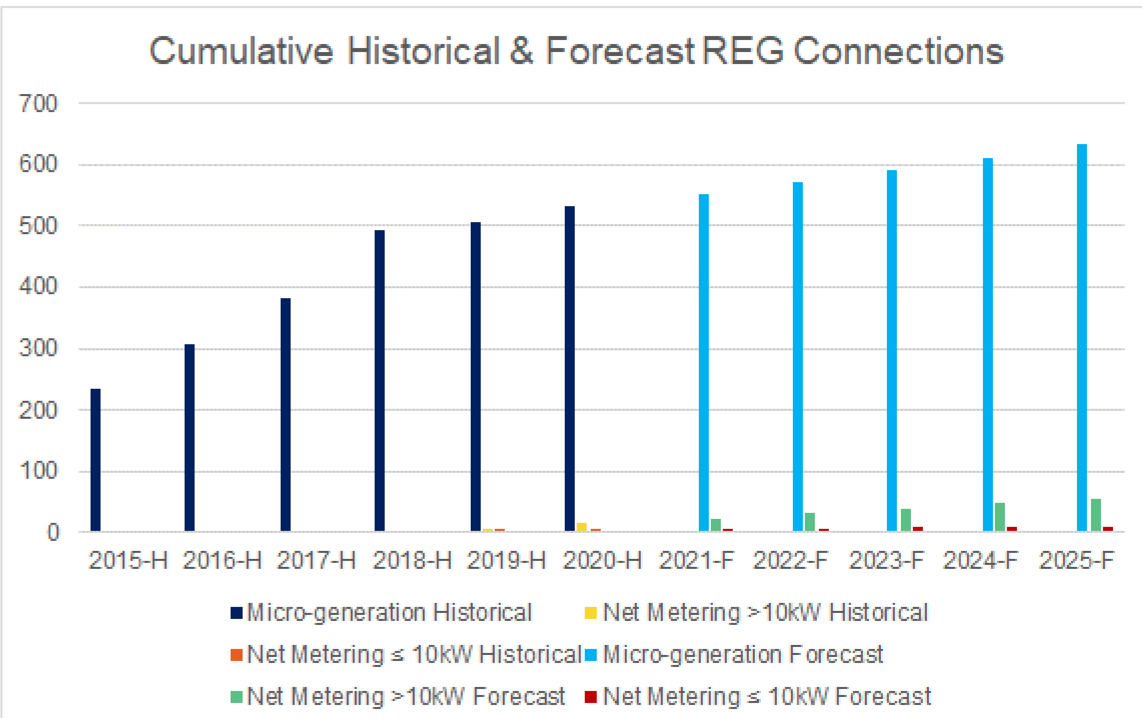
Forecasted REG Connections

With regards to generation connections, Elexicon has forecasted an expected number of REG connections across the future DSP period as found in Figure 4. An estimate is driven from the past two years of connection numbers. The connection amounts before 2018 are not symbolic of the number of expected connections into the future as FIT was a major catalyst for past connections. Over the next few years, it is expected that twenty micro-generation connections, eight net metering >10KW connections, and one Net Metring ≤ 10kW connections will be annually made.

Table 6: Forecast number of new REG connections by type and size

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	20	20	20	20	20
Net Metering >10 kW	8	8	8	8	8
Net Metering ≤10 kW	1	1	1	1	1

Figure 4: Cumulative Historical & Forecasted REG Connections year over year



2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

Customer Satisfaction- For Customer Requested Work, projects planned may have an impact on the first contact resolution that customers will have with Elexicon. Customers will request work or ask for assistance from the utility and Elexicon should be effective in addressing any concerns or needs of the customer. Measures such as first contact resolution are potentially affected by Elexicon responding to customer inquiries.

Safety- When performing customer requested work for customers, Elexicon will abide by O.Reg 22/04 (Electrical Distribution Safety) in ensuring the safety of the public and workers.

Conditions of Service- Elexicon is obligated to produce a condition of service for its customers to demonstrate the obligations the company has to its customers. Specific services such as locates and customer isolations are provided as service to customers. Both former utilities and Elexicon also responded to other customer requested work such as the relocation of plant from individual customers.

OEB Act, Section 92:

Leave to Construct approval is not required for these investments.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.*

Reliability of Supply

If the Customer wants to pursue changes on electrical equipment on their end of the connection and Elexicon does not respond, it could jeopardize or affect the reliability of the system within the area. Elexicon should evaluate the customer service request and ensure that adequate changes/relocations are performed to address the customer changes and to ensure the distribution system's reliability is intact.

Customer Service/Satisfaction

Elexicon has obligations to existing customers to address customer service requests that are deemed feasible and appropriate to consider. If the request is not completed on time or ignored, Elexicon may encounter damage to the overall brand and the trust it has with its customers. One customer satisfaction measure that is affected by customer service requests is the first contact resolution. As described by the OEB, 'Utilities should aim to address their customer's needs as quickly as possible. Ideally, their concerns and issues can be resolved the first time the customer contacts the utility. Customers expect consistent and excellent service for electricity; customer requests will be responded to by Elexicon. Electrical Service must be maintained such that customers are not affected and can utilize the service for their daily purposes. Annual projects such as isolations and cable locations assist customers with capital or maintenance work that they have planned.

Public Policy Responsiveness-Conditions of Service

As mandated by the Ontario Energy Board, all utilities need to provide customers with their conditions of service. Elexicon has responsibility for the policies it has provided to the public. For instance, the conditions of service provide details on Customer Station Isolations, Underground Cable locates, and relocations of assets.

2.5 Merger-Related Objectives:

With the two former utilities merging into Elexicon, it provides more internal resources to address customer service requests. The collective experiences of both inside and outdoors staff will enable Elexicon to address customer service requests more easily. Additionally, as Whitby is close to the other municipalities within Durham, crews are positioned to address more customer service requests that Elexicon receives.

3. Program Alternatives

-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

3.1 Alternative Descriptions and Comparative Analysis

Number	1	2	3
Scenario Description	Status Quo: Budgeted Customer Requested Work	Provide more storm hardened measures for Customer Requested Work.	Perform OH to Underground Conversions for Customer Requested Work.
Annual Program Scope	The current program considers the typical amount of customer requested work year over year with annual programs. In the short term, certain initiated projects are also placed in this program.	Customers are provided with more storm hardened options regarding changes when asking for Elexicon's service.	For areas where overhead infrastructure is required changes, Elexicon could potentially convert Overhead distribution systems to Underground.
Annual Gross CAPEX	$0.42M	$0.82M	$1.26M
Annual Net CAPEX	$0.09M	$0.18M	$0.27M
Annual Program Benefits	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, operational effectiveness and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, operational effectiveness and public policy responsiveness.	The mandatory projects belonging to this program specifically address the objectives of improving customer focus, operational effectiveness and public policy responsiveness.
Program Economics	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.	Placing of significant public or private infrastructure and simultaneous job creation.

Customer Feedback	200 customers were surveyed online, and 626 customers were surveyed by phone. When asked about what Elexicon should focus on as investment objectives in addition to addressing customer growth and system safety, 3.3% (29 of the 862) of respondents indicated they felt Elexicon should focus on addressing customer requests faster and more efficiently. Other choices such as improving grid resilience and preparing the grid for new types of uses like Electric Vehicles and Renewable Generation were preferred.	200 customers were surveyed online, and 626 customers were surveyed by phone. When asked about what Elexicon should focus on as investment objectives in addition to addressing customer growth and system safety, 3.3% (29 of the 862) of respondents indicated they felt Elexicon should focus on addressing customer requests faster and more efficiently. Other choices such as improving grid resilience and preparing the grid for new types of uses like Electric Vehicles and Renewable Generation were preferred.	Elexicon Customers (262 that were online-surveyed and 600 that were telephone-surveyed) were asked about underground conversions or underground systems related to current rear lot lines. About 20.4% (176 of the 862 surveyed customers) of customers support maintaining status quo i.e., keeping the overhead lines in the rear lots and replacing them as they fail. 62% of customers were in favour of underground systems.
Other Constraining Factors	Further Customer Requested work may be produced in the DSP period. Elexicon shall ensure that budgets are flexible that they can be adjusted if more customer requested work appears in the future.	Elexicon presents options to customers regarding new connections where applicable. Providing only the most expensive option should not be important. The option that is the most economical, reliable and safe shall be chosen. Practicality also needs to be taken into consideration.	Performing OH to Underground Conversions for initiated conversion work by Customers is much more expensive and complex.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Reliability is addressed as Customer Service Requests are primarily geared towards upgrades to their equipment or for operation and maintenance purposes. Pole relocations help renew the assets that are being replaced.

Grid Resiliency: When performing asset replacements and relocations in response to a customer request, Elexicon can ensure that the new design and build are more resilient. As climate change becomes an even greater problem, Elexicon will take note and apply appropriate action where required.

Operational Efficiency and Cost Effectiveness: The preferred alternative – only completing the work requested by customers – is the most operationally efficient and cost effective since the requested customer work is completed for the least cost compared to other options.

Safety: Customer Station Isolations are essential in ensuring new work performed on the Customer end is done so in a safe manner. New relocations also ensure that safety protocols and considerations are followed before relocation. Underground Capital cable locates also help customers understand the risk and location of power cables within their properties.

Cyber-Security/Privacy: N/A

Environmental Benefits: Assisting in Generation Connections within the region assists Elexicon. As customers become more environmentally driven and invest in new REG investments, Elexicon shall assist the customer in ensuring a safe and reliable connection.

Coordination/Interoperability: Coordination between third parties will be addressed with customer requested work. Third Parties are key to two of the planned annual budgets being third party damages and third-party make-ready work. Coordination internally in the consolidated utility will also improve with larger customer requested work.

Conservation and Demand Management: N/A

Net Customer Benefits: Customer receives benefits in terms of being able to update and maintain their equipment. For Cable Locates, it is a free service that enables customers to identify where power cable assets are and to be safer. The relocation of assets also allows the renewal of current assets and an extension of End of Life.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

If a System Access project has not materialized, it is budget will be shifted to a similar system access project or new system access project. As system access projects are on a per needs basis, the financial resources will be saved in the pool unless a more pressing project required further financial resources from the System Access Portfolio. Customer Requested Work is on a per needs basis and entirely dependent on the need of individual customers.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Typically, the planning of annual budgets and projects within the Customer Requested Work portfolio follows historical requested work patterns. As Elexicon continues to increase in customer base due to developments within the service territory, customer requested work may increase. Current projects forecasted are annual projects that can be expected year over year. Individual Specific Customer Requests vary year over year depending on the specific request and the nature of the customer's expectations/requirements. Inputs utilized for Customer Requested work include the assets related to, the connection requirements, customer information, and the needs that the customer presents to Elexicon. Elexicon must address these requests in due time as it is a mandatory obligation that the utility has with customers.

As designated in Elexicon's Conditions of Service, standard construction for the main power supply system on roadways, major corridors, and rights of ways, railways and commercial/industrial parks is an overhead system. Construction for new residential customers within Elexicon territory is preliminarily underground. Customer Requests such as Customer Station Isolations and Capital Program locates are provided free of charge by Elexicon during regular working hours with specific limits assigned to each.

In cases, where a customer has a request that is outside of the scope of normal work or requiring significant work by Elexicon, the customer shall pay for the new changes they require on the grid. If a request is due in part to Elexicon's responsibility, Elexicon will take up the charge. Planning of customer requested work is performed when the customer request is initiated and evaluated. As such, forecasting of work is not able to be performed over future years as it is dependent on Customer needs.

It is expected that across the future DSP period that more net metering connections shall take place. This provides Elexicon with more unique challenges as the portfolio continues to expand. The REG forecast found in Figure 4 estimates that about 9 total net metering connections will be expected year over year.

4.2 Legacy Work Execution Approaches vs. Combined Operations

In the past, the two former utilities have different processes and design standards in completing work. Elexicon has standardized the material and distribution construction standards into one consolidated format for the whole utility to use. Distribution standards from the two former utilities were influenced by one another as staff had worked with one another and in the two companies prior. Differences are not vast from one another as Whitby service voltages and makeup is like that of the neighboring cities of Ajax and Pickering. There is no emerging work towards performing the physical work that is different from the two utilities. Elexicon will send internal representatives to assist in the location of cables and isolations of service. When Elexicon receives a customer request to perform work or relocate plant, the work shall be performed internally. For more complex projects that Elexicon cannot fulfill, third party contractors are utilized to execute the work. An understanding of the customer's location, the distribution system, and the equipment of the project is gathered. The requirements to work execution are dependent on the ownership demarcation point that Elexicon and the Customer have agreed on. Tree trimming can also be requested from customers if a tree on the customer property is interfering with lines. With regard to its Conditions of Service, Elexicon has combined the best practices from both former utilities in creating a consolidated version. A description of the current practices with regards to annual budgeted Customer requested work is further described under the following bullets.

Customer Requested Plant Relocation Work Execution: In the circumstances where a customer requests relocation of Elexicon's assets, Elexicon will recover from the customer the cost of the relocation of the asset, except to the extent recovery is limited under law. Requests will be accommodated where the relocation does not affect the reliability of the system or if the relocation results in the replacement of the asset on any property not owned by the customer requesting the relocation. Relocations of assets are not an obligation if a reasonable alternative is not available.

Generation Connections Work Execution: Before connecting to Elexicon's distribution system, the customer shall prepare technical documentation outlining the details of the generation connection as per Elexicon's Conditions of Service. Where applicable, Elexicon shall then perform a Connection Impact Assessment to ensure the connection does not negatively influence the system.

Capital Program Locates: Elexicon will charge at its discretion if the Customer is to be exposing underground primary cables. Where isolation is not practical, an Elexicon representative will stand by during the customer's work.

Station/Service isolations: Residential customers can receive one free power interruption per year. Residential Customers have the right to disconnect service for maintenance or upgrade/modification after giving sufficient notice to Elexicon. For Primary Isolation, Elexicon also provides isolation services for customers requesting disconnection from high voltage. Primary Service Customers will need to schedule an outage with Elexicon and provide a fee. These requests are under Elexicon's availability. Secondary Service Isolations shall require an isolation request to be submitted to Elexicon.

4.3 Scale Increase Considerations

Benefits are realized from the consolidation and combined skill sets of the technical and operational workforce. Both former utilities can share the collective experiences in terms of working towards customer service requests. Furthermore, there will be more staffing resources combined to address customer service requests. As Whitby is close in proximity to many of the other Durham municipalities under Veridian connections, it will be easier to consolidate operational work done within the Elexicon territory. These include capital cable locates and service isolations found within neighboring service areas. Customer Requested work may increase due to the combination of the former Veridian and Whitby territories.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

With the merger, Elexicon identified certain merger synergies that are expected to lead to OM&A savings in the Customer Requested Work portfolio. The consolidation of legacy programs using best practices from both utilities has afforded cost savings with regards to Customer Station Inspections and the Connections Process. These savings will be re-invested into other programs or projects within Elexicon's investments across the future DSP period. Additionally, the consolidation of tree trimming contracts enables cost savings. Tree Trimming may be requested by the customer to Elexicon where trees are currently interfering with lines. Further opportunities for automation and consolidation shall be evaluated at Elexicon as the utility continues customer requested work across the future DSP period. Elexicon is committed to ensuring and identifying cost savings throughout the utility as continuous improvement.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

There are no material projects within the Customer Requested Work program in 2021.

5.2 Individual Material Project Scopes

There are no material projects within the Customer Requested Work program in 2021.

Budget Category	BRT Relocations: Highway 2 (Dixie to Liverpool and Glenanna to Brock)
OEB Investment Category	System Access
Primary Driver	Third-Party Infrastructure Requirements
Secondary Driver(s)	Mandated Service Obligations

-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Elexicon's Bus Rapid Transit ("BRT") Relocations project is driven by Metrolinx, the Region of Durham, and Durham Region Transit to relocate existing overhead or underground infrastructure for the proposed BRT network. It is mandatory to comply with these initiated changes to public roads as based upon the *Public Service Works on Highways Act* ("*PSWHA*"). The BRT network will bring about a streamlined and enhanced public transportation option for Durham residents and Elexicon customers. This scope of work pertains to planned worked in Pickering along Highway 2, from Dixie Rd to Liverpool Rd and from Glenanna Rd to Brock Rd. Future BRT work in Ajax and Whitby is still pending an environmental assessment by the Road/Transportation Authorities and has not been budgeted at this time.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.00	0.00	0.00	5.30	0.00	0.00	0.00	0.00
Contributions	0.00	0.00	0.00	1.92	0.00	0.00	0.00	0.00
Net Program Expenditures	0.00	0.00	0.00	3.38	0.00	0.00	0.00	0.00

There are no O&M costs proposed for recovery in rates associated with this project. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this project. There are no total capital and OM&A costs associated with REG investment included in this project.

Transportation plans such as the *Region of Durham Transportation Master Plan*, and *Metrolinx Transportation* plan drive the BRT Relocations work in 2022. The common objectives between each of these plans include future planning of transportation infrastructure, sustainable travel, and road enhancements. The Durham-Scarborough BRT is a major infrastructure project that will require significant investment from Elexicon. This project spans multiple towns, cities, and municipalities within Elexicon's service territory, requiring significant financial investment.

Recently, the Ontario Government approved the *Building Transit Faster Act*, which could impact major infrastructure projects in Ontario across the DSP period. The Act's purpose is to "expedite the delivery of transit projects of provincial significance by removing barriers and streamlining processes that may result in delays to the timely completion of these projects, while enhancing coordination and engagement with and being fair to public and private sector stakeholders." However, the Act lists affected infrastructure investments but does not explicitly cover the Durham-Scarborough BRT project at this time.

Elexicon will engage in BRT Relocations efficiently and safely while achieving project deadlines. This project has a large impact on customer service and public perception, and is prioritized as a mandatory investment to serve customers and service obligations. In completing this project, Elexicon will maintain close contact with various external stakeholders.

BRT Relocations will set the benchmark for many of Elexicon's collaborated efforts. The combined expertise of field and office workers will provide potential improvements. The consolidated staffing will especially help in this project as it spans multiple towns, cities, and municipalities within Durham. The insights between both predecessors will be beneficial in determining how to approach the upcoming BRT Relocations.

2. Basis for Action

2.1 Performance Trends:

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project

Elexicon's BRT Relocations projects are driven by Road Authorities who are defined as bodies having jurisdiction and control of a highway (or road). Any major developments in transportation or road improvements have an impact on Elexicon infrastructure. The major drivers of these projects stem from transportation plans and major cross-regional transportation projects. Stakeholders involved in BRT Relocations include transportation authorities like Metrolinx, the Region of Durham, and Durham Region Transit. Individual towns, cities, and municipalities also identify key requirements that Elexicon is expected to uphold when completing relocation projects; in this case, the BRT Relocations work is being completed in Pickering. The complexities of BRT Relocations projects can differ from one another and affect multiple parties. In these cases, coordination with an assortment of parties is required to relocate assets affecting roads.

1. **Transportation Plans**

Transportation planning defines the future, policies, investments, and designs for the ability to move people and goods within a select region. The major contributor to BRT Relocations has been the Region of Durham especially considering its development efforts.

Region of Durham Transportation Master Plan

The *2017 Durham Transportation Master Plan* (https://durhamtmp.wordpress.com/) produces the basis of many transportation-related projects. Based on Durham's *Regional Official Plan* forecasts, the Region's population and employment will grow by 49% and 55%, respectively, resulting in corresponding increases in travel demand. The forecasted growth period is from the year 2006 to 2031. The seven facets of the plan that relate to Road Relocation projects are to:

1. Strengthen the bond between land use and transportation;
2. Elevate the role of integrated public transit including Rapid Transit;
3. Make walking and cycling more practical and attractive;
4. Optimize Road infrastructure and operation;
5. Promote sustainable travel choices;
6. Improve good movement to support economic development; and
7. Invest strategically in the transportation system.

A key action that is recommended by the *2017 Durham Transportation Master Plan* is to support Direction #2, which is to "elevate the role of integrated public transit including rapid transit". The continued expansion of the BRT in the Highway 2 corridor is directly affected by this focus. Elexicon will be completing the BRT Relocations project highlighted in this business case.

Metrolinx 2041 Regional Transportation Plan

The *Metrolinx 2041 Regional Transportation Plan* (http://www.metrolinx.com/en/regionalplanning/rtp/) outlines projects expected to enhance transportation around the Greater Toronto and Hamilton Area. Elexicon stakeholders such as the Region of Durham, City of Pickering, and the City of Clarington were involved in the peer review of the report. The Durham Scarborough Bus Rapid Transit project included in this plan.

2. Durham Scarborough Bus Rapid Transit

The Durham Scarborough Bus Rapid Transit is the specified relocations project that this project considers. Considerable relocation work will take place within the Elexicon territory as this project spans multiple towns, cities, and municipalities.

The Durham Scarborough BRT project shown in Figure 1 is intended to create rapid transit infrastructure connecting Durham to Toronto. The enhanced BRT line will span 36 km across Highway 2 from Simcoe St. in Oshawa to Scarborough Centre in Toronto. Elexicon territories within the area of the BRT line affected include Whitby, Ajax, and Pickering. This project will feature dedicated lanes for buses, smart signals, and quicker transportation service from Durham to Toronto. As the dedicated lanes will be placed in the middle of the road, Elexicon will need to move distribution assets because of road widening.

Figure 1: Durham-Scarborough Bus Rapid Transit Path

Historical Metrolinx Road Relocation Projects

As shown in the historical road relocation projects related to Metrolinx, Elexicon is experiencing an increase in Metrolinx projects in the year 2021 as compared to the 2015 to 2019 years. As shown in the planned capital spending, Elexicon will match with historical Metrolinx projects in 2020 but will be investing significantly in road relocations in 2021. The BRT project in 2022 is influenced by many stakeholders such as Metrolinx, the Region of Durham, and Durham Region Transit.

Figure 2: Historical Metrolinx Road Relocation Projects

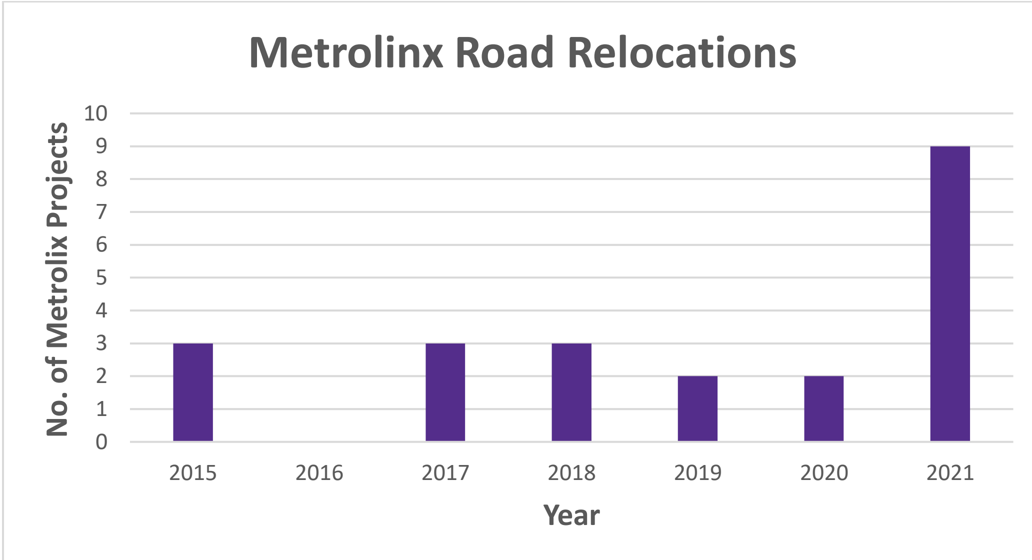


Table 2: Metrolinx Relocation Projects Year over Year

Year	2015	2016	2017	2018	2019	2020	2021
Number of Metrolinx Projects	3	0	3	3	2	2	9

2.2 Current-State Analysis:

-C.a.3 (SA) Factors affecting the final cost of the project
-C.a.8 (SA) Where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered
-A.3 Related customer attachments and load, as applicable

The current system is in conflict with the BRT construction; therefore, existing overhead or underground infrastructure needs to be moved to accommodate the transportation infrastructure. New assets may be required to facilitate the distribution of electricity around the updated location. By relocating assets, Elexicon can also renew the affected assets. Thus, both the current system can be updated to meet the needs of the new infrastructure and Elexicon's system can also realize renewed benefits in parallel.

Assets Affected from BRT Relocations

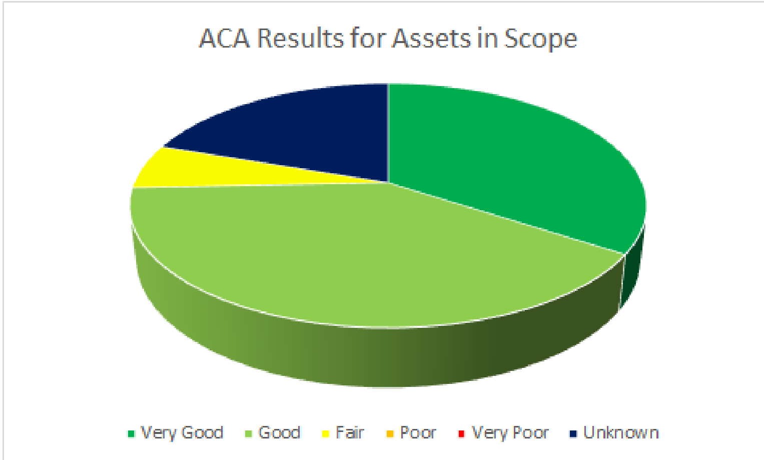
Table 3 shows the breakdown of the assets affected by the BRT Relocations project.

Table 3: Assets affected by the BRT Relocations Project

Asset Type	Count
AIS-9	1
FAULT_INTERRUPTER	3
FUSED_CUTOUT	5
FUSED_RISER	7
INLINE_DISCONNECT	6
LIVE_LINE_OPENER	1
LOAD_INTERRUPTER	23
SOLID DIELECTRIC	1
SOLIDBLADE_RISER	8
PAD_MOUNTED_DISTRIBUTION	11
POLE	68
POLE-MOUNTED	7
PMH-10	1
PMH-11	2
PMH-3	2
PMH-9	1
SWITCHGEAR_FUSE	5

When assets are relocated, they are usually replaced with like-for-like assets. By replacing assets affected by BRT Relocations, the lifespan of the area is extended with the third-party contributing a portion of the cost. In that case, Elexicon benefits from the financial contributions of third parties by renewing asset lifecycles from completing projects. As demonstrated in Figure 3, most of the affected assets are in "Good" condition of better, so asset health is not a driver for this investment.

Figure 3: Asset Condition Assessment Results for Assets Affected by BRT Relocations



2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.
-C.a.8 (SA) Where applicable, the results of the final economic evaluation carried out as per section 3.2 of the DSC

BRT Relocations must follow the *PSWHA*, wherein the "road authority" (i.e., MTO, municipal corporation, or other entity with control and construction of a highway) can provide notice to Elexicon to remove or change or works placed on the highway.

With the enactment of the *Building Transit Faster Act*, Elexicon will comply and ensure the successful delivery of transit projects in its service area. The Act's purpose is to expedite the delivery of transit projects of provincial significance. Although the Durham-Scarborough BRT project is not explicitly listed in this Act, Elexicon will follow and ensure that BRT relocation projects are delivered nonetheless.

All new infrastructure projects need to follow the Electrical Safety Authority guidelines and compliances. Installations and designs need to follow O. Reg. 22/04, *Electrical Distribution Safety*. Relevant sections to note include Section 4 pertaining to safety, Section 5 pertaining to safety standards, Section 6 pertaining to approval of electrical equipment, Section 7 pertaining to approval of plans, drawings, and specifications for installation work and section 8 pertaining to inspection and approval of construction. Any new BRT Relocation work that impacts the distribution system needs to follow the full list of compliances under O. Reg. 22/04. When performing work, Elexicon will ensure the safety of its workers and the public.

The BRT Relocations project needs to follow the Distribution System Code while engaging in road authority projects. Section 3.1.1 suggests: Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that asset, except to the extent recovery is limited under law.

Neither Leave to Construct approval nor a Final Economic Evaluation are not required for BRT Relocations.

2.4 *Consequences of Inaction*

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service: Residents would feel the impact if the BRT Relocations work was not completed. Without the project, the BRT construction would be delayed, directly affected nearby residents and affecting transit across the region more broadly. Residents will enjoy more efficient and safer travel routes and additional travel options through the BRT network. The ongoing improvement of transportation resulting from this project will benefit the daily lives of customers.

Operational Effectiveness: Not completing the BRT Relocation project on time or without correct planning can lead to decreases in operational effectiveness. Further resource utilization would be expected if the project is not finished near deadlines, and operations may need to work around suboptimal planned BRT relocations if the project is not of high quality.

Public Policy responsiveness: Towns, cities, municipalities, and other Road Authorities are engaging in transportation initiatives like the Scarborough-Durham BRT. Elexicon responds to these projects as they are influenced by public policies to help Ontarians with transportation. If Elexicon does not respond to the BRT Relocations request, it faces compliance problems with the *PSWHA* and its obligations to Road Authorities. Within the *PSWHA*, clauses (3) and (4) specify the minimum time interval or additional time as agreed upon by the road authority and the operating corporation, Elexicon.

Financial Performance: BRT Relocations work provides an opportunity to rebuild infrastructure and renew assets. By investing in new assets, the utility will benefit from financial investments into the future. Lastly, as BRT relocation projects are funded to some percentage by external parties, Elexicon can prolong asset life in the area with funding from other parties from completing these projects.

2.5 Merger-Related Objectives:

-C.a.5 (SA) Whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why

With the consolidation of resources of the two utilities, more resources are available for BRT Relocations work in terms of labor and expertise. Furthermore, as the BRT network spans Durham and into both the former Whitby Hydro and Veridian Connections territories, it provides benefits in that work is no longer separate and can be combined under a singular entity.

The status quo for BRT Relocations work is to complete the projects on time, as efficiently as possible, and safely. The BRT Relocations project provides high value for service continuity as it is a system access project and is mandated by legislative or regulatory requirements. During BRT Relocations, older assets are replaced with new assets, providing extra benefit in addition to complying with road authority projects. A high value of utility integration is provided as it improves the throughput of planning, design, construction, operations, and back-office capabilities relative to both predecessors.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. -B.1.d
Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.a.4 (SA) How controllable costs have been minimized
-C.a.6 (SA) Whether other project design and/or implementation options were considered and if not, why not
-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

Number	1	2	3
Scenario Description	Like-for-Like Conversion	Overhead Conversion	Underground Conversion
Program Scope	Relocate plant to current construction (Mix of overhead and underground systems	Relocate all plant overhead	Relocate all plant underground
Gross CAPEX	\$5.30M	N/A	\$8.00M
Net CAPEX	\$3.38M	N/A	\$5.27M
Program Benefits	Like-For-Like conversions avoids conflicts with Hydro One, ensures appropriate clearances, and complies with requirements from the City of Pickering.	The Overhead Conversion is not feasible based upon conflicts with Hydro One, inadequate clearances, and non-compliance with the requirements set forth by City of Pickering.	The underground conversion achieves same benefits as like for like replacements.
Program Economics	This option is the most economical taking into consideration the current state of infrastructure in the area.	This option is not feasible as it conflicts with requirements set forth by Hydro One and the City of Pickering and inadequate clearances.	This option is not feasible as it is much more expensive than that of the first option while achieving the same program benefits.
Customer Feedback	63% of Elexicon customers (544 of the 862 surveyed) considers the proposed Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit to be appropriate. 77% of surveyed customers when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.		
Other Constraining Factors	The constraining factors to this program is that the BRT Relocation project: • Project is initiated externally, and schedule is dictated by BRT construction. • Must avoid conflicts with Hydro One. • Compliant with requirements from the City of Pickering. • Maintain adequate clearances with nearby infrastructure.		
Preferred Alternative	**X**		

As BRT Relocation are System Access investments, there is a mandatory obligation to relocate assets and distribution infrastructure. Commonly, the Utility will perform a like-for-like replacement with changes. However, if another capital project is within the area, BRT relocation work could be done in parallel. In these situations, there are opportunities to enhance cost efficiency and effectiveness.

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.

Reliability: The selected alternative replaces assets like-for-like. Therefore, overhead assets are replaced with overhead assets and underground assets are replaced with underground assets. In this manner, reliability of the affected feeders will be maintained. There will be some reliability improvements due to renewal of the infrastructure.

Grid Resiliency: Grid resiliency increases as new distribution infrastructure is relocated and renewed. The selected option of like-for-like replacements balances the greater resiliency of underground distribution against its higher cost.

Operational Efficiency and Cost Effectiveness: Among the options considered, the selected approach is the most operationally efficient and cost effective.

Safety: The selected option ensures that clearances from nearby buildings and transmission lines are maintained.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: The selected alternative has been coordinated with other stakeholders involved in the construction of the BRT line. It is a requirement from the City of Pickering to have sections of the feeder underground, per its current construction.

Conservation and Demand Management: N/A

Net Customer Benefits: Customers will benefit from the most cost-effective option being selected. More broadly, people in the region will experience the benefits of improved transportation due to the BRT being completed.

Priority: This is a mandatory investment.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-A.4 Start date, in-service date and expenditure timing over the planning horizon

As the BRT Relocations work is initiated by external parties, the biggest risk to the project is external delays to starting the work. This risk is completely outside of Elexicon's control. Other risks relate to construction delays once the project is initiated. This risk is being mitigated through deliberate planning and coordination with other parties involved in the BRT construction. The project start date, in-service date, and expenditure timing will be dictated by external requirements and are not known at this time.

BRT work in future years has yet to be firmed up by the Transportation/Road Authorities, since the environmental assessment has not yet been completed. Thus, future relocation work related to the BRT project in Ajax and Pickering is unknown at this time and has not been budgeted by Elexicon. Regular coordination and updates with the Region of Durham, Metrolinx, Durham Region Transit will mitigate this risk by ensuring that Elexicon is up to date on the latest construction plans and status.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

In the planning process, a review of the current distribution system configuration at the location is performed. Previously, for road authority projects that spanned various territories, third parties needed to communicate with both Veridian Connections and Whitby Hydro. Third parties now only communicate with Elexicon and provide the scope of the project. For example, a request for road widening prompts Elexicon to analyze how and where assets can be moved. A bill of materials and design is prepared internally by Elexicon to identify the new distribution network around the road. Previously, a set of distribution standards for both Veridian Connections and Whitby Hydro were used for their associated territories. Elexicon has consolidated new standards to service the whole territory taking the best practices of both former utilities.

Elexicon will purchase new assets such as poles, conductors, and implement or extend ductwork or line extensions to complete BRT Relocations work. In this case, Elexicon benefits as the distribution system assets are renewed and improved in reliability from asset renewal from the investment. The merger has provided a benefit in providing a higher-level view for projects that span multiple territories of the two former utilities.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Standard construction at Elexicon is to utilize overhead wood poles on public roadways and underground for new residential developments. If a Road Authority wishes to relocate existing Elexicon overhead assets to underground, the cost-sharing portion of the relocation will be as if the system was an overhead rebuild and the cost difference between overhead and underground systems. For relocations, not part of the road (e.g., due to installation of sidewalks, multi-use paths), the Road Authority will pay the full cost of relocation of Elexicon Assets. External inspectors are used to evaluating the work required to complete relocation projects. Depending on the location of the project, legacy equipment or connections may be present within the area. Elexicon will assess the distribution equipment and the network in ensuring that the configuration is understood by the two former utilities and applicable to the current system. Previously, the two utilities had their own specific set of standards in terms of overhead and underground design. Consolidated standards from the two utilities have been completed and are used for projects into the future within the Elexicon territory. BRT Relocations design is completed with a mix of internal employees and external contractors.

4.3 Scale Increase Considerations

In lieu of Regional plans for Durham for transportation projects, coordination between the selected towns, cities and municipalities will be easier. Past operations required communication between Whitby Hydro and Veridian Connections for projects that spanned across the two jurisdictions. The BRT line and other transportation-related projects that municipalities are within should be more efficiently done. The BRT line specifically crosses from Oshawa to Whitby to Ajax to Pickering.

As Elexicon is a merged utility, work carried out between the two utilities will be easier and the purchasing power of the two former utilities will be combined. As projects are more efficient in coordination within the one utility, it allows for greater purchasing power to be used in contracting or using more financial resources towards BRT Relocations work and other projects.

The initial timeline for design deadlines and construction can be adjusted based upon the Region or Road Authority decisions. At times, the Road Authority or transportation authority may discover other conflicts while engaging further into projects which could affect the timeline.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

BRT Relocations are mandated investments for Elexicon. The timing of the project depends entirely on parties external to Elexicon. Delays are often experienced organically due to the nature of major infrastructure projects.

The consolidation of operations will be beneficial as a merged utility. The Durham-Scarborough BRT is a project that crosses over the two former utilities' (Veridian Connections and Whitby Hydro) territory. Having knowledge of the project and coordinating internally will realize various benefits. For instance, operations between the two utilities will understand the project scopes and work being done. Elexicon could realize savings from having the two former utilities work together in accomplishing and completing the BRT project. Designers from both former utilities can work together in accomplishing designs that are approved by one utility and not two designs that may or may not work together. Overall, the merger between Whitby Hydro and Veridian Connections will provide benefits financially and operationally to Elexicon and its customers with regards to BRT Relocations.

Budget Category	Renewal Program – Substations
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of Their Service Life
Secondary Driver(s)	Reliability, Operational Efficiency, Environmental Compliance

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$3.63M	**$4.04M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Substation Renewal program at Elexicon consists of System Renewal investments by the utility to proactively replace deteriorating and aging assets at their respective substations. Every year, an Asset Condition Assessment is performed for various station classes where certain station assets are then identified to be in poor or very poor condition. Elexicon will make proactive and prioritized replacements for these candidates to deliver reliable service and renew assets at the end of their service life. A significant number of assets at the substation level have been combined because of the merger. Elexicon will ensure an optimal plan for station sustainment investments into the future through Asset Replacement Plans, the Asset Condition Assessment, and System Condition Forecasts.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	3.63	2.97	7.08	9.40	2.64	0.86	3.46	0.81
Contributions	0.04	0.00	0.00	0.00	1.62	0.00	0.00	0.00
Net Program Expenditures	3.59	2.97	7.08	9.40	1.02	0.86	3.46	0.81

As station assets have deteriorated, Elexicon will proactively replace these assets to reduce the number of outages and failures that arise from the substation group. From 2015 to 2019, twenty substation outages have occurred, and 28,748 Customer Hours were interrupted. Due to the complexity and importance of substation equipment, Elexicon will assess Substation assets and their criticality. Poor and very poor conditioned assets will be prioritized for replacement. As determined by the recent Asset Condition Assessment, there are currently seven poor circuit breakers, four poor station transformers, five very poor station transformers, and one poor station fencing. All circuit breaker and station transformer replacement candidates are located in the former Veridian territory.

As a result of the consolidation, an increased workforce will allow for opportunities to consolidate resources in asset renewal projects. A combined inspection procedure for Substation assets with practices considered of both former utilities will be created. The average age of Substation assets in the former Veridian territory is much older than that of Whitby. As Veridian has absorbed different service areas throughout history, substations have been accumulated and thus the age of assets is much higher. Most poor conditioned assets in the substation category reside in Veridian. Whitby has been proactive in substation replacements as their former inspection and testing cycles were every 1.5 years. Former Veridian's cycles were every three years. Moving forward, Elexicon will be dedicating three-year dedicated cycles due to the large increase in substation assets.

Substation asset replacements and renewals target the very poor and poor conditioned assets in the system. These assets have the most potential in becoming failures. Elexicon has an obligation and commitment to providing excellent customer service and electrical reliability. If replacements are not made for poor assets, SAIDI and SAIFI measures could increase which reflects poorly on the utility. It is more cost-effective for Elexicon to be proactive when replacing assets. The increased labor and situation of reactive scenarios are also more costly than planned replacements. These replacements are ultimately made to ensure customers are adequately serviced by proper operating equipment. As Station equipment is critical and the starting point of service from the distributor, it is imperative that careful and planned investments into substations are made. Contingencies are also planned for in place of asset failure such that Elexicon can adjust where failures occur and that station spares are at hand.

2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

Substation renewals are performed to address deteriorating assets found in substations under Elexicon. To illustrate the condition trending of substation assets, 2020 results from asset condition assessments are analyzed. Substation assets that were assessed include:

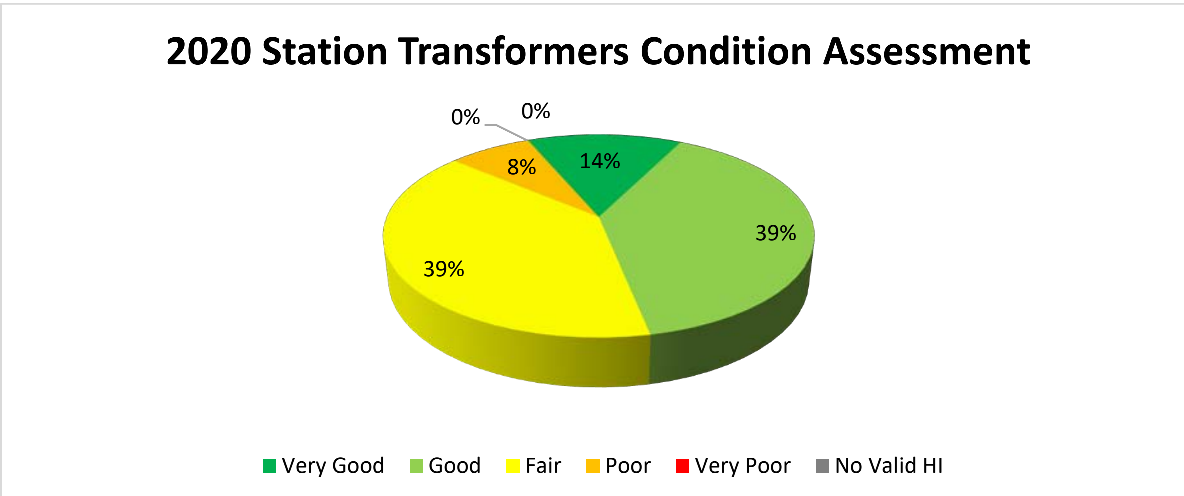
1. Station Transformers
2. Station Circuit Breakers
3. Station Batteries
4. Station Protection Relays (Former Whitby only)
5. Station fences (Former Whitby only)
6. Station buildings (Former Whitby only)

Using inspection data, assets were assigned conditions and placed into categories such as good, very good, fair, poor, and very poor for overall condition health. The following figures, Figure 1, Figure 2, Figure 3, Figure 4, Figure 5, and Figure 6 show the results of the Asset Condition Assessments performed for station transformers, circuit breakers, batteries, protective relay, fences, and buildings for 2020. Note that protective relays and buildings were only assessed in the Whitby service area. Please refer to Figure 8 and Table 3 for the asset counts and conditions across the station portfolio and for each asset class tied to the condition figures. The unit counts that contribute to the individual station asset class percentage are found in Table 3.

Station Transformers

As shown in Figure 1, seven percent of the in-service station transformers are in poor condition. These transformers shall be prioritized for replacement. The 2020 condition assessment has also indicated that a large percentage of station transformers in the fair category. As these fair substation transformers continue to remain in service, age and conditions will deteriorate which may necessitate replacement. Elexicon shall monitor these fair condition station transformers for further degradation. Any failure of transformers at the station level has a significant effect on customers, metrics, and service.

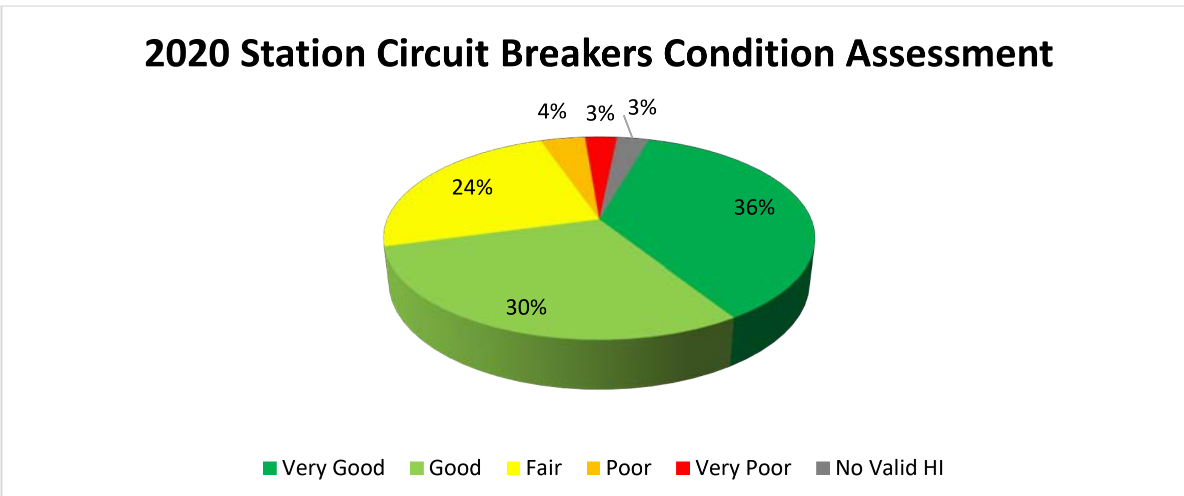
Figure 1: 2020 Condition Assessment of Station Transformers



Station Circuit Breakers

Figure 2 shows the distribution of Elexicon's station circuit breakers in terms of condition category for 2020. Currently, three percent of station circuit breakers are in very poor condition and four percent of the population is in poor condition. These assets shall be prioritized for replacement. About 24% of the circuit breaker population is found in the fair category. As time passes, Fair assets may shift towards poor and very poor conditions and Elexicon may need to address these assets in future replacements. Fair assets shall be monitored for further degradation. Elexicon will continue to acquire condition and inspection data for the four percent of circuit breakers that do not have a valid HI due to poor data availability.

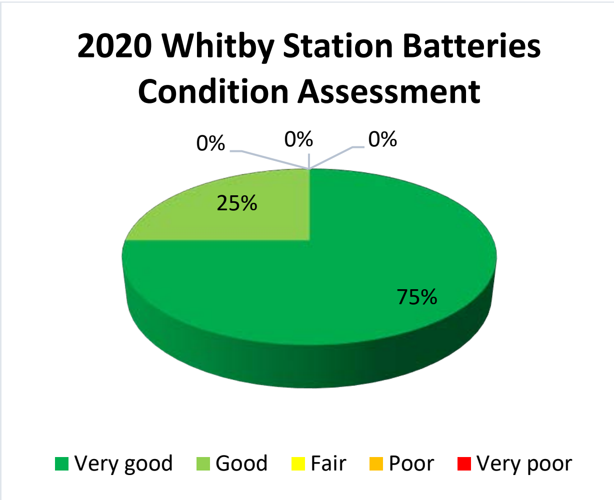
Figure 2: 2020 Condition Assessment of Station Circuit Breakers

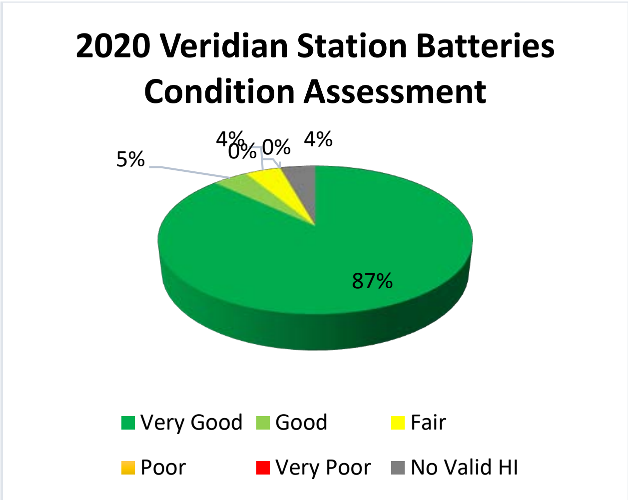


Station Batteries

Whitby and Veridian Station Batteries were assessed separately based on the difference in data collection methods in 2020. Monthly Substation visual inspections and three-year full Substation Inspections and Testing will be performed to assess station batteries throughout the DSP period. It must be noted that Elexicon replaces batteries when they are at 50% of its manufactured life to ensure reliability of back-up supply.

Figure 3: 2020 Condition Assessment of Station Batteries for Veridian and Whitby Regions

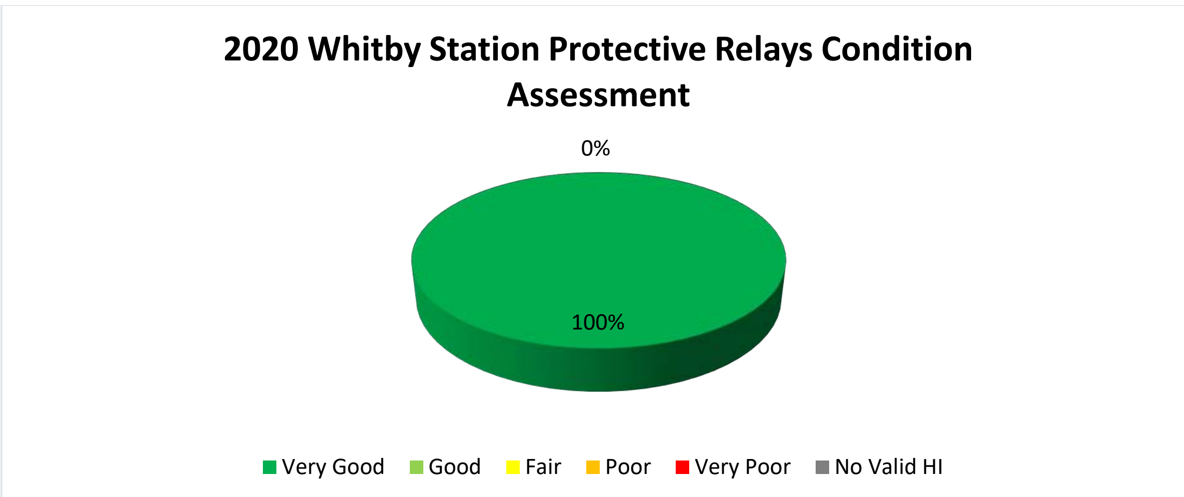




Station Protective Relays

Figure 4 shows the distribution of Elexicon's station relays in terms of condition category for 2020. However, in the recent ACA, station relay condition assessments were only performed on Whitby relays. In future condition assessments, further data will be collected for all relays in service. Overall, the conditions of Station Relays demonstrate that replacements are not required in the Whitby Service Area. Further data collection through testing and inspections shall be performed for the former Veridian territory.

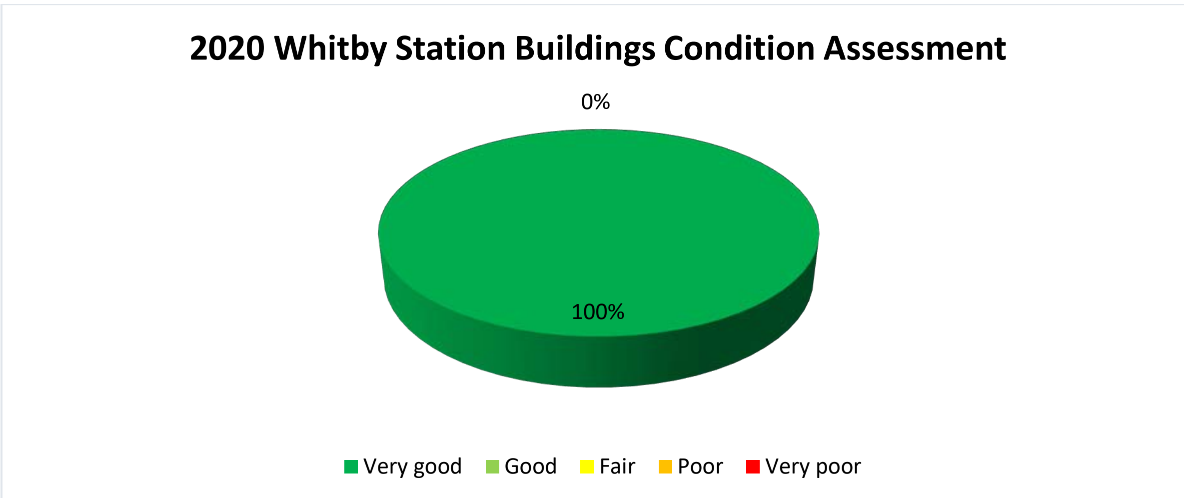
Figure 4: 2020 Condition Assessment of Whitby Station Protective Relays



Station Buildings

As demonstrated in Figure 5, Station buildings in the Whitby region have not shown any degradation. Elexicon will not be preparing any investments or changes into the substation buildings across the near future. Conditions shall continue to be evaluated through inspections performed monthly and more rigorous inspections performed every three years.

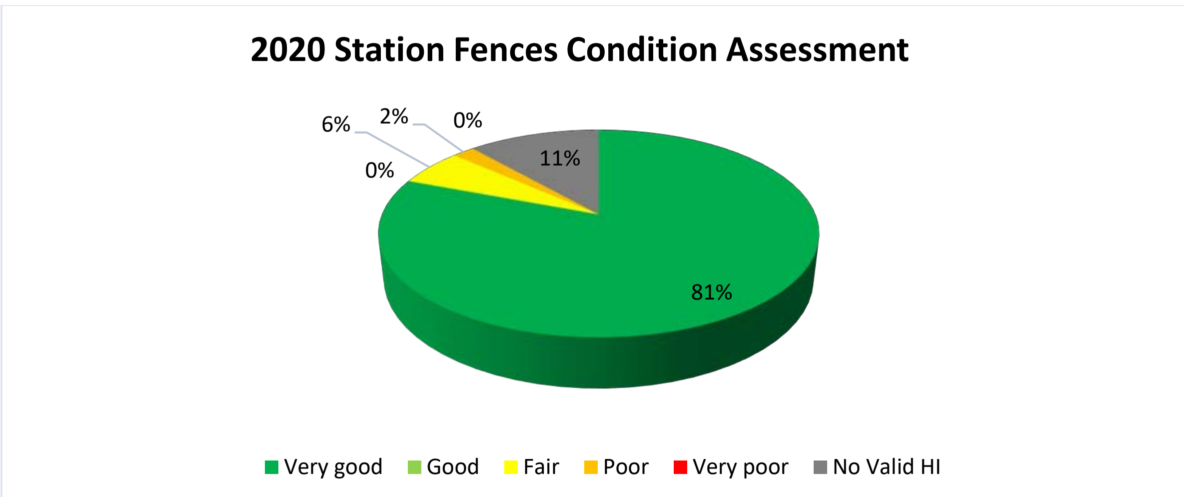
Figure 5: 2020 Condition Assessment of Station Buildings



Station Fences

Figure 6 shows the distribution of Elexicon's station fences in terms of condition category for 2020. According to the Asset Condition Assessments, two percent of station fences are considered poor, and six percent are considered fair, with the rest being in very good condition. Station Fences in poor condition will be replaced. Fair station fences shall be monitored for further degradation. Substation Fences help protect the public from potentially lethal situations and high voltage equipment; they will be replaced concurrently with other substation renewal projects at the substation.

Figure 6: 2020 Condition Assessment of Station Fences



Outage Metrics by Stations Defective Equipment

When Elexicon performs Substation Renewal investments, the reliability performance of equipment at substations is reviewed by the utility. Table 2 summarizes the total number of outages experienced from substation assets and related effects on customers and outage duration from 2015 to 2019. Throughout the years 2015 to 2019, Elexicon has experienced a fluctuation in the number of station outages each year. In general, as a utility experiences more outages, an increase in customer hours and customers interrupted will be experienced. Elexicon looks to prevent these outages through investments through the substation renewal program. Further analysis of substation outage data supplements asset condition data to determine investment decisions in the substation renewal program.

Figure 7: Outage Metrics by Substation Assets

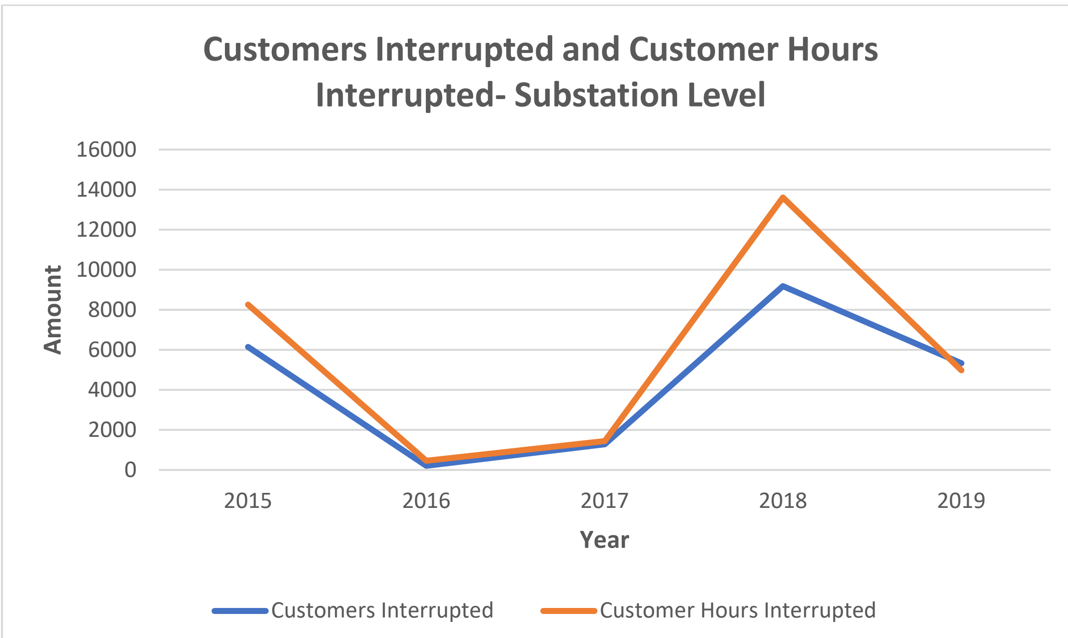


Table 2: Outage statistics of station assets during 2015-2019

Statistic	2015	2016	2017	2018	2019
Outages	9	1	1	6	3
Customers Interrupted	6,149	208	1,274	9,180	5,332
Customer Hours Interrupted	8,256	458	1,444	13,607	4,983

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

The current situation concerning all Stations Asset and health deduced from the most recent Asset Condition Assessment in 2020 is shown in Figure 8. The assessment is completed by gathering information based on condition parameters assigned to each asset class. Each condition parameter has an assigned weight, which reflects its importance relative to the other condition parameters. The condition parameters along with their weights are used to calculate an asset's health index which is used to determine which condition an asset is in.

Substation Asset Health Overview

Whitby was proactive as the utility performed full substation inspections every eighteen months compared to Veridian who performed full inspections every thirty-six months. When considering major station assets, former Veridian assets have higher numbers of poor and very poor candidates compared to Whitby assets. These major assets will be prioritized for replacement across the future DSP period. As compared to Whitby's assets, major station assets of Veridian are also prevalent in fair condition. Fair conditioned Station Assets can deteriorate and fall into poor and very poor conditions as time passes. Whitby Station Assets are comparatively healthier across all asset categories.

Figure 8: Substation Asset Health Overview

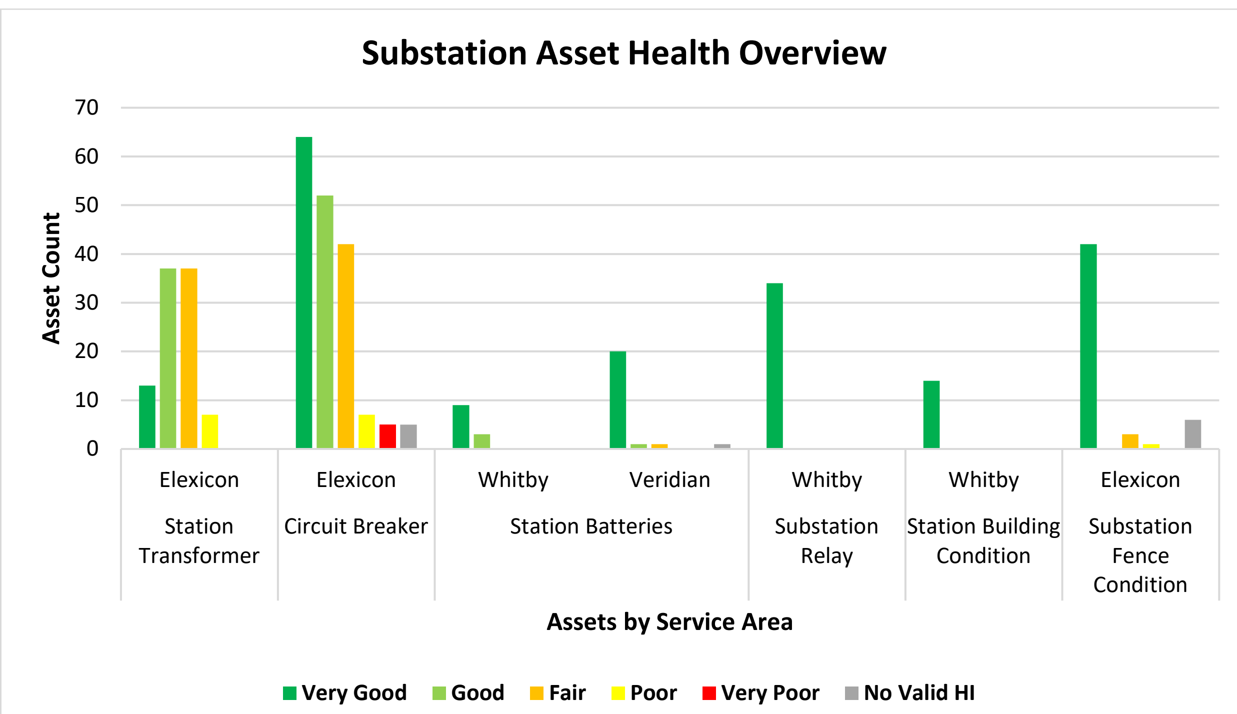


Table 3: Substation Asset Counts by Health and Territory

Asset	Territory	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Station Transformer	Elexicon	13	37	37	7	0	0
Circuit Breaker	Elexicon	64	52	42	7	5	5
Station Batteries	Whitby	9	3	0	0	0	0
	Veridian	20	1	1	0	0	1
Substation Relay	Whitby	34	0	0	0	0	0
Station Building Condition	Whitby	14	0	0	0	0	0
Substation Fence Condition	Elexicon	42	0	3	1	0	6

Section 4.1 which encompasses Elexicon's planning criteria will show the condition parameters and weights utilized to calculate asset health across different substation assets. Annually, Elexicon prepares specific station projects and station replacement projects through the ACA. A list of recurring station renewal projects is listed below:

Table 4: Substation Annual Projects

Project Name	Year
Substation Breakers	2021-2026
Substation HVAC Units	2020-2021
Substation Fencing and painting	2021-2026
Substation Ground Grid Upgrades & Oil Containment	2020-2026
Substation Deficiency Corrections	2021-2026
Replace Switch RTUs	2020-2026

Substation Transformer Oil Leak Conditions- Elexicon

From the historical substation inspections of transformers, it was determined that nine out of the 96 inspected substations had a letter grade of C and one having a letter grade of D. Nearly ten percent of the substation power transformers have concerns about the leakage of oil. These grades were assigned based upon visual inspection comments of transformer leaks. Oil Leaks on transformers could compromise the internal insulation for transformer windings leading to aging, inadequate performance, or even failure.

Figure 9: Station Transformer Oil Leak Condition

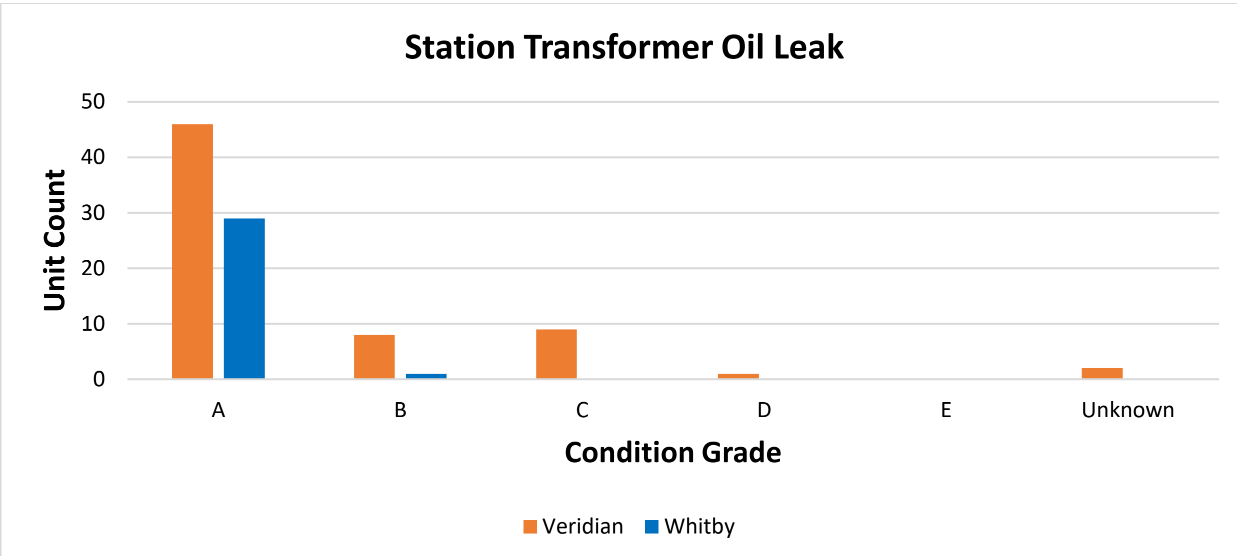


Table 5: Substation Transformer Asset Count by Oil Leak Condition

Territory	A	B	C	D	E	Unknown
Whitby	46	8	9	0	0	0
Veridian	29	1	0	1	0	2
Total	75	9	9	0	0	2

Substation Grounding Conditions-Elexicon

From the historical substation inspections, it was determined that two of the 59 substations had poor conditions for gradient mats. Other ground grids and rods were deemed intact as per inspection forms. Upgrades to ground grids are meant to decrease the risk of shock during the occurrence of a fault. Elexicon is committed to reducing the risk that operational staff face while working within substations. As found in the inspections of gradient mats, a higher percentage of Veridian substations reported N/A for gradient mats and poor for two separate occasions.

Figure 10: Grounding Conditions

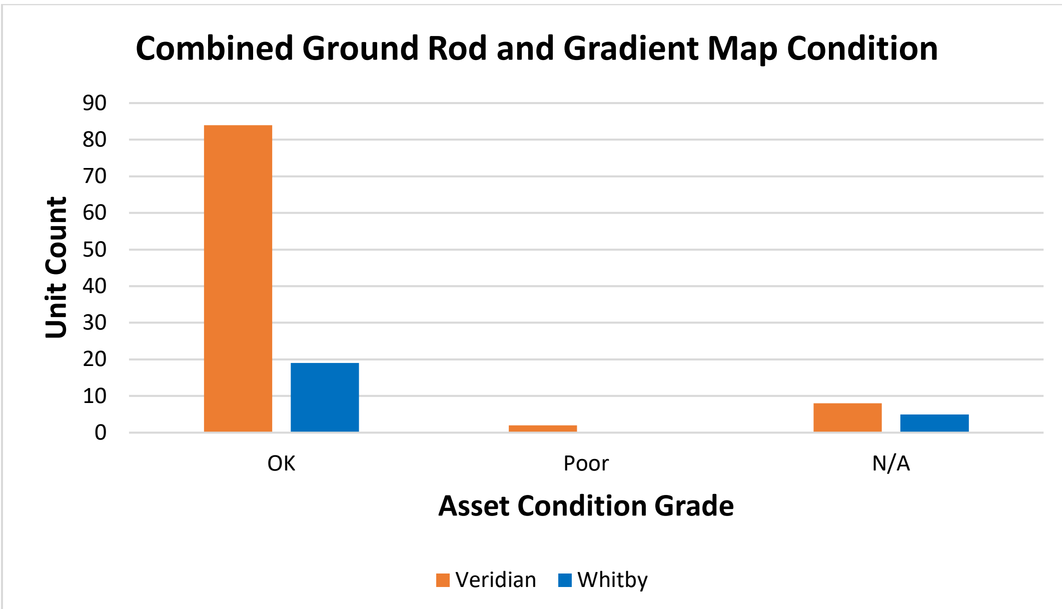


Table 6: Grounding Condition Count

Territory	OK	Poor	N/A
Whitby	19	0	5
Veridian	84	2	8
Total	103	2	13

Current Age Distributions- Station Transformers and Circuit Breakers

The below graphs demonstrate the age variability of major Station assets such as circuit breakers and transformers between the former utilities of Whitby Hydro and Veridian Connections. As seen in the distribution of ages for both assets, Veridian station assets are much older than Whitby counterparts.

Figure 11: Station Transformer Age Distribution

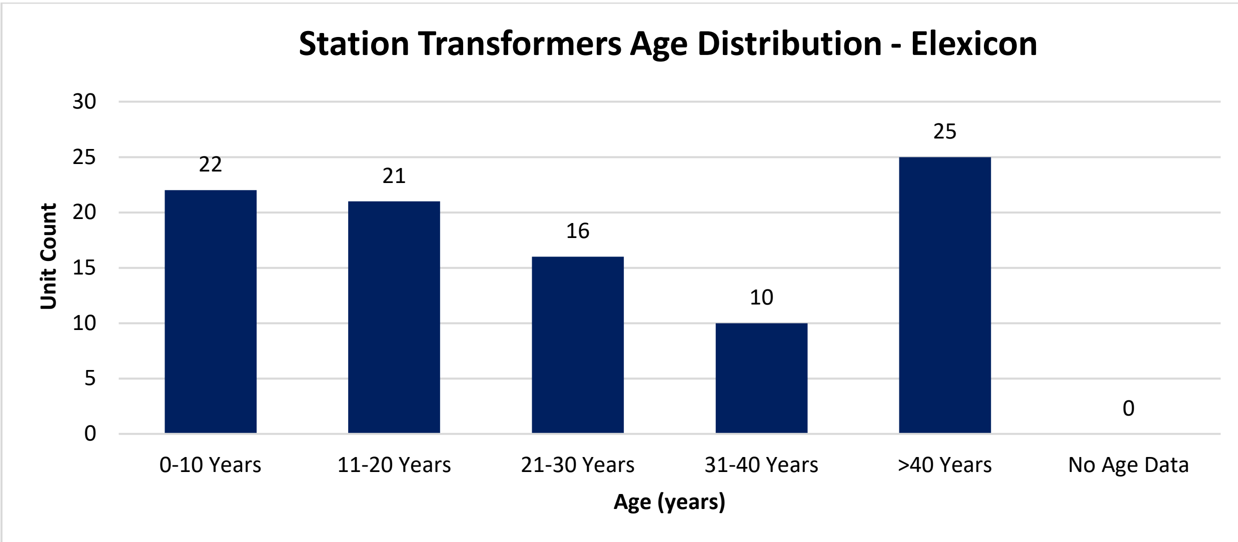
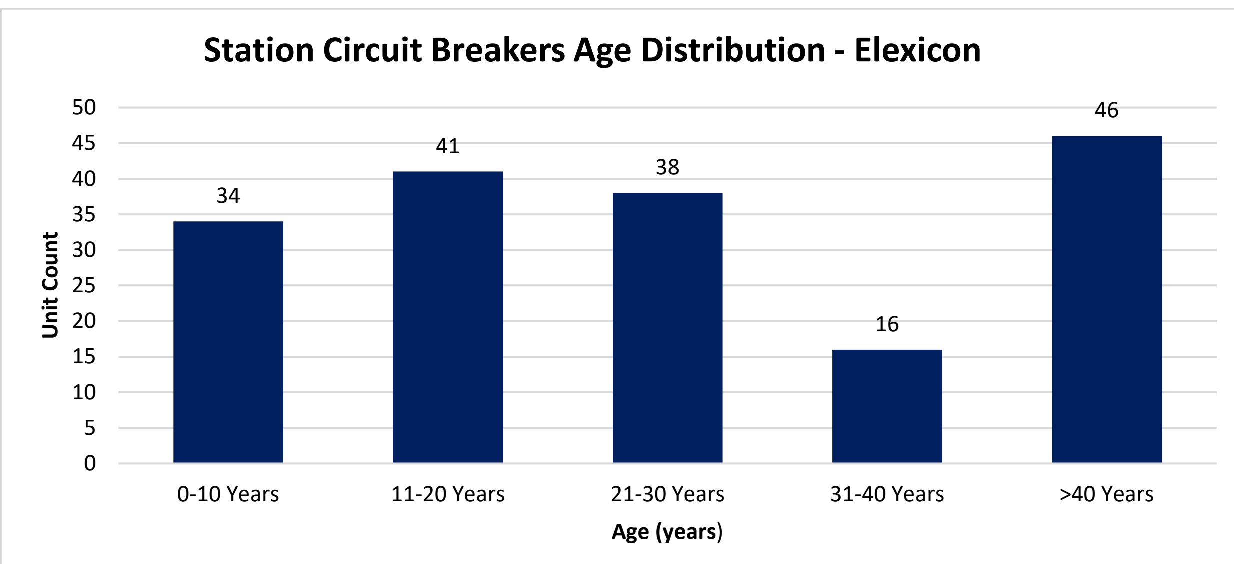


Figure 12: Station Circuit Breaker Age Distribution



The asset condition assessment has shown that Veridian-owned station assets are in a comparatively older condition than Whitby assets. The combination of condition results and increasing age is influencing Elexicon to invest further into former Veridian substation assets across the DSP period. This is also reflective of the more frequent inspection and assessments of former Whitby assets than Veridian. None of the major station assets are greater than 40 years of age in Whitby whereas about 72 station assets are over 40 years in Veridian. Veridian's 72 Assets older than 40 years of age represent 26% of the total population of major station assets. Typical Useful Life for Breakers and Substation Transformers are 45 years of age. Twenty Station transformers (All former Veridian) in Elexicon's inventory are past the 45-year-old typical useful life quota. Thirty-four Circuit Breakers (All former Veridian) in Elexicon's inventory is also past the 45-year-old typical useful life quota.

Asset Replacement Plan

The Asset Replacement Plan, prepared by METSCO in 2020, is formulated using the results of the Asset Condition Assessment. In conjunction with asset condition results, the Asset Replacement Plan incorporates an age-based analysis to determine how some assets could deteriorate to a condition that will require replacement. The age-based distributions of current station assets are utilized in this asset forecast. It is expected that the higher age of former Veridian assets will push replacements to the former Veridian territory. Figure 13 and Table 7 illustrates the replacement schedule produced by the Asset Replacement Plan. It is to note that Elexicon replaces station batteries when 50% of the manufacturers expected typical useful life. This notion is driving the 7 expected replacements year over year at Elexicon.

Figure 13: Stations Asset Replacement Plan

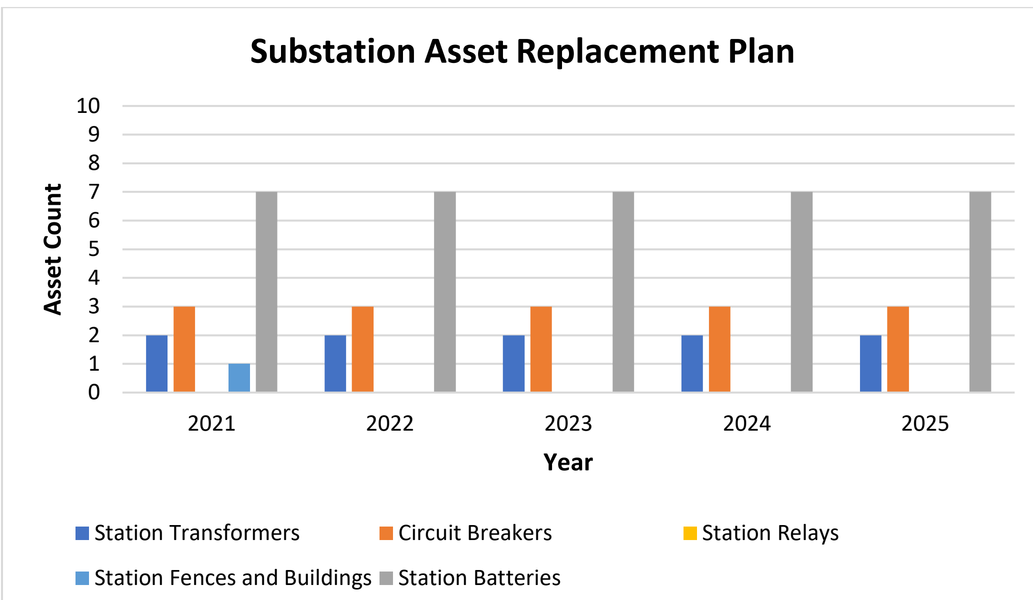


Table 7: Asset Replacement Plan for the assets discussed in this business case

	Projected Replacement					
Asset	2021	2022	2023	2024	2025	2026
Station Transformers	2	2	2	2	2	2
Circuit Breakers	3	3	3	3	3	3
Station Batteries	7	7	7	7	7	7
Station Relays	0	0	0	0	0	0
Station Fences and Buildings	1	0	0	0	0	0

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

OEB Metrics

The Substation renewal program will affect a multitude of compliance considerations including OEB performance metrics such as reliability. For instance, SAIDI and SAIFI are metrics tracked with utilities. SAIDI is described as the duration or average number of hours that power to a customer is interrupted. SAIFI is described as the frequency of outages or the average number of times that power to a customer is interrupted. As shown in the outage statistics, Station level outages are responsible for a larger number of customers without power and longer times. Any negligence of substation assets can result in higher durations and more frequent outages. It is imperative that Elexicon makes valued investments into existing substations as failure to do so could result in increases in SAIDI and SAIFI.

O'Reg 22/04:

Distribution stations are referred to in Ontario Regulation 22/04 as part of the Electrical Distribution Safety Act. Clause 1 of section 6 describes that Operating electrical equipment shall be maintained in proper operating condition. Asset Replacements and investments by Elexicon are made to ensure proper operating conditions of substation assets.

ISO 55000:

ISO 55000 is a series of standards that describe how a company can establish a framework to achieve an optimal balance between managing the use and preservation of assets. It covers various aspects of asset management such as planning, operation, performance evaluation, and information on specific asset management activities. This standard drives Asset Management activities at Elexicon as it aims to adhere to the principles laid out in the ISO55000 series. For example, section 6.1 of ISO 55002 states that the organization should ensure that the asset management system manages risk associated with distribution system assets to an acceptable level. This program supports alignment with this standard as its primary goal is to mitigate the risk associated with the failure of poles.

Safety:

Older equipment may fail in the field which could prompt safety issues with staff or the public. Elexicon as a utility is assessed based on safety performance each year. These include Compliance with O'Reg 22/04 and the Serious Electrical Incident Index.

Ministry of Environment - Environmental Protection Act – Part X

A spill refers to a pollutant, meaning a discharge from or out of a structure, vehicle, or other container. Elexicon is obligated under Section 91.1 in the Environmental Protection Act to have spill prevention and contingency plans. These plans are in place to prevent or reduce the risk of spills of pollutants and prevent, eliminate, or ameliorate any adverse effects that result or may result from spills of pollutants. Various other clauses within the Environmental protection act dictate the necessity for utilities to be aware of and implement spill protection plans.

Distribution System Code: System Inspection Requirements and Maintenance:

Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with consideration to good utility practice quality, and reliability for short term and long-term basis. Inspection Activities are made following requirements found in the Distribution System Code and where more frequent inspections are required. Where defects are discovered, replacements are made immediately or planned across into the future.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.
-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o The number of customers in each customer class potentially affected by a failure of the assets included in the project
o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)
o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure
-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project

An age-based failure curve analysis was conducted using Weibull Distribution. The parameters of the distribution were found using a typical useful life of 45 years for power transformers and circuit breakers and a typical useful life of 15 years for batteries. The analysis yielded the expected number of station assets that will fail during 2020-2025. Since there is missing information for some of the asset classes, the expected number of failures also includes extrapolated data. To extrapolate the data, the ratio of failed assets to the total number of assets with unknown data matches the ratio of failed assets to the total number of assets with known data. Table 8 shows the expected number of failed station assets during 2020-2025.

Figure 14: Station Asset Failure Projections

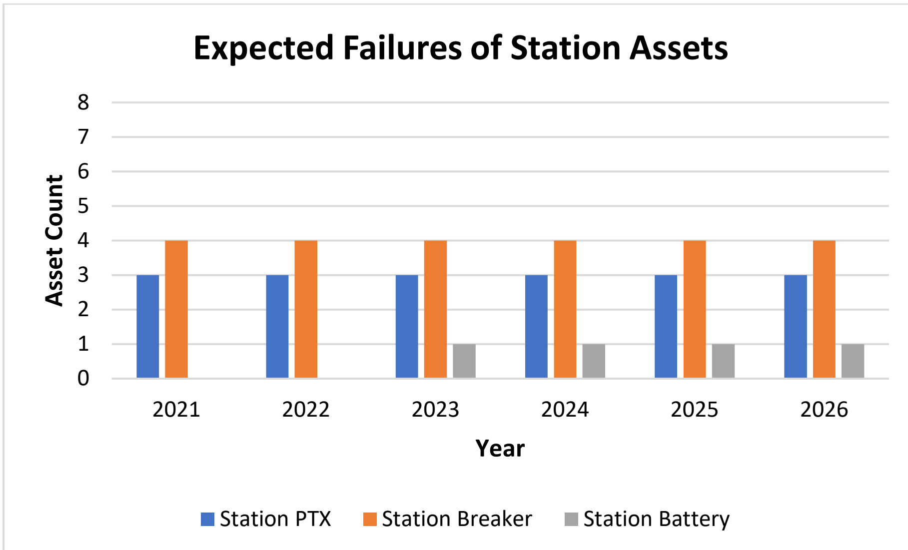


Table 8: Expected Volume of failed station assets during 2021-2025

Asset Class	Total Population	Unknown Age	2021	2022	2023	2024	2025
Station PTX	96	0	2	2	2	2	2
Station Breaker	178	0	4	4	4	4	4
Station Battery (Whitby Only)	12	0	0	1	1	1	1

It can be seen from the above table that a significant portion of station assets will experience a failure during the next 5 years. Approximately 10% of power transformers are expected to fail until 2025, while over 11% of circuit breakers and 33% of station batteries are expected to fail during the same timeframe. Whitby Batteries were the only batteries that had age data which made the total population of failure analysis only twelve in total.

Customer Service: Substation Asset failure negatively impacts customer service metrics through the reliability of service. As substations are positioned to provide large amounts of customers with power and are the starting point of service for most LDCs, failure at the substation level would have significant impacts. Elexicon must invest in substation renewals to ensure that reliability metrics do not decline in performance and such that customer service is held for customers. Customers expect excellent and consistent electrical service; investing in critical points of the system such as the substation will maintain or improve reliability of electricity provided to customers for their daily lives. In particular

Operational Efficiency: The identification and analysis that forms the asset condition assessment of Substation Assets help Elexicon determine efficient replacement plans and required maintenance activities. By replacing an asset proactively before it has failed and that is exhibiting declining performance, Elexicon can become more operationally efficient. Plans can be made by the utility to address maintenance and renewal investments. Replacing only when an asset has failed is not an operationally efficient and bad practice.

2.5 Merger-Related Objectives:

Elexicon has determined some merger-related objectives that could be achieved by optimally operating its system and correctly prioritizing its programs. The objectives are service continuity and utility integration. These objectives could be further broken down into sub-criteria which are used to assess how well a program helps achieve the objectives.

Regarding service continuity, the station renewal program looks to renew assets located in stations, which is the starting point of the flow of their services. Faults occurring at a station level can have heavy repercussions on the quality of their services, meaning renewing assets that are prone to faults is essential to keep Elexicon's service continuity consistent. A sub-criterion for service continuity is how the condition of the assets in question compares to other similar assets. Another relevant sub-criterium of service continuity is that the replacement of particular transformers and circuit breakers is mandated by the PCB Regulations, which targets that all transformers and circuit breakers containing PCBs in a concentration of at least 500 mg/kg and that were in use on September 5, 2008, should be removed by end of 2025.

A relevant sub-criterium of utility integration that is relevant to the station assets renewals program is that the program aims to integrate core operations of the legacy utilities. The legacy utilities replaced distribution transformers separately, each with their specific approach. The program looks to consolidate these approaches to a single-core operation.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	***1***	***2***	***3***	***4***
Scenario Description	Status Quo: Replace Asset with newer generation assets with upgraded capabilities and Like for Like	Further Investment into the renewal of Substation Assets (10% more)	Less Investment into the renewal of Substation Assets (10% less)	Like for Like replacements
Annual Program Scope	In this scope, replacements are planned to use the ACA, ARP, and failure curve analysis. New Assets with upgraded capabilities replace legacy equipment.	Elexicon shall invest further into the Substation Renewal category where 10% more annual funding is placed into the program.	Elexicon shall invest less into the Substation Renewal category where 10% less annual funding is placed into the program.	Like for like replacements are planned for substation assets. New upgrades from new generation equipment during replacements will not be utilized when performing renewal.
Annual Gross CAPEX	$4.04M	$4.44M	$3.64M	$3.29M
Annual Net CAPEX	$4.04M	$4.44M	$3.64M	$3.29M
Annual Program Benefits	The budgeted plan for substation renewal projects is paced to address asset renewal requirements over the DSP year. Benefits produced from this program	Program Benefits may increase marginally from increasing Substation renewal investments. This program is budgeted to account for substation	Program Benefits may not be realized if Elexicon underinvests in the Substation renewal program. This program is budgeted to account for substation	Directly replacing substation assets with like for like replacements may not produce the most benefits. Like for Like replacements may be hard to source for legacy stations equipment.

	include asset renewal, and reliability improvements.	requirements over the future DSP period.	requirements over the future DSP period.	Elexicon should be able to choose between a like for like or enhanced replacement.
Program Economics	The current planned investment makes optimal use of Elexicon's resources. Increasing or decreasing investments may be inefficient.	An increase in the program's budget may result in additional resources being required which may not be present at the Utility.	A decrease in the program's budget may under-utilize the resources currently at Elexicon.	It is not economically efficient to always perform like for like replacements. Legacy Substation equipment may not be able to be sourced.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.			
Other Constraining Factors	If further deterioration is found for Substation Assets, Elexicon will need to shift budgets from the investment categories or the program level to address the issue.	Further investment into Substation Assets for renewal would assist in an increased acceleration of replacing older assets within the territory. However, the currently planned investments are made to satisfy and ensure economic renewal decisions.	Less investment into Substation Assets for renewal would decrease the number of substation assets renewed. This would not be beneficial as the planned investments are optimal such that failures will not negatively impact Elexicon service. A lower budget could cause less optimal decisions.	Like for Like replacements will renew assets but will not be an actual upgrade except for asset health. By incorporating new assets in the system renewal category with added functionality or resilience, the program would improve.
Preferred Alternative	**X**			

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies. *-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.* *For proposed distribution rate funded CDM programs the following details are required:* *• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers* *• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred* *-C.b.4 (SR) The impact on reliability and safety factors*

Reliability: Stations are key to the transformation of high voltages to distribution level voltages for Elexicon Customers. Any assets in deteriorating conditions could pose a threat to Elexicon's reliability standards. Station outages, in general, affect a larger number of customers which in part would affect the number of customer hours. Elexicon must invest in substation renewals to maintain and improve reliability.

Grid Resiliency: Elexicon can invest in substation asset renewals that are better suited to combat climate change and are more resilient to weather. Investigations and evaluations of more climate-adaptive substation equipment will be performed.

Operational Efficiency and Cost Effectiveness: Proactively replacing station equipment approaching the end of life reduces the chance of permanent outages at the station level. Any unplanned outages can vary in magnitude and would require a significant amount of work to identify and restore power. Proactively replacing assets that are deteriorating would reduce the costs of unplanned outages. Furthermore, it is operationally more efficient to replace an asset proactively than to wait until failure. Planned replacements allow Elexicon to prepare and ensure a smooth transition of asset replacement and sustainment is performed.

Safety: Deteriorating assets may prompt safety concerns due to the legacy technologies that older assets encompass. Renewals of substation assets can provide safety benefits and an introduction of newer technology that surpasses legacy equipment with regards to safety.

Cyber-Security/Privacy: Substation Assets with SCADA capabilities will need to be Cyber Security compliant. Any assets which lack security could provide negative outcomes and jeopardize operational efficiency and outcomes of the Utility.

Environmental Benefits: Deteriorated station transformers may leak oil, which damages the environment. Replacement of older station transformers can lower the chances of having an oil leakage in the station, thus reducing the risk of negative impact on the environment.

Coordination/Interoperability: New Substation assets shall be operationally efficient and tied to technology streams to ensure coordination and interoperability with Elexicon and external operators such as Hydro One.

Conservation and Demand Management: *N/A*

Net Customer Benefits: The customer enjoys the benefits of a more reliable service due to asset renewal on substations. As the station directly affects many customers, the bulk effect of substation replacements will improve and provide benefits to more customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

Elexicon performs analysis on a variety of factors to understand the failure of substation assets, and to plan for proactive replacements. An expected number of failures for each asset class is predicted through historical failure data and age. The list of substation assets is utilized to forecast replacements based upon condition and age. An asset condition assessment provides an overview of Elexicon of the current conditions of Elexicon substation assets. Any assets that have been identified in poor or very poor condition are prioritized to be replaced. An Investment prioritization process is then conducted to prioritize the other planned investments in the program. Considerations such as safety, service continuity, the effect on metrics, and asset life are taken to perform the assessment. In circumstances where further degradation of assets is found, Elexicon will shift other renewal project budgets in the substation renewal program or system renewal investment category to the issue. Budgets can then be pushed and adjusted for later years, but the issue must be addressed if more severe deterioration or problems arise that were not foreseen.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

The planning approaches of both legacy utilities and Elexicon are similar in that they are dependent on the results of the Asset Condition Assessment. Table 9, Table 10, Table 11, Table 12, and Table 13 shows the condition parameters along with their weights used in 2020 for the condition assessment of various Station Assets.

Table 9: Condition parameters along with their respective weights used for assessing station transformers in the 2020 Asset Condition Assessment

Station Transformers	
Elexicon	
Condition Parameter	Weight
Dissolved Gas Analysis	10
Insulation Power Factor	10
Oil Quality	8
Service Age	6
Overall Condition	6
Brushing Condition	5
Cooling Equipment	2
Grounding Condition	1
Foundation Condition	1
Gasket Condition	1
Connections Condition	1
Oil Leaks	1

Table 10: Condition parameters along with their respective weights used for assessing station circuit breakers in the 2020 Asset Condition Assessment

Station Circuit Breakers	
Elexicon	
Condition Parameter	Weight
Service Age	8
Test Results	8
Visual Inspection	4
Functional Obsolescence	8*

Table 11: Condition parameters along with their respective weights used for assessing station batteries in the 2020 Asset Condition Assessment

Station Batteries			
Elexicon			
Whitby		Veridian	
Condition Parameter	Weight	Condition Parameter	Weight
Service Age	4	Visual Inspection	4
Test Results	4	Test Results	4

Table 12: Condition parameters along with their respective weights used for assessing station protective relays in the 2020 Asset Condition Assessment

Station Protective Relays	
Whitby	
Condition Parameter	Weight
Service Age	4
Test Results	4
Overall Condition	3

Table 13: Condition parameters along with their respective weights used for assessing station fences and buildings in the 2020 Asset Condition Assessment

Station Fences and Buildings	
Elexicon	
Condition Parameter	Weight
Overall Condition	8

Moving forward, Elexicon will identify areas of improvement and further data that can be collected to perform a more accurate and data-driven condition assessment of substation assets. As former utilities had different procedures and inputs to condition assessments, a consolidated inspection form will be created. This inspection form will take advantage of the subject matter expertise of the two former predecessors.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Due to the increase in substation assets through consolidation, Elexicon has opted to utilize a holistic three-year life cycle maintenance procedure which includes testing and maintenance for most station assets. Monthly maintenance will still be performed. For more detailed Substation work that is performed every three years, external contractors are utilized to perform inspections, testing, and maintenance. A review of the consolidated and legacy approaches of the utility is provided.

Station Transformers Consolidated & Legacy Approach

Elexicon conducted inspections for station transformers through visual inspections every month. Maintenance work is done through predictive maintenance based on a 3-year cycle, with the maintenance work including dissolved gas analysis (DGA), oil quality, and power factor (PF) testing. Replacements of station transformers are done based on the condition of assets or to address capacity issues. Legacy Veridian and legacy Whitby also planned and similarly executed their plans to the consolidated approach, in which they conducted visual inspections for station transformers monthly. Legacy Veridian performed predictive maintenance based on a 3-year cycle and legacy Whitby performed predictive maintenance based on an 18-month cycle, with maintenance work for both legacy utilities including DGA, oil quality, and PF testing. Replacements of station transformers for the legacy utilities were also done based on the condition of the assets and to address capacity issues.

Station Circuit Breakers Consolidated & Legacy Approach

Elexicon inspects circuit breakers visually every month and performed maintenance work based on 3-year cycles. Replacements are based on the condition of the circuit breakers, with some upgrades being necessary by fault current exceeding the circuit breaker's intended capacity. Legacy utilities Veridian and Whitby both conducted visual inspections for circuit breakers monthly, with their maintenance work consisting of predictive maintenance that is done based on a 3-year cycle and an 18-month cycle for each of Veridian and Whitby, respectively.

Station Batteries Consolidated & Legacy Approach

Visual inspections were done by Elexicon every month for batteries. Predictive maintenance, which consists of electrical testing, is completed every 3 years. Elexicon replaces batteries based on their condition. Legacy utilities Veridian and Whitby both inspected batteries visually every month, and they both performed predictive maintenance that consisted of electrical testing. However, their maintenance work differed in cycle length. Veridian performed maintenance based on a 3-year cycle whereas Whitby performed maintenance based on an 18-month cycle.

Station Protective Relays Consolidated & Legacy Approach

Protective relays are visually inspected every month by Elexicon. Predictive maintenance, consisting of electrical testing, is done based on a 3-year cycle. Elexicon replaces protective relays based on their condition, age, and functional obsolescence. Legacy utilities Veridian and Whitby also conducted visual inspections for protective relays every month and performed predictive maintenance consisting of electrical testing. Veridian and Whitby performed predictive testing in a cycle of 3-years and 18-months, respectively.

Station Buildings Consolidated & Legacy Approach

The legacy utilities and Elexicon's consolidated approach for inspections, maintenance, and replacements of fences and buildings are the same. For buildings and fences inspections, Elexicon and the legacy utilities conducted visual inspections every month. For maintenance of the buildings and fences, repairs were done as much as was required.

Stations Grounding and Oil leak identification Consolidated & Legacy Approach

Fall of potential methods are used to evaluate the grounding resistance as found in the soil and supplementary data such as the soil surface type, ground condition, and weather are also taken to consideration. Visual inspections of grounding connections and the gradient mats are also performed around the substation. Based on the degree of leakage described in Visual Inspection forms, a letter grade was assigned to the oil leaks. Any severe or alarming leakage is reported to Elexicon and prioritized as a maintenance task. Gaskets, Bushings, Connections, Pads, Oil Levels are checked to ensure oil leakage is not present on transformers.

4.3 Scale Increase Considerations

As a result of the merger, the combined inventory of substation assets for Elexicon is a mixture of former Veridian and Whitby substations. A substantial increase in inventory of substation assets is received where processes and work execution need to also be consolidated. Opportunities for more efficient maintenance and inspection processes could be conducted around Whitby, Ajax, and Pickering. Additionally, further resources are now available collectively for the substations in the area. As Veridian substation assets are much older than Whitby, Elexicon will inevitably prioritize investments of station sustainment in the Veridian territories. This decision is made to address the aging equipment and deteriorating conditions of substation assets in the former Veridian territory. Moving forward, Elexicon will also own Seaton MTS which is constructed in response to the large Seaton development in Pickering. This station shall provide new opportunities for knowledge advancement and technical development. Maintenance, Testing, and Inspection procedures shall be determined to ensure its reliable service to Elexicon customers.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

The consolidation period/rate freeze will not affect the lifecycle management approach or volumes for this program. Elexicon has identified the required replacements in the station’s portfolio for the upcoming DSP period. If further work is required in this program, other budgets could be shifted. Substation replacements are critical due in most part to the number of customers that each substation will serve. It is imperative that Elexicon maintains and replaces substation assets which are reaching end of life.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net Capex ($M)	Priority
2021-1110	Garden Station T2 Repair/Rewind	2021	0.5	191
2021-1118	Westney Heights SS- T1 and T2 Radiator Replacement	2021	0.3	191
2019-1105	Pickering Beach Station upgrade (T1)	2021	1.0	179.6
2021-1107	Rossland W (MS8) Substation TX & Relay replacement	2021	1.2	179.6
2021-1101	Substation Deficiency Corrections	2021	0.52	172.7
2021-1124	MS11 T2 44KV Reliability W Lawler SS	2021	1.5	92.5
2020-1106	27.6 to 8.32kV Station (Brock & Conc Rd 7)	2021	0.3	30

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. [Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

Project name	Whitby District – Garden SS T2, LV Rewind				
Project numbers	2021-1110				
Job numbers	WRP201002				
Project District	Whitby				
Project Location	Garden Station				
Investment Category	System Renewal				
Budget Category	R1 - Substation Renewal				
Project Driver	Reactive project - Cyclic inspection				
Proposed Start Date	2021 JANUARY 2				
Required In-Service Date	2021 DECEMBER 31				
Scope of Work	Rewind of Garden SS T2, LV winding only after failure				
Preliminary Estimate: Total Capital Cost	Gross: $500,000.00	Contribution: $0		Net: $500,000.00	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$45,000	$50,000	$85,000	$320,000
Rationale for Intervention	Reactive measure to repair damaged LV winding on Garden SS T2 after equipment failure. Transformer failed maintenance testing with an internal fault. Winding failure confirmed at repair shop.				
Criteria Score	191				
Impacted Customers and Entities	Approximately 3080 customers are typically connected to Garden T2.				
Intervention Options	Transformer is still needed for normal system capacity so it is required to repair the transformer. Field repair is not possible as it's in the winding of the transformer.				
Effect on System O&M Costs	No impact.				
Targeted Outcomes	As available in the existing business cases and at a minimum the OEB RRFE outcomes.				
Cost Benchmarks	Cost estimate received for this repair of $440,000 for transformer repair shop costs. Craning/trucking/Elexicon staff costs in addition to this.				
Value-Added Approach	Partial rewind will be selected and not full rewind.				

Project name	Westney Heights SS- T1 and T2 Radiator Replacements				
Project numbers	2021-1118				
Job numbers	ARP211000				
Project District	Ajax				
Project Location	Ajax				
Investment Category	System Renewal				
Budget Category	R1 - Substation Renewal				
Project Driver	Repair of defective (leaky) radiators				
Proposed Start Date	2021 Jan 1				
Required In-Service Date	2021 Dec 30				
Scope of Work	Replacement of leaking power transformer radiators (T1 and T2) . Radiators are welded on to main tank and likely to require shipment to repair shop to complete repairs.				
Preliminary Estimate: Total Capital Cost	Gross: $300,000	Contribution: $0		Net: $300,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$27,000	$30,000	$51,000	$192,000
Rationale for Intervention	Leaky radiators due to corrosion. Unable to be patched. Rad failure could lead to catastrophic loss of transformers.				
Priority	191				
Impacted Customers and Entities	Approximately 7000 customers are typically connected to Westney Heights Substation- T1 and T2.				
Intervention Options	Field patching of leaks unsuccessful. Metal too thin to weld. Investigating ability to repair in place.				
Effect on System O&M Costs	Minor impact from reduction of costs associated with ongoing containment/cleanup of small leaks.				
Targeted Outcomes	Successful replacement of radiators.				
Cost Benchmarks	No similar replacement has been done by Elexicon.				
Value-Added Approach	Elexicon will combine other work, if any required, during same transformer outage for repairs.				

<table>
<tr><td>Project name</td><td colspan="5">Pickering Beach station upgrade</td></tr>
<tr><td>Project numbers</td><td colspan="5">2019-1105</td></tr>
<tr><td>Job numbers</td><td colspan="5">-</td></tr>
<tr><td>Project District</td><td colspan="5">Ajax</td></tr>
<tr><td>Project Location</td><td colspan="5">36 Hickman Rd Ajax</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R1-Renewal Programs – Station Assets</td></tr>
<tr><td>Project Driver</td><td colspan="5">Assets at the End of Their Service Life</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The Pickering Beach Station Upgrade project shall include:
- Installation of new HV switchgear (Transrupter), new transformer protection relay (SEL787)
- Installation of Current transformer at T1 wye side ground connection
- Construction of duct banks and civil structures
- Replacement of underground cables
- Installation of new riser poles for outgoing feeders so each feeder be on separate pole
The overall construction time for the project shall be 3 months.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $1,000,000</td><td colspan="2">Contribution: $0</td><td>Net: $1,000,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$97,741</td><td>$108,602</td><td>$184,623</td><td>$695,050</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The project will improve the reliability of the system through sustainment and better protection for station assets.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">179.6</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Customers serviced by Pickering Beach</td></tr>
<tr><td>Intervention Options</td><td colspan="5">No alternatives to the project. The status quo (do nothing) is not recommended due limited protection level for station assets (plus deteriorating condition of assets).</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Lower operating and maintenance costs resulting from the investment</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">Replacement of existing assets due to poor condition / reliability of plant. Reliability should be improved due to the reduce frequency of outages and reduced duration of outages.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

<table>
<tr><td>Project name</td><td colspan="5">Rossland W (MS8) Substation TX and Relay Replacement</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-1107</td></tr>
<tr><td>Job numbers</td><td colspan="5">WCA211107</td></tr>
<tr><td>Project District</td><td colspan="5">Whitby</td></tr>
<tr><td>Project Location</td><td colspan="5">Whitby</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R1 - Substation Renewal</td></tr>
<tr><td>Project Driver</td><td colspan="5">Reliability improvement and capacity expansion</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 Jan 1</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 Dec 30</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Upgrade TX capacity to 20/26/33/37MVA transformer due to load growth in area and to upgrade GE protection relaying at station due to end of life.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $1,200,000</td><td colspan="2">Contribution: $0</td><td>Net: $1,200,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$108,000</td><td>$120,000</td><td>$204,000</td><td>$768,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Reliability and safety- proper relay operation maintained to operate breakers to interrupt system faults and to accommodate load growth in area (West Whitby).</td></tr>
<tr><td>Priority</td><td colspan="5">179.6</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">All customers that are fed by this substation- approximately 4200 customers.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">No ability to supply load growth from existing capacity at other stations. Relaying replacement required due to end-of-life considerations.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Minimal impact to O&M.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">Maintained reliability of protection hardware, ability to serve more customers.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Rebuild of Toronto Substation in Newcastle in 2020- $2.2M</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Replacement of transformer only without upgrade of other station equipment.</td></tr>
</table>

<table>
<tr><th>Project name</th><td colspan="5">Substation Deficiency Corrections</td></tr>
<tr><th>Requested date</th><td colspan="5">2020 Sep 30</td></tr>
<tr><th>Project numbers</th><td colspan="5">2021-1101</td></tr>
<tr><th>Job numbers</th><td colspan="5">Several</td></tr>
<tr><th>Project District</th><td colspan="5">General</td></tr>
<tr><th>Project Location</th><td colspan="5">General</td></tr>
<tr><th>Investment Category</th><td colspan="5">System Renewal</td></tr>
<tr><th>Budget Category</th><td colspan="5">R1 - Substation Renewal</td></tr>
<tr><th>Project Driver</th><td colspan="5">Equipment repairs and upgrade of station ground grids</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021 Jan 1</td></tr>
<tr><th>Required In-Service Date</th><td colspan="5">2021 Dec 30</td></tr>
<tr><th>Scope of Work</th><td colspan="5">Complete various reactive capital equipment repairs over 2021 as well as improve ground grids at two substations- James SS (Gravenhurst) and Edgehill SS (Belleville).</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td colspan="2">Gross: $520,000</td><td colspan="2">Contribution: $0</td><td>Net: $520,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$46,800</td><td>$52,000</td><td>$88,400</td><td>$332,800</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">Safety improvement at ground grid improvement substations and repair of various substation components as found during monthly inspections or scheduled preventative maintenance.</td></tr>
<tr><th>Priority</th><td colspan="5">172.7</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">Any customers fed by substations improved by these reactive repairs or ground grid improvements.</td></tr>
<tr><th>Intervention Options</th><td colspan="5">Elexicon will assess each reactive repair for most effective use of capital. Ground grid improvement projects will be minimized to essential work and make best use of equipment outage opportunity.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">Reduction in O&M as minor repairs will be reduced following completion of capital project.</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">Improved reliability, improved safety.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">Ground grid improvements at Howard Walker and James Collins stations each totalled $100,000 approximately and are expected to be representative for the two stations selected for 2021. $320,000 for other reactive repairs is typical for recent spending years.</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">Consideration of low-cost repairs where possible- includes onsite repairs instead of shipment to suppliers, select replacement of components in ground grid upgrades- not a full rehab of all equipment on site.</td></tr>
</table>

Project name	MS11 T2 44kV Reliability W Lawler SS				
Project numbers	2021-1124				
Job numbers	WRP201001, ASP190138T				
Project District	Whitby				
Project Location	Whitby				
Investment Category	System Renewal				
Program Category	R1-Substations				
Project Driver	Reliability improvement and capacity expansion				
Proposed Start Date	2021 Jan 1				
Required In-Service Date	2021 Dec 30				
Scope of Work	Add 44kV protective device (Transrupter), new power transformer 15/20/25MVA, two new 13.8kV feeder reclosers, associated protective relaying and controls and upgrading of one existing feeder's egress cables from 500MCM to 1000MCM.				
Preliminary Estimate: Total Capital Cost	Gross: $1,500,000	Contribution: $0		Net: $1,500,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$135,000	$102,000	$255,000	$960,000
Rationale for Intervention	Reliability (difficult to resupply customers from MS11 from other sources in the event of station issues) and also to accommodate load growth in area (Brooklin).				
Priority	92.5				
Impacted Customers and Entities	All customers that are fed by this substation- approximately 6700 customers.				
Intervention Options	Elexicon could attempt to find an alternate location for new station equipment. No ability to supply load growth from other stations. No ability to re-organize system to improve ability to resupply from other sources.				
Effect on System O&M Costs	Positive impact on reduction of switching time for planned or unplanned outages. Positive effect on O&M per customer costs with the addition of new customers in Brooklin area.				
Targeted Outcomes	Improved reliability, ability to serve more customers.				
Cost Benchmarks	Rebuild of Toronto Substation in Newcastle in 2020- $2.2M				
Value-Added Approach	Use of existing site, maximized sharing of existing equipment, existing feeders.				

<table>
<tr><td>Project name</td><td colspan="5">27.6 to 8.32kV Station (Brock & Conc Rd 7)</td></tr>
<tr><td>Project numbers</td><td colspan="5">2020-1106</td></tr>
<tr><td>Job numbers</td><td colspan="5">-</td></tr>
<tr><td>Project District</td><td colspan="5">Ajax</td></tr>
<tr><td>Project Location</td><td colspan="5">Brock & Concession Rd 7, Pickering</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R1-Renewal Programs – Station Assets</td></tr>
<tr><td>Project Driver</td><td colspan="5">Growth and Capacity (new customer connections; increase in load/supply constraint</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 Dec 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">This project shall include:
- Building new 27.6/8.32kV 1.5MVA substation which involves installation of a pad mounted transformer and high voltage cables.
The Overall construction time for the project shall be one month.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $239,660</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $239,660</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$27,000</td><td>$30,000</td><td>$51,000</td><td>$192,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">New loads including commercial developments,
Not sufficient capacity on existing 27.6/8.32kV stations</td></tr>
<tr><td>Criteria Score</td><td colspan="5">30</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Customers serviced by new substation</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There are no alternatives to the project. The status quo (do nothing) is not recommended due to supply constraint on existing 27.6/8.32kV Greenwood substation.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">Improved capacity/access for existing customers and access to the system for new customers. Reliability should be improved due to the reduce frequency of outages and reduced duration of outages. Improved System Management Capabilities and improved emergency response shall also be produced.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	Renewal Programs – Rebuilds
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of their Service Life
Secondary Driver(s)	System Reliability

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$4.62M	**$5.04M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Renewal Programs – Rebuilds program includes projects for several types of work including cable rejuvenation, cable testing, cable injections, and cable replacements in specific areas with significant asset deterioration. The rebuilds requirements are established by the results of the Asset Condition Assessment ("ACA") exercise, equipment-specific reliability trending analysis, and area-specific reliability trending analysis.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	4.62	2.60	5.65	5.30	8.30	6.93	2.73	1.33
Contributions	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00
Net Expenditures	4.54	2.56	5.65	5.30	8.30	6.93	2.73	1.33

This program is comprised of cyclical spending (primarily for underground cable) as well as specific projects which target rebuilds in areas with significant asset deterioration. As outlined above, the need for this program is established through the combination of ACA results, reliability trending analysis, issues identified during inspection, and failures in field. The support for the routine underground cable work which includes testing, injections, and replacement is established through the ACA results. The ACA results show that there is a significant population of underground cables that are at risk of deteriorating to Poor or Very Poor condition over the forecast period. The reliability trending analysis also shows an increase in Customer Hours Interrupted ("CHI") due to underground cable failure in recent years; however, improvements have been observed in areas that have received cable injections. The trending analysis is also the basis for targeted rebuilds that occur in Whitby. An analysis of CHI by the municipality shows that Whitby is one of the most significant contributors to total CHI (due to Cause Code 5 – Defective Equipment outages).

Several alternatives of investments were considered for this program, including consideration of no corrective action; however, this option has significant negative consequences. If no action is taken to improve the health of assets targeted by this program, a notable portion of assets will fail and require reactive replacement – which is a more costly and operationally inefficient alternative to the action proposed in this program. These alternatives are described in detail in Section 3. The preferred alternative – namely the plan outlined in this business case – provides many benefits in terms of aspects including, but not limited to, reliability, grid resiliency, and operational efficiency.

The merger of the legacy utilities, Whitby Hydro and Veridian Connections, is relevant to the inputs and outcomes of this program. This program directly supports the two major merger-related objectives: Service Continuity and Utility Integration. The latter is thoroughly explored in this business case, as sections 4.1 and 4.2 outline the legacy and consolidated planning and work execution practices. Elexicon's consolidated approach draws elements from both legacy processes to create a solution that leverages the expertise and resources of both predecessor utilities. Elexicon's strategy for optimizing this scale increase is also outlined in this business case.

2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

This program consists of several projects that aim to rejuvenate or replace assets on underground or overhead lines to improve their condition, reliability, and safety. These projects include routine efforts for asset refurbishment or replacement that address recurring needs as well as targeted efforts that aim to address asset deterioration in specific geographic areas. The drivers for the projects within this program may differ depending on the configuration of the distribution line (overhead vs. underground) and the type of project (routine vs. targeted).

The routine projects within this program only target the renewal of underground cables which include assets such as primary underground cable and distribution transformers. A list of routine projects and a brief description of their purpose are provided in Table 2.

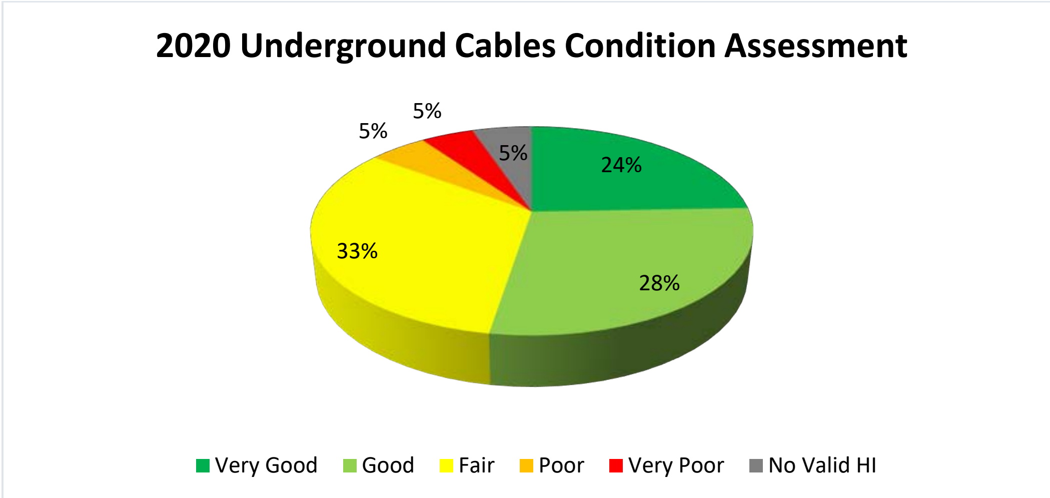
Table 2: Recurring Projects in the Rebuilds Program

Project Name	Purpose
Faulted Cable Upgrade (Injection)	This project involves reactive cable injections to address unexpected failures.
Primary Cables and Transformers – Replacements Driven by Previous Year Injection Work	The contractor that completes cable injections may report that cable injections are not a suitable option in some cases. This project replaces those cable segments and associated transformers on a like-for-like basis, or a modified replacement pending engineering review and study.
Submarine Cable Replacement	This project consists of replacements for submarine cables in Gravenhurst. Submarine Cable assets are found in Gravenhurst due to the nature of the legacy system that was built and how customers are positioned in the area.
Primary Cable Renewal	This budget is focused on the testing of cables to determine whether injection or replacement is the suitable option. It also provides a budget for proactive injections/replacements as outlined by testing results.

While other assets are also addressed through these routine investments, the bulk of the spending is allocated for underground cables. The performance trends which demonstrate the need for these investments are the change in the health index scores of the asset class and reliability statistics.

The latest ACA exercise was completed by METSCO Energy Solutions (“METSCO”) in 2020 for the entire Elexicon system. In addition, there is a significant portion of Underground Cables in the Fair category which can deteriorate to the Poor or Very Poor categories within the next five years if there is no intervention. This unaddressed deterioration would decrease reliability and increase safety risks of the system. Please refer to Figure 3 for the asset counts pertaining to Figure 1.

Figure 1: 2020 condition assessment of UG Cables



Some additional insights are revealed through an analysis of Elexicon's reliability performance and statistics. Elexicon tracks detailed information about outages, which includes the cause codes describing the nature of the outage. Cause code 5 for defective equipment is relevant to the need for this program as it includes sub-cause codes for specific asset failures, including primary and secondary underground cable. The customer hours interrupted due to underground cable failure are summarized in Table 3. These statistics reflect the impact that underground cable failures have on Elexicon's reliability performance.

Figure 2: Historical CHI linked to underground cable failures

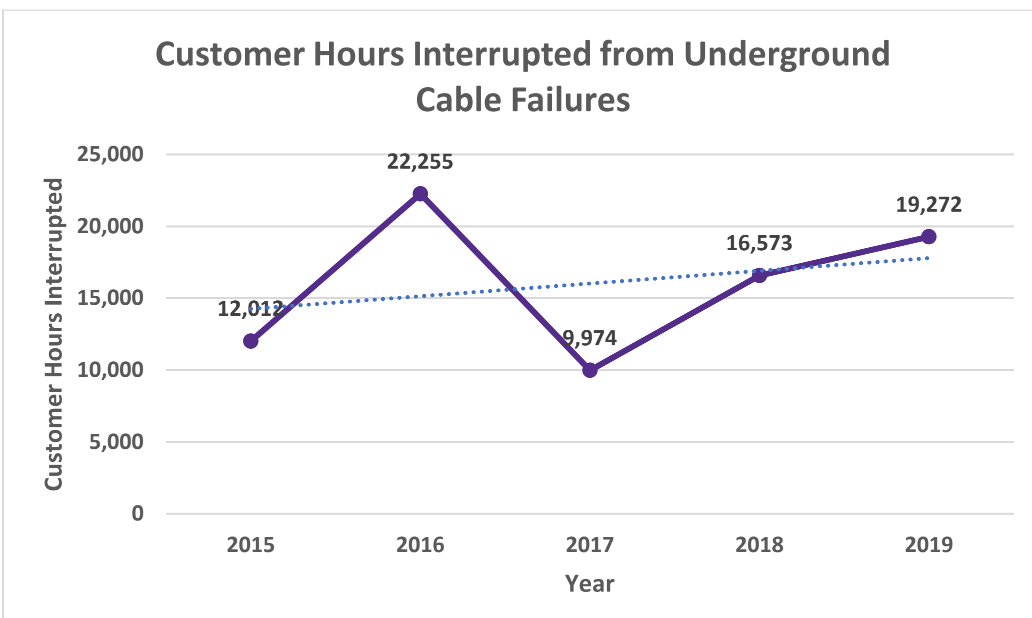


Table 3: Customer Hours Interrupted due to Underground Cable Failure

Defective Equipment					
Sub Cause Code	**2015**	**2016**	**2017**	**2018**	**2019**
Underground Primary cable failure (hrs)	11,588	22,159	9,778	16,265	18,995
Underground Secondary cable failure (hrs)	424	95	196	308	277
Total	**12,012**	**22,255**	**9,974**	**16,573**	**19,272**

Underground cable failures contributed significantly to customer hours interrupted as they accounted for a minimum of 9,000 customer hours interrupted every year and 16,000 customer hours interrupted per year on average. There was an increasing trend until 2016, after which the customer hours interrupted dropped significantly in 2017. However, underground cable failures have become a more significant contributor to outages in recent years. This suggests that additional work is required to improve the condition of underground cable assets and system reliability.

In addition to the routine work within this program, there are also initiatives listed in Table 4 targeting rebuilds in specific areas with a high concentration of deteriorated assets. These projects can be driven by external factors such as third parties. There are both overhead and underground rebuilds planned for specific areas over the forecast period, primarily in Whitby. These projects are summarized below.

Table 4: Targeted Rebuilds Projects in the Rebuilds Program

Project	Purpose
Cherrywood TS 44kV Rebuilds	Relocate a substation within the Cherrywood TS as an independent facility. This relocation effort involves rebuilding feeders as an initial step.
Overhead Rebuilds	Planned overhead rebuilds for specific line segments in Whitby with a high concentration of deteriorated assets.
Otter Creek UG Rehab	Planned underground rebuilds in the Otter Creek area in Whitby which has a high concentration of deteriorated assets.

All other rebuilds projects are located in the Whitby area. Some useful insights about the performance of assets in the Whitby can be derived through an analysis of outage data by service territory below. Table 5 below shows the customer hours interrupted due to "Cause Code 5 – Defective Equipment" for the towns and cities that Elexicon serves. The top three service areas that are the most significant contributors to total outage duration experienced by customers over the last five years are Ajax, Pickering and Whitby.

Table 5: Cause Code 5 Defective Equipment Outages by Service Area

Service Area	2015	2016	2017	2018	2019	Total
AJAX	38,623	25,607	7,019	7,264	17,310	95,823
BEAVERTON	159	734	51	85	344	1,372
BELLEVILLE	8,128	3,689	1,301	9,699	1,956	24,773
BOWMANVILLE	2,936	1,355	682	3,252	3,746	11,971
CANNINGTON	9	99	57	586	37	787
GRAVENHURST	2,278	4,034	1,502	1,791	1,753	11,358
NEWCASTLE	4,133	9	3	5,775	4,048	13,967
ORONO	12	1	15	12	31	71
PICKERING	33,666	16,710	19,657	44,016	13,671	127,719
PORT HOPE	1,520	976	1,981	2,480	894	7,851
PORT PERRY	88	3	6,039	1,778	46	7,954
SUNDERLAND	262		3	532	28	825
UXBRIDGE	2,088	33	39	255	96	2,512
WHITBY	23,887	27,169	5,619	5,758	16,407	78,840

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

As outlined in Section 2.1, this program consists of routine projects which primarily address recurring needs related to underground cable and targeted rebuilds that address specific areas with a high concentration of deteriorated assets. The current state analysis for these two types of projects differs slightly. Annual projects primarily target underground infrastructures such as primary underground cables and distribution transformers, but the former comprises the bulk of the investment. The condition parameters used for the ACA for underground cable and their relative weights are presented in Table 6 below. The results of the ACA for this asset class are presented in Figure 3.

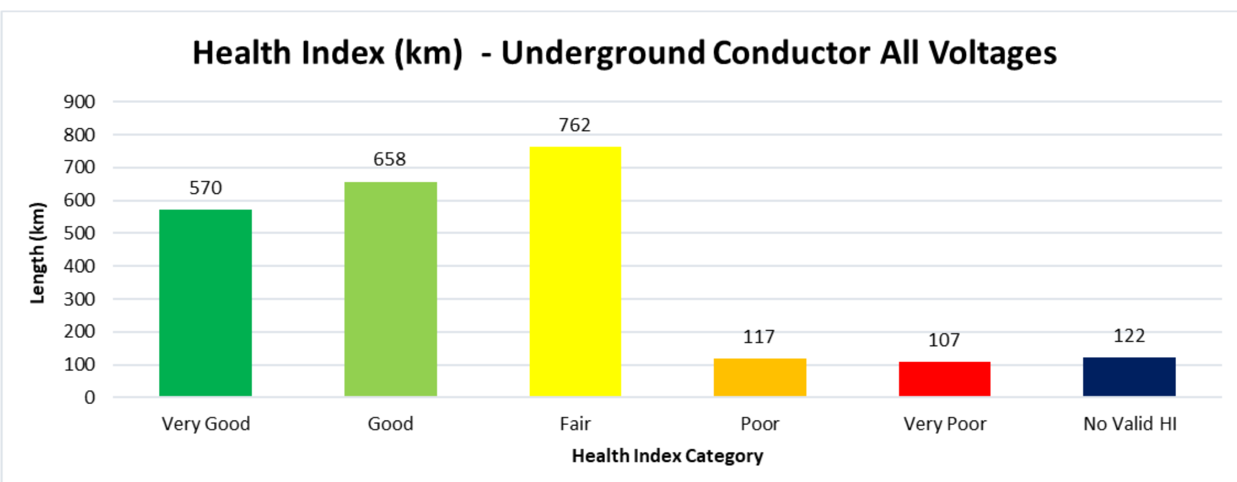
Underground System Rebuilds

There is a total of 117km of underground cable in Poor condition and 107km of underground cable in Very Poor condition. This results in a total volume of 224km of underground cable requiring attention and monitoring over the forecast period. In addition, there is a substantial quantity of underground cable in the Fair condition category which can potentially deteriorate into the Poor and Very Poor categories over the forecast period.

Table 6: Condition Parameters for UG Cable ACA

Condition Parameter	Weight
Service Age	8
Faulted Section	4

Figure 3: 2020 ACA Results for UG Cable



Based on these factors, the recommended replacements are summarized in Table 7 below. The routine project investments described above will enable Elexicon to complete these replacements and improve the condition, reliability, and safety of its distribution system.

Table 7: Recommended Replacement Volume for UG Cable

Length of Underground Primary Cable Recommended for Replacement						
Year	2021	2022	2023	2024	2025	2026
Underground Primary Cables (km)	50	65	65	82	82	82

As outlined in Section 2.1, this program also includes targeted rebuilds for areas with a high concentration of deteriorated assets. These projects target both overhead and underground rebuilds in the Whitby area. The asset classes considered in underground rebuilds are underground cable and distribution transformers – depending on condition and replacement economics – but cables comprise the bulk of the investment. In order to outline the current state of the distribution system, the ACA results of the underground cable asset class and recommended replacements presented above are considered. The Otter Creek UG Rehab project enables Elexicon to complete these replacements, improve the condition of its distribution system, increase reliability, and reduce safety risks.

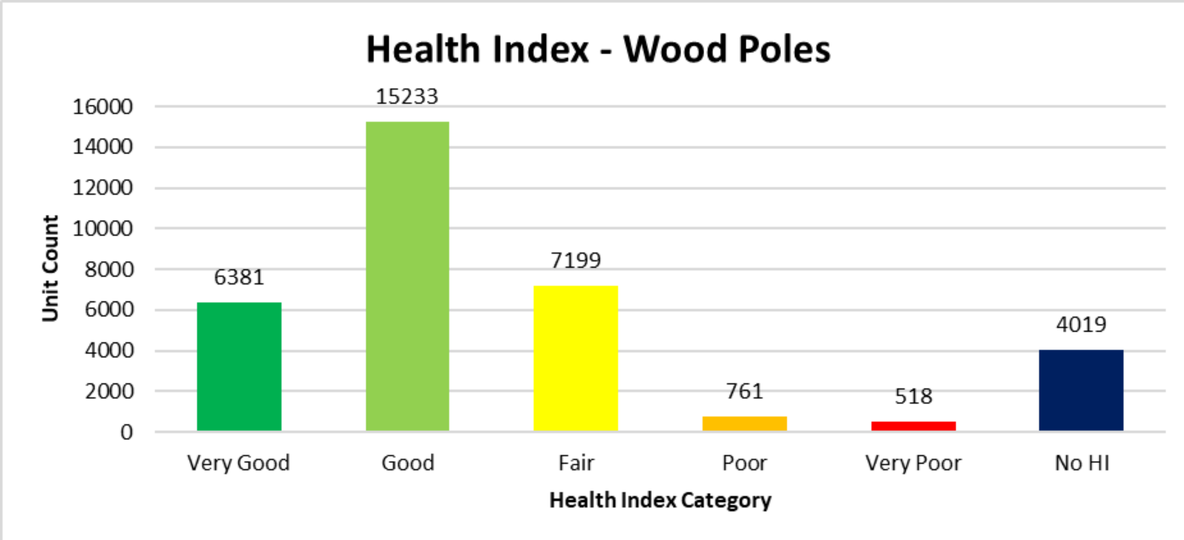
Overhead System Rebuilds

The remaining targeted rebuild projects are for overhead lines, which consist of asset classes such as overhead conductor, wood poles, overhead switches, and distribution transformers. However, the bulk of the investment is comprised of renewal for the wood poles and overhead conductor asset classes. ACA results sufficiently outline the current state of the system to be addressed, but the ACA was only completed for the wood poles asset class as there was insufficient data for overhead conductors. While this is not ideal, there is a strong relationship between wood pole replacements and overhead conductor replacements which can be used to estimate replacement volumes for the latter. The condition parameters used for the wood poles ACA are presented in Table 8 below along with their relative weightings. The results of the ACA are presented in Figure 4.

Table 8: Condition Parameters for Wood Poles ACA

Condition Parameter	Weight
Service Age	1
Remaining Strength	8
Wood Rot	6
Out of Plumb	2
Overall Condition	7

Figure 4: 2020 ACA Results for Wood Poles



The ACA results show that there are 761 wood poles in Poor condition and 518 wood poles in Very Poor condition. This amounts to a total of 1,279 wood poles which require monitoring over the forecast period. In addition, there is a significant population of wood poles in Fair condition which could potentially deteriorate into Poor or Very Poor condition over the next five years. Based on these factors, recommended replacement volumes have been outlined and are presented below in Table 9. In addition, recommended replacement volumes for overhead conductors have been established based on the wood pole replacement recommendations and are presented in Table 10 below. The estimate is derived through an analysis of the amount of conductor supported by a wood pole and the assumption that wood pole condition/risk drives the replacement needs for overhead conductors. The targeted overhead rebuilds projects within this program will enable Elexicon to complete these wood pole and overhead conductor replacements, improve the condition of its distribution system, and reduce reliability and safety risks.

Table 9: Recommended Replacements for Wood Poles

Number of Wood Poles Recommended for Replacement						
Year	2021	2022	2023	2024	2025	2026
Wood Poles	350	350	350	350	350	350

Table 10: Recommended Replacements for Overhead Conductor

Length of Overhead Conductor Recommended for Replacement						
Year	2021	2022	2023	2024	2025	2026
Overhead Conductor (km)	60	60	60	60	60	60

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

The Renewal Programs – Rebuilds program is primarily driven by poles, overhead conductor, and underground cable assets in deteriorating conditions in specific areas. The program includes routine work as well as targeted rebuilds in specific geographic areas. Both types of projects are driven by the age and condition of relevant assets. These assessments entail compliance considerations that drive part of the work in this program. Specifically, the key standards which serve as program drivers are CSA Standards, the Distribution System Code, and Ontario Regulation 22/04.

CSA Standards

The Canadian Standards Association publishes guidelines for various distribution system assets which detail best practices for the materials, configuration, and strength requirements of poles and related accessories. This standard provides load factors which must be used to determine the vertical, transverse, and angular load-bearing characteristics for the poles in the system. In addition, it specifies the strength requirements of distribution system support assets. A specific clause within the standard drives some of the pole replacement work planned by Elexicon in clause 8.3.1.3. This clause states that when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced. Elexicon regularly conducts remaining strength tests to ensure that poles that fail to meet this limit are replaced or refurbished.

Distribution System Code: System Inspection Requirements and Maintenance

Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with consideration to good utility practice quality, and reliability for short term and long-term basis. Inspection Activities are made following requirements found in the Distribution System Code and where more frequent inspections are required. Where defects are discovered, replacements are made immediately or planned across into the future.

Ontario Regulation 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of equipment and construction, proximity to distribution lines, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure which is tracked and reported by Elexicon. This regulation has sections that are directly applicable to the rebuilds program – specifically, section 4 which discusses safety standards for overhead distribution lines, and section 5 which discusses safety standards for underground distribution lines. These sections outline the following key clauses which drive the rebuild program:

- Operating electrical equipment shall be maintained in proper operating condition.
- Adequate space shall be provided around electrical equipment for proper operation and maintenance.

The first clause is related to the condition of the assets targeted by the rebuilds program and the second drives rebuild that are intended to renew assets that no longer meet current safety standards. Additional clause in section 4 and 5 outline requirements related to energized components, grounding, loading requirements, and interactions with customer-owned property and/or natural gas pipelines.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.* *-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:* *o The number of customers in each customer class potentially affected by a failure of the assets included in the project* *o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)* *o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)* *o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure* *-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project*

The rebuilds program targets deteriorated underground assets or assets in poor condition in specific geographic areas. If no action is taken to address these groups of assets in poor condition, there are potential consequences to system reliability, operational efficiency, and compliance. Assets in poor condition pose a risk to system reliability as their condition increases the likelihood that they will fail catastrophically and cause service interruptions. This risk compounds in an area that has a high concentration of deteriorated assets. If multiple components fail collectively, there is a risk of a major outage which entails several repairs/replacements and requires a significant effort to resolve. The rebuilds program reduces the risk of such situations by targeting aged or deteriorated assets in specific geographic areas. Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of assets like cable and conductors that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

When evaluating System Renewal Investment options, Elexicon undergoes analysis of options with regards to its effects on SAIDI and SAIFI by defective equipment and Residual Risk. The effect that an asset class has with regards to SAIDI and SAIFI values due to defective equipment failure is evaluated as the renewal program seeks to improve on these defective equipment metrics through proactive equipment renewal. Residual Risk is the monetized value of the left-over risk on the system after mitigations. It is monetized based on the quantified failure probability and monetized failure impacts (reliability, financial, environmental, and safety impacts).

The increased risk to system reliability also translates to an increased risk for cost and operational efficiency. Proactive replacements are typically less expensive and more efficient than reactive repairs required to restore service in emergency situations. If no action is taken to address the areas with assets in poor condition, the risk of catastrophic failure increases, and additional emergency repair costs can be expected.

A benefit afforded by the rebuilds program is that it allows Elexicon to reconstruct legacy systems using updated construction standards that best reflect the current practices of the utility. Asset failure that arises from non-compliance with safety standards could have significant repercussions and penalties – especially if injury/death occurs.

These risks have been quantified through the development of failure curves for the primary asset classes targeted by this program – specifically, wood poles, underground cable, and overhead conductor. While other asset classes such as distribution transformers and overhead switches are also replaced as part of this program, the aforementioned three asset classes drive the bulk of the investment. The wood poles failure curve is based on in-field failure data whereas the failure curves for underground cable and overhead conductor are based on their typical useful lives ("TUL"). The assumed TUL for underground cable is 40 years and the assumed TUL for an overhead conductor is 60 years. The failure curves can be used to estimate the expected failure volumes for these asset classes – these results are shown below in Table 11.

Table 11: Expected Failures for UG Cable, OH Conductor, and Wood Poles

Asset Class	2021	2022	2023	2024	2025	2026	2027	2028	2029
UG Cable (km)	147.5	139.6	132.0	124.8	118.0	111.6	105.5	99.9	94.5
OH Conductor (km)	33.3	34.5	35.7	36.9	38.1	39.2	40.4	41.5	42.6
Wood Poles	564	568	572	574	576	578	579	579	579

2.5 Merger-Related Objectives:

Elexicon has adopted two merger-related objectives that are relevant to the Rebuilds Program: service continuity and utility integration. These high-level objectives are disaggregated into several sub-criteria that assess whether or not a program supports the objective. The Rebuilds Program meets criteria within both objectives and therefore supports Elexicon's overarching merger-related goals.

The relevant criteria for the service continuity objective are related to safety benefits, effects on a worst-performing feeder ("WPF"), and legislative requirements. One criterion for the service continuity objective is the relative importance of the program as dictated by the dollar-weighted HI analysis. Programs are evaluated with regards to the investment's effects on the health of assets as defined by unit costs. Another criterion of this objective is whether the program aims to mitigate safety non-conformances verified by inspections. In this case, the rebuilds program meets these criteria as there are safety non-conformances verified by inspections. In addition, the rebuilds program aims to replace assets that no longer meet safety requirements. Rebuilds programs target areas in poor condition which are often located along with worst performing feeders. The impact that a program has on a worst-performing feeder is another criterion of the service continuity objective which is met by this program.

There is only one relevant criterion for the utility integration objective. The rebuilds program supports the integration of core objectives of the legacy utilities as it requires the documentation of a consolidated approach to planning and work execution related to rebuilds. Additional details can be found in sections 4.1 and 4.2.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	0	1	2
Scenario Description	Current Budgeted Rebuilds Plan	Investment Pace Increased by 10%	Investment Pace Decreased by 10%
Annual Program Scope	The current replacement plan is described in the business case. Rebuilds efforts target poor condition assets identified in the ACA.	An increased program budget would allow the utility to renew additional assets.	A decreased program budget would allow the utility to prioritize other needs.
Annual Gross CAPEX	$5.04M	$5.54M	$4.54M
Annual Net CAPEX	$5.04M	$5.54M	$4.54M
Annual Program Benefits	The base values as influenced by Defective Equipment are 0.271 for SAIDI, and 0.562 and SAIFI. Other Investment scenarios (1 and 2) are relative percentages to scenario 0. Residual Risk in Scenario 0 is $6.427M.	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 1 are relative to the scenario 0 investment. SAIFI = -1.07% SAIDI = -0.158% Residual Risk = -1.695%	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 2 are relative to the scenario 0 investment. SAIFI = 0.21% SAIDI = 0.32% Residual Risk = 2.584%
Program Economics	The base scenario involves investing $5.04M annually and results in the residual risk of $6.427M projected by 2029. It is the preferred trade-off of costs and benefits.	By investing 10% more in the rebuilds program, the forecasted residual risk decreases by 1.695%.	By investing 10% less in the rebuilds program, the forecasted residual risk increases by 2.584%.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable. When Elexicon Customers were asked about rear lot lines, 62.1% (535 of the 862) of customers responded that rear-lot lines should be moved underground and Elexicon should either plan work to worst performing areas or geographically, finishing all work in one area before moving		

	elsewhere. 20.4% (176 of the 862) of customers believed that the status quo should be kept, where overhead lines in rear lots are replaced when they fail.		
Other Constraining Factors	The current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.
Preferred Alternative	X		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: The planned investments will help sustain or improve system reliability as they will improve the condition of deteriorated assets and reduce the risk of unexpected failures. Deteriorated assets targeted by this program such as poles, underground cable, and overhead conductor all play integral roles in the distribution system. Assets in poor condition can fail catastrophically and cause outages – especially when triggered by external circumstances such as weather events, physical impacts, and/or foreign interference. These asset failures could result in a significant impact on reliability and customer experience given that assets targeted by the rebuilds program are often located in proximity. The planned investments mitigate this risk by replacing or refurbishing these poor condition, high-risk assets.

Grid Resiliency: The rebuilds program is intended to improve the health of material segments of distribution lines. While all asset replacements improve grid resiliency as they result in a reduction in reliability risk, the rebuilds program contributes more significantly. Planned rebuilds improve the condition of large sections of the distribution system as opposed to like-for-like asset replacements which are isolated and can still hold significant risk due to the condition of surrounding assets. The improved condition of a material segment of the distribution line has a considerable impact on grid resiliency as it improves the condition of several assets. These assets can better withstand external factors such as adverse weather events, physical impacts, and foreign interference as their condition is improved collectively.

Operational Efficiency and Cost Effectiveness: The majority of the investments within this program will be used for proactive asset replacements – the only exceptions are a series of projects intended to fund reactive replacements/refurbishments when necessary. Proactive replacements allow a greater deal of flexibility in the asset replacement process as they are not subject to the same constraints as reactive replacements. Reactive replacements occur after an asset has failed and often require immediate response, the dispatch of reactive replacement crews to restore service and entail additional emergency response costs. These additional constraints do not apply to proactive replacements which can be planned and, as a result, are less costly and more efficient. In addition, this program also includes a budget for reactive refurbishment work which partly mitigates the cost risks associated with unexpected asset failure.

Safety: Deteriorated assets targeted by this program pose a significant safety risk to Elexicon representatives and the general public. The primary asset classes that these investments targets are wood poles, underground cables, and overhead conductors. In poor condition, these assets pose several safety risks including:

- Injury to nearby crews and/or customers caused by the catastrophic failure of the asset (e.g., a falling pole)
- Damage to infrastructure, customer, or third-party owned property located in proximity to a failed asset.
- Fire risk posed by the interaction of energized assets and the surrounding environment.

The investments in this program will improve the health of these assets and reduce the associated safety risk.

Cyber-Security/Privacy: *N/A*

Environmental Benefits: Distribution lines carry assets and components which can negatively affect the environment. For example, overhead lines often include pole-mounted transformers which include oil and other harmful chemicals. Line assets in poor condition can fail catastrophically, resulting in these substances being released into the environment. The investments within this program will improve the condition of line assets and reduce the risk of catastrophic failure and the subsequent release of harmful substances into the environment. In addition, as linear assets such as underground cable and overhead conductor age, there is an increase in the system losses as they are unable to transmit electricity efficiently. Renewing these assets improves the distribution line's ability to efficiently transfer energy which results in reduced system losses and a lesser environmental impact.

Coordination/Interoperability: The rebuilds program supports coordination with other organizations through the creation of partnerships. Elexicon engages the services of several contractors such as CableQ and Novinium Energy in order to complete the work in the scope of this program. These relationships are not limited to contractors as Elexicon also conducts business with vendors, engineering design companies, and materials suppliers as part of this program. In addition, this program also addresses work that results from discussion with regulatory organizations and transmitters such as HONI (e.g., Cherrywood TS 44kV rebuilds) and supports the development of these relationships.

Conservation and Demand Management: N/A

Net Customer Benefits: The primary benefits for customers resulting from this program are improved reliability, safety, and cost control. Assets in poor condition are more likely to fail and cause interruptions to electrical service. This causes inconvenience for customers as these outages can last for significant amounts of time. Poor condition assets also pose a safety risk to Elexicon, customer, and third-party representatives as they are more likely to fail and cause injury or damage to property. The investments included in this program will improve the condition of material segments of the distribution line and result in a decreased likelihood of outages. In addition, there are cost-related benefits afforded to customers as a result of this program. The proactive replacements/refurbishments will reduce the likelihood of catastrophic failure and the need for reactive replacements. Reactive replacements are typically more costly than planned investments due to emergency repair costs and additional constraints. The planned investments in this program allow Elexicon to minimize the risk of reactive costs which may contribute to increases in customer costs. In addition, there are costs associated with outages to the customer as a result of lost productivity or value, particularly for commercial and industrial customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated *-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects*

Changes to operating circumstances can occur over the planning period and may impact Elexicon's ability to perform its planned work. Elexicon has contingencies in place which will allow it to address some of these changes and remain aligned with its planned work. A common change in operating circumstances occurs when there are expected asset failures. These unexpected failures often cause interruptions to electrical service and may not be included in the budget for planned replacement. However, the utility is still responsible for addressing these situations and performing the appropriate repairs. In order to be able to complete these remedial actions without sacrificing planned replacements, Elexicon dedicates a portion of this program budget to reactive actions. For example, there are planned projects every year that are intended to fund reactive cable injections.

Elexicon's budget prioritization process also allows it to adjust its investments in response to evolving circumstances. In the case where additional work is required due to external circumstances such as severe deterioration being discovered in a particular area, Elexicon can reapply its budget prioritization process to determine which projects provide the most benefit at a given cost. However, there is a possibility that the prioritization process will determine that the investments in this program are not a high priority. In this case, the assets would continue to deteriorate and pose a significant risk to the reliability, safety, and customer satisfaction. However, there are some contingencies in place to address this situation as well. There are several other programs in Elexicon's distribution system plan which target many of the same assets as the Rebuilds program. While this is not an ideal solution as it does not guarantee that Elexicon will be able to complete all of its planned replacements, it offers some support in ensuring that line assets remain reliable and do not pose safety risks.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Elexicon's planning approach for the rebuilds program draws elements from the planning approaches of both predecessor utilities. When planning underground rebuilds, Whitby Hydro considered the condition of underground cables. The condition assessment was based on the age of the cable segment and the number of cable faults. The results were then added to the Whitby Hydro's GIS system, which allowed the utility to identify areas with a high concentration of poor condition assets that would be prime candidates for underground rebuilds. Underground assets in other areas were replaced using a like-for-like replacement approach which was based on the available budget and prioritized according to condition.

When planning overhead rebuilds, Whitby Hydro considered the age of overhead conductor segments. The approach applied to planning overhead rebuilds was the same as the approach for planning underground rebuilds. The age data was visualized in the GIS, which allowed the utility to identify areas with a concentration of poor condition assets that would benefit most from overhead rebuilds. A difference between the approaches for overhead and underground rebuilds is that Whitby Hydro did not consider like-for-like replacements for overhead assets and only completed replacements as part of rebuilds. The only exception is if a wood pole was identified as a "danger pole" (high risk of short-term failure) – in these situations, like-for-like replacements were completed immediately.

In 2017, Veridian adopted a new approach to planning underground rebuilds by conducting DC Polarization/Depolarization testing in order to assess intervention options for underground cable segments. The cable testing revealed whether a given segment of cable was suitable for refurbishment via cable injection or if a replacement was required. This data was analyzed in Veridian's GIS system in order to identify areas that would be suitable for rebuilds based on the cables requiring replacement. Cable injections and like-for-like replacements were used for underground assets that were not included in rebuilds programs. Veridian did not consider rebuilds for overhead lines and instead only completed-like-for-like replacements based on condition data.

The consolidated approach that will be adopted by Elexicon includes aspects of the methodologies applied by both predecessor utilities. Elexicon will consider rebuilds and like-for-like replacements for both underground and overhead lines. Elexicon will use condition data and cable testing data as the inputs for underground rebuild planning. Condition data consists of the age of the cable and the number of cable faults and is used to prioritize intervention. DC Polarization/Depolarization testing is also performed on underground cables in order to determine if refurbishment via cable injection is a suitable option or if replacements must be performed. The results of the condition assessment and the cable testing are analyzed in Elexicon's GIS to identify areas that would be ideal for rebuilds. Underground assets outside of these areas are replaced using a like-for-like replacement approach prioritized according to condition.

When planning overhead rebuilds, Elexicon considers the condition of overhead conductor segments and other overhead assets such as wood poles. The condition of an overhead conductor is assessed based on age, visual inspections, and IR scanning, and the condition of wood poles are assessed based on age, strength, and visual inspections. This data is analyzed in Elexicon's GIS system in order to identify areas that would be suitable for overhead rebuilds. If poor condition assets are not located in close proximity, like-for-like replacements will be conducted and prioritized by the condition. However, like-for-like replacements for overhead lines typically fall outside the scope of the rebuilds program. Elexicon's GIS system also contains layers of analysis for work driven by external factors such as the Cherrywood TS 44kV feeder rebuilds which were driven by discussions between Elexicon and Hydro One.

4.2 Legacy Work Execution Approaches vs. Combined Operations

The work that Whitby Hydro completed as part of this program included rebuilds and replacements for underground lines and only rebuilds for overhead lines. Underground asset replacements were completed Whitby Hydro's work crews and rebuilds were completed through an internal and external mix of resources. Whitby's internal work crews primarily addressed the electrical components of underground lines, but external contractors were required for the construction of civil infrastructure. Like-for-like replacements were not completed for overhead lines and only rebuilds were considered. Overhead rebuilds were completed by Whitby's internal work crews and external contractors. When danger poles were identified, replacements were completed by internal work crews.

The work that Veridian completed as part of this program included testing, refurbishment, rebuilds, and replacements for underground lines. DC polarization/depolarization testing was completed by an external contractor, CableQ, and refurbishments via cable injections were completed by another contractor, Novinium Energy. Rebuilds were completed using a mix of internal and external resources as Veridian's internal crews were able to perform work related to the electrical system but contractors were required for civil construction work. Like-for-like replacements were completed by Veridian's internal resources as well. Overhead lines were not rebuilt, and only like-for-like replacements were completed by Veridian's internal work crews.

Elexicon plans to continue using the contractors employed by Veridian for underground cable testing and injections – CableQ and Novinium, respectively. Previously, the predecessor utilities collectively tested approximately 22km of underground cable annually. Elexicon plans to increase this testing effort and inject 15km of cable on average annually. Underground rebuilds will be completed by a mix of internal and external employees as Elexicon's internal crews can perform rebuild work related to the electrical system, but require support from contractors for civil construction work. The IR testing and visual inspections for overhead systems are completed by an external contractor. Overhead rebuilds are completed using the same approach as underground rebuilds – internal and external workers complete work related to electrical components and external contractors are engaged for civil construction work. Like-for-like replacements for both overhead and underground systems will be completed by internal resources.

4.3 Scale Increase Considerations

The merger of the two predecessor utilities affords some benefits to Elexicon's planning and operations. These benefits occur as a result of larger contiguous service territory in the Ajax-Whitby-Pickering area. The Rebuilds program is intended to renew assets in poor condition located in proximity to one another. The larger contiguous service territory in the Ajax-Whitby-Pickering area may enable more options for rebuilds in the area – especially, in areas along the border of the Whitby service area. There are also reliability benefits afforded by the merger as there will be more reactive replacement crews in deployment in the Ajax-Whitby-Pickering area. In certain situations, this results in decreased outage restoration times as more crews will be readily available to address outages. Some challenges arise as a result of the merger as well. There is some conflict between Elexicon's strategic decisions and the ongoing work which the predecessor utilities were in the process of completing prior to the merger. For example, Elexicon has decided to reduce the volume of underground rebuilds to be completed over the next five years. These rebuilds must be completed as they are already underway. However, it is expected that these challenges will become irrelevant in the short to mid-term as ongoing projects are completed and future projects can be planned according to Elexicon's strategic goals. On the other hand, the aforementioned benefits for rebuild options and system reliability are expected to remain.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

In the following graphics as shown below, scenarios 0, 1 and 2 represent the base case with the current investment plan, decreasing the current investment plan by 10% and increasing the current investment plan by 10%. These graphics illustrate the total system renewal spending for certain renewal programs, the Health forecast of Assets in 2029 as part of the overall system renewal portfolio and the residual risk produced with these investment options.

Figure 5: System Renewal Spending Forecast until 2029

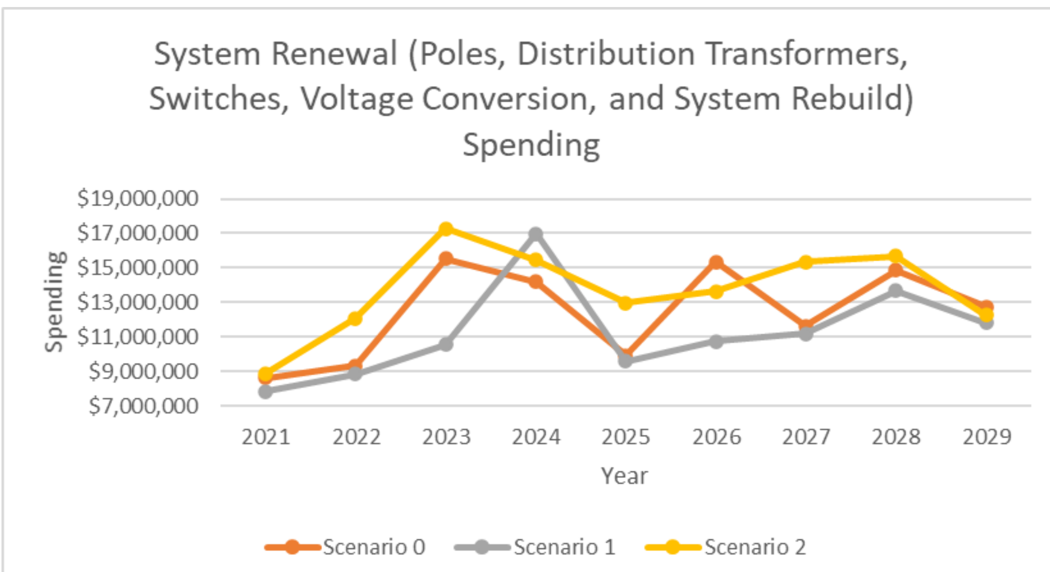


Figure 6: Health Index Forecast until 2029

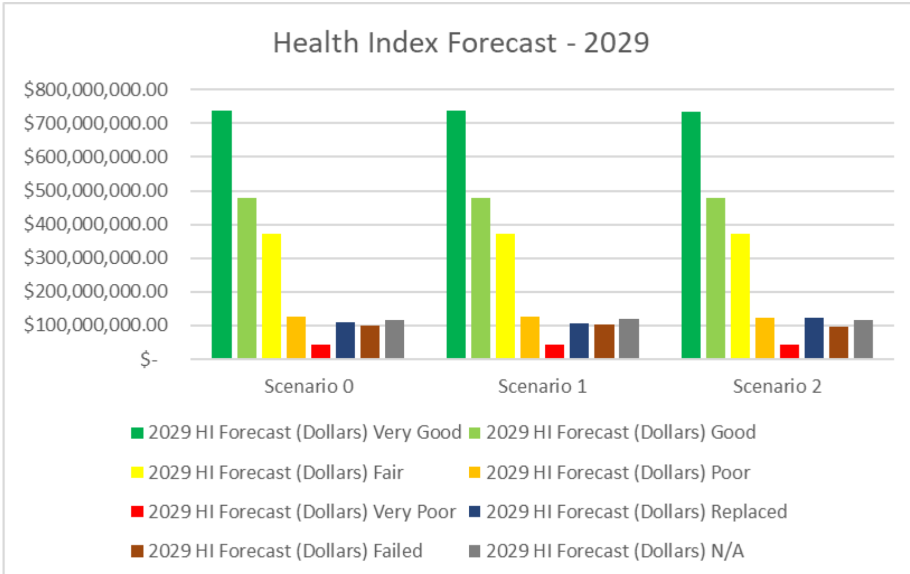
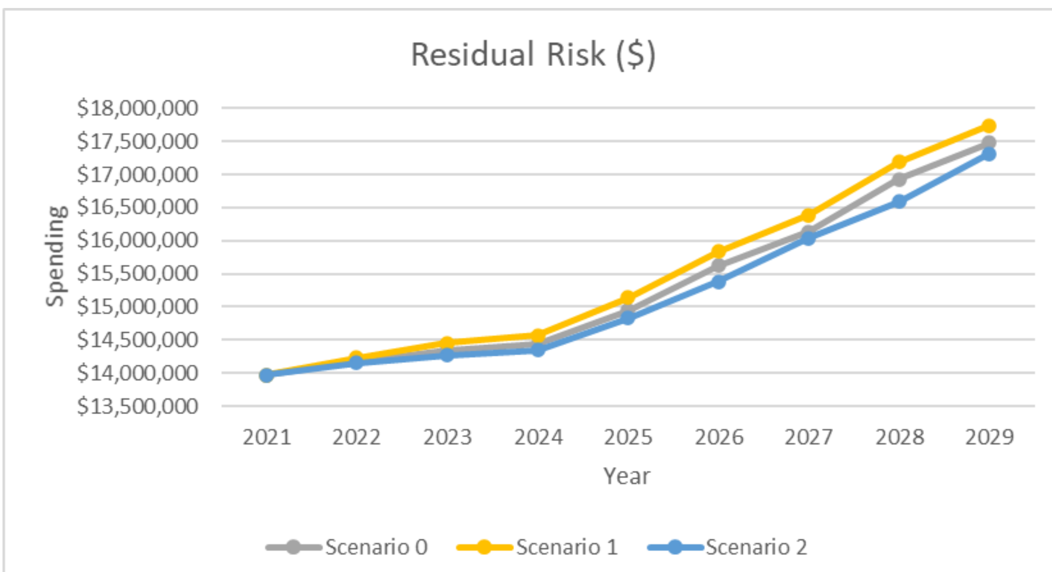


Figure 7: Residual Risk ($) Forecast until 2029



5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2020-5526A	Ashburn Rd (Townline Rd x Brawley) OH Rebuild Ph3	2021	0.40	141.9
2020-5523	Underground Rehab - Pringle Creek (Phase 3 of 3)	2021	2.40	61.6
2021-5511	Primary Cables Renewal-Planned Injection	2021	1.80	30.7

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

<table>
<tr><td>Project name</td><td colspan="5">Ashburn Rd (Townline Rd x Brawley) OH Rebuild Ph3</td></tr>
<tr><td>Project numbers</td><td colspan="5">2020-5526A</td></tr>
<tr><td>Job numbers</td><td colspan="5">WSP200100A</td></tr>
<tr><td>Project District</td><td colspan="5">Whitby</td></tr>
<tr><td>Project Location</td><td colspan="5">Whitby</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM RENEWAL</td></tr>
<tr><td>Budget Category</td><td colspan="5">R2 - Renewal Programs-Rebuilds</td></tr>
<tr><td>Project Driver</td><td colspan="5">Asset condition and new 13.8kV OH loop designed for North of Whitby</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2020 DEC 01</td></tr>
<tr><td>Required In Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Rebuild existing 1PH pole line with new 3-PH 13.8KV line along Ashburn from Townline to Brawley Rd. Phase 3 of the project is from Townline Rd to Brawley Rd.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $400,000</td><td colspan="2">Contribution: $0</td><td>Net: $400,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$36,000</td><td>$40,000</td><td>$68,000</td><td>$256,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon (Legacy Whitby Hydro) have designed new 13.8kV OH to support the customers in North area of Whitby. The Loop includes Ashburn Rd, which have old 1 Phase pole line. Considering the age and condition of the pole line along Ashburn Rd, Elexicon initiated the project to rebuild the pole line on Ashburn Rd.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">141.9</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">The project will improve access/capacity for existing customers and system reliability.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to the project. Elexicon is building new 13.8kV loop for customer located in North part of Whitby to improve system capabilities. The design includes the pole line on Ashburn Rd that have poor condition. In order to have reliable system the pole lines needs to be replaced.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project will reduce the number of trouble call, which will increase system reliability and reduces the emergency repair charges.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The average cost the pole replacement project based on historical projects is $10,000</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

<table>
<tr><th>Project name</th><td colspan="5">Underground Rehab - Pringle Creek (Phase 3 of 3)</td></tr>
<tr><th>Project numbers</th><td colspan="5">2020-5523</td></tr>
<tr><th>Job numbers</th><td colspan="5">WSP190104</td></tr>
<tr><th>Project District</th><td colspan="5">Whitby</td></tr>
<tr><th>Project Location</th><td colspan="5">Pringle Creek Subdivision- East of Pringle Dr and Bradley Dr</td></tr>
<tr><th>Investment Category</th><td colspan="5">System Renewal</td></tr>
<tr><th>Budget Category</th><td colspan="5">R2 - Renewal Programs-Rebuilds</td></tr>
<tr><th>Project Driver</th><td colspan="5">Poor condition of cables and Multiple cable faults
Poor condition of pad mounted transformers</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021 JAN 01</td></tr>
<tr><th>Required In Service Date</th><td colspan="5">2021 DEC 31</td></tr>
<tr><th>Scope of Work</th><td colspan="5">Replace 7.1-kilometre underground primary and secondary cables
Replace 35 pad mounted transformer</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td>Gross: $2,399,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $2,399,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$215,910</td><td>$239,900</td><td>$407,830</td><td>$1,535,360</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">The area experienced multiple cable faults. Considering the age of the cables and pad mount transformers and the consequence of the failure on system reliability, Elexicon initiated the project to address these deficiencies.</td></tr>
<tr><th>Criteria Score</th><td colspan="5">61.6</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">There are 395 customers connected to the distribution system in project area. The project will lower operating and maintenance costs and improve system reliability.</td></tr>
<tr><th>Intervention Options</th><td colspan="5">There is no alternative to projects. Considering the age of the assets and system reliability, the status que is not recommended.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">The project will result in reduction in O&M costs by reducing the number of cable failures and emergency repair costs.</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">This project addresses the RRF objectives of customer focus and Operational Effectiveness.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">Average cost for cable replacement using directional boring: $300 per meter. Cost will go up significantly if trenching is needed.
The Average cost for pad mounted transformer replacement is $5000</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">Not applicable</td></tr>
</table>

Project name	Primary Cables Renewal-Planned Injection				
Project numbers	2021-5511				
Job numbers	Several				
Project District	General				
Project Location	General				
Investment Category	System Renewal				
Budget Category	R2 - Renewal Programs-Rebuilds				
Project Driver	Asset Condition Assessment study and Non-Destructive Cable Testing Results determine the cables segments for cable injection. The geographical area to be tested is selected based on two factors: The number of underground cable faults per kilometer inside the area. The number of customers affected by power outages caused by underground cable faults.				
Proposed Start Date	2021 JAN 01				
Required In Service Date	2021 DEC 31				
Scope of Work	Injection of the cables based on NDT test results, Total length of cables 20km.				
Preliminary Estimate: Total Capital Cost	Gross: $1,800,000	Contribution: $0		Net: $1,800,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$162,000	$180,000	$306,000	$1,152,000
Rationale for Intervention	Elexicon used Asset Condition Assessment Methodology to determine underground cables Health Index. Elexicon has approximately 2,336 km underground primary voltage cables in service. The total useful life of cables is 40 years. Considering the HI of the cables and the Non-Destructive Cable Testing Results, the cable injection plan has been developed which will extend the TUL of the underground cables.				
Criteria Score	30.7				
Impacted Customers and Entities	Not Applicable.				
Intervention Options	Do nothing: This alternative was dismissed as it would not protect nor improve reliability in the project area. Another alternative is to replace cables that is dismissed due to high cost. The cost of cable replacement is 2-3 times more expensive compared to cable injection and far more disruptive to residents in the project area.				
Effect on System O&M Costs	O&M costs are expected to decrease because of the underground rejuvenation project driven by the results of this project. The project will likely reduce the number of cable faults, which will increase system reliability and reduces the emergency repair charges.				
Targeted Outcomes	This project addresses the RRF objectives of customer focus and Operational Effectiveness. The project will improve the system reliability and reduce cable faults and exposure of workers to hazards.				
Cost Benchmarks	Average cost based on historical projects for cable injection project is $73.14 per meter.				
Value-Added Approach	N/A				

Budget Category	Renewal Programs – Poles
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of their Service Life
Secondary Driver(s)	System Reliability

Average Annual Program Spend – Historical	**Average Annual Program Spend – Forecast**
$2.43M	**$2.49M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Pole Renewals Program is intended for proactive replacements of deteriorated wood and concrete poles in Elexicon Energy Inc.'s ("Elexicon") distribution system and related capitalized costs such as pole testing. The need for this work is supported by the 2020 Asset Condition Assessment ("ACA") which shows that there is a notable population of poles that are at risk of deteriorating and catastrophically failing over the next five years. Specifically, this program intends to address poles that are at risk of failing because they have reached the end of their service life. This program does not include pole replacements carried out as part of overhead rebuilds or road relocation work.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	$2.43	$1.57	$1.20	$2.40	$2.20	$2.10	$2.39	$4.64
Contributions	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Expenditures	$2.43	$1.57	$1.20	$2.40	$2.20	$2.10	$2.39	$4.64

The ACA exercise completed by METSCO in 2020 revealed that 21% of the pole population is in the Fair condition category and 4% is in the Poor or Very Poor condition categories. While the Poor/Very Poor category includes a relatively small proportion of the population, Fair condition poles also carry the risk of deteriorating into the Poor/Very Poor categories over the forecast period and negatively affecting system reliability, operational efficiency, and customer experience. This potential risk is supported by the fact that 9,522 wood poles have exceeded the Typical Useful Life ("TUL") threshold of 45 years.

Several pacing alternatives were considered for this program. The preferred alternative provides several benefits related to reliability, operational efficiency and cost-effectiveness, safety, environment, and coordination, and interoperability. The pole replacements will decrease the risk of catastrophic failure associated with deteriorated poles, which decreases the risk of outages, third-party damage, and environmental impacts. In addition, this program will improve the health of the distribution assets, resulting in a system that is more reliable and benefits other organizations with third part attachments connected to Elexicon's distribution assets.

This program also encourages Elexicon to plan merged operations and identify insights. Whitby Hydro and Veridian Connections planned and executed pole replacements separately prior to the merger and this program offers Elexicon an opportunity to consolidate operational activities such as inspections, removals, refurbishments, and replacements. In addition, Elexicon can consider and plan around the advantages of the merger and increase operational efficiency through integrated operations, increased resources, and improved quality of human resources.

2. Basis for Action

<u>2.1 Performance Trends</u>:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

The performance trends discussed in this section are primarily based on the results of the 2020 Asset Condition Assessments ("ACA") completed by METSCO Energy Solutions. Pole testing data is a key input to the ACA exercise and offers some useful insights about the condition of the poles in the system over time. Elexicon engages contractors to complete pole testing and identification of poles that are flagged for short term replacement. Table 2 shows the percentage of poles that are flagged year over year. There is an increasing number of poles that are flagged for the short-term replacement which indicates that the health of the pole population is declining. However, this does not indicate a need for a substantial replacement effort as the percentage of flagged poles is relatively low. A more complete outlook on the health of wood poles is provided by the ACA exercise.

Table 2: Summary of Historical Pole Testing Results

Year	Volume Tested	Volume Flagged	Volume Flagged %
2014	4,250	97	2.3%
2015	4,685	122	2.6%
2016	3,407	89	2.6%
2017	5,918	234	4.0%
2018	1,831	113	6.2%
2019	5,729	285	5.0%

The most recent ACA was completed in 2020 by METSCO and covers two sub-classes of poles: concrete and wood poles. Metal poles also exist in the system, but they were excluded from the ACA because they account for a negligible portion of the pole population and are typically replaced with wood poles upon failure.

The results of the 2020 ACA are summarized in Figure 1. While Whitby concrete pole condition data is available for 2020, it accounts for a small fraction of the concrete pole asset class (20% based on 2020 ACA) and an even smaller fraction of the pole asset class (1.3% based on 2020 ACA).

Figure 1: Wood Pole Condition Demographics - 2020

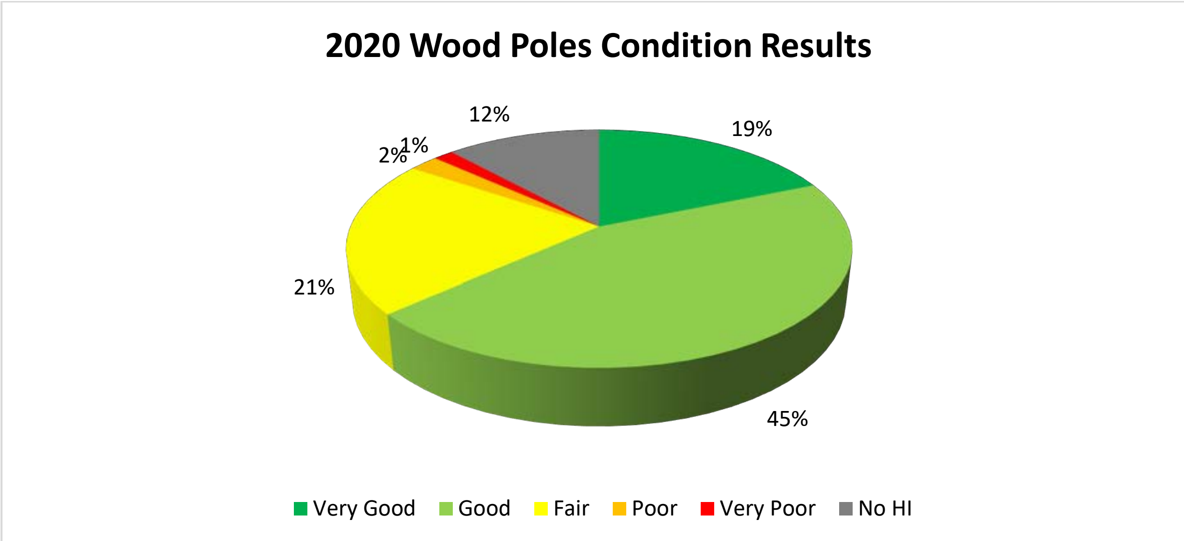


Figure 1 shows that Elexicon's wood pole asset class was in good condition in 2020 as 64% of wood poles were in Good or Very Good condition, 21% were in Fair condition, and only 3% were in Poor or Very Poor Condition. However, there is some risk associated with these results. Given that there is a large population of Fair condition poles, there is a risk that these poles could deteriorate into Poor or Very Poor condition during the forecast period. These fair assets shall be monitored for future degradation. Poles that are currently in Poor and Very Poor condition shall be prioritized for replacement. Please refer to Figure 2 for the asset counts pertaining to the percentage breakdown for wood poles.

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

The current-state analysis primarily looks at the outputs of the ACA exercise completed at the end of 2020. In addition, the age-based analysis is also summarized in order to provide another viewpoint of asset deterioration relative to the TUL. The condition parameters and relative weights used for the ACA are summarized in Table 3 and Table 4 below and discussed in greater detail in Section 4.1 of this business case. Figure 2 and Figure 3 show the results of the ACAs for wood and concrete poles, respectively.

Table 3: Wood Poles ACA Condition Parameters

Condition Parameter	Weight
Service Age	1
Remaining Strength	8
Wood Rot	6
Out of Plumb	2
Overall Condition	7

Table 4: Concrete Poles ACA Condition Parameters

Condition Parameter	Weight
Service Age	3
Overall Condition	8

The results of the wood poles ACA indicate that there are 761 poles in Poor condition and 518 poles in Very Poor condition. This suggests that 1,279 poles are recommended for replacement over the forecast period. It is important to note that there is also a subsection of 1,863 of the 7,199 poles in Fair condition at high risk of deteriorating into Poor or Very Poor condition within the next five years. Extrapolating these numbers across the total population indicates a total replacement of 3,562 poles over the next ten-year period. Elexicon will prioritize the replacement of poor and very poor wood pole assets and any fair assets shall be monitored for further degradation into the future. Figure 4 represents the current age demographics of Elexicon's wood poles. The recommended replacement volumes from the Asset Replacement Plan ("ARP") are presented below in Table 5. The ARP suggests that a total of 1,750 wood poles should be replaced between 2021 and 2025.

Table 5: ARP Wood Poles Replacement Recommendations

Number of Wood Poles Recommended for Replacement						
Year	2021	2022	2023	2024	2025	2026
Wood Poles	350	350	350	350	350	350

The results of the concrete poles asset condition assessment indicate that there are 4 poles in Poor Condition and 1 pole in Very Poor condition within the Whitby region. After extrapolation, this suggests that 10 poles are recommended for replacement over the forecast period within Whitby and a further 120 concrete poles identified in the Veridian region through failure analysis. It is important to note that there are also seven concrete poles in Fair condition which could deteriorate to Poor or Very Poor condition during the next five years. Figure 5 represents the current age demographic of Elexicon's concrete poles. Elexicon plans to complete these replacements over the forecast period but prioritizes wood poles given their relatively large volume. The recommended replacement volumes from the Asset Replacement Plan ("ARP") are presented below in Table 6. The ARP suggests that a total of 70 concrete poles should be replaced between 2021 and 2025.

Table 6: ARP Concrete Poles Replacement Recommendations

Number of Concrete Poles Recommended for Replacement						
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Concrete Poles	14	16	16	12	12	12

Figure 2: Wood Pole Condition Demographics

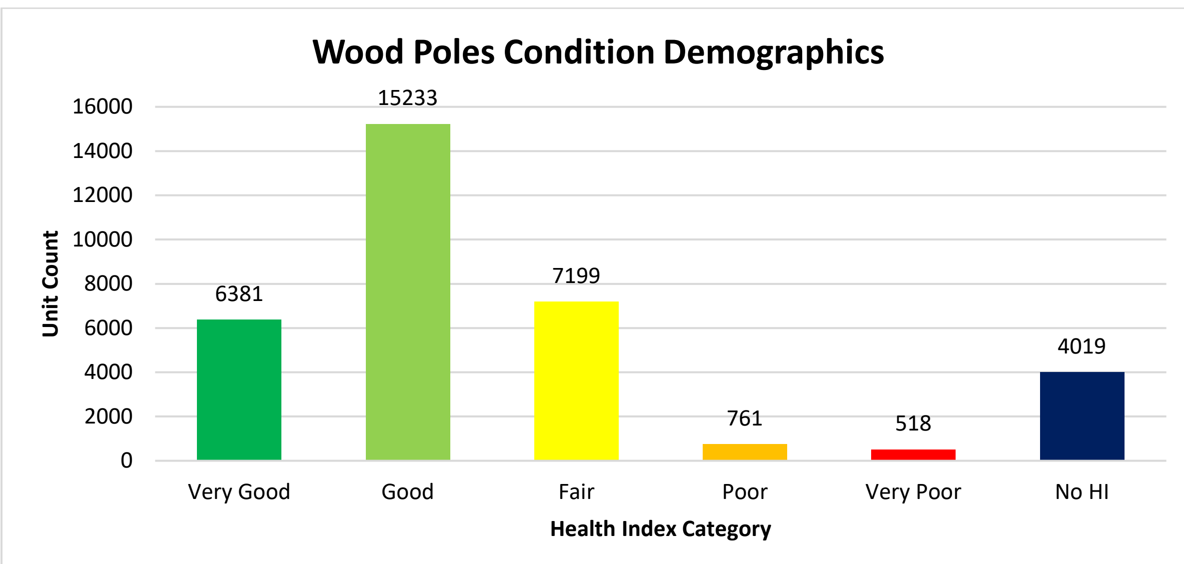


Figure 3: Concrete Pole Condition Demographics

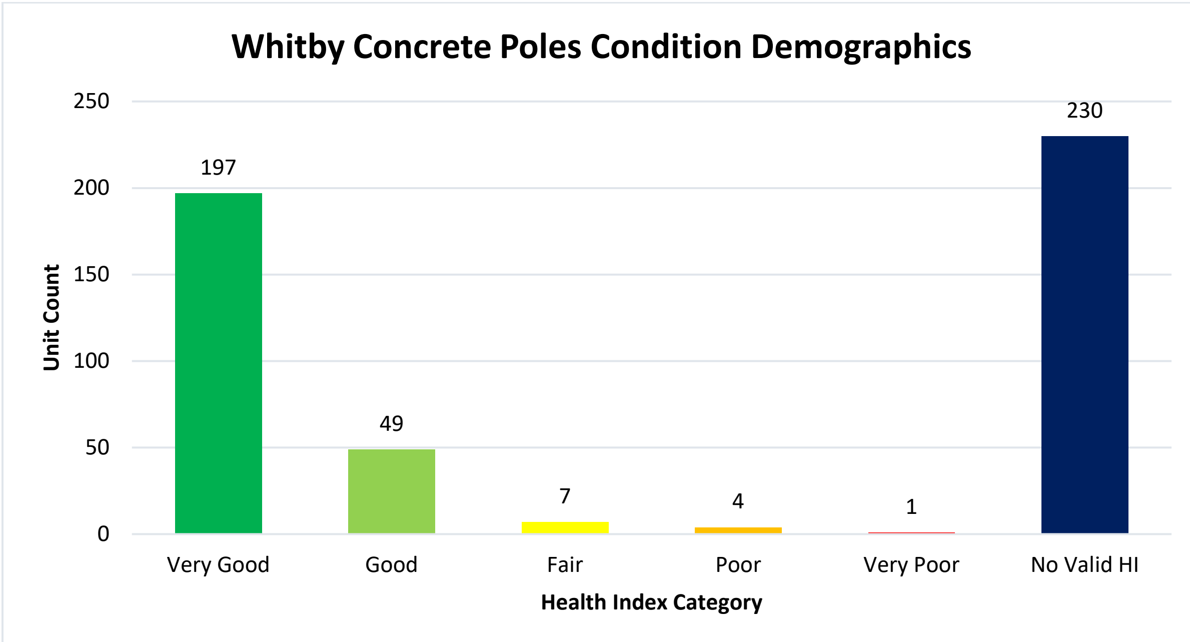


Figure 4: Wood Poles Age Demographics

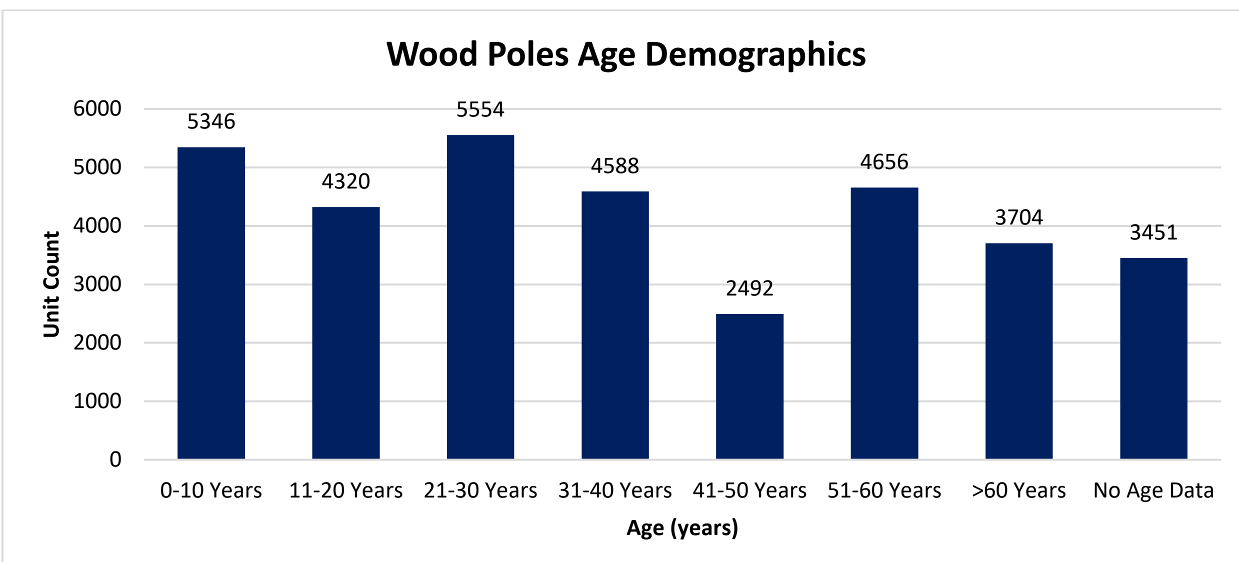


Figure 5: Concrete Poles Age Demographics

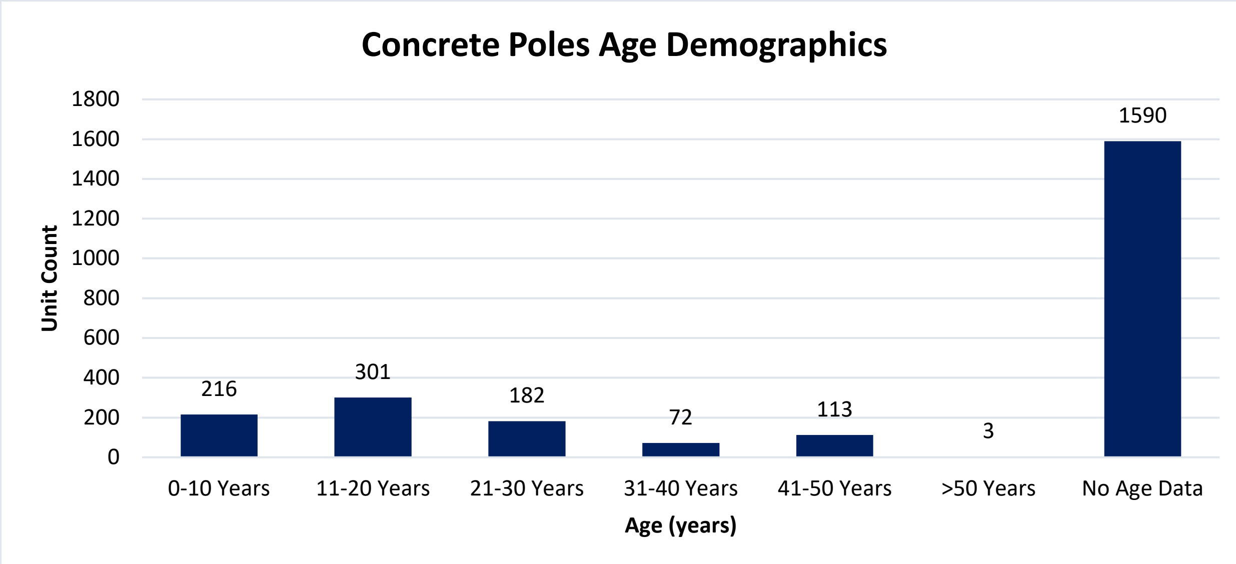


Table 7 below summarizes Elexicon's planned replacement volumes and provides a comparison to the recommendation of the ARP. The total replacement volume suggested by the ARP from 2021 to 2025 is 1,750 and the total planned replacement volume is 2,933. These numbers indicate that Elexicon is planning to surpass the pole replacements recommended by the ACA. The small discrepancy occurs as a result of the available budget for this program and is not expected to pose a significant risk to the system. Wood poles will be used for all replacements as Elexicon plans to phase concrete poles out of its distribution system.

Table 7: Comparison of Recommended and Planned Replacement Volumes

Scenario	2020	2021	2022	2023	2024	2025	2026
Planned Replacements	166	387	403	683	730	730	730
ARP Recommendation	N/A	350	350	350	350	350	350

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

There are several standards and legislative/regulatory requirements which outline and influence utility best practices related to pole asset management. These standards include:

- CSA C22.3
- ISO 55000
- Ontario Regulation 22/04
- Distribution System Code
- Internal Elexicon Standards

CSA Standards

The Canadian Standards Association publishes guidelines for various distribution system assets which detail best practices for the materials, configuration, and strength requirements of poles and related accessories. This standard provides load factors which must be used to determine the vertical, transverse, and angular load-bearing characteristics for the poles in the system. In addition, it specifies the strength requirements of distribution system support assets which must withstand these load requirements. This standard permits the use of guy wires and braces in order to meet the strength requirements. A specific clause within this standard drives some of the pole replacement work planned by Elexicon in clause 8.3.1.3. This clause states the when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced. Elexicon regularly conducts remaining strength tests to ensure that poles that fail to meet this limit are replaced or refurbished.

ISO 55000

ISO 55000 is a series of standards that describe how a company can establish a framework to achieve an optimal balance between managing the use and preservation of assets. It covers various aspects of asset management such as planning, operation, performance evaluation, and information on specific asset management activities. This standard drives Asset Management activities at Elexicon as it aims to adhere to the principles laid out in the ISO55000 series. For example, section 6.1 of ISO 55002 states that the organization should ensure that the asset management system manages risk associated with distribution system assets to an acceptable level. This program supports alignment with this standard as its primary goal is to mitigate the risk associated with the failure of poles.

Ontario Regulation 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure tracked by Elexicon. Elexicon's predecessor utilities have achieved compliance with Ontario Regulation 22/04 for all years in the historical period.

Distribution System Code: System Inspection Requirements and Maintenance

Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with consideration to good utility practice quality, and reliability for short term and long-term basis. Inspection Activities are made following requirements found in the Distribution System Code and where more frequent inspections are required. Where defects are discovered, replacements are made immediately or planned across into the future.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.
-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o The number of customers in each customer class potentially affected by a failure of the assets included in the project
o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)
o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure
-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project

Failure Curve Analysis

The consequences of inaction are assessed in this section in relation to the four OEB Outcome Criteria: Customer Service, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. As discussed in Section 2.2 of this business case, poles in the Poor and Very Poor categories have a high chance of failure and there is a significant population of poles in the Fair category which could deteriorate and require replacement during the forecast period. Poles play a critical role in ensuring that the distribution system functions properly as they physically support other assets such as overhead lines and distribution transformers. If a run to failure approach is adopted over the forecast period, there will be consequences in terms of the four OEB criteria. Expected failure rates for wood and concrete poles have been estimated through the development of failure curves and are presented below in Table 8.

Table 8: Expected Failure Rates

Asset Class	2021	2022	2023	2024	2025
Wood Poles	564	568	572	574	576
Concrete Poles	14	14	15	16	17

Poles reaching the end of their service life typically experience a rapid decline in remaining strength, which is arguably the most important condition parameter for poles as their primary function is to support other assets. This often occurs due to the presence of wood rot or other forms of decay. These poles become vulnerable to catastrophic failure if they experience any significant physical impact. Adverse weather conditions such as snow, wind, and ice storms can also cause deteriorated poles to fail catastrophically as they are already compromised. In turn, this can result in damage to the distribution system assets such as overhead lines and distribution transformers which leads to outages. An increase in outages is expected if no action is taken to address deteriorating poles and this would ultimately result in a negative customer experience.

In addition to the impact that catastrophically failed poles have on system reliability, there is also a negative impact on financial performance and operational efficiency. If poles are not replaced proactively, they will fail and reactive replacements will have to be completed in order to restore service. Reactive replacements are more costly and less efficient than proactive replacements as they require resources to be diverted from other operational activities, hinder the progress of planned work, and are subject to stricter time constraints. Although there are contingencies for reactive replacement work in Elexicon's budget, it is far more efficient to replace poles proactively.

Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of poles that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

When evaluating System Renewal Investment options, Elexicon undergoes analysis of options with regards to its effects on SAIDI and SAIFI by defective equipment and Residual Risk. The effect that an asset class has with regards to SAIDI and SAIFI values due to defective equipment failure is evaluated as the renewal program seeks to improve on these defective equipment metrics through proactive equipment renewal. Residual Risk is the monetized value of the left-over risk on the system after mitigations. It is monetized based on the quantified failure probability and monetized failure impacts (reliability, financial, environmental, and safety impacts).

2.5 Merger-Related Objectives:

There are two merger-related objectives that are relevant to the Poles Renewal Program: service continuity and utility integration. These high-level objectives are disaggregated into several sub-criteria that assess whether or not a program supports Elexicon's primary merger-related objectives. The Poles Renewal Program will help Elexicon achieve both of the aforementioned objectives.

The relevant sub-criteria for the service continuity objective is the relative importance of the program as dictated by the dollar-weighted HI analysis. Programs are evaluated with regards to the investment's effects on the health of assets as defined by unit costs.

The relevant sub-criteria for the utility integration objective involve ensuring that the project is an investment that integrates core operations of the legacy utilities. Pole replacement was considered a core asset management process and was planned and executed separately by the legacy utilities, Whitby Hydro and Veridian Connections. The Pole Renewals program assists Elexicon in meeting the Utility Integration objective as it requires consolidation of the planning and execution of pole replacements which were formerly completed separately.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be
quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	0	1	2
Scenario Description	Current Budgeted Poles Renewal Plan	Investment Pace Increased by 10%	Investment Pace Decreased by 10%
Annual Program Scope	The current replacement plan is described in the business case. Replacement efforts target poor condition assets identified in the ACA.	An increased program budget would allow the utility to renew additional assets.	A decreased program budget would allow the utility to prioritize other needs.
Annual Gross CAPEX	$2.49M	$2.75M	$2.25M
Annual Net CAPEX	$2.49M	$2.75M	$2.25M
Annual Program Benefits	The base values as influenced by Defective Equipment are 0.006 for SAIDI, and 0.013 and SAIFI. Other Investment scenarios (1 and 2) are relative percentages to scenario 0. Residual Risk in Scenario 0 is $1.267M.	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 1 are relative to the scenario 0 investment. SAIFI = -4.945% SAIDI = -2.785% Residual Risk = -5.85%	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 2 are relative to the scenario 0 investment. SAIFI = 6.43% SAIDI = 2.88% Residual Risk = 7.26%
Program Economics	The base scenario involves investing $2.49M annually and results in the residual risk of $1.267M projected by 2029. It is the preferred trade-off of costs and benefits.	By investing 10% more in the poles program, the forecasted residual risk decreases by 5.85%.	By investing 10% less in the poles program, the forecasted residual risk increases by 7.26%.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.		

Other Constraining Factors	The current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

The preferred alternative involves performing pole replacements summarized in Table 9 below. As discussed in the performance trends section, there is a large population of poles in the Fair category which could deteriorate to Poor or Very Poor conditions over the forecast period. Elexicon aims to replace more poles than suggested by the population of Poor/Very Poor poles to offset the potential risk. The benefits of these replacements are discussed below.

Table 9: Planned Replacement Volumes

Wood Poles	2021	2022	2023	2024	2025	2026
Number of Replacements	387	404	683	730	730	730

Reliability: The planned investments will help sustain system reliability as the risk of deteriorated poles failing is reduced by this program. Poles are an integral component of the distribution system which supports other, energized components such as overhead lines and distribution transformers. Deteriorated poles can be easily destroyed/damaged by physical impacts, foreign interference, or weather events and result in outages. The planned investments mitigate this risk by replacing poles in poor condition.

Grid Resiliency: N/A.

Operational Efficiency and Cost Effectiveness: The planned investments will be used for proactive pole replacements. Proactive replacements allow a greater deal of flexibility in the asset replacement process as they are not subject to the same constraints as reactive replacements. Reactive replacements occur after an asset has failed and often require immediate response and the dispatch of reactive replacement crews to restore service. These additional constraints do not apply to proactive replacements and, as a result, these replacements are less costly and allow for more efficient operations.

Safety: Deteriorated poles can pose a significant safety risk to utility representatives and the general public. Pole at end of life (EOL) often fails because their internal strength is insufficient to support other distribution assets or resist external impacts and weather effects. A deteriorating pole in poor condition poses several safety-related risks including:

- Damage to nearby crews and/or customers caused by a failed pole
- Damage to customer, utility, or third party owned property located in proximity to a failed pole
- Fire risk posed by the interaction of energized components supported by the pole and the environment

These risks are mitigated by this program as it targets replacements for poles in poor condition which have a high chance of failure.

Cyber-Security/Privacy: N/A

Environmental Benefits: The primary environmental benefit that occurs as a result of these investments is a decreased risk of environmental damage. Deteriorated poles can fail and caused the energized components they support to interact with the environment. This can result in damage to the environment through impact or fire risk and these investments which address deteriorated poles will minimize this environmental risk.

Coordination/Interoperability: The effectiveness of efforts for coordination/interoperability with other LDCs, transmitters, and other third-party organizations depends on the robustness of the system. These pole replacements will target assets in poor condition and, as a result, decrease failure risk and ensure that interoperability is maintained at an acceptable standard.

Conservation and Demand Management: N/A

Net Customer Benefits: As a result of these investments, customers will experience improved system reliability and increased safety. Deteriorated poles pose risks to reliability as their failure risk increases closer to EOL. These failures can cause outages which will affect customers' access to uninterrupted electrical service and, as a result, customer satisfaction. In addition, failed poles can cause damage to customer-owned property and the environment in which customers interact with. These investments reduce the risk of pole failure and improve system reliability and safety for customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

Elexicon has strategies in place to address unforeseen circumstances that may interfere with its ability to perform the pole replacements outlined in this program. For example, these unforeseen circumstances could include:

- More poles deteriorate/fail unexpectedly (e.g., due to foreign interference, adverse weather, or other factors)
- Additional mandated work is required (e.g., customer connection requests or road relocations)
- Project prioritization decreases the budget available for pole renewals
- Severe deterioration/other issues discovered in a localized area

There are several contingencies available for Elexicon to address these issues. In the event that there are unforeseen circumstances such as adverse weather or foreign interference result in more pole failures than expected, Elexicon will use its Reactive Renewals budget to perform these repairs. The Reactive Renewals program's purpose is to provide funding for reactive renewals that are necessitated by unforeseen circumstances. These types of pole failure/deterioration issues are not expected to derail Elexicon's planned replacements in the Poles Renewals Program.

The requirement for mandated work can increase if the customer population grows faster than expected or if municipal projects requiring road relocations arise. Given that these circumstances involve mandated work, it would be considered a high priority relative to other projects and there is a risk that the budget available to the Poles Renewals program would decrease. In the event that this occurs, Elexicon leverages the results of the prioritization process to redistribute its budget (which may or may not affect this program). In addition, other budgeted programs entail pole replacements and can be used to perform priority replacements (e.g., Overhead Rebuilds program).

Elexicon can review and reprioritize its budgets as necessary, which allows a certain degree of flexibility, but also increases the risk of the budget for this program decreasing. In this case that this occurs, Elexicon has contingencies in place which allow it to continue performing some pole replacements to offset the decreased budget. Unexpected pole failures will be addressed through the reactive renewals program which allows Elexicon to improve the condition of some poles. However, there is a constraint on this program as it is limited to poles that have failed unexpectedly. Another program that allows Elexicon to complete pole replacements is the Rebuilds program which targets replacements of deteriorated assets in geographic clusters.

The aforementioned programs – Overhead Rebuilds and Reactive Renewals – can also assist in addressing the issue of more poles deteriorating than planned for. For example, if a subset of poles is found to be in worse condition than expected, the volume of required pole replacements may increase. These additional pole replacement requirements can be offset by allowing existing poles to run to failure and addressing them through the Reactive Renewals program.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Elexicon's predecessor utilities, Whitby Hydro and Veridian Connections, completed pole replacements proactively. These replacements were prioritized primarily based on ACA exercises which are detailed below and considered inputs such as visual inspection results, wood rot testing, and remaining strength testing. Veridian Connections had a significantly larger population of poles which required an eight-year inspection cycle whereas Whitby Hydro's inspection cycle was three years. Elexicon plans to adopt a three-year inspection cycle moving forward.

The planning process for the Poles Renewal program is primarily based on the results of ACAs, for which Elexicon's predecessor utilities engaged consultation firms. These ACAs were conducted separately for Whitby Hydro and Veridian Connections in 2018 - Veridian engaged Kinectrics and Whitby Hydro engaged METSCO Energy Solutions. These planning processes varied in the factors they considered, the relative weightings of each factor, and the assets assessed. For example, Kinectrics did not assess concrete poles for Veridian in 2018. The condition parameters used by METSCO for the 2020 ACA were previously summarized in Table 4 and Table 5 in the current state analysis.

The current process is similar to the legacy process as it follows the same procedure. A consulting firm is engaged to complete the ACA, which categorizes the assets into one of the five categories mentioned above. Budgets and proactive replacement plans are developed based on these categorizations. A key advantage between the legacy and current planning approaches is that the current approach involves a single consultation firm. This means that the ACAs are conducted using the same factors with the same relative weights and allows for a clearer interpretation of the final results. Elexicon has implemented the current process as the 2020 ACA for all Elexicon assets was conducted by METSCO.

Elexicon also performs risk management for all asset classes, including wood poles, primarily through two methods: the risk management policy and the system risk assessment. The risk management policy outlines the objectives, principles, and processes that Elexicon uses to address risks associated with its system assets. There are two major components to the risk management policy: the risk registry and the risk matrix. The risk registry describes and evaluates risk using a combination of quantitative and qualitative methods. It outlines key information associated with risk management such as the scope of the risk, quantification of the risk level, risk treatment and control, and potential action for improvement. The quantification of the risk level is completed through the risk matrix which uses ACA results as an input to quantify the probability and consequences of failure and to calculate a risk level. The goal of the system risk assessment is to quantify the risk associated with an asset in terms of cost impacts due to reliability, safety, environmental, and financial consequences. This assessment allows Elexicon to plan capital expenditures as it can be used to compare asset replacement costs with the risk costs and determine the optimal replacement point. Detailed procedures associate with the risk management policy and system risk assessment are outlined in the DSP section 5.4a).

In addition to ACA and risk assessment results, other factors were also considered when planning and prioritizing pole replacements. Both predecessor utilities assigned greater priority to the pole that supported critical feeders (e.g., 44kV lines). However, Elexicon does not plan to adopt this practice moving forward because it is implementing a three-year inspection cycle which allows for inspections/testing of all poles in a relatively short period. In addition, the legacy visual inspection practices for both utilities included identifying and prioritizing replacements for poles with a high risk of short-term failure. If a high-risk pole was identified through inspection, it was replaced immediately or within one year (depending on the severity of its condition). This approach will also be adopted by Elexicon moving forward. In addition, predecessor utilities considered performing rebuilds if severe asset deterioration was found in a specific geographic cluster. This approach will also be adopted by Elexicon, but if it chooses to complete rebuilds, they will be budgeted through the Rebuilds program instead of the Poles Renewal program.

4.2 Legacy Work Execution Approaches vs. Combined Operations

There are some differences in the work execution approaches used by the predecessor utilities and by Elexicon. Veridian started to test wood poles in 2012. Testing was conducted on an eight-year cycle, which translated to a testing volume of approximately 4,000 poles per year. The testing was carried out by contractors and included visual inspections, testing for wood rot, and calculation of remaining strength. Veridian prioritized testing by pole age and feeder rating – poles qualified for testing only if they were more than five years old and additional priority was given to poles on feeders rated at 44-kV in terms of both testing and replacement. Veridian did not conduct refurbishment on wood poles. Maintenance was limited to predictive maintenance in the form of the aforementioned wood rot testing and remaining strength testing. Pole replacements were completed by internal work crews. Veridian did not conduct testing on concrete or metal poles as they are being phased out and replaced with wood poles as they reach the end of life.

Whitby Hydro’s wood pole inspections were completed on a three-year cycle as they had a smaller population of poles compared to Veridian. This translated to an annual inspection volume of approximately 2400 poles. Similar to Veridian, predictive maintenance such as wood rot testing and remaining strength testing was carried out by contractors. Testing was only conducted on poles with an age greater than X years and poles supporting 44kV feeders were given additional priority for both testing and replacement. Whitby Hydro did not complete refurbishment for poles. Maintenance was limited to predictive maintenance testing in the form of the aforementioned wood rot testing and remaining strength testing. Pole replacements were completed by internal work crews.

Given that there are several similarities between the legacy work execution approaches, the consolidated approach will remain relatively consistent. Elexicon will continue to use contractors to conduct testing of poles such as visual inspections, wood rot testing, and remaining strength testing. Elexicon plans to switch to a three-year inspection/testing cycle, or approximately 10,000 poles a year based on the available budget. This increase is driven by the fact that Veridian’s pole inspection cycle was incomplete at the time of the merger and Elexicon is increasing testing volume to address these poles. The age threshold for pole testing will be increased to poles that are over 10 years old and 44-kV feeders will no longer be prioritized given the increase in annual testing volume. Like-for-like pole replacements will be conducted by internal work crews. Contractors are only involved in pole replacements if inspection/testing results indicate that rebuilds are an optimal solution. However, these replacements will be completed as part of the Rebuilds program.

4.3 Scale Increase Considerations

The merger of Veridian Connections and Whitby Hydro is beneficial with regard to pole replacements. The primary benefits of the merger include integrated operations, increased availability of resources, additional flexibility, additional purchasing power, and improved quality of human resources. The impact of these benefits is strongest in the Whitby-Pickering-Ajax area as these municipalities are located in close proximity.

The merger allows Elexicon to integrate operations across the predecessor utilities, including shared use of resources and flexibility with certain operations such as reactive replacements and faster response time to outages. In addition, combined resources have other benefits such as increased purchasing power and availability of general plant assets such as fleet, tools, and IT hardware/software. The combined skill sets of former Whitby Hydro and Veridian Connections human resources can also be leveraged to yield more informed and efficient operations.

There are some disadvantages to the merger as well, but they are not significant enough to diminish the aforementioned advantages as they can be resolved over time. These disadvantages include the increased population of pole assets which must be properly managed and the effort required to consolidate operations. While more resources are available to Elexicon, there is some increased difficulty in planning processes as it now has to address a larger service area. Increased efforts will also be required in order to integrate operations as the predecessor utilities have different work standards and procedures in place. The organizational restructuring will also be required as Whitby Hydro and Veridian Connections had different organizational structures, policies, and goals which need to be consolidated. These merger-related disadvantages pose a challenge to Elexicon, but they can be nullified over time whereas the benefits can compound.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

In the following graphics as shown below, scenarios 0, 1 and 2 represent the base case with the current investment plan, decreasing the current investment plan by 10% and increasing the current investment plan by 10%. These graphics illustrate the total system renewal spending for certain renewal programs, the Health forecast of Assets in 2029 as part of the overall system renewal portfolio and the residual risk produced with these investment options.

Figure 6: System Renewal Spending Forecast until 2029

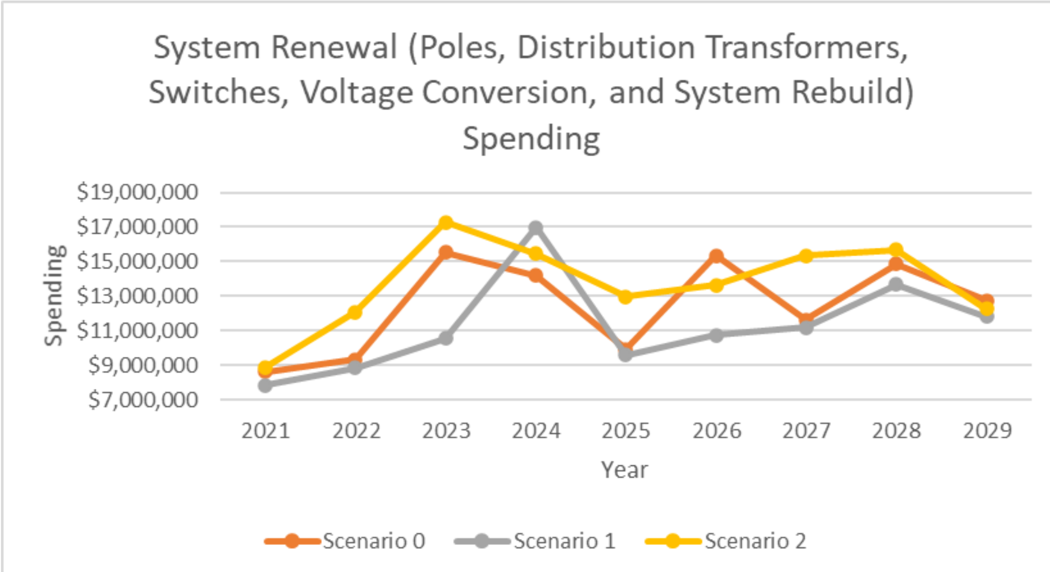


Figure 7: Health Index Forecast until 2029

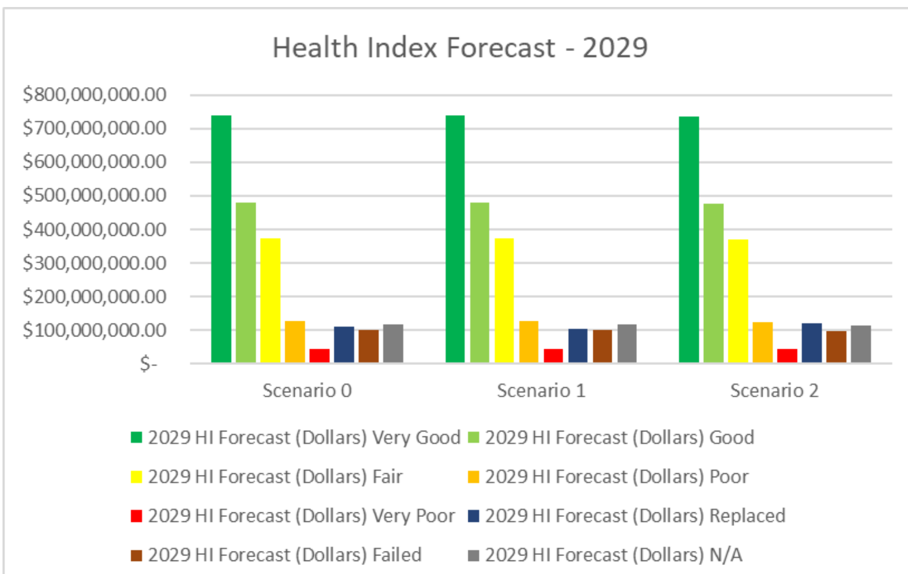
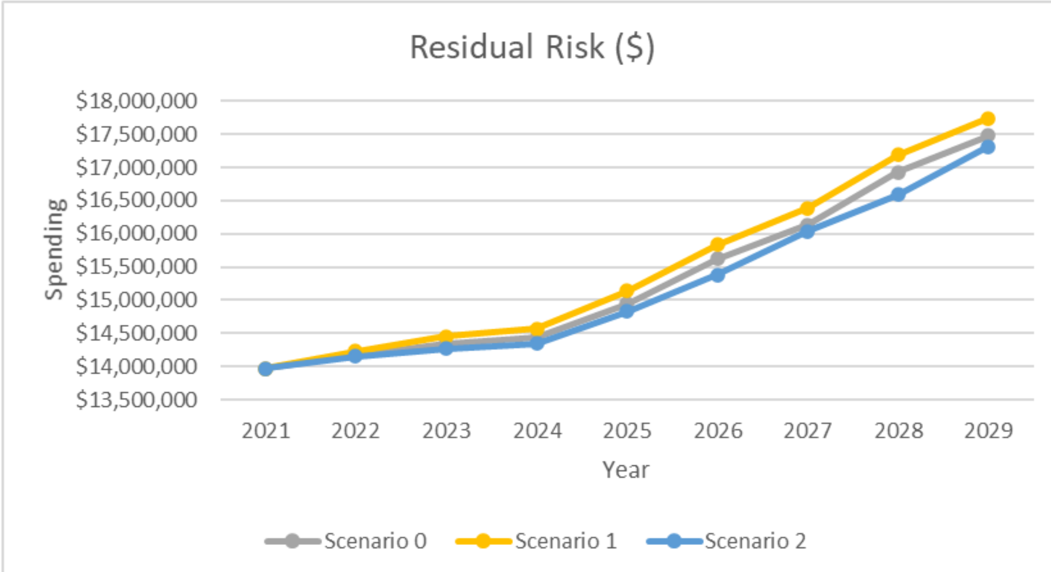


Figure 8: Residual Risk ($) Forecast until 2029



5. Individual Projects Comprising the Program

5.1 Overview of Projects

Budget ID	Budget Name	Year	Net CAPEX ($M)	Priority
2021-5510	Wood Poles Renewal – Planned	2021	$1.2	174

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

<table>
<tr><td>Project name</td><td colspan="5">Wood Poles Renewal-Planned</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-5510</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R3 - Renewal Programs-Poles</td></tr>
<tr><td>Project Driver</td><td colspan="5">Elexicon uses ACA methodology to calculate the HI for wood pole. The health index takes into account any condition information of the assets and pole strength testing results. Based on ACA report, Elexicon has 518 poles in Very Poor condition and 761 poles in Poor. As per Asset Replacement Program, it is recommended that Elexicon address the Very Poor condition poles (518) in year 2021 and the Poor condition poles (761) in years 2022 and 2023.</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Replace 137 wood poles that identified as poor /very poor condition.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $1,200,000</td><td colspan="2">Contribution: <$000></td><td>Net: $1,200,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$108,000</td><td>$120,000</td><td>$204,000</td><td>$768,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Wood poles are the support structure for overhead distribution lines as well as assets such as overhead transformers, switches, and reclosers. Any pole failures will result in risk to public and staff safety and reliability issues.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">174</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not applicable.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">Considering the importance of the wood poles in OH distribution and the consequence of their failure, poles that are in poor/very poor condition required to be replaced. This will ensure public and workers safety and system integrity.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project will reduce the number of trouble call, which will increase system reliability and reduces the emergency repair charges.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The average cost of the pole replacement varies between $8,000 to $20,000 considering the number of circuits and the pole class.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Other overhead assets (i.e., overhead transformers, LIS switches) will be assessed and if required will be replaced along with the wood pole.</td></tr>
</table>

Budget Category	Renewal Programs – Distribution Transformers
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of their Service Life
Secondary Driver(s)	System Reliability, System Performance

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.90M	**$1.58M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Distribution Transformers Renewal Program is a System Renewal program meant to replace aging, deteriorating transformers at Elexicon. The program looks at different types of transformers such as pad-mounted transformers, and pole-mounted transformers. From the 2020 Asset Condition Assessment results for pad-mounted transformers, 428 (3%) of the assets are considered poor, with 69 (1%) of the assets considered very poor. Additionally, 3,881 (29%) pad-mounted transformers are described to be in a fair state. The 2019 Asset Condition Assessment only included pole-mounted transformers operated in the Whitby service area as there wasn't sufficient data to analyze the health of pole-mounted transformers in the Veridian service area. From the Asset Condition Assessment results for pole-mounted transformers, 88 (6%) fall within the poor criteria with 37 (3%) being considered very poor. The ACA also states that 219 (15%) pole-mounted transformers are currently in fair condition. Vault transformers are also evaluated by the ACA but Elexicon does not have any replacement plans for these assets.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.90	0.48	1.08	1.30	1.87	1.74	1.74	1.74
Contributions	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	0.89	0.48	1.08	1.30	1.87	1.74	1.74	1.74

As distribution transformers deteriorate, Elexicon Energy ("Elexicon") will proactively replace these assets to reduce the number of outages and failures that arise from this asset group. Through the years extending from 2015 to 2019, OH Transformers suffered a total of 111 outages resulting in exactly 4,583 Customer Hours Interrupted. The UG Transformers have suffered 94 failures from 2015 to 2019 resulting in a total of 7,374 Customer Hours Interrupted. From 2018 to 2019, both UG OH transformer outages have decreased in terms of the total number of Customer Hours Interrupted. Elexicon will proceed with investing to reduce the impact of failed transformers on customers. Poor and very poor transformers are prioritized for replacement.

Due to the consolidation of the former utilities, the combination of personnel from the two utilities will allow for opportunities to consolidate resources in asset renewal projects. A combined inspection procedure for Distribution Transformers with practices considered from both former utilities will be prepared. The increase in assets to be accounted for will require further analysis and prioritization.

The Distribution Transformer replacements and renewals program target the poor and very poor conditioned assets in the system. These assets are prone to causing significant failures. Elexicon has an obligation and commitment to providing excellent customer service and electrical reliability. If the assets in "poor" condition are not addressed at the earliest, the SAIDI and SAIFI measures will increase thereby reflecting poorly for the utility's overall performance. In addition, it is more cost-effective for Elexicon to be proactive when replacing assets. Increased labor and the resulting reactive scenarios are costlier in comparison to planned replacements. These replacements ensure customers are adequately serviced by adequately operating equipment.

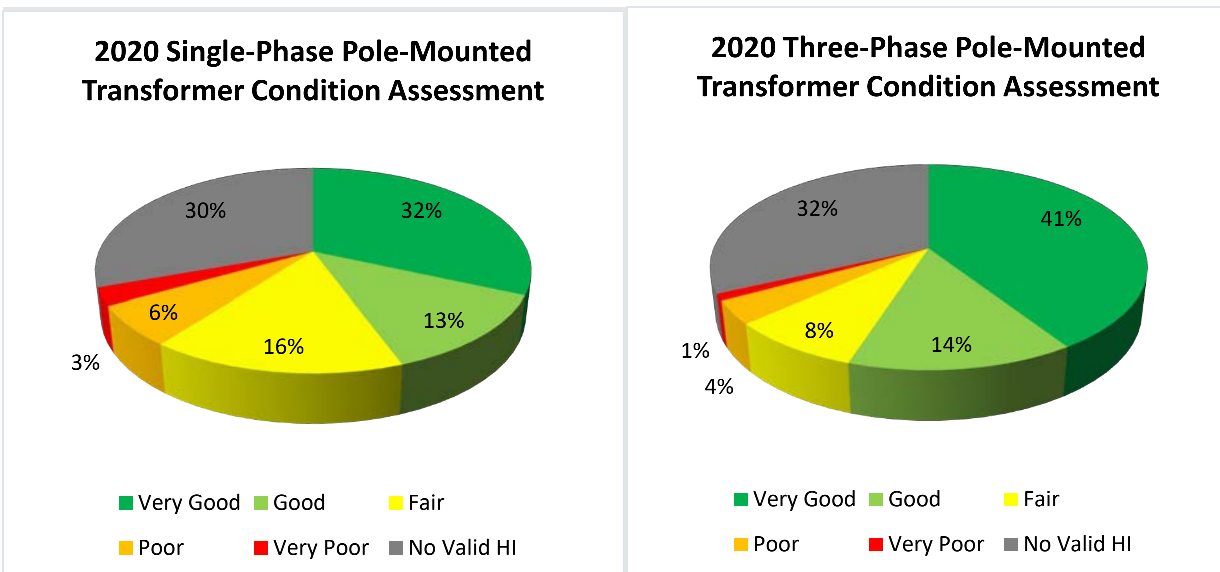
2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

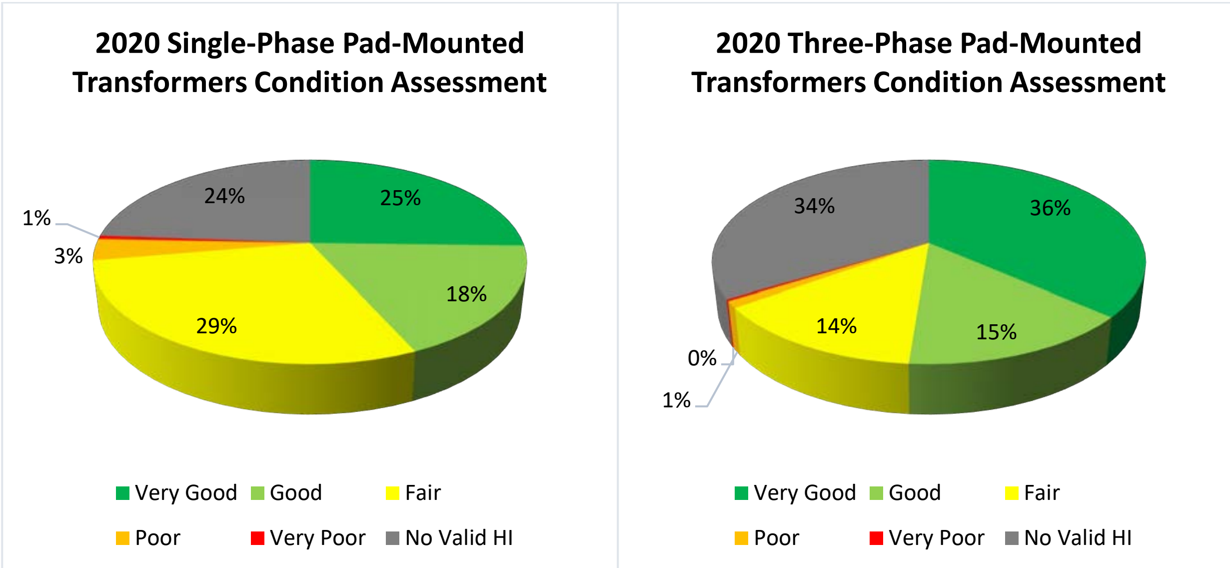
In 2020, METSCO performed an Asset Condition Assessment for Elexicon, after the merger of Whitby and Veridian. The analysis was carried out separating single-phase and three-phase transformers for the pole- and pad-mounted categories. Figure 1 and Figure 2 show the distribution of the assessments' results for pole-mounted and pad-mounted transformers, respectively.

Figure 1: Pole-mounted Transformers Condition Demographics 2020



When assessing the condition demographics of pole-mounted transformers, the assessments show that the level of pole-mounted transformers whose condition is categorized as being poor or very poor is roughly 9% of the population. Poor and Very Poor Pole-mounted transformers will be prioritized for replacement. Fair conditioned pole-mounted transformers will be monitored for degradation across the DSP period. Please refer to Figure 3 and Table 5 for an asset count breakdown of pole-mounted transformers at Elexicon.

Figure 2: Pad-mounted Transformers Condition Demographics



When assessing the condition demographics of the pad-mounted transformers, the assessments indicate that there is a small population of pad-mounted transformers in poor or very poor condition. Fair conditioned pad-mounted transformers are the second largest in quantity. Poor and very poor pad-mounted transformers will be prioritized to be replaced. Pad-mounted transformers within the "fair" category close to the "poor" category will be monitored and replaced where needed. Please refer to Figure 4 and Table 6 for an asset count breakdown of pad-mounted transformers at Elexicon.

Table 2 and Table 3 show the outage statistics of OH transformers and UG transformers, respectively, from 2015 to 2019. Table 4 shows that there has been an increase in the number of outages caused by pole-mounted transformers in recent years, due to an increase in the number of pole-mounted transformers that are in a poor or very poor condition. However, customers interrupted by OH transformers were significantly less in 2019 than in the prior years. Additionally, 2017 had significantly less customer hours and customers interrupted than other years.

Table 2: Outage statistics of OH transformers during 2015-2019

Statistic	2015	2016	2017	2018	2019
Outages	27	16	14	26	28
Customers Interrupted	739	503	74	2,849	237
Customer Hours Interrupted	1,227	1,640	212	818	686

Table 3 shows that there has been a reduction in the number of outages caused by UG transformers in 2019, and in turn, a reduction in customers interrupted and customer hours interrupted. In 2018, Elexicon peaked with respect to the number of customers interrupted and customer hours interrupted. The starting and ending years of 2015 and 2019 had the lowest amount of underground transformer outages alongside customer hours interrupted.

Table 3: Outage statistics of UG transformers during 2015-2019

Statistic	2015	2016	2017	2018	2019
Outages	12	21	19	30	12
Customers Interrupted	332	493	447	1,379	433
Customer Hours Interrupted	534	1,050	1,501	3,674	615

2.2 Current-State Analysis:

In the Distribution Transformers Replacement Program, Elexicon has 4 annual replacement programs planned. Pad-mounted Transformer and Pole mounted Transformer replacement projects are produced from the results of the Asset Condition Assessment and ARP. The annual 27.6KV pad mount transformer project is adopted from Elexicon's new switching policies. Pole Trans replacements were initiated by the planning department at Elexicon.

Table 4: Distribution Transformer Renewal Annual Projects

Project Name	Years
27.6-kV Pad-mounted Transformers-Renewal-Planned	2021-2026
Pad-mounted Transformers-Renewal-Planned	2020-2026
Pole Trans Replacement	2020-2026
Pole mounted Transformers Renewal Planned	2020-2026

The current state and condition of distribution transformer assets are provided in the following pages. Through the assessment, an Asset Replacement Plan was formulated using a combination of the current condition of the assets and the age of the assets in relation to the typical useful life. The Asset Condition Assessment evaluated assets based on condition parameters related to the assets, with each condition parameter given a weight based on its importance relative to the other parameters. The condition parameters and their respective weights were then used to calculate a health index for each asset. Table 5 and Table 6 summarize the quantities of transformers in each condition category.

Pole-mount Transformers Asset Condition 2020

The 2020 Asset Condition Assessment results for pole-mounted transformers are shown below. Due to a lack of condition data on Veridian pole-mounted transformers, the 2020 ACA only includes Whitby pole-mounted transformers. The results from the assessment show that 125 of the 1,465 pole-mounted transformers classify as poor or very poor. These transformers are suggested to be replaced in the present time as they are at high risk of failure. Furthermore, 219 pole-mounted transformers were categorized as Fair. The transformers that are categorized as fair are expected to degrade in condition in future years. Fair Assets shall be monitored in case further degradation moves the asset to a poor or very poor condition.

Figure 3: Unit count per condition category for Pole-mounted Transformers

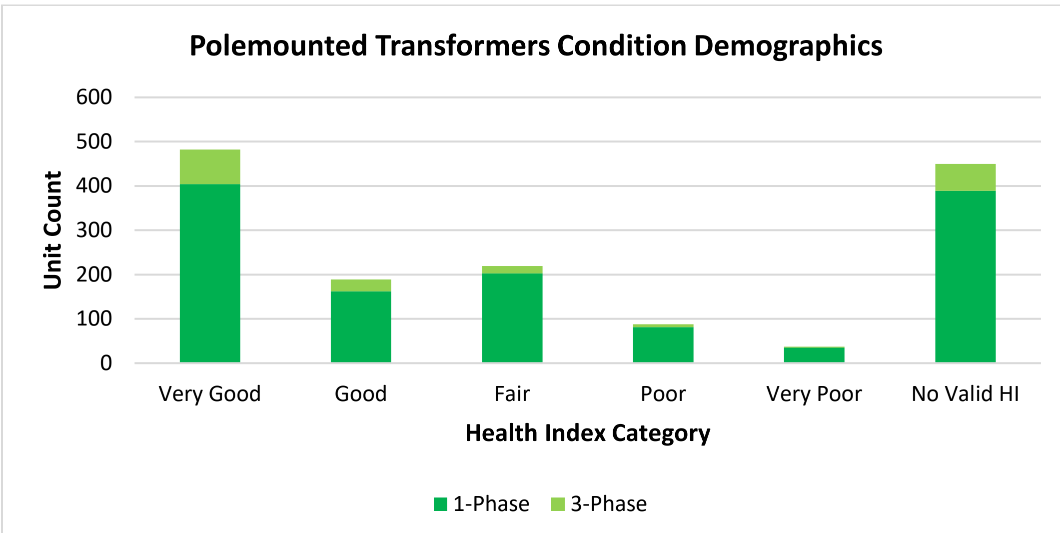


Table 5: Pole-mount Transformer Asset Count by Condition

Asset Type	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
1-Phase	404	162	203	81	35	389
3-Phase	78	27	16	7	2	61
Total	482	189	219	88	37	450
%	33%	13%	15%	6%	3%	31%

Pad-mounted Transformers Asset Condition 2020

The 2020 Asset Condition Assessment shows that 497 out of 13,599 pad-mounted transformers ranked as either poor or very poor. Furthermore, 3,881 pad-mounted transformers were ranked as fair. Fair Assets shall be monitored in case further degradation moves the asset to a poor or very poor condition.

Figure 4: Unit count per condition category for pad-mounted transformers

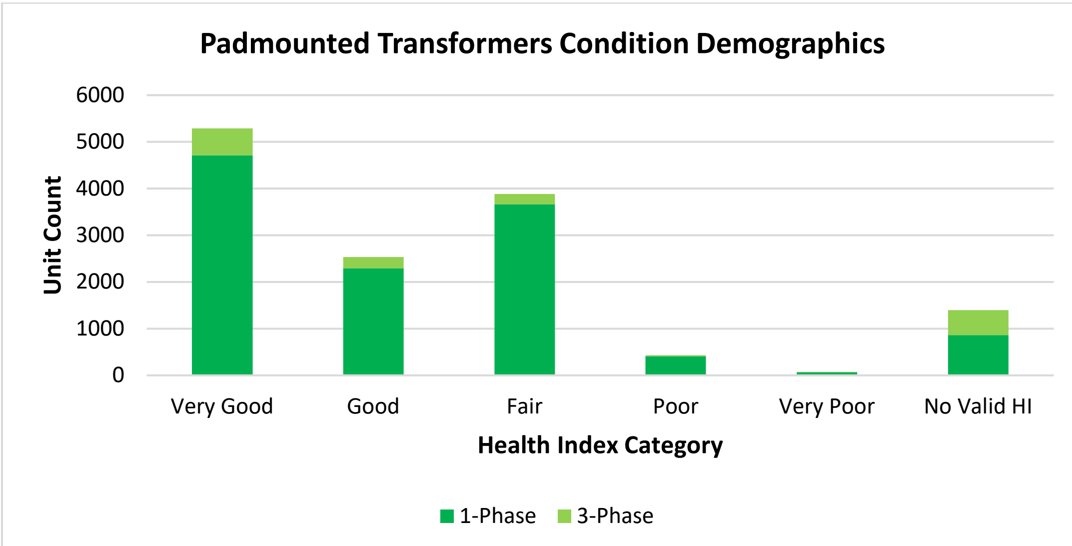


Table 6: Pad-mounted Transformer Asset Count by Condition

Asset Type	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
1-Phase	4,712	2,297	3,662	411	65	865
3-Phase	579	234	219	17	4	534
Total	5,291	2,531	3,881	428	69	1,399
%	39%	19%	29%	3%	1%	10%

Vault Transformers Asset Condition 2020

For Vault Transformers, 86% of the assets in the field are in the very good category. There are no assets currently in the poor and very poor category. Any Vault Transformers found in fair condition will be monitored for degradation to assess if its condition worsens in future years. There are no planned investments currently for Vault Transformers.

Figure 5: Unit count per condition category for vault transformers

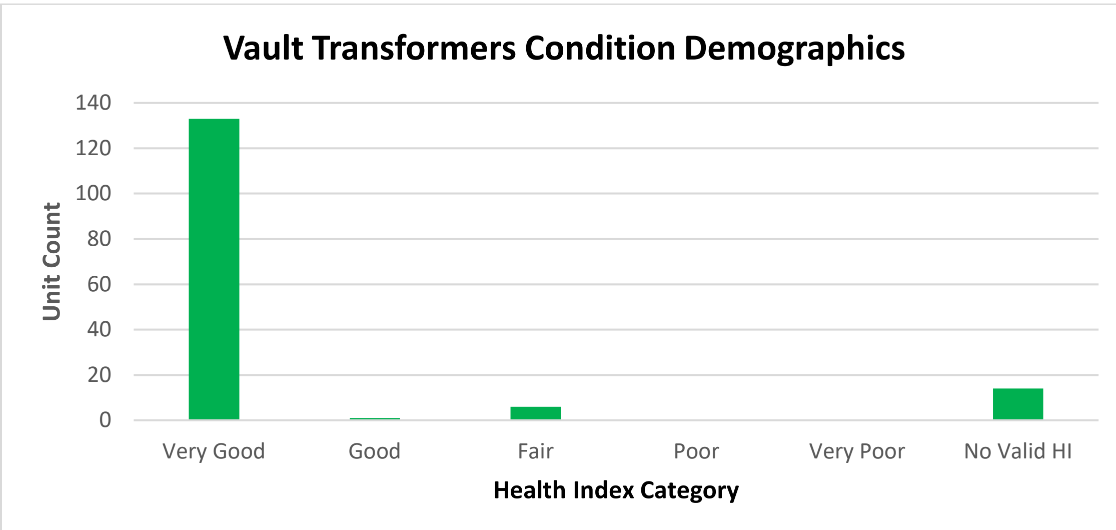


Table 7: Vault Transformer Asset Count by Condition

Asset	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Vault Transformer Veridian	133	1	6	0	0	14
%	86%	1%	4%	0%	0%	9%

Asset Replacement Plan

The Asset Replacement Plan considers assets that need to be replaced in the present time as well as assets with conditions that are expected to worsen. Table 8, Table 9, and Table 10 show the recommended replacement schedule for 2021 to 2025 presented by the Asset Replacement Plan.

Table 8: Recommended Pole-mounted Transformers Replacement by year from the ARP

Number of Pole Mounted Transformers Recommended for Replacement						
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Pole-Mounted Transformers: Single-Phase (#)	140	160	180	200	200	200
Pole-Mounted Transformers: Three-Phase (#)	20	20	20	20	20	20

Table 9: Recommended Pad-mounted Transformers replacement by year from the ARP

Number of Pad-Mounted Transformers Recommended for Replacement						
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Pad-Mounted Transformers (#)	200	240	280	300	300	300

Table 10: Recommended Vault Transformers replacement by year from the ARP

Number of Vault Transformers Recommended for Replacement						
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Vault Transformers (#)	0	0	0	0	0	0

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

CSA Standards

The Canadian Standards Association (CSA) is a standards organization that provides standards for many different areas and sectors. One of CSA's standards is its electrical standards, which look to improve the safety and reliability of the electrical system.

CSA 22.3 No. 1 Overhead Systems

CSA 22.3 No.1 is a standard that applies to electric supply, communication lines, and equipment placed outside of buildings and fenced supply stations. The standard includes clause 5.3.2.1, which states that there is a minimum vertical separation between pole-mounted transformers and the ground that depends on the location and voltage of the transformer. The standard also includes clause A.5.10.1, which states that there is a minimum vertical separation between supply and communication attachments on a joint-use pole, such as having a pole-mounted transformer. The minimum vertical separation depends on the voltage of the supply conductors. A key driver of this program would be having to comply with these standards if the equipment doesn't currently meet the clauses.

CSA 22.3 No. 7 Underground Systems

CSA 22.3 No. 7 is a standard that applies to the lines and equipment related to underground electric supply and communication systems placed outside of buildings and fenced supply chains. Section 10 of the standard includes clauses related to above-ground equipment, such as pad-mounted transformers. Clause 10.1 states that live parts must be inaccessible. Live parts of pad-mounted transformers being accessible makes it prone to rust, which would then require the transformer to be replaced or treated. Clause 10.2 states that there must be adequate working space around the pad-mounted transformer. Clause 10.6, which is broken down into 2 sub-clauses, states that the pad-mounted transformer must be designed to withstand a seismic event equal to the values given by the National Building Code.

ISO 55000

The International Organization for Standardization (ISO) is an international standard-setting body that promotes worldwide proprietary, industrial, and commercial standards. The ISO 55000 series provides an overview of asset management and asset management systems and identifies common practices that can be applied to a broad range of assets. This standard drives Elexicon's asset management strategy as Elexicon adheres to the principles laid out in the ISO 55000 series. For example, section 6.1 of ISO 55002 covers actions to address risks and opportunities for the asset management system by planning to take action to mitigate the current and future risks as well as how to implement these actions and evaluate their effectiveness.

Ontario Regulation 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure tracked by Elexicon. Elexicon's predecessor utilities have achieved compliance with Ontario Regulation 22/04 for all years in the historical period. Equipment that is overhead and underground needs to be in proper operating condition as defined in O'Reg 22/04. Asset renewal programs such as these ensure that equipment on the grid aligns with the regulation.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.
-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o The number of customers in each customer class potentially affected by a failure of the assets included in the project
o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)
o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure
-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project

An age-based failure curve analysis was conducted using Weibull Distribution. The parameters of the distribution were found using a typical useful life of 40 years for distribution transformers. The analysis yielded the expected number of distribution transformers that will fail over the next five years. Since there is missing information for some of the asset classes, the expected number of failures also includes extrapolated data in which the ratio of failed transformers to the total number of transformers with unknown data matches the ratio of failed transformers to the total number of transformers with known data. Table 11 shows the expected number of failed pole-mounted and pad-mounted transformers during 2020-2025.

Table 11: Expected number of distribution transformer failure

Asset Class	Total Population	Unknown Age	2021	2022	2023	2024	2025
Pole-mounted TX	8,751	4,125	136	139	141	143	145
Pad-mounted TX	13,599	803	243	253	262	272	281

It can be seen from the above table that a significant number of transformers will experience a failure during the next 5 years. Almost 10% of pole-mounted transformers and 10% pad-mounted transformers is expected to experience a failure during 2020-2025. This underlines the need to have a transformer replacement program to avoid the imminent outages that would occur.

Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of distribution transformers that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

When evaluating System Renewal Investment options, Elexicon undergoes analysis of options with regards to its effects on SAIDI and SAIFI by defective equipment and Residual Risk. The effect that an asset class has with regards to SAIDI and SAIFI values due to defective equipment failure is evaluated as the renewal program seeks to improve on these defective equipment metrics through proactive equipment renewal. Residual Risk is the monetized value of the left-over risk on the system after mitigations. It is monetized based on the quantified failure probability and monetized failure impacts (reliability, financial, environmental, and safety impacts).

2.5 Merger-Related Objectives:

Elexicon's merger-related objectives can be grouped into service continuity and utility integration. These objectives can be further broken down into sub-criteria which are used to check if a program is in line with Elexicon's primary merger-related objectives.

One criterion for the service continuity objective is the relative importance of the program as dictated by the dollar-weighted HI analysis. Programs are evaluated with regards to the investment's effects on the health of assets as defined by unit costs.

A sub-criteria of utility integration relevant to the distribution transformers renewal program is that the program aims to integrate core operations of the legacy utilities. The legacy utilities replaced distribution transformers separately, each with their specific approach. The program looks to consolidate these approaches to a single-core operation.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	***0***	***1***	***2***
Scenario Description	Using the allocated budget for this program	An increase in the allocated budget to this program by 10%	A decrease in the allocated budget to this program by 10%
Annual Program Scope	The current replacement plan is described in the business case. Replacement efforts target poor condition assets identified in the ACA.	An increased program budget would allow the utility to renew additional assets.	A decreased program budget would allow the utility to prioritize other needs.
Annual Gross CAPEX ($M)	$1.58M	$1.74M	$1.42M
Annual Net CAPEX ($M)	$1.58M	$1.74M	$1.42M
Annual Program Benefits	The base values as influenced by Defective Equipment are 0.003 for SAIDI, and 0.008 and SAIFI. Other Investment scenarios (1 and 2) are relative percentages to scenario 0. Residual Risk in Scenario 0 is $3.168M.	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 1 are relative to the scenario 0 investment. SAIFI = -1.43% SAIDI = -1.47% Residual Risk = -1.48%	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 2 are relative to the scenario 0 investment. SAIFI = 0.95% SAIDI = 1.08% Residual Risk = 1.32%
Program Economics	The base scenario involves investing $1.58M annually and results in the residual risk of $3.168M projected by 2029. It is the preferred trade-off of costs and benefits.	By investing 10% more in the distribution transformers program, the forecasted residual risk decreases by 1.48%.	By investing 10% less in the distribution transformers program, the forecasted residual risk increases by 1.32%.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.		

Other Constraining Factors	The current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.
Preferred Alternative	X		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: The program for replacing distribution transformers helps improve the reliability of Elexicon's service and minimizes the probability of failure. As time passes, the condition of the assets deteriorates, and the portion of assets that are deemed failed or damaged increases, thereby resulting in the necessity of replacing them to maintain reliable services.

Grid Resiliency: N/A

Operational Efficiency and Cost Effectiveness: When adding or replacing a distribution transformer, Elexicon makes sure that the asset itself as well as the method of the installation follow its internal standards. The correct choice of the transformer along with the appropriate setup would increase the reliability level of the service, leaving the asset at risk of technical faults only due to deterioration or external factors. Replacing overloaded transformers with new transformers with the appropriate capacity can lead to fewer interruptions since we are minimizing the number of transformers operating in extreme overloading conditions,

Safety: The replacement of distribution transformers is done by following the standards set internally by Elexicon as well as Ontario Regulation 22/04 to ensure minimal risk when carrying out the work.

Cyber-Security/Privacy: N/A

Environmental Benefits: Damaged or failed transformers are at risk of leaking oil, which can have a negative impact on the environment. The impact can be reduced by replacing damaged or failed transformers to marginalize the chance of spillage.

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Customers benefit from Elexicon's replacement of distribution transformers because it minimizes the risk of failure of aging assets that could lead to outages.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

To consider possible changes in the future, Elexicon takes into account several considerations. An expected number of failures for each asset class is predicted and an asset condition assessment is performed to have an overview of how the system may evolve over the next few years. Additionally, Elexicon also predicts an increase in the number of connections to accordingly plan for which areas would require their services expanded. With all the collected information, a prioritization framework will be put into effect to prioritize scopes in accordance with the current status quo and how the system would look like in the next couple of years.

However, in the need for more resources, an assessment of the availability of budget from other renewal programs could provide further funding to this program. Elexicon will balance and adjust the approved budgets to the changing scenario of increased deterioration of Distribution Transformers. However, Elexicon considers distribution transformers as the lowest priority in replacement due to the number of transformers connected to distribution transformers being the lowest. OH Conductors, UG Cables, Switchgears and poles in comparison serve much more customers.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

The legacy utilities of Elexicon (i.e., Whitby Hydro and Veridian Connection) had their asset management approach rely heavily on the results of the Asset Condition Assessments. In 2018, the two legacy utilities approached consultant firms to perform the Asset Condition Assessment. Whitby Hydro approached METSCO whereas Veridian Connections approached Kinectrics for their services to carry out the assessments. After the merger in 2019, METSCO conducted an asset condition assessment for Elexicon's assets. All assessments evaluated assets based on condition parameters that were ultimately weighted based on their significance. The condition parameters were used to calculate the overall health index of an asset, which decides which condition category the asset is in. Table 12 and Table 13 show the condition parameters used for the assessment done on pole-mounted transformers and pad-mounted transformers, respectively.

Table 12: Pole-mount Transformer's condition parameters

Pole-mount Transformers	
Elexicon	
Condition Parameter	Weight
Service Age	3
Overall Condition	4

Table 13: Pad-mount Transformer's condition parameters

Pad-mount Transformers	
Elexicon	
Condition Parameter	Weight
Service Age	3
Overall Condition	4

4.2 Legacy Work Execution Approaches vs. Combined Operations

Pole-mounted Transformers

To inspect pole-mounted transformers, Elexicon performs infrared scans annually as well as to conduct visual inspections on a three-year cycle. Maintenance work is done based on the results of the mentioned inspection methods. Pole-mount transformers are currently being proactively replaced. Previously, Veridian also conducted infrared scans and visual inspections annually as inspection practices for pole-mounted transformers, and maintenance was completed based on infrared scans. Veridian operated pole-mount transformers until they failure. In 2018, Veridian began to consider transformer loading as a criterion for replacement. Whitby also conducted inspections on pole-mount transformers through infrared scans and visual inspections, and their maintenance work was based on the results of the inspection.

Pad-mounted Transformers

Elexicon performs visual inspections based on three-year cycles for pad-mount transformers. Currently, Elexicon re-paints rusted transformers based on customer requests for maintenance work, which is to be gradually transitioned to a reactive approach based on inspection results. Previously, Veridian inspected pad-mount transformers visually on a three-year cycle. Maintenance on these units were driven by customer requested where the transformer would be repainted. Veridian ran pad-mount transformers to failure until 2018. In 2018, Veridian began to consider the loading of the transformer as a factor for replacement. Whitby also conducted inspections visually based on three-year cycles, with maintenance work comprising of re-painting rusted transformers. Whitby ran transformers until failure unless inspections signaled a need for a replacement.

Vault Transformers

Elexicon inspects vault transformers every three years and does not perform maintenance work on the asset. Comparatively, Veridian inspected vault transformers visually based on a three-year cycle, with no maintenance work or replacement program being put into place. Whitby did not have programs for vault transformers that covered either inspection, maintenance, or replacements.

4.3 Scale Increase Considerations

An increase in service territory prompts an increase in the inventory of distribution transformers owned by Elexicon. Coordination of work in the Whitby, Ajax, and Pickering service areas can become more efficient. Further inspections will be required with a consolidation of both legacy approaches. The increase in workforce and skill will also benefit Elexicon in the long run for addressing renewal programs targeting Distribution Transformers.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

In the following graphics as shown below, scenarios 0, 1 and 2 represent the base case with the current investment plan, decreasing the current investment plan by 10% and increasing the current investment plan by 10%. These graphics illustrate the total system renewal spending for certain renewal programs, the Health forecast of Assets in 2029 as part of the overall system renewal portfolio and the residual risk produced with these investment options.

Figure 6: System Renewal Spending Forecast until 2029

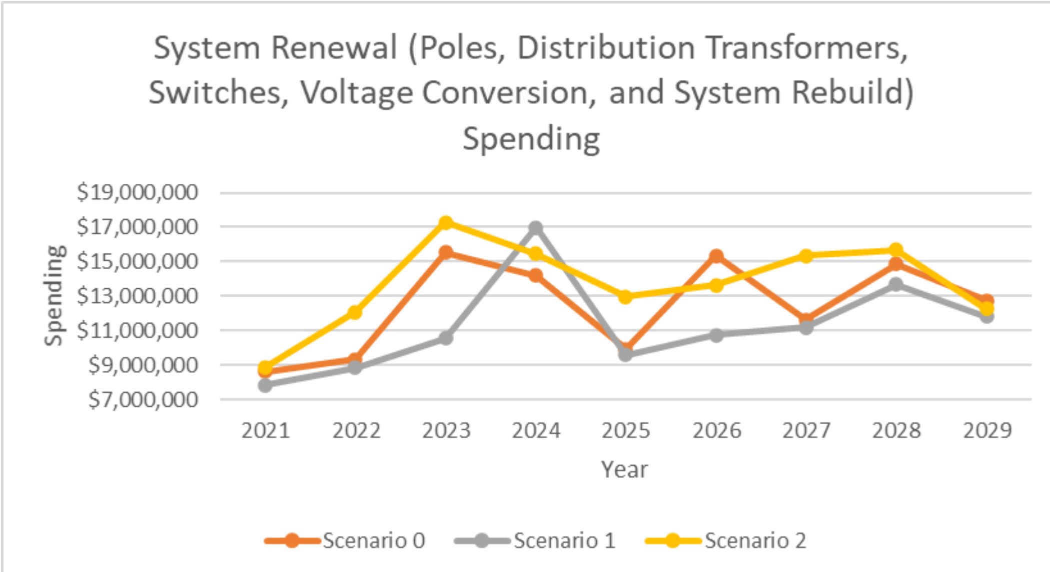


Figure 7: Health Index Forecast until 2029

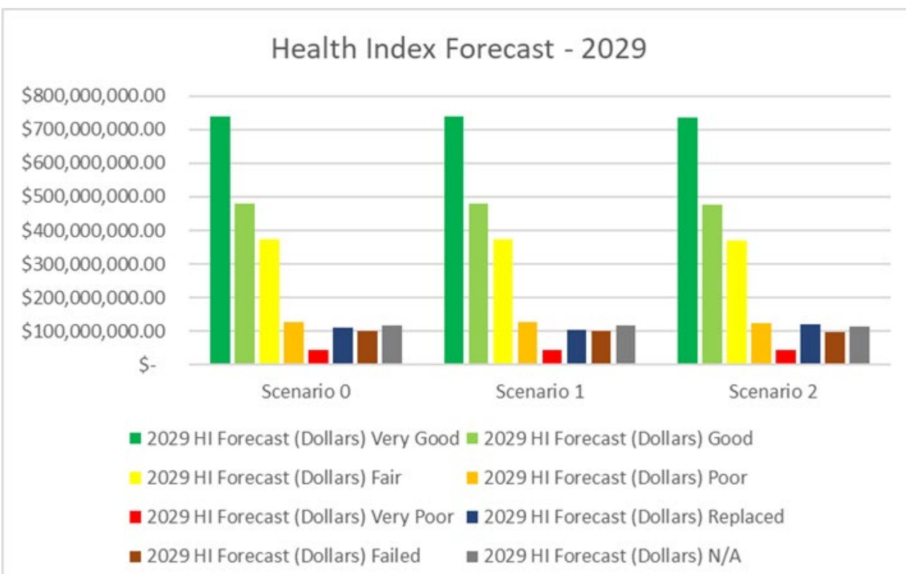
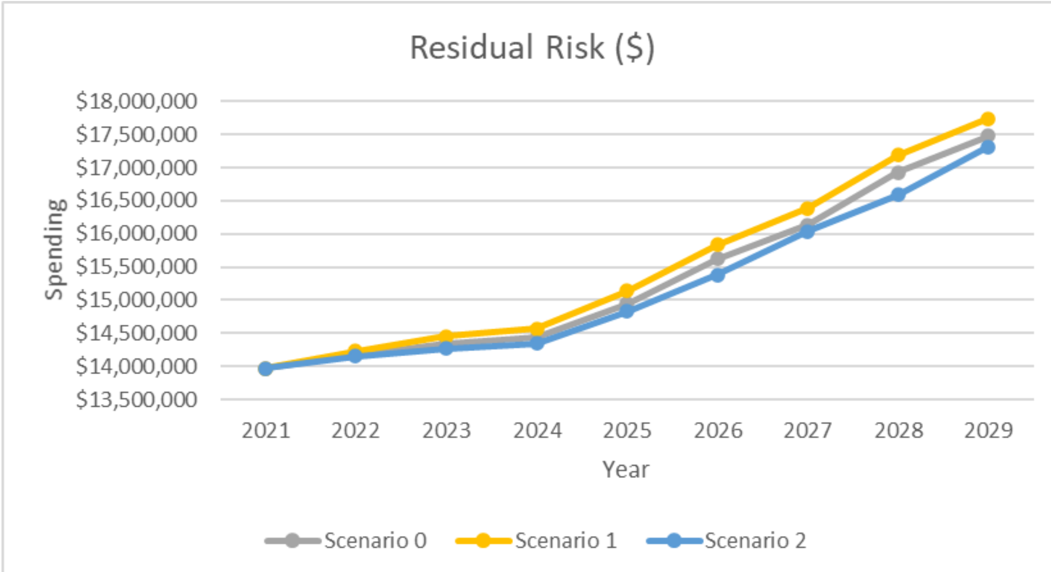


Figure 8: Residual Risk ($) Forecast until 2029



5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2021-5508	Pad-mount Transformers-Renewal-Planned	2021	0.33	126.9
2021-5529	27.6kV Pad-mount Transformers – Renewal - Planned	2021	0.41	85.8

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

Project name	Pad-mount Transformers-Renewal-Planned
Project numbers	2021-5508
Job numbers	WCA211108
Project District	General
Project Location	General
Investment Category	System Renewal
Budget Category	R4 - Renewal Programs-Distribution Transformers
Project Driver	Elexicon used Asset Condition Assessment Methodology to determine asset Health Index. The Health Index for pad mounted transformers is a two-factor formulation consisting of age and overall condition with the dominate factor being condition. Elexicon has about 13,599 Transformers (12,002 single phase and 1,587 three-phase pad mounted transformers). As per ACA study, 69 (0.5%) pad-mount transformers are in Very Poor condition and 428 (3.1%) are in Poor condition over a population of 12,200 assets with valid Health Indices. Reasonable extrapolations of the 1,399 assets with unknown results would predict 554 (4.1%) of the total asset base is in Poor or Very Poor condition. See the table below for recommended replacement quantities as per ARP.
Proposed Start Date	2021 JAN 01
Required In-Service Date	2021 DEC 31
Scope of Work	Replace 65 pad-mounted transformers with very poor condition as per ACA report.
Preliminary Estimate: Total Capital Cost	Gross: $327,800 / Gross: $327,800 / Gross: $327,800
Rationale for Intervention	The transformer in very poor condition as per ACA report are to be replaced to improve system reliability and prevent safety hazard to workers and public.
Criteria Score	126.9
Impacted Customers and Entities	Not Applicable
Intervention Options	No alternatives to the project are available. The status quo (do nothing) is not recommended. The selected pad-mounted transformers are in very poor condition.
Effect on System O&M Costs	The new pad mounted transformer will improve system reliability and reduce the number of the emergency repair charges.
Targeted Outcomes	The project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.
Cost Benchmarks	Average cost based on historical projects for each pad-mounted transformer is $5000
Value-Added Approach	Not Applicable

Number of Pad-Mounted Transformers Recommended for Replacement

Year	2021	2022	2023	2024	2025	2026
Pad-Mounted Transformers (#)	200	240	280	300	300	300

Expenditure Timing

Quarter	Q1	Q2	Q3	Q4
Gross CAPEX	$29,502	$32,780	$55,726	$209,792

<table>
<tr><td>Project name</td><td colspan="5">27.6kV Pad-mount Transformers-Renewal-Planned</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-5529</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R4 - Renewal Programs-Distribution Transformers</td></tr>
<tr><td>Project Driver</td><td colspan="5">Worker Safety</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Replace 58 27.6kV Pad-mounted Transformers that do not have load break switch. Transformers are selected based on their condition.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $410,200</td><td colspan="2">Contribution: $0</td><td>Net: $410,200</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$36,918</td><td>$41,020</td><td>$69,734</td><td>$262,528</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Former Veridian connections has some 27.6kV pad mounted transformers that do not have load break switch and the crew require disconnecting the elbow while the transformer is under load. This will impose safety hazard on workers. Elexicon initiated the project to replace these 27.6 kV transformers to eliminate the hazard and improve workers safety.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">85.8</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to project. Elexicon planned to replace the 27.6 kV transformers that do not have load break switch in order to eliminate the safety hazard and improve the workers safety.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project will improve workers safety and reduces the operation time required to service/isolate a transformer.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives Operational Effectiveness. The project will eliminate the worker safety hazard.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The historic cost of transformer replacement is $7,000.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	Renewal Programs – Switches and Switchgears
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of their Service Life
Secondary Driver(s)	System Reliability, System Performance

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$1.68M	**$1.80M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

This program proactively replaces Firon switches, LIS switches and pad-mounted switchgear. Firon Switches are replaced due to operational issues with the asset whereas LIS are replaced based on age. Switchgears are replaced as part of the inspection program at Elexicon. The program spending can be divided into three categories of switching devices, namely single-phase switches, three-phase switches, and pad-mounted switchgear. The 2020 Asset Condition Assessment ("ACA") results and defective equipment outage tracking from 2015 to 2019 are key analyses used to select, evaluate, and prioritize replacements within this program.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	1.68	1.80	1.32	1.53	1.60	2.13	2.13	2.13
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	1.68	1.80	1.32	1.53	1.60	2.13	2.13	2.13

As Switches and Switchgears have deteriorated, Elexicon will proactively replace these assets to reduce the number of outages and failures that arise from this asset group. Through the years of 2015 to 2019, there were thirteen outages due to defective switchgear totaling 10,594 Customer Hours Interrupted (“CHI”). Over the same period, there were 161 overhead switch failures which resulted in 17,713 CHI. By proactively replacing switchgear and switches at the end of their service lives, Elexicon reduces the probability of asset failure, which consequently reduces the overall risk profile of the system.

The ACA results are utilized as a reference point to determine the overall pacing of switch and switchgear replacements, as well as to select switches and switchgear as candidates for replacement. From the 2020 ACA results, 13 single-phase switches are found in the “Poor” condition and 97 are found in “Very Poor” condition (approximately 1% of the population for this asset class). Furthermore, 257 single-phase switches are described to be in a “Fair” condition by the ACA. The ACA results for three-phase switches show 3 that are in a “Very Poor” condition, while none are considered to be in a “Poor” condition. The ACA also shows that 69 three-phase switches are in a “Fair” condition. Nine pad-mounted switchgears are considered to be in a “Poor” state from the ACA, while none are considered “Very Poor”. Additionally, 90 pad-mounted switchgears are currently in a “Fair” condition. Switches and switchgear in “Poor” and “Very Poor” are prioritized for replacement, with assets rated in “Fair” condition monitored for further degradation.

Following the consolidation of the legacy utilities Veridian Connections Inc. (“VCI”) and Whitby Hydro Electric Corporation (“WHEC”), the combined workforce will allow for opportunities to consolidate resources in asset renewal projects. A combined inspection procedure for switches and switchgears with practices from both former utilities will be created. The increase in assets to be accounted for will require further analysis and prioritization.

Elexicon has an obligation and commitment to providing excellent customer service and service reliability. If proactive replacements are not attained, SAIDI and SAIFI measures would increase which reflects poorly on the utility. In addition, it is more cost-effective to replace assets proactively, since reactive replacements tend to cost more.

2. Basis for Action

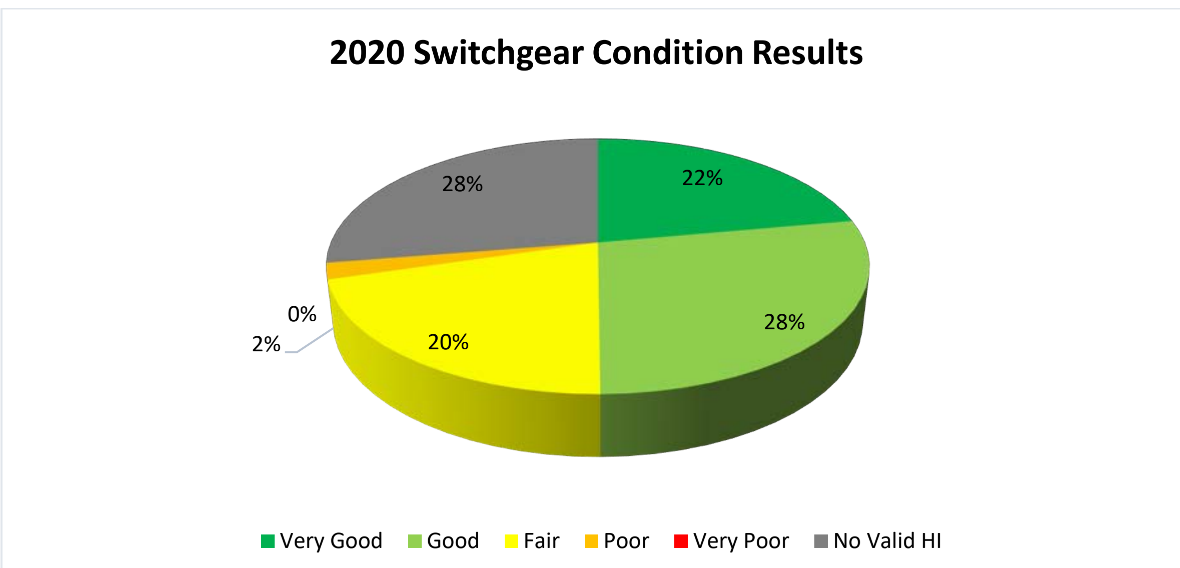
2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

Asset Condition Assessment Results

Elexicon places switches and switchgears under a single program as part of its annual system renewal investments. These switches and switchgears have been evaluated and classified based on their condition through the ACA into one of five condition categories: Very Poor, Poor, Fair, Good, and Very Good. Post-merger, only switches were further categorized, with the subclasses being: overhead switch - three-phase and overhead switch – single phase. Figure 1 and Figure 2 show the aggregated distribution of the 2020 assessments' results for each of switchgears and switches, respectively.

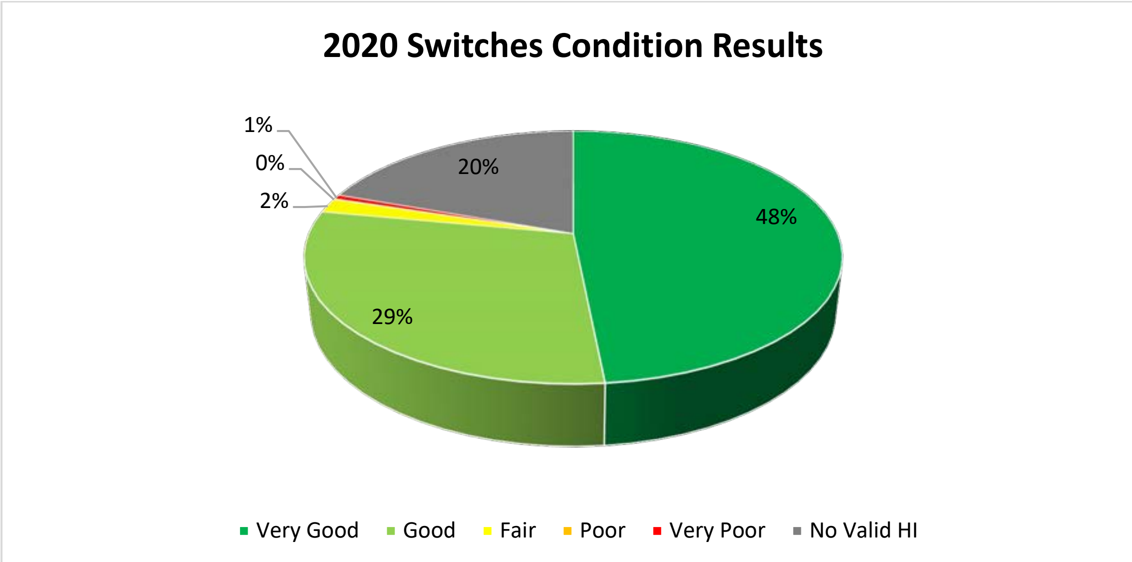
Figure 1: 2020 switchgear condition assessments results



In the case of switchgears, only Veridian further divided the asset class into subclasses, which are: air-insulated pad-mounted switchgear and non-air insulated pad-mounted switchgear.

Figure 1 demonstrates the overall condition demographics of the pad-mounted switchgear asset class portfolio. Twenty percent of switchgears have fallen into the fair category and two percent of switchgears are in the poor category. Poor conditioned switchgears shall be prioritized for replacement and Elexicon will monitor the condition of fair conditioned switchgears for degradation. Figure 3 and Table 4 highlight the switchgear condition breakdown represented in unit counts.

Figure 2: 2020 switches condition assessments results



The two legacy companies divided their asset classes into different subclasses. WHEC divided switches into three subclasses: K-fused cut-outs, load interrupters, and solid blade disconnects. Veridian Connections divided switches into two subclasses: gang-operated overhead line switches and solid blade overhead line switches.

Figure 2 demonstrates the overall condition demographics of the combined switches (three-phase and single-phase switches) asset class portfolio. The combined switches asset class portfolio is in a healthy state, with only 1% of the combined switches have been deemed poor in the asset condition assessment. These candidates will be prioritized for replacement in the nearest replacement cycle. Overall, Elexicon's switches present a healthier index than other distribution assets. Figure 4 and Table 5 highlight the three-phase switch condition breakdown represented in unit counts. Figure 5and Table 6 highlight the single-phase switch condition breakdown represented in unit counts.

Outage statistics based on Switchgears & Switches

Elexicon also considers outage metrics relating to the failure of switchgears and switches. As shown in the below charts, failures for both assets can prove to impact SAIDI and SAIFI numbers.

Table 2 shows the outage statistics of switchgears. Through the years of 2015 to 2017, there were no outages for switchgears. Recently, in 2018 and 2019, Elexicon has experienced an increase in switchgear related outages. The current 2020 ACA has identified fewer poor switchgears but more fair switchgears that will need to be planned to be replaced.

Table 2: Outage statistics of switchgears during 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	0	0	0	9	3
Customers Interrupted	0	0	0	6,744	2,003
Customer Hours Interrupted	0	0	0	10,127	467

Table 3 shows the outage statistics relating to switches at Elexicon. The amount of outages year over year from 2015 to 2019 are consistent. However, the number of customers interrupted is increasing. This infers that the asset failures are causing losses on lines that carry more customers. If this trend continues, and the outage duration becomes more severe as a result of asset deterioration, switches will have to be reactively replaced more frequently. It is important to note that the failure of switches and switchgears affects many customers downstream because of their location on the grid.

Table 3: Outage statistics of switches during 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	36	32	24	30	29
Customers Interrupted	7,645	4,219	1,293	5,259	9,939
Customer Hours Interrupted	8,393	4,258	1,238	1,967	1,410

2.2 Current-State Analysis:

2020 Asset Condition Distribution

The current Asset Condition Assessment evaluated assets based on condition parameters relating to the assets, taking into consideration the respective weight of each parameter to calculate a final health index. Switches have different condition parameters depending on whether the asset is located in the Whitby service area or the Veridian service area.

Figure 3: Unit count per condition category for Pad-mounted Switchgears

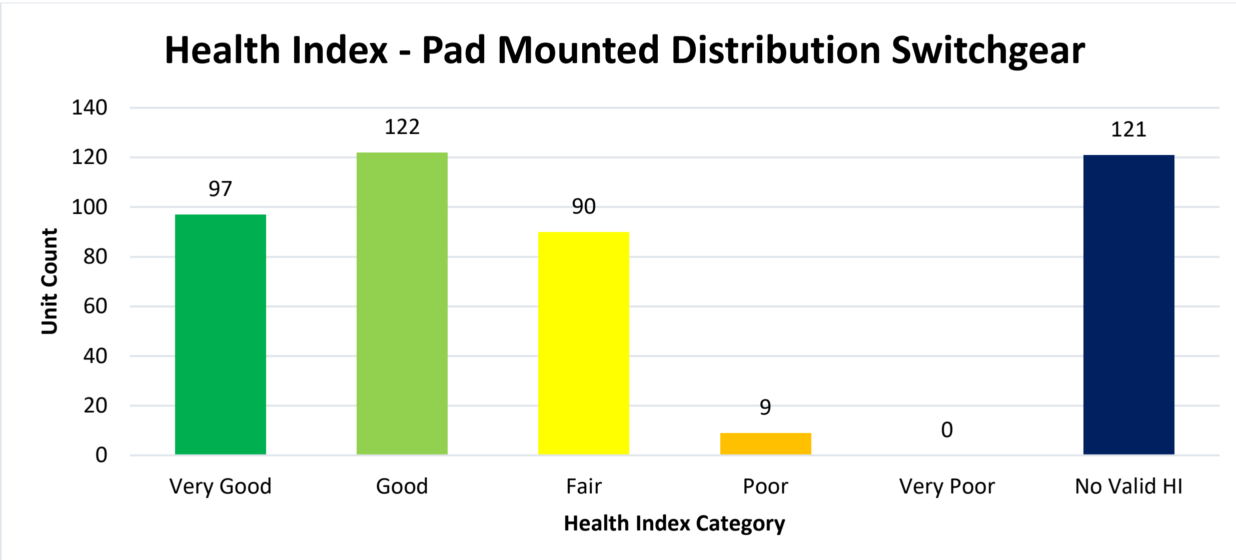


Table 4: Pad-mount Switchgear Asset Count by Condition

Health Index	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Total	97	122	90	9	0	121
Total (%)	**22.1%**	**27.8%**	**20.5%**	**2.1%**	**0.0%**	**27.6%**

The results from the Asset Condition Assessment show that nine switchgears out of 439 classify as poor. These switchgears are at risk of failing which means given that there is a replacement schedule, they would be the first to get replaced. Ninety switchgears were assessed to be in fair condition, which means for the time being their performance is acceptable. However, these switchgears are expected to further deteriorate the longer they are in service.

2020 Asset Condition Distribution for Switches

The Asset Condition Assessment shows that only 3 out of 3,387 3-phase switches rate as very poor, with no three-phase switches rating as poor. It also indicates that 69 three-phase switches are fair. These numbers show that the overall situation concerning three-phase switches is healthy. Switches in the very poor category will be prioritized for replacement with replacements for fair conditioned assets to follow.

Figure 4: Unit count per condition category for Three-Phase Switches

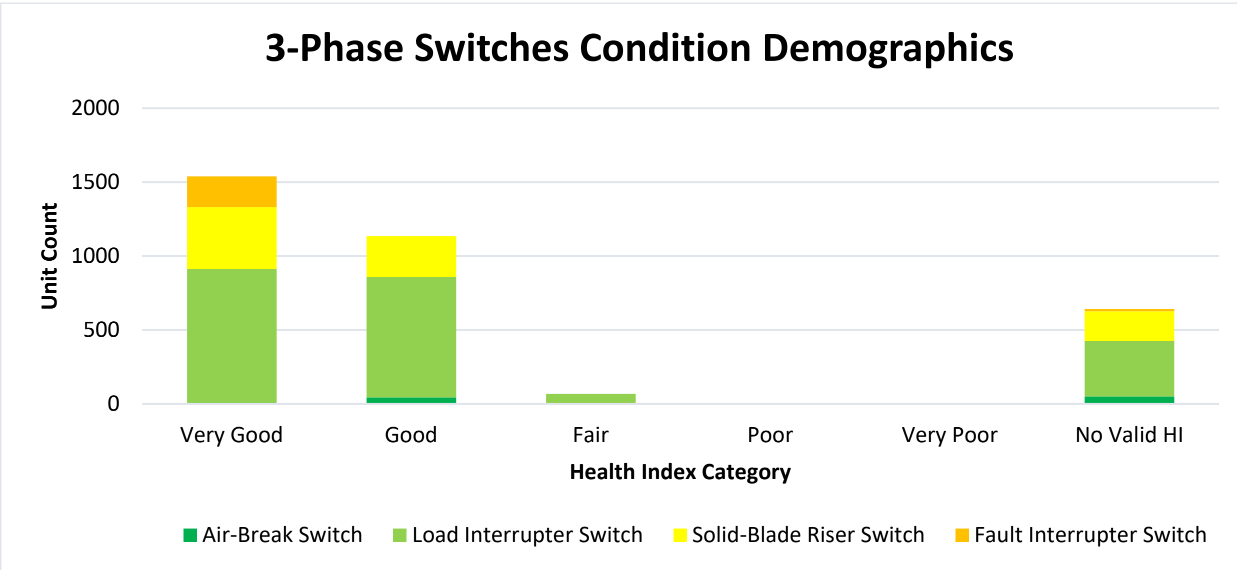


Table 5: 3 Phase Switch Asset Count by Condition

Category	Very Good	Good	Fair	Poor	Very Poor	Invalid HI
Air-Break Switch (ABS)	9	45	0	0	0	51
Load Interrupter Switch (LIS)	903	813	69	0	0	375
Solid-Blade Riser Switch (SRS)	420	277	0	0	3	200
Fault Interrupter Switch (FIS)	207	0	0	0	0	15
Total %	**45.4%**	**33.5%**	**2.0%**	**0.0%**	**0.1%**	**18.9%**

Figure 5: Unit count per condition category for Single-Phase Switches

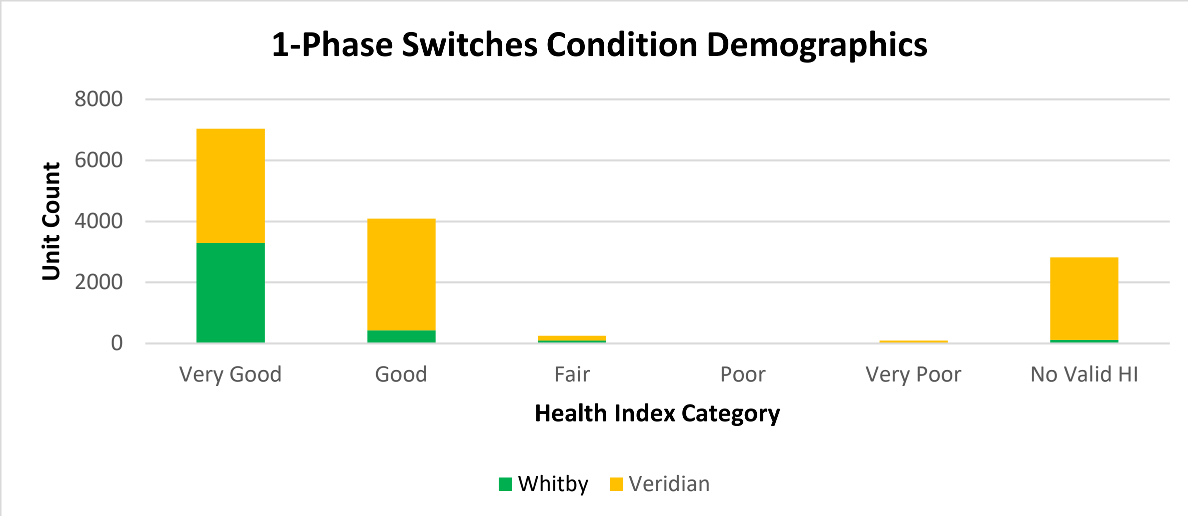


Table 6: Single Phase Switch Asset Count by Condition

Category	Very Good	Good	Fair	Poor	Very Poor	Invalid HI
Whitby	3,736	3,658	165	0	97	2,708
Veridian	3,299	435	92	13	0	112
Total %	**49.1%**	**28.6%**	**1.8%**	**0.1%**	**0.7%**	**19.7%**

Of the 14,315 single phase switches Elexicon operates, 97 were rated as very poor, 13 rated as poor, and 257 rated as fair. The replacement schedule is mainly driven by pole replacements, which occurs at a rate of 1.6% per year. Assets in the very poor category will be prioritized to be replaced, followed by the poor 1 phase switches. Once the lower categories have been replaced, Elexicon will review the fair inventory of single-phase switches.

Asset Replacement Plan for Switchgears and Switches

The Asset Replacement Plan prepared by METSCO produces a schedule of replacing switchgears based on the current switchgears that tested as poor or very poor. The Asset Replacement Plan also uses the age-based analysis to decide how many switchgears that were assessed as fair should be replaced, based on their typical useful life of 30 years.

Table 7 shows the recommended replacement schedule brought forth by the Asset Replacement Plan for the years 2021-2026.

Table 7: Recommended switchgear replacement by year from the ARP

Number of Distribution Switchgear Recommended for Replacement						
Year	2021	2022	2023	2024	2025	2026
Distribution Switchgear	12	12	12	12	12	12

Table 8 shows the recommended replacement schedule the Asset Replacement Plan suggests. It is expected that about 9% of single-phase switches will need to be replaced. About 0.3% of the current inventory of three-phase switches will be replaced.

Table 8: Recommended switches replacement by asset subtype from the ARP

Switches Recommended for Replacement (estimated)						
Year	2021	2022	2023	2024	2025	2026
Single Phase Switches	250	250	250	250	250	250
Three Phase Switches	2	2	2	2	2	2

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

CSA Standards

The Canadian Standards Association (CSA) is a standards organization that provides standards for many different areas and sectors. One of CSA's standards is its electrical standards which dictate the requirements of electrical installations.

CSA 22.3 No. 1 Overhead Systems

CSA 22.3 No.1 is a standard that applies to electric supply, communication lines, and equipment placed outside of buildings and fenced supply stations. The standard includes clause 5.3.2.1, which states that there is a minimum vertical separation between switches and the ground depending on the voltage. The standard also includes clause 5.9.5, which states that there's a minimum separation or clearance that needs to be abided by between switches and conductors depending on the voltage and relation between the two assets (e.g., whether they are connected to different circuits but not connected together).

CSA 22.3 No. 7 Underground Systems

CSA 22.3 No. 7 is a standard that applies to the lines and equipment related to underground electric supply and communication systems placed outside of buildings and fenced supply chains. Section 10 of the standard includes clauses related to above-ground equipment, such as switchgears. Clause 10.1 states that live parts must be inaccessible. Live parts of pad-mount transformers being accessible makes it prone to rust, which would then require the transformer to be replaced or treated. Clause 10.2 states that there must be adequate working space around the pad-mount transformer. Clause 10.6, which is broken down into 2 sub-clauses, states that the pad-mount transformer must be designed to withstand a seismic event equal to the values given by the National Building Code.

ISO 55000

The International Organization for Standardization (ISO) is an international standard-setting body that promotes worldwide proprietary, industrial, and commercial standards. The ISO 55000 series provides an overview of asset management and asset management systems and identifies common practices that can be applied to a broad range of assets. This standard drives Elexicon's asset management strategy as Elexicon adheres to the principles laid out in the ISO 55000 series. For example, section 6.1 of ISO 55002 covers actions to address risks and opportunities for the asset management system by planning to take action to mitigate the current and future risks as well as how to implement these actions and evaluate their effectiveness.

Ontario Regulation 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure tracked by Elexicon. Elexicon's predecessor utilities have achieved compliance with Ontario Regulation 22/04 for all years in the historical period. Overhead distribution lines should have operating electrical equipment be maintained in proper operating condition. In addition, all underground lines shall also have operating electrical equipment be maintained in proper operating condition.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.
-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o The number of customers in each customer class potentially affected by a failure of the assets included in the project
o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)
o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure
-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project

An age-based failure curve analysis was conducted using Weibull Distribution. The parameters of the distribution were found using a typical useful life of 30 years for switchgears whereas a typical useful life of 45 years was used for switches. The analysis yielded the expected number of assets that will fail during 2020-2025. Since there is missing information for some of the asset classes, the expected number of failures also includes extrapolated data in which the ratio of failed assets to the total number of assets with unknown data matches the ratio of failed assets to the total number of assets with known data. Table 9 shows the expected number of failed station assets during 2020-2025.

Table 9: Expected number of failed switchgears and switches during 2020-2025

Asset Class	Total Population	Unknown Age	2021	2022	2023	2024	2025
Distribution Switchgear	439	123	10	10	10	10	11
Overhead Switch	17,863	3,643	104	114	125	137	149

It can be seen from the above table that switchgears are more prone to failure in the coming years. 14% of distribution switchgears are expected to fail during the next 5 years, whereas only 4% of overhead switches are expected to fail during the same period. Because of the location of switches and switchgears in the grid, a failure is expected to affect many customers. The expected failures are a significant figure to pay attention to when planning for replacement programs as they indicate the importance of the program as well as the areas of focus.

Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of switches and switchgears that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

When evaluating System Renewal Investment options, Elexicon undergoes analysis of options with regards to its effects on SAIDI and SAIFI by defective equipment and Residual Risk. The effect that an asset class has with regards to SAIDI and SAIFI values due to defective equipment failure is evaluated as the renewal program seeks to improve on these defective equipment metrics through proactive equipment renewal. Residual Risk is the monetized value of the left-over risk on the system after mitigations. It is monetized based on the quantified failure probability and monetized failure impacts (reliability, financial, environmental, and safety impacts).

2.5 Merger-Related Objectives:

Elexicon's merger-related objectives service continuity and utility integration. If a project does not meet either of the two objectives, it is eliminated. These objectives can be further broken down into sub-criteria which are used to check if a program is in line with Elexicon's primary merger-related objectives.

The relevant sub-criterium of service continuity involves the program being compared to similar assets; more specifically, the assets' dollar-weighted average HI is compared to that of other assets and is checked to see if it is in either of the 3rd or 4th quartiles. Being in the worst 50% means the assets pose a risk to service continuity relative to the other similar assets since they would be deemed to be in poor condition along with having higher maintenance and replacement costs. Meeting this sub-criterion partly justifies the viability of needing a switches and switchgears replacement program.

A relevant sub-criterium of utility integration that is relevant to the switches and switchgears renewals program is that the program aims to integrate core operations of the legacy utilities. The legacy utilities replaced distribution transformers separately, each with their specific approach. The program looks to consolidate these approaches to a single-core operation.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be
quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	***0***	***1***	***2***
Scenario Description	Using the allocated budget for this program	An increase in the allocated budget to this program by 10%	A decrease in the allocated budget to this program by 10%
Annual Program Scope	All scopes concerning switches and switchgears	All scopes concerning switches and switchgears	All scopes concerning switches and switchgears
Annual Gross CAPEX ($M)	$1.81M	$1.99M	$1.63M
Annual Net CAPEX($M)	$1.81M	$1.99M	$1.63M
Annual Program Benefits	The base values as influenced by Defective Equipment are 0.101 for SAIDI, and 0.048 and SAIFI. Other Investment scenarios (1 and 2) are relative percentages to scenario 0. Residual Risk in Scenario 0 is $1.111M.	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 1 are relative to the scenario 0 investment. SAIFI = -3.25% SAIDI = -2.37% Residual Risk = -4.12%	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 2 are relative to the scenario 0 investment. SAIFI = 2.03% SAIDI = 2.03% Residual Risk = 3.88%
Program Economics	The base scenario involves investing $1.58M annually and results in the residual risk of $3.168M projected by 2029. It is the preferred trade-off of costs and benefits.	By investing 10% more in the switches/switchgears program, the forecasted residual risk for switches decreases by 4.12%.	By investing 10% less in the switches/switchgears program, the forecasted residual risk for switches increases by 3.88%.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.		
Other Constraining Factors	The current budget is constrained by the operational needs of system investments and	A faster pace of investment would reduce the budget available for system	A slower pace of investment would increase the budget available for system

	other non-system investments.	investments and other non-system investments.	investments and other non-system investments.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: Replacing switches and switchgears in poor condition will reduce the risk of outages. Since a single switch or switchgear serves many customers in relevance to other assets, monitoring them and replacing them at the right time will help bolster Elexicon's reliability.

Grid Resiliency: N/A

Operational Efficiency and Cost Effectiveness: In general, proactively replacing assets is much more cost-efficient as outages can incur heavy costs on the utility company. Because switches and switchgears serve many customers, a failure will result in an outage for many customers and will in turn cost the utility more than an average failure would. If Elexicon proactively replaces switches and switchgears, Elexicon can avoid the outage costs as well as maintain its quality of service.

Safety: Asset failure can pose a threat to the public as well as the crew members working these assets. Aiming to replace these assets before a failure will mitigate the risks of hazard and maintain safety.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Customers will benefit from this program by experiencing outages less frequently because of proactively replacing assets expected to fail.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

To plan for possible changes soon, Elexicon takes into account several considerations. An expected number of failures for each asset class is predicted and an asset condition assessment is performed to have an overview of how the system may change during the next couple of years. An increase in connections is also predicted to plan for which areas would need to have their services expanded. With all the collected information, a prioritization framework will be put into effect to prioritize scopes in accordance with the current status quo and how the system would look like in the next couple of years.

If more expected deterioration is expected of an asset, a shift of spending will be influenced. Planners will determine where other parts of the budgeted investments in the renewal category can be shifted to these annual programs. A renewal budget is set forth every year for each asset but changes in the overall spending of each asset can change as long as the overall renewal budget stays the same.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

In 2020, after the merger of Veridian and Whitby which resulted in Elexicon, METSCO completed a new Asset Condition Assessment. METSCO used the same condition parameters used in the previous year. The condition parameters were then used to calculate a health index which would indicate which condition bucket the asset would be placed in. In the case of Switches, separate approaches were taken for calculating the Health Index of Veridian and Whitby region Switches based on different data collection methods. Table 10 and Table 11 show the condition parameters used for each utility's completed Asset Condition Assessment for switchgears and switches, respectively.

Table 10: Switchgears condition parameters with respective weights used in the 2020 ACA

Elexicon	
Condition Parameter	**Weight**
Condition of Enclosure	2
Visual Inspection	4
Service Age	2
IR Scan	4

Table 11: Switches condition parameters with respective weights used in the 2020 ACA

Elexicon		
Condition Parameter	**Weight (Whitby)**	**Weight (Veridian)**
IR Scan	4	-
Overall Condition	4	4
Service Age	2	2

4.2 Legacy Work Execution Approaches vs. Combined Operations

Elexicon conducts inspections for switchgears through infrared scanning and visual inspections annually. Maintenance work comprises repairs based on the inspection results. Elexicon replaces switchgears proactively, with the replacements being based on the inspection results as well as age. Legacy Veridian conducted switchgear inspections through infrared scanning, visual inspections, evaluating the condition of the enclosure, and inspection of internal components based on a 3-year cycle. Veridian based their maintenance work on the inspection results. Veridian also replaced switchgears based on inspections as well as age. Legacy Whitby similarly conducted inspections of switchgears as Veridian did, in that the inspections included infrared scanning, visual inspections, evaluating the condition of the enclosure, and inspection of internal components based on a 3-year cycle. Whitby's maintenance work was based on the results of those inspections. Whitby also proactively replaced switchgears based on the result of the inspections as well as the age of the switchgears.

For all types of overhead switches, Elexicon conducts inspections visually every 3 years and conducts infrared scanning annually. Elexicon's maintenance work for switches is based on the inspection results. [insert Elexicon's replacement approach]. Planning approaches were done differently for load interrupter switches and the other types of overhead switches by Veridian. Legacy Veridian conducted infrared scanning annually to inspect all types of switches except for load interrupter switches, which were inspected visually based on a 3-year cycle. Maintenance work for all types of switches except for load interrupter switches was based on the infrared scanning results, whereas there was no maintenance work done for load interrupter switches. Veridian replaced load interrupter switches based on age whereas replacements for all other types of overhead switches were done reactively upon failure. Whitby inspected switches through infrared scanning, conducted annually, and visual inspections, conducted every 3 years. Whitby's maintenance work was based on the results of these inspections. Whitby ran switches until failure unless inspections signaled that there was a need for replacements.

4.3 Scale Increase Considerations

Due to the scale increase because of the merger, Elexicon will need to reorganize asset replacement volumes considering the assets inherited by both former utilities. An increase in staff will assist the utility in performing replacements throughout the territory. The additional service territory will allow work done in the larger Whitby, Ajax, and Pickering service area to be more coordinated. However, information of assets from both locations will need to be consolidated and an approach to all asset inspections will need to be agreed on internally.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

In the following graphics as shown below, scenarios 0, 1 and 2 represent the base case with the current investment plan, decreasing the current investment plan by 10% and increasing the current investment plan by 10%. These graphics illustrate the total system renewal spending for certain renewal programs, the Health forecast of Assets in 2029 as part of the overall system renewal portfolio and the residual risk produced with these investment options. Note that the system renewal forecast only forecasts for switches and not switches and switchgears.

Figure 6: System Renewal Spending Forecast until 2029

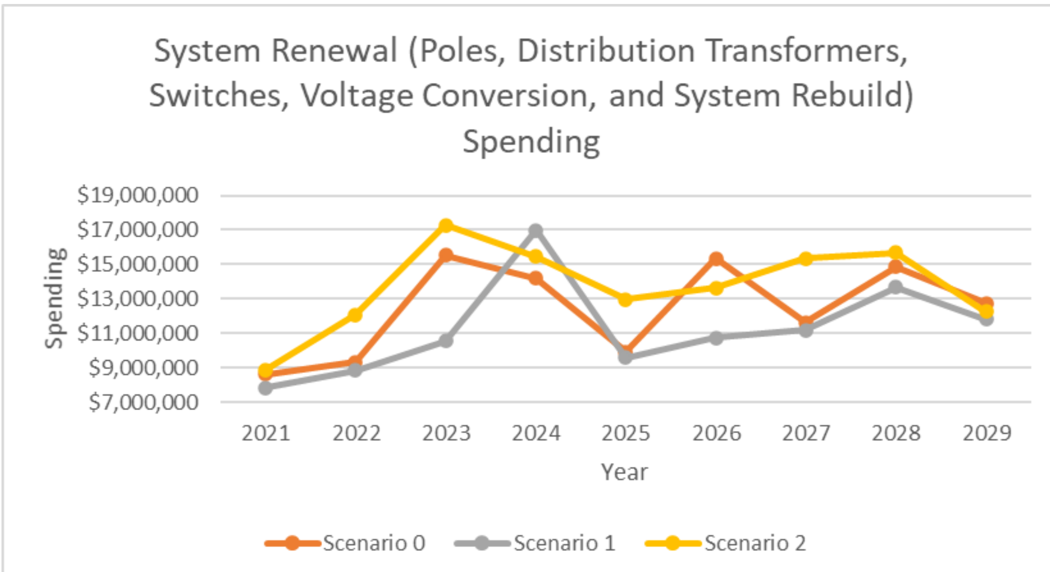


Figure 7: Health Index Forecast until 2029

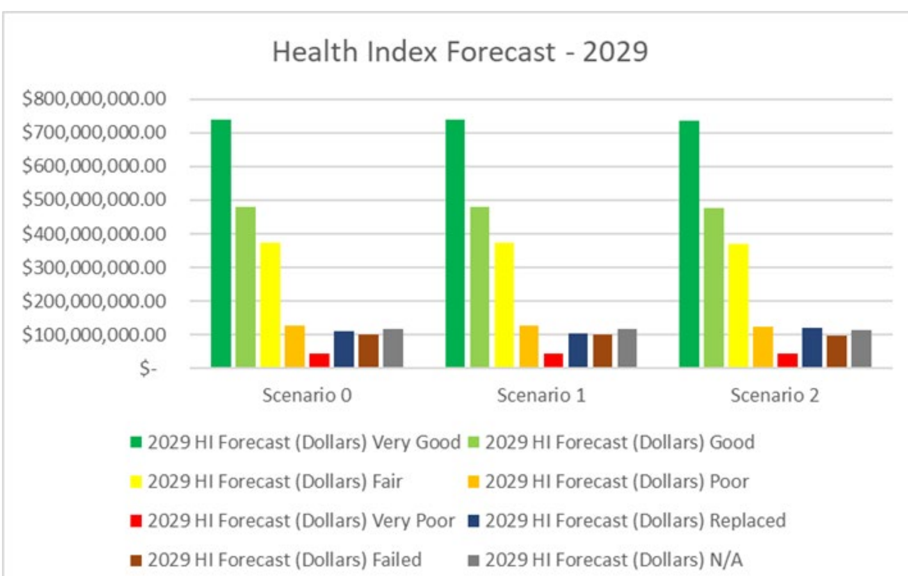
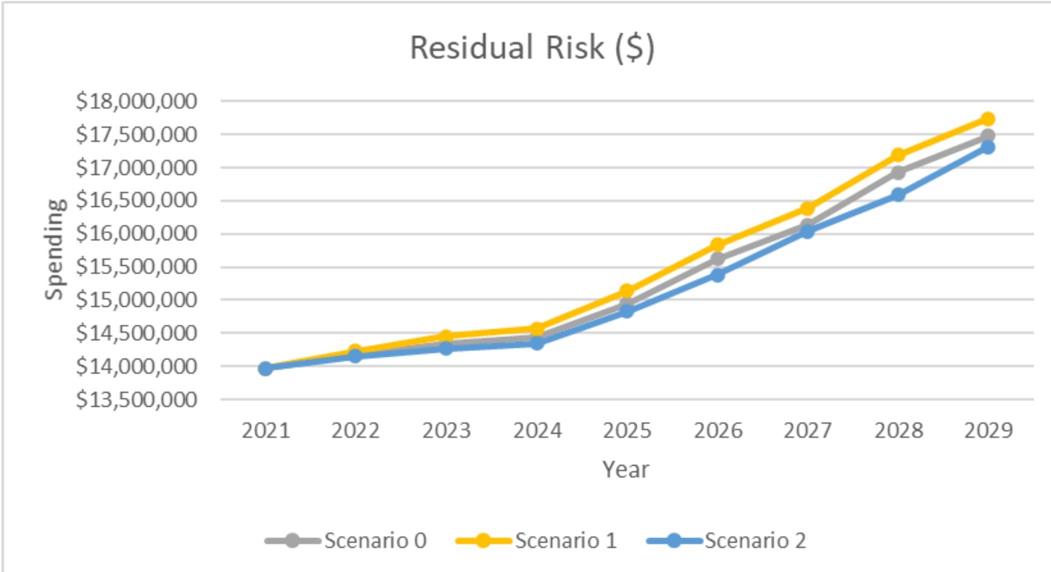


Figure 8: Residual Risk ($) Forecast until 2029



5. Individual Projects Comprising the Program

5.1 Overview of Projects

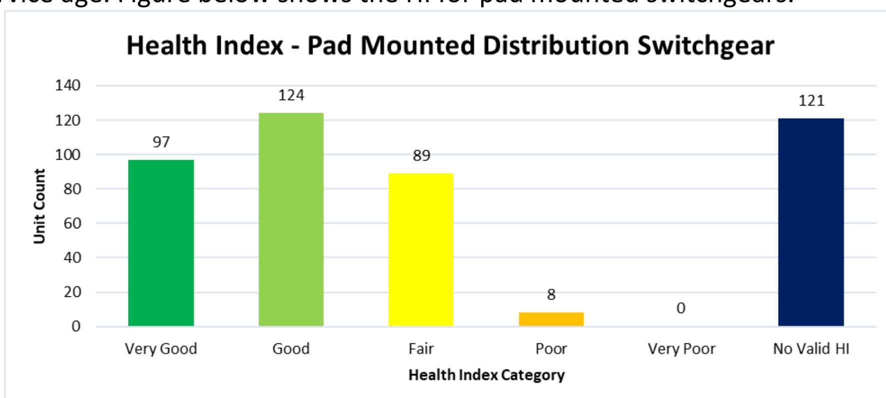
Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2021-5527	Firon In-Line Switch Replacements	2021	0.32	53.7
2021-5506	Overhead Line Switches (LIS) - Renewal Planned (VW)	2021	0.30	52.4
2021-5507	Pad-mount Switchgear-Renewal Planned	2021	0.70	50.6

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

<table>
<tr><th>Project name</th><td colspan="5">Firon In-Line Switch Replacements</td></tr>
<tr><th>Project numbers</th><td colspan="5">2021-5527</td></tr>
<tr><th>Job numbers</th><td colspan="5">Several</td></tr>
<tr><th>Project District</th><td colspan="5">General</td></tr>
<tr><th>Project Location</th><td colspan="5">General</td></tr>
<tr><th>Investment Category</th><td colspan="5">System Renewal</td></tr>
<tr><th>Budget Category</th><td colspan="5">R5 - Renewal Programs-Switches & Switchgears</td></tr>
<tr><th>Project Driver</th><td colspan="5">Asset failures, Worker safety</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021 JAN 01</td></tr>
<tr><th>Required In-Service Date</th><td colspan="5">2021 DEC 31</td></tr>
<tr><th>Scope of Work</th><td colspan="5">Replace Firon in line switches
The budget allows us to replace about 20 units and remove another 20 units in 2021
Units that are considered redundant are considered for removal</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td>Gross: $317,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $317,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$28,530</td><td>$31,700</td><td>$53,890</td><td>$202,880</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">Firon inline switches are prone to be lock up and might break during operation of the switch. This will impose safety risk for worker and public. Elexicon initiated the project to replace these switches.</td></tr>
<tr><th>Criteria Score</th><td colspan="5">53.7</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">Not Applicable</td></tr>
<tr><th>Intervention Options</th><td colspan="5">There is no alternative to the project. Firon in-line switches might lock up and break when operated which imposes safety hazard to workers. Elexicon is required to replace these types of switches.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">The project will reduce the cost of O&M by eliminating the risk of the Firon in-line switches failure and extra works required to isolate and replace the failed assets.</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">The project addresses the RRF objectives of Financial Performance, and Operational Effectiveness.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">The average cost of Firon inline switch replacement is $7,000 for Three phase switches.</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">Not Applicable</td></tr>
</table>

<table>
<tr><td>Project name</td><td colspan="5">Overhead Line Switches (LIS) - Renewal Planned (VW)</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-5506</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R5 - Renewal Programs-Switches & Switchgears</td></tr>
<tr><td>Project Driver</td><td colspan="5">Asset Condition Assessment (ACA) report, asset age and poor condition</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project scope is to replace six (6) Overhead Line Switches (LIS) which includes:
Removing existing LIS and wood pole (Concrete poles to be evaluated and replaced if required)
Installation of new wood pole and Overhead Line switch.
3 switches added to 2021 budget due to reactive circumstances. (44-689L, 44-439L, 921)</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $300,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $300,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$27,000</td><td>$30,000</td><td>$51,000</td><td>$192,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The Overhead Line Switches have 20 years IFRS Useful Life. The selected Overhead Line switches have poor condition and been in service for more than 33 years.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">52.4</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">No alternatives to the project are available. The status quo (do nothing) is not recommended. The Overhead Line Switches are in poor condition and they have passed their useful life.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">New Overhead Line Switches will be automated type and improve system outage response and planned maintenance operations.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Average cost based on historical projects for each LIS replacement is $100,000.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Project name	Pad-mount Switchgear-Renewal Planned
Project numbers	2021-5507
Job numbers	Several
Project District	General
Project Location	General
Investment Category	System Renewal
Budget Category	R5 - Renewal Programs-Switches & Switchgears
Project Driver	Elexicon used Asset Condition Assessment Methodology to determine asset Health Index. The Health Index formulation for switchgears typically uses service age, visual inspections, and IR scan results as condition parameters. Elexicon's distribution switchgear Health Index consists of four parameters, with the combination of visual inspection and infrared (IR) scan results accounting for two-thirds of the total maximum health score. The remaining one-third is comprised of the results of the enclosure condition inspection and the units' service age. Figure below shows the HI for pad mounted switchgears.  For 121 switchgears, there is not a valid health index. The missing parameter in the units without a valid health index is generally age. The recommendation for replacements based on replacing the units that are recorded to be in Poor and/or Very Poor condition in year 2021, and the units, which have historically been identified in the inspection and maintenance processes. See table below for replacement quantities based on ARP report. **Number of Distribution Switchgear Recommended for Replacement** Year: 2021 / 2022 / 2023 / 2024 / 2025 Distribution Switchgear: 21 / 20 / 18 / 18 / 15
Proposed Start Date	2021 JAN 01
Required In-Service Date	2021 DEC 31
Scope of Work	The project scope is to replace nine (9) Pad-mounted Switchgear based on ACA study and field inspections. The following table lists all the units that are of concern. It includes all the units whose HI results were either age-driven or determined by combination of age and inspection information. (5) Switchgear in the Belleville territory to be replaced in 2021 due to high temperature

Number of Distribution Switchgear Recommended for Replacement					
Year	2021	2022	2023	2024	2025
Distribution Switchgear	21	20	18	18	15

determined by IR scan analysis, these will be like-for-like replacements. Additionally, unit 2IP04 KBAR will be removed from service.

Priority	Switch Number	Service Area	KV Rating	Type	Proposed Replacement Year	Year Built	Age	HI ACA 2020
1	SC5120	Bowmanville	13.8kV	PMH-12	2021			56%
2	SP158	Whitby	13.8kV	PME	2021	1999	21	45%
3	SC7	Belleville	13.8kV	PMH-9	2021	1997	23	56%
4	SP070	Whitby	13.8kV	KBAR	2021	1996	24	45%
5	SC3	Belleville	13.8kV	PMH-9	2021	1996	24	75%
6	SC1	Belleville	13.8kV	PMH-9	2021	1990	30	81%
7	SC4	Belleville	13.8kV	PMH-9	2021	1996	24	89%
8	SC8	Belleville	13.8kV	PMH-9	2021	1998	22	64%
9	SC9	Belleville	13.8kV	PMH-9	2021	1998	22	67%

Preliminary Estimate: Total Capital Cost	Gross: $700,000	Contribution: $0	Net: $700,000		
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$63,000	$70,000	$119,000	$448,000
Rationale for Intervention	The selected switchgears have poor condition and they have been flagged for action in field inspections.				
Criteria Score	50.6				
Impacted Customers and Entities	Not applicable				
Intervention Options	No alternatives to the project are available. The status quo (do nothing) is not recommended. The pad-mounted switchgears are in poor condition.				
Effect on System O&M Costs	The new switchgears will be SCADA controlled and improve system outage response and planned maintenance operations.				
Targeted Outcomes	This project addresses the RRF objectives of customer focus and Operational Effectiveness.				
Cost Benchmarks	Average cost based on historical projects for each switchgear replacement is $125,000.				
Value-Added Approach	Not Applicable				

Budget Category	Renewal Program – Substations
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of Their Service Life
Secondary Driver(s)	Reliability, Operational Efficiency

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.42M	**$0.91M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Others Renewal Program is a System Renewal program meant to replace porcelain insulators and where other expenses such as capitalized planning, operations, and interest are placed. Elexicon has a long-term initiative to replace porcelain insulators with polymer to increase safety and operational efficiency. Capitalization of planning, operations, and interest is meant to capitalize on work across projects and labor throughout Elexicon.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.42	1.13	0.95	0.77	0.74	0.99	0.99	0.99
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	0.42	1.13	0.95	0.77	0.74	0.99	0.99	0.99

2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

The Others renewals program encompasses projects that don't fall into any particular program. The program includes projects such as porcelain insulator replacements, porcelain cut-out replacements, capital planning, capital interests, and capitalized operations. ACA and ARP reports are placed into this category alongside the 2020 DSP study. The Mason Windows Substation removal from service is also placed into this category. The porcelain insulator replacement project and porcelain cut-out project are the only projects that directly involve work on assets, in which it aims to replace porcelain insulators with polymer insulators. Table 2 shows the number of outages caused by insulators as well as the customers interrupted, and the customer hours interrupted for the past five years.

Table 2: Summary of outages caused by insulators from 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	32	10	6	6	9
Customers Interrupted	34,783	3,738	7,826	5,908	9,548
Customer Hours Interrupted	40,590	7,910	7,112	14,890	9,061

Besides being a cause of outages, porcelain insulators are replaced for safety reasons. When porcelain insulators fail, they can burst and release shrapnel around the area which pose a threat to the safety of the workers and the public.

The capital planning project is the capitalized work that Elexicon performs every year to manage the capital budget and resources. Capital interest is the interest paid to partners based on how much they would earn from a hypothetical liquidation of the company. The capitalized operations project is the work done to capitalize control rooms related to Elexicon's capitalized projects. It is budgeted in a way that capital interest would be the costliest of all for the current time the projects cover, which is from 2019 to 2025.

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

For the porcelain insulator replacement program, any porcelain insulators are replaced by polymeric versions. Elexicon's company practice is to replace porcelain insulators with greater functioning insulators of a different material. Year over year, a renewal budget is set forth for all programs by the Asset Management department. The budget that is set to the replacement of Porcelain Insulators are dependent on the overall budget. Other assets are prioritized first for replacement using the overall budget and the asset replacement plan. The remaining budget is assigned to the Porcelain Insulator program.

The ACA and ARP reporting project is updated every year as these projects determine the conditions of Elexicon assets and proposed replacement quantities. The ACA is core to the System Renewal program at Elexicon as it drives substation and distribution assets renewal around the service territory.

Table 3: Annual Renewal Programs-Others Projects

Annual Projects List	Years
ACA & ARP Reports	2021-2026
Capital Planning	2021-2026
Capitalized Operations	2021-2026
Capital Interest	2021-2026
Porcelain Insulator Replacement Program	2021-2026
Porcelain Cut-out Replacement Program	2021-2026
Engineering Work CAA Dept	2021-2026

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

ISO 55000

The International Organization for Standardization (ISO) is an international standard-setting body that promotes worldwide proprietary, industrial, and commercial standards. The ISO 55000 series provides an overview of asset management and asset management systems and identifies common practices that can be applied to a broad range of assets. This standard drives Elexicon's asset management strategy as Elexicon adheres to the principles laid out in the ISO 55000 series. For example, section 6.1 of ISO 55002 covers actions to address risks and opportunities for the asset management system by planning to take action to mitigate the current and future risks as well as how to implement these actions and evaluate their effectiveness. ACA and ARP work helps Elexicon determine an asset management strategy and plan in managing the distribution and substation assets found within the territory.

O'Reg 22/04: As insulators are part of the overhead system, all operating electrical equipment shall be maintained in proper operating condition. Adequate space shall also be provided around electrical equipment for proper maintenance and operation.

OEB: Safety metrics are part of the overall OEB performance measures. As Porcelain insulators can affect the public and staff, it is beneficial that legacy insulators are replaced with polymer. In addition, zero injuries are a goal at Elexicon for operational staff.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.
-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o The number of customers in each customer class potentially affected by a failure of the assets included in the project
o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)
o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure
-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project

The Consequences of inaction related to Porcelain Insulators is that safety metrics could decrease due to the material. Insulators after failure also can become jagged and could exhibit sharp edges that would affect the safety of operational staff. By installing new polymer insulators, safety would increase, and asset renewal would take place. Polymer insulators would be newly installed and introduce a new life cycle into that portion of the system.

In addition, as the ACA determines the condition of all assets found in Elexicon, it is required to trend and to understand where specific assets have deteriorated or in danger of failing. Any replacements that are not identified if an ACA is not performed could affect SAIDI and SAIFI and customer satisfaction. Elexicon is obligated to ensure that all assets are in proper operating condition.

Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of porcelain insulators/cut-outs that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

2.5 Merger-Related Objectives:

Elexicon's merger-related objectives are summarized by the following criteria: service continuity and utility integration. If a project does not meet both of those criteria, it is eliminated. These criteria are broken down into sub-criteria. Meeting any sub-criterium under any of the mentioned criteria means the project meets the objectives.

as the program's main project is the porcelain insulators replacement program, the program is considered to provide a safer environment to staff. Two sub-criteria relating to the service continuity that is met by the program are that the program mitigates safety conformances verified by inspections as well as mitigates risk to indoor staff to provide a healthy and safe environment. The program also meets the utility integration objective because it provides improved safety to foster consistent service delivery. In case of a failed outage due to porcelain insulators, downtime would be increased because the environment is considered hazardous due to the shrapnel, which will increase the time needed for staff to amend the outage in order to resume service.

The ACA helps consolidate the asset data found in both Whitby and Veridian's service territories. A holistic understanding of all service territories is provided so that Elexicon can prioritize system investments that benefit the company as a whole and not two former entities.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be
quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	1	2	3
Scenario Description	Using the allocated budget for this program	An increase in the allocated budget to this program by 10%	A decrease in the allocated budget to this program by 10%
Annual Program Scope	Program is budgeted for various capitalized projects and for replacements of porcelain insulators/cut-outs.	Program is budgeted for various capitalized projects and more funding in the replacements of porcelain insulators/cut-outs.	Program is budgeted for various capitalized projects and less funding in the replacements of porcelain insulators/cut-outs.
Annual Gross CAPEX ($M)	$0.91M	$1.00M	$0.82M
Annual Net CAPEX ($M)	$0.91M	$1.00M	$0.82M
Annual Program Benefits	Continued implementation of ACA and ARP reports helps determine asset conditions across the system for renewal planning. Risk of danger is decreased from replacing porcelain insulators/cut-outs with polymeric replacements.	Continued implementation of ACA and ARP reports helps determine asset conditions across the system for renewal planning. Risk of danger is increased as less porcelain insulators/cut-outs are replaced.	Continued implementation of ACA and ARP reports helps determine asset conditions across the system for renewal planning. Risk of danger is decreased as even more porcelain insulators/cut-outs are replaced.
Program Economics	Current program budgeting is optimal spending across the DSP period.	Increased spending for this program may have marginal returns.	Decreased spending for this program will reduce the returns as budgeted in the preferred alternative.

Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.		
Other Constraining Factors	The current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: Asset Renewal in the form of new insulators would increase reliability. An introduction of new lifecycles due to the newer asset being installed would ensure the reliability of the system.

Grid Resiliency: N/A

Operational Efficiency and Cost Effectiveness: Proactively replacing aging insulators can introduce cost efficiencies without waiting for the insulator to fail. In addition, since polymer insulators are lighter and better performing, operational efficiencies of installation and performance would assist Elexicon.

Safety: As porcelain insulators pose a risk to the public and workers, it is beneficial that Elexicon continues to invest in polymer replacements.

When porcelain insulators are overused, they burst and send shrapnel around the work area. This could be very dangerous to workers, and thus replacing them can help improve safety.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: The customer would enjoy the benefits of safety and reliability through the replacement of older porcelain insulators with polymer.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

If significant deterioration is found for Porcelain Insulators, further investments will be made into the program by increasing the budget for the year. The overall budget will stay the same as it is assigned for the overarching renewal portfolio. However, other projects may have their budgets shifted depending on how severe the deterioration of the porcelain insulators proves to be. Other information such as outage statistics and safety incidents will be taken into consideration.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Legacy and current planning for Porcelain Insulators is dictated by the budget year over year set by the overarching renewal program. Based upon the number and after all other assets are determined by the ARP and ACA, a budget is set for the porcelain insulators. Elexicon is proactively replacing porcelain insulators for safety, reliability, and operational efficiencies.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Replacements of insulators to polymer are driven by internal planning. For larger utility projects, external contractors are used where reconstruction of lines may be required. In these cases, the contractor is provided with the new polymer insulators and the older legacy insulator is replaced. In more routine capital work, Elexicon operational staff will replace the porcelain insulators.

The analysis could be performed in the future for the insulators in the field. However, as there is no formalized inspection for insulators of condition, it could be difficult to plan for porcelain replacements. Locations are marked however on the GIS portal.

4.3 Scale Increase Considerations

As the porcelain insulators within the service territory have increased, the combined resources and funding from the two former utilities will assist in ensuring older legacy insulators are replaced. Due to the larger size of workers, capitalized interest, operations, and planning could potentially increase. The combined workforce could afford further efficiencies in the capitalization of projects and the insulator program.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Whereas Elexiocn’s budget is constrained by the deferred rebasing period, there are no significant impacts to this program. The program pacing is defined by the operational needs of the system.

5. Individual Projects Comprising the Program

No 2021 projects exceed the Material threshold for Renewal Programs- Other.

Budget Category	Renewal Programs – Reactive
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of their Service Life
Secondary Driver(s)	Reliability, Performance/Functionality

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$2.74M	**$1.83M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

Executive Summary

The Renewal-Reactive Program is a System Renewal program that designates and budgets for reactive replacements required during equipment failures, outages, and events requiring unplanned work. The program is split into different distribution assets at Elexicon. From the Asset Condition Assessment results of 2019, the amount of poor and very poor assets is identified for proactive replacements. However, there are situations where unexpected equipment failures, outages, and events requiring replacements occur which this program targets. In larger service areas with more distribution and substation assets, a larger investment budget is assigned. Outage metrics are also used to determine the historical outage statistics behind asset failures.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	2.74	2.33	1.87	1.84	1.81	1.82	1.82	1.82
Contributions	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	2.61	2.33	1.87	1.84	1.81	1.82	1.82	1.82

When outages and equipment failures occur, Elexicon will immediately address the problem and restore service to customers affected. A budget is set in place for these instances. Larger budgets are set forth on service areas that have a higher number of assets. Due to the consolidation of the former utilities, an increased workforce will allow for opportunities to consolidate resources in asset renewal projects. With the combined service territory, there will be more operational staff to answer outage issues and equipment failures in the field. The budget is utilized to ensure stock and spares are kept when an asset replacement is required.

Elexicon has an obligation and commitment to providing excellent reliability and customer service. If failed assets are not replaced, SAIDI and SAIFI measures could increase which reflects poorly on the utility. Additionally, safety could be affected by certain outages or events that impact distribution equipment. For instance, vehicle incidents may cause downed lines and poles could negatively impact the reliability. Elexicon needs to budget for distribution assets replacements that can be used to replace assets at times of reactive work.

With the merger, Elexicon will afford higher purchasing power and greater operational resources that can respond to reactive calls due to the consolidation of the two former utilities. More specifically, Whitby, Ajax, and Pickering are near one another as service areas. More staffing will require greater communication and organization from the control room and operational staff.

2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

The Reactive Renewals Program is a program that reactively replaces assets when assets fail or require replacements in the field. Reactive programs are split into six service areas under Elexicon which include Ajax-Pickering, Belleville, Brock, Clarington, Gravenhurst, and Whitby. Clarington also contains the service area of Port Hope; in this case while Brock includes Uxbridge, Port Perry, Sunderland, Beaverton and Cannington. The assets considered and budgeted for in the Reactive Renewals programs include:

- Wood poles;
- Underground cables
- Overhead conductors;
- Pad-mount transformer;
- Pad-mount switchgear; and
- Overhead in-line disconnect switches.

Outage statistics related to defective equipment are also tied to distribution assets found in the reactive program. As outages are a fundamental catalyst for reactive work, Elexicon must understand the impact of outages on customers for each asset class.

Unlike other planned system renewal programs, reactive replacements are required when in-service equipment fails or requires replacement. Age and deterioration contribute to equipment failures, but other external factors can also be catalysts to replacement. In this case, a reactive budget is set for each service area encompassing expected assets to fail. This allows for spare assets to be on hand when equipment fails, and reactive work is required. The magnitude of the reactive budget is allocated based on the size and asset inventory of the service area. As a result, the larger Elexicon service areas such as Ajax, Belleville, and Whitby have larger reactive budgets in comparison to other areas.

Historically, the legacy Veridian Connections budgeted for reactive renewals as dedicated programs, whereas the legacy Whitby Hydro Electric Corporation included reactive replacements in other renewal budgets. The analysis of the historical spending within this program at Veridian has been done by district as well as by asset type. Figure 1 and Table 2 show the five districts within the legacy Veridian utility and their respective spending from 2015 to 2017. Based on the trends, it is evident that the budget allocated to this program is in a downward trend.

Figure 1: Historical Reactive Spending by District

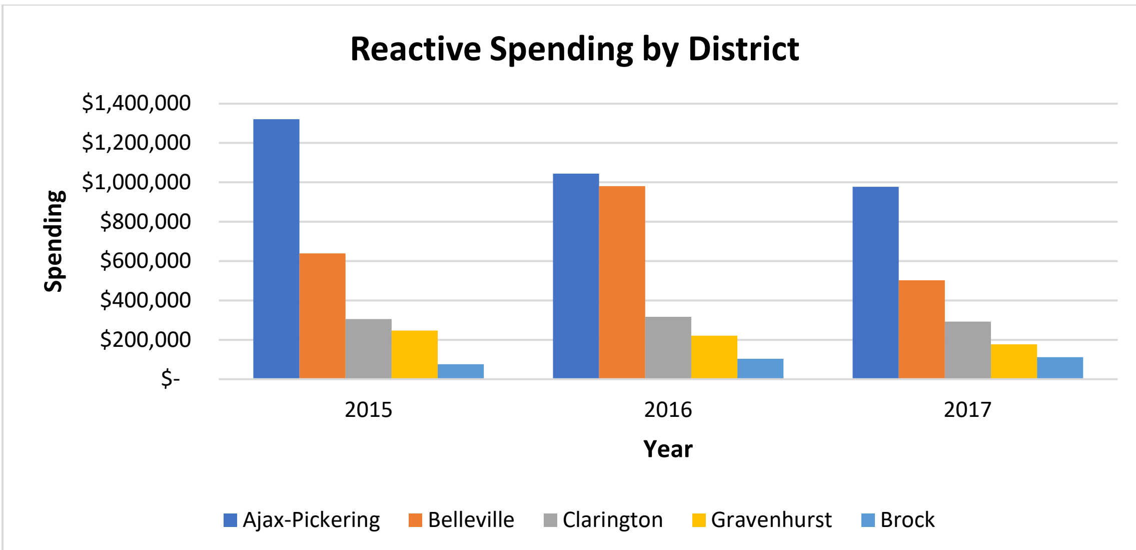


Table 2: Historical Reactive Spending by District 2015-2017

District	2015	2016	2017
Ajax-Pickering	$1,320,302	$1,044,486	$977,988
Belleville	$639,810	$981,365	$502,563
Clarington	$305,087	$317,297	$292,394
Gravenhurst	$247,690	$220,436	$177,411
Brock	$76,901	$103,998	$111,615

The historical spending for the reactive renewals program has also been analyzed by asset type. Figure 2 and Table 3 show the seven main accounts which fall within the reactive renewals program and their annual spending from 2015 to 2017. Based on the trendlines, it is evident that most accounts are generally in a downward spending trend except for Overhead Conductors and Devices (non-44kV) for which spending has been relatively constant.

Figure 2: Historical Reactive Spending by Asset Type/Account

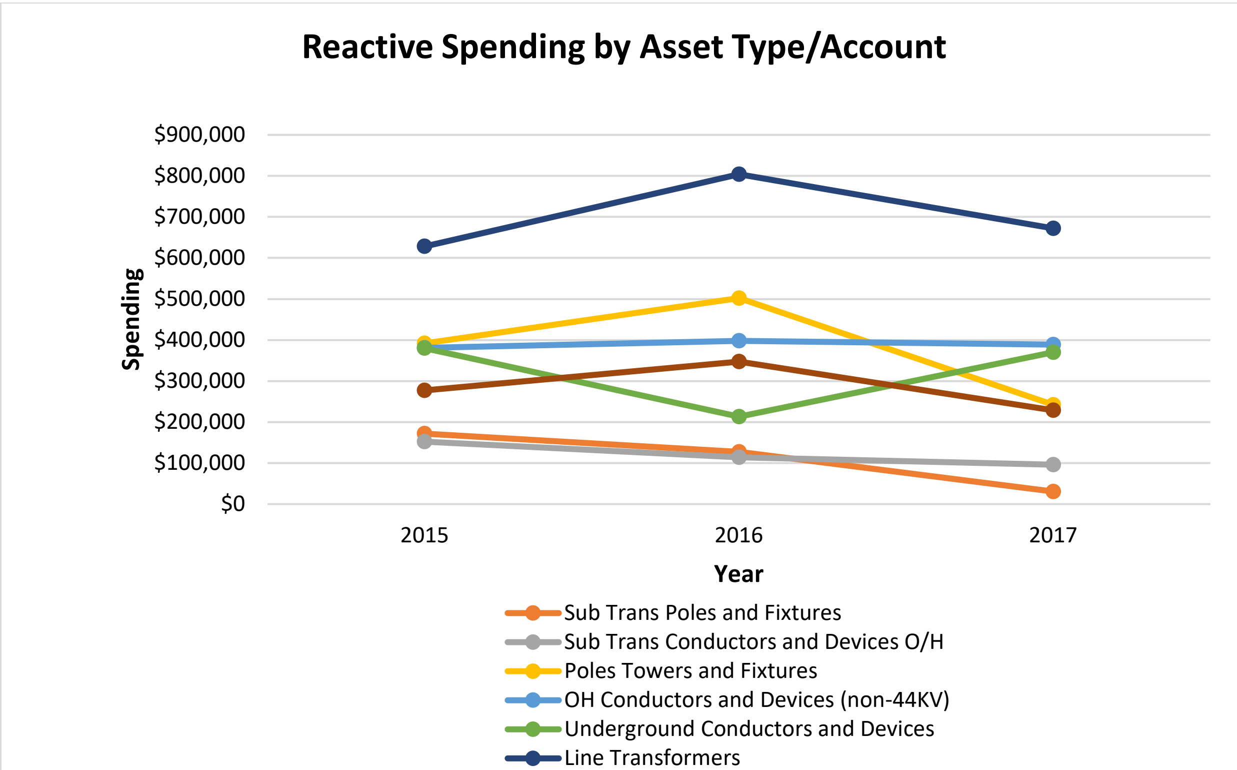


Table 3: Historical Reactive Spending by Asset Type/Account 2015-2017

Account	2015	2016	2017
Sub Trans Poles and Fixtures	$171,721	$127,574	$30,687
Sub Trans Conductors and Devices O/H	$152,181	$113,676	$96,075
Poles Towers and Fixtures	$391,799	$502,111	$242,194
Overhead Conductors and Devices (non-44KV)	$380,861	$397,867	$389,092
Underground Conductors and Devices	$379,916	$213,171	$370,014
Line Transformers	$628,136	$803,999	$672,101
Service System - OH / UG	$277,430	$347,279	$228,650

Underground Conductor Outage Metrics

Underground Cable influenced outages have stayed consistent from 2015 to 2018 with an increase found in 2019. As Underground Cable is essential to the service of many customers, Elexicon must prepare a budget that can capture the reactive work needed to remedy UG Cable outages. The Cable replacement program at Elexicon is meant to deter and prevent costly outages to the customer and Elexicon. Underground Cable outages can have major effects as represented by the historical customers and customer hours interrupted.

Table 4: 2015 to 2019 Outage Statistics for Underground Primary and Secondary Cable

Statistic	2015	2016	2017	2018	2019
Outages	137	106	128	138	195
Customers Interrupted	11,595	14,276	6,811	5,467	13,715
Customer Hours Interrupted	12,012	22,254	9,974	16,573	19,089

Switchgear Outage Metrics

Switchgear outages did not occur from 2015 to 2017 but in 2018 and 2019. As most of the switchgear is in very good, good, and fair conditions, switchgear failure due to conditions should not be expected in normal circumstances. In proportion to other asset classes, one switchgear outage can affect a significant number of customers and customer hours depending on the location of the asset.

Table 5: 2015 to 2019 Outage Statistics for Switchgears

Statistic	2015	2016	2017	2018	2019
Outages	0	0	0	10	3
Customers Interrupted	0	0	0	7,393	2,003
Customer Hours Interrupted	0	0	0	10,127	467

Pad-mount Transformer Condition and Outage Metrics

Pad-mount Transformers have had consistent outage numbers historically with an increase in 2018. As Transformers are directly providing power to customers, its impact on the number of customers interrupted can be large.

Table 6: 2015 to 2019 Outage Statistics for Pad-mount Transformers

Statistic	2015	2016	2017	2018	2019
Outages	12	21	19	30	12
Customers Interrupted	332	493	447	1379	433
Customer Hours Interrupted	534	1,050	1,501	3,674	615

Switch Outage Metrics

Across the years of 2015 to 2019, overhead switches have contributed to similar annual outage numbers. However, in the past years of 2018 and 2019, the number of customers interrupted by switch failures has increased. Depending on the location of the switch in the system, a varying number of customers could be affected. Across all asset types, the magnitude and effect that switch outages have on customers and service continuity are considerable.

Table 7: 2015 to 2019 Outage Statistics for Switches

Statistic	2015	2016	2017	2018	2019
Outages	36	29	24	30	29
Customers Interrupted	7,645	4,219	1,293	5,259	9,939
Customer Hours Interrupted	8,393	4,258	1,238	2,422	1,410

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

When an asset has failed in field, Elexicon will replace the asset to address its current failed state. The replacement would begin its lifecycle and effectively replace the asset that had reached end-of-life through failure.

Elexicon performs an Asset Condition Assessment every year to assess the current condition of its system and individual assets. The poor and very poor conditioned assets are addressed through planned asset replacement programs at Elexicon.

2.3 Compliance Considerations:

OEB Metrics: SAIDI measures the average hour of interruptions for Customers. Without a reactive program budgeted and planned for outages, SAIDI numbers could increase. Elexicon is measured on their performance on SAIDI. SAIFI measures the average frequency of interruptions for Customers. Without a reactive program budgeted and planned for outages, SAIFI numbers could increase. Elexicon is measured on their performance on SAIFI.

ISO 55000: The International Organization for Standardization (ISO) is an international standard-setting body that promotes worldwide proprietary, industrial, and commercial standards. The ISO 55000 series provides an overview of asset management and asset management systems and identifies common practices that can be applied to a broad range of assets. This standard drives Elexicon's asset management strategy as Elexicon adheres to the principles laid out in the ISO 55000 series. For example, section 6.1 of ISO 55002 covers actions to address risks and opportunities for the asset management system by planning to take action to mitigate the current and future risks as well as how to implement these actions and evaluate their effectiveness.

Ontario Regulation 22/04: *Ontario Regulation 22/04* is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure tracked by Elexicon. Elexicon's predecessor utilities have achieved compliance with Ontario Regulation 22/04 for all years in the historical period. Equipment on Distribution Lines overhead and underground alongside at Stations needs to be in proper operating condition as stated in O'Reg 22/04. Renewal programs help satisfy and ensure equipment is in proper operating condition.

Distribution System Code: System Inspection Requirements and Maintenance: Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with considerations to good utility practice quality, and reliability for short term and long-term basis. The Reactive Renewal program sets the ability for Elexicon to ensure that service is repaired in the case that reactive work concerning distribution assets is required.

2.4 Consequences of Inaction

An age-based failure curve analysis was conducted using Weibull Distribution. The parameters of the distribution were found using a typical useful life of the various assets. The analysis yielded the expected number of assets that will fail during 2021-2025. Since there is missing information for some of the asset classes, the expected number of failures also includes extrapolated data in which the ratio of failed assets to the total number of assets with unknown data matches the ratio of failed assets to the total number of assets with known data. Table 19 shows the expected number of failed assets from the relevant asset classes during 2021-2025.

Table 8: Expected number of failed assets during 2021-2025

Asset Class	Total Population	Unknown Age	2021	2022	2023	2024	2025
Wood Poles (#)	34,111	3,451	564	568	572	574	576
Underground Cable (km)	2,336	122	148	140	132	125	118
OH Conductor (km)	3,778	2,315	33	35	36	37	38
Distribution Switchgear (#)	439	123	10	10	10	10	11
Pad-mount TX (#)	13,599	803	243	253	262	272	281
Switches (#)	17,863	3,643	104	114	125	137	149

The above table shows that a significant portion of the mentioned assets is expected to fail during the next 5 years. Almost 8% of wood poles, 28% of UG cable, 10% of pad-mount transformers, and near 5%

of overhead conductor length are expected to fail between 2020-2025. The proactive replacements of these assets are addressed by their respective replacement programs. The reactive replacement program aims to address the assets that will fail, and the size of the program would be in line with the amount of work done on the other programs.

Customer Service: Customer Service is maintained and ensured through the Reactive-Renewal program. If a distribution asset fails in the field, spares will be required to replace the failed equipment. Elexicon budgets for spares and places them in storage at warehousing to ensure adequate stock is available when reactive work is required. Spares are also required to repair connections and the system in as timely a manner as possible. Having no stock would require the system to remain unchanged and reactive work would be significantly delayed. Customers expect excellent and consistent electrical service from Elexicon. By addressing areas or assets which have failed, Elexicon can restore service by introducing new assets to serve customers. This is important as asset failures affect the daily lives of customers that are connected downstream to the asset.

Operational Effectiveness: It is operationally effective for Elexicon to keep spares for Reactive-Renewal Program work. This is required to ensure Reliability Metrics such as SAIDI and SAIFI are addressed in an operationally effective manner. Expediting orders on equipment replacement for failed distribution equipment is not operationally effective and may cost significantly more.

2.5 Merger-Related Objectives:

Two merger-related objectives that relate to the reactive renewal program are service continuity and utility integration. While reactive replacements do not decrease the number of outages since it deals with already failed assets, they reduce the outage duration, minimizing downtime for customers and associated costs for Elexicon. If a project does not meet both objectives, it is eliminated. Merger related objectives can be broken down into sub-criteria which are used to evaluate how a program supports the objective.

The relevant sub-criterium of service continuity for the reactive renewals program is that the continued implementation of reactive budgets upholds the service levels that the two former utilities had. It is imperative that customers do not experience differences in reliability as a result of the merger. Budgeting for reactive work for service areas allows Elexicon to continue to serve customers when failures of assets occur in field.

The relevant sub-criterium of utility integration for the reactive renewals program is that the program is an investment that integrates core operations of the legacy utilities. Reactive replacements were done separately by each legacy utility before the merger, and the renewals program looks to consolidate these operations into a single core operation for Elexicon.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be
quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	***1***	***2***	***3***
Scenario Description	Status Quo: Current Budgeted Investments for Reactive Work	Further investment (10% more) into the reactive program	Less Investment (10% less) into the reactive program
Annual Program Scope	The Current annual scope is budgeted for depending on the size of the Service Area and the number of assets in each area. Larger Areas with more assets are provided with a higher annual budget. Outage statistics are also taken into consideration in determining reactive work spares.	10% more investment is budgeted for the Reactive Renewal Program. This would provide Elexicon with more resources in the case that more reactive work is forecasted.	10% less investment is budgeted for the Reactive Renewal Program. This would provide Elexicon with fewer resources to perform reactive work.
Annual Gross CAPEX	$1.83M	$2.01M	$1.65M
Annual Net CAPEX	$1.83M	$2.01M	$1.65M
Annual Program Benefits	The annual program benefit for this program is that Elexicon will have replaced the failed asset. Depending on the nature and magnitude of the failure, Elexicon may also restore service to customers through reactive replacements.	Benefits would not increase because of increased investment into the reactive program. Further investments into the program are made when required due to increased reactive work.	Benefits would decrease if investments into the reactive program were decreased. Current budgeted amounts evaluate historical outages and the amount of assets in a field. It is not recommended to decrease the investment.
Program Economics	Based upon historical reactive costs, the current budget is made	Increasing reactive spending by 10% may have marginal returns for Elexicon. If Elexicon	Decreasing reactive spending by 10% is not preferred and would not be optimal for Elexicon.

	to account for potential reactive work.	experiences further outages, funding from other programs may be shifted to this program.	Elexicon budgets reactive work based upon historical outages and the amount of assets in the area. Reducing the budgeted amount could introduce complexities and negative returns.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable. This is addressed through planned replacements from Elexicon. Generally, customers believe that the duration and frequency of outages that have occurred are the most inconvenient aspects when power outages occur. The combination of reactive and planned renewal spending seeks to decrease the duration and frequency of outages that Elexicon customers face.		
Other Constraining Factors	If Elexicon experiences further outages or issues requiring reactive work, budgets will need to be shifted across the investment category or program in current or future years.	Elexicon has planned optimally for investments so the increasing investment would be marginal in return.	Elexicon has planned optimally for investments so the decreasing investment would be harmful.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: While reactive replacements do not decrease the number of outages, they soften the blow of an outage by decreasing downtime, making the system overall more reliable.

Grid Resiliency: New System Hardening measures can be implemented through the reactive renewal of distribution assets. Installing more rigid assets with regards to weather will improve grid resiliency.

Operational Efficiency and Cost Effectiveness: Costs of outages are calculating based on a constant event cost added to a linear expression that is the outage duration multiplied by a cost per unit of time. The reactive renewals program minimizes the outage duration and therefore minimizes the cost of an outage.

Safety: In contingencies, asset failures can cause a threat to public safety as well as the safety of the crew members working those assets. The faster the reaction to those failed assets is, the smaller the chance of the hazard being overly dangerous.

Cyber-Security/Privacy: N/A

Environmental Benefits: Upon aging or failing, some assets can release chemicals that can harm the environment. As an example, pad-mount transformers can leak oil which could harm the environment. The ability to quickly replace failed pad-mount transformers can reduce the impact on the environment.

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Customers enjoy benefits from the renewal of distribution assets that provide service and electricity. As renewals introduce new asset lifecycles, the reliability of equipment and service can increase. Additionally, reactive budgets need to be set in cases where outages or unplanned work occurs to ensure that adequate resources are present in these scenarios.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

To plan for possible changes in the future, Elexicon considers several considerations. An expected number of failures for each asset class is predicted and an asset condition assessment is performed to have an overview of how the system may change during the next couple of years. An increase in connections is also predicted to plan for which areas would need to have their services expanded. With all the collected information, a prioritization framework will be put into effect to prioritize scopes following the current status quo and how the system would look like in the next couple of years.

If further deterioration is found or more outages are taking place, a shift of allocation of resources will be moved from another renewal program to the reactive program. Reactive renewal programs are crucial in ensuring electrical service is restored to customers. Elexicon must have a budget planned for reactive replacements to ensure customer service.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Table 9 summarizes the legacy planning approaches and the combined approach moving forward for the utility.

Table 9: Legacy and Combined Planning Approaches

Asset	Legacy Approach and Combined Approaches
Wood Poles	There are no differences between planned approaches of Elexicon and the legacy approaches of the previous utilities for this asset class.
Pole-mounted Transformer	The two pervious utilities would run pole-mounted transformers to failure. Elexicon will be adopting a more proactive approach.
Pad-mounted Transformer	The two pervious utilities would run pad-mounted transformers to failure. Elexicon will be adopting a more proactive approach.
Overhead Conductors	Veridian's approach to overhead conductors were to run the asset to failure. Whitby planned rebuilds within sections of the system. Elexicon will be planning section rebuilds into the future.
Overhead Switches	Overhead Switch replacements were reactive for the two previous utilities. Elexicon will be adopting a more proactive approach.
Pad-mounted Switchgear	There are no differences between planned approaches of Elexicon and the legacy approaches of the previous utilities for this asset class.
Underground Cable	Both utilities were proactive for underground cable replacement. Elexicon will continue to utilize testing as part of its planning approaches to underground cable replacements.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Wood Pole Consolidated and Legacy Inspections and Work Execution

Elexicon inspects wood poles every three years, with the inspections including wood rot testing, remaining strength tests, and visual inspections. The inspection cycle includes predictive maintenance through wood rot testing and remaining strength testing. Elexicon replaces wood poles based on the inspection and testing results as well as the age of the poles. Legacy Veridian conducted inspections based on an 8-year cycle with no maintenance work being included. Veridian replaced wood poles based on the results of the inspections. Whitby inspected poles based on a three-year cycle with no maintenance work being included. Whitby immediately replaced poles that were identified as hazards, while some poles were identified as needing replacements within a year being replaced the following year.

Underground Cable Consolidated and Legacy Inspections and Work Execution

Elexicon conducted underground cable inspections based on age and number of failures. For maintenance work, Elexicon currently performs cable injections based on the inspection results. Legacy Veridian inspected underground cable based on their age and number of failures, and also injected cable based on the inspection results as maintenance work. Veridian replaced underground cable based on age and inspection results. Legacy Whitby did not have an inspection and maintenance program for underground cable and replaced a subdivision-size section of underground cable annually.

Switchgear Consolidated and Legacy Inspections and Work Execution

Elexicon conducts inspections for switchgears through infrared scanning and visual inspections annually. Maintenance work comprises repairs based on the inspection results. Elexicon replaces switchgears proactively, with the replacements being based on the inspection results as well as age. Legacy Veridian conducted switchgear inspections through infrared scanning, visual inspections, evaluating the condition of the enclosure, and inspection of internal components based on a three-year cycle. Veridian based their maintenance work on the inspection results. Veridian also replaced switchgear based on inspections as well as age. Legacy Whitby similarly conducted inspections of switchgears as Veridian did, in that the inspections included infrared scanning, visual inspections, evaluating the condition of the enclosure, and inspection of internal components based on a three-year cycle. Whitby's maintenance work was based on the results of those inspections. Whitby also proactively replaced switchgears based on the result of the inspections as well as the age of the switchgears.

Pad-mount Transformer Consolidated and Legacy Inspections and Work Execution

Elexicon does visual inspections based on three-year cycles for pad-mount transformers. Currently, Elexicon re-paints transformers with rust based on customer requests for maintenance work, which is to be gradually transitioned to a reactive approach based on inspection results. Previously, Veridian inspected pad-mount transformers visually based on a three-year cycle, with maintenance work being mostly based on customer requests for the transformers to be re-painted. Veridian ran pad-mount transformers until failure until recently when loading of the transformer became a factor for replacement. Whitby also conducted inspections visually based on 3-year cycles, with maintenance work comprising of re-painting rusted transformers. Whitby ran transformers until failure unless inspections signaled a need for a replacement.

4.3 Scale Increase Considerations

Due to the scale increase of Elexicon from the merger, the service area responsibility has expanded. A large number of distribution assets need to be considered when creating assessments and plans regarding renewal programs. Outage statistics of the combined portfolio need to be understood to analyze where reactive outages occur. The larger combined resources of outside and inside staff will assist with ensuring the renewal of distribution assets are carried out. A consideration of the different approaches to inspections will be consolidated into the future. Material differences and designs will also be consolidated.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

The consolidation period/rate freeze will not affect the lifecycle management approach or volumes for this program. As this program is purely reactive, any issues that arise in the field must be addressed. This is to ensure customers will have electrical service and to maintain the reliability and safety of Elexicon's system. If further reactive work is required than originally budgeted, Elexicon shall ensure that program funding from other programs may need to be shifted to account for failures in field. Unexpected failures that require reactive work must be addressed by Elexicon and are top priority.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2021-5501-A	Ajax Renewal – Reactive	2021	0.5	59.4
2021-5501-B	Belleville Renewal – Reactive	2021	0.4	59.4
2021-5501-W	Whitby Renewal - Reactive	2021	0.5	59.4

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

<table>
<tr><td>Project name</td><td colspan="5">Ajax Renewal-Reactive</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-5501-A</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">Ajax</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td>Budget Category</td><td colspan="5">R7 - Renewal Programs-Reactive</td></tr>
<tr><td>Project Driver</td><td colspan="5">Asset failures</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project scope includes replacing the assets that have failed and/or flagged for action by crew due very poor condition. These renewals will correct system deficiencies and are required for reliable service to the customers.</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $500,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $500,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$45,000</td><td>$50,000</td><td>$85,000</td><td>$320,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon is required to keep reliability of plant. The project is to correct system deficiencies and replace/upgrade the assets that failed or flagged for action.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">59.4</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to the project. Elexicon is required to correct any system deficiencies and/or safety hazard by replacing the assets that failed or flagged for action by crew.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus, Public Policy Responsiveness and Operational Effectiveness. The project will improve system reliability and quality of service.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The project cost varies based on type of the asset that requires to be replaced.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Project name	Belleville Renewal-Reactive				
Project numbers	2021-5501-B				
Job numbers	Several				
Project District	Belleville				
Project Location	General				
Investment Category	System Renewal				
Budget Category	R7 - Renewal Programs-Reactive				
Project Driver	Asset failures				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 DEC 31				
Scope of Work	The project scope includes replacing the assets that have failed and/or flagged for action by crew due very poor condition. These renewals will correct system deficiencies and are required for reliable service to the customers.				
Preliminary Estimate: Total Capital Cost	Gross: $400,000	Contribution: $0		Net: $400,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$36,000	$40,000	$68,000	$256,000
Rationale for Intervention	Elexicon is required to keep reliability of plant. The project is to correct system deficiencies and replace/upgrade the assets that failed or flagged for action.				
Criteria Score	59.4				
Impacted Customers and Entities	Not Applicable				
Intervention Options	There is no alternative to the project. Elexicon is required to correct any system deficiencies and/or safety hazard by replacing the assets that failed or flagged for action by crew.				
Effect on System O&M Costs	Not Applicable				
Targeted Outcomes	This project addresses the RRF objectives of customer focus, Public Policy Responsiveness and Operational Effectiveness. The project will improve system reliability and quality of service.				
Cost Benchmarks	The project cost varies based on type of the asset that requires to be replaced.				
Value-Added Approach	Not Applicable				

Project name	Whitby Renewal-Reactive				
Project numbers	2021-5501-W				
Job numbers	Several				
Project District	Whitby				
Project Location	General				
Investment Category	System Renewal				
Budget Category	R7 - Renewal Programs-Reactive				
Project Driver	Asset failures				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 DEC 31				
Scope of Work	The project scope includes replacing the assets that have failed and/or flagged for action by crew due very poor condition. These renewals will correct system deficiencies and are required for reliable service to the customers.				
Preliminary Estimate: Total Capital Cost	Gross: $500,000	Contribution: $0		Net: $500,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$45,000	$50,000	$85,000	$320,000
Rationale for Intervention	Elexicon is required to keep reliability of plant. The project is to correct system deficiencies and replace/upgrade the assets that failed or flagged for action.				
Criteria Score	59.4				
Impacted Customers and Entities	Not Applicable				
Intervention Options	There is no alternative to the project. Elexicon is required to correct any system deficiencies and/or safety hazard by replacing the assets that failed or flagged for action by crew.				
Effect on System O&M Costs	Not Applicable				
Targeted Outcomes	This project addresses the RRF objectives of customer focus, Public Policy Responsiveness and Operational Effectiveness. The project will improve system reliability and quality of service.				
Cost Benchmarks	The project cost varies based on type of the asset that requires to be replaced.				
Value-Added Approach	Not Applicable				

Budget Category	Renewal Program – Voltage Conversions
OEB Investment Category	System Renewal
Primary Driver	Assets at the End of Their Service Life
Secondary Driver(s)	Capacity, Operability

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.27M	**$2.36M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

The Voltage Conversion Program is a System Renewal program meant to replace legacy voltage networks and distribution equipment at Elexicon with new higher distribution voltage rated systems and equipment. The assets include wood poles, pole-mount transformers, pad-mount transformers, switches, and overhead and underground cables. Voltage Conversion projects are initiated when Elexicon deems it beneficial to increase service voltage within an area due to the combination of equipment renewal, and increased reliability, capacity, and operational efficiency. Elexicon is continuing to phase out 4.16 kV networks by converting to higher voltages in Port Hope, Gravenhurst, and Belleville, and other 8.32 kV networks in Pickering.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Summary of Forecast Expenditures

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.27	0.69	0.53	0.90	2.33	3.32	2.78	4.30
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.25
Net Program Expenditures	0.27	0.69	0.53	0.90	2.33	3.32	2.53	4.05

As the system developed, legacy service voltages remain in place throughout the distribution system at Elexicon. For instance, 4.16 kV is still present within some service areas. Elexicon is proactively looking to convert these legacy voltages into higher voltages. Voltage Conversion projects found in the System Renewal category are primarily condition driven. Capacity and Operability are secondary drivers to this program.

From the view of a newly merged company, Whitby has replaced its 4.16 kV assets. The legacy 4.16 kV systems are found within the areas of Belleville, Gravenhurst, and Port Hope. 4.16 kV also exists in the Brock Territory but there are no plans to convert these voltages in the future DSP period. Elexicon aims to proactively replace legacy 4.16-kV and 8.32-kV systems in the future DSP period.

2. Basis for Action

2.1 Performance Trends:

C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:

The Voltage Conversion Renewal Program is intended to increase the voltage of feeders. This investment falls into the System Renewal category since it is primarily driven by assets at the end of their service life. In the long term, voltage conversions allow for the elimination of medium-voltage substations, which increases operational efficiency. Investment decisions are made based on failure risk, defined as the product of asset failure probability and its impact. Assets involved in voltage conversion projects include:

- Overhead conductors;
- Underground cables;
- Wood poles;
- Distribution transformers (pad-mount and pole-mount); and
- Switches.

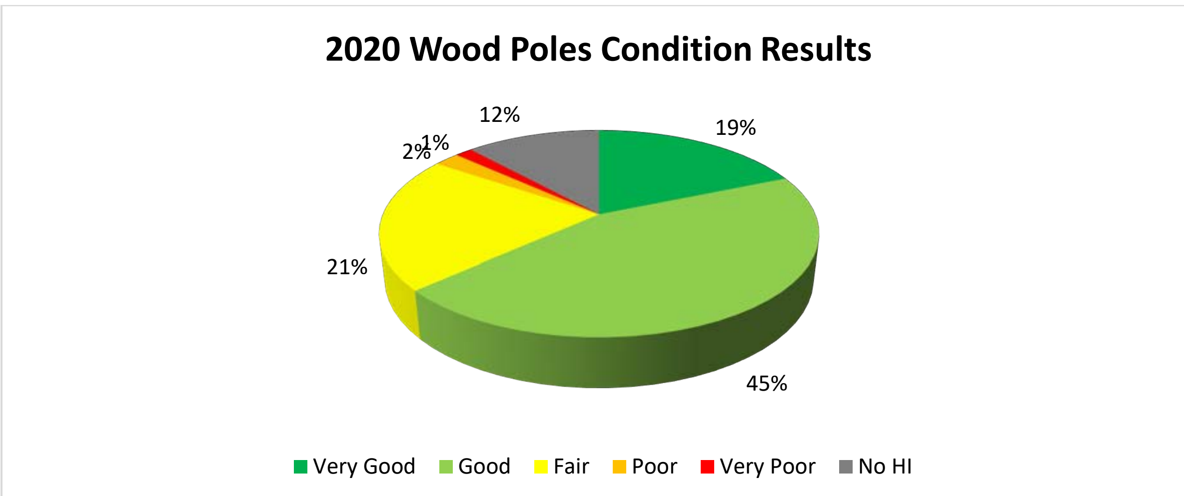
Voltage Conversion projects differentiate from one another in the number of legacy assets that need to be replaced and converted. The complexity of the current system and the number of circuits fed by the feeders needs to be taken into consideration. Substation Assets are also replaced in Voltage Conversion projects, but those replacements are found in the Substation Renewal program.

Asset Condition Assessments were completed in 2020 for Elexicon. An Asset Condition Assessment evaluates assets by producing a health index based on condition parameters, which is used to place each asset in one of the following condition categories: very poor, poor, fair, good, and very good. Results shown reflect the data availability of the population where assets with sufficient data inputs are displayed as results.

Wood Poles Condition Results 2020

Figure 1 demonstrates the condition breakdown percentage for distribution assets at Elexicon. About 19% of wood poles are in very good condition and 45% are in good condition. However, the second highest portion of wood poles are found in the fair condition category. These Fair-conditioned assets will continue to deteriorate further, which means they must be monitored and considered for future replacements. Elexicon will prioritize Poor and Very Poor Conditioned Poles for replacement. Figure 6 and Table 6 breaks down the wood pole condition demographics into unit counts.

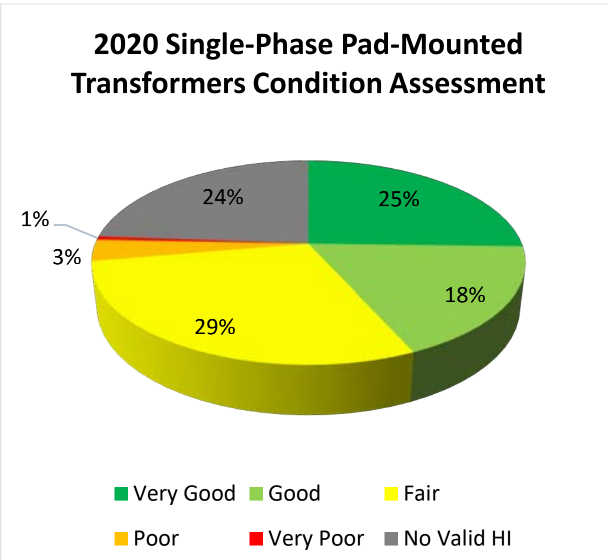
Figure 1: 2020 condition assessment for wood poles

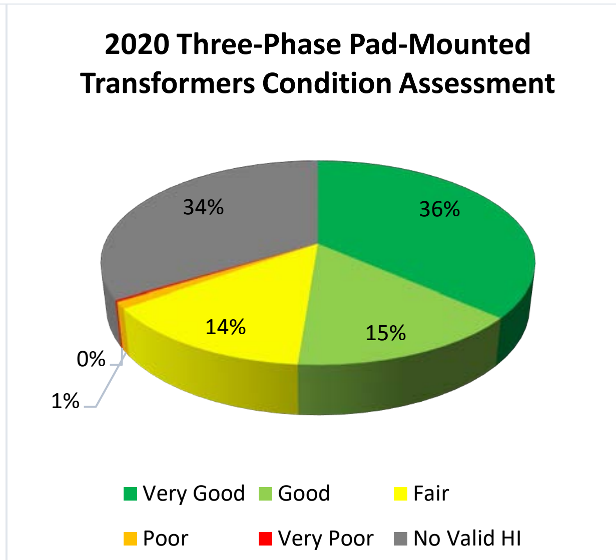


Pad-mount Transformers Condition Results 2020

Pad-mounted transformers are in a relatively good condition given that the percentage of poor or very poor assets is much lower than those in good and very good condition. However, for Single-Phase Pad-mounted Transformers, the fair category possesses the most assets with 29% of the population. For three-phase pad-mounted transformers, fair conditioned assets are the fourth highest of the categories. It can be expected that in the coming years these assets could deteriorate further which could raise concerns over the reliability of the system. Elexicon prioritizes transformers in the very poor and poor category while monitoring fair assets for further degradation. Figure 2 represents the percentage breakdown for each pad-mounted transformer measured to its asset class and phase. Figure 7 and Table 7 provide a breakdown of both the three-phase and single-phase pad-mounted transformer by asset count combined.

Figure 2: 2020 condition assessment of pad-mount transformers





Across the years of 2015 to 2019, Pad-mount transformers have contributed to similar annual outage numbers. However, in the year 2018, Pad-mount transformers peaked in outages, customers interrupted, and customer hours interrupted. No visible trend in increased outages from this asset class is found.

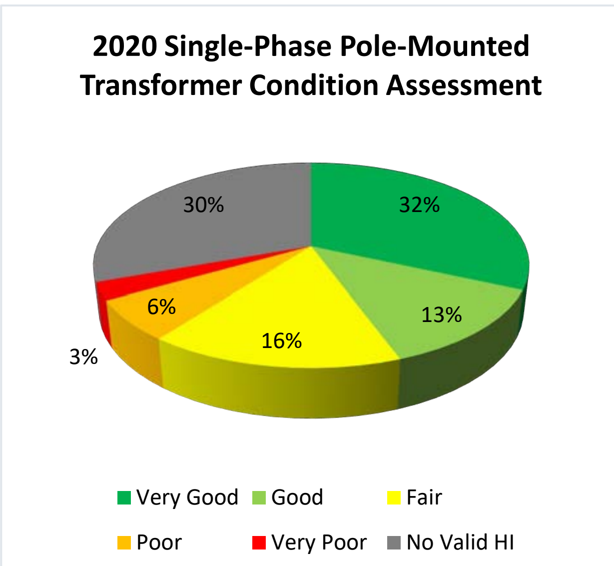
Table 2: Outage statistics by UG Transformer 2015 to 2019

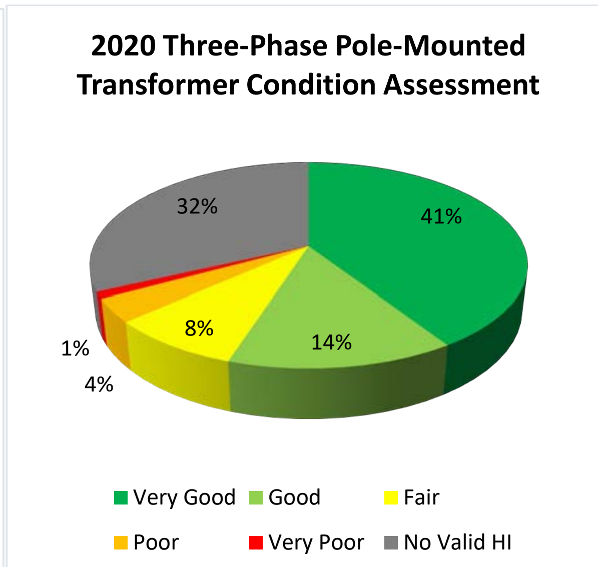
Statistic	2015	2016	2017	2018	2019
Outages	12	21	19	30	12
Customers Interrupted	332	493	447	1379	433
Customer Hours Interrupted	534	1,050	1,501	3,674	615

Pole-mount Transformer Condition Results 2020

Pole-mounted Transformers are also in relatively good condition but have larger amounts of poor and very poor assets than pad-mounted transformers. Poor and very poor pole-mount transformers will be prioritized for replacement. Fair conditioned pole-mounted transformers are not as significant in amount as the pole-mounted transformer class. These fair assets will be monitored and replaced if any further significant deterioration is found in the DSP period. Figure 3 represents the percentage breakdown for each pole-mounted transformer measured to its asset class and phase. Figure 7 and Table 7 provide a breakdown of both the three-phase and single-phase pole-mounted transformer by asset count combined.

Figure 3: 2020 condition assessment of Pole mounted Transformers





Across the years of 2015 to 2019, pole-mount transformers have contributed to similar annual outage numbers. In the years 2016 and 2017, the total number of outages that occurred dropped. No visible trend in increased outages from this asset class is found. The year 2018 peaked in customers interrupted and the year 2016 peaked in customer hours interrupted.

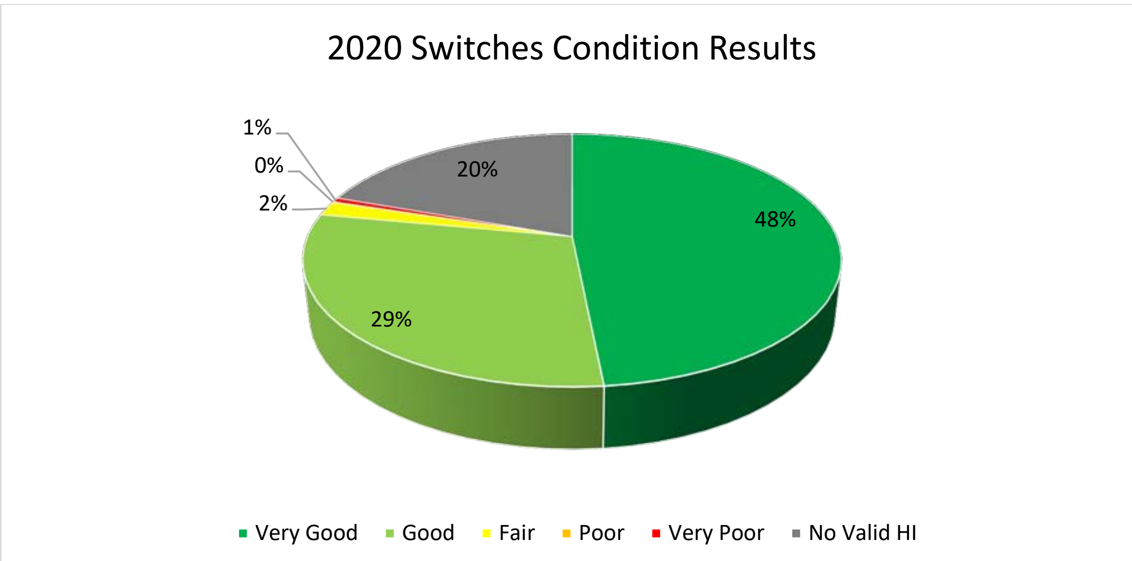
Table 3: Outage statistics by OH Transformer 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	27	16	14	26	28
Customers Interrupted	739	503	74	2,849	237
Customer Hours Interrupted	1,227	1,640	212	818	686

Switches Condition Results 2020

Overall, Elexicon switches are in good condition. About 48% of switches are found to be very good and 29% of switches are also found to be in good condition. Only 2% of switches are in the fair condition and 1% of the asset population is very poor. Very Poor switches will be prioritized for replacements and fair conditioned switches will be monitored for future degradation. Figure 4 represents the percentage breakdown for all switches. Figure 8 and Table 8 provide a breakdown of single-phase and three-phase switches by type and or location by asset count.

Figure 4: 2020 condition assessment of Switches



Across the years of 2015 to 2019, overhead switches have contributed to similar annual outage numbers. However, in the past years of 2018 and 2019, the number of customers interrupted by switch failures has increased. Depending on the location of the switch in the system, a varying number of customers could be affected. Across all asset types, the magnitude and effect of switch outages are considerable with regards to service continuity.

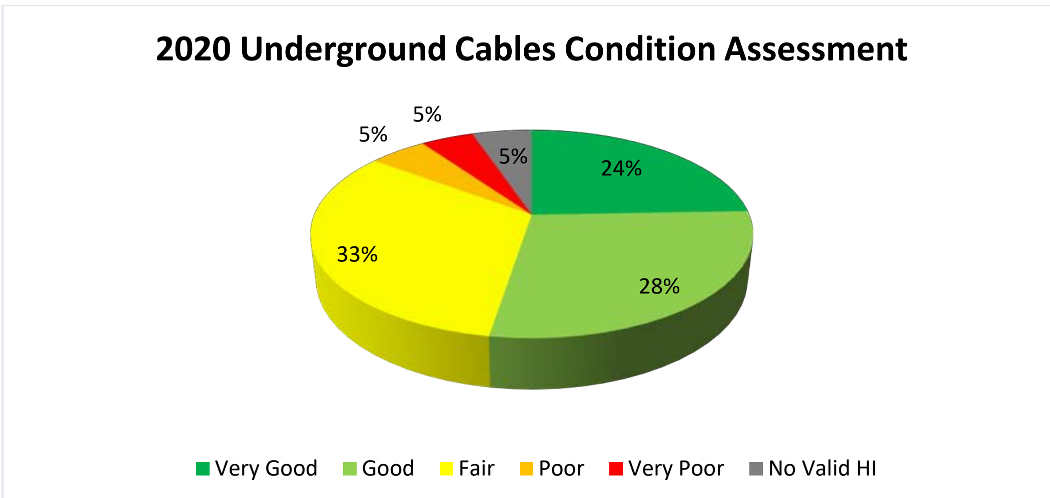
Table 4: Outage Statistics by Switches 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	36	29	24	30	29
Customers Interrupted	7645	4219	1293	5259	9939
Customer Hours Interrupted	8,393	4,258	1,238	2,422	1,410

Underground Cables Condition Results 2020

Overall, Elexicon's Underground cable population are found to be in good condition. About 24% of underground cables are very good and 28% are in good condition. However, about 33% of the population is found to be fair and this portion represents the highest percentage of the asset population. These cables will be monitored for further degradation. Overall, 10% of underground cables are either in very poor or poor condition. These assets will be prioritized for replacement. Figure 5 represents the percentage breakdown for all underground cables. Figure 9 and Table 9 provides a breakdown of all underground cable to voltage levels and length.

Figure 5: 2020 condition assessment of UG Cables



As shown in the analysis of outage statistics with regards to underground cable, failures regarding cable produce larger numbers of customers and customer hours interrupted. For UG primary cable outages found in Table 5, there has been a drop in customers interrupted for the years 2017 and 2018. Furthermore, 92 outages occurred in 2019 which is significantly higher than the next highest number, 58 outages in 2016. Due to the criticality that primary underground cable has with providing electricity to customers, Elexicon must proactively replace these assets.

Table 5: Outage Statistics by UG Primary Cable 2015 to 2019

Statistic	2015	2016	2017	2018	2019
Outages	137	106	128	138	195
Customers Interrupted	11,595	14,276	6,811	5,467	13,715
Customer Hours Interrupted	12,012	22,254	9,974	16,573	19,089

2.2 Current-State Analysis:

-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:
o Information on the condition of the assets relative to the typical life-cycle and performance record of the assets targeted by the project [Continued in Section 2.4]

The Asset Health and condition distributions of assets related to voltage conversion renewal programs are provided in the following sections. The condition assessment was done on each asset based on pre-determined condition parameters. Each condition parameter has a weight depending on the importance of the condition parameter relative to the others. Using both the score of each condition parameter along with its respective weight, a health index can be calculated, which determines which condition bucket the asset falls into.

Wood Poles Asset Condition 2020

The 2020 Asset Condition Assessment shows that there are 1,279 out of 34,111 wood poles currently in either poor or very poor condition. These poles would be included in the recommended replacement plan as they are at risk of failure and therefore could lead to an outage. We also have 7,199 wood poles whose condition is considered fair. These poles could further deteriorate to poor or very poor before the next assessment, meaning they should be accounted for in the later stages of the replacement plan. The typical useful life used to analyze the assets is 45 years for wood poles.

Figure 6: 2020 Wood Pole Condition Assessment

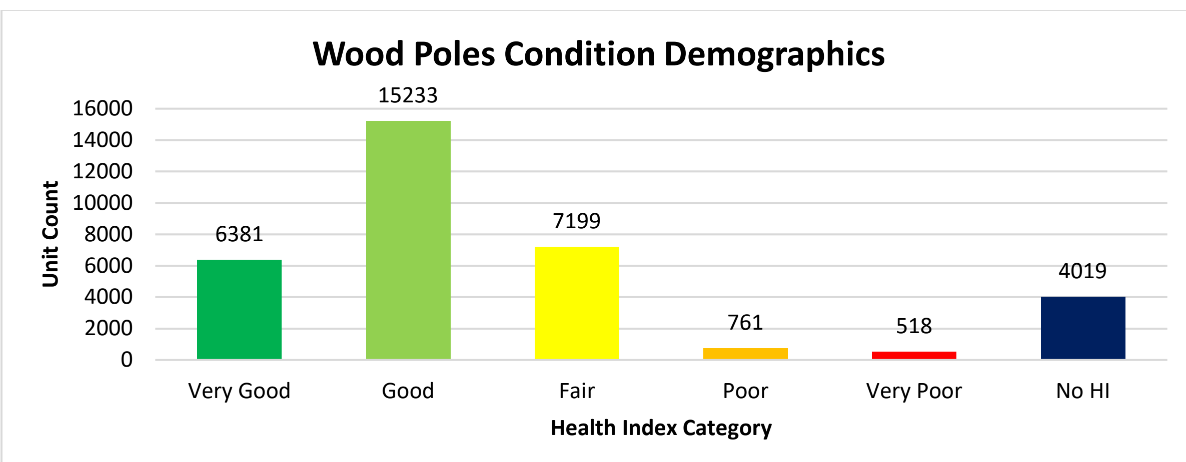


Table 6: Wood Pole Asset Count by Condition

Asset	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Wood Poles	6,381	15,233	7,199	761	518	4,019
Total (%)	**19%**	**45%**	**21%**	**2%**	**2%**	**12%**

Distribution Transformers Asset Condition 2020

The 2020 Asset Condition Assessment results are shown in Figure 7 and Table 7. About 622 transformer assets are found to be in the Poor and Very Poor Category; these candidates are to be prioritized for replacement across the future DSP period. About 4,100 transformers are identified as fair candidates; these transformers shall be evaluated and monitored year over year for degradation. Fair transformers potentially can become poor or very poor as time passes and the equipment continues to be in service.

Figure 7: Distribution Transformer Asset Health Overview

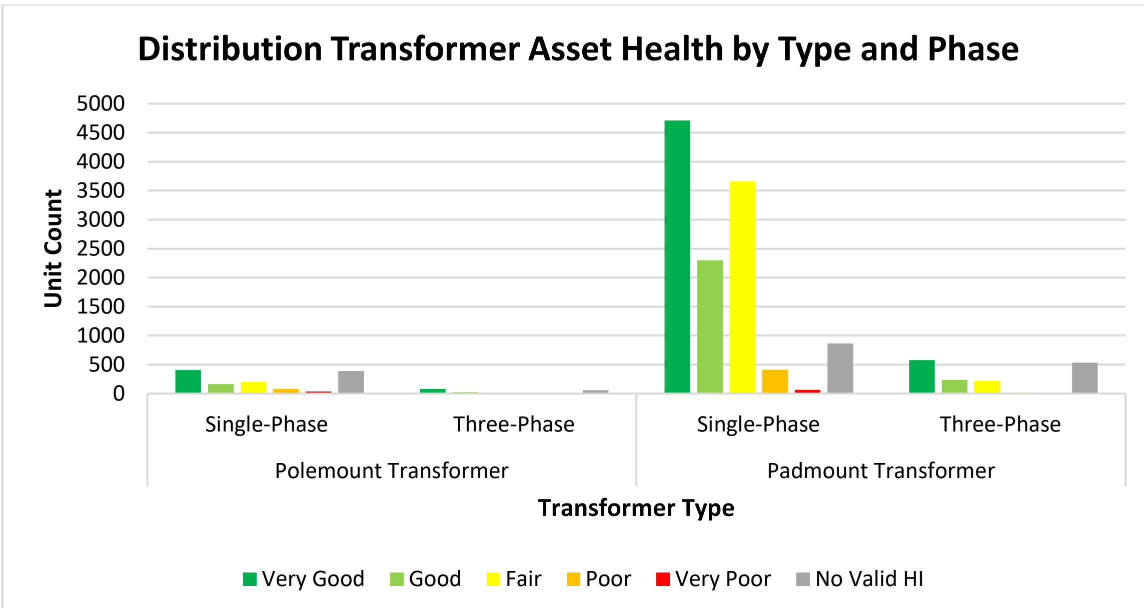


Table 7: Distribution Transformer Asset Health by Phase and Type

Asset	Phase and Territory	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Pole-mount Transformer	Single-Phase	404	162	203	81	35	389
	Three-Phase	78	27	16	7	2	61
	Total (%)	**32.9%**	**12.9%**	**14.9%**	**6.0%**	**2.5%**	**30.7%**
Pad-mount Transformer	Single-Phase	4,712	2,297	3,662	411	65	865
	Three-Phase	579	234	219	17	4	534
	Total (%)	**38.9%**	**18.6%**	**28.5%**	**3.1%**	**0.5%**	**10.3%**

Asset Condition for Switches 2020

The 2020 Asset Condition Assessment results for Switches (Three Phase and Single Phase) are provided in Figure 8 and Table 8. About 113 of all switches are found to be in Poor or Very Poor Condition; These assets shall be prioritized for replacement. 326 of the total switch inventories are found to be in fair condition; the health of these assets could deteriorate. About 13,802 switches are in the good or very good category which reflects the general health of the asset portfolio; this represents about 78% of the Switch population.

Figure 8: Switch Asset Health Overview

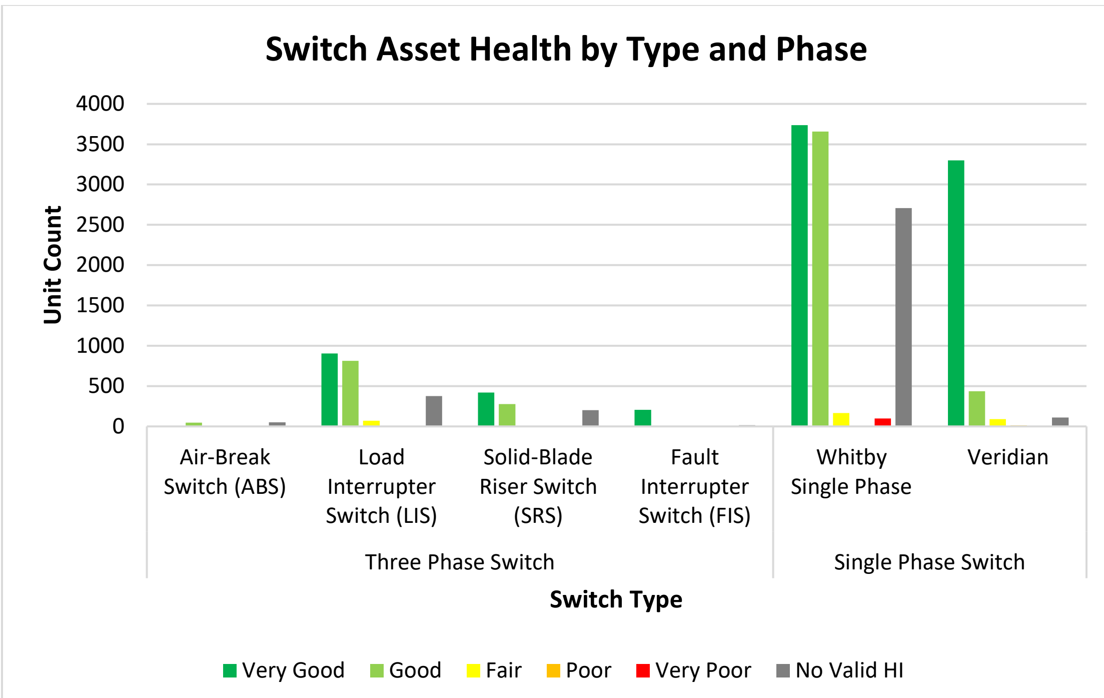


Table 8: Switch Asset Health Overview by Phase and Type/or Territory

Asset	Type	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Three Phase Switch	Air-Break Switch (ABS)	9	45	0	0	0	51
	Load Interrupter Switch (LIS)	903	813	69	0	0	375
	Solid-Blade Riser Switch (SRS)	420	277	0	0	3	200
	Fault Interrupter Switch (FIS)	207	0	0	0	0	15
Single Phase Switch	Whitby	3,736	3,658	165	0	97	2,708
	Veridian	3,299	435	92	13	0	112
All Switches	**Total**	**48.4%**	**29.5%**	**1.8%**	**0.1%**	**0.6%**	**19.6%**

Underground Cable Asset Condition 2020

Underground cables are different than the other assets as they are counted based on length (in km) as opposed to the other assets being counted by quantity. The total length of underground cables is 2,336 km. The 2020 assessment shows that 224 km of underground cable is in either poor or very poor condition. The severity of a failure depends on the location of the cable in the system. Cables that are in either poor or very poor condition should be replaced as they could fall short of the reliability standards Elexicon commands. 726 km of underground cable is fair. Like other assets, fair underground cables could deteriorate to poor or very poor before the next assessment, meaning it is recommended to include them in the replacement plan.

Figure 9: Underground Cable Condition Assessment

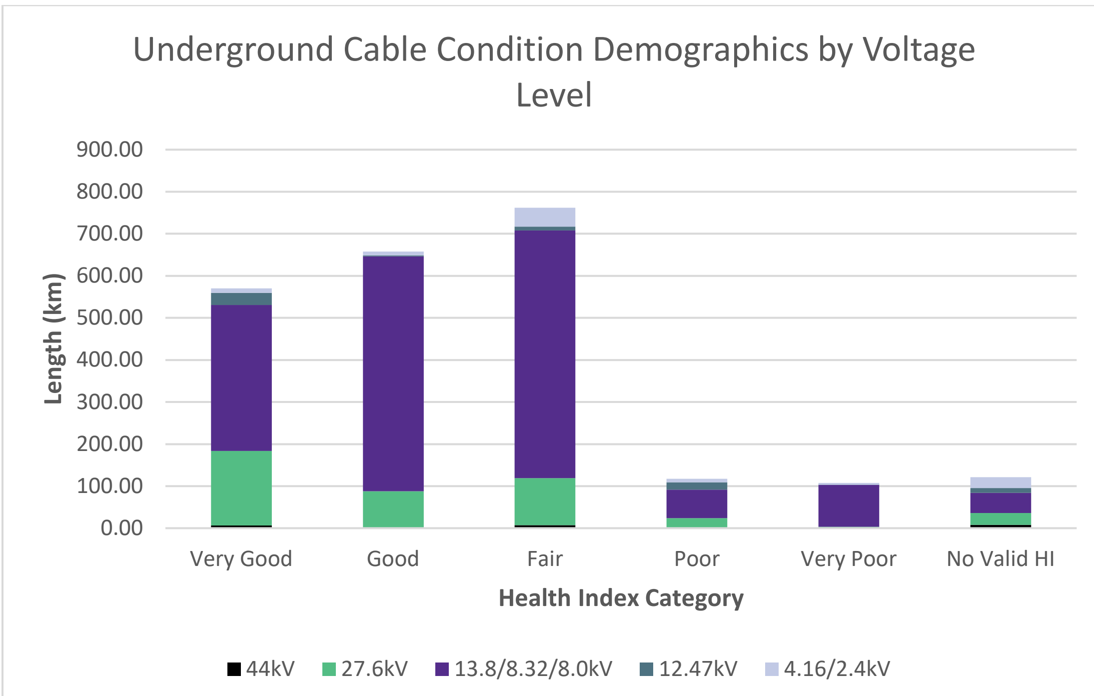


Table 9: Underground Cable length Count (km) by Condition and Voltage

Asset	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
44kV	6.34	1.42	6.96	0.14	0.82	7.98
27.6kV	177.10	86.56	111.70	23.56	2.66	27.89
13.8/8.32/8.0kV	347.52	558.65	589.19	68.18	99.30	47.83
12.47kV	28.45	1.67	9.21	16.89	0.60	11.81
4.16/2.4kV	10.94	9.35	44.92	8.61	3.92	26.11
Total (km)	570.36	657.65	761.97	117.39	107.30	121.61
Total % (km)	**24%**	**28%**	**33%**	**5%**	**5%**	**5%**

Current State of Service Area Voltages for Switching and Transfers

Table 10 illustrates the service area voltages prevalent in the four areas targeted for Voltage Conversion projects. 'TBC' ('To be Converted') is attached to the service stations that will be converted to higher voltages now and into the future. Higher voltages will provide increased capacity and reliability in the system. Additionally, older legacy voltage assets will be replaced thus increasing asset life and renewing service continuity. If one common service voltage for Elexicon stations in the area is developed, greater contingency planning and switching operations can also be conducted.

Figure 10: Voltage Makeup of current targeted Service Areas for Voltage Conversion

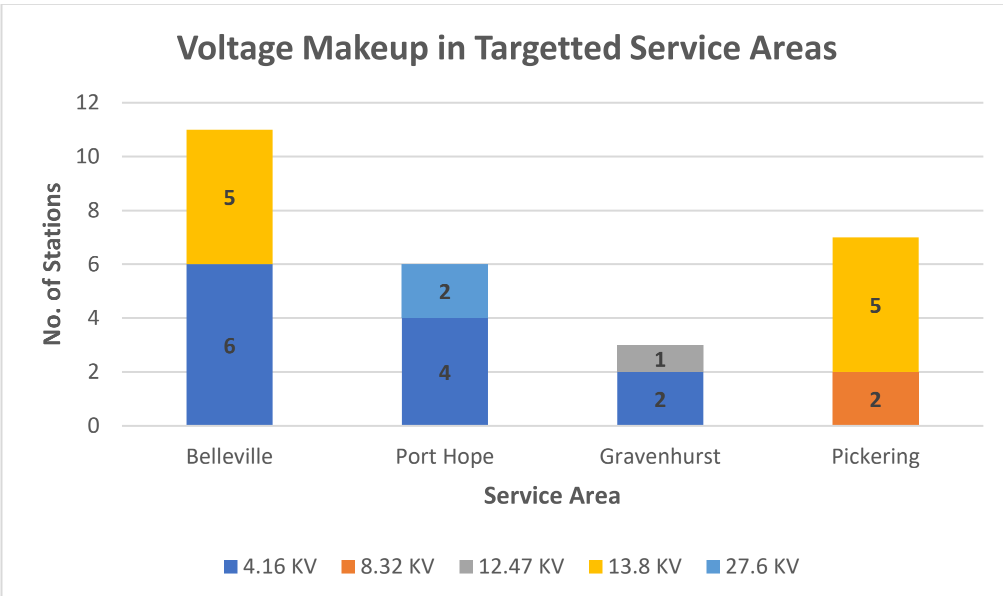


Table 10: Elexicon Station Service Voltages to Be Converted (TBC)

Voltage	Belleville	Port Hope	Gravenhurst	Pickering
4.16 kV	6 (TBC)	4 (TBC)	2 (TBC)	
8.32 kV				2 (TBC)
12.47 kV			1	
13.8 kV	5			5
27.6 kV		2		
Legacy Voltage (%)	54.5%	66.6%	66.6%	28.5%

State of 4.16 kV Assets in targeted Voltage Conversion Areas

An overview of all legacy 4.16 kV voltage areas is provided. Elexicon has longer-term initiatives at the utility to replace all 4.16 kV assets which extend past the DSP. In Elexicon, about 37% of the stations (21 in total) are associated with the legacy 4.16 kV. These stations are found in the service areas of Belleville (6), Brock (9), Port Hope (4), and Gravenhurst (2). Elexicon has currently planned for 4.16 kV voltage conversion projects in Belleville, Port Hope, and Gravenhurst in the DSP period. 4.16 kV conversion feasibility in Brock will be reviewed in the future.

Figure 11: Elexicon Station Percentage Makeup of Voltage Levels

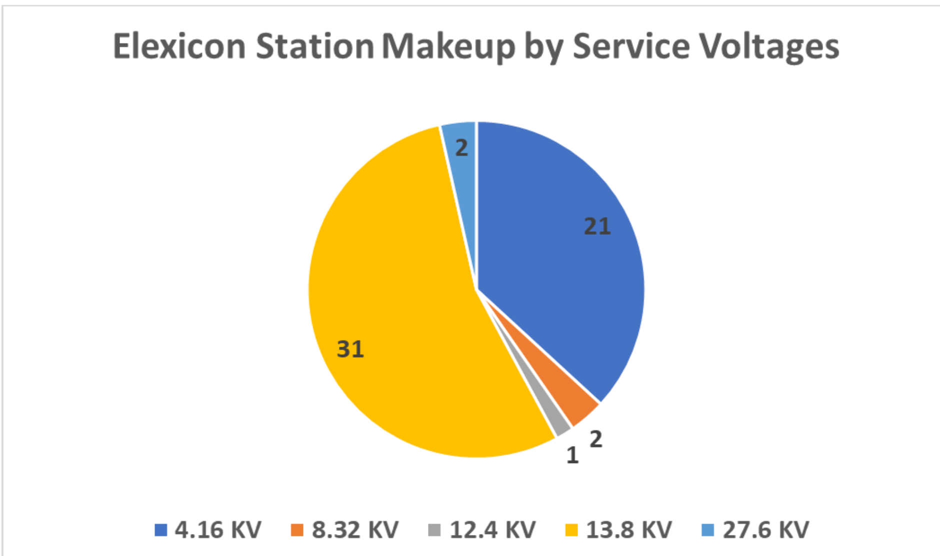


Table 11: Station Count by Voltage Level

Service Voltage	Station	%
4.16 kV	21	37%
8.32 kV	2	4%
12.47 kV	1	2%
13.8 kV	31	54%
27.6 kV	2	4%

A list of recurring Voltage Conversion projects is provided below:

Table 12: Recurring 4.16 kV Voltage Conversion Projects

Service Area	Projects Name	Years	Legacy Voltage	Converted Voltage
Gravenhurst	First Voltage Conversion	2023,2024	4.16 kV	12.47 kV
Port Hope	Cavan South Voltage Conversion	2023,2024	4.16 kV	27.6 kV
Belleville	Cascade Voltage Conversion	2022	4.16 kV	13.8 kV
	Belleville Long Term 4.16 kV Voltage Conversion	2023-2026	4.16 kV	13.8 kV

Average Age and Health Index of Belleville, Port Hope, and Gravenhurst 4.16 kV Assets

Age and Health index data is provided for all the associated 4.16 kV Station transformers in the planned 4.16 kV Voltage Conversion projects. The average age of all 4.16 kV Power Transformers is 50 years which is above the typical useful life of 45 years. The average health index of the 4.16 kV Transformers is 57%. Voltage Conversion projects will assist in renewing the asset life found within 4.16 kV Networks with higher voltage rated equipment and new service life. Five of the Nine Transformers are higher than typical useful life representing the age of the legacy voltage in the area. Three of the Nine Transformers are a minimum of three years away from the typical useful life of 45 years. When a feeder is completely converted, the substation transformer will also be replaced. Table 13 shows the relevant Age and HI for legacy 4.16-kV transformers.

Table 13: Average Age and HI% for selected 4.16-kV Stations.

Service Area	Substation Transformer	Age	HI %	Typical Useful Life
Port Hope	CAVS T1	65	75%	45
Port Hope	CAVS T2	65	58%	
Gravenhurst	First T1	45	47%	
Belleville	Cascade T1	52	63%	
Belleville	Catherine T1	68	56%	
Belleville	Edge Hill T1	59	36%	
Belleville	Harder T1	48	45%	
Belleville	Herchimer T1	45	56%	
Belleville	Herchimer T2	43	68%	

The average age and health indices are provided for applicable distribution assets found commonly in voltage conversion projects. These assets either are rated or in use with 4.16 kV equipment. Each voltage conversion project differs in terms of the actual assets required due to the differences in previous system configuration, land use within the area, and project scope.

Table 14: Average Age and HI% for selected 4.16 kV Assets.

Area	4.16KV Asset	Average Age	Average HI %	Typical Useful Life
Port Hope	Wood Pole	36.75	78%	40
Gravenhurst		26.62	73%	
Belleville		16.67	67%	
Port Hope	UG Cable	36.80	68%	40
Gravenhurst		28.80	71%	
Belleville		35.80	64%	
Port Hope	OH Conductor	14.67	87%	60
Gravenhurst		7.00	94%	
Belleville		13.47	99%	
Port Hope	3PH Pad-mount Transformer	N/A	100%	30
Gravenhurst		4.80	100%	
Belleville		41.36	19%	
Port Hope	1PH Pad-mount Transformer	22.65	78%	30
Gravenhurst		19.18	75%	
Belleville		18.65	78%	
Port Hope	Pole-Mounted Transformer	15.23	81%	40
Gravenhurst		5.33	96%	
Belleville		31.49	40%	

Asset Introduction from Voltage Conversion Projects

Wood Poles are expected to be the largest contributor of assets to Voltage Conversion projects from 2020 to 2024. Other assets such as overhead conductor and cable shall also be included in the installation and construction of voltage conversion projects. No switchgear introductions are to take place from Voltage Conversion projects in Elexicon.

Figure 12: New Asset introduction by Voltage Conversion

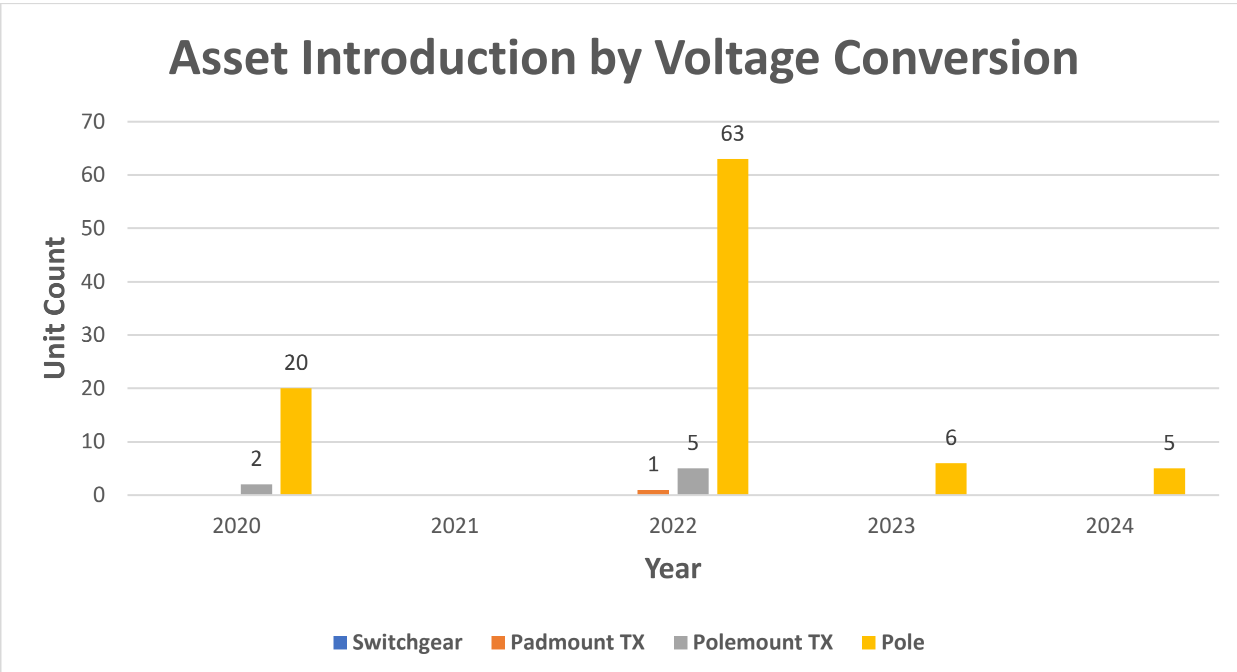


Table 15: Total Asset Count by Year

Asset	2020	2021	2022	2023	2024
Switchgear	0	0	0	0	0
Pad-mount transformers	0	0	1	0	0
Pole-mount transformers	2	0	5	0	0
Pole	20	0	63	6	5

Asset Replacement Plan

The Asset Replacement Plan prepared by METSCO in 2020 shows the recommended replacement plan based on the current condition along with the expected deterioration rate.

The below table shows the recommended replacement schedule brought forth by the Asset Replacement Plan.

Table 16: Recommended Asset Replacement Volumes

Projected Replacement						
Asset / Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Wood Poles (#)	350	350	350	350	350	350
Underground Primary Cables (km)	50	65	65	82	82	82
Overhead Conductor (km)	60	60	60	60	60	60
Pad Mounted Transformers	200	240	280	300	300	300
Overhead Switch (Three-Phase and Single-Phase)	252	252	252	252	252	252

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

CSA Standards

The Canadian Standards Association (CSA) is a standards organization that provides standards for many different areas and sectors. One of CSA's standards is its electrical standards, which look to improve the safety and reliability of the electrical system.

CSA 22.3 No. 1 Overhead Systems

CSA 22.3 No.1 is a standard that applies to electric supply, communication lines, and equipment placed outside of buildings and fenced supply stations. The standard includes clause 5.3.2.1, which states that there is a minimum vertical separation between pole-mount transformers and the ground that depends on the location and voltage of the transformer. The standard also includes clause A.5.10.1, which states that there is a minimum vertical separation between supply and communication attachments on a joint-use pole, such as having a pole-mount transformer. The minimum vertical separation depends on the voltage of the supply conductors. Clause 8.7.2 of the standard states that conductors must have a minimum rated strength of 14,2kN, and design clause 8.7.3.2.1 states that conductor tensions under ice and wind loads shall not exceed 60% of the conductor's rated tensile strength. A key driver of this program would be having to comply with these standards if the equipment doesn't currently meet the clauses.

CSA 22.3 No. 7 Underground Systems

CSA 22.3 No. 7 is a standard that applies to the lines and equipment related to underground electric supply and communication systems placed outside of buildings and fenced supply chains. Section 10 of the standard includes clauses related to above-ground equipment, such as pad-mount transformers. Clause 10.1 states that live parts must be inaccessible. Live parts of pad-mount transformers being accessible makes it prone to rust, which would then require the transformer to be replaced or treated. Clause 10.2 states that there must be adequate working space around the pad-mount transformer. Clause 10.6, which is broken down into 2 sub-clauses, states that the pad-mount transformer must be designed to withstand a seismic event equal to the values given by the National Building Code. The standard also includes clauses related to the installation of conductors. Clause 5.1.3 states that underground cable must be buried at a minimum depth depending on the voltage of the cable as well as the location description of what the cable would be buried under. Clause 14.6.1 also states that supply lines must operate within limits on the voltage and power transmitted through these supply lines.

ISO 55000

The International Organization for Standardization (ISO) is an international standard-setting body that promotes worldwide proprietary, industrial, and commercial standards. The ISO 55000 series provides an overview of asset management and asset management systems and identifies common practices that can be applied to a broad range of assets. This standard drives Elexicon's asset management strategy as Elexicon adheres to the principles laid out in the ISO 55000 series. For example, section 6.1 of ISO 55002 covers actions to address risks and opportunities for the asset management system by planning to take action to mitigate the current and future risks as well as how to implement these actions and evaluate their effectiveness.

Ontario Regulation 22/04

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998 and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. This regulation drives parts of Elexicon's renewal programs as compliance with this regulation is a performance measure tracked by Elexicon. Elexicon's predecessor utilities have achieved compliance with Ontario Regulation 22/04 for all years in the historical period. Equipment in overhead and underground systems need to be in a proper operating condition where renewals from voltage conversion will satisfy.

Distribution System Code: System Inspection Requirements and Maintenance

Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with consideration to good utility practice quality, and reliability for short term and long-term basis. Inspection Activities are made following requirements found in the Code and where more frequent inspections are required. Where defects are discovered, replacements are made immediately or planned across into the future.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.* *-C.b.1 (SR) A description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to:* *o The number of customers in each customer class potentially affected by a failure of the assets included in the project* *o Quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)* *o Qualitative customer impacts (e.g. customer satisfaction, customer migration) with associated risk level(s)* *o The value of customer impact (e.g. high, medium, low) considering the characteristics of customers potentially affected by asset failure and the cost of failure* *-C.b.3 (SR) The consequences for system O&M costs, including the implications for system O&M of not implementing the project*

An age-based failure curve analysis was conducted using Weibull Distributions. The parameters of the distribution were found using a typical useful life of 40 years for pad-mount transformers and underground cable, whereas typical useful lives of 45 years and 60 years were used for wood poles and overhead conductors, respectively. The analysis yielded the expected number of assets that will fail during 2020-2025. To determine the number of failed assets, a forecast was run on assets with a known age. The percentage failure of the known aged assets was then applied to the unknown age population for extrapolation. Thus, the total failures forecasted is a percentage failure forecast on the total population. Table 17 shows the expected number of failed assets over the next five years.

Without intervention, it is expected that 8% of wood poles would fail during the next five years, whereas almost 28% of underground cable length and 5% of overhead conductor length is expected to fail. It is important to note that most of the overhead conductor length data is unknown so this value is extrapolated. The table also shows that nearly 10% of pad-mount transformers would be expected to fail without intervention.

Table 17: Expected Asset Failures for Distribution Assets

Asset Class	Total Population	Unknown Age	2021	2022	2023	2024	2025
Wood Poles (#)	34,111	3,451	564	568	572	574	576
Underground Cable (km)	2,336	122	148	140	132	125	118
Overhead Conductor (km)	3,778	2,315	33	35	36	37	38
Pad-mount TX (#)	13,599	803	243	253	262	272	281
Overhead Switch	17,863	3,643	104	114	125	137	149

Customer Service: Voltage Conversion projects provide benefits to Customer Service through the renewal of distribution system assets that provide electricity to customers. Improved equipment health ensures a well-kept system and increasing voltage levels within an area also increases the capacity of the specific feeder. Available capacity shall be open for new customer connections. Customers expect excellent and consistent electrical service from Elexicon. By proactively addressing areas or assets which have a higher risk of failure, Elexicon can maintain and improve the conditions of assets that serve customers. This is important as any asset failures would affect the daily lives of customers that are connected downstream to the asset.

Operational Effectiveness: Operational effectiveness through optimized asset investments from asset condition assessments is achieved. By understanding the state of all assets within the service Area, Elexicon can make optimized investments that address assets that exhibit deterioration. Furthermore, when legacy voltages are transformed into one service voltage in the area, operationally efficient switching and contingencies can be built in place.

When evaluating System Renewal Investment options, Elexicon undergoes analysis of options with regards to its effects on SAIDI and SAIFI by defective equipment and Residual Risk. The effect that an asset class has with regards to SAIDI and SAIFI values due to defective equipment failure is evaluated as the renewal program seeks to improve on these defective equipment metrics through proactive equipment renewal. Residual Risk is the monetized value of the left-over risk on the system after mitigations. It is monetized based on the quantified failure probability and monetized failure impacts (reliability, financial, environmental, and safety impacts).

2.5 Merger-Related Objectives:

Elexicon's merger-related objectives are service continuity and utility integration. For a project to be considered, it has to meet both those objectives. These merger-related objectives are broken down into sub-criteria which are used to evaluate how relevant a program is to its objectives.

The relevant criteria for the service continuity objective are related to safety benefits, effects on a worst-performing feeder ("WPF"), and legislative requirements. One criterion for the service continuity objective is the relative importance of the program as dictated by the dollar-weighted HI analysis. Another sub-criterium of service continuity that relates to the program is that the voltage conversion program looks to increase feeder capacities, which will increase connection capacity to the feeder and address feeders whose long-time load transfer is uneconomic.

A sub-criterion of utility integration that is relevant to the program is that through increasing the voltage of the feeders, the transformer substation will be eliminated, which will, in turn, eliminate redundant legacy assets of the legacy utilities. Another sub-criterion is that the potential new customer connections can generate new net revenues for the utility.

3. Program Alternatives

-C.b.5 (SR) An analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs, the value of which cannot readily be
quantified, these should be described and explained in relation to the proposed project and all alternatives.

3.1 Alternative Descriptions and Comparative Analysis

Number	**0**	**1**	**2**	**3**
Scenario Description	Status Quo: Planned Voltage Conversion Investments	10% More Investment into the Voltage Conversion Program	10% Less investment into the Voltage Conversion Program	Typical Asset Replacement; No Conversion
Annual Program Scope	In this scenario, planned Voltage Conversions take place for the current DSP period. These voltage conversion projects are longer-term initiatives.	Elexicon will invest 10% more into the Voltage Conversion budget. More voltage conversions shall be performed.	Elexicon will invest 10% less into Voltage Conversion projects. Less Voltage Conversion projects to be performed.	In this scenario, Voltage Conversions do not take place. Asset renewal is instead chosen as the option.
Annual Gross CAPEX	$2.36M	$2.60M	$2.12M	$0.00M
Annual Net CAPEX	$2.28M	$2.51M	$2.05M	$0.00M
Annual Program Benefits	The base values as influenced by Defective Equipment are 0.015 for SAIDI, and 0.053 and SAIFI. Other Investment scenarios (1 and 2) are relative percentages to scenario 0. Residual Risk in	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 1 are relative to the scenario 0 investment. SAIFI = -0.74% SAIDI = -0.74% Residual Risk = -0.68%	Percentages of SAIFI, SAIDI and Residual Risk values in scenario 2 are relative to the scenario 0 investment. SAIFI = 0.78% SAIDI = 1.15% Residual Risk = 1.44%	Program Benefits were not calculated for this scenario. Replacement of assets would introduce new asset lifecycles. However, this is inefficient and Elexicon has long term plans to convert legacy voltages.

	Scenario 0 is $2.413 M.			
Program Economics	The base scenario involves investing $2.36M annually and results in the residual risk of $2.413 projected by 2029. It is the preferred trade-off of costs and benefits.	By investing 10% more in the voltage conversion program, the forecasted residual risk decreases by 0.68%.	By investing 10% less in the voltage conversion program, the forecasted residual risk increases by 1.44%.	A cost benefit ratio was not calculated for this scenario. Elexicon has long term plans to convert legacy voltages.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.			
Other Constraining Factors	The current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.	Like for like replacements instead of voltage conversions would not remove the operational constraints that legacy voltages have on Elexicon's system.
Preferred Alternative	**X**			

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.b.4 (SR) The impact on reliability and safety factors

Reliability: The Voltage Conversion Program can increase the reliability of Elexicon's services as the replacement of deteriorated assets reduces the chances of having an outage. However, the Voltage Conversion Program aims to replace current feeders with higher voltage feeders, which tend to be longer. The longer a feeder is, the more prone it is to external factors that can harm the system, such as wind, fire, accidents, etc.

Grid Resiliency: Replacing Elexicon's current feeders with higher voltage feeders can enable more customers to connect to the system as capacity is increased for the feeder in the long term as well as addressing load growth. Proactive replacements through the voltage conversion program also enable more resilient infrastructure where aged replacements may further deteriorate with climate change. For instance, new hardened distribution assets can be utilized as replacements.

Operational Efficiency and Cost Effectiveness: Replacing assets before they fail is more cost-efficient than replacing them after they fail since assets that failed incur an outage cost on the utility. This program pushes for the replacement of assets based on their conditions and inevitable failure, implying that any spending on this program is cost-effective.

Safety: Assets in poor conditions can pose a safety threat to the public and the crew members working on those assets. Poles in poor condition may not have sufficient strength to support other distribution assets and may under contingencies collapse and cause harm to persons around the pole's area. Older legacy voltage equipment is aged and substandard prompting potential safety issues at hand. Converting to newer assets can improve safety margins and legacy clearances.

Cyber-Security/Privacy: N/A

Environmental Benefits: Voltage Conversion includes upgrading/replacing distribution transformers. When distribution transformers deteriorate to become faulty, they tend to leak oil, which can harm the environment. Proactive replacement of distribution transformers helps reduce oil leakage. A distribution transformer failure may also cause an oil spill, which this program aims to avoid.

Coordination/Interoperability: Coordination in the system is improved as legacy voltages are all transformed into one service voltage in the area. This helps improve contingency planning and switching operations internally with potential benefits with external operators. Load Growth is not expected to be high in the areas of Belleville, Gravenhurst, and Port Hope*.*

Conservation and Demand Management: Since the program deals with replacing transformers in poor condition, the newer transformers would be more efficient and would result in fewer line losses.

Net Customer Benefits: Since the program can produce a more reliable service, customers would benefit from it by experiencing fewer outages. Also, more customers will be able to connect to the grid as a result of the feeders being upgraded to a higher voltage.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.b.2 (SR) Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects

To plan for possible changes in the future, Elexicon takes into account several considerations. An expected number of failures for each asset class is predicted and an asset condition assessment is performed to have an overview of how the system may change during the next couple of years. An increase in connections is also predicted to plan for which areas would need to have their services expanded. With all the collected information, a prioritization framework will be put into effect to prioritize scopes following the current status quo and how the system would look like in the next couple of years. If any degradation is expected to occur which would require voltage conversions, budget from future years or within the system renewal category may be moved to address the problem.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

The planning approaches of both legacy utilities, as well as Elexicon, are similar. They are all based on the results of the Asset Condition Assessment. To evaluate the assets, specific condition parameters along with their weights, which is determined by the significance of the parameter relative to the others, are used to calculate a health index. The health index determines which condition bracket the asset falls into. The condition brackets are very poor, poor, fair, good, and very good. As the health index is an integral part of the planning approach, the condition parameters become the defining factor of how each legacy plans to manage its assets. The following tables illustrate the parameters from 2018 and 2019 of the inputs to asset health and renewal.

Table 18: Consolidated and Legacy Station Transformer Parameters

Condition Parameter	Weight
Dissolved Gas Analysis	10
Insulation Power Factor	10
Oil Quality	8
Service Age	6
Overall Condition	6
Brushing Condition	5
Cooling Equipment	2
Grounding Condition	1
Foundation Condition	1
Gasket Condition	1
Connections Condition	1
Oil Leaks	1

Table 19: Consolidated and Legacy Pole Condition Parameters

Condition Parameter	Weight
Service Age	1
Remaining Strength	8
Wood Rot	6
Out of Plumb	2
Overall Condition	7

Table 20: Consolidated and Legacy UG Cable Condition Parameters

Condition Parameter	Weight
Service Age	8
Faulted Section	4

Table 21: Consolidated and Legacy Pad-mount Transformers Condition Parameters

Condition Parameter	Weight
Service Age	3
Overall Condition	4

Table 22: Consolidated and Legacy Pole-mount Transformers Condition Parameters

Condition Parameter	Weight
Service Age	3
Overall Condition	4

Table 23: Consolidated and Legacy Switch Condition Parameters

Condition Parameter	Weight (Whitby)	Weight (Veridian)
IR Scan	4	-
Overall Condition	4	4
Service Age	2	2

4.2 Legacy Work Execution Approaches vs. Combined Operations

Wood Pole Consolidated and Legacy Inspections and Work Execution

Elexicon inspects wood poles every 3 years, with the inspections including wood rot testing, remaining strength tests, and visual inspections. The inspection cycle includes predictive maintenance through wood rot testing and remaining strength testing. Elexicon replaces wood poles based on the inspection and testing results as well as the age of the poles. Legacy Veridian conducted inspections based on an eight-year cycle with no maintenance work being included. Veridian replaced wood poles based on the results of the inspections. Whitby inspected poles based on a 3-year cycle with no maintenance work being included. Whitby immediately replaced poles that were identified as hazards, while some poles were identified as needing replacements within a year being replaced the following year.

Overhead Conductor Consolidated and Legacy Inspections and Work Execution

Overhead conductors are inspected by Elexicon annually through infrared scanning based on a 3-year cycle. The overhead conductors' condition data is also collected during the cycle. Maintenance work is currently done based on the inspection results. Legacy Veridian inspected overhead conductors through infrared scanning annually, and their maintenance work was based on the results of these inspections. Veridian ran overhead conductor until failure and replaced it with the same conductor type. Legacy Whitby conducted inspections for overhead conductor through infrared scanning done annually, with maintenance work being done based on the results of the inspections. Whitby also replaced the overhead conductor based on the results of the inspections.

Underground Cable Consolidated and Legacy Inspections and Work Execution

Elexicon conducted underground cable inspections based on age and number of failures. For maintenance work, Elexicon currently performs cable injections based on the inspection results. Legacy Veridian inspected underground cables based on their age and number of failures and injected cable based on the inspection results as maintenance work. Veridian replaced underground cable based on age and inspection results. Legacy Whitby did not have an inspection and maintenance program for underground cable and replaced a subdivision-size section of underground cable annually.

Pad-mount Transformer Consolidated and Legacy Inspections and Work Execution

Elexicon does visual inspections based on 3-year cycles for pad-mount transformers. Currently, Elexicon re-paints transformers with rust based on customer requests for maintenance work, which is to be gradually transitioned to a reactive approach based on inspection results. Previously, Veridian inspected pad-mount transformers visually based on a 3-year cycle, with maintenance work being mostly based on customer requests for the transformers to be re-painted. Veridian ran pad-mount transformers until failure until recently when loading of the transformer became a factor for replacement. Whitby also conducted inspections visually based on 3-year cycles, with maintenance work comprising of re-painting rusted transformers. Whitby ran transformers until failure unless inspections signaled a need for a replacement.

Pole-mount Transformer Consolidated and Legacy Inspections and Work Execution

To inspect pole-mount transformers, Elexicon performs infrared scans annually as well as carry out visual inspections based on a 3-year cycle. Maintenance work is done based on the results of the mentioned inspection methods. Pole-mount transformers are currently being reactively replaced, i.e. they operate until failure or until a customer requests replacement. Formerly, Veridian also conducted infrared scans and visual inspections annually as inspection practices for pole-mount transformers, and maintenance was completed based on infrared scans. Veridian also ran pole-mount transformers until failure until 2 years ago, when loading of the transformer became a criterium for replacement. Whitby also conducted inspections on pole-mount transformers through infrared scans and visual inspections, and their maintenance work was based on the results of the inspection. Whitby ran pole-mount transformers until failure unless inspections signaled that a replacement was needed.

Overhead Switch Consolidated and Legacy Inspections and Work Execution

For all types of overhead switches, Elexicon conducts inspections visually every 3 years and conducts infrared scanning annually. Elexicon's maintenance work for switches is based on the inspection results. Planning approaches were done differently for load interrupter switches and the other types of overhead switches by Veridian. Legacy Veridian conducted infrared scanning annually to inspect all types of switches except for load interrupter switches, which were inspected visually based on a 3-year cycle. Maintenance work for all types of switches except for load interrupter switches was based on the infrared scanning results, whereas there was no maintenance work done for load interrupter switches. Veridian replaced load interrupter switches based on age whereas replacements for all other types of overhead switches were done reactively upon failure. Whitby inspected switches through infrared scanning, conducted annually, and visual inspections, conducted every 3 years. Whitby's maintenance work was based on the results of these inspections. Whitby ran switches until failure unless inspections signaled that there was a need for replacements.

4.3 Scale Increase Considerations

Elexicon assets are now a combination of the inventory of former Veridian and Whitby assets. The increase in staff and skillset allows for more resources and potential efficiency when engaging in voltage conversion projects. Resources can be pulled together and the experiences with voltage conversions can be utilized moving forward as a combined utility. Elexicon is positioned to transform legacy voltages to higher voltages and one service voltage in each area. The scale increase of staff and resources shall enable such a transition.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

In the following graphics as shown below, scenarios 0, 1 and 2 represent the base case with the current investment plan, decreasing the current investment plan by 10% and increasing the current investment plan by 10%. These graphics illustrate the total system renewal spending for certain renewal programs, the Health forecast of Assets in 2029 as part of the overall system renewal portfolio and the residual risk produced with these investment options.

Figure 13: System Renewal Spending Forecast until 2029

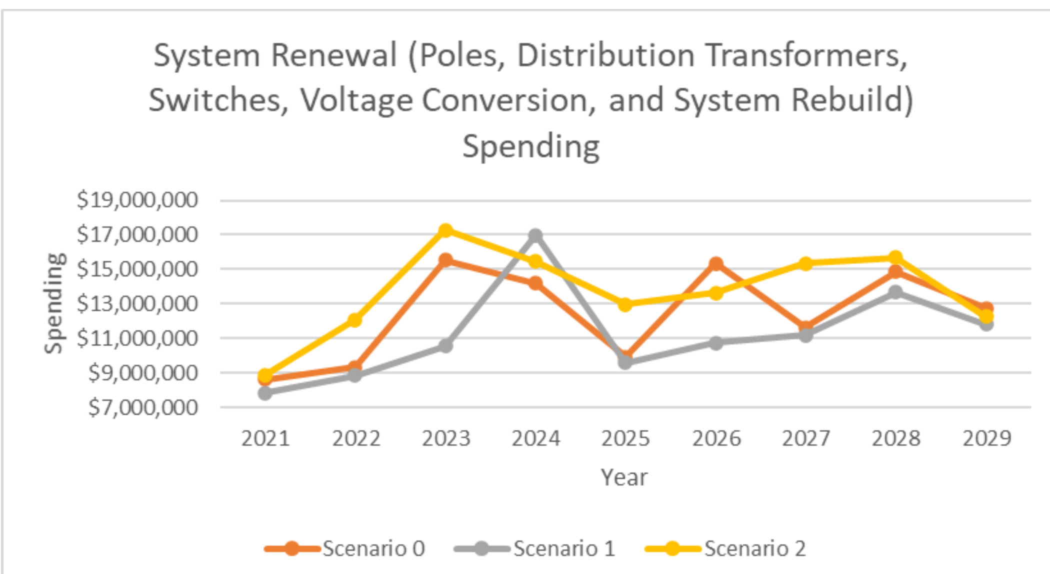


Figure 14: Health Index Forecast until 2029

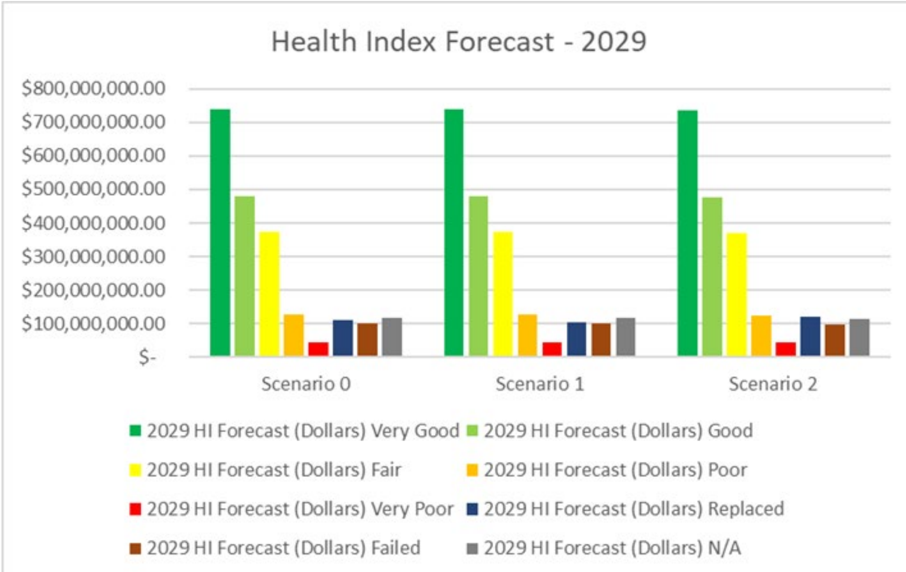
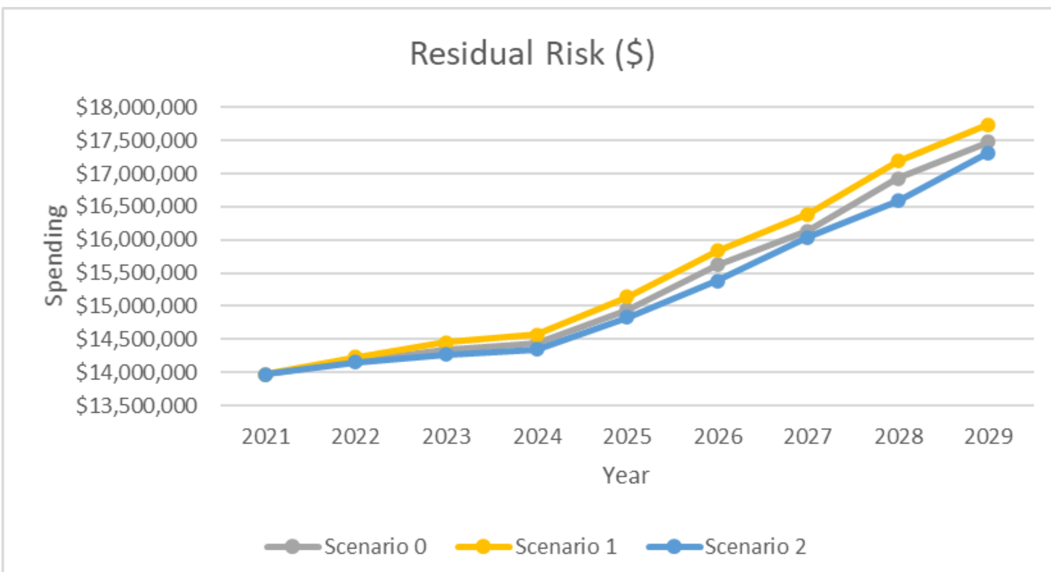


Figure 15: Residual Risk ($) Forecast until 2029



5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2016-0401B	Cavan South Ph 2 Voltage Conv (4.16kV x 27.6kV)	2021	0.5	75.6

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.b.6 (SR) Where the proposed project is a 'like for like' renewal but has been configured at extra cost to address other distributor planning objectives, an analysis of project benefits and costs must be provided comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

<table>
<tr><td>Project name</td><td colspan="5">Cavan South Ph 2 Voltage Conv (4.16kV x 27.6kV)</td></tr>
<tr><td>Project numbers</td><td colspan="5">2016-0401B</td></tr>
<tr><td>Job numbers</td><td colspan="5">CCA201010</td></tr>
<tr><td>Project District</td><td colspan="5">Clarington</td></tr>
<tr><td>Project Location</td><td colspan="5">Port Hope</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM RENEWAL</td></tr>
<tr><td>Budget Category</td><td colspan="5">R8 - Voltage Conversion-Reliability</td></tr>
<tr><td>Project Driver</td><td colspan="5">Increase in load / supply constraint, age and condition of 4.16kV pole line</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The project is to convert part of Cavan F3 voltage from 4.16kV to 27.6kV</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $500,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $500,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$45,000</td><td>$50,000</td><td>$85,000</td><td>$320,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The 4.16kV system in Port Hope is reaching its maximum capacity. Additionally, the pole lines are old and some pole required placement. Elexicon initiated a project to convert the voltage from 4.16kV to 27.6kV. The project is second phase of voltage conversion of Cavan F3. The project will provide customers with more reliable service.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">75.6</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">There is no alternative to the project. The 4.16kV system is reaching its capacity and considering the age and condition of the assets, do nothing is not recommended.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project will likely reduce the cost of O&M by replacing the old assets and reducing the requirement for emergency repairs.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">The project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">The cost of voltage conversation projects varies based on the location and type of the assets that required. On Average for voltage conversions, each pole cost is $15,000.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	S1-Substations Growth and Expansion
OEB Investment Category	System Service
Primary Driver	System Capacity
Secondary Driver(s)	Reliability, Customer Service

Average Annual Program Spend – Historical	**Average Annual Program Spend – Forecast**
$0.96M	**$6.79M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Substation Growth and Expansion projects are investments made by Elexicon Energy ("Elexicon") to address load growth within its service territory. It is expected that the Whitby Transmission Station ("TS") 27.6-kV bus BY will exceed its limited time rating ("LTR") due to the major development of the Seaton community in Pickering. In the early 2000s, Seaton was planned and projected to bring about 70,000 residents and 35,000 jobs into the Pickering area. After various consultations with the Independent Electricity System Operator ("IESO") and Hydro One Networks Inc. ("HONI") during the Regional Planning Process ("RPP"), it was determined that Elexicon will build and own Seaton TS to step power down from 230 kV to 27.6 kV to service customers in the area. Throughout the Distribution System Plan ("DSP") forecast period, major investments in the Substation Growth and Expansion program pertain to the purchase of Seaton TS land and construction of Seaton TS.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recover Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	$0.96	$0.64	$0.00	$40.76M	$0.00	$0.00	$0.00	$0.00
Contributions	$0.55	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Program Expenditures	$0.41	$0.00	$0.00	$40.76M	$0.00	$0.00	$0.00	$0.00

Supporting Summary Statements:

The new Seaton development area was first brought forth as an idea by the provincial government in the 1970s. In 2006, the *Central Pickering Development Plan* outlined that Seaton would house 70,000 people in six neighbourhoods and create 35,000 new jobs. Recent housing projections from the Regional Municipality of Durham ("the Region") represent the major expected household growth from the City of Pickering ("the City") by Seaton. The City also produces forecasts of expected households in the Seaton Lands. Elexicon shared these plans and developments with HONI during RPP to identify the expected load growth within the area. Elexicon and HONI decided to investigate other options as Whitby 27.6-kV TS LTR would be near its limit. It was ultimately determined that Seaton TS would be built by Elexicon to serve the large development area and alleviate pressure from the HONI-owned Whitby TS supplying distribution substations within the area. LTR is defined as the threshold at which one transformer can carry the full load of the station during emergency conditions. Building Seaton TS allows Elexicon to exclusively operate and own the designated TS for the area. HONI will extend an existing 230-kV transmission line to Seaton TS.

The quantifiable benefits realized from Seaton include cost savings for both HONI and Elexicon. Existing stations such as Malvern TS and Sheppard TS would not need to supply lines to the Seaton area in the short term. The ability for Whitby TS to service customers would not be affected in the long run. Having a separate substation for the area allows Elexicon to specifically have a resource designated for the larger neighbourhood for Seaton. Although complex, it provides Elexicon with further ability in addressing any potential problems on the ground level. Furthermore, the capacity constraints within Elexicon would be addressed and not pressure the existing Pickering substations. Although much of the growth is expected in Seaton, Elexicon also expects growth in other areas of Pickering; the existing stations need to have adequate capacity available and a new TS provides further capacity specifically to the larger development area. Having one TS designated for the neighbourhood alleviates the need for expansion of other existing distribution networks. After the construction of Seaton TS, Elexicon will be pursuing related projects such as providing connections of new services and feeders expansion from Seaton TS to service the new neighbourhood.

2. Basis for Action

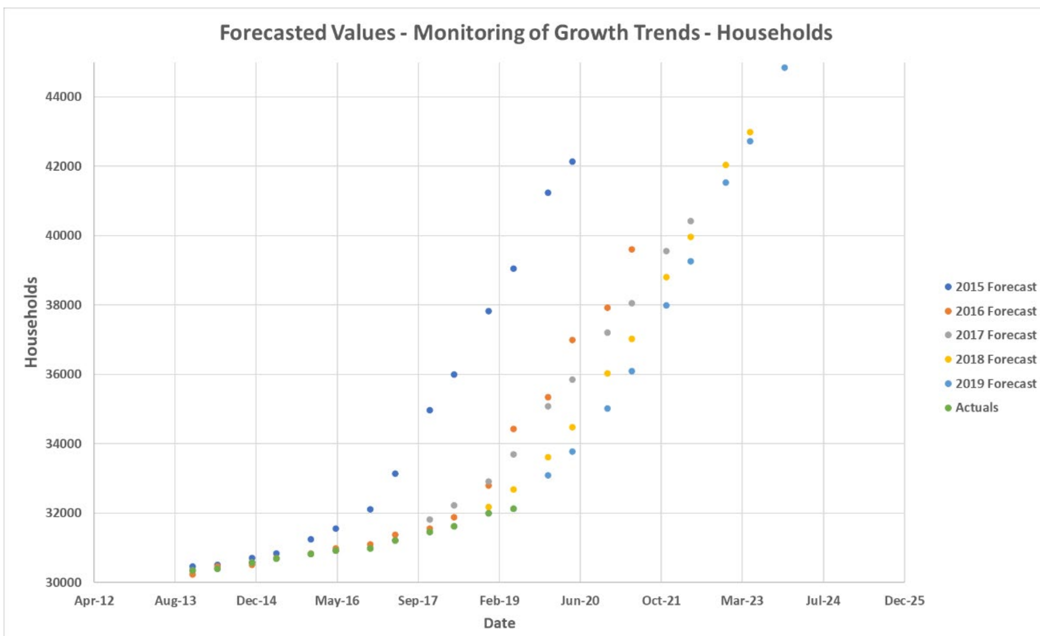
2.1 Performance Trends:

-A.3 Related customer attachments and load, as applicable

Regional Municipality of Durham Pickering Household Forecasts 2015 to 2019

Household forecasts for Pickering produced by the Region of Durham are provided in Figure 1, detailing the past expectations of household development in the area. On a semi-annual basis, household forecasts and estimates are produced by the Region. Between 2015 and 2019, major household growth for Pickering has been expected but has not been realized in the area. The steepness of the historical and current forecasts demonstrates the new households within the area that the region has expected consistently annually. Elexicon shall construct Seaton TS to address the large customer growth and development in the area.

Figure 1: Past Forecasts for Pickering Household Development



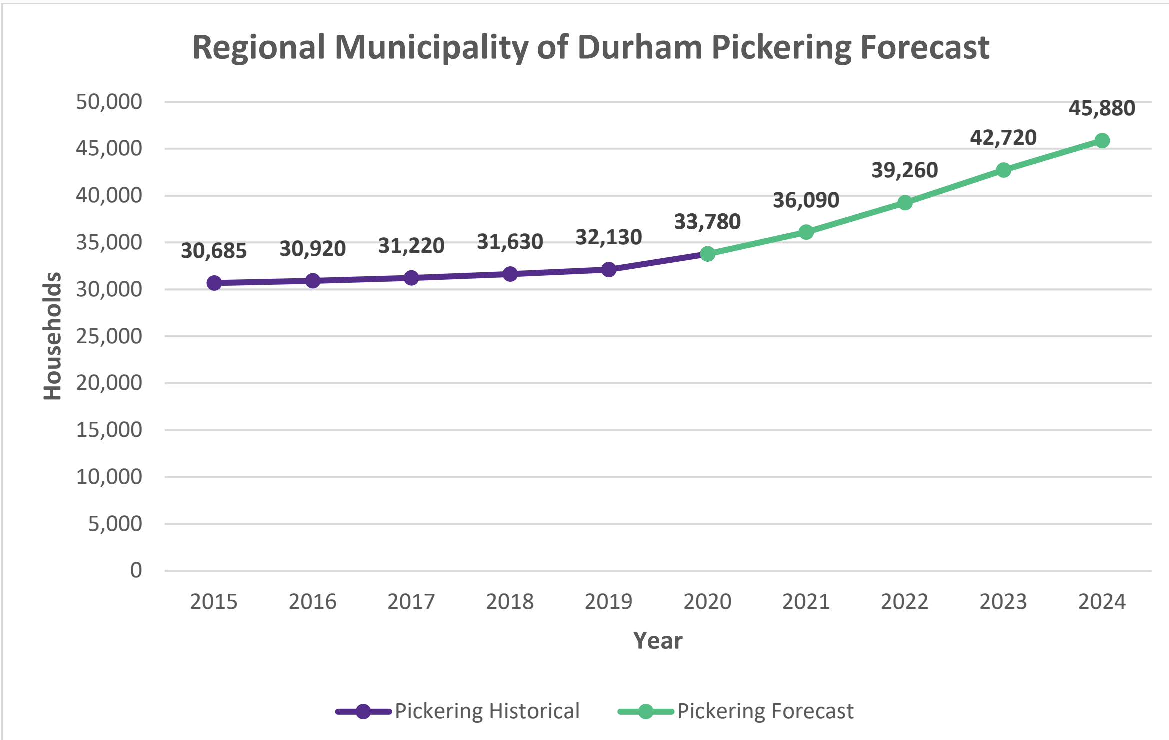
Pickering Household Development Forecast

The 2019 Pickering household projections are reviewed further and provided in Table 2. As seen from the projections, the City of Pickering is expecting significant growth over the next four years. Over the past five years, the number of households built in Pickering were less than the forecasted values. The total household forecast from 2020 shown in Figure 2 suggests that significantly more total household completions are expected than past historical household completions. Many of the households added in Pickering are expected to arise from the Seaton development.

Table 2: Pickering Total Households – Historical and Forecasted as of May each year

Time	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Households	30,685	30,920	31,220	31,630	32,130	33,780	36,090	39,260	42,720	45,880

Figure 2: Pickering Household Projections from the Region



Over the last four years, 1,445 households were completed. In the next four years, the Region expects that 13,750 households will be completed in the area., equating to a 35% total increase in Pickering households from 2020 to 2024. The household forecasts from the Region were compiled before COVID-19, which may impact the actual number of housing completions.

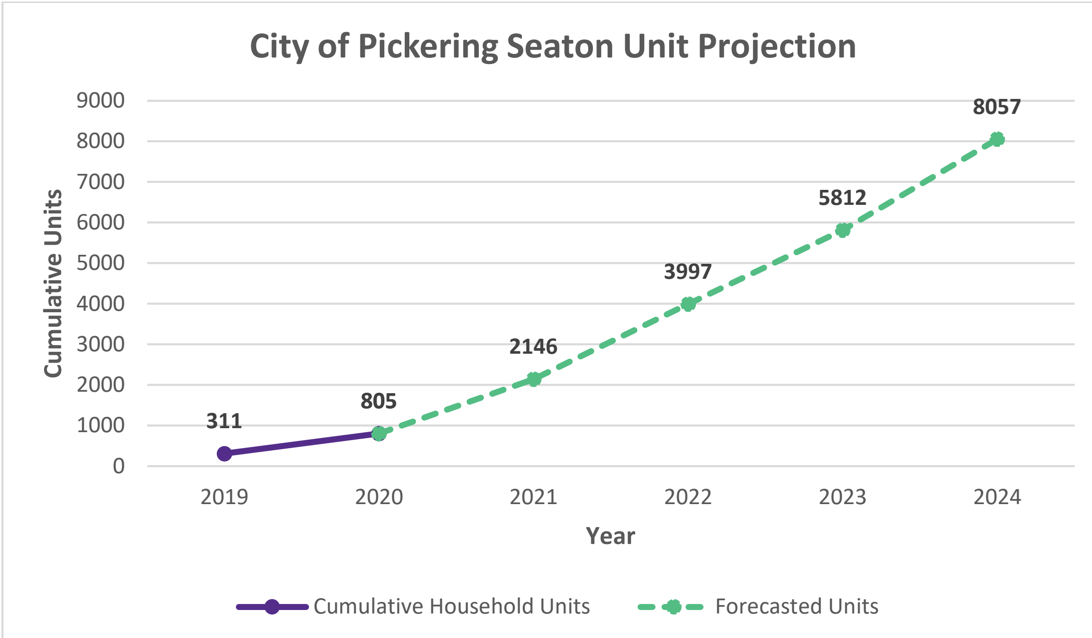
Seaton Unit Projections from City of Pickering

From 2020 to 2024, it is expected that 7,747 new households will be built in Seaton. The annual number of new developments is expected to increase drastically from 2021 onwards.

Table 3: Pickering Cumulative Household Unit Projections – 2020 to 2024

Year	2019	2020	2021	2022	2023	2024
Cumulative Number of New Households	311	805	2,146	3,997	5,812	8,057

Figure 3: City of Pickering Seaton Cumulative Unit Projection

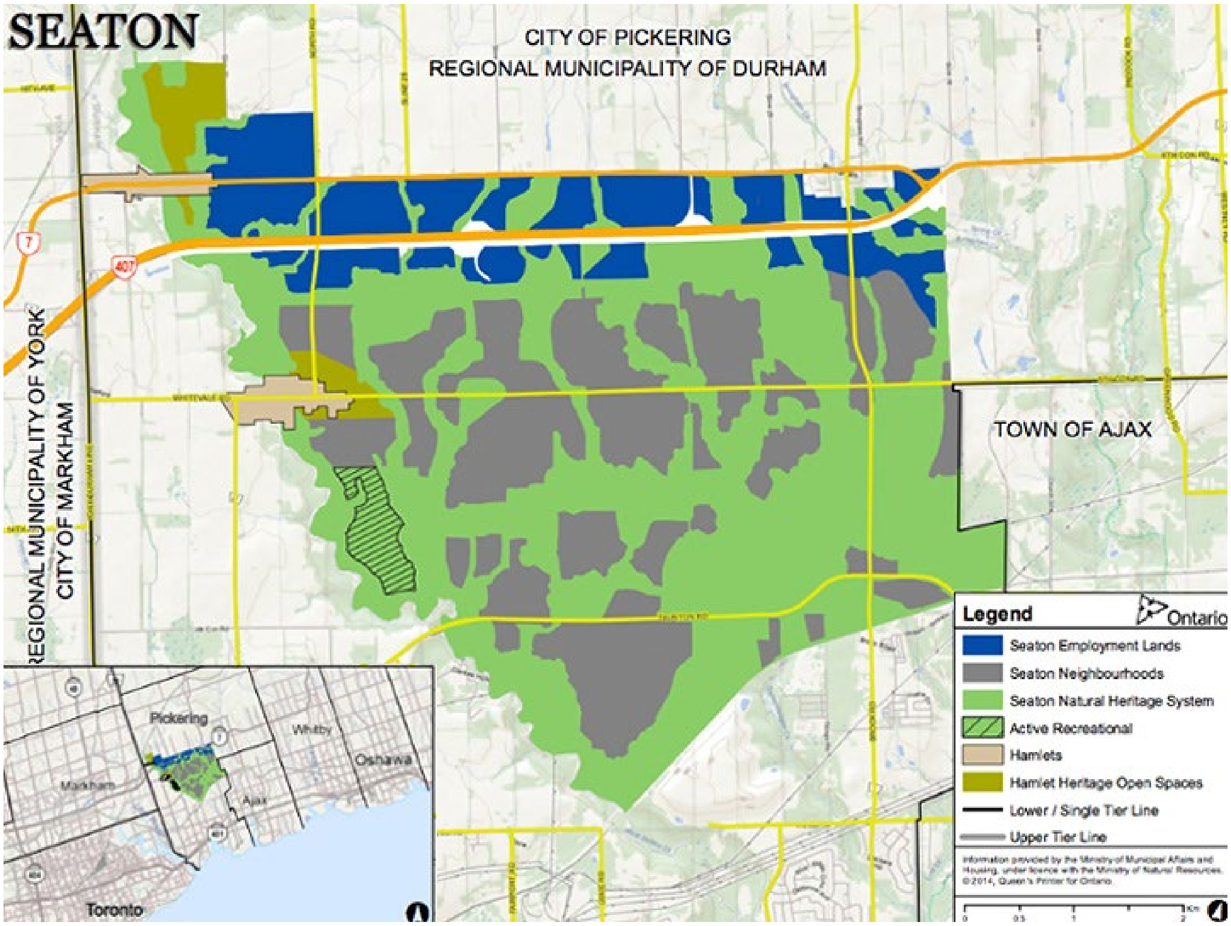


Seaton has been designated as a development spot by the province of Ontario since the 1970s for a community northeast of Toronto. The development will be a mixed-use area where employment lands and neighbourhoods will be constructed around designated natural heritage areas as shown in Figure 4. In 2006, the *City of Pickering Development Plan* was completed, outlining the development of Seaton for 70,000 people and 35,000 jobs were to be created east of the West Duffins creek and an agricultural area west of the creek. Other facilities other than housing developments expected to be built in Seaton include:

- Three high schools and fourteen elementary schools;
- Two fire halls;
- One police station;
- One EMS station;
- Two recreational complexes with libraries;
- A variety of parks and open green spaces;
- One transit depot; and
- Three community nodes with 48 hectares for retail and commercial use.

These buildings and facilities are expected to contribute heavily to the demand growth within Pickering and the surrounding area.

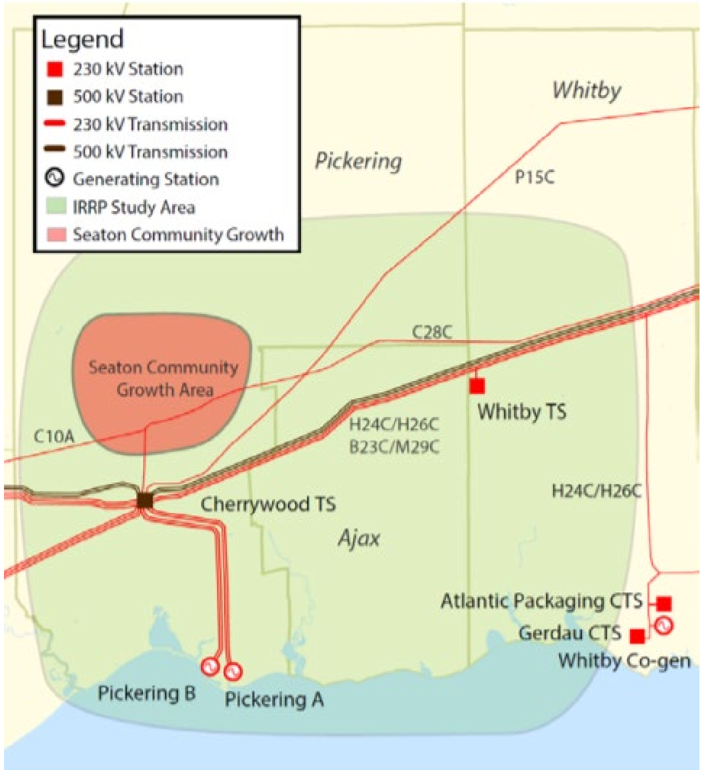
Figure 4: Seaton Lands Map from Infrastructure Ontario



Pickering Ajax Whitby IRRP Report 2016

As stated in the Pickering Ajax Whitby Integrated Regional Resource Plan ("IRRP"), "By 2019, peak summer 27.6 kV electrical demand at Whitby TS is expected to exceed the LTR of the transformer that supplies electricity at 27.6 kV by 12 MW increasing to 132 MW by end of the study period in 2034." The transformation capacity need in Pickering is triggered by a new growth pocket with no current access to transmission supply. The most economic course of action determined through consultation was to construct a new 230/27.6-kV station and upgrade an existing 230-kV line in the proximity of Seaton. Demand growth from the new community of Seaton and various intensification projects in Pickering, Ajax, and Whitby are contributing to the need for Seaton TS. The new station will be owned and operated by Elexicon and connected to HONI's existing high-voltage transmission system. Figure 5 demonstrates the interconnection of transmission lines and TS in the area.

Figure 5: Seaton Location to the HONI Transmission System



A satellite image is shown in Figure 7: Seaton TS Location Satellite View with respect to development lands. It illustrates the location of Seaton TS and the location where the 230-kV transmission line will be extended into Seaton. The 27.6-kV forecast provided in the IRRP demonstrates that new developments will contribute demand that will exceed station capacity in 2019. HONI will convert the existing single-circuit 230-kV transmission line to a double-circuit line from Duffin Junction to Seaton TS to serve the station. Developments are still being constructed in the area and Seaton TS construction and implementation have been pushed to 2022.

Figure 6: Locations of Alternative Sources of 27.6 kV Supply from HONI IRRP

Figure 7: Seaton TS Location Satellite View with respect to development lands (Seaton Location 2)

As seen in the 2016 IRRP, it was forecasted that the Whitby TS 27.6-kV LTR would be exceeded by 2018. LTR is classified as the ability for a second transformer in a DESN load connection facility to carry full load under emergency conditions for a single transformer failure contingency. The years 2019 to 2024 demonstrate the expected increasing load growth from Seaton in addition to the intensification projects of Whitby, Ajax, and Pickering.

Figure 8: Whitby TS 27.6-kV load projections noted in the 2016 IRRP

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

Seaton TS is currently projected to be built in 2022. Development areas by Seaton are still being built and constructed as stated on the City's website. Elexicon will ensure that Seaton TS will be built in advance of all developments being finished. This will ensure that Seaton can be commissioned and to start connecting the customers to the new Elexicon substation. The current state of construction for the new neighbourhood outside of electrical work includes new roads and transportation connections, stormwater sewer and sanitary networks, water lines, natural gas delivery, and telecommunication expansion.

Ajax-Pickering Regional Coincident Summer Peak (MW) Forecast

Major load growth in the Ajax-Pickering region of Elexicon's service territory is expected from new developments such as Seaton, which leads to further feeder expansions to new neighbourhoods within Pickering. The infrastructure surrounding the land designated for Seaton developments is not as developed; neighbourhoods are being built in areas where distribution infrastructure is currently not set. A large majority of the new feeder expansion projects are found in Pickering which will accompany the construction of Seaton TS. Twelve feeders from Seaton TS will be constructed as feeder expansions towards the new neighbourhoods.

Elexicon hired a consultant to develop a regional load forecast for its service territory. The load forecast analyzes historical customer growth trends and forecasted customer additions from developers, the Region, and municipalities. Forecasts are produced to predict the weather-normalized ("WN") peak load and the "P10", "P50", and "P90" exceedance values. The WN peak is the load that would occur during the average weather conditions for that season, whereas the P10, P50, and P90 forecasts all include the effects of day-to-day weather variations and extremes weather events. The P10 forecast is the weather-dependent peak load event that Elexicon would expect to exceed once every ten years, the P50 forecast would be exceeded every other year, and the P90 forecast would be exceeded nine out of every ten years. The P10 forecast is used for capacity planning to ensure sufficient capacity to meet peak customer demand.

The region of Ajax-Pickering is summer-peaking. Figure 9 depicts the P10, P50, and P90 peak load projections for the DSP forecast period. The area is expected to experience intense growth due to new customer connections, which is reflected in the peak load forecasts. This load increase constrains existing capacity in the area, driving investments into substation growth and expansion.

Figure 9: Ajax-Pickering Forecasted Regional Peak

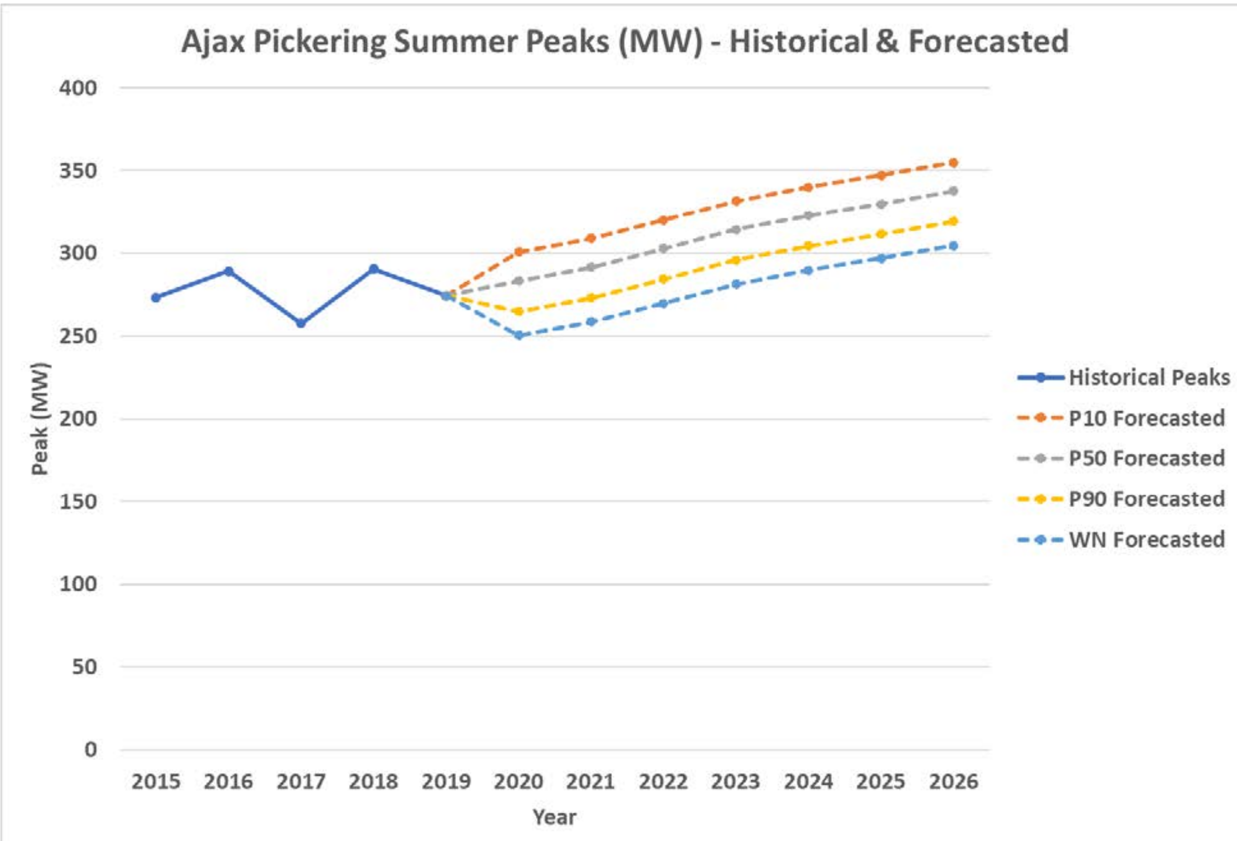


Table 4: Ajax-Pickering Forecasted Peak Load (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026
P10	300.72	308.94	320.17	331.68	340.15	347.28	355.02
P50	283.35	291.57	302.80	314.31	322.78	329.91	337.64
P90	264.95	273.18	284.41	295.92	304.39	311.51	319.25
WN	250.47	258.69	269.92	281.43	289.90	297.03	304.76

2.2 Current-State Analysis:

-C.c.2 (SS) Where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs

In determining the current state with regards to the Seaton Lands and planned construction for Seaton TS, loading data and the updated 2020 coincident load forecast for Whitby TS and Seaton are shown.

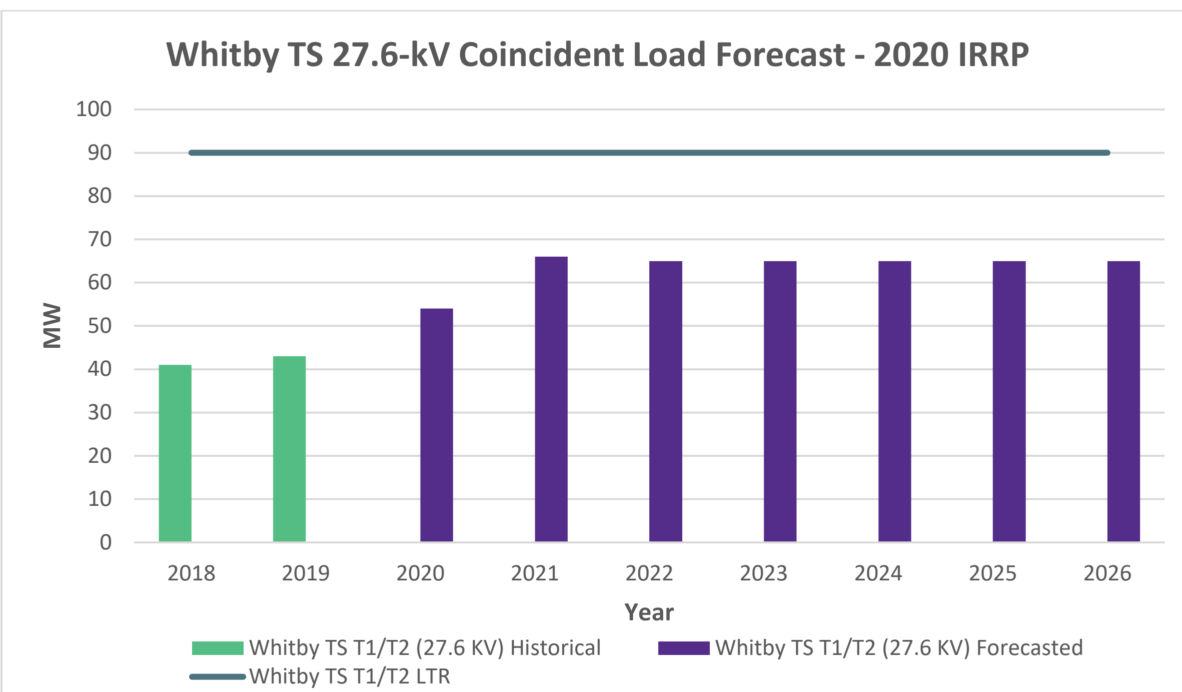
Whitby TS 27.6-kV Coincident Load Forecast 2020 IRRP

The recent 2020 IRRP coincident load forecast for Whitby TS T1/T2 (27.6 kV) shows that for 2018 and 2019, the projected load from the 2016 report has not materialized. Seaton development and construction are still underway. Further loading analysis of the "BY" bus is presented in the following section. Whitby TS will continue to be allocated customer loads into 2021. At the start of 2022, load growth will begin to be allocated to Seaton TS. As a result of this allocation, loading on Whitby TS T1/T2 (27.6 kV) is expected to remain consistent from 2021 onwards to 2026. This will ensure that the LTR is not exceeded and a margin of the LTR to current loading is maintained.

Table 5: Whitby TS T1/T2 (27.6 kV) Coincident Load Forecast

Station	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load Forecast (MW)	41	43	54	66	65	65	65	65	65
LTR (MW)	90	90	90	90	90	90	90	90	90

Figure 10: Whitby TS 27.6-kV Coincident Load Forecast from 2020 IRRP



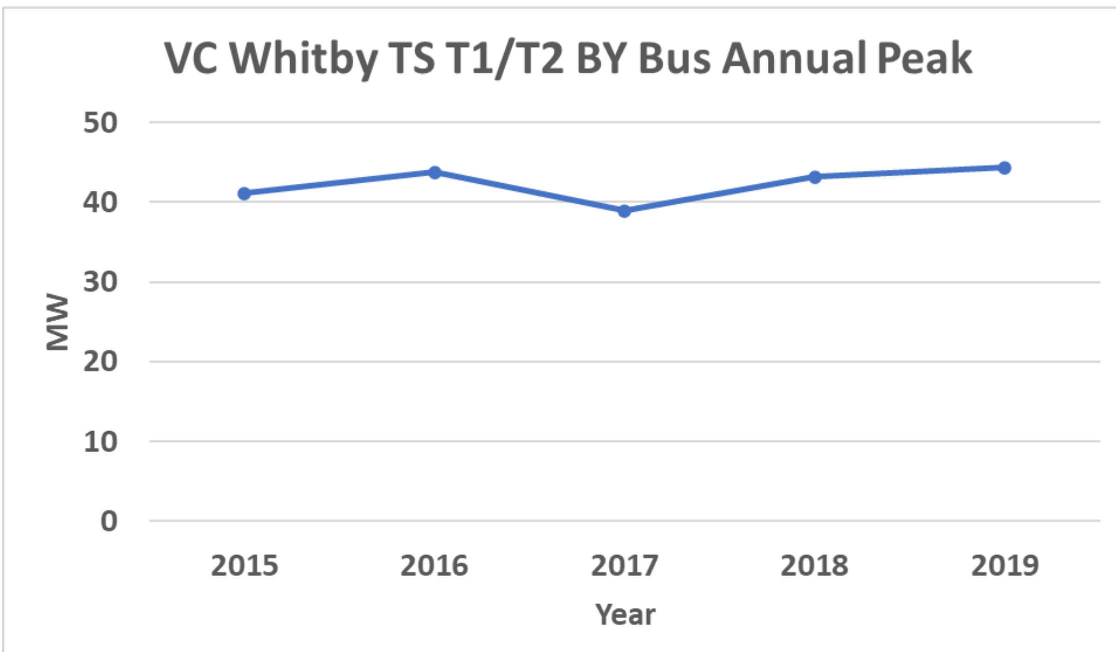
Whitby TS T1/T2 BY Bus Annual Non-coincident Peak (2015 to 2019)

Over the course of the past five years from 2015 to 2019, the BY Bus for Whitby TS has been at relatively stable loading in terms of the annual non-coincident peak. In 2019, under a load transfer situation, 58.21 MW of loading occurred. Abnormal system operating conditions are omitted from the capacity analysis, as the buffer between actual peak load and the station's LTR supports contingency and load-transfer scenarios.

Table 6: Recorded Non-Coincident Peaks on Whitby BY Bus

Year	2015	2016	2017	2018	2019
Annual Non-Coincident Peak	41.14	43.73	38.87	43.14	44.37

Figure 11: Current State Peak Loading on the Whitby TS BY Bus



As the Seaton community is expanding and new customer connections are requested, it is expected that the growth will surpass the LTR of the Whitby TS 27.6 kV in the long term. As seen in the year-end Pickering residential customer counts, the large influx of new customers from Seaton has not yet occurred. It was forecasted that a total of 33,090 households were expected in 2019, however, a total of 32,250 households were added. Thus, the construction of Seaton TS is scheduled for completion in 2022. As presented in Table 7, over the past five years, an estimated 1,435 households and about 1,470 new residential customers have been added.

Table 7: Pickering Residential Customers and Households December Year-End

Year	2015	2016	2017	2018	2019	Total Additions
Year-End Pickering Residential Customers	28,779	29,050	29,471	29,957	30,249	1,470
Year-End Pickering Households	30,815	30,985	31,465	31,990	32,250	1,435

Seaton TS 27.6-kV Coincident Load Forecast 2020 IRRP

In the IRRP the Seaton TS load was forecasted to start by 2021 as indicated in Figure 12. However, completion of Seaton TS has been deferred until 2022.

Figure 12: Seaton TS 27.6-kV Coincident Load Forecast

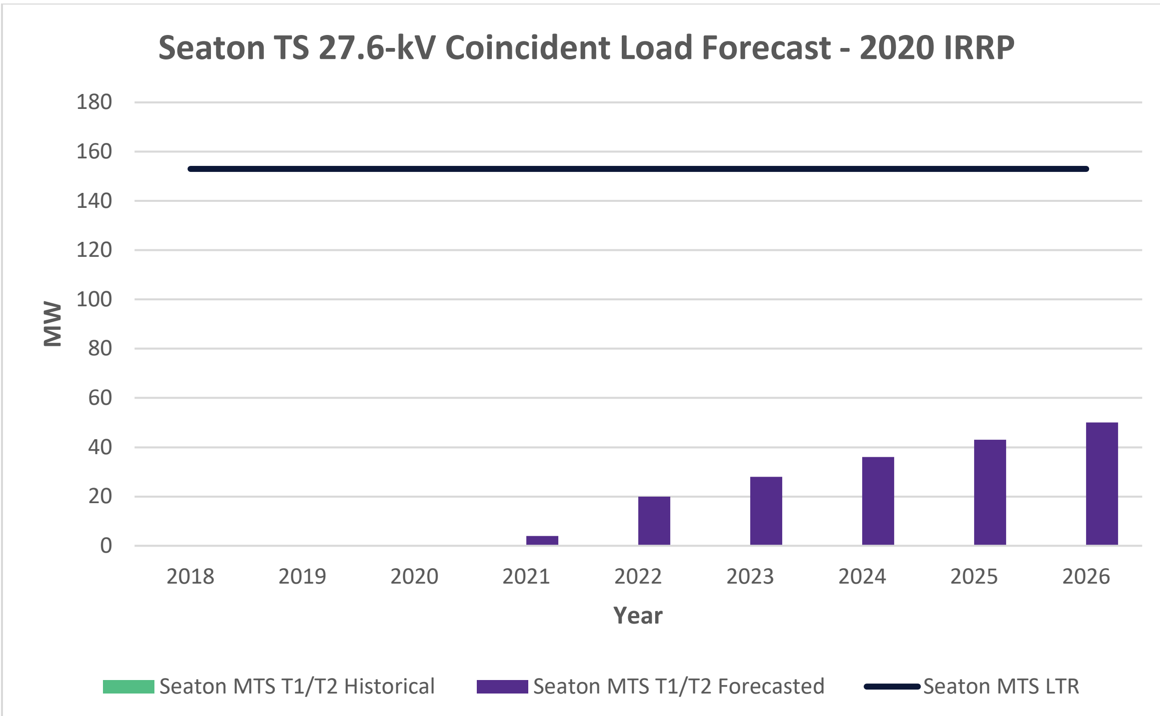


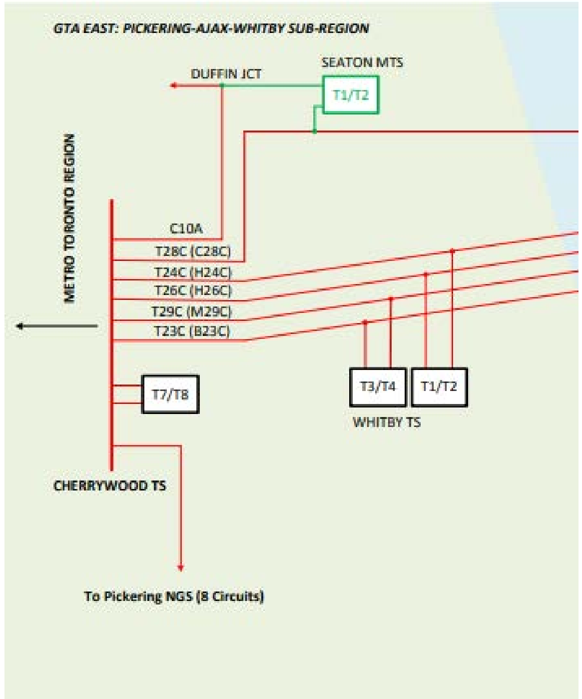
Table 8: Seaton TS 27.6-kV Coincident Load Forecast from IRRP

Station	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load (MW)	0	0	0	4	20	28	36	43	50
LTR (MW)	153	153	153	153	153	153	153	153	153

The schematic for the proposed connection is provided in Figure 13. A detailed procedure for connecting Seaton TS is described below.

1. At Duffin Junction, the C10A east circuit will be extended to the proposed Seaton TS location.
2. Two 75/125 MVA, 230/27.6/27.6-kV transformers will be connected to the 230-kV circuits, C10A and T28C.
3. Twelve 27.6-kV feeders with a normally open tie configuration will be built outwards from Seaton TS. These feeders correspond to Feeder Expansion investments in the System Access category.

Figure 13: Proposed Seaton Connection



Asset Investment Costs for Seaton TS Construction

The construction of Seaton TS will introduce new TS assets listed in Table 9, wherein the typical useful life ("TUL") and costs associated with each asset type are provided. Elexicon will ensure that TS assets introduced by the construction and operation of Seaton TS shall be maintained and reviewed in future condition assessments.

Table 9: Asset Introduction by Seaton TS

Asset Introduced	OEB Code	Cost ($M)	Asset TUL
TS Transformer	1815-001	$9.00M	45
TS Switchgear	1815-002	$3.00M	40
TS Equipment	1815-003	$3.00M	-
TS Building	1815-004	$15.00M	50
SCADA	1980-001	$2.50M	20
Total		$32.5M	

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.* *-C.c.3 (SS) Description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met*

Distribution System Code

Elexicon's Seaton investments are made in compliance with the *Distribution System Code* specifically with respect to Section 3.3 covering expansions. The *Distribution System Code* defines an "expansion" as a modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made. As the Seaton community will result in thousands of additional customer connections, Seaton TS will be built to facilitate these connections. During the RPP, it was identified that future forecasted values for Whitby TS 27.6-kV loading would exceed the LTR in the future. Elexicon strives to accommodate all new customer connections within the timeline prescribed in the *Distribution System Code*. Building a separate TS which relieves pressure off Whitby TS and can be operated and owned by Elexicon is the preferred approach which came out of the RPP. New feeder expansions will distribute power from the TS to customers in the new community.

Regional Planning Process

The development of Seaton follows the regional planning process, which includes the consultations with the transmitter, HONI. As per section 8.2.1 of the Distribution System Code, a transmission connected distributor shall participate in regional planning upon being requested to do so by the transmitter. As per section 8.3.1, Elexicon provides prompt notice of developments in Pickering that may trigger the need for investments in transmission facilities or distribution facilities. Elexicon consulted with HONI to create the RIP as part of the RPP.

Performance Measures - SAIDI and SAIFI

SAIDI and SAIFI numbers could be impacted if Elexicon does not build Seaton TS. If one line or transformer at Whitby TS were forced out of service, a remaining transformer could carry the present-day peak load using ten-day LTR capacity. As load growth in the area continues, however, the ability to supply customers in a contingency situation becomes more concerning. The TS supplies a large number of customers, making this a critical impact. The potential chance that LTR capacity would not be available if is of concern for customers in both Ajax and Pickering. If there is not enough capacity to serve load during a contingency, a major system outage would occur, affecting SAIFI and SAIDI performance.

Leave to Construct Approval

Leave to Construct approval is not required for this project.

Ontario Cyber Security Framework:

Elexicon is required to comply with the *Ontario Cyber Security Framework* and new investments into Seaton TS will leverage advanced technology while complying with standards for interoperability and cybersecurity.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change) *B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.* *B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.* *B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.*

Stations Overloading: There are no existing stations in the area. Elexicon runs the risk of overloading existing station assets (i.e., Whitby TS 27.6 kV) due to the new developments in the Seaton neighbourhood. Overloaded assets experience accelerated thermal degradation, which reduces the assets' lifetimes and increase the probability of catastrophic failure. The construction of Seaton TS increases the capacity to handle new load without constraining existing Pickering substations.

Reliability of Service: The Seaton community is a major neighbourhood. A dedicated TS is the preferred solution to service the load in the area. Feeder expansions will be required in the area to connect the new neighbourhoods to the new TS. This approach ensures the required reliability of the grid and customer service in the new developments.

Operational Effectiveness: Having one dedicated TS for which Elexicon is responsible increases the operational efficiencies in addressing the infrastructure within Pickering. In the proposed solution the customers will be supplied from distribution transformers connected to 27.6-kV feeders, eliminating the need to operate and maintain substations between the TS and the customers.

Public Policy Responsiveness: The Ontario Government has designated Seaton as an area of significant development. Providing sufficient electrical infrastructure will ensure reliable power is supplied to new customers, while maintaining the reliability performance of existing customers.

Customer Service: Seaton TS is built specifically for new customers that will be living within the new Seaton community. A designated TS allows Elexicon to provide greater customer service to the new area. Customers expect consistent and excellent electrical service when connected to the grid. The additional capacity afforded by this project shall ensure that customers can utilize available electricity for the purposes of their daily lives. In addition, as these customers are serviced by feeders and infrastructure for the new development, existing infrastructure will not be over-burdened and existing customers will not be impacted. Service continuity of all customers in the area will be upheld through this investment.

2.5 Merger-Related Objectives:

There are no merger-related objectives associated with this investment.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties): *• The effect of the investment on system operation efficiency and cost effectiveness* *• The net benefits accruing to customers as a result of the investment* *• The impact of the investment on reliability performance including on the frequency and duration of outages* *Where alternatives have been considered and the ranking of a proposed project* *relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. [Continued below under Value-Added Approach]* *-C.c.7 (SS) An analysis of project benefits and costs comparing the proposed project to a) doing nothing and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.* *Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these qualitative factors in relation to the proposed project and all alternatives, including how these factors affected the selection of the proposed project.* *-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.* *-C.c.1 (SS) An assessment of both the benefits of the project for customers based on achievement of the project objectives and the cost impact to customers of the investment*

As part of the planning process for Seaton TS, both wires and non-wires solutions were considered. From the 2014 Scoping Assessment for the GTA East region:

> *"A review of potential energy management opportunities completed as part of the Master Environmental Servicing Plan for the Seaton community indicates that energy plans could have an impact on the ultimate size of a new TS to supply the area. New distributed generation at Cherrywood TS T7/T8, however, is currently restricted due to short circuit capacity constraints*
>
> *The timing of the need for capacity relief at Whitby TS T1/T2 (27.6 kV supply), based on the findings of the Needs Screening, will depend on the forecasted load growth at the station, the timing of the new Seaton community load, and achievement of the CDM targets in the medium to long term. Therefore, non-wires alternatives assessed through an IRRP could defer station needs in the Sub-Region."*

For cost reference, in their recent ICM application (EB-2019-0170), PUC Distribution Inc. estimated the cost of a 10-MW, 80-MWh battery storage solution at $390/kWh ($31.2M) based on a vendor quote. Given that the Whitby TS 27.6 kV is forecast to exceed its LTR by over 100 MW without the construction of Seaton TS (Figure 8), a similar battery storage solution could defer construction of Seaton TS by two years if there was sufficient short-circuit capacity at Cherrywood TS T7/T8, but could not replace the need to build Seaton TS. This is also noted in the 2014 Scoping Assessment reference above.

Number	***1***	***2***	***3***	***4***	***5***
Scenario Description	Current Plan to build Seaton TS at Site 2	Maintain the status quo of the system – Do Nothing	Non-Wire Alternatives to address Load Growth in the area	Use Malvern TS 27.6 kV Capacity and build Seaton TS at Site 1 or 2	Use Malvern TS 27.6 kV Capacity and build Seaton TS-3 and associated Feeders
Program Scope	Build Seaton TS for new development. Twelve Feeders to emanate from the station. 153 MW capacity to be added directly from the new TS.	Existing Whitby TS 27.6 kV capacity will continue to serve the area. No changes shall be made to the system.	Non-Wire Alternatives were considered when planning for the new Seaton community. Energy management, and distributed generation were aspects that were reviewed. A 10-MW, 80-GWh battery storage system may defer the construction of Seaton TS if there were short-circuit capacity at Cherrywood TS T7/T8.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton will be built in 2023.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton TS-3 to be built with Feeders 1&2 in 2023. Two Additional feeders to follow in 2026. Finally, two more feeders would be constructed in 2033.
Total Gross CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Total Net CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Annual Program Benefits	This option provides sufficient capacity from the new TS to	This option does not provide sufficient capacity. It was	This option does not provide sufficient capacity for the new	This option provides sufficient capacity from the new TS and	This option provides sufficient capacity from the new TS and

Number	***1***	***2***	***3***	***4***	***5***
	serve the annually increasing load of the upcoming development.	considered but rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV.	Seaton development. Non-Wire Alternatives could reduce the capacity designated for the new TS to supply the area. However, there are short circuit capacity constraints at Cherrywood TS T7/T8 which restrict connections of new distribution generation downstream.	additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.	additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.
Program Economics	From the program economics perspective, this option provides significant benefits in cost-efficiency when compared with other options.	From the program economics perspective this option is less attractive than the preferred alternative 1. By continuing to utilize the status quo of Whitby TS, the risk of thermal overloading would result. Secondly, continuing to load the station until it reaches operational and equipment limits is not preferred. Overloading could result in reliability issues, equipment degradation and operational	From the program economics perspective this option is less attractive than the preferred alternative 1. This alternative can potentially reduce the overall capacity of the transformer station being built but does not address the entire load growth within the area. Additional investments to address the load growth in the area would still be required. As a result, this option would not be a full solution.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 128% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 155% increase comparing to preferred alternative 1.

Number	***1***	***2***	***3***	***4***	***5***
		inefficiencies. Inevitably, the area would require additional capacity where a new scoping of solutions or new transformer station would be required.			
Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered "unsure/ none", indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton will need to be built to address the new growth as soon as possible. This option is the most economical of the alternatives.	The constraining factor is that the status quo would not address incoming load growth in the area. An eventual solution would be required for the area.	The constraining factor is that Seaton TS or another solution would still need to be built.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.
Preferred Alternative	**X**				

Number	***6***	***7***	***8***	***9***	***10***
Scenario Description	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at Site 1 or 2	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at site 3 and associated feeders	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at Site 1 or 2	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at site 3 with associated feeders	Build Seaton TS at site 3 alongside its associated feeders
Annual Program Scope	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built. Additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built alongside two feeders. 2 additional feeders shall be built two years later, and another two feeders will follow two years later. Finally, two feeders will be built seven years later. An additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS will then be built three years from Malvern's final set of feeders. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS and two feeders to be built three years from the construction of Sheppard's final 2 Feeders. 2 Additional Seaton Feeders to follow 6 years later. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Seaton TS to be built with two initial feeders. Following the initial construction, two additional feeders shall be built two years later. Two additional feeders will then be built two years later with a final pair being built 6 years after.
Average Annual Gross CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M

Average Annual Net CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M
Annual Program Benefits	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. Capacity is not increased from preferred option 1.
Program Economics	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 79% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more average total CAPEX – a 123% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 158% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 177% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It does not provide additional capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 230% increase comparing to preferred alternative 1.

Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered "unsure/ none", indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will be much more costly being built at location 3.
Preferred Alternative					

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies. *-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.* *For proposed distribution rate funded CDM programs the following details are required:* *• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers* *• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred* *-C.c.4 (SS) Identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system* *-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.*

Reliability: Connecting the new customers to Whitby TS 27.6-kV will result in exceeding the LTR capacity and the substation equipment thermal overloading which might in consequence result in service interruption. Thus, the degradation of assets could impact customers. A new separate station will provide the neighbourhood with new capacity and provide more reliability as a designated station.

Grid Resiliency: The construction of Seaton TS supports the ability to maintain grid operations during contingency situations. This supports a resilient grid with sufficient capacity and redundancy.

Operational Efficiency and Cost Effectiveness: The selected option is the most cost efficient. Ownership of the new Seaton TS by Elexicon will allow it to be operated and maintained from Elexicon's existing operations centres. Preventing the overloading of Whitby TS 27.6-kV increases the expected lifespan of the substation assets.

Safety: Safety is generally not a driver for this project; however, without the planned Seaton TS, Whitby TS would experience a thermal overload. This presents not only an operational issue but a safety issue as the thermal overload might increased likelihood of catastrophic failure occurrence. A new TS with feeders specifically designated for the service area would prevent overloading.

Cyber-Security/Privacy: The options represent equivalent levels of cyber-security and privacy.

Environmental Benefits: The options represent equivalent environmental benefits.

Coordination/Interoperability: Coordination is present through the RPP – with HONI, the IESO, and other stakeholders – when evaluating alternatives to address the load growth and capacity constraints in the area. The relevant parties are specifically engaged in consultations for Seaton TS. Elexicon will be involved further with coordination during the construction and commissioning of Seaton TS.

Conservation and Demand Management: Conservation and Demand Management are not significant drivers of this investment program.

Net Customer Benefits: The selected option is the lowest cost by $6.53M to $10.28M annually while providing a comparable level of reliability (since all options require a dedicated TS for the area; thus, it provides the most benefits to customers). Existing customers benefit from reliability being maintained if the new load was added to the existing feeders and TS.

Priority: This investment is mandatory to provide sufficient capacity to connect new customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated *-C.c.5 (SS) Identification and explanation of the factors affecting implementation timing/priority* *-A.4 Start date, in-service date and expenditure timing over the planning horizon*

As the design and final planning work are still being done for Seaton TS, Elexicon will remain prudent and continue working towards ensuring adequate capacity will be in place by the time the load materializes. Significant coordination with HONI will be required to complete the Seaton TS work. Currently, Elexicon is planning to purchase the land for the Seaton TS in 2021. As the COVID-19 pandemic could impact the construction of buildings within the Seaton area, Elexicon will maintain clear contact with developers and HONI. While the investment has a planned in-service year of 2022. The start date, expenditure timing, and in-service date are uncertain at this time.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Any new station built by the utility needs to be coordinated with HONI to ensure that transmission supply feeders can support the new station. The planning inputs drawn to justify the need for Seaton TS included system loading reports and metering data, third-party development information, municipal household forecasts, and land use designations from Region and the City. These data points drove the system-level load forecast for the combined utility, which signified the larger demand expected over the next few years. Historically, separate load forecasts were completed by WHEC and Veridian in-house, which have since been combined into a single load forecast outsourced to a contractor.

The resulting demand forecast is communicated with HONI where Elexicon and HONI held numerous meetings in the RIP (Regional Infrastructure Planning) process. IESO was also involved in determining the integrated resource plan for the region. In all stages, Seaton MTS was communicated as a need with understanding from the system operator and transmission entity. As the resulting demand from developments is expected to exceed the LTR of Whitby TS 27.6kV, it was determined that a solution would need to be found. In this case, Seaton MTS was the final decision to alleviate Whitby TS and provide the community with a dedicated TS. As Seaton TS is a new station, there will be rejuvenation and introduction of new assets in the neighbourhood area. Existing Whitby TS customers will continue to be supplied by the station. This should provide better value and longer-term lifecycles of substation assets to Elexicon. Elexicon will continue to evaluate trends and update its annual Load Forecast to plan for the Seaton Load. Moving forward, development information, land-use designations, and housing forecasts will continue to be used to plan for system capacity investments such as Substation Growth & Expansion. Elexicon will ensure that adequate capacity will be available for the future demands of new customers.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Seaton TS will be a new venture for Elexicon due to the complexity of the station and being the first TS exclusively owned by the utility. Additionally, due to the scale of new connections forecasted for the Seaton community, there will be new operations and maintenance procedures for the station. A significant amount of feeder expansion investments will take place concurrently with the substation investment to ensure service to new customers.

Planning for Seaton TS was done concurrently with Hydro One in determining the most suitable alternative to address the development in Pickering for Seaton. The construction of Seaton TS will be carried out by external design consultants and contractors. The environmental assessment is also being done externally. Connections of the transmission line to Seaton will be handled by HONI. Construction evaluation and design review will be overseen by Elexicon through all stages. Routine maintenance and operations will be handled by Elexicon staff moving forward. Elexicon has historically outsourced some of the substation inspection and maintenance activities to third parties which might also be an option moving forward. These include testing of major station assets such as power transformers, circuit breakers, switches, relays, and other items such as buildings and fences.

4.3 Scale Increase Considerations

The consolidation of staff from the two former utilities provides a larger workforce with collective experiences to address the new Seaton TS. As Whitby is close in proximity to Pickering, there will be more crews and resources available in case a reactive action is required in Seaton. Other benefits from the project include ensuring that Whitby TS LTR capacity will not be exceeded. As Whitby TS feeds the Whitby area in addition to Ajax and Pickering, Elexicon will now understand the capacity constraints and requirements from all three service areas. A balance of decision-making can be made now that the two former utilities have been combined and more efficient and detailed resource utilization can be fulfilled.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Across the future DSP period, Seaton TS will be the single major investment in the Substation Growth & Expansion category. Elexicon will be applying for an ICM for 2022 by filing in the Summer of 2021 with regards to the construction of the station. Major growth has been indicated by the City of Pickering and developers across the Seaton Lands and construction is currently underway for a variety of infrastructure around the area. The new TS will ensure that Whitby TS 27.6 kV is not overloaded.

Seaton TS allows for Elexicon to control the level of service it provides to its customers. It also provides improved switching and sufficient contingencies for the grid overall. At the end of the consolidation period, Elexicon will be well positioned to serve the electricity needs of its customers. Customers will benefit from the new station servicing the region.

Scoping Assessment Outcome Report

Region:	**GTA East**		
Start Date:	**September 9, 2014**	**End Date:**	**December 15, 2014**

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The purpose of the Scoping Assessment is to determine the type of planning approach that can best address the potential needs identified in the Needs Screening Report that require further regional coordination.

The Needs Screening is the first stage in the regional planning process and is initiated by the lead transmitter, Hydro One Networks Inc. ("Hydro One") in this case. The Needs Screening Report[1] for GTA East, issued on August 11, 2014, concluded that some needs in the Region may require regional coordination, and these needs should be reviewed further under the OPA-led Scoping Assessment process.[2]

The Scoping Assessment process further reviews the potential needs in the Region with the relevant Local Distribution Companies ("LDCs"), the transmitter and the IESO ("Regional Participants" or "Study Team"). This review includes information on potential wires and non-wires alternatives, to determine whether the OPA-led integrated regional resource plan ("IRRP") or the transmitter-led Regional Infrastructure Plan ("RIP") should be undertaken to address the needs. If localized wires-based solutions do not require further coordinated regional planning, the Scoping Assessment may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This Draft Scoping Assessment Outcome Report:

- Defines any Sub-Regions within the GTA East Region ("Region") which have needs that may require regional coordination;
- Determines the appropriate regional planning approach and scope for each Sub-Region with identified needs that require regional coordination;
- Establishes a draft terms of reference in the case where an IRRP is the recommended approach for the Sub-Region(s); and
- Establishes a Working Group for any Sub-Region(s) recommended for an IRRP.

2. Team

The Scoping Assessment was carried out by the Regional Participants that were involved in the Needs Screening process, as follows:

- Ontario Power Authority ("OPA")
- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")

[1] The Needs Screening Report for the GTA East Region can be found at: http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Needs%20Screening%20Report_GTA%20East%20Region_August%2011%202014%20(Final).pdf

[2] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

- Veridian Connections Inc. (“Veridian”)
- Whitby Hydro Electric Corporation. (“Whitby Hydro”)
- Hydro One Networks Inc. (“Hydro One Distribution”)
- Oshawa PUC Networks Inc. (“Oshawa PUC”)

3. Categories of Needs, Analysis and Results

The Needs Screening included a station capacity assessment over a 10-year study period for the 230 kV transmission facilities in the Region using the station summer peak demand forecast provided by the Study Team. Gross load forecast information was provided by the LDCs and a net load forecast was produced using the Conservation and Demand Management (“CDM”) and Distributed Generation (“DG”) forecast provided by the OPA.

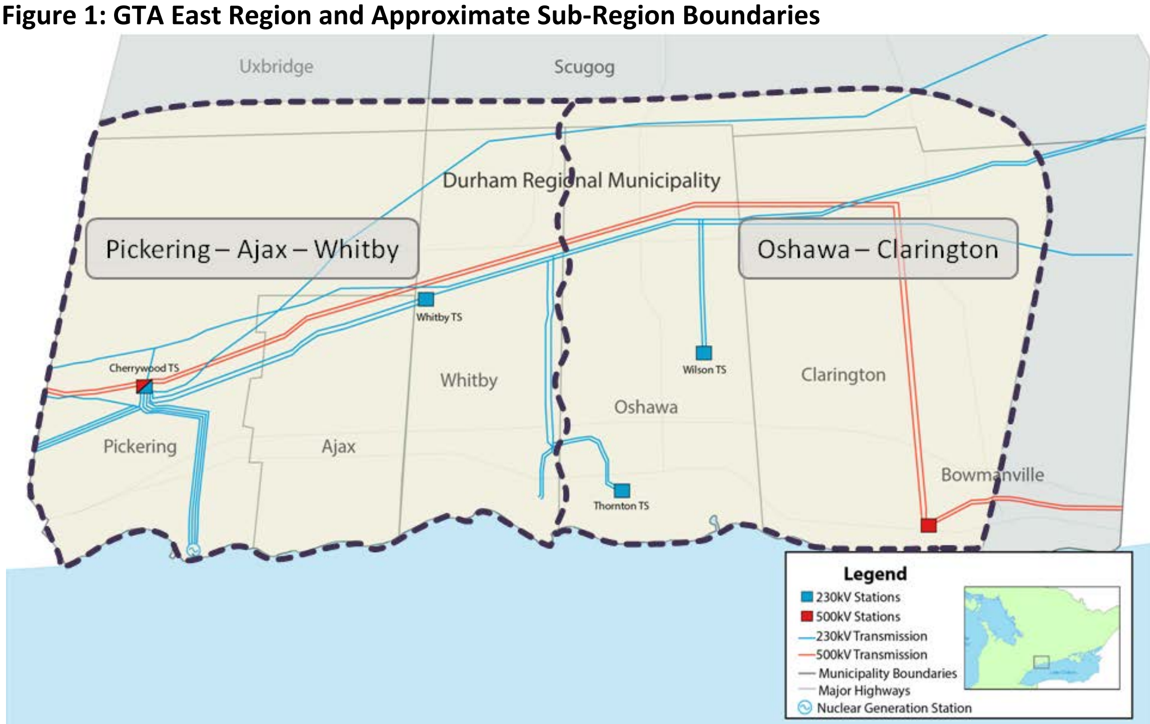
The Needs Screening recommended that the Scoping Assessment process be undertaken for the area served by Cherrywood TS and Whitby TS; and that no further regional coordination is required for the area served by Thornton TS and Wilson TS.

Thus the GTA East Region can be divided into two Sub-Regions for the Scoping Assessment:

- **Pickering-Ajax-Whitby** which includes the area served by Cherrywood TS and Whitby TS and the 230 kV lines connecting 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 Townships of Uxbridge and Scugog), and
- **Oshawa-Clarington** which includes the area served by Thornton TS and Wilson TS and the 230 kV lines connecting the transmission facilities (includes the City of Oshawa, part of the Municipality of Clarington and part of the Township of Scugog).

Based on the approximate service areas supplied by these stations, the area boundaries are as shown in Figure 1.

Figure 1: GTA East Region and Approximate Sub-Region Boundaries



Note: Some Whitby Hydro load is supplied by Thornton TS in Oshawa.
Source: OPA

The needs identified in the Pickering-Ajax-Whitby Sub-Region of the GTA East Region are subject to this Scoping Assessment process to determine the appropriate regional planning process going forward.

The needs identified in the Oshawa-Clarington Sub-Region will be addressed by Hydro One Networks and the relevant LDCs.

The needs to be addressed as part of this Scoping Assessment are as follows:

- station capacity at Cherrywood TS T7/T8 (230/44 kV),
- station capacity at Whitby TS T1/T2 (230/27.6 kV), and
- load restoration for the loss of two elements (230 kV circuits).

Available station capacity and feeder capacity utilization in the GTA East region was also recommended for review as part of further assessing the needs identified in the Needs Screening Report. The need for a new transformer station in Central Pickering to supply the planned Seaton community will also be reviewed.

Regional Overview

Descriptions of each need identified in the Needs Screening Report are described as follows. The time horizon considered in the Needs Screening was from 2014 to 2023 (10 years).

230 kV Connection Facilities

A. Needs Reviewed in the Scoping Assessment

The following station capacity needs were identified in the Needs Screening as requiring further review in the Scoping Assessment.

Cherrywood TS (230/44 kV transformers T7/T8) is forecast to slightly exceed its normal supply capacity based on the gross demand forecast starting in 2014 to 2023. However, the station capacity is expected to be adequate to meet the demand over the study period when considering the net demand forecast which includes the planned Provincial CDM targets for the area. The years 2014 and 2015 may have slight overloads until the planned CDM initiatives offset the expected load. It is noted that the step-down transformers at Cherrywood TS that supply the local demand in the GTA East Region are within the scope of this assessment. The bulk transmission and 500/230 kV autotransformer facilities also located at Cherrywood TS are not within the scope of this regional planning study (bulk system planning is conducted under a separate process).

Whitby TS (230/27.6 kV transformers T1/T2) is forecast to exceed its normal supply capacity based on the gross demand forecast from 2018 onwards. However, the station capacity is expected to be adequate to meet the net demand in 2018, until growth in the new Seaton community exceeds the station capacity. In the absence of a new station in the area to supply the new community load, the station capacity could be exceeded even after accounting for the effect of the planned CDM targets.

A new greenfield community named "Seaton" is planned to be developed in Central Pickering, within Veridian's service territory, just north of the Cherrywood TS. Veridian has planned to supply this new community load at 27.6 kV. Veridian has forecasted the gross demand for this new community to be approximately 5 MW starting in 2018 and increasing up to 75 MW by 2023. The existing stations in the area are not able to supply the entire projected new load. Hydro One and Veridian assessed the station capacity requirements and plans for a proposed new 230/27.6 kV station called "Seaton TS" prior to the new regional planning process. Further assessment will be undertaken as part of the regional planning process.

B. Needs Not Reviewed in the Scoping Assessment

The following station capacity needs were identified in the Needs Screening as not requiring further review under the Scoping Assessment or not requiring further action at this time.

Whitby TS (230/44 kV transformers T1/T2 and transformers T3/T4) is not forecast to exceed its normal supply capacity during the study period. Therefore, no further action is required at this time. It should be noted however that available capacity at this station would be considered as part of a solution to meeting needs at other stations in the Region forecasted to exceed their normal supply capacity during the study period.

Wilson TS DESN 1 (230/44 kV transformers T1/T2) is forecast to exceed its normal supply capacity in 2014 and 2017 through to 2023 under the gross demand forecast, and from 2018 to 2023 under the net demand forecast. It was agreed by the Regional Participants that transformation capacity relief is needed and further assessment is required through local planning between the transmitter and impacted LDCs.

Wilson TS DESN 2 (230/44 kV transformers T3/T4) is forecast to exceed its normal supply capacity from 2014 to 2023 under both gross and net demand forecasts. In the past, overloading at Wilson TS DESN 2 under certain conditions was significant enough that emergency rotating load shedding was required. It was agreed that relief is needed as soon as possible and that this need could be most efficiently assessed through local planning between the transmitter and the impacted LDCs.

Thornton TS (230/44 kV transformers T3/T4) is forecast to exceed its normal supply capacity based on the gross and net demand forecast from 2015 to 2023. Hydro One is scheduled to replace the two transformers at Thornton TS in 2015 as they are approaching their end-of-life. This will also eliminate the existing transformer gassing issue, but will not address the capacity needs at the station. It was agreed that transformation capacity relief is needed and that this need could be most efficiently assessed through local planning directly between the transmitter and the impacted LDCs.

Finally, with respect to the 230 kV connection facilities in the GTA East Region, the Needs Screening Report recommended that available station capacity and feeder capacity utilization be reviewed in the next stage of the regional planning process.

System Reliability, Operation and Restoration

No significant system reliability and operating issues were identified for this Region in the Needs Screening Report. Based on the gross coincident demand forecast, no load interruption would result from the loss of one element. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600 MW throughout the 10-year study period reviewed in the Needs Screening Report.

For the loss of two elements (2 x 230 kV transmission circuits), the load interrupted by configuration may exceed 150 MW and 250 MW. The double circuit contingency to be addressed is the loss of circuits M29C and B23C, affecting supply to Whitby TS (T3/T4) and Wilson TS (post Clarington TS configuration) and the loss of H26C and H24C affecting supply to Whitby TS (T1/T2), Thornton TS, and some large transmission connected industrial customers in the Region.

The Study Team agreed that load restoration for the loss of M29C+B23C and H24C+H26C would be further assessed in the next stage of the regional planning process.

Based on information provided by Hydro One, the Thornton TS transformers (T3/T4) are scheduled for end-of-life replacement in 2015. No other significant sustainment plans are scheduled within the Region in the near-term.

Findings of the Scoping Assessment

The Regional Participants reviewed the GTA East regional needs and discussed next steps at a meeting on September 9, 2014. It was concluded in the meeting that in addition to wire-solutions, CDM and embedded generation solutions could address some of the needs that have been identified for the scoping assessment. It was proposed that the next step of the regional planning process of this Region would be an IRRP.

Based on a review of the findings of the Needs Screening, the Study Team determined that non-wires alternatives should be a consideration in overall planning of supply to the new Seaton community in Central Pickering. A review of potential energy management opportunities completed as part of the Master Environmental Servicing Plan for the Seaton community indicates that energy plans could have an impact on the ultimate size of a new TS to supply the area.[3] New distributed generation at Cherrywood TS T7/T8, however, is currently restricted due to short circuit capacity constraints
The timing of the need for capacity relief at Whitby TS T1/T2 (27.6 kV supply), based on the findings of the Needs Screening, will depend on the forecasted load growth at the station, the timing of the new Seaton community load, and achievement of the CDM targets in the medium to long term. Therefore, non-wires alternatives assessed through an IRRP could defer station needs in the Sub-Region. Furthermore, continued strong growth is expected in the Town of Whitby, and Whitby Hydro may run out of 44 kV capacity to supply the growth by about 2026. Planning to address these needs if done in an IRRP would consider a 20-year planning horizon.

The scope of an IRRP would include a review of load restoration needs in the Sub-Region, to determine if a wires or non-wires option, or combination of the two, could address the need.

[3] The Seaton Development Energy Management Plan can be accessed at: http://www.pickering.ca/en/cityhall/resources/energymgmtplanjuly09.pdf

4. Conclusion

This Scoping Assessment concludes that an IRRP be undertaken to further assess the capacity and restoration needs in the Pickering-Ajax-Whitby Sub-Region of the GTA East Region.

The draft Terms of Reference outlining the study area, objectives, scope, data requirements, Working Group, accountabilities and schedule for the IRRP is attached.

PICKERING-AJAX-WHITBY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA East Planning Region | June 30, 2016

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Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Pickering-Ajax-Whitby Sub-region

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Pickering-Ajax-Whitby Sub-region Working Group ('the Working Group"), which included the following members:

- Independent Electricity System Operator
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Pickering-Ajax-Whitby Sub-region over a 20-year period beginning in 2015; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the Pickering-Ajax-Whitby Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. The Pickering-Ajax-Whitby Sub-region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
DR	Demand Response
DG	Distributed Generation
EA	Environmental Assessment
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC or Committee	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	Long-Term Energy Plan
LTR	Limited Time Rating
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
PV	Photovoltaic (solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TS	Transformer Station
TWh	Terawatt Hours
Veridian	Veridian Connections Inc.
Whitby Hydro	Whitby Hydro Electric Corporation
Working Group	Technical Working Group for Pickering-Ajax-Whitby IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Pickering-Ajax-Whitby Sub-region (the "sub-region") over the next 20 years, from 2015-2034. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group composed of the IESO, Veridian Connections Inc. ("Veridian"), Whitby Hydro Electric Corporation ("Whitby Hydro"), Hydro One Distribution and Hydro One Transmission [1] (the "Working Group").

The sub-region is part of the GTA East planning region ("GTA East Region"). The GTA East Region is within the Region of Durham and extends from Lake Ontario northward to the southern parts of Scugog and Uxbridge, and includes the municipalities of Pickering, Ajax, Whitby, Oshawa and the eastern part of Clarington. The area is supplied by several transformer stations ("TS") fed by the 230 kV transmission system in the area. The local distribution companies ("LDCs") providing services to the GTA East Region include: Hydro One Distribution, Oshawa PUC Networks ("Oshawa PUC"), Veridian and Whitby Hydro.

The sub-region includes the City of Pickering, Town of Ajax, the Town of Whitby and the southern parts of the Townships of Uxbridge and Scugog. The sub-region is currently served by Cherrywood TS 230/44 kV step-down transformers, Whitby TS and a portion of Thornton TS. The scope of this sub-region IRRP also includes consideration of the entire GTA East regional supply for the purposes of restoration analysis. A map of the GTA East Region is provided in Figure 1-1 below.

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

Figure 1-1: Map of Region

Source: Data provided by Hydro One Networks Inc.
Copyright: Hydro One Networks Inc. [2016].

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB's regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the province's 21 electricity planning regions at least once every five years. The GTA East Region is one of these planning regions.

This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies investments for immediate implementation necessary to meet near-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies planning considerations over the longer term. It does not identify or recommend any specific projects for the longer term at this time but maintains flexibility to meet longer-term needs as they arise by monitoring growth and impacts of conservation and distributed generation ("DG") uptake at area transformer stations.

This report is organized as follows:

- A summary of the recommended plan for the Pickering-Ajax-Whitby Sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Pickering-Ajax-Whitby Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and DG assumptions, are described in Section 5;
- Electricity needs in the Pickering-Ajax-Whitby Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- Considerations for meeting regional growth needs in the longer term are discussed as in Section 8;
- A summary of engagement carried out to date in developing this IRRP and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

This IRRP addresses the sub-region's electricity needs over the next two decades, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC").[2] The IRRP identifies the needs that are forecast to arise in the near term (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034). The medium to longer term is referred to as the longer-term plan throughout this report as no distinct needs have been identified for the area past the near-term horizon. These two planning horizons are distinguished in the IRRP to reflect the level of commitment required to address needs over these time periods. The plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria and input received during engagement with local communities and other stakeholders. The planning criterion includes technical feasibility, cost, reliability, and, in the near-term, the IESO sought to maximize the economic use of existing electricity infrastructure.

This IRRP identifies specific projects for implementation in the near- term. This is necessary to ensure that they are in-service in time to address the sub-region's more urgent needs while respecting the lead time for development of the recommended and required infrastructure.

The IRRP also identifies possible longer-term electricity needs and considerations to keep in mind for the next round of planning. In preparation for the longer term, actions are identified to gather information and lay the groundwork for future planning processes. These actions are intended to be completed before the next IRRP cycle so that their results can inform further consideration at that time.

The needs and recommended actions comprising the near-term plan, as well as the long-term plan, are summarized below.

[2] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

2.1 Near-Term Plan (Up to 2020)

By 2019, peak summer 27.6 kV electrical demand at Whitby TS is expected to exceed the Limited Time Rating[3] ("LTR") of the transformer that supplies electricity at the 27.6 kV level by 12 MW, increasing to 132 MW by end of the study period in 2034. This increased loading is chiefly influenced by the forecast growth in demand in the greenfield community of Seaton in North Pickering. As the transformation capacity need is triggered by a new growth pocket with no current access to transmission supply, the near-term plan considers options to provide additional 27.6 kV supply to meet the entire capacity need of the new Seaton community.

Near-Term Needs

- Need for additional 27.6 kV transformation capacity to supply growth
- Need to conduct analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines

Currently, a portion of customers supplied from the circuits H24/26C and M29/B23C in the GTA East Region would not be able to be restored within ORTAC timelines for rare failure events at peak times. A restoration shortfall exists for the 30 minute and 4 hour timelines. The 2015 30 minute and 4 hour shortfalls are 49 MW and 64 MW for the H24/26C circuits and 81 MW and 29 MW for the M29/B23C circuits respectively. The near-term plan considers the relative benefit of wires options versus the status quo for the 30 minute and 4 hour restoration timelines for rare double element failure events.

Recommended Actions

1. Build a new 230/27.6 kV station and upgrade an existing 230 kV line

Action is required to provide additional 27.6 kV supply capacity for the sub-region, specifically in proximity to the greenfield community of Seaton. Feeders are currently being built from Whitby TS to the new load centre to provide some additional supply to Seaton, however, the 27.6 kV transformation capacity at Whitby TS is forecast to be exceeded by 2019 and additional 27.6 kV capacity will be required to meet the forecast demand. Based on the analysis, included as Appendix B and summarized in Section 7.1.3, it has been determined that the most economic

[3] LTR determines the capacity of a station to serve load

course of action is to construct a new 230/27.6 kV station and upgrade an existing 230 kV line in the proximity of Seaton by 2018 in order to meet the need for additional capacity in 2019 (hereinafter, this solution is referred to as "Seaton MTS"). An Environmental Assessment ("EA"), which is currently underway, will recommend the preferred site for Seaton MTS. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Hydro One and Veridian undertake further planning and project development along with approval for implementation of Seaton MTS.

2. Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region

Preliminary technical and economic analysis indicates that the cost of addressing the restoration shortfall may be less than the potential cost of prolonged supply interruptions to local electricity customers. This preliminary analysis accounted for the low likelihood of the rare failure event (the simultaneous and prolonged loss of two supply lines serving the area) and assumed the higher end of customer interruption costs.

Based on this preliminary analysis it is recommended that the transmission and distribution companies conduct detailed studies to determine if specific restoration facilities can be justified. These detailed studies should be conducted as part of the Regional Infrastructure Plan ("RIP") for the GTA East Region and should consider outage statistics, associated wires solutions/costs and incremental reliability benefits.

2.2 Longer-Term Plan (2021-2034)

Over the long term, factors such as intensification of established areas, progress on community energy plans, conservation, DG uptake at the transformation station level and the electrification of the transportation sector could affect electrical service for the sub-region. These factors could impact the capacity of the existing electricity supply infrastructure. Near-term actions in order to prepare for the long term will focus on monitoring these factors.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure — over the near, medium and long term and develops a plan to ensure cost-effective and reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board ("OEB") convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and in August 2013 formalized the process timelines through changes to the Transmission System Code and Distribution System Code, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a "wires" solution is the best option. If the

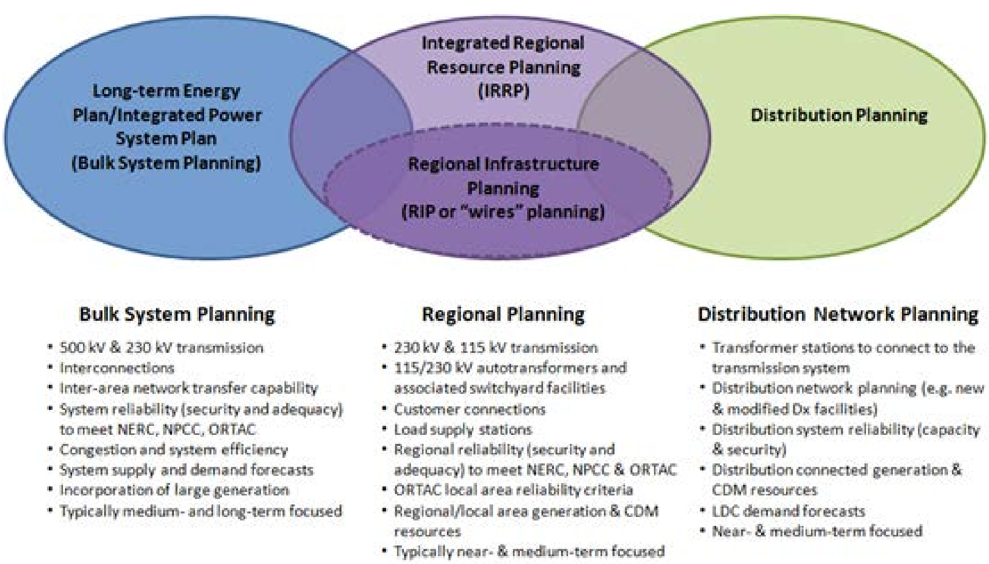
IESO recommends a wires solution, then a transmission- and distribution-focused RIP is developed. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment process, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is recommended, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it following the completion of the IRRP. Both RIPs and IRRPs must be updated at least every five years.

The final IRRPs and RIPs must be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate application or leave to construct. They may also be used by municipalities for planning purposes and by other parties to facilitate a better understanding of local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one forms of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

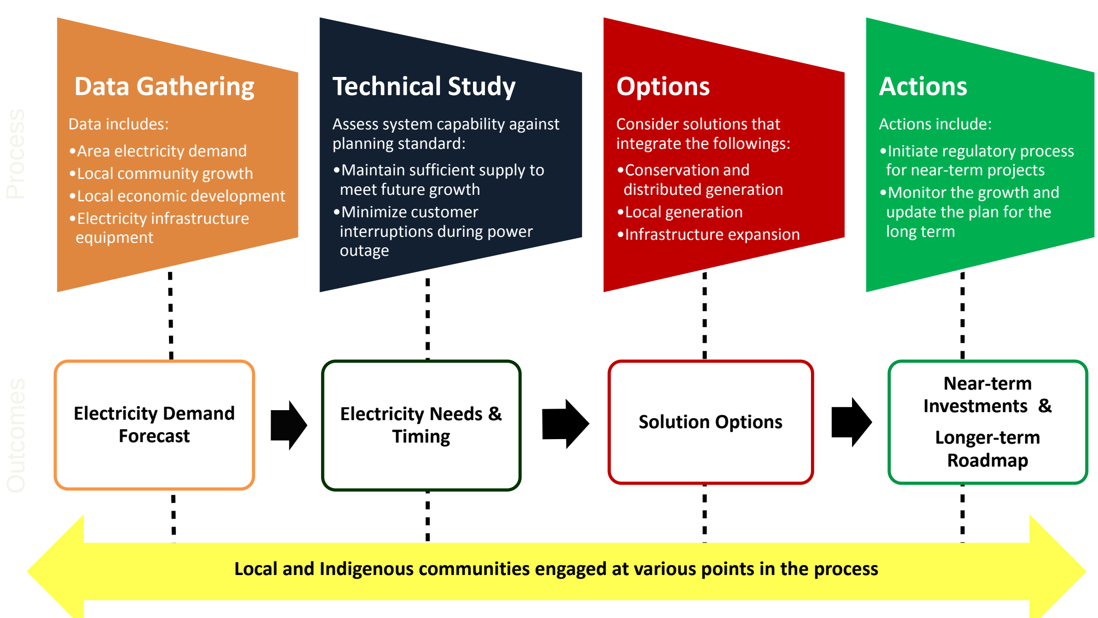
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and technical working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process. Other recommendations in the IRRP may include: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Pickering-Ajax-Whitby Sub-region Working Group and IRRP Development

The initial impetus for the sub-region IRRP was a 2014 Needs Screening report for GTA East. This report was produced by Hydro One Transmission with input from the OPA and IESO, Veridian, Whitby Hydro, Oshawa PUC and Hydro One Distribution. The Needs Screening was carried out to identify any needs which required coordinated regional planning. The Needs Screening Report found that there were needs which potentially required regional coordination, therefore the former OPA conducted a Scoping Assessment process and issued a Scoping Assessment Report in December 2014, in which it identified needs in the Pickering-Ajax-Whitby Sub-region that should be further assessed through an IRRP.

In late 2014 the Working Group was formed to develop a Terms of Reference for the IRRP, gather data, identify near to long-term needs in the sub-region, and develop the near-term recommend actions included in this IRRP.

4. Background and Study Scope

This report presents an IRRP for the Pickering-Ajax-Whitby Sub-region for the 20-year period from 2015 to 2034.

The IRRP planning approach for this sub-region was determined during the GTA East Region Scoping Assessment process. The combination of greenfield growth in North Pickering and supply capacity limitations in the area triggered the need for a coordinated approach by way of an IRRP for the sub-region.

A greenfield community -Seaton is planned to be developed in north Pickering, just north of the Cherrywood TS, within Veridian's service territory. This development is being planned for residential capacity for up to 70, 000 people and 35,000 jobs. Veridian plans to supply this new community load at 27.6 kV. Hydro One and Veridian assessed the station capacity requirements and plans for a proposed new 230/27.6 kV station called "Seaton MTS" prior to the regional planning process for the sub-region. Further assessment of the 27.6 kV supply situation was undertaken as part of this IRRP.

To set the context for this IRRP, the scope of this IRRP and the sub-region's existing electricity system are described in Section 4.1.

4.1 Study Scope

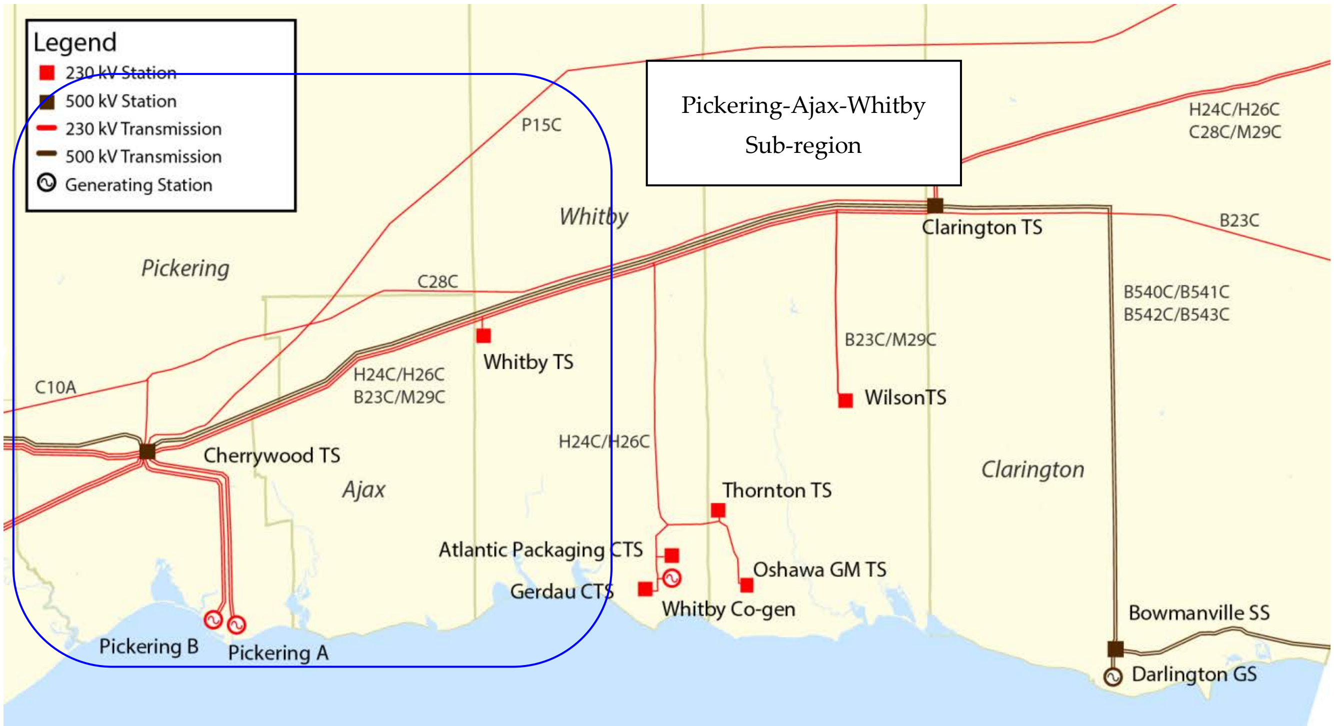
This IRRP recommends options to meet supply needs of the sub-region in the near, and longer term. The plan is a joint initiative involving the Working Group members, the IESO, Veridian, Whitby Hydro, Hydro One Distribution and Hydro One Transmission, and incorporates input from other stakeholders. The plan takes into account forecast electricity demand growth, conservation and demand management ("CDM" or "conservation") in the area, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, FIT and other generation uptake through province-wide programs.

This IRRP addresses regional needs in the sub-region, including capacity, security, reliability and relevant end-of-life consideration of assets.

The following transmission facilities are included in the plan scope and illustrated in Figure 4-1:

- Stations—Cherrywood TS, Whitby TS
- Transmission circuits—H24/26C and M29/B23C

Figure 4-1: Regional Transmission Facilities



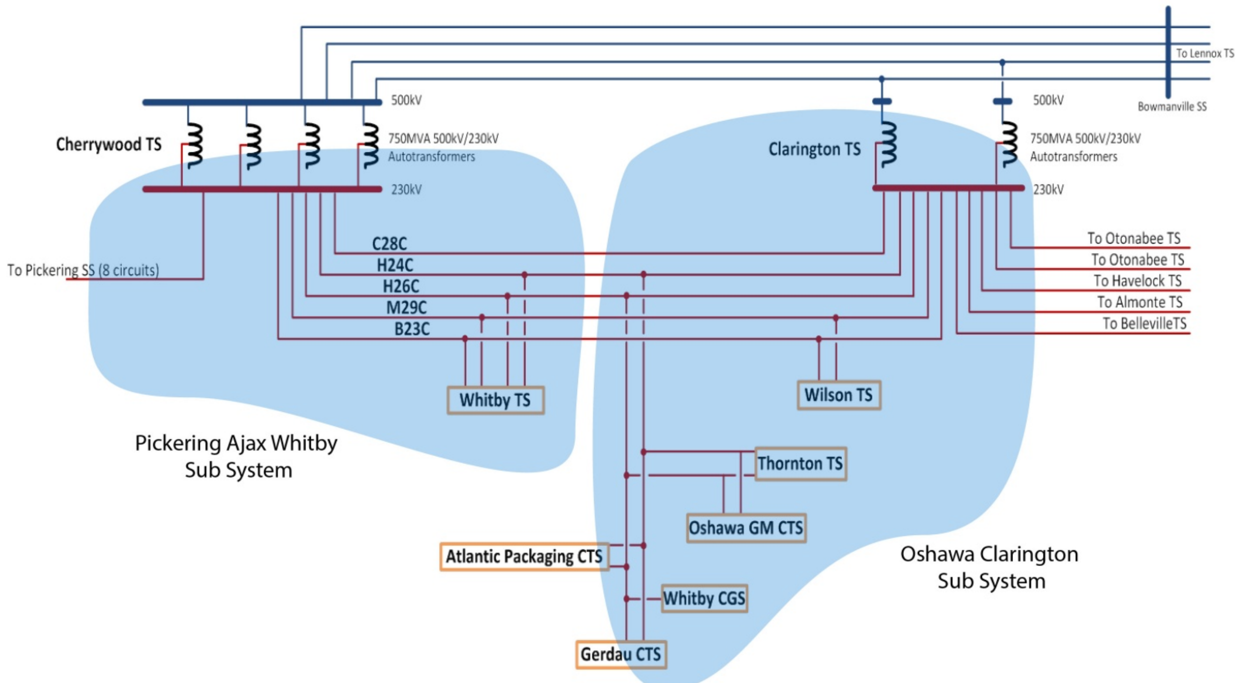
Source: Data provided by Hydro One Networks Inc.

The IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the capacity and reliability of the existing transmission system supplying the sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC.
- Establishing feasible integrated alternatives to address needs, including a mix of conservation, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using planning criteria which may include: technical feasibility, cost, reliability performance, environmental and social factors.
- Conducting community engagement to obtain local input on options for meeting the needs.
- Developing and communicating findings, conclusions, and recommendations.

Figure 4-2 below shows the electrical configuration of the main stations, supply sources, and transmission assets for the GTA East Region as a single line diagram. Note that the needs analysis includes Clarington TS which is currently under construction and is expected to be in-service for 2018.

Figure 4-2: Electrical Sub-systems



Source: Hydro One Networks Inc.

5. Demand Forecast

This section outlines the forecast of electricity demand for the Pickering-Ajax-Whitby Sub-region. It highlights the assumptions made for peak-demand load forecasts and the contributions of conservation and DG to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electricity system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times of the area's overall peak.

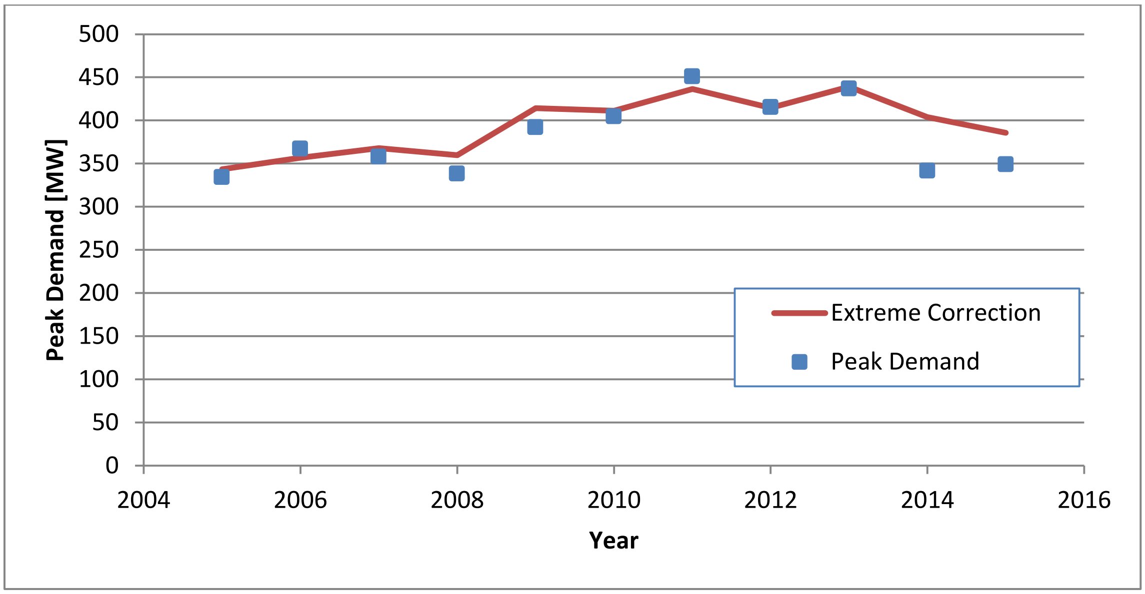
Within the sub-region, the peak loading hour for each year typically occurs in the early-evening of the hottest weekday during the summer. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day. The 2015 regional peak occurred on July 30 at 5:00 pm. Although a large group of industrial customers exists in the GTA East Region, both the regional and sub-regional peak is generally driven by the air conditioning loads of residential and commercial customers. The introduction of the IESO's Industrial Conservation Initiative program in recent years has decreased the overall effect of industrial customer load during peak hours.

Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2015. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The sub-region has seen steady demand growth since 2005. The peak demand in this sub-region is heavily driven by weather conditions. Residential and commercial customers combine for approximately 80% of the load in the area and during the summer months, load from air conditioning drives the peak demand. The recent decline in peak demand during 2014 and 2015 can be attributed to the cool summers experienced across the GTA and province-wide. The peak day temperature in 2014 and 2015 averaged 29.4 degrees Celsius, compared to 34.2 degrees Celsius from 2010 to 2013.

Figure 5-1: Historical Peak Demand in Pickering-Ajax-Whitby Sub-region



The red line in Figure 5-1 shows the weather corrected customer demand for the same hour as the actual peak demand. The weather corrected line has been adjusted to reflect the expected behaviour of the load under extreme weather conditions. Correction factors between actual and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

5.2 Demand Forecast Methodology

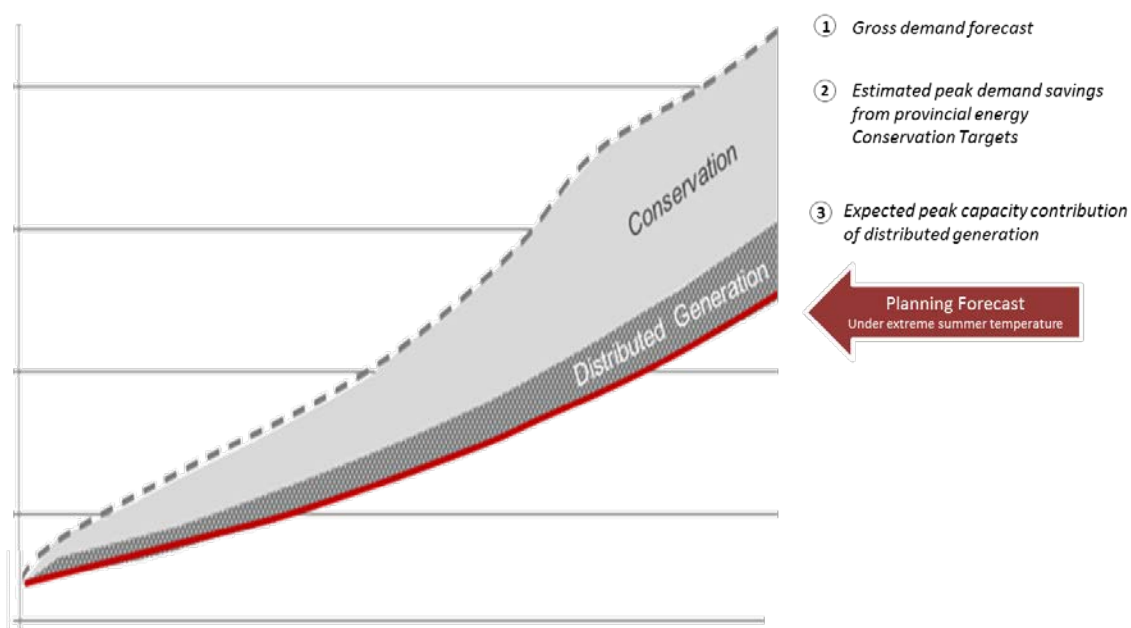
For the purpose of this IRRP, a 20-year planning forecast was developed to assess supply and reliability needs at the regional level.

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

The 20-year planning forecast is divided notionally into two timeframes. The near (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034).

The sub-region's peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in the LDCs' service territory. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to produce a planning forecast - i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT, and to reflect extreme weather conditions where necessary. The planning forecast was then used to assess any growth-related electricity needs in the sub-region.

Figure 5-2: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the corresponding local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

Each participating LDC and transmission-connected customer in the LDCs' service territories prepared gross demand forecasts at the TS level or bus level for multi-bus stations. Gross demand forecasts account for the increases in demand from new or intensified development, but do not account for the impact of new conservation measures such as codes & standards or demand response ("DR") programs. LDCs are only expected to account for changes in consumer demand resulting from efficiency improvements and increasing electricity prices, known as "natural conservation".

Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The graph below shows the gross demand forecast provided by the LDCs[4] for the sub-region, with historical data points for comparison. The demand in the sub-region is serviced by Whitby TS and Cherrywood TS. Whitby TS is split into two DESNs and provides supply at both 27.6 kV and 44.0 kV levels, while Cherrywood TS only provides supply at the 44.0 kV level.

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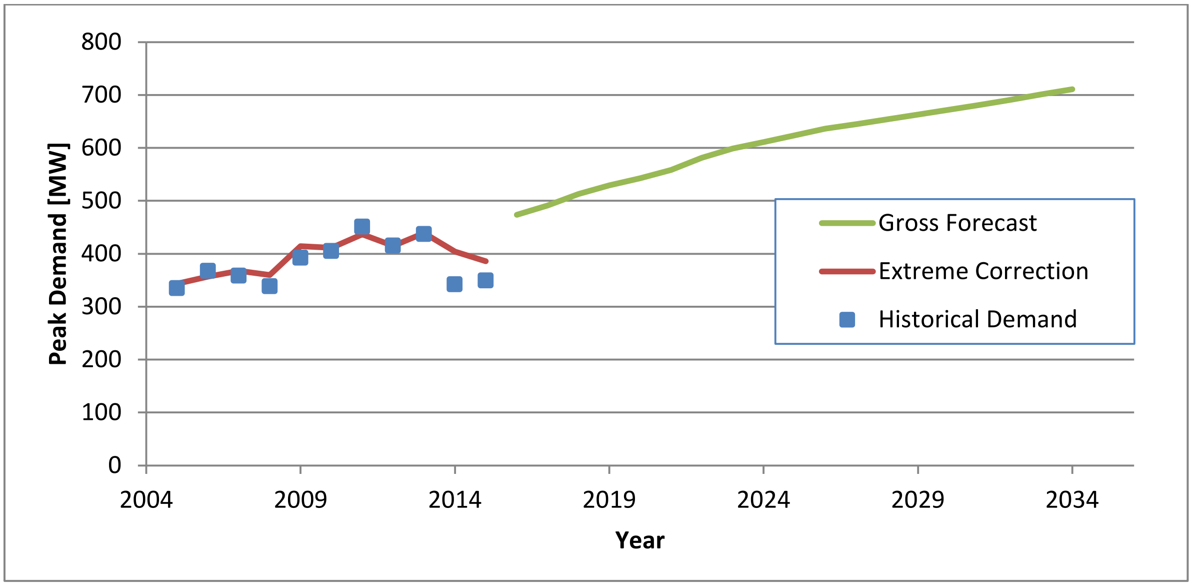
[4] Forecasts are subject to change as population information continues to be updated as part of provincial and local growth plan reviews

Figure 5-3: Sub-region Gross Demand Forecast



Both the weather corrected peak and historical demand shows that demand in the sub-region has been generally increasing over the past decade, with a slight dip in the most recent year. However, the data for summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although an extreme weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments.

The total annual growth for this area averages 2.3% over the 20-year planning horizon. The highest growth is forecast to occur in the near term (year 0-5) at a rate of 3.7%. The demand growth decreases to 2.8% in the medium term (year 5-10) and further declines to 1.5% for the last 10 years of the planning period.

Demand growth in the sub-region is driven by a series of development projects which include the new community of Seaton, and various intensification projects in Pickering, Ajax and Whitby[5]. The new community of Seaton is envisioned as sustainable urban community[6] and is forecast to account for 22% of the total demand in the sub-region by 2034. The resulting demand of this new development will be initially serviced by available 27.6 kV capacity at Whitby TS, but is expected to exceed station capacity in 2019 as shown in Figure 5-4.

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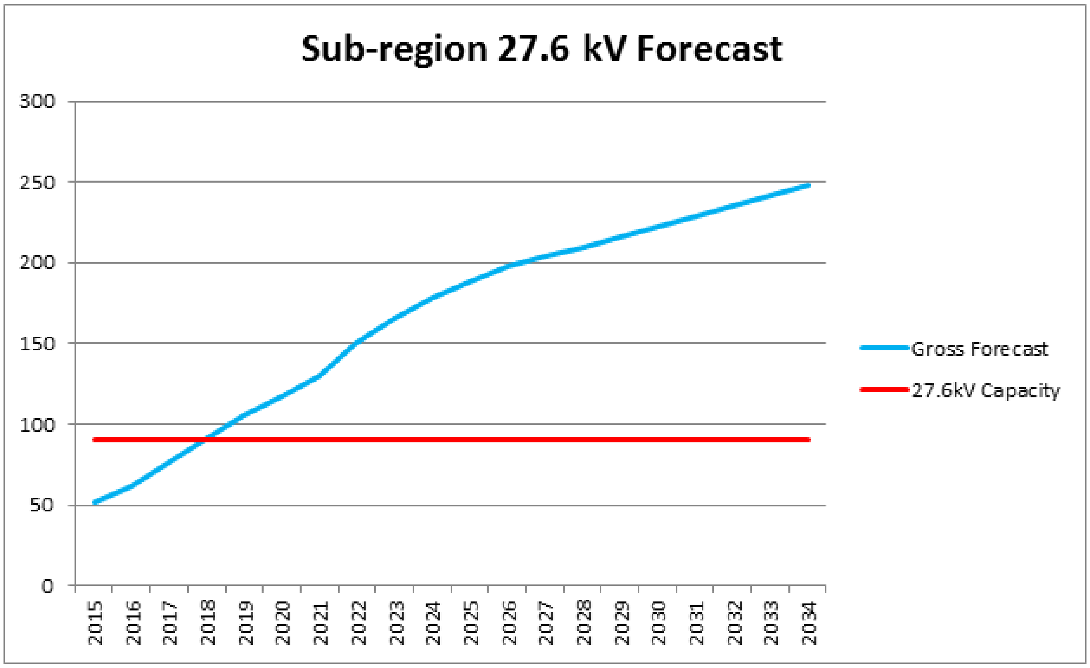
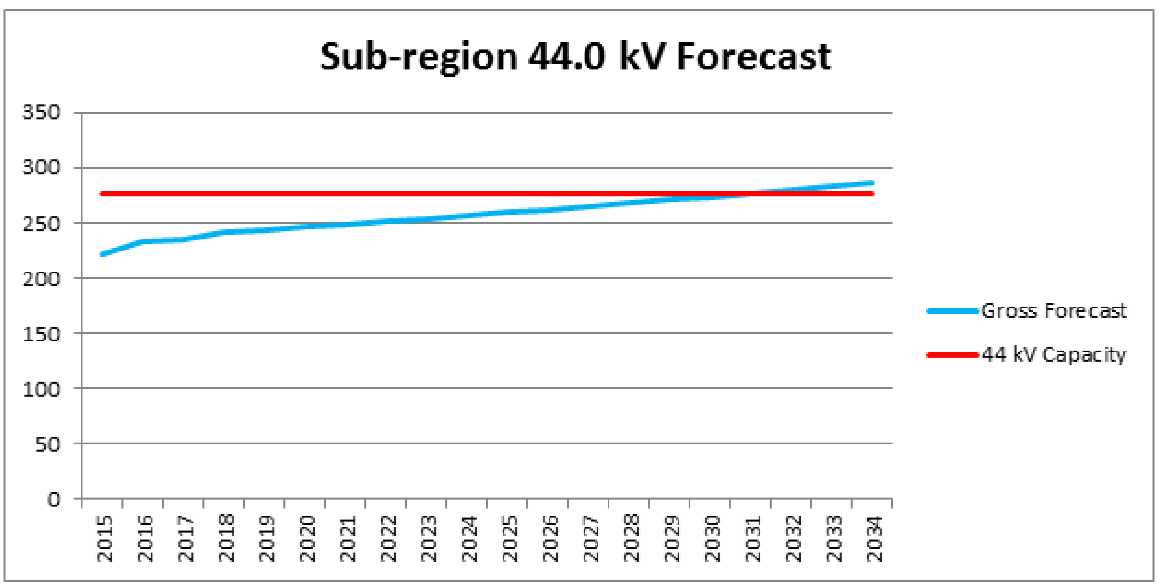
[5] https://www.pickering.ca/en/living/resources/DowntownPickering_FinalVisionDocument_June2013.pdf
https://www.ajax.ca/en/doingbusinessinajax/resources/Planning_Services/Ajax_Official_Plan_Consolidation_Jan_15_2016.pdf
http://www.whitby.ca/en/townhall/resources/pl_opa1-chart_march28_2013.pdf
[6] https://www.pickering.ca/en/cityhall/seatoncommunity.asp

Figure 5-4: Sub-region 27.6 kV Gross Forecast



The 44.0 kV demand in the area is supplied by Whitby TS and Cherrywood TS, and the 44 kV capacity is expected to be sufficient to supply forecast demand into the longer term.

Figure 5-5: Sub-region 44.0 kV Gross Forecast



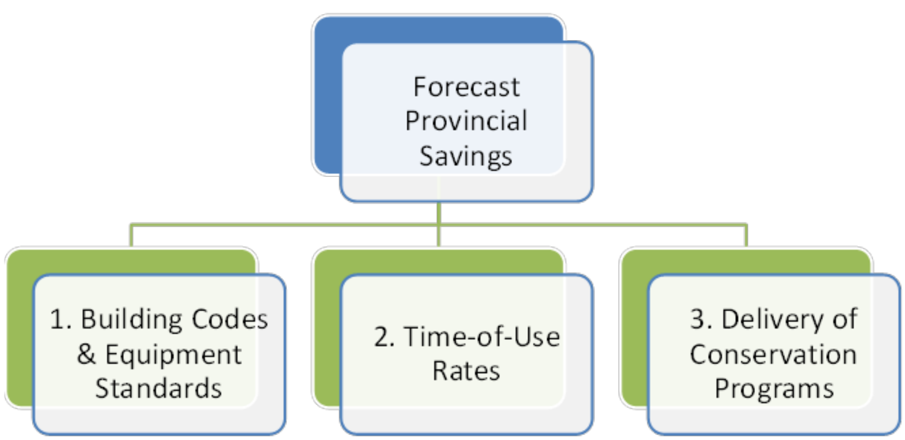
The gross demand forecasts provided by the LDCs, and forecast methodology are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is the first resource considered in planning, approval and procurement processes. It plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. The conservation savings forecast for the sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.5), to determine the net peak demand or planning forecast for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. A portion of this province-wide energy conservation target was allocated to the sub-region, and, as further described below, it was further converted to an estimated peak demand reduction for the sub-region. The expected peak demand savings for the sub-region are shown below in Table 5-1. To estimate the impact of the conservation savings in the area, the forecast provincial savings were divided into three main categories:

Figure 5-6: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time of Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The 2013 LTEP committed to establishing a new 6-year Conservation First Framework ("CFF") beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near-term, Ontario's LDCs have an aggregate energy reduction target of 7 TWh, as well as individual LDC specific targets. These targets are to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the CFF. Each LDC was required to prepare a Conservation and Demand Management ("CDM") plan by May 1, 2015 describing how their target will be achieved. LDCs are also required to provide updates to their CDM plans.

As part of the Conservation First policy, the provincial government has adopted a broad definition of conservation that includes various types of customer action and behind-the-meter generation. This means that conservation includes any programs or mechanisms that reduce the amount of energy consumed from the provincial electricity grid. Conservation initiatives, including behind the meter generation projects and on-site generation, are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the sub-region.

To provide a more regional specific forecast, the impact of the savings for each category were broken down by the residential, commercial and industrial customer sectors. The IESO then worked together with area LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of the forecast conservation, as conservation potential varies by sector due to different energy consumption characteristics and conservation opportunities.

For the sub-region, LDCs were requested to provide their gross demand forecast and provide the breakdown of their demand forecast by sector at each TS based on their knowledge of local customers. For TSs that an LDC cannot provide gross load segmentation for, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors[7] was used to help estimate the breakdown of demand. Once sector gross demand at each TS was available, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rate, and conservation programs. The estimates for each of these categories were done separately due to their unique characteristics and data availability. In general, hourly profiles of IESO's gross forecast and conservation

[7] OEB Yearbook of Electricity Distributors:
http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

savings were used to determine the impact that each conservation category has on peak demand. Impacts were estimated for residential, commercial and industrial sectors reflecting that various sectors have different conservation opportunities.

The planning forecast assumes that the targets will be met, and will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs.

The table below shows the final estimated conservation peak demand savings, which were applied to the gross demand to create the net forecast for the sub-region.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
Total East GTA Savings (MW)	33	57	74	92	111	134	154	174	184	185
Sub-region Only Savings (MW)	6	14	24	33	44	55	64	72	77	78

Over the 20-year time period, it is expected that conservation savings for the GTA East planning region will amount to the deferral of one TS the size of Cherrywood TS. For the sub-region the conservations savings over the study period are expected to amount to approximately 40% of the capacity provided by a station similar to Cherrywood TS

Additional conservation forecast details are provided in Appendix A.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Pickering-Ajax-Whitby Sub-region is also anticipated to help offset peak demand requirements at select stations. The introduction of the *Green Energy Act, 2009* and the associated development of Ontario's FIT program, have increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, after applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution from existing and contracted DG in the area. The effects of projects that were already in-service prior to the base year of the gross demand forecast were not included as they are already embedded in the gross demand forecast which is the starting point for the planning forecast. Potential future DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of August 2015, existing and contracted DG projects are expected to offset an incremental 18 MW of peak demand within the sub-region. The largest project in the sub-region is a renewable biomass generator in Ajax with the capability to generate up to 25 MW, and currently contracted for 18 MW. Other projects in the area are small scale solar projects (<500 kW). Table 5-2 shows the DG by technology that is currently under contract in the sub-region.

Table 5-2: Distributed Generation by Technology in the Pickering-Ajax-Whitby Sub-region

Technology	Contract Capacity [MW]	Capacity Contribution [MW]	Capacity Factor
Solar	2	1	32%
Renewable Biomass	18	17	98%

The capacity contribution for each DG project was calculated by applying a capacity factor based on fuel type to the contracted capacity of each project. The capacity factors used in this study are based on historical data gathered during Ontario's overall system peak.

In the sub-region, all of the DG projects are planned to be connected to Whitby TS to help offset some of the load during peak demand hours. Currently, new DG connection is restricted from connecting to Cherrywood TS due to short circuit ("SC") constraints because of an out-of-service 30 MW landfill gas generation facility. Hydro One is in discussions with the land and facility owner and is seeking legal and regulatory advice on the process for the removal of this allocated capacity. If capacity allocation is removed, the SC restriction can be lifted and new DG can apply to connect to this station.

The following table shows the cumulative DG in the sub-region.

Table 5-3: Cumulative DG used for Planning Forecast

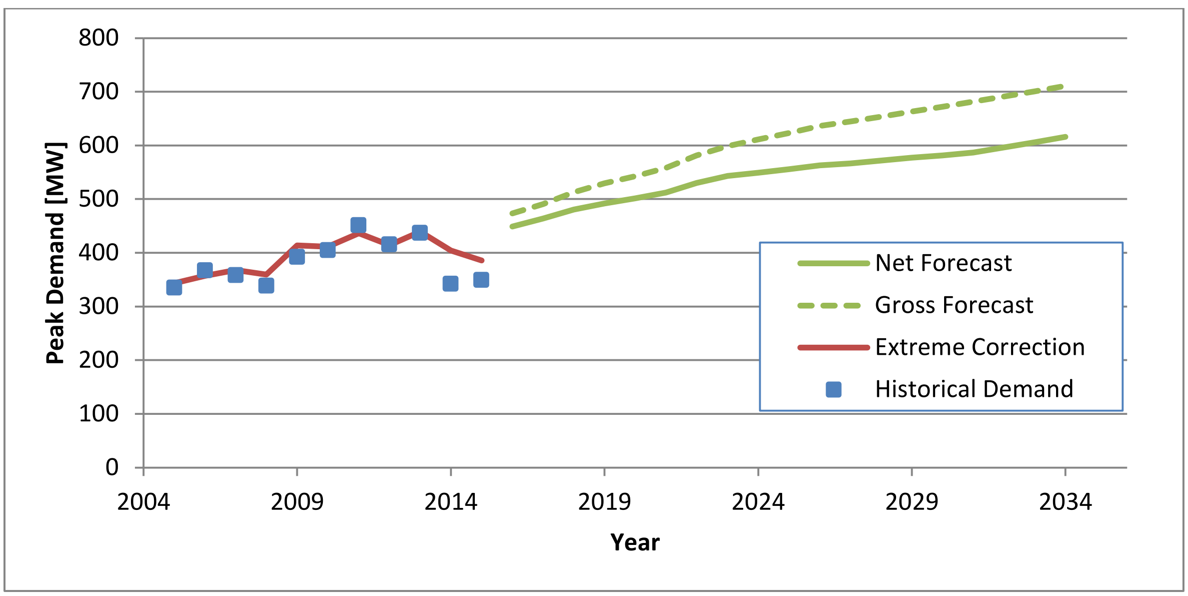
Year	2015	2016	2017	2018	2019	2020	2034
Pickering-Ajax-Whitby [MW]	18	18	18	18	18	18	18

5.6 Planning Forecasts

A 20-year planning forecast was produced based on the LDCs' gross demand forecasts and net of anticipated conservation and DG.

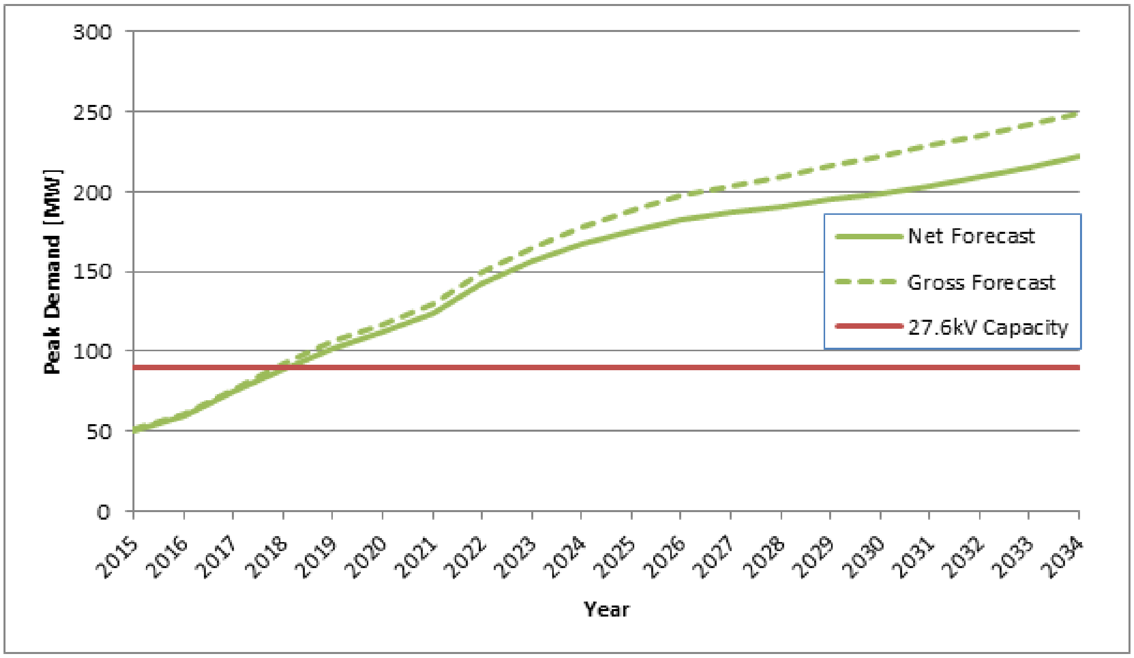
Figure 5-7 illustrates the planning forecast, along with historical demand for the sub-region. The combined effects of DG and conservation are expected to reduce the peak demand in the Pickering-Ajax-Whitby Sub-region by 95 MW by the end of the planning period in 2034. This corresponds to 13% of the overall gross demand in 2034 of 711 MW.

Figure 5-7 Pickering-Ajax-Whitby Sub-region Planning Forecast



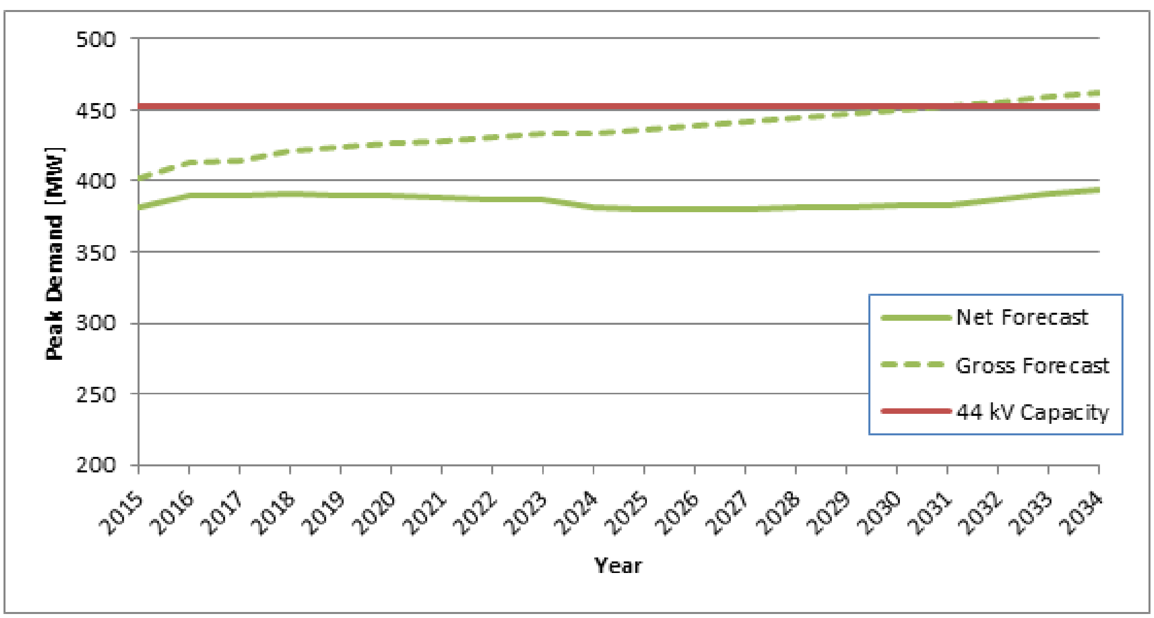
The net 20-year planning forecast for the 27.6 kV load serviced by Whitby TS is shown below in Figure 5-8. By 2034 the combined effects of DG and conservation are expected to decrease the peak demand by 27 MW; this accounts for 11% of the gross demand in 2034.

Figure 5-8 Pickering-Ajax-Whitby Sub-region 27.6 kV Planning Forecast



The net 20-year planning forecast for the 44.0 kV load serviced by Whitby TS and Cherrywood TS is shown in Figure 5-9 below. By 2034 the combined effects of DG and Conservation are expected to decrease the peak demand by 50 MW; these effects account for 15% of the gross demand in 2034.

Figure 5-9 Pickering-Ajax-Whitby Sub-region 44.0 kV Planning Forecast



6. Needs

The Pickering-Ajax-Whitby Sub-region Working Group identified two electricity needs in the near-term, based on the planning forecasts, system capability and application of planning criteria. This section describes the identified needs for the near-term in the sub-region.

6.1 Needs Assessment Methodology

The IESO's ORTAC[8] was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements.

The application of these criteria in an area is used to generally identify three broad categories of needs as follows:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the 10-day LTR of the step-down transformer stations in the local area. Transformer station capacity need arises when the peak demand at step-down transformer stations in the local area exceeds the combined LTR ratings.
- **Upstream Transmission System Capacity** describes the electricity system's ability to provide continuous supply to a local area. This is limited by the load meeting capability ("LMC") of the transmission line or sub-system and is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See **Appendix D** for more details). These capacity needs arise when coincident peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** describes the electricity system's ability to minimize the impacts 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 amount of load susceptible to supply interruptions 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.

[8] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

6.2 Needs

Two needs were identified in the area which impact the ability to serve local loads:

1. There is a need arising in 2019 for additional 27.6 kV TS capacity to supply new growth.
2. There is a need to conduct detailed analysis to assess the economic justification for addressing a restoration shortfall (MW) that exists in the GTA East Region for rare loss of supply events.

6.2.1 Transformer Station Capacity-27.6 kV

The sub-region is supplied by two stations, Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either the 27.6 kV or 44 kV distribution levels. The Cherrywood TS provides supply at the 44 kV level while Whitby TS provides supply at the 27.6kV and 44 kV levels. Whitby Hydro provides distribution service at the 44 kV level, however Veridian uses both voltage levels to supply its service territory;. Dedicated 27.6 kV feeders from Malvern TS and Sheppard TS also supply the western portion of Veridian's service territory. These two stations are in the eastern part of an adjacent planning region-Metro Toronto.

Figure 6-1 and Figure 6-2 below show the historical and forecast 44 kV peak demand for the study area. Based on the planning forecast, sufficient 44 kV capacity exists to supply current and forecast 44 kV demand in the area until the end of the study period.

Figure 6-1: Planning Forecast for Cherrywood TS 44.0 kV

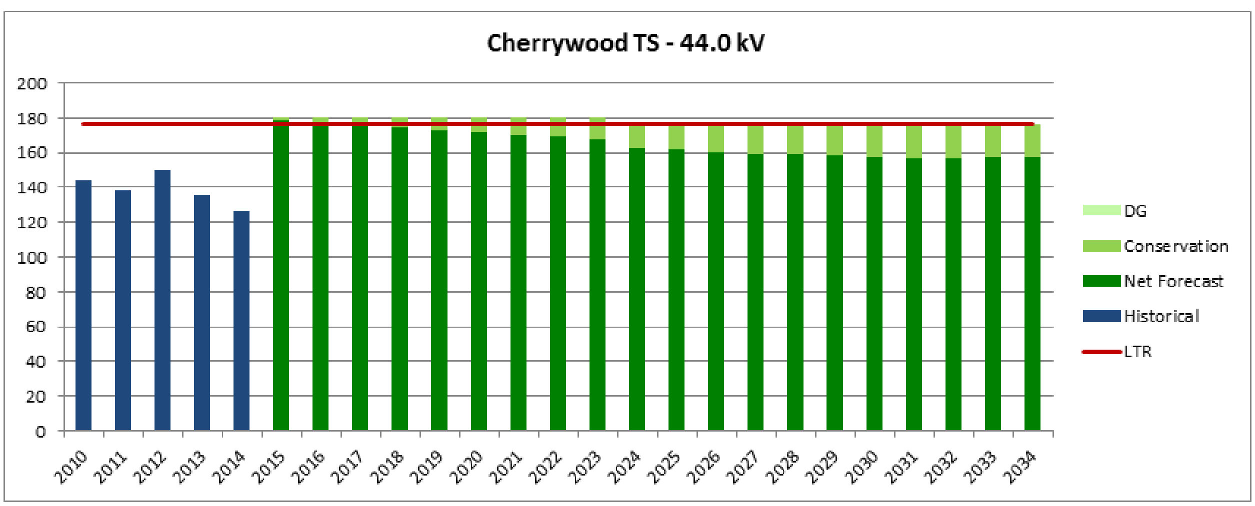


Figure 6-2: Planning Forecast for Whitby TS 44.0 kV

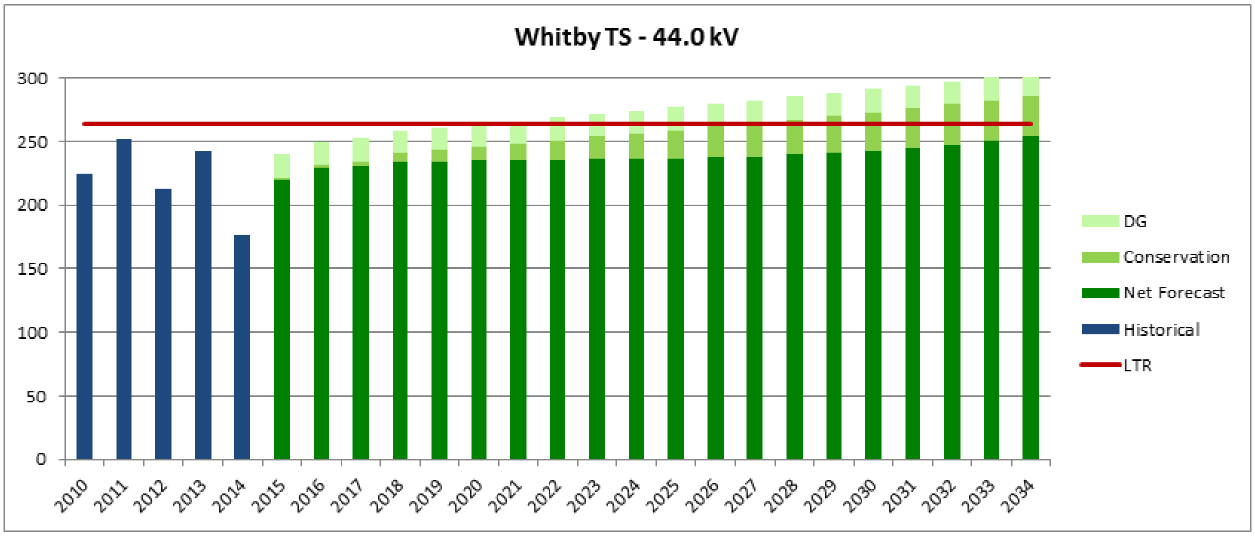
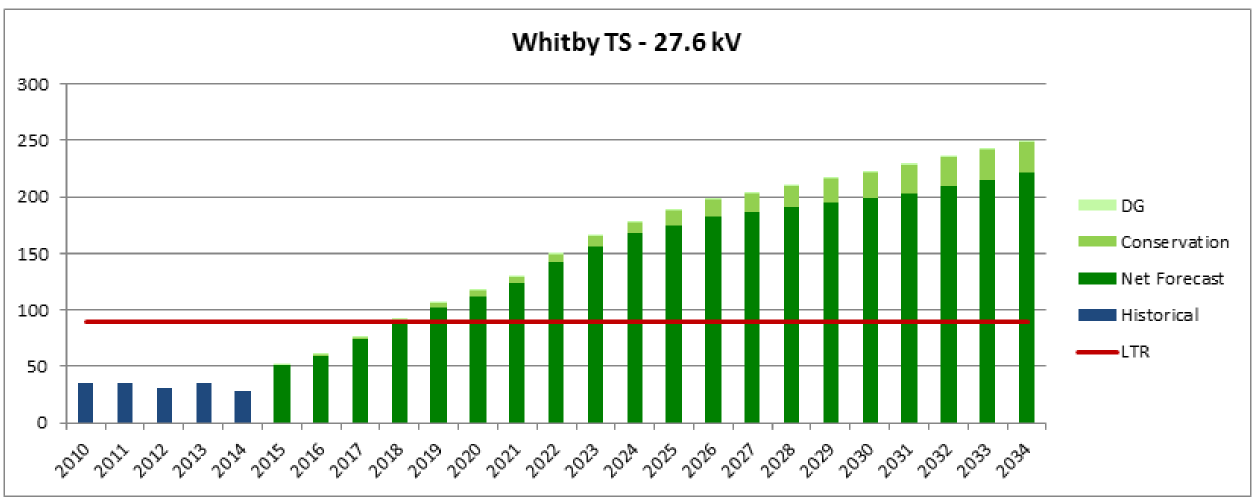


Figure 6-3 below shows the planning forecast for the 27.6 kV demand in the study area. The 27.6 kV demand in the study area is expected to exceed available capacity by 2019.

Figure 6-3: Planning Forecast for Whitby TS 27.6 kV



The 10 year forecast for 27.6 kV demand for the sub-region is shown in Table 6-1 below, with figures shown in red indicating demand levels that exceed the 90 MW transformation capacity limit for the 27.6 kV bus.:

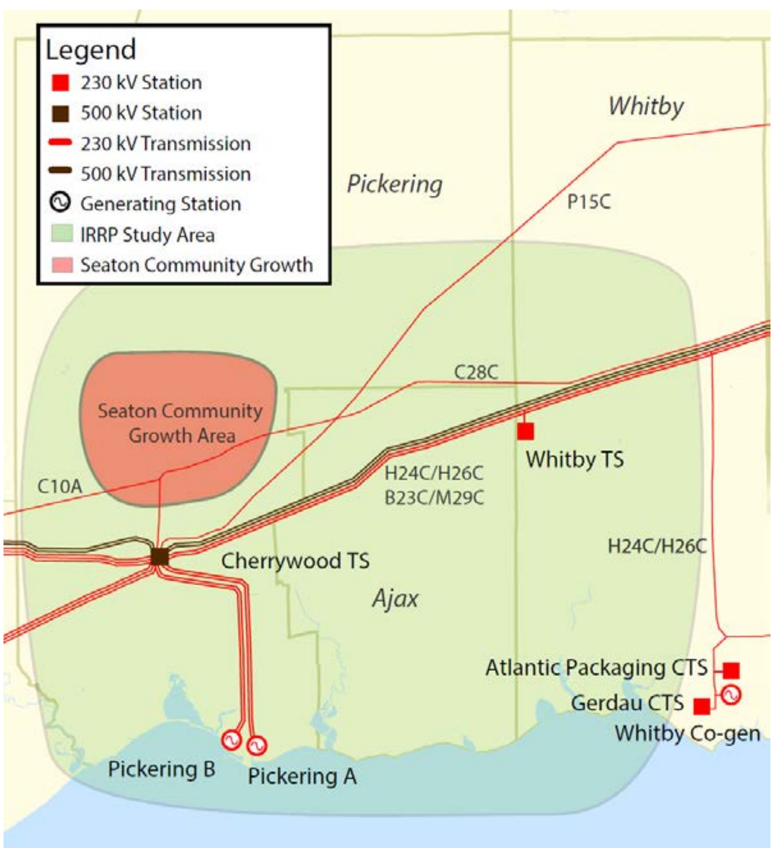
Table 6-1: Sub-region 27.6 kV Planning Forecast from 2015 to 2024

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

The new community of Seaton in North Pickering accounts for more than 60% of the total 27.6 kV demand by 2034, influencing a transformation capacity shortfall of approximately 12 MW in 2019 and up to 132 MW in 2034.

The location of the greenfield growth due to Seaton relative to the other infrastructure facilities in the area is shown in the figure below (in red). The community of Seaton is just north of Cherrywood TS and west of Whitby TS.

Figure 6-4: Location of Seaton in the Study Area



Source: Data provided by Hydro One Networks Inc. Copyright: Hydro One Networks Inc. [2016].

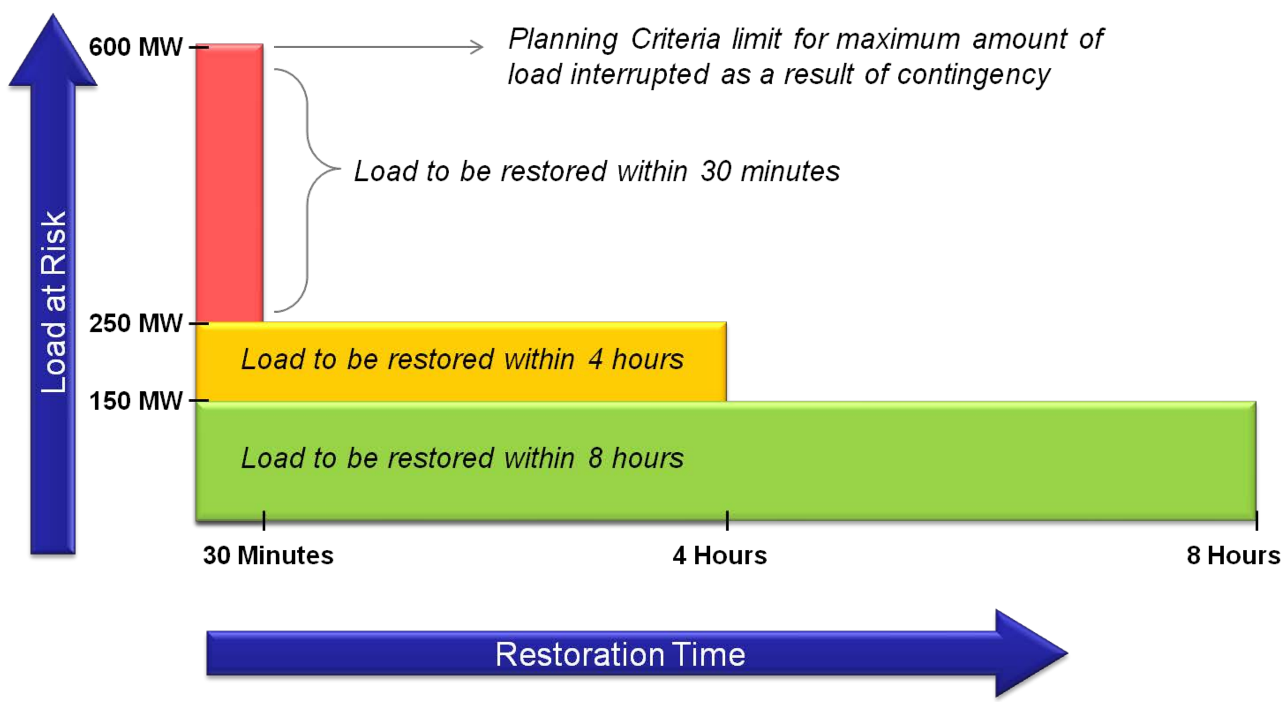
Additional 27.6 kV capacity is required for the sub-region to meet forecast 27.6 kV demand.

6.2.2 Load Restoration

Restoration refers to the ability of the system to restore sufficient amount of load within defined periods of time following the prolonged loss of a major supply source from the transmission system.

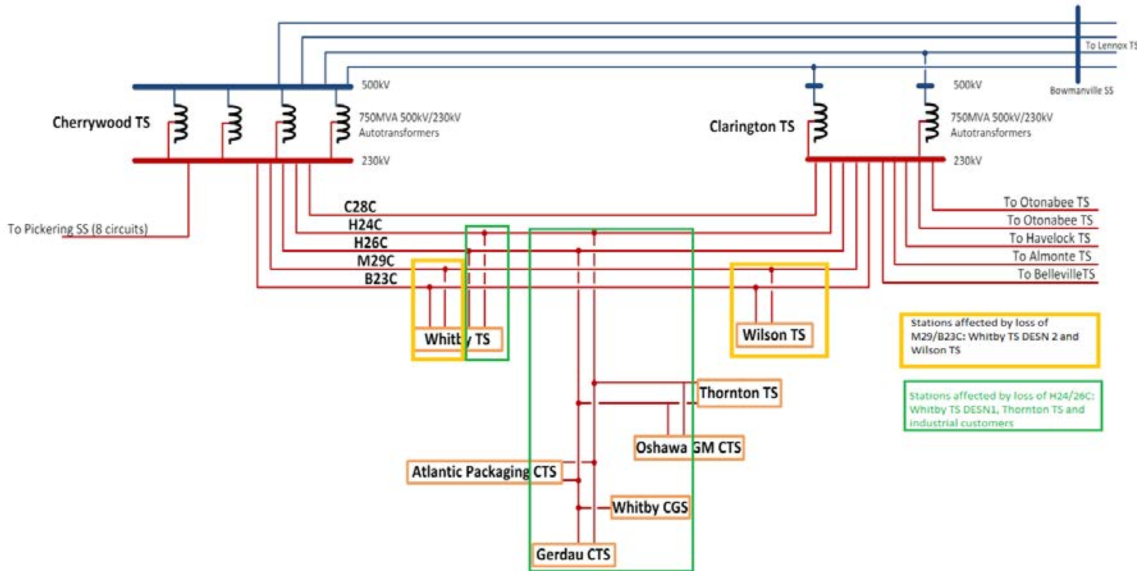
The group of stations and customers supplied from the H24/26C and M29/B23C circuits within the GTA East Region have been identified as being at risk of not meeting restoration levels as defined in ORTAC. ORTAC indicates that, for the loss of two elements, any load in excess of 250 MW should be restored within 30 minutes and any load in excess of 150 MW should be restored within 4 hours. The assessment must also consider restoration of all loads within 8 hours. These restoration levels are summarized in Figure 6-5 below.

Figure 6-5: ORTAC Load Restoration Criteria



The figure below shows the stations and customers served by each of the circuit pairs of H24/26C and M29/B23C.

Figure 6-6: Restoration Pocket for H24/26C and M29/B23C



Source: Hydro One Networks Inc. [2016].

As shown in Figure 6-6 , Whitby TS DESN 1 and the Oshawa radial pocket that includes direct connect customers and Thornton TS are served by the same circuits H24/26C, meaning both are at risk of supply interruption following the simultaneous loss of the pair of circuits. The industrial loads or direct connect customers account for 153 MW of the load supplied by the H24/26C circuits. These industrial loads cannot be restored by the LDCs in the event of an outage as these customers are connected directly to the transmission system.

For the simultaneous loss of the other pair of circuits M29/B23C, the stations Whitby DESN2 and Wilson TS are at risk of supply interruptions.

Table 6-2 below shows the total peak load at risk of interruption for select years, and the 30 minute and 4 hour restoration capability required to meet this criteria for both outages:

Table 6-2: Peak Load at Risk of Interruption for Select Years

Load Pocket	2015 Peak (MW)					2025 Net (MW)				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	567	57	259	142	275

It is assumed that given the proximity of emergency crews and equipment, all loads would be restored within 8 hours through conventional transmission supply.

Based on discussions with area LDCs, up to 105 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 257 MW within 4 hours for customers supplied off the M29/B23C circuits. This leaves a maximum 2015 shortfall of 81 MW after 30 minutes, and 29 MW after 4 hours.

Similarly, for the H24/26C circuits, up to 57 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 142 MW within 4 hours for customers supplied off these circuits. This leaves a maximum 2015 shortfall of 49 MW after 30 minutes, and 64 MW after 4 hours.

After taking into account the load transfer capability of LDCs in the area, ORTAC restoration timelines and load levels are currently not met for the 30 minute and 4 hour criteria for both pairs of circuits. According to ORTAC[9], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The transmission customer and transmitter may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons provided the bulk power system adheres to NERC and NPCC standards". For the GTA East Region,

[9] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

there is a need to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines.

6.3 Needs Summary

Two near-term needs have been identified in the study area, and are summarized in Table 6-3 below.

Table 6-3: Summary of Needs in Pickering-Ajax-Whitby Sub-region

Area	Need	Description	Need Date
North Pickering	Transformation Capacity	Need for additional 27.6 kV transformation capacity to supply growth	2019
GTA East Region	Restoration	Need to conducted analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines	Now

7. Near-Term Plan

This section describes the alternatives considered in developing the near-term plan for the Pickering-Ajax-Whitby Sub-region, provides details of and the rationale for the recommended plan, and outlines an implementation plan. The capacity and restoration needs identified above are discussed in separate sections below.

7.1 Alternatives for Meeting the Near-Term Transformation Capacity Need

In developing the near-term plan for the capacity need in the sub-region, the Working Group considered a range of integrated options. The Working Group specifically considered technical feasibility, cost and consistency with longer-term needs and priorities in the sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were also given priority, where they were determined to be cost effective.

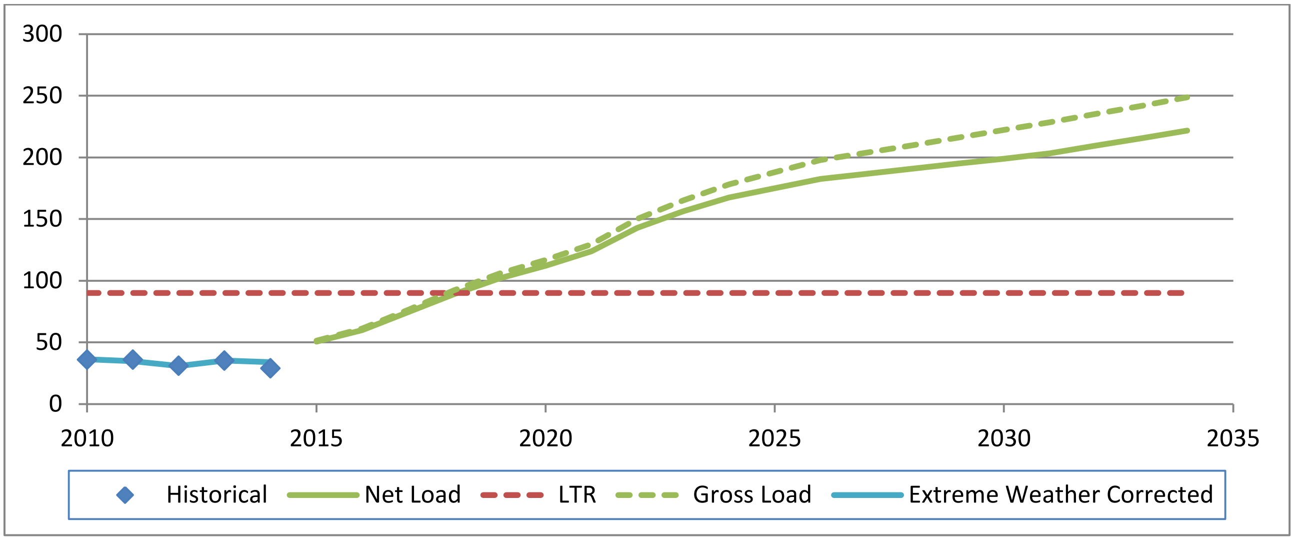
As mentioned previously, the transformation capacity need in the sub-region is mainly influenced by the forecast demand from the Greenfield development of Seaton in north Pickering. This development is being planned for residential capacity for up to 70,000 people and 35,000 jobs. Veridian is also planning to supply this community via 27.6 kV supply.

The following sections detail the alternatives considered. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets. Achieving the estimated peak demand reductions associated with the provincial conservation targets does not, however, result in deferring any of the near-term capacity needs. Achieving these conservation targets does however significantly reduce the magnitude of the 27.6 kV transformation capacity required over the long term by 27 MW, from 249 MW to 222 MW by 2034. It also effectively offsets new demand growth at Whitby TS (the only station providing supply at the 27.6 kV level in the sub-region) until 2034. The Whitby TS 27.6 kV load under both the gross and planning load forecasts is shown in Figure 7-1.

Figure 7-1: Effect of Conservation Targets on 27.6 kV Demand in the Sub-region



As explained in Section 5.4 provincial conservation targets are achieved over an entire year, while transmission needs are triggered by peak demand (single highest observation in a year). As a result, in order to reduce, defer, or address transmission capacity needs, conservation programs must have an impact during the hour of peak demand. In the case of this study area this typically means late afternoon on the hottest weekdays of summer.

The peak demand impact shown in the planning forecast represents the Working Group's estimate of how meeting the sub-region's allocation of provincial energy targets will translate into peak demand reductions. There is uncertainty in this estimate, arising both from whether the sub-region is able to meet provincial energy conservation targets and how energy conservation, in fact, translates to corresponding peak demand reductions. As a result, there is a wide range of demand impacts which could be experienced (both higher and lower than forecast).However, higher or lower demand impacts due to conservation achievement are not a significant factor in this sub-region, because 60% of the capacity need is due to greenfield growth in the new community of Seaton. Without this Greenfield growth, it is expected that there would be sufficient 27.6 kV capacity until the end of study period with the achievement of conservation targets for the localized 27.6 kV electrical demand.

7.1.2 Generation

Since the need for LMC in this area stems from residential growth served at the 27.6 kV voltage level, transmission-connected bulk generation is not a viable option. Also, the new Seaton load requires transmission/distribution infrastructure to connect to the existing grid; therefore a bulk generation solution would not avoid the above infrastructure investment.

Standalone local generation could theoretically supply the new community without the need for grid connection; however, without the diverse pool of system resources, the standalone approach would require implementing a portfolio of community based resources, including different types of generation, storage, demand management, transmission, and distribution to meet area needs (capacity, energy, operability) over the entire study period. In order to match the same level of service provided to a grid-connected system and maintain reliable supply to the community, a margin above the base generation requirements is needed to cover planned and forced generation outages. Based on the IESO's understanding of electricity service for the 25 Remote Communities (northern off-grid communities) in Ontario, it is assumed that for a standalone DG option for the Seaton community capacity redundancy would need to be approximately 130% of net-peak demand to provide reliable electricity service in the event of planned or forced generation outages.

The level of local distribution investment required to enable both the standalone option and grid-connected option would be similar in terms of design characteristics and cost. Assuming the standalone portfolio would be a mix of local natural gas generation, renewable generation, and storage, the cost associated with this approach is estimated to be at least three times that of the grid-connected option.

Local small scale generation solutions are better suited to areas with existing wires infrastructure and small incremental resource needs. The potential role of DG to manage long-term growth in the overall study area will be reviewed as part of future regional planning cycles.

7.1.3 Transmission and Distribution

As discussed in the previous sections additional conservation and generation are not feasible options to meet the near-term needs. In parallel with assessing these options, the Working Group developed transmission and distribution options to address the transformation capacity need.

These options provide new or upgraded transmission or distribution system assets, including lines, stations, feeders and related equipment. Solutions of this nature are characterized by high upfront capital costs, but have high reliability over the lifetime of the asset and enable the economic delivery of the incremental capacity and energy requirements from the provincial power system.

As noted previously, Veridian and Hydro One have been monitoring the need for station capacity in this area and given the lead times for development of a new step-down transformer station have initiated EA work for three potential sites to supply the community of Seaton. The preferred site will be determined by this EA process which is currently underway, with results expected in Q1 2017. A new station at any of the three sites will also require an upgrade to the associated 230 kV connecting circuits in the area in order to connect the station to the transmission system; this transmission line upgrade is a necessary feature of all the station alternatives discussed below. For the transformation capacity need, utilization of available station and feeder capacity from proximal stations outside the GTA East Region was also considered as part of the transmission and distribution set of options. Figure 7-2 below shows the relative locations of the infrastructure considered in the alternatives described below.

Figure 7-2: Proposed Station Sites and Related Infrastructure

Source: Data provided by Hydro One Networks Inc.

The alternatives to meet the transformation capacity need can be found in the Appendix B, and are summarized below. There are two main wires solutions that are suitable for addressing the need: 1. Build new feeders from existing stations, which have available capacity, followed by construction of a new step-down station, once the available capacity is utilized, or 2. Build a new step-down station near the load centre by 2019.

1. Build new 27.6 kV feeders from existing stations followed by a new 230 kV to 27.6 kV step-down station and associated 230 kV transmission line reinforcement at the proposed station sites.

Malvern TS and Sheppard TS already provide 27.6 kV supply to Veridian territory and also have a total of 85 MW of surplus 27.6 kV capacity available until the end of the study period. Combinations of building new feeders from these two stations to the Seaton load centre by 2019 were considered, followed by building a new step-down station and associated 230 kV transmission line reinforcement(see reference to three sites below) in order to meet the remaining capacity need.

2. Build a new 230 kV to 27.6 kV step-down transformer station near the Seaton load centre, with associated 230 kV transmission line reinforcement, by 2019. Three sites for the station are being considered within the EA.

Based on a net present value cost comparison, building a new station at Sites 1 or 2 was determined to be the most economic alternative, as shown below.

Table 7-1: Net Present Value of Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7. Build Seaton TS-1 or 2	60-68
8. Build Seaton TS-3 and associated feeders	94-108

Building a new step-down station at Sites 1 or 2 is the most cost-effective option[10] for meeting the 27.6 kV transformation capacity need in the sub-region. The EA, which is currently underway, will determine the preferred station site. The EA results are expected in Q1 2017.

Should Site 3 be selected through the EA process more detailed technical and economic analysis[11] is require to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

The detailed economic assumptions and methodology used to assess the options are detailed in Appendix B.

7.2 Alternatives for Meeting the Near-Term Restoration Need for the Region

The other major need identified in the area is the shortfall in meeting restoration timelines following the coincident loss of two transmission circuits to the GTA East Region. Although the IRRP is for the sub-region, the restoration analysis considers the entire GTA East Region, because the loss of two circuits impacts supply to the entire GTA East Region. This was acknowledged by the regional participants during the scoping phase of the regional planning process for the GTA East Region. The restoration analysis considers the loss of a pair of 230 kV circuit in the area, either H24/26C or M29/B23C, and the ability to restore load within the ORTAC prescribed timelines.

7.2.1 Conservation

Meeting restoration criteria requires that the faulted elements (line sections) be isolated, such that customer electrical demand can be restored from a reliable line section or an alternate source. Conservation is not a feasible option for addressing these types of needs.

7.2.2 Generation

Generation was ruled out as a feasible option to address restoration needs in the GTA East Region from both a technical and economic perspective, given the number of facilities that would be required and given the surplus generation capacity available in the province.

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[10] See Appendix B for details on proposed station Site 3

[11] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

Approximately 93 MW of supply would be required today and 372 MW by 2025 in order to provide back-up in the event of a four hour outage on all four circuits.

Large generation is not a suitable option for addressing restoration needs because multiple facilities are needed in order to address loss of supply along the various line segments. Additionally, these facilities would need to have black start and islanded operation capabilities, a costly generation and system design feature.

Using smaller scale DG was also determined to be infeasible for the same technical and economic reasons as noted above. In order to provide restoration, each of these facilities would also have to be able to supply their local loads in islanded mode. Some high value loads (such as pumping and water purification facilities) are typically developed with onsite gas or diesel generation to ensure they can continue to operate during a power supply outage. While there is benefit to building this type of supply redundancy to ensure restoration capability for some loads, it is impractical on a larger scale to address regional restoration needs.

7.2.3 Transmission and Distribution

Since additional conservation and generation are not feasible options to meet the restoration shortfall, the Working Group considered transmission and distribution options. According to ORTAC[12], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". Additionally, these parties may also agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. A preliminary assessment was undertaken to determine high level costs and benefits of transmission and/or distribution options giving consideration to the factors outlined in ORTAC. In carrying out this assessment, the Working Group took into account that many jurisdictions justify costs of this nature by comparing the cost to customers of supply interruption for the low probability/high impact events to the cost of mitigation. These jurisdictions: 1. assess the probability of the failure event occurring; 2. estimate the expected magnitude and duration of outages to customers served by the supply lines; 3. monetize the cost of a supply interruption to the affected customers; and 4. determine the cost of solutions and their impact on supply interruptions to the affected customers. If the cost of meeting the

[12] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

security and restoration criteria exceeds the expected cost of customer supply interruptions, then it is not considered cost-justified.

The Working Group undertook a preliminary costs/benefit analysis (Appendix C) and concluded that there may be value in mitigating these restoration shortfalls. However a more detailed analysis is required to establish specific solutions and determine if these are cost justified. The GTA East regional participants recommended that this further restoration analysis and recommendations be conducted as part of the RIP to be led by Hydro One in collaboration with the affected LDCs and IESO.

7.3 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term transformation capacity need in the sub-region, and the restoration need identified for the GTA East Region. Successful implementation of this plan will address the region's electricity needs until the end of the study period in year 2034.

1. Build a new 230/27.6 kV (75/125MVA) step-down station in 2018 and associated circuit upgrade to the new community of Seaton.
2. Undertake detailed restoration analysis and recommend next steps as part of the RIP for the GTA East Region.

7.4 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of the Pickering-Ajax-Whitby Sub-region are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near-term plan are outlined in Table 7-2, along with recommended timing for implementation.

The Pickering-Ajax-Whitby Sub-region Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the sub-region and to track progress.

Table 7-2: Summary of Needs and Associated Recommendations in the Pickering-Ajax-Whitby Sub-region

Area	Need	Recommendation	Implementation Date
North Pickering	Transformation Capacity	Build a new 230/27.6 kV (175/25MVA) step-down station in 2018 and associated circuit upgrade to provide supply by 2019 to the new community of Seaton.	Veridian and Hydro One to start work on implementing the station and line work as soon as possible
GTA East	Restoration	Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region.	Q3 2016

Veridian and Hydro One are pursuing a combined EA for the proposed station sites and related 230 kV line work. The assessment will determine the preferred site. It is expected to be completed by Q1 2017. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Veridian complete all work required for implementation of Seaton MTS as soon as possible.

The RIP should be initiated for the GTA East Region upon completion of the IRRP.

The IESO has committed to working with the affected parties to assist with any approval requirements associated with this IRRP.

8. Long-Term Plan

Given the uncertainty in forecasting demand beyond a 10-year timeline, the purpose of the long-term plan is to consider alternate potential demand scenarios in order to facilitate discussions about how the sub-region may need to plan its future electricity supply and to lay the groundwork for the next regional planning cycle. This section describes potential long-term needs, approaches to addressing these needs, and recommended actions.

With the implementation of the proposed new step-down station in North Pickering, the local electricity infrastructure is expected to be capable of reliably supplying the forecast growth in the sub-region over the next two decades. As a result, longer term planning initiatives will focus on monitoring developments associated with factors that could affect longer term electrical service plans for this area. This includes monitoring progress on conservation efforts at the transformer station level.

One of the potential longer term needs identified through discussion with area LDCs is growth in electrical demand exceeding the capacity of existing transmission and distribution infrastructure serving the established areas of Pickering-Ajax-Whitby, including in the lakeshore area. Reviews and updates of Official Plans in this sub-region are expected in the near future. Similar to past Official Plans[13] for the City of Pickering, the lakeshore area is expected to continue to experience intensification through development of high rise multi-unit residential and commercial buildings. Given that this area is south of a major highway-the 401 and approximately 5 km from Cherrywood TS and more than 10 km from Whitby TS, this intensification could drive the need for a new step-down transformer station closer to future growth areas. This new step-down transformer station could be supplied by the transmission lines currently dedicated to delivering bulk power from Pickering GS. When the generation facilities at Pickering GS begin retiring and plans for the site become clearer over the next few years, these transmission lines could be repurposed and used to reliably supply longer term local development.

The provincial growth plan is under review and is expected in late 2016. The plan is expected to consider growth scenarios up to the year 2040. Municipal reviews of growth plans including that of Pickering, Ajax and Whitby will follow the release of the provincial plan and potentially have an impact on the longer term electrical supply for this sub-region. Other initiatives that

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[13] https://www.pickering.ca/en/cityhall/resources/op6.pdf

could impact future electricity use are the City of Pickering's corporate energy management plan, the Town of Whitby's sustainability plan and the renewable energy and energy conservation policies in the Town of Ajax Official Plan. Additionally, the upcoming Durham Region Community and Municipal Energy Plans and the projects and initiatives identified by the GTA East Local Advisory Committee could also impact future electricity use. These initiatives will be monitored over the long term (see Section 9).

On a regional and provincial basis, the province's new climate change action plan and the new LTEP is expected to have a significant electrical demand impact through encouraging the electrification of customer end uses and transportation. For instance, the new rail maintenance facility in Whitby is expected to require an incremental demand of 30 MW by 2018 from the regional supply. Such demand requirements are expected to be more frequent in the future as regional transit continues to expand and electrify.

Switching from carbon based fuel sources to electricity to meet provincial or municipal environmental goals are also a factor that could impact the capacity of the existing transmission and distribution systems servicing these developed areas in the longer term.

Monitoring of growth in electricity demand and the achievement of conservation and DG targets in the sub-region will be the key components of ongoing electricity planning in this sub-region and the supply situation will be reviewed in subsequent regional planning studies.

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date for the Pickering-Ajax-Whitby IRRP and those that will continue to take place to discuss the medium and long-term priorities and initiatives identified by the Local Advisory Committee ("LAC" or "Committee").

A phased community engagement approach was undertaken for the Pickering-Ajax-Whitby IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Pickering-Ajax-Whitby Sub-region IRRP Community Engagement Process

Creating Transparency:

Creation of GTA East IRRP Information Resources

- Dedicated GTA East Region IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page created on Hydro One website
- Self-subscription service established for GTA East for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal & First Nation Outreach

- Individual meetings and discussions about the Pickering-Ajax-Whitby IRRP with the City of Pickering, Towns of Ajax and Whitby, and Region of Durham (September 2015)
- Information provided to First Nation communities (April 2015, September 2015)
- Status: initial outreach complete; dialogue continues

Bringing Communities to the Table:

Broader Community Outreach

- GTA East Region LAC formed in winter 2016; dedicated GTA East engagement page added to IESO website
- Two LAC meetings held focused on introducing the regional planning process and initiating a discussion of the medium- and long-term priorities in the area
- LAC meetings are open to the public and materials are posted to the GTA East engagement webpage
- Status: begun in winter 2016; on-going

Creating Transparency

To start the dialogue on the Pickering-Ajax-Whitby IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page[14] was created on the IESO website including a map of the regional planning area,

[14] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/GTA-East/default.aspx

information on why an IRRP was being developed for the Pickering-Ajax-Whitby Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the GTA East planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the GTA East Region IRRP was to provide information to the municipalities and First Nation communities in the planning area.

In September 2015 individual meetings were held with municipal representatives from the City of Pickering, Towns of Ajax and Whitby and Region of Durham. Key topics of discussion included growth trends, discussion of the near-term needs in the sub-region, a review of the identified near-term projects including those that have already begun due to timing requirements, and a discussion of the possible approaches that can be used to address medium- and long-term needs in regional planning. The regional plan was also discussed in the context of the bulk electricity system in the area, more specifically the upcoming closure of the Pickering Nuclear Generating Station ("NGS") , the refurbishment of the Darlington NGS and the construction of the Clarington TS. The presentations and information were well received and formed the foundation for the broader engagement in the development of the Pickering-Ajax-Whitby Sub-region IRRP.

The IESO continues to work with First Nation communities to arrange a joint information session with all Williams Treaty communities and to jointly develop a plan for their engagement in this and other IRRPs moving forward. It is expected that the session will be held in the summer of 2016.

Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the GTA East Region in winter 2016. The role of a LAC is to provide advice on the development of the regional plan as well as to provide input on broader community engagement. LACs are generally comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's GTA East engagement web page[15].

[15] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/GTA-East/default.aspx

Development of the GTA East LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across Durham Region; localized digital advertising on The Weather Network for a two-week period and promotions through facebook and Twitter; emails sent to municipal representatives across GTA East Region; an e-blast sent to the IESO's GTA East subscribers list which includes over 700 subscribers; and inclusion of the call for nominations in the IESO's weekly Information Bulletin.

Two meetings of the GTA East LAC were held on March 10 and May 4, 2016. At the first LAC meeting, an overview of the regional planning process was presented to the Committee, along with information on the bulk level planning in the area. The Committee was also provided information on the two near-term needs in the Pickering-Ajax-Whitby Sub-region, these being: capacity needs in North Pickering and restoration needs across the entire GTA East Region. Due to the timing of the capacity needs, the Committee was informed that Veridian and Hydro One had already begun the EA process for a new TS and upgraded line in order for these critical pieces of infrastructure to be in-service by their need date of 2019. For the restoration needs, the Committee was presented with an overview of this need and promised additional information at the second LAC meeting once the Working Group undertook additional analysis.

The second meeting of the LAC included an update on the restoration work undertaken by the Working Group and a brainstorming session about the medium- and long-term priorities. For the restoration work, Committee members were informed that, due to the complexity of the required analysis, a Hydro One-led RIP subsequent to the completion of the IRRP will further develop the restoration analysis. For the medium- and long-term priorities, several questions were also posed to the Committee members to generate a group discussion on long-term growth projections and community priorities for inclusion in the plan. This meeting was followed by a two-week comment period for LAC members to provide additional information to inform the long-term portion of the plan. A summary of this discussion and feedback can be found in Appendix D along with the meeting summaries from the GTA East LAC meetings.

Moving forward, engagement will continue on both the near-term projects and the IRRP. For the transformer station and replacement line to meet near-term needs in north Pickering, Veridian and Hydro One will undertake engagement as part of the EA process. For the Pickering-Ajax-Whitby IRRP, the GTA East LAC will be provided with a presentation of the final plan and if requested by LAC members an additional LAC meeting will be held in the fall of 2016 to discuss next steps in the continued development of the long-term priorities.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website[16]. Additional information on outreach activities for the Pickering-Ajax-Whitby IRRP can be found on the GTA East webpage and updates will continue to be sent to all GTA East subscribers.

[16] http://www.ieso.ca/Pages/Participate/Regional-Planning/default.aspx

10. Conclusion

This report documents the IRRP that has been carried out for Pickering-Ajax-Whitby Sub-region. The IRRP identifies electricity needs in the sub-region over the 20-year period from 2015 to 2034, recommends a plan to address near-term needs and identifies actions to monitor long-term developments.

The step-down station solution recommended to meet the near-term need for 27.6 kV transformation capacity in the sub-region is already underway. Veridian and Hydro One have submitted a combined application for an EA of proposed station sites and related 230 kV line work. Results of the EA that is currently underway will determine the preferred station site and are expected in Q1 2017.

In order to further study and analyze the restoration needs and determine a preferred solution it is recommended that a RIP be initiated for the GTA East Region. The RIP is to be led by Hydro One Transmission, and include Veridian, Whitby Hydro, Oshawa PUC, Hydro One Distribution and IESO as Working Group members. It is recommended that this RIP be initiated after the completion of the PAW IRRP in June 2016, with RIP study completion in Q1 2017.

In the longer term, the Pickering-Ajax-Whitby Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will monitor developments focused on the factors described in the long-term section above that could impact electricity infrastructure, along with progress on conservation efforts and DG uptake at the transformer station level.

PICKERING-AJAX-WHITBY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the GTA East Planning Region | June 30, 2016

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Pickering-Ajax-Whitby Sub-region IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

This Appendix provides details of the methodology used to develop the demand forecasts produced by the LDCs, as well as conservation and distributed generation assumptions, and detailed planning forecasts.

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.2 describe the methodologies used by LDCs to prepare the gross demand forecasts used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.3.

A.1.1 Veridian Connections

Veridian Connections receives its power from Hydro One Networks Inc. (HONI) through two (2) transformer stations (TS), Whitby TS – DESN 1 & DESN 2 and Cherrywood TS in Pickering. Both stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and deliver 44kV supply from Whitby DESN2, Cherrywood TS and 27.6kV supply from Whitby DESN1 for Veridian's use.

Veridian relies primarily on the relationship between population and typical load per customer type to generate its demand forecasts. Average load per customer type comes from analysis of Veridian's own customer data as well as incorporating the impacts of mandated CDM targets. This average load is also reviewed against changing trends in consumption to incorporate changes such as the charging of electric cars, or the penetration of DG with net metering.

Information on expected population changes typically comes from the Planning departments at the City of Pickering and the Town of Ajax. Additional information to help inform Veridian about future population growth may also come from the Region of Durham and/or developers/builders as well.

A.1.2 Whitby Hydro

Whitby Hydro receives its power from Hydro One Networks Inc (HONI) through two (2) transformer stations (TS), one located within the town's boundary (Whitby TS – DESN 1 & DESN 2) and one outside of the town's boundary (Thornton TS). All of these stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and to Whitby Hydro's subtransmission system at 44 kV.

In general, the long term forecast relies on the historic relationship between electricity consumption and socio-economic indicators such as population growth.

Economic conditions, population growth and the availability of serviceable lands are the principle factors that influence load growth. Information used to forecast residential growth is collected from the following sources:

- The Town of Whitby's Planning Department

- Total number of vacant lots in existing developments
- Proposed subdivisions to be constructed
- Developers and/or builders
- Building permits issued by the Town of Whitby

The methodology for load forecasting is based on the history of feeder loads which are studied and correlated to population growth. The results are plotted and Linear Regression methods are used to establish a trend line. The trend line is then used to forecast future loads. Past trends are judged to assess if they will affect future expectations. Planning for a New TS should begin when loads exceed 80% of the 10-Day Limited Time Rating (LTR).

A.1.3 Gross Demand Forecast by TS

The following table shows the gross peak demand per station, as provided by LDCs. Where necessary, forecasts were extended until the end of the study period in 2034.

Table A-1: Gross Demand Forecast (MW)

Gross Demand	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	180	180	180	180	180	180	180	180	180	176	176	176	176	176	176	176	176	176	176	176
Whitby TS DESN1	101	115	131	143	146	147	148	149	150	151	152	153	154	155	156	157	158	159	160	161
Whitby TS DESN2	172	178	180	185	187	189	190	192	194	196	198	199	201	203	205	207	209	211	213	215
Seaton TS (Proposed)	0	0	0	5	16	27	40	60	75	88	98	108	114	120	126	132	139	145	152	159

A.2 Conservation

The following tables show the expected peak demand impact of provincial energy targets, as assumed at each station for the purpose of the Planning forecast.

Table A-2: Conservation Assumptions by station (MW)

Conservation Savings	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	1	2	3	5	7	8	10	11	12	13	15	16	17	17	18	19	20	19	19	19
Whitby TS DESN1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	17	17	18	18	18	18
Whitby TS DESN2	1	2	3	5	6	8	9	11	13	15	17	18	20	21	22	23	24	24	24	24
Seaton TS (Proposed)	0	0	0	0	0	1	1	2	3	4	6	7	9	10	12	13	15	16	16	17

A.3 Distributed Generation

As of September 2014, the IESO (then OPA) had awarded 20 MW of distributed generation contracts within the Pickering-Ajax-Whitby Sub-Region. Of these, 1.5 MW had already reached commercial operation. Since LDCs were producing their demand forecasts to align with actual peak demand, any DG already in service during the most recent year's peak hour would already be accounted for in gross forecasts. As a result, only contracts for projects that had not yet reached commercial operation when the forecasts were produced needed to be incorporated.

There were a total of 51 contracts signed for the Pickering-Ajax-Whitby Sub-Region, a majority for solar projects contracted through the Feed in Tariff (FIT) program. Contract information provided the installed capacity, generation fuel type, connecting station, and maximum commercial operation date (MCOD) for each project. It was assumed that all active contracts would be connected by their MCOD. The supply mix of DG contracts in the Sub-Region included solar and renewable biomass, as stated in table 5-2 of the IRRP, along with their respective capacity contributions.

For the IRRP, the IESO relied upon observed historical capacity contribution factors for renewable biomass and solar generation. Based on this methodology, summer peak capacity contributions of 34% and 98% were assumed for solar and renewable biomass, respectively. After considering the anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions, by Station

The following table shows the expected peak demand impact of DG contracts by station by kW. All effective capacity before 2015 was assumed to be already working into the historical data. Only DG impacts in 2015 and later were added, cumulatively, to the planning forecast.

Station	Pre 2015	2015	2016
Whitby TS DESN 1	492	215	215
Whitby TS DESN 2	965	17,863	17,863

A.4 Planning Forecasts

The Planning forecast is the primary forecast for carrying out system studies and was based on gross demand forecasted by LDCs within their respective service territories. It was then adjusted by the IESO to account for the anticipated peak demand impacts of provincial conservation energy targets, and the effect of contracted DG. It represents the most likely outcome based on currently available information and initiatives, both local and provincial.

In the planning forecast, the final demand allocated to the Veridian Connections and Whitby Hydro stations were adjusted between adjacent stations to account for typical station loading and operating practices. This balancing practice ensured that a station already at full capacity would continue at full utilization, even if incremental peak demand-reducing measures (such as CDM and DG) would have produced a net decrease in the load. The IESO worked with Veridian Connections and Whitby Hydro to understand and implement these adjustments consistent with expected operation.

The final Planning forecast is provided in Appendix A.4.1.

A.4.1 Planning Forecast, by TS (MW)

Planning Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	179	178	177	175	173	172	170	169	168	163	162	161	160	159	158	157	157	157	157	158
Whitby TS DESN1	100	113	128	138	141	140	140	140	140	139	139	138	138	139	139	139	139	140	142	143
Whitby TS DESN2	153	158	159	163	163	163	163	163	163	163	163	163	164	165	166	166	167	169	171	174
Seaton TS (Proposed)	0	0	0	5	15	26	38	58	72	84	92	101	105	110	114	119	124	129	135	142

Pickering Ajax Whitby IRRP

Appendix B: Transmission and Distribution Options for Meeting Near-Term Forecast Electrical Demand within the Pickering-Ajax-Whitby Sub-region

B.1 Purpose and Introduction

This document reviews the near-term need and timing for additional 27.6 kV transformation and feeder capacity required to serve growth in the Pickering-Ajax-Whitby Sub-region and identifies the technically and economically viable transmission and distribution options for meeting this need. This analysis was carried out as part of the Integrated Regional Resource Plan ("IRRP") for the Pickering-Ajax-Whitby Sub-region

The study process considered:

- The magnitude and location of growth in electrical demand within the IRRP study area
- The capability of existing transmission and distribution facilities to meet the growth in electrical demand within the area
- The technically feasible transmission and distribution options available for meeting forecast electrical demand
- The relative cost of the transmission and distribution options

The sub-region study area is outlined in the figure below and includes the service territory of Veridian Connections Inc. ("Veridian") and Whitby Hydro Electric Corporation ("Whitby Hydro"), with some customers in the area served by Hydro One Distribution as an embedded distributor within Veridian and Whitby Hydro facilities.

Figure 1 Pickering Ajax Whitby Study Area

Source: Data provided by Hydro One Networks Inc.

B.2 Area Supply

The main sources of transmission supply to this area are from Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either 44 kV or 27.6 kV distribution level voltages. The Cherrywood TS only steps down voltage to the 44 kV level, while Whitby TS steps voltage down to 27.6 kV and 44 kV levels. Only Veridian uses both voltage levels to supply its service territory, while Whitby Hydro provides distribution service at the 44 kV level. Dedicated feeders from Malvern TS and Sheppard TS also supply the western portion of

Veridian's service territory. These two stations are in the eastern part of another region-Metro Toronto.

B.3 Forecast Growth

Load forecasts used to perform this analysis were provided to the IESO by the three LDCs serving this area, Veridian, Whitby Hydro and Hydro One Distribution. The electrical demand impact of the energy based provincial conservation targets, which are outlined in the December 2013 LTEP, has been included in all planning forecasts. Uptake of DG through the FIT program and other projects has also been included. Additional information on the methodology used to prepare the net demand forecasts used in this study is available in appendix A of the IRRP.

Load growth within the overall study area is forecast to grow at an average annual rate of 2.1% over the 20-year study period, after accounting for the expected impact of provincial conservation targets and distributed generation.

- In the near term, Seaton-a greenfield development that is being planned in North Pickering with residential capacity for up to 70,000 people and 35,000 jobs, is influencing the strong growth rate mentioned above. Veridian plans to supply this community at 27.6 kV by the 2018 time period when significant development is expected to materialize. This area is currently not served by any transmission or distribution infrastructure, and is expected to fully utilize the capacity of a typical 230 / 27.6 kV step-down station over a 20-year time period.
- In the longer-term, growth is expected from the intensification and expansion of existing urban areas in downtown Pickering, Ajax, Whitby and targeted expansion of some areas such as the village of Brooklin in North Whitby. The growth targets for these municipalities are tied in part to the provincial growth targets for the Greater Golden Horseshoe and have been accounted for in the load forecasts provided by the LDCs.
- Given the nature of the near-term growth, 27.6 kV supply will be utilized leaving the remaining 44 kV capacity for serving the rural and industrial developments in the area. There is adequate 44 kV capacity to meet the growth needs of the area until the end of the study period.
- The highlighted area in Figure 2 shows the approximate geographic locations of the Seaton community relative to the local transmission infrastructure.

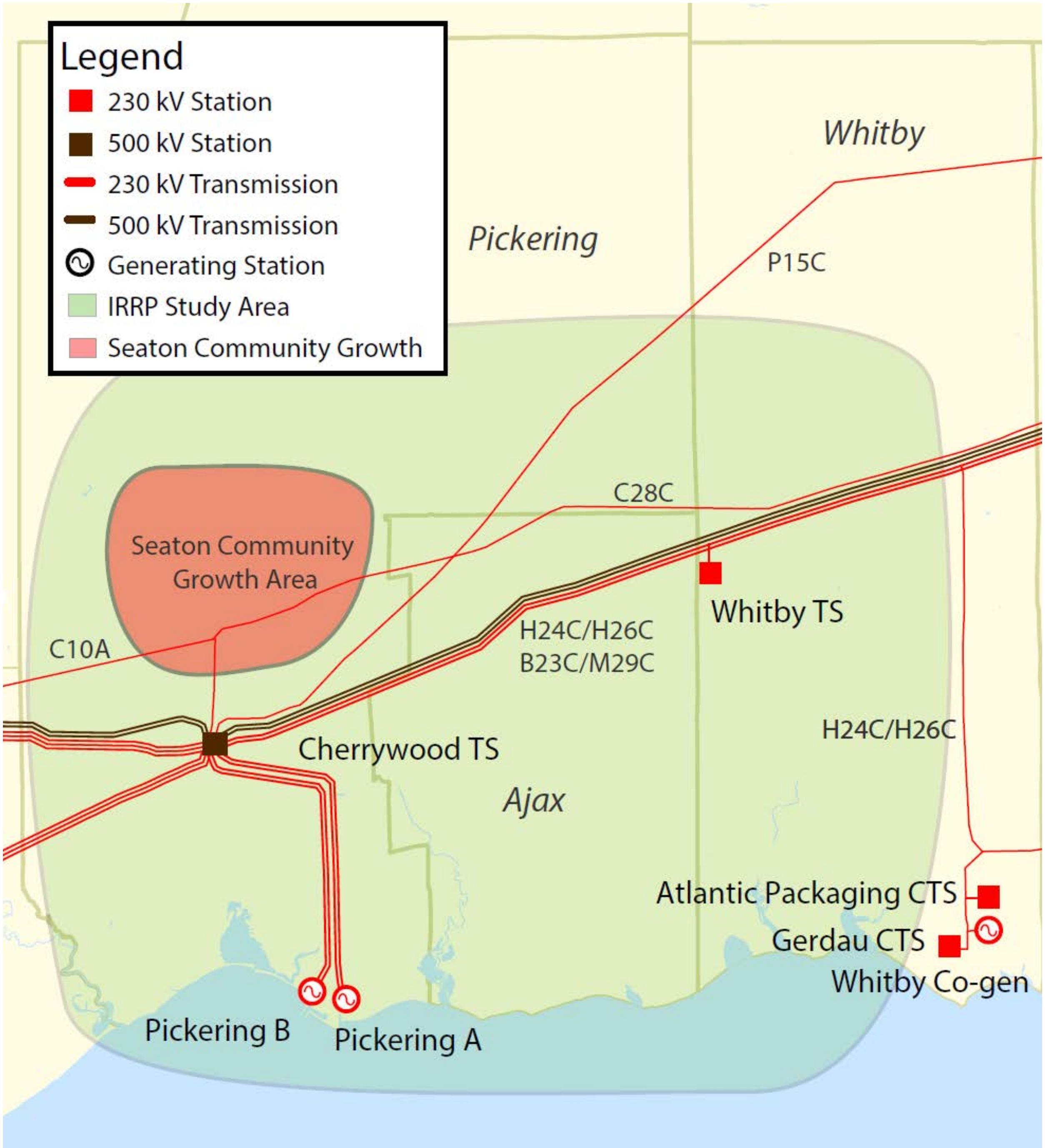


Figure 2 Growth Area

Source: Data provided by Hydro One Networks Inc.

B.4 Near Term Needs

Based on the planning forecast being used in this analysis, the capacity of the 230/27.6 kV transformers serving the sub-region is expected to be exceeded in 2019 (Figure 3). Sufficient 44 kV capacity exists in the study area to supply 44 kV demand until the end of the study period.

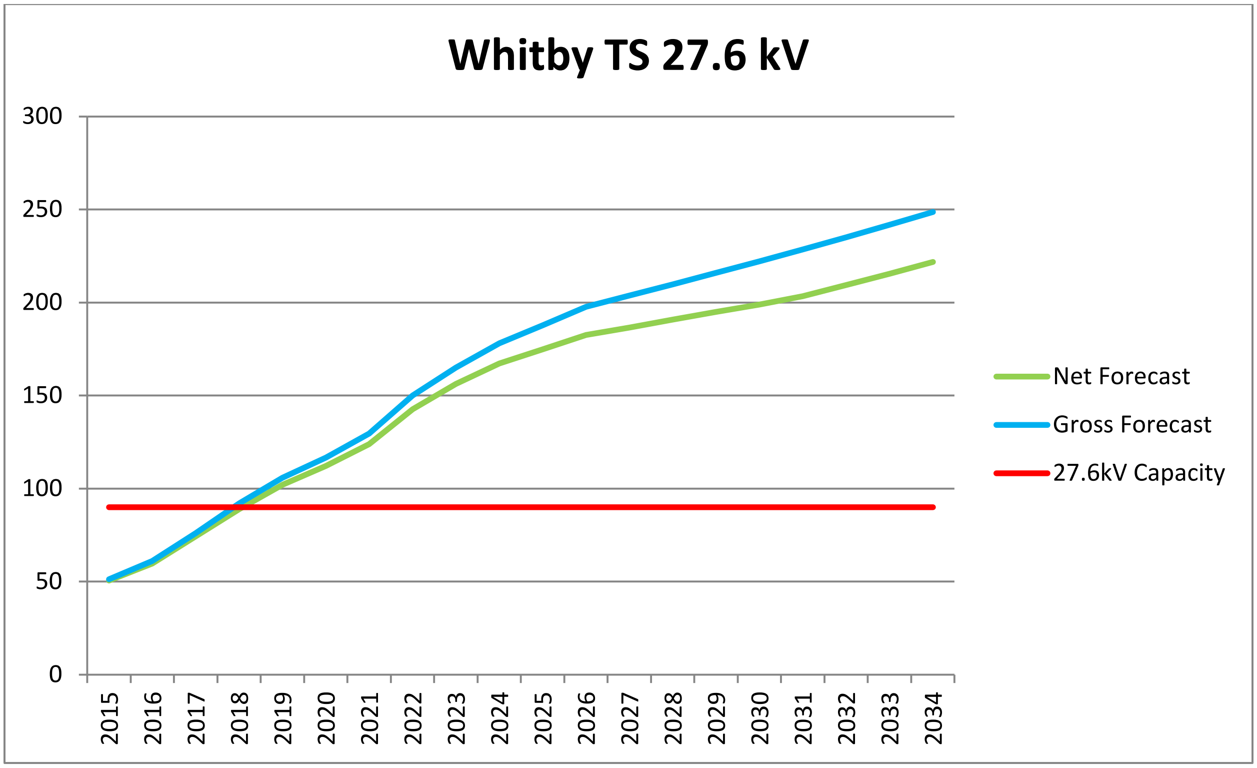


Figure 3 Whitby TS 27.6 kV Capacity

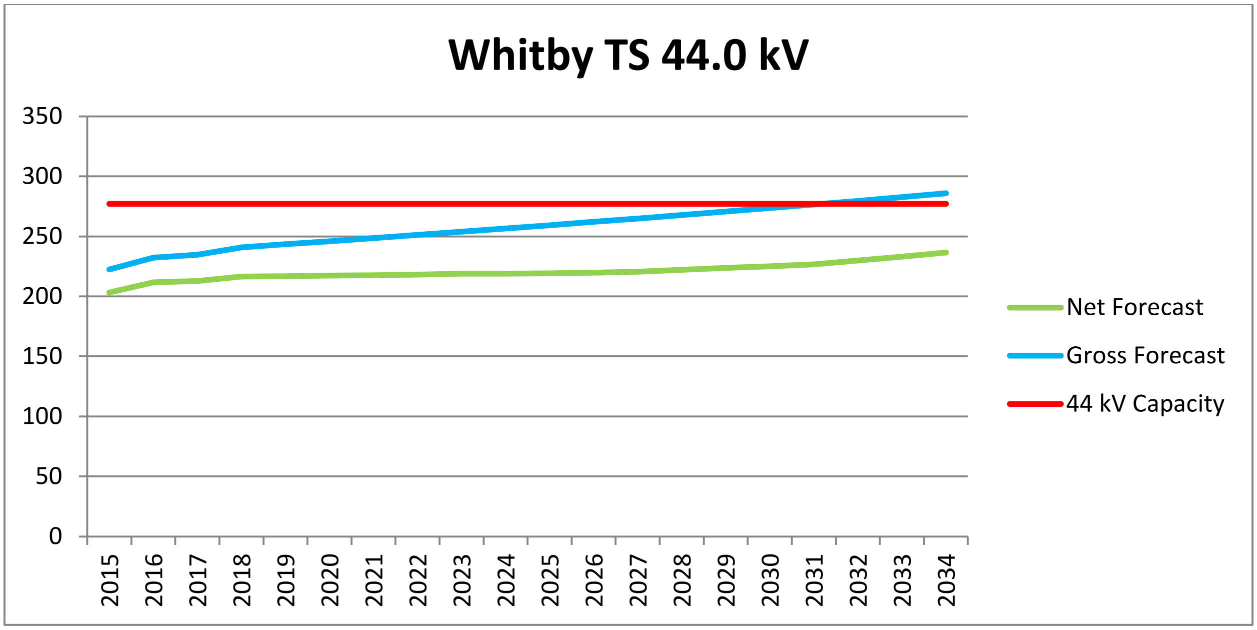


Figure 4 Whitby TS 44 kV Capacity

The 10 year forecast for 27.6 kV demand in the area is shown in the table below, with demand exceeding available capacity highlighted in red:

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

Table 1 Whitby TS 27.6 kV loading and expected growth (MW) to 2024

Incremental 27.6 kV capacity of approximately 12 MW will be needed by 2019 increasing to approximately 132 MW by 2034 at the end of the study period. The majority of this 27.6 kV growth from 2018 onwards is due to the expected demand from the new community of Seaton. This community is forecast by 2034 to have a gross electricity demand of 160 MW, reduced to approximately 142 MW of demand after considering the impacts of conservation and DG.

Given the near-term nature of this need, this report provides a detailed planning analysis of the technically feasible transmission and/or distribution alternatives for meeting the area's 27.6 kV capacity shortfall.

The following sections analyze the technical and economic feasibility of transmission and distribution options in the sub-region. The options include building feeders from an existing step-down transformer station ("TS") having incremental capacity, the incorporation of new step-down stations, and combinations of these options.

B.5 Near-Term Supply Options

Provide additional 27.6 kV supply from existing Transformer Stations

Generally speaking, where technically and economically feasible, distribution transfers can be used on a short- or long-term basis to supply load growth from existing TSs that have available capacity. Currently, no incremental 27.6 kV capacity is available at the existing stations within the sub-region. However, two stations within the adjacent Metro Toronto Region-Sheppard and Malvern TS that already provides supply to Veridian customers are forecast to have incremental 27.6 kV transformation capacity available. Therefore new feeders from these existing stations were investigated as alternatives for providing the needed 27.6 kV capacity to the area.

Sheppard 230/27.6 kV TS:

Sheppard TS is a station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 25 MW of 27.6 kV supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 11 km west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for additional 27.6 kV capacity in the study area.

Malvern TS 230/27.6 kV TS:

Malvern TS is a 230/27.6 kV station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 60 MW of supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 12 km south west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the study area.

As both these stations only provide a portion (85 MW) of the total incremental 27.6 kV capacity (132 MW) that will be required by 2034, they will be considered as part of a staged wires based solution that can meet the entire capacity need.

Provide additional 27.6 kV supply from a new Transformer Station in the sub-region

New step-down station 230/27.6 kV:

Another option is to provide a new (75/125 MVA) 230/27.6 kV station in the vicinity of the growth area to meet the incremental 27.6 kV demand. Figure 5 shows the locations of the three station sites undergoing an Environmental Assessment. Sites 1 and 2 are the closest to the load centre while Site 3 is the furthest away. This analysis considers building feeders from Site 3 to the approximate load centre which for study purposes is assumed to be at Site 2 as it is closest to the load centre and feeders from other 27.6 kV supply stations, and closest to the transmission supply.

This option is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the sub-region.

Figure 5 shows the relative locations of Sheppard TS and Malvern TS to the new growth area in North Pickering and the prospective sites for a new station within the community of Seaton (outlined in pink).

Figure 5 Locations of Alternative Sources of 27.6 kV Supply

Source: Data provided by Hydro One Networks Inc.

B.6 Transmission and Distribution Infrastructure Alternatives

Eight potential supply alternatives were developed for providing the capacity needed to meet the near-term growth in the area and are summarized in the table below. These alternatives were a combination of the feeder and station options presented in the previous section. The years that assets will need to be in service in order to serve the load for each alternative are also shown in Table 2 below:

Alternatives	**Alternative Details and Need Date**
1. Use Malvern TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS (2023)
2. Use Malvern TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS and Feeders 1&2 (2023) -Build Feeders 3&4 (2026) -Build Feeders 5&6 (2033)
3. Use Sheppard TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Seaton TS (2021)
4. Use Sheppard TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Seaton TS and Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Feeders 5&6 (2025) -Build Feeders 7&8 (2032)
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021)

or 2	-Build Feeders 3&4 (2023) -Build Seaton TS (2026)
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Seaton TS and Feeders 1&2 (2026) -Feeders 3&4 (2032)
7. Build Seaton TS- 1 or 2	-Build Seaton TS (2019)
8. Build Seaton TS-3 and associated feeders to load area	-Build Seaton TS and Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Feeders 5&6 (2023) -Build Feeders 7&8 (2026) -Build Feeders 9&10 (2033)

Table 2 Alternatives and need dates

Additional Details:

- A forecast net of conservation and distributed generation has been used in order to determine magnitude and timing of need.
- Two feeders will be built when a capacity need is triggered.
- Feeders are assumed to provide a maximum of 15.5 MW capacity.
- Feeders from Malvern TS will follow transmission right of way until Whites Rd, and then run North on Whites Rd, and East on to Taunton Rd to the load centre.
- Feeder losses were calculated using typical 27.6 kV conductor specifications.
- Planning level feeder construction and station costs were provided by Veridian.

- Planning level transmission line costs were provided by Hydro One Networks Inc.

B.7 Economic Comparison of Alternatives

To compare alternatives based on cost to the ratepayer[1], an economic assessment was performed. The evaluation present valued costs to 2016, considering a 45-year study period – 2019 to 2063 (based on the first replacement decision across all six alternatives; transmission station assets assume a 45-year life). Table 3 and Table 4 summarize the main cost assumptions considered in the evaluation of each alternative (planning level estimates in 2014$ Canadian). All investments were converted to a real annual levelized cost (including on-going annual costs), spread across the asset's assumed life, and only levelized costs falling within the study period were considered. This approach credits value to assets whose life ends beyond the study period (terminal value credit). Table 5 summarizes the net present value results of the six alternatives (in 2016$ Canadian).

The tables below summarize the major economic assumptions used for this analysis:

Cost Breakdown	Malvern TS ($M)	Sheppard TS ($M)
Breaker position at TS	2	2
Feeders to overhead risers	0.4	0.4
Double circuit 28 kV wood pole construction ($0.2M/km) [2]	2.47-2.85	2.26-2.65
Cost adder-off road construction	0.40-0.80	0.40-0.80

[1] Ratepayer Perspective is defined as the viewpoint of the end-use electricity consumer. It includes residential, commercial, and industrial customers within Ontario, and in terms of economics, ratepayer perspective includes costs that flow to bills for their consumption of electricity.

[2] Costs are per pair of feeders-Veridian's deck dated July 2014

Engineering (10% of construction cost)	0.53-0.61	0.51-0.58
Contingency 10%-25%	0.58-1.66	0.56-1.61
Annual Feeder losses	0.36-0.42	0.22-0.25
TOTAL[3] [4] ($M)	**6.37-8.32**	**6.13-8.04**

Table 3 Capital and On-Going Annual Costs for Malvern and Sheppard TS

[3] Total Feeder costs in table above excludes Feeder losses, those are NPV'd separately and added to the feeder costs in the Results section

[4] The total cost shown is dependent on the contingency percentage, off –road construction cost adder and the distances to sites 1 and 2.

Cost Breakdown	Build Seaton TS – Site 1 ($M)	Build Seaton TS – Site 2 ($M)	Build Seaton TS-Site 3 ($M)	Build Feeders to Site 2 from Site 3 ($M) [5]
Feeders to overhead risers	2.40	2.40	2.40	n/a
Double circuit 28 kV wood pole construction ($0.2M/km)	n/a			6.46
Engineering (10% of construction costs)	n/a			0.65
Contingency costs	Included in cost of station			0.71-1.78
Connecting preferred station Site to the transmission system[6]	15	10	8	n/a
Annual	n/a			0.19

[5] Used the same feeder costs as provided by Veridian's consultant excluding off-road construction costs
[6] Transmission connection costs from Sites 1&2 Hydro One December 2015; connection cost for Site 1 from Veridian

feeder losses				
Build 230/28 kV station 170 MVA[7]	25.56			n/a
TOTAL ($M)	**42.96**	**37.96**	**35.96**	**8.01-9.09**

Table 4 Capital and On-Going Annual Costs for Seaton TS Sites

Alternative 1, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 1 or 2 and associated 230 kV line (2023):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Sites 1 or 2.

Alternative 2, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2023) +Feeders 3&4 (2026) +Feeders 5&6 (2033):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 6 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 3, Sheppard TS Feeders 1&2 (2019) + Seaton TS 1 or 2 and associated 230 kV line (2021)

This alternative considers building a pair of feeders from Sheppard TS to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, to be built at Sites 1 or 2.

[7] Station costs from Veridian-November 2015

Alternative 4, Sheppard TS Feeders 1&2 (2019) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2021) +Feeders 3&4 (2023) + Feeders 5&6 (2025) + Feeders 7&8 (2032)

This alternative considers building a pair of feeders from Sheppard to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 8 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 5, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 1 or 2 and associated 230 kV line (2026)

Alternative 5 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 1 or 2.

Alternative 6, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2026) + Feeders 3&4 (2032)

Alternative 6 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 3 and associated feeders to the load centre.

Alternative 7, Seaton TS Site 1 or 2 associated 230 kV supply line (2019)

This alternative considers building a new station near the load centre at Sites 1 or 2 in 2019 when incremental 27.6 kV transformation and distribution capacity is needed in the area.

Alternative 8, Seaton TS at Site 3 and associated 230 kV supply line +Feeders 1&2 (2019)+Feeders 3&4 (2021) + Feeders 5&6 (2023) + Feeders 7&8 (2026) +Feeders 9&10 (2033)

This alternative considers building the new station at Site 3, the associated 230 kV supply line and 10 feeders to the load centre with a pair being built every time a capacity need is triggered. Additionally 8 of these feeders are assumed to be above ground (4 on each side of a road), while the remaining 2 will be underground.

The table below summarizes the total costs for each alternative:

Table 5 Net Present Value Range for Seaton Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7. Build Seaton TS-1 or 2	60-68
8. Build Seaton TS-3 and associated feeders	94-108

The results in Table 5 demonstrate that the most economic alternative for providing near-term 27.6 kV capacity to the area is to build a new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, to be in service for 2019. A new TS near the load centre would result in highest relative reliability given the much shorter feeder distances. Additionally, this option also avoids the approval challenges of building several distribution feeders through a national park-Rouge Valley Urban National Park.

Should Site 3 be selected through the EA process, more detailed technical and economic analysis[8] is required to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

B.8 Conclusion

A new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, connected to transmission line C28C[9] to be in service for 2019, is the most cost-effective option to meet the need for additional 27.6 kV capacity in the sub-region.

The analysis was conducted assuming a 2019 in service date. However, given the uncertainty associated with the load forecast, which depends on fully meeting local conservation targets, working group members believe that it is prudent to target a 2018 in service date for the new step-down station. As part of implementation Veridian will monitor growth and adjust the station in-service date accordingly.

[8] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

[9] Currently C28C is a 230 kV single circuit and would need to be modified to 230 kV double circuit for a limited amount of length in order to connect the new station to the power system

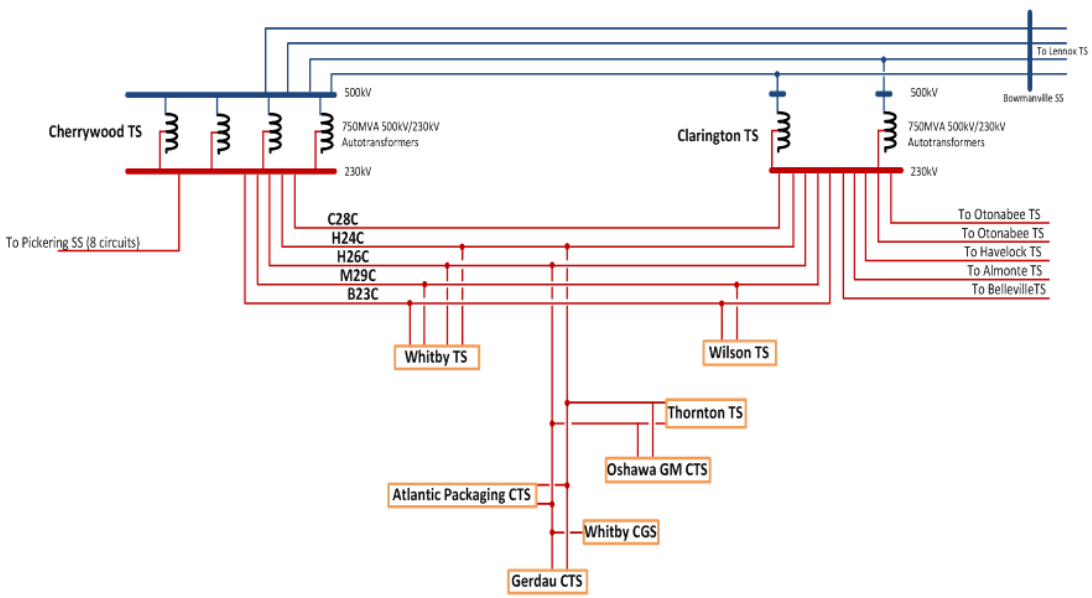
Pickering-Ajax-Whitby Sub-region IRRP

Appendix C: Analysis of Alternatives to Address Regional Restoration Need

Options to Address GTA East Restoration Needs

GTA East Region is served by four 230 kV circuits that emanate from Cherrywood TS and run eastwards towards Ottawa for 120-300 km[1]. These circuits supply Whitby TS, Wilson TS and a pair of these circuits is tapped by a radial line section which runs south to provide supply to Thornton TS and a number of direct connect customers. Figure 1 below shows these circuits and related points of supply. Once Clarington TS is in service in 2018, the region will be served by a new high capacity 230 kV supply point (connected to the 500 kV system) on the eastern end of the regional area. This new supply point will significantly reduce the length of the lines supplying this regional area (from hundreds of kilometers to less than 30) thereby improving supply reliability.

Figure 1-Single Line Diagram of the GTA East Region



The four circuits supplying this area are supported by a common tower line. The supply to customers however is split between the pairs of circuits. H24/26C supply Whitby TS DESN 1, Thornton TS and direct customers in the Whitby pocket; while M29/B23C supply Whitby

[1] Individual circuits terminate at different distances

DESN2 and Wilson TS. Together, these four circuits supplied approximately 792 MW of electrical demand during 2015 summer peak

The areas supplied by these circuits have been identified as not meeting ORTAC restoration load levels and timelines in the GTA East Region, as summarized in Table 6.2 of the IRRP. Transmission outages within the GTA are typically of short duration, due to the proximity of repair crews. A typical outage of this nature will be expected to be restored within 4 to 8 hours. Consequently the analysis only considers the area's ability to meet 30 minute and 4 hour restoration timelines.

Restoration capability is assessed assuming two simultaneous and prolonged outages occur on the transmission system. Restoration is achieved by isolating the faulted elements and restoring customers through supply sources which have electrical continuity. These supply sources could be at the transmission level, distribution level, or a combination of both. The customer demand or load levels that require restoration are specified in ORTAC Section 7.2.2. According to ORTAC[2], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". These affected customers and transmitters may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. For this sub-region, a high level assessment of cost justification was undertaken to establish if more detailed analysis is warranted. Some jurisdictions assess cost justification for low probability / high impact events by comparing the cost risk (i.e., the probability of an event occurring and the consequences if it does) of the failure event to the cost of mitigating the risk. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of supply interruptions to the affected customer
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost justified.

[2] ORTAC Section 7.4 Application of Restoration Criteria <copy> or link pdf

This IESO applied this methodology to facilities serving transmission customers in GTA East.

First, the extent of the existing risk was quantified based on the supply line and load characteristics. The assessment was conducted with Clarington TS in service as it is scheduled to be in service for 2018. The inclusion of the new TS significantly shortens the circuits' lengths to approximately 30 km, and as a result the related reliability indices for annual frequency and duration are theoretically expected to significantly improve from current levels.

Based on a typical outage rate for double circuit lines in southern Ontario of 0.19/km/yr (calculated from historical outage rates for N-2 and N-1-1 type contingencies), and the length of the H24/26C and M29/B23C circuits (27 km with Clarington TS in service), the coincident outage rate is estimated to be approximately 1 outage every 20 years[3]. Although the present analysis has used average outage data from Southwestern Ontario, outage data for double circuits on common towers for the eastern portion of the GTA would further refine the current analysis.

The Table below shows the current demand served from these pairs of circuits and the increase in electrical demand expected to be served from these circuits in the next 10 years.

Load Pocket	2015 Actual Peak	2025 Net Forecast
H24/26C: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	567
M29/B23C: Whitby TS DESN2, Wilson TS	436	504

Following a double circuit outage on either circuit pair, area LDCs have the ability on a temporary emergency basis to transfer some amount of load to unaffected stations through the distribution system. The actual amount of transfer capability at a given moment would depend on several factors, including the operating condition at the time of the outage, and how the

[3] Historically, the H24/26C and M29/B23C circuits have sustained only one outage in 2008 which lasted for two hours. The cause was human error with regards to the protective settings on the B23C/M29C circuits; there has been no outage occurrence on the H24/26C circuits in the past 15 years.

distribution network is configured when the failure event occurs. In order to develop a conservative estimate of future restoration capability, the current restoration capabilities were assumed to remain constant. Table 1 shows the restoration shortfalls in MW for the 2015 recorded actual peak and 2025 planning forecast for the 30 minute and 4 hour timelines after taking into account area LDCs load transfer capabilities after a double circuit outage.

Table 1: Restoration Shortfall in MW for 2015 Peak and 2025 Planning Forecast

Load Pocket	2015 Peak					2025 Planning Forecast				
	Actual Demand	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**	**Forecast**	**30 min Restoration**	**30-minute Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24/H26: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	57	49	142	64	567	57	259	142	275
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97

Going forward this analysis considers the two new step-down stations that have been recommended for this Regional area. A new step-down station in the proximity of Seaton is recommended as part of this IRRP for 2018, while the implementation of another station is underway in Clarington, which was recommended as part of the Oshawa-Clarington local planning report. The table below assumes that these stations will be in service and consequently any electrical demand forecast above current station limits is assumed to be transferred to one of the new stations. Any 27.6 kV electrical demand that exceeds Whitby TS LTR is assumed to be transferred to Seaton MTS, while any of the 44 kV demand that exceeds Wilson TS and Thornton TS combined LTR is assumed to be served by the new TS in Clarington. These assumptions are consistent with area LDC plans once the stations come into service.

Table 2: Restoration Shortfall in MW with the two new TSs in service

Load Pocket	2015 Peak					2025 Net				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30 min Restoration	30-minute Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	453	57	146	142	161
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	463	105	108	257	56

In order to consider the worst case scenario from a customer risk perspective, it is assumed that an H24/26C outage would interrupt the maximum 356 MW of load; and an M29/B23C outage would interrupt the maximum 436 MW of load. Assuming this event occurs at a rate of 0.05016 times per year, and lasts for 4 to 8 hours, this contingency represents a maximum of around 79.1 – 125.0 MWh of customer load at risk per year for H24C/H26C, and 89.3 – 160.1 MWh of customer load at risk for the M29C/B23C load pocket.

In order to quantify the cost risk of unserved energy, value of lost load ("VOLL"), represented in $/unserved energy, is used. Different jurisdictions have proposed a wide range of possible values, based on factors such of the type of customer, duration of outage, approximate loss of GDP, and estimated economic consequences of historical blackouts.

A 2013 briefing paper prepared by London Economics International LLC for the Electric Reliability Council of Texas carried out an international literature review of VOLL studies. The executive summary noted:

Average VOLLs for a developed, industrial economy range from approximately [US]$9,000/MWh to [US]$45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ([US]$0/MWh - [US]$17,976/MWh) than commercial and industrial ("C/I") customers (whose VOLLs range from about [US]$3,000/MWH to [US]$53,907/MWh)[4].

Assuming equal parts residential and commercial/industrial load within the GTA East Region, this would suggest that the VOLL could range anywhere from $1.50/kWh to $35.94/kWh. While

[4]http://www.puc.texas.gov/industry/projects/electric/40000/40000_427_061813_ERCOT_VOLL_Literature_Review_and_Macroeconomic_Analysis.pdf

this represents a large range, it is consistent with a 2006 Canadian example of VOLL that was used in a regulatory application to upgrade the Cathedral Square Substation in downtown Vancouver. In a supporting paper released by BCTC, a low and high value for VOLL was estimated to be $3.07/kWh and $35.57/kWh, after considering customer composition and provincial GDP[5].

A VOLL range of $10- $30/ kWh is used in this analysis to provide a low and high estimate of the risk borne by local customers.

Using a VOLL of $10-30/kWh and assuming all load is restored within 4 hours, the equivalent economic risk by the 58.6 – 89.3 MWh/yr regional restoration vulnerability is approximately $586,000 – $2,680,000/yr. This roughly translates to a maximum present day risk of approximately $8 – $36 million over the 20 year planning horizon of this study.[6] From the VOLL calculations, it is reasonable to assume that there could be a benefit of between $8-23 million and $12-36 million to restore customer load along the H24C/H26C and M23C/B23C lines respectively for a wires solution; in other words it could be cost justified to implement a solution up to these monetary amounts.

Distribution level solutions, transmission level solutions or a combination of both could therefore be technically and economically feasible options to providing alternative sources of supply to loads during a rare double element outage up to the amounts specified above. A distribution solution for the GTA East Region could include the construction of additional load transfer capability between stations at the feeder level. The costs and technical feasibility of this type of solution however needs to be investigated further.

A transmission-based restoration solution for the GTA East Region would require the installation of motorized disconnect switches on the circuits. These disconnect switches enable operators to segregate faulted line sections and restore service to customers via an alternate supply source. The figure below shows the maximum number of switches (8 pairs) that could be utilized to account for the full complement of outages. The estimated cost of installing motorized switches is $5-6 million per circuit pair for a total capital cost of $40-48 million to account for all outages along the corridor.

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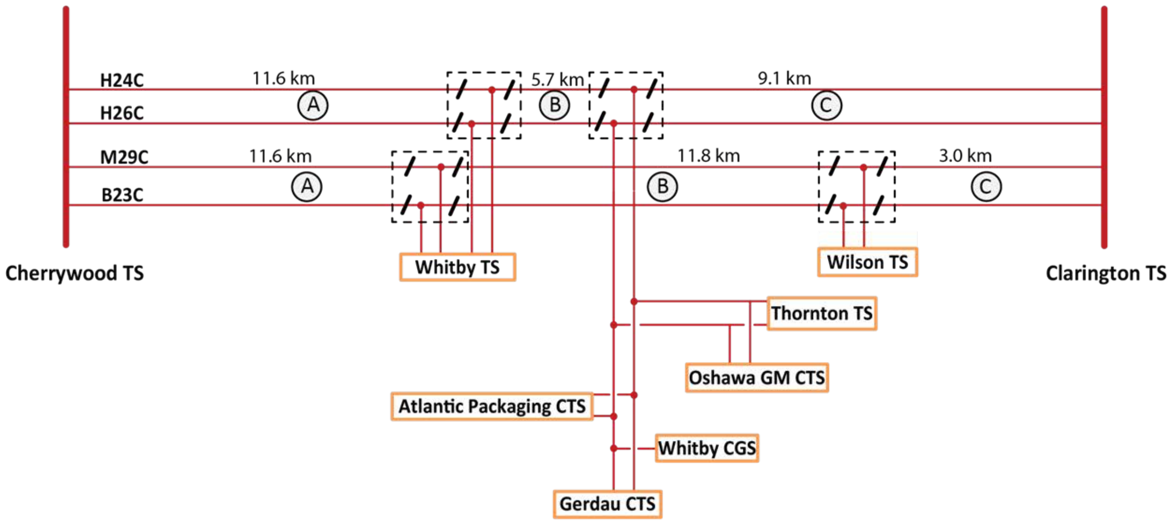
[5] http://transmission.bchydro.com/nr/rdonlyres/86da00e7-105f-4f72-8d3c-342c06919b8e/0/oorareliabilityassessmentofcathedralsquaresubstation.pdf

[6] Present value of annual risk, over 29 years, 4% interest rate



This preliminary analysis indicates that there may be economic justification for proceeding with mitigating solutions in the area. More detailed analysis is required to be conducted by the transmitter and LDCs in the area. This analysis should account for detailed local outage statistics, refined solutions and cost assumptions.

Note that 8 pairs of switches is a very conservative estimate and further analysis is needed to determine the optimum number and location to substantially meet restoration load levels and timelines. The inclusion of switches or other wires based solutions on the regional transmission system adds another element of complexity that could negatively impact reliability; this also needs to be considered when conducting a detailed comparison of options for restoration. The risk to reliability is especially important as there are large industrial customers connected directly to the grid in this area and these types of customers typically have the highest impacts during these failure events. In order to justify any investment to meet the restoration timelines, assumptions should be refined to include the following:

- The amount of load at risk for interruption should be calculated based on typical load duration curves, instead of assuming the annual peak demand is maintained throughout the duration of an outage.
- Actual customer composition should be used to estimate VOLL (or a range of VOLLs) specific to the area.

Detailed study is also needed to determine the optimum number and location of switches, the inherent increase in risk introduced by the switches and other LDC operational benefits provided by distribution level transfers. It is recommended that this detailed study be conducted as part of the Hydro One led RIP for the GTA East Region. This RIP is expected to be completed in Q1 2017 and will include all regional participants as working group members.

Pickering-Ajax-Whitby Sub-region IRRP

Appendix D: GTA East LAC Meeting Summaries

ieso
Independent Electricity System Operator

Meeting Information	
Date:	Thursday, March 10, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #1
Attendees:	**Committee Members in Attendance** Ed Belsey Gilbert Boehm Jeff Brooks Meagan Craven Gabe Czegledy Adam Murree Dorothy Skinner Ralph Sutton Dr. Anita Tucker René C. Viau **Hydro One Distribution** Dhaval Patel **Hydro One Transmission** Ajay Garg **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Rui Victal **Oshawa PUC** Ivano Labricciosa Jayesh Shah Eric Andres Rajendra Patel
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

	Key Topics	Follow-up Actions
1	**Opening Remarks and Roundtable Introductions** • Mr. Toneguzzo and Ms. Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Role of LAC and Review of LAC Manual** • Ms. Da Rocha provided an overview of the Local Advisory Committee's role and the nature of issues and topics that the LAC will be discussing. It was indicated that the	

	focus of this LAC is on providing input on community preferences towards approaches for meeting mid and longer-term electrical growth. The solutions focused on the near-terms needs are already underway. The Integrated Regional Resource Plan for the Pickering-Ajax-Whitby sub-region will be posted in June 2016. **Review of LAC Manual** • The contents of the LAC manual were reviewed.	
2	**Presentation and Discussion GTA East Local Needs and Next Steps** *<u>Presentation Summary – Bulk System:</u>* *Joe Toneguzzo and Jiya Shoaib presented information on the bulk electricity system in the area, the regional electricity planning process and the needs that have been identified specifically in the Pickering-Ajax-Whitby sub-region. To set the context for the discussion, an overview was provided of the bulk electricity system focusing on how the Pickering Nuclear Generating Station (NGS) and the Cherrywood Transformer Station (TS) in Pickering serve the 900 MW demand in south Durham Region. Once Pickering NGS is closed, Clarington TS (currently under construction) will help transform electricity from the 500KV system supplied by the Darlington NGS to the 230KV lines currently supplied by the Pickering NGS.* Questions and feedback from the LAC members: • Ontario Power Generation (OPG) is currently collecting information on uses for the Pickering NGS following its closure. ○ OPG is undertaking a Re-purposing Pickering Study and they are working with the city and community to determine the future of the site. The site will continue to house spent fuel until a long-term solution is developed. • What is the capacity at Pickering NGS? ○ The facility produces 3,000 MW from six units each producing 500MW. This provides baseload electricity generation which means it runs 24 hours/day, 7 days/week, and 365 days/year. • What is the date for the Clarington TS to be in-service? ○ Hydro One is building this TS and it is scheduled to be in-service in 2018. • Without the closure of Pickering NGS, there is 3,000MW less being supplied in to the electricity grid – where is this generation coming from? Is the Durham Energy from Waste (EFW) facility part of this solution? ○ The IESO has known about the upcoming closure of Pickering NGS and has been planning for this. Over the last few years, there have been a number of gas plants built to assist with the shift off coal generation and these will run more when Pickering is out of service. There is also an opportunity to investigate Combined Heat and Power (CHP) projects once Pickering is out of service. The Durham EFW facility is also part of the solution. ○ It was also noted that the Seaton TS will be able to serve approximately 150 MW of demand and this already takes in to consideration a considerable amount of conservation. The TS will be 170MVA which is a standard station size and is the optimum size for this station given the pace of growth in the area. The facility will have a lifespan of 40-50 years.	

<u>Presentation Summary – Near – Term Regional Needs and Plan:</u> From a regional planning perspective, two sub-regions were identified based on the type of needs within the larger GTA East region: Pickering-Ajax-Whitby and Oshawa-Clarington.

One near-term need for transformation capacity was identified for the Oshawa-Clarington area. This need was further assessed by a Hydro One led Local Planning Working Group in 2015. This Working Group recommended a new step-down transformer station (currently called Enfield TS) for providing the required transformation capacity to Local Distribution Companies serving the Oshawa-Clarington area.

Two near-term needs were identified in the Pickering-Ajax-Whitby area - the need for additional transformation <u>capacity</u> to be in-service by 2018 to support urban and greenfield growth in Pickering; and a need to investigate the value of addressing <u>restoration</u> criteria for rare failure event. Three options were explored to address the transformation capacity need, an economic analysis was conducted and based on the results, a new transformer station near the community of Seaton was recommended to meet the near-term transformation capacity need. In order to connect this new station, a small length of an existing transmission line would also have to be rebuilt from single to double circuit. Veridian has begun the Environmental Assessment (EA) process for the new station and Hydro One will begin the EA for the transmission line portion of the project. For the restoration needs, the Working Group is exploring the rationale for meeting the restoration criteria for these rare failure events and will report back at the next LAC meeting.

- ☐ Restoration cost-benefit analysis to be presented at next LAC meeting

Questions and feedback from the LAC members:

- What growth assumptions are being used in the study – housing stats etc.?
  - The Local Distribution Companies (LDCs) closely monitor growth and development activity and discuss this growth with the municipal planners. Once each LDC has developed a growth forecast, this is provided to the IESO and the forecasts are then combined into one regional planning forecast. The timing of developments is monitored.
  - A LAC member noted that at the provincial level, a growth plan is developed with a forecast. This plan is sent to the region, where it is distributed to the local municipalities and subsequently divided into neighbourhoods. This information is shared with the LDCs every year.
- Who sets the standards for energy consumption for the average house?
  - The LDCs develop the growth forecasts and incorporate changes such as the addition of household renewable projects (microFIT) and increased energy efficiency. The forecasts are also discussed with the municipalities. An important consideration is that population growth does not match energy growth – energy efficiency is better today, so energy growth is less than population growth.
- There is a large potential for changes in the study horizon with regards to electricity usage from homes. A net zero home is opening in Ajax. Energy storage is increasing.
  - These trends have been accounted for in developing the forecast. Consumer behaviour plays an important part in electricity planning.
- Has the Pickering airport been accounted for?
  - The airport has not been included in the load forecast.

- What assumptions are being made with regards to the changes in industry and jobs? Is there a factor that is being used?
    - Municipal population and employment forecasts drive the forecast. Since there is a degree of uncertainly, there could be low, medium and high growth scenarios for some regions.
- Where is the electricity capacity coming from to replace Pickering NGS? We can't expect expensive gas to fill this void.
    - On the provincial system level, there is generation capacity to supply the system from a combination of combined cycle gas generation and other renewable generation sources. There is also a need to transform electricity locally. Until 2024, there is lots of supply provincially. Beyond this, we will need to look at other solutions and the provincial government is about to start the next Long-term Energy Plan to look at this.
- Is there an advantage for Site #3 in Seaton to be closer or further away from growth?
    - Site 3 is the least advantageous due to its distance from the geographic centre of the new electrical demand. Other factors also need to be considered such as the distance to a transmission line etc. If it is located further away, losses are factored in as well.
- Does it make a difference that the province owns lands in Seaton?
    - All the new Seaton TS stations sites being considered are owned by Infrastructure Ontario; however the portion of the transmission line will be rebuilt within the existing Hydro One right-of-way
- What is the cost difference between the options to address capacity needs (slide 26)?
    - The transformer station and line is about $60M and the distribution feeders are about $70-100M. A new station is the lowest cost alternative; it is more costly to use the existing transformer stations and build feeders through the Rouge Valley.
- Need to have a level playing field across all of the municipalities (for anything that becomes mandatory for developers)

<u>Presentation Summary – Mid- and Long-Term Needs</u>

A key focus of the GTA East LAC is to discuss the mid and long-term considerations for the area and the community's preferred options to supply the long-term electricity demand. This includes conservation and demand management, and community self-sufficiency options. The LAC will also be asked to provide feedback on how to engage the community on the development of a long-term electricity strategy for the region.

☐ Community priorities and preferences for addressing long-term electricity needs to be discussed at next LAC meeting

Questions and feedback from the LAC members:

- What is the land needed for solar generation on a large scale?
    - A LAC member noted that for 1MW of solar, 5-6 acres of land is needed.
- Behaviour modification is outside of our control. What is the biggest bang for the buck in regards to infrastructure? Renewables can't be prescribed through planning – where are the provincial partners?
    - Electricity planners are part of this discussion and we can influence this through policy such as the Long-term Energy Plan.
- The provincial government doesn't have any regulations in place for a builder to add solar panels. If these regulations were in place, this would change things.
- Need a level playing field – there can't be different regulations in different

municipalities.

- The cost of solar panels is going down and the quality is going up
- A partnership between builders, municipalities and the province is needed
- Solar energy also has a negative effect on the province through the Global Adjustment. It will drive out industry if the province keeps putting panels on the system at premium costs.
    - The subsidy is part of the global adjustment; however, we are looking at net metering. This would eliminate this subsidy.
- Why are we looking at new transmission instead of distributed generation (DG) for a subdivision?
    - Solar panels alone will not eliminate the need for Seaton TS which serves new sub divisions. DG is a viable solution however experience shows that people want a wire connecting their home or business to the grid to provide supply security. Cost is a factor and it is uneconomical to have grid supply and DG.

LDC Presentations

Veridian Presentation - Questions/Feedback

- Can there be a micro-grid the size of Seaton?
    - Yes, however this was not factored in to the analysis because the need is immediate, given lead times. Other opportunities are being explored such as combined heat and power plants
- What are the steps to looking in to a micro-grid? Suggest a sub-committee of LAC members be established to look in to micro-grids.
    - Micro-grids become more complicated due to the broader policy implications such as purchase agreements, having a steam host etc.
- Has the opportunity to connect to Markham been explored?

☐ Investigate establishing a dedicated micro-grid LAC group before next LAC meeting

Whitby Hydro Presentation - Questions/Feedback

- No questions

Oshawa PUC Presentation - Questions/Feedback

- To what extent have the LDCs collaborated with other countries that are experiencing the same issues (i.e. development of micro-grids)
    - Europe is further ahead on combined heat and power projects. Australia has strong policy, but in Ontario there may be pushback. Asia-Pacific is also very proactive. LDCs are aware of what other countries are doing but the business, policy and development context is not as advanced in Canada..
- The global spotlight isn't energy, its greenhouse gas emissions
    - The existing system is very green. The province is trying to do more in this area such as moving transportation to electricity.
    - The market has to drive some of this. For example, a combined heat and power project in Seaton would need a private developer, not the LDCs, along with a secure customer base. Also, distribution wires would still need to be built.

	Public Questions • With the closure of Pickering NGS, does the Special Protection System (SPS) for Darlington NGS need to be upgraded given that it takes several years? o Local reliability is maintained by the development of Clarington TS after the closure of Pickering NGS. • Given that there is a 160 MW demand for the Pickering area, what is the total capacity in the area over the next 20 years? o The Seaton community is the main driver for the near-term capacity. • Will the next Long-term Energy Plan include off-shore wind; there is currently a 5km moratorium from the shoreline? o The IESO does not have a mandate for such policy; the next version of the LTEP will reveal the provincial renewable energy policy as mandated by the government.	
6	**Next Meeting & Adjournment** • Focus of the next meeting is identifying priorities for addressing the mid- and long-term needs so these ideas can be included in this IRRP. The LAC will also be asked about other local priorities and initiatives such as status of community energy plans. Together, these two topics will be used to guide a discussion on the next steps for the LAC. • Next meeting to be held at the beginning of May. • Fall meeting to include a presentation of the completed IRRP.	

Connecting Today.
Powering Tomorrow.

Meeting Information	
Date:	May 4, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #2
Attendees:	**Committee Members in Attendance** Brad Anderson Stev Andis Ed Belsey Jeff Brooks Grant McGregor Ralph Sutton René C. Viau **Hydro One Distribution** Dhaval Patel Charlie Lee **Hydro One Transmission** Ajay Garg Jehangir Qayyum **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Kevin Whitehead Faisal Habibullah Evan Wade **Oshawa PUC** Jayesh Shah Eric Andres Rajendra Patel Janet Taylor
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Everyone was welcomed to the meeting • Roundtable introductions were made	
Review of Summary from Meeting #1 • LAC members were asked for their feedback on the summary from the inaugural meeting. Being none, the summary was deemed final and a copy will be posted to the GTA East Engagement page on the IESO website.	

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Presentation and Discussion – Near-Term Needs and Next Steps

<u>Presentation Summary – Near-Term Needs:</u>
Joe Toneguzzo and Jiya Shoaib reviewed and provided an update on the two near-term needs identified for the Pickering-Ajax-Whitby sub-region presented at the inaugural LAC meeting. With regards to the <u>capacity</u> needs, it was noted that an environmental assessment (EA) is ongoing for the new transformer station in north Pickering and related upgrade to transmission circuits. Veridian and Hydro One have submitted a joint application. These processes will determine the location of the new station and line. With regards to the <u>restoration</u> need, an update was provided indicating that four options have been identified to address this need since the last LAC meeting, It has been determined that a refinement of the restoration analysis and the related solution recommendations will be determined as part of a Regional Infrastructure Plan lead by Hydro One and expected to be completed by Q1 2017. It was noted that the Integrated Regional Resource Plan (IRRP) for the Pickering-Ajax-Whitby area is to be completed by June 2016.

Questions and feedback from the LAC members:

- Will the new transformer station (TS) in Pickering alleviate the generation connection restraint at the Cherrywood TS?
  - No. The new station is to service increased demand in north Pickering, while the generation connection restraint at the Cherrywood TS is related to the ability to add generation.
- Is the Pickering Airport in scope for the regional plan?
  - Yes. It is a consideration for the long-term.
- Does the plan account for climate change?
  - Yes. This was included in the study and had a minimal effect on the results.
- Is there full redundancy in the system if one line goes down?
  - In the event of a single circuit failure, no one loses power. If two circuits fail, the power will go out. To address this, if switches are installed on the line, the station can receive power from either direction. There are currently no switches on the circuits from Cherrywood TS, but the economic and reliability justification for their implementation are being investigated.
- Is time a parameter in the restoration evaluation?
  - Yes. This has a large impact in terms of cost.
- What is the life span of the towers?
  - Towers can last 50+ years. They are continuously monitored and regularly maintained.

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LDC Presentations on their Conservation and Demand Management Plans

Each of the Local Distribution Companies in the GTA East area presented an overview of their Conservation and Demand Management Plans, including their conservation targets and the programs and initiatives that will help to achieve the targets.

</td><td>☐ Determine if changes to the High Performance New Construction program will follow the 2017 changes to the Ontario Building Code</td></tr>
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LAC Member Discussion – Mid- and Long-Term Growth and Priorities *Presentation Summary: The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.* • *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?* • *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?* • *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?* The following feedback was received from LAC members. <u>City of Pickering</u> • The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans. • The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities. <u>Durham Region</u> • The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process. o An offer was made by the IESO to sit as a member of this advisory group, if requested. • The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016. • The "white belt" along Highway 407, east of the Pickering Airport Lands, was identified as an area for potential future development through Regional Official Plan Amendment 128. This land area is approximately 4,150 acres. Further details on these lands can be found in the Region's Official Plan, specifically policy 7.3.11 and Land Use Schedule A. • The Region is developing a climate change adaptation plan that is expected in the first half of 2017. The regional municipalities will develop their own climate change adaptation plans once the plan is developed at the regional level. • In the long-term, the region is exploring electrification of transit such as light rail along the Highway 2 corridor.	☐ LAC members to review discussion questions and provide any additional information to be considered in the mid- to long-term portion of the IRRP

<u>Town of Ajax</u> • Ajax will exceed its population and residential unit forecast for the mid- and long-term time periods for the downtown area. o Downtown Official Plan projections by 2031 are: 1,850 residential units and 3,500 people o Current approved development to be built by 2018 includes: 1,000 residential units, 1,800 people, 4,200 sq.m. retail Gross Floor Area and 5,000 sq.m. office Gross Floor Area o Proposed additional development (pending development applications) by 2022: 1,182 residential units and 2,140 people • The steam plant in downtown Ajax has been redeveloped to a nameplate capacity of 18 MW and burns biomass. It has approvals to increase capacity to 25 MW. <u>Town of Whitby</u> • The town's official plan will be updated in 2017. • The town is investigating a district energy feasibility study within the community of Brooklin. • A community sustainability plan is expected in 2017. <u>General LAC Discussion</u> • Short-term growth in the region will be seen in greenfield areas before intensification happens in established parts of the region. Some municipal representatives indicated that they are receiving many queries for building condominiums; however this is not resulting in a similar number of buildings being built. However other municipalities in the area are seeing higher density facilities under development. • Durham Region and the City of Pickering will be holding a builder education program on net zero homes in the coming weeks. <u>Energy Trends Discussion</u> • There is an increasing trend of using waste as clean energy, for example by using plasma torches. These technologies are not inexpensive but the technology exists. Photovoltaic film efficiency has increased and the costs have decreased from a decade ago. There is opportunity to take advantage of government programs aimed towards these clean energy technologies. An example is the energy from waste project in Durham Region. • Electrification of personal vehicles will impact future electricity use. However, a number of factors affect the use and impact of these vehicles, such as climate, distances traveled, availability of charging stations, etc. • A question was asked about the life extension and eventual retirement of the Pickering Nuclear and the impact to the local area in terms of electricity. o The IESO explained that the retirement has a major impact to the area; however a mitigating solution is already under development in the form of Clarington TS. This new TS will backstop the regional system once Pickering is retired. • The group noted that distributed generation is prohibited from connecting at Cherrywood TS due to a short circuit constraint that impacts the older parts of the City of Pickering. o Hydro One is actively pursuing the removal of this constraint.	

<u>Other Items</u> • The IESO informed LAC members that the provincial Long-Term Energy Plan is expected in 2017. Prior to its release, it is also expected that engagement will be undertaken, as was the case during the development of the 2013 Long-Term Energy Plan. • The province's climate action plan is expected to be released next month	
Public Questions • Will cap and trade increase electricity consumption? ○ Kilowatt savings won't be dampened by cap and trade.	
Next Steps & Adjournment • LAC members will be sent a copy of the mid- and long-term priorities identified in the meeting and asked for any additional material for consideration in the development of the IRRP. • Next LAC meeting to take place in the fall and will include a presentation of the completed IRRP and discussion of the next steps for the LAC.	

LAC Member Discussion – Mid- and Long-Term Growth and Priorities

The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.

- *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?*
- *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?*
- *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?*

The following feedback was received from LAC members.

City of Pickering

- The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans.
- The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities.

Durham Region

- The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process.
- The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016.
- The "white belt" along Highway 407, east of the Pickering Airport Lands, was identified as an area for potential future development through Regional Official Plan Amendment 128. This land area is approximately 4,150 acres. Further details on these lands can be found in the Region's Official Plan, specifically policy 7.3.11 and Land Use Schedule A.
- The Region is developing a climate change adaptation plan that is expected in the first half of 2017. The regional municipalities will develop their own climate change adaptation plans once the plan is developed at the regional level.
- In the long-term, the region is exploring electrification of transit such as light rail along the Highway 2 corridor.

Town of Ajax

- Ajax will exceed its population and residential unit forecast for the mid- and long-term time periods for the downtown area.
    - Downtown Official Plan projections by 2031 are: 1,850 residential units and 3,500 people
    - Current approved development to be built by 2018 includes: 1,000 residential units, 1,800 people, 4,200 sq.m. retail Gross Floor Area and 5,000 sq.m. office Gross Floor Area

    - Proposed additional development (pending development applications) by 2022: 1,182 residential units and 2,140 people
- The steam plant in downtown Ajax has been redeveloped to a nameplate capacity of 18 MW and burns biomass. It has approvals to increase capacity to 25 MW.

Town of Whitby

- The town's official plan will be updated in 2017.
- The town is investigating a district energy feasibility study within the community of Brooklin.
- A community sustainability plan is expected in 2017.

General LAC Discussion

- Short-term growth in the region will be seen in greenfield areas before intensification happens in established parts of the region. Some municipal representatives indicated that they are receiving many queries for building condominiums; however this is not resulting in a similar number of buildings being built. However other municipalities in the area are seeing higher density facilities under development.
- Durham Region and the City of Pickering will be holding a builder education program on net zero homes in the coming weeks.

Energy Trends Discussion

- There is an increasing trend of using waste as clean energy, for example by using plasma torches. These technologies are not inexpensive but the technology exists. Photovoltaic film efficiency has increased and the costs have decreased from a decade ago. There is opportunity to take advantage of government programs aimed towards these clean energy technologies. An example is the energy from waste project in Durham Region.
- Electrification of personal vehicles will impact future electricity use. However, a number of factors affect the use and impact of these vehicles, such as climate, distances traveled, availability of charging stations, etc.
- A question was asked about the life extension and eventual retirement of the Pickering Nuclear and the impact to the local area in terms of electricity.
- The group noted that distributed generation is prohibited from connecting at Cherrywood TS due to a short circuit constraint that impacts the older parts of the City of Pickering.

Other Items

- The IESO informed LAC members that the provincial Long-Term Energy Plan is expected in 2017. Prior to its release, it is also expected that engagement will be undertaken, as was the case during the development of the 2013 Long-Term Energy Plan.
- The province's climate action plan is expected to be released next month

GTA East

REGIONAL INFRASTRUCTURE PLAN

January 9th, 2017

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Oshawa PUC Networks Inc.
Veridian Connections Inc.
Whitby Hydro Electric Corporation

DISCLAIMER

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA EAST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA East Region which consists of the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. It follows the completion of the GTA East Region's Needs Assessment ("NA") in August 2014, the Oshawa-Clarington Sub-Region's Local Plan ("LP") in May 2015, and the Pickering-Ajax-Whitby Sub-Region's Integrated Regional Resource Plan ("IRRP") in June 2016.

This RIP provides a consolidated summary of needs and recommended plans for the entire GTA East Region that includes the Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The major transmission and distribution infrastructure investments planned for the GTA East Region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Cost
1	Enfield TS; new 230/44kV station	2019	$34M[1]
2	Seaton MTS; new 230/27.6/27.6kV station	2019	$43M-$48M[2]

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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[1] Considers 6x44kV feeder breaker positions initially without capacitor banks
[2] Class Environmental Assessment (EA) not complete at time of RIP. Range of costs includes all sites under consideration – includes transmission line rebuild costs and all station equipment less capacitor banks for 12x27.6kV feeders and a spare transformer.

TABLE OF CONTENTS

List of Figures

List of Tables

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the study with input and consultation with Hydro One Distribution, Oshawa PUC Networks Inc. (“OPUCN”), Veridian Connections Inc. (“Veridian”), Whitby Hydro Electric Corporation (“Whitby Hydro”) and the Independent Electricity System Operator (“IESO”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and Clarington. Electrical supply to the Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (“TS”) and five[3] 230kV transmission lines that supply the four local area step-down transformer stations. The boundaries of the Region are shown in Figure 1-1 below.

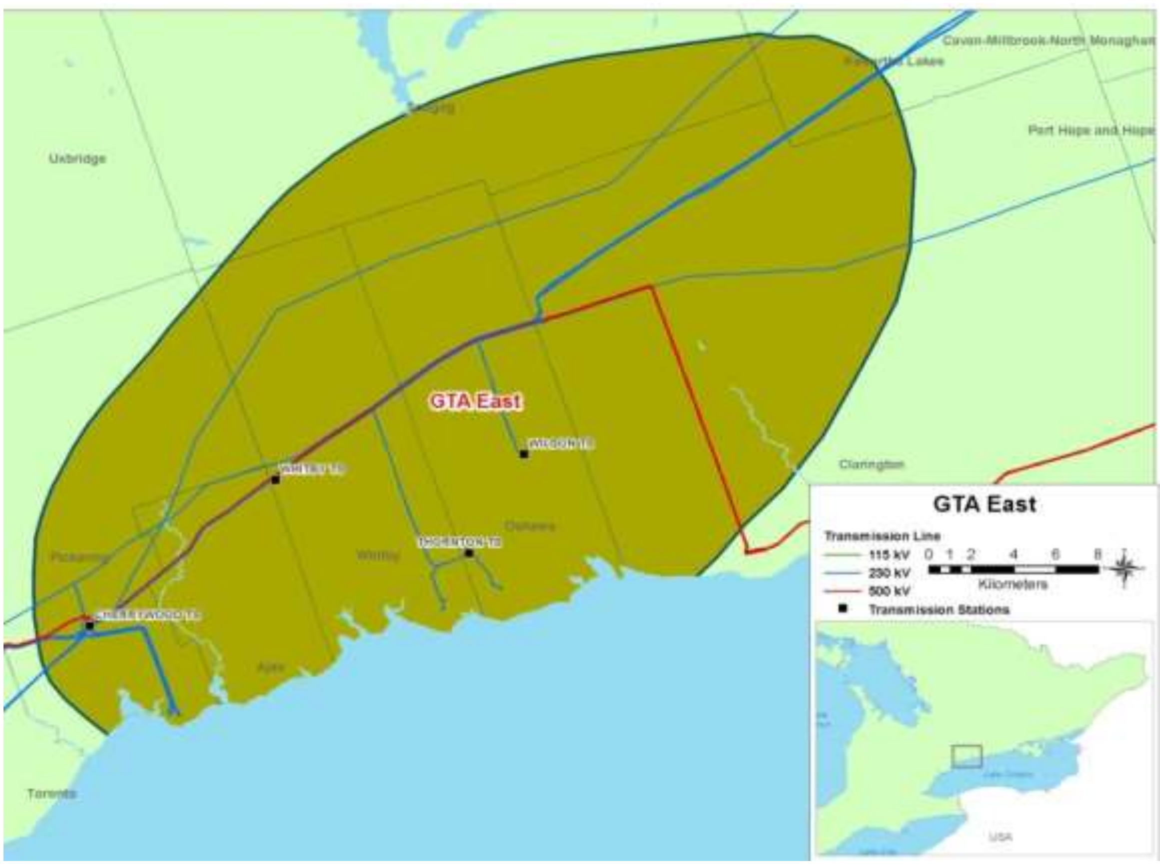

Figure 1-1 GTA East Region

[3] Including 230kV circuit C28C (T28C with Clarington TS) which extends 2km north from Cherrywood TS to Duffin Jct. and then extends 26km east to be terminated at Clarington TS in 2018

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Pickering-Ajax-Whitby Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[4] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customer) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited investments of wires (transmission or distribution) solutions c) does not require upstream transmission investments d) does not require plan level stakeholder engagement and e) other approvals such as Leave to Construct (S92) application or Environmental Approval.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. If there are needs that do not required regional coordination, Working Group can recommend them to be undertaken as part of the LP approach discussed above. Else, the approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

[4] Also referred to as Needs Screening.

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

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

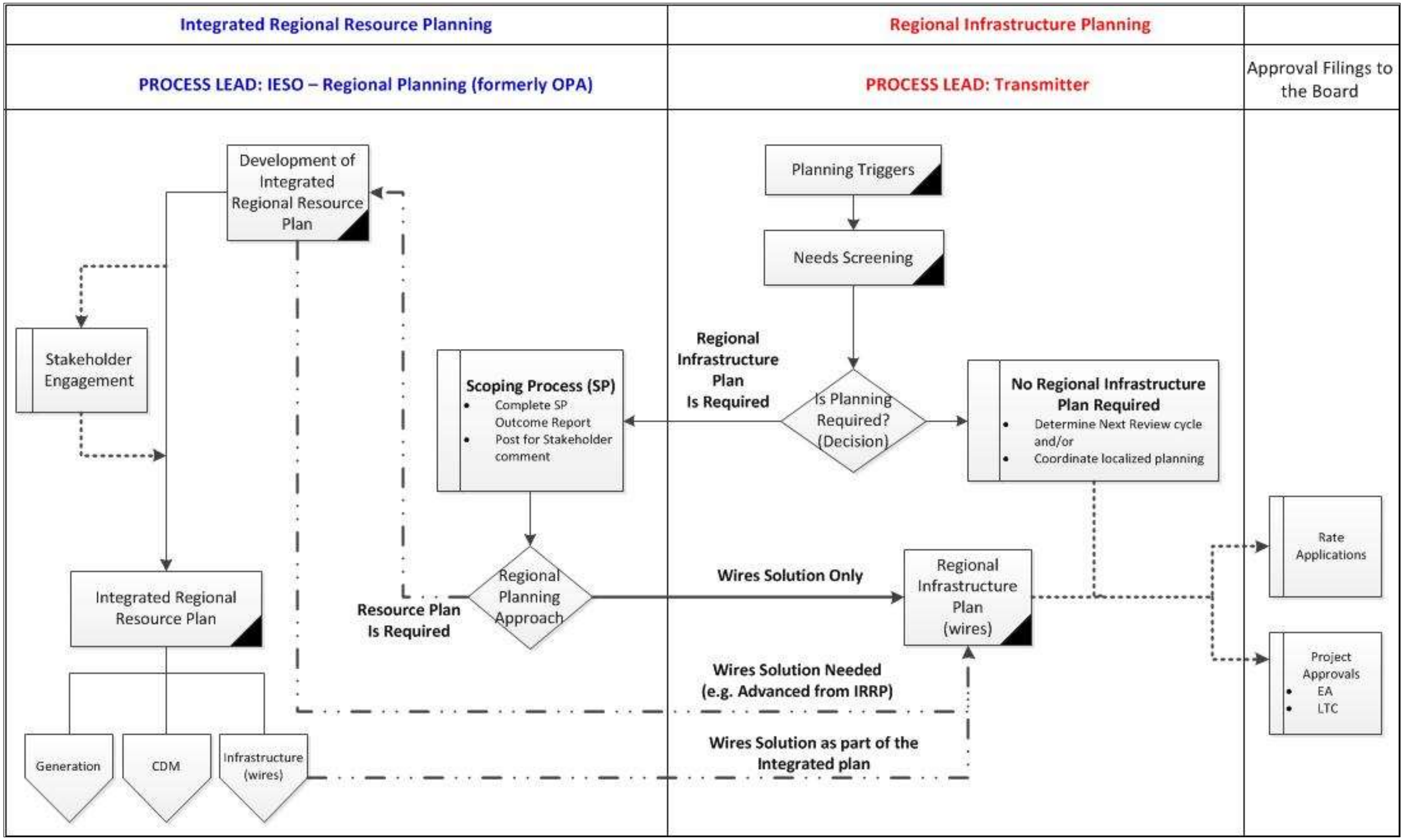

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required.

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

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

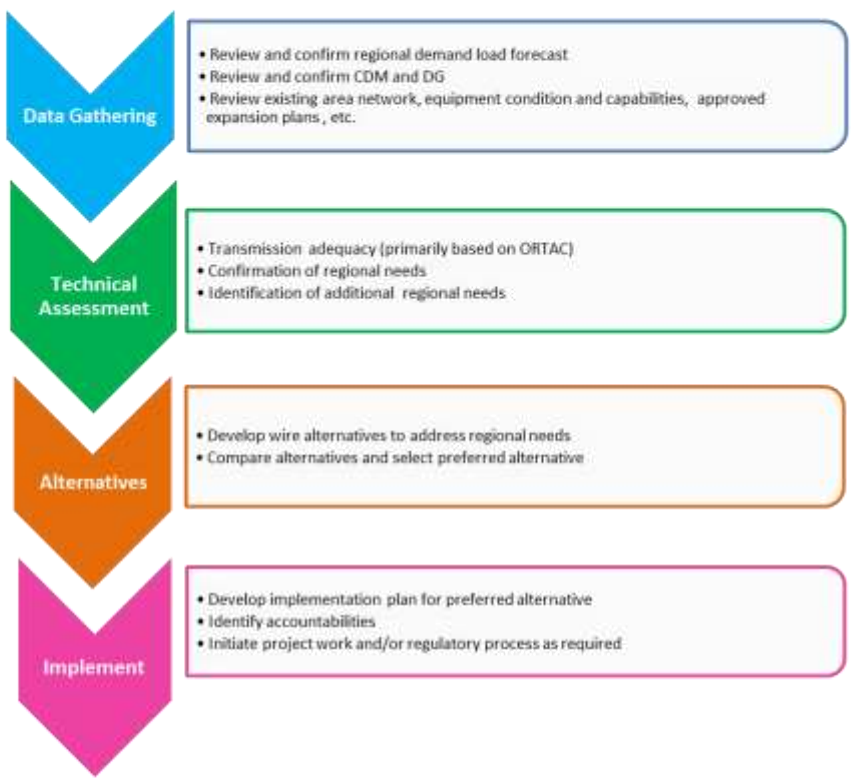

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FOUR 230KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 938.5 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS, a major 500/230kV autotransformer station in the City of Pickering, and five 230kV circuits emanating east from Cherrywood TS that supply four local area step-down transformer stations and four other direct transmission connected load customers. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2014 GTA East Region NA report, prepared by Hydro One, considered the GTA East Region as a whole. Subsequently, the GTA East Region was divided into two sub-regions, Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The IRRP report focused on the needs in the Pickering-Ajax-Whitby Sub-Region. The May 2015 Oshawa-Clarington Sub-Region LP report focused solely on the Oshawa-Clarington Sub-Region. A map of the GTA East Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Pickering-Ajax-Whitby Sub-Region

The Pickering-Ajax-Whitby Sub-Region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-Region are Hydro One Distribution, Veridian, and Whitby Hydro.

3.2 Oshawa-Clarington Sub-Region

The Oshawa-Clarington Sub-Region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV, and four other direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit H26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby Sub-Region. The LDCs supplied in the Sub-Region are Whitby Hydro, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington (called Clarington TS) is also being developed and is expected to be in-service in 2018. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS. The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principal supply source for the GTA East Region load.

A single line diagram of the GTA East Region transmission system including the connection of Clarington TS is shown in Figure 3-2.

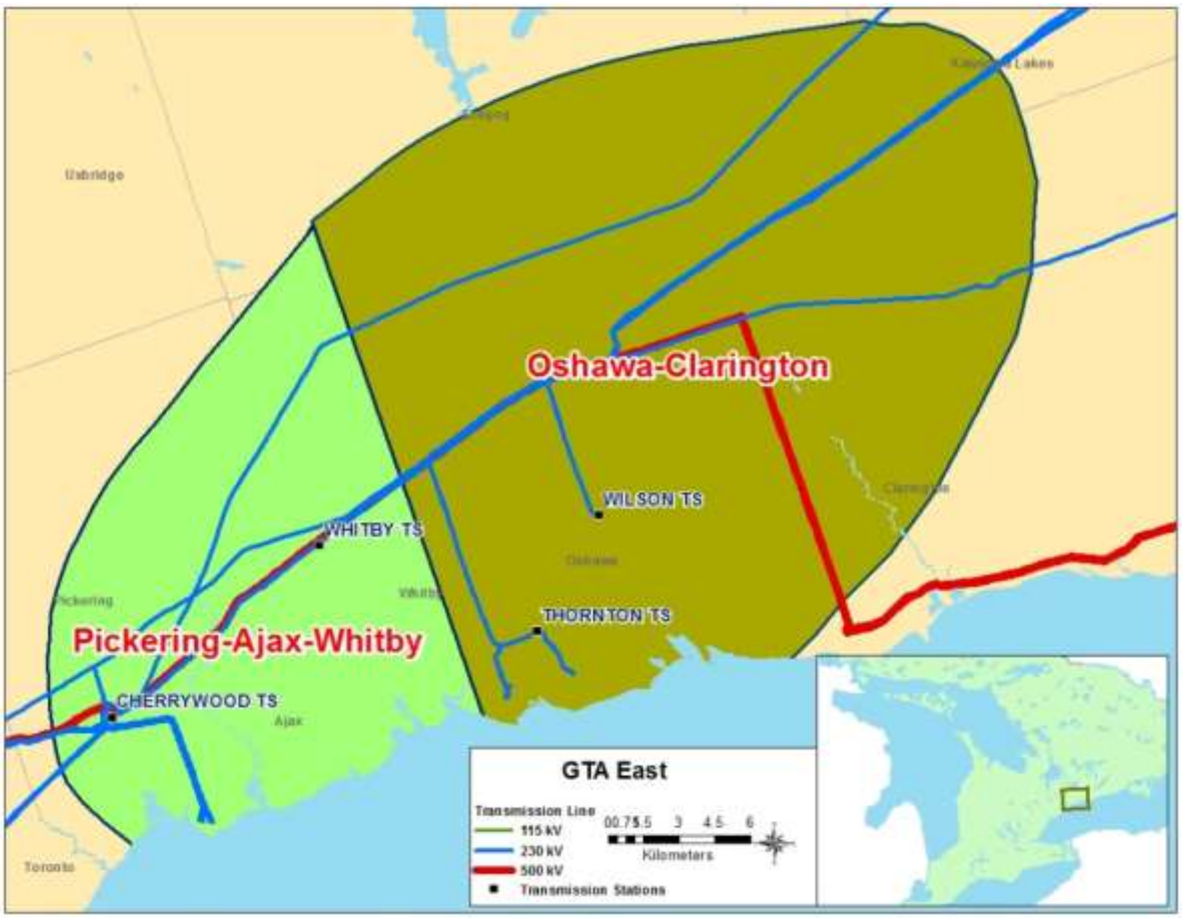

Figure 3-1 GTA East Region – Supply Areas

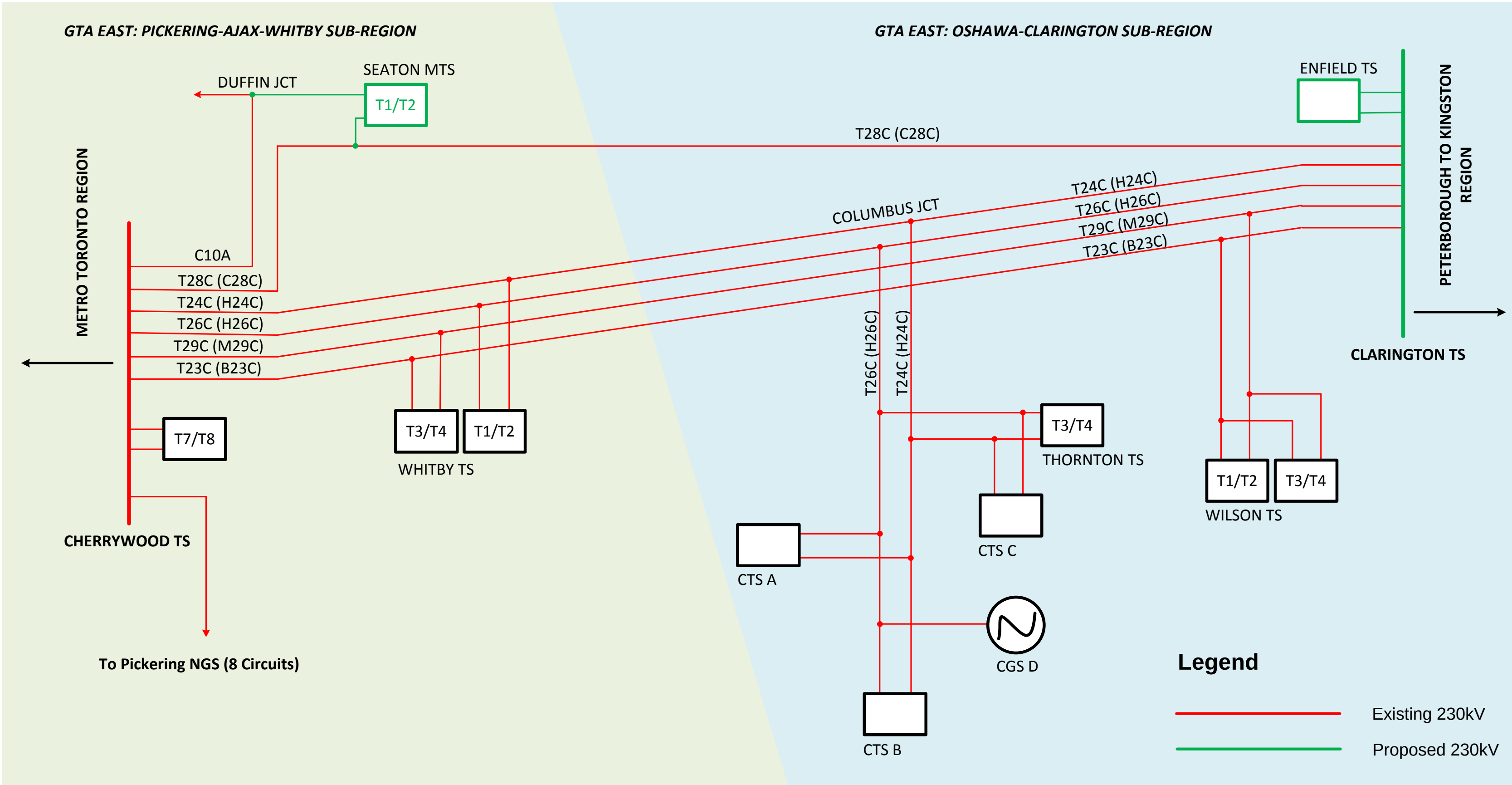

Figure 3-2 GTA East Region Single Line Diagram

Note: Current circuit designations (before Clarington TS is in-service) are provided in brackets

4. TRANSMISSION FACILITIES COMPLETED OR CURRENTLY UNDERWAY OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA EAST REGION.

A brief listing of the developed projects along with their in-service dates over the last 10 years is given below:

- Whitby TS T1/T2 (2009) – built new step-down transformer station supplied from 230kV circuits H24C and H26C in municipality of Whitby to increase transformation capacity for Whitby Hydro and Veridian requirements.

- Installed LV neutral grounding reactors at Wilson TS T1/T2 DESN1 (2015) – to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 transformer replacements and install LV neutral grounding reactors (2016) – to replace end-of-life transformers and reduce line-to-ground short circuit fault levels to facilitate DG connections.

The following development projects are currently underway:

- Clarington TS (2018) – a 500/230kV autotransformer station at the Oshawa Area Jct. to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region. The thermal limits of the 230kV circuits supplying the Region will be upgraded and will be terminated at Clarington TS.

- Seaton MTS (2019) – a 230/27.6/27.6kV municipal transformer station to increase supply capacity in the Pickering-Ajax-Whitby Sub-Region and provide relief to Whitby TS 27.6kV following the development of new community of Seaton. The station will be serviced by two parallel 230kV circuits, C10A and C28C, emanating from Cherrywood TS. C10A will be extended eastward from Duffin Jct. to the site of the station.

- Enfield TS (2019) – a 230/44kV DESN to increase supply capacity in the Oshawa-Clarington Sub-Region and provide relief to Wilson TS. This station will be located at the Oshawa Area Jct. and will be directly connected to Clarington TS 230kV bus.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA East Region is expected to increase at an annual rate of approximately 2% between 2016 and 2025. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

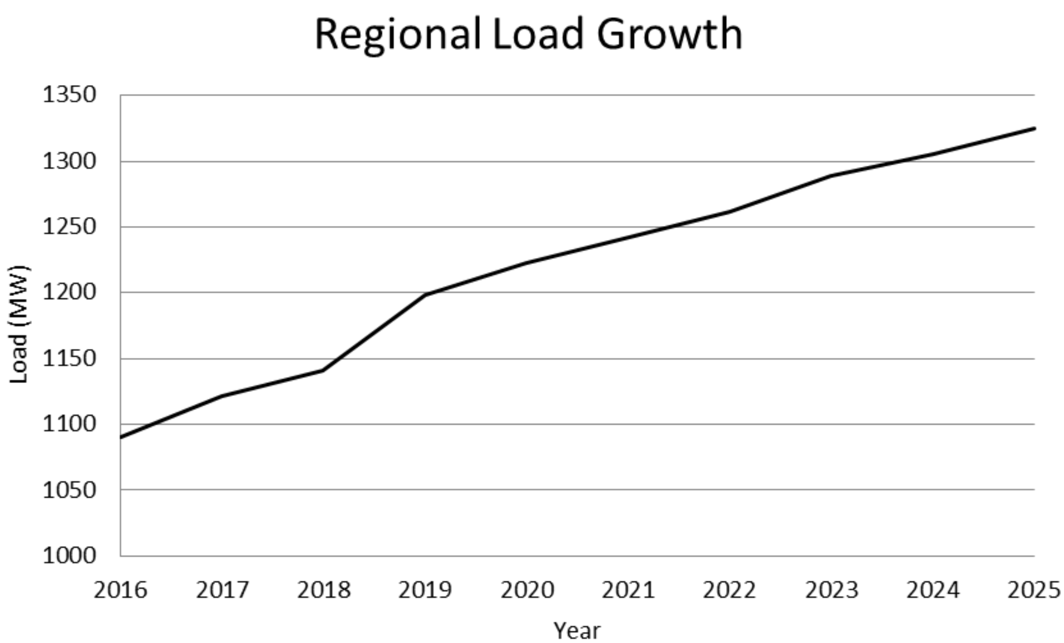

Figure 5-1 GTA East Region Coincident Net Load Forecast

Prior to the RIP's kick-off, the Working Group were asked to confirm load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for Pickering-Ajax-Whitby Sub-Region did not have a significant revision compared to the IRRP's load forecast. However, the revised forecasted non-coincident stations' peaks for Wilson TS and Thornton TS in the Oshawa-Clarington Sub-Region had a significant increase; therefore, the needs identified in previous assessments were reconfirmed.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2025.
- Pickering NGS is assumed to be out-of-service by 2024.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations 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 in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA EAST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA East Region. The findings of these studies are input to the RIP:

1. IESO's Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan – June 30, 2016[1]
2. Hydro One's Oshawa-Clarington Sub-Region Local Planning Report – May 15, 2015[2]
3. Hydro One's GTA East Region Needs Assessment Report – August 11, 2014[3]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the GTA East Region assuming Clarington TS will be in-service by 2018, Seaton MTS and Enfield TS by 2019, and Pickering NGS out-of-service between 2018 and 2024.

Sections 6.1 – 6.3 present the results of this review and Table 6-1 lists the Region's near to mid-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA East Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
	7.2	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
Load Restoration	7.3	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
Short Circuit Constraint	7.4	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome

6.1 500kV and 230kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, B23C/M29C, H24C/H26C, and C28C, supplying both the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. Refer to Figure 3-2 for existing and proposed facilities to be operational in the Region in near future.

Bulk system planning is conducted by the IESO and is informed by government policy such as the long term energy plan ("LTEP"). The next LTEP is expected to be issued in 2017. Any outcomes from this level of planning that impact regional planning are expected to be integrated into the respective regions as necessary.

6.2 Pickering-Ajax-Whitby Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations in the Pickering-Ajax-Whitby Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Pickering-Ajax-Whitby Sub-Region

Station	DESN	Voltage Transformation
Cherrywood TS	T7/T8	230/44kV
Whitby TS	T1/T2	230/44/27.6kV
	T3/T4	230/44kV

Based on the LTR of these load stations, additional 27.6kV capacity is required at Whitby TS T1/T2 in 2019 which will be addressed by the proposed Seaton MTS (see details in Section 7.1). Cherrywood TS T7/T8 may be slightly overloaded initially, however, due to CDM and commissioning of Seaton MTS, the capacity need is expected to be eliminated by 2019. Forecast loads at Whitby TS T1/T2 44kV windings, and Whitby TS T3/T4 44kV windings are adequate over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

Table 6-3 Transformation Capacities in the Pickering-Ajax-Whitby Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Cherrywood TS T7/T8 44kV	175	156	-
Whitby TS T1/T2 27.6kV	90	41	2019
Whitby TS T1/T2 44kV	90	56	-
Whitby TS T3/T4 44kV	187	161	-

6.3 Oshawa-Clarington Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations and four direct-connected customers in the Oshawa-Clarington Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Oshawa-Clarington Sub-Region

Station	DESN	Voltage Transformation
Wilson TS	T1/T2	230/44kV
	T3/T4	230/44kV
Thornton TS	T3/T4	230/44kV
Industrial Customer TS x4	-	-

Based on the LTR of these load stations, additional 44kV capacity is immediately required to provide relief to Wilson TS. Under certain conditions, overloading at Wilson TS T3/T4 was significant enough to plan for emergency rotating load shedding, if and when required. Plan to address this need is discussed further in Section 7.2. Thornton TS is adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Oshawa-Clarington Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Wilson TS T1/T2 44kV	161	167	Immediately
Wilson TS T3/T4 44kV	133	146	Immediately
Thornton TS T3/T4 44kV	159	126	-

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

7. REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA East Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the Pickering-Ajax-Whitby Sub-Region and the NA and LP for the Oshawa-Clarington Sub-Region. Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.1% annually.

Based on the DG and CDM forecasts in the Sub-Region, adequate 44kV transformation capacity is available at Cherrywood TS T7/T8 and Whitby TS to maintain reliable supply to meet the demand over the study period.

With the proceeding of a new residential and mixed use commercial area in the Sub-Region, called Seaton, significant increase in load demand is expected at 27.6kV level resulting in a shortage transformation capacity by 2019. The gross demand in the new development of Seaton is expected to be 88MW at the end of the study period (2025) and will continue to grow over long term period. The growth resulting from Seaton will have a significant impact on the 27.6kV transformation capacity in the Sub-Region.

Recommended Plan and Current Status

During the regional planning process, the Working Group considered multiple alternatives to address the transformation capacity in the Sub-Region. Preference was given to already existing facilities to ensure system's maximum capacity had been considered in line with the future demand. Other alternatives included CDM, local generation, and transmission & distribution facilities.

After considering estimated DG and CDM targets over the study period, the stations' capacities in the Sub-Region can be relieved to a certain extent. However, existing facilities alone will not be adequate to meet the future demand resulting from the new Seaton community load planned to be supplied at 27.6kV level.

As a result, an investment in wires infrastructure development in the Sub-Region is mandatory to connect and supply the development of Seaton via transmission/distribution facilities. Following the completion of the IRRP, the Working Group recommended Seaton MTS as the best solution to meet the transformation capacity need in the Sub-Region. Veridian Connections Inc. and Hydro One Networks Inc. have jointly submitted an EA application for the proposed station site and related 230kV transmission line work. Consistent with the regional planning studies, Veridian Connections Inc. is developing a plan for a new transformation station called Seaton MTS in northern Pickering. As confirmed by Veridian, the in-service timeline of this transformation station has been deferred to 2019 due to revised 2018 load forecast.

Class Environmental Assessment (EA) is in progress for the three potential construction sites for Seaton MTS illustrated in Figure 7-1.

Figure 7-1 Seaton MTS: Proposed Construction Sites

The project will have the following connection arrangement:

- From Duffin Jct, extend the circuit C10A east to proposed location under EA process
- Connect 2x75/125MVA, 230/27.6/27.6kV transformers to 230kV circuits; C10A and T28C[5]
- Supply 12x27.6kV feeders with a normally open tie-breaker configuration

The total cost of this project is estimated to be \$43M – \$48M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection

[5] T28C circuit nomenclature to replace C28C following Clarington TS (2018)

arrangements as defined above, feeder egress to the distribution risers outside of the station, and a spare transformer.

7.2 Increase Transformation capacity in Oshawa-Clarington Sub-Region

Description

The load forecast reflects an annual growth of 1.85% in Oshawa and Clarington area throughout the study period. Based on the 2015 historical demand and station's net demand forecast, Wilson TS T1/T2 and T3/T4 have already exceeded their respective normal supply capacities and will continue to do so over the study period. Overloading at Wilson TS T3/T4 has been significant enough that plans were put in place for emergency rotating load shedding, if and when required. Thornton TS may briefly exceed its transformation capacity in 2018 and 2019 but is adequate over the study period as well as long term period due to CDM contributions and distribution load transfer capability.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for Wilson TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

To accommodate the load growth of Hydro One Distribution's and OPUCN's feeders at Wilson TS, a new transformer station, Enfield TS, is recommended to relief the transformation capacity. The proposed transformer options to be evaluated for the DESN are as follows:

1. 2x75/125MVA, 230/44kV transformers with 6x44kV feeder breaker positions, with space for future 2x44kV feeder positions and capacitor banks (Preliminary Cost Estimate: $23 million)
2. 2x75/125MVA, 230/44kV transformers with 8x44kV feeder breaker positions (Preliminary Cost Estimate: $27 million)

The Working Group recommends option 1 to address the transformation capacity need in the Sub-Region. Six feeders will be adequate to supply demand over the study period. Also, option 2 is not considered the best economic solution since option 1 will reserve extra space for 2x44kV feeder positions and capacitor banks for future, when required.

The new DESN, 2x75/125MVA 230/44kV transformers with 6x44kV feeder breaker positions with 2x44kV spare feeder positions, is proposed to be located at the Oshawa Area Junction in the municipality of Clarington. This junction is on the ROW of the Bowmanville and Cherrywood transmission line corridor illustrated in Figure 7-2. The property is already owned by HONI and it is also the site of the new 500/230kV autotransformer Clarington TS supplied by circuits B540C and B543C. The proposed in-service date for the new DESN has a preliminary cost estimate of $34M including feeders egress to the distribution risers outside the station and will be aligned with Clarington TS which is scheduled for 2018.

Figure 7-2 Enfield TS: Proposed Construction Site

Advantages in proceeding with this particular location are as follows:

- The land proposed has already been purchased as part of the property where Clarington TS will be situated resulting in one less station footprint in the Sub-Region.
- Class EA approval has been already obtained for the construction of new TS on Hydro One land at the Clarington TS site.
- The site is also near new development areas which results in minimizing the length of supply feeders from the station.

7.3 GTA East Load Restoration Assessment

Description

GTA East load restoration need was identified in the NA and IRRP reports as the Working Group recommended that further assessment was required to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria and requires further assessment.

Recommended Plan and Current Status

In collaboration with the Working Group, a detailed report[6] was completed to make a recommendation for the load restoration need identified in the Region. The Working Group's assessments in the report, attached in the Appendix F, concluded the following:

- The historical performance of the circuits over the last 15 years has been excellent with little or no impact on supply reliability and security.

- Working Group is recommending that further investment in motorized disconnect switch (MDS) at this time is not a feasible solution to the load restoration need because the risk and/or probability of loss of load is small based on past performances. Therefore, no further action is required at this time.

7.4 Short Circuit Constraint at Cherrywood TS T7/T8

Description

Currently, new DG is restricted from connecting to Cherrywood TS T7/T8 due to short circuit capacity constraints. Veridian Connections Inc., supplied by this station, has indicated that they have several customers that have expressed interest in connecting DG (over 5MW) to Cherrywood TS T7/T8 but are prevented due to the existing restriction. There is an existing 30MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the short circuit capacity restriction. This generating unit has been shut down and/or has not generated electricity now for more than one year.

Recommended Plan and Current Status

The short circuit capacity is currently held by an earlier landfill generation connection. Although the facility has not been generating and partially dismantled, there is an uncertainty about availability of the short circuit capacity. Hydro One and the IESO will continue to assess this issue to have this capacity reservation released.

[6] GTA East: Load Restoration, Transmission Planning Report, circulated within the Working Group on August 31, 2016

7.5 Long Term Regional Plan

As discussed in Section 5, the electricity demand in GTA East Region is forecasted to grow at 2% annually over the next 10 years. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1.3% annually from year 2026 to 2036. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the Pickering-Ajax-Whitby Sub-Region were identified in the IRRP. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades. As indicated in the IRRP, official plans by the municipalities expect the lakeshore area in the southern part of Pickering-Ajax-Whitby Sub-Region to grow due to development of high rise residential and commercial buildings. With Pickering NGS expected to retire by 2024, the 230kV transmission lines can be utilized along with a new step-down transformer station to address capacity needs in the southern part of the Sub-Region.

The current forecast did not consider future Pickering Airport which may have an impact on transformation capacity in the long term. Such potential needs will be monitored and system supply capability will be reviewed in the next planning cycle based on the official plans released by the municipalities.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will mainly provide relief to Wilson TS by supplying the excess load through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
II	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
III	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
IV	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome
V	Additional transformation capacity for Oshawa-Clarington Sub-Region	Long term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

Table 8-2: Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Seaton MTS and associated line work	Veridian and Hydro One	2019	$43M-$48M	I
2	Enfield TS	OPUCN and Hydro One	2019	$34M	II

GTA East load restoration need, Need ID III, has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended (see Appendix F). Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

Hydro One is working with the IESO to explore the best course of action to relieve the short circuit constraint at Cherrywood TS, Need ID IV.

Additional transformation capacity for Oshawa-Clarington Sub-Region, Need ID V, will be reviewed as part of the next Regional Planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan". June 30, 2016.
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http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Local%20Planning%20Report%20-%20WilsonThornton%20-%2015_May_2015%20-%20Final.pdf

[3]. Hydro One, "Needs Screening Report, GTA East Region. August 11, 2014.
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[4]. "Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario". May 17, 2013.
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[5]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
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APPENDICES

Appendix A: Stations in the GTA East Region

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, Bus DK
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	H24C/H26C
Whitby TS T3/T4	230/44kV	B23C/M29C
Wilson TS T1/T2	230/44kV	B23C/M29C
Wilson TS T3/T4	230/44kV	B23C/M29C
Thornton TS T3/T4	230/44kV	H24C/H26C

Appendix B: Transmission Lines in the GTA East Region

Location	Circuit Designation	Voltage Level
Cherrywood TS to Whitby TS T3/T4, Wilson TS, and Clarington TS	B23C/M29C	230kV
Cherrywood TS to Whitby TS T1/T2, Thornton TS, and Clarington TS	H24C/H26C	230kV
Cherrywood TS to Clarington TS	C28C	230kV

Appendix C: Non-Coincident Load Forecast 2016-2025

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	Veridian	*T7/T8*	*BY (44kV)*	*175*	Gross Peak Load				180	180	180	180	180	180	180	180	176	176
					CDM				2	3	5	7	8	10	11	12	13	15
					Net Load Forecast	163	143	156	178	177	175	173	172	170	169	168	163	161
Whitby TS	Veridian	*T1/T2*	*BY (27.6kV)*	*90*	Gross Peak Load				61	76	80	90	90	90	90	90	90	90
	Whitby Hydro		*EZ (44kV)*	*90*	Gross Peak Load				54	55	56	57	57	58	59	60	61	62
					DG				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					CDM				2	3	4	6	7	8	9	10	12	13
					Net Load Forecast	77	88	97	113	128	132	141	141	140	140	140	139	139
Whitby TS	Veridian	*T3/T4*	*JQ (44kV)*	*187*	Gross Peak Load				70	70	74	74	74	74	74	74	74	74
	Whitby Hydro				Gross Peak Load				108	110	111	113	115	116	118	120	122	124
					DG				18	18	18	18	18	18	18	18	18	18
					CDM				2	3	5	6	8	9	11	13	15	17
					Net Load Forecast	175	161	162	159	160	163	164	163	164	164	164	163	163
Seaton MTS	Veridian	*T1/T2*	*(27.6kV)*	*153*	Gross Peak Load							5	16	27	40	60	75	88
					CDM								1	1	2	3	4	6
					Net Load Forecast	0	0	0	0	0	0	5	15	26	38	57	71	82
Wilson TS	OPUC	*T1/T2*	*BY (44kV)*	*161*	Gross Peak Load				156	161	167	148	145	142	140	140	140	140
	Hydro One				Gross Peak Load				30	31	35	35	41	41	41	41	41	41
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	157	174	167	184	189	197	176	177	173	170	170	169	168
Wilson TS	OPUC	*T3/T4*	*JQ (44kV)*	*134*	Gross Peak Load				25	26	27	25	25	25	25	25	25	25
	Hydro One				Gross Peak Load				150	151	152	152	153	154	155	156	157	158
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	166	133	146	173	174	174	171	170	170	170	170	170	170

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thornton TS	Whitby Hydro	*T3/T4*	*BY (44kV)*	*160*	Gross Peak Load				52	58	63	79	80.0	81	82	82	83	84
	OPUC				Gross Peak Load				100	101	103	95	88	86	84	80	80	80
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast	157	103	126	151	156	162	168	160	158	156	152	152	152
Enfield TS	OPUC	T1/T2	*(44kV)*	*153*	Gross Peak Load				0.0	0.0	0.0	38	57	71	84	98	108	118
	Hydro One				Gross Peak Load				0.0	0.0	0.0	26	33	34	35	36	37	38
					CDM							3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast				0	0	0	62	86	100	113	126	135	145
CTS A					Gross Peak Load				20.0	20.0	20.2	20.6	21.0	21.2	21.4	21.6	21.7	21.9
					Net Load Forecast			19.5	19.8	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.2	20.3
CTS B					Gross Peak Load				97.0	97.5	98.0	99.8	101.6	102.2	103.0	103.4	103.9	104.4
					Net Load Forecast			96.3	96.0	96.1	96.2	96.3	96.3	96.4	96.5	96.6	96.6	96.7
CTS C					Gross Peak Load				47.5	52.8	53.3	54.5	55.7	56.3	57.0	57.5	58.0	58.5
					Net Load Forecast			52	47.0	52.0	52.3	52.6	52.8	53.1	53.4	53.7	53.9	54.2
CGS D					Gross Peak Load				0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
					Net Load Forecast			0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Appendix D: Coincident Load Forecast 2016-2025

Stations	DESN ID	Historical (MW)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	T7/T8	156	173	172	170	168	167	165	164	163	158	156
Whitby TS (27.6kV)*	T1/T2	33	59	74	78	87	87	87	87	87	87	87
Whitby TS (44kV)*	T1/T2	39	52	53	54	55	56	56	57	58	59	60
Whitby TS	T3/T4	145	154	155	158	159	158	159	159	159	158	158
Seaton MTS	T1/T2	0	0	0	0	5	15	25	37	55	69	80
Wilson TS	T1/T2	128	179	184	192	172	173	169	166	166	165	164
Wilson TS	T3/T4	144	168	169	169	166	165	165	165	165	165	165
Thornton TS	T3/T4	125	146	151	157	163	155	153	151	147	147	147
Enfield TS	T1/T2	0	0	0	0	60	83	97	110	122	131	141
CTS A		19.5	19	19	19	19	19	19	19	20	20	20
CTS B		96.3	93	93	93	93	93	93	94	94	94	94
CTS C		52	46	50	51	51	51	51	52	52	52	53
CGS D		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

*DG/CDM contribution excluded from 2016-2036 coincident forecast

GTA East Coincident Load	**938.5**	**1091**	**1122**	**1141**	**1199**	**1223**	**1242**	**1262**	**1289**	**1306**	**1324**
Region’s Annual Growth Rate		2%									

Appendix E: List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
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
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
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F: GTA East Load Restoration Report

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

TRANSMISSION PLANNING REPORT

GTA East: Load Restoration

Revision: Final
Date: August 31, 2016

Prepared by: Hydro One Networks Inc.

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Executive Summary

REGION	GTA East (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	August 31, 2016

1. INTRODUCTION

The purpose of this Transmission Planning (TP) report is to undertake a comprehensive assessment of the load restoration need identified in the Needs Assessment (NA) and Integrated Regional Resource Plan (IRRP) and develop a preferred recommendation. The recommendations of this TP report will become part of the Regional Infrastructure Plan (RIP) and is intended to facilitate the regional planning process as set out by Ontario Energy Board's (OEB) in the Transmission System Code (TSC) and the Planning Process Working Group (PPWG) report to the Board.

Based on Section 6 of the NA and IRRP report, the study team recommended that further assessment was required to address the load restoration need during peak load in the GTA East region. The NA and IRRP report indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration may exceed load restoration criteria and requires further assessment. The IESO led IRRP recommended this need be further assessed in the RIP, to be completed in Q4 2016. This report provides a detailed assessment along with options and the WG recommendation to be included in the RIP report.

2. REGIONAL NEED ADDRESSED IN THIS REPORT

The circuits M29C/B23C and H24C/H26C are on the same tower line in the GTA East Region 230kV corridor. The loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively.

3. OPTIONS CONSIDERED

Hydro One Transmission along with the WG members have considered the following options to addressing the load restoration need:

Option 1 – a) Status quo/Current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

See Sections 4 & 5 for detailed assessment.

4. PREFERRED SOLUTION

At this time, B23C, M29C, H24C, and H26C are approximately 120km-300km long and the historical performance since 2000 has been excellent with no relevant outages. With the new Clarington TS in 2018, the line exposure in the region will reduce to only 46km including tap sections. The assessment concluded that

a) The annual carrying cost of the switches is not justified compared to the annual outage cost, and
b) The installation of Motorized Disconnect Switches will not result in significant enhancement to the reliability of the system after the Clarington TS is in service in 2018.

Option 1 is the preferred solution recommended by the WG at this time. Further details of the assessment and justification are provided in Sections 4 & 5.

5. NEXT STEPS

There are no further actions required at this time.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Region 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 Region.

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Region. Whitby TS DESN2, Thornton TS, and other CTS in the Region are supplied by H24C/H26C while Whitby TS DESN1 and Wilson TS are supplied by B23C/M29C.

A new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is expected to be in service by 2018. The assessments in this report evaluate the reliability impact of Clarington TS in the region as well as the installation of Motorized Disconnect Switches (MDS). The new Clarington TS will provide additional load meeting capability in the Region and will eliminate any overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 1[1].

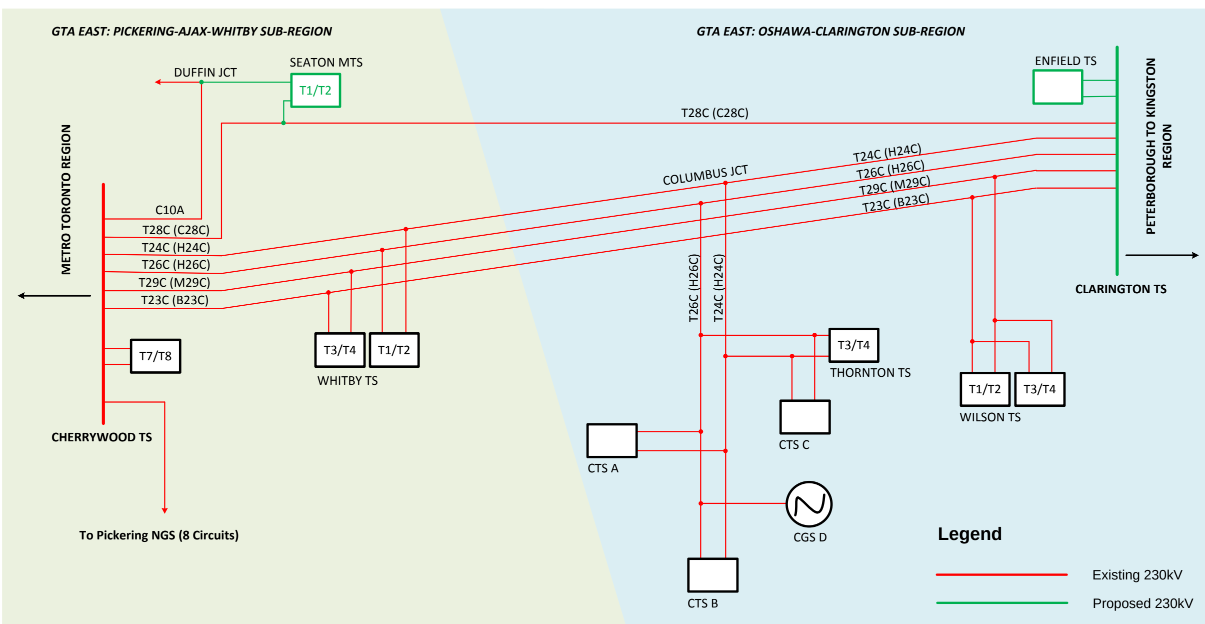

Figure 1 **GTA East Region - Single Line Diagram**

[1] Circuits' nomenclature is shown following the commissioning of Clarington TS (2018) with current convention in parentheses

2 Identified Need

2.1 Load Restoration Criteria

In case of contingencies on the transmission system, the Ontario Resource Transmission Assessment Criteria (ORTAC) provides the load restoration times relative to the amount of load affected. Planned system configuration must not exceed 600MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within approximately 8 hours.
b. Load interrupted in excess of 150MW must be restored within approximately 4 hours.
c. Load interrupted in excess of 250MW must be restored within approximately 30 minutes.

In addition, ORTAC also provides a provision for exemption from the above restoration criteria on a case-by-case basis.

Figure 2 illustrates the load restoration timelines as discussed above.

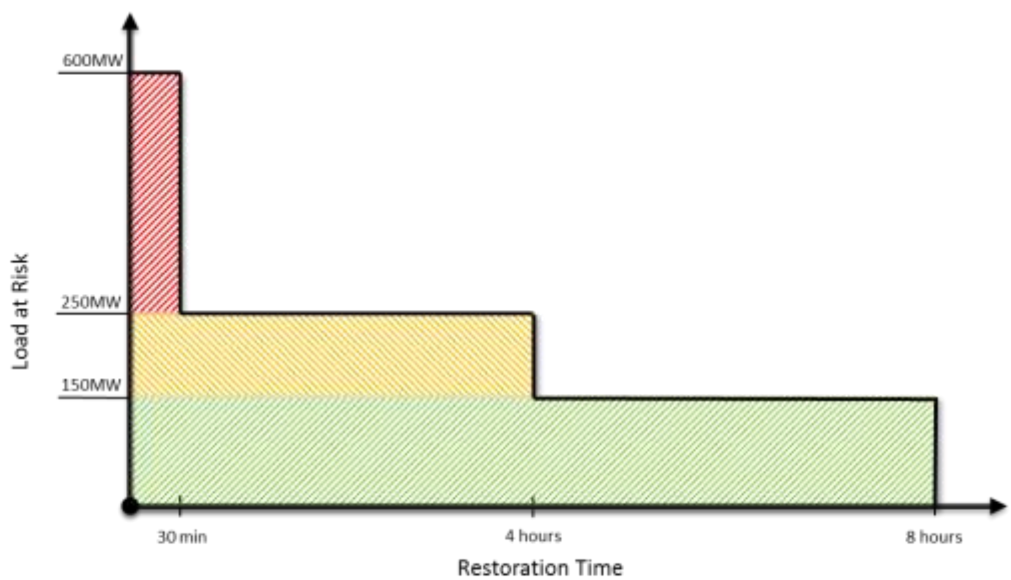

Figure 2 **Load Restoration Criteria**

2.2 Shortfall Need

In 2015, H24C/H26C and M29C/B23C supplied a coincident peak demand of approximately 366MW and 417MW, respectively.

It is expected and assumed that all loads can be restored within 8 hours. However, consistent with the NA and IRRP reports, during peak load periods all loads cannot be restored in the region subsequent of a double circuit contingency between Cherrywood TS and Clarington TS within 30 minutes to 4 hours.

Further findings from the Local Distribution Companies (LDC) in the Region and as reported in the IRRP[2], up to 57MW and 142MW can be restored for customers supplied by H24C/H26C through distribution transfers within 30 minutes and 4 hours, respectively. This leaves the maximum shortfall of 59MW after 30 minutes, and 74MW after 4 hours to be restored from these circuits.

Similarly, for the M29C/B23C, up to 105MW can be restored through distribution transfers within 30 minutes and 257MW within 4 hours for customers supplied by these circuits under the current supply arrangement. This leaves the maximum shortfall of 62MW after 30 minutes, and 10MW after 4 hours to be restored from these circuits.

Table 1 summarizes the 2015 peak demands for each pair of circuit and differentiates between restorable load and the shortage load for 30-minutes and 4-hour periods as discussed above.

Table 1 **Load Restoration/Shortfall in 2015**

2015 Coincident Peak					
Load Pocket	**Actual Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	366	57	59	142	74
M29C/B23C: Whitby TS DESN2, Wilson TS	417	105	62	257	10

By the end of 2025, the load that cannot be restored increases due to load growth in the region illustrated in Table 2.

Table 2 **Load Restoration/Shortfall in 2025**[3]

2025 Coincident Peak (Net Forecast)					
Load Pocket	**Forecast Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	445	57	138	142	153
M29C/B23C: Whitby TS DESN2, Wilson TS	425	105	70	257	18

[2] Published in June, 2016
[3] Load forecast is subject to change

2.3 Options considered

An option to build a new 26km of line would have resulted in a cost of more than $75M, obtaining new right-of-way and was not further considered. Following options were further assessed:

Option 1a is status quo and option 1b includes Clarington TS to be in-service by 2018. Accordingly, following two options are further evaluated against each other:

Option 1 – a) Status quo/current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

A conceptual configuration of the switches (marked by the red X) is shown for Option 2 in Figure 3.

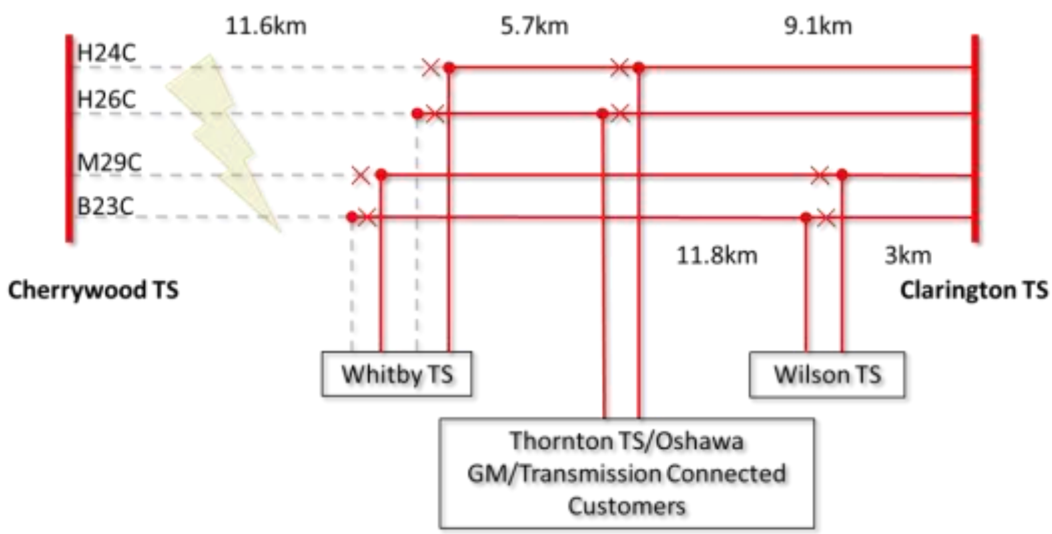

Figure 3 **MDS: Conceptual Configuration**

Similar cases can be shown to isolate faults on other sections of the corridor to restore the loads. It must be noted that although the corridor is protected using 8 MDSs as shown above, the tap offs will still remain unprotected. Further, a common mode fault (refer to section 4) at the tap off line sections will cause an outage regardless of installed switches. With the use of 8 MDS, the optimal locations of the switches are the junction points and 2 switches per circuit as shown in Figure 3.

3 Evaluation Method & Assumptions

The options identified in the previous section were evaluated from the reliability and cost points of view. The reliability indices for overlap outages were evaluated with the help of the AREP Program (Area Reliability Evaluation Program). The reliability for each option is expressed in terms of the frequency and duration of supply interruptions to customers.

Two cost components, one representing the capital cost and one representing the outage cost were evaluated for each option. The two annual costs are given as follows:

Annual cost of carrying charge = C*R,

Where: C – Capital cost of the switches
R – Annual discount rate

The annual outage cost (or risk cost) = F*P*I,

Where: F – Annual duration of load interruption in hours
P – Average kW interrupted including load factor
I – Customer interruption cost ($/KWh)

The following assumptions were made in the assessments:

1. All MDSs are assumed to be perfect (100% reliable).
2. Outages on line tap sections are excluded in common mode outages assessment in section 4.
3. All customer loads are restored within 8 hours for Option 1 and within 30 minutes for Option 2.
4. In case of overlap outages, switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour.
5. Faults do not occur on lines section where MDSs are located.

The assessment data used in the benefit/cost analysis for all options is provided in Table 3.

Table 3 **Data Used in Reliability Studies**

Assessment Data	
No. of circuit pairs on same towers	27
Total circuit length	551.347km
Circuit years in service	26 years
Distance between Cherrywood TS and Clarington TS	26km
2015 Peak load supplied from B23C and M29C, P	417MW
2015 Peak load supplied from H24C and H26C, P	366MW
Load factor for all load stations	0.6
Customer interruption cost, I	\$10–\$30/kWh[4]
Load restoration time without switches	8 hours
Load restoration time with switches	30 minutes
Cost of one switch (x4 per pair, C)	\$3 Million (\$12 Million)
Annual discount rate, R	5%

[4] Known as Value of Lost Load (VOLL), range is consistent with a Canadian Regulatory Application conducted in 2006 after considering customer composition and provincial GDP – IRRP (2016)

4 Impact of Common Mode Outages

A common mode outage is defined as an event involving two or more outages with the same initiating cause and where the outages are not consequences of each other and occur nearly simultaneously.

4.1 Line Outage Data

The historical common mode outage data for all 230 kV circuits on same structures and east of Cherrywood TS from 1990 to 2015 was used to compute the frequency and duration of common mode line outages. A summary of the common mode line outage events, along with the duration, over the period of 25 years is given in Table 4.

Table 4 **Common Mode Outage Events (from 1990 to 2015)**

Event #	Circuits Involved	Year	Outage Duration	Outage Cause
1	X3H and X4H	1992	927.6h	High winds toppled 16 towers
2	D5A and B5D	1998	0.15h or 9m	Electrical storm
3	B23C and M29C	2008	2.02h	Human error, relay settings
4	L21H and L22H	2011	0.08h or 5m	Relay problems

Only 4 common mode outages have been recorded in eastern Ontario in the last 25 years, of which, only one event is of relevance for this assessment. Hence, Event # 1, in Table 4 is the only one used in calculating the frequency of common mode line outages. This event occurred in November 1992 where adverse weather toppled multiple towers. The other outage events are not relevant to common mode outages because either the outage duration is less than 30 minutes (time assumed for switches to restore power supply to customers) or the outage was preventable or both.

NOTE: Event #1 has never occurred on the GTA East 230kV corridor which is the scope of this assessment but used as a proxy for assessment.

4.2 Reliability Results

The annual frequency of line common mode outages for 230 kV circuits east of Cherrywood TS was calculated by dividing the number of common mode line outages in 25 years by the product of the number of circuit in service years and the total circuit km over the 25 years period. The annual frequency was found to be **0.00007 outages/km** for all of eastern Ontario's 230kV transmission circuits. A low reliability index indicates the circuits in eastern Ontario have performed exceptionally well.

The commissioning of Clarington TS, Option 1b, does not affect the reliability indices for the common mode line outages because of the location of the station at the Oshawa Area Junction. All four 230 kV circuits currently emanate east on single towers from Cherrywood TS to the Oshawa Area junction point. From there on, B23C disperses south towards Belleville TS while the remaining three circuits emanate east on individual towers towards eastern Ontario. Therefore, a common mode line outage on these circuits cannot occur east of Oshawa Area

Junction, future site for Clarington TS.

It is also emphasized that the MDS would have no impact on the frequency of supply interruptions to customers. However, depending upon the location of a permanent fault, the switches can reduce the duration of interruption to customers by isolating the faulted section of the line and restoring the load from the alternative path.

The frequency and duration indices for all options are given in Table 5. The 8 hour restoration time for Option 1a and 1b, without switches, is in accordance with the standard outlined in ORTAC.

Table 5 **Reliability Indices, Common Mode Line Outages**

Options	Annual Frequency of Loss of Supply to any Customer	Duration of loss of Supply in Hours per Occurrence	Annual Duration of Supply Interruptions, F
Option 1a or 1b	0.00182	8	0.01456h or 52.4s
Option 2	0.00182	0.5	0.00091h or 3.3s

4.3 Cost Results

The capital cost and outage cost components were evaluated for all options using the formulae stated earlier. Table 6 shows the results for Circuits B23C and M29C while Table 7 shows the results for Circuits H24C and H26C.

Table 6 **Cost Results, Common Mode Line Outages (B23C/M29C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$36.43-$109.29	$36.43-$109.29
Option 2	$600.00	$2.28-$6.84	$602.28-$606.84

Table 7 **Cost Results, Common Mode Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$31.97-$95.92	$31.97-$95.92
Option 2	$600.00	$2.00-$6.00	$602.00-$606.00

The reliability and cost benefit assessment for the common mode line outages is based on the past 25 years of historical performance of 230kV circuits in eastern Ontario. Based on these findings, the annual reliability index for the GTA East region is only 0.00182 outages. As stated earlier, the installation of switches will not have an impact on the frequency index of events. Rather, as seen in Table 5, the duration of an event is the only dependent variable where the annual duration of an outage is reduced from 52.4s to 3.3s with the installation of switches.

The cost analysis in each option is dependent on the reliability index and is calculated using the assessment data provided in Table 3. Using the cost calculation formulas in Section 3, annual carrying cost of the switches and annual outage costs are calculated for B23C/M29C and

H24C/H26C. The annual carrying cost of the 4 switches per circuit pair is based on the minimum operating period of 20 years while the annual outage costs are based on the duration of outages, calculated from the reliability index, with and without the installation of switches.

The annual cost for just common mode line outages for each pair in the region is approximately $32k-$109k while the annual carrying cost of switches, including cost of outages, for each pair is nearly 5-19 times more, $602k-$607k. Also, the annual outage cost due to a common mode line outage is calculated on a very small probability of an event occurring. The annual frequency of loss of supply to any customer in the region is only 0.00182 outages, 1 in over 549 years, with or without switches as MDS have no impact on the frequency of supply interruptions.

As shown, the annual reliability and cost benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The installation of switches improves the outage duration, if occurred, from 52.4s to 3.3s for a certain annual investment of over $1.2M for both pairs of circuits. The annual benefits will still be lower than the carrying costs even if higher values are used for the frequency of common mode line outages. In addition, MDS are assumed to be 100% reliable in this assessment while they introduce a weak link on the system. The reliability and cost analysis show that the installation of MDS is not justifiable.

5 Impact of Overlap Outages

An overlap outage is referred to an event where two or more components are out of service at the same time. The outage initiating causes are different and outages can start at different time. The overlap outage may occur as one of two types; Forced-Forced or Planned-Forced.

5.1 Line Outage Data

The historical outage data from 1990 to 2014 was used to compute the frequency and duration of H24C/H26C line sections and line terminal indices due to forced and planned outages. A reliability model was developed using Area Reliability Evaluation Program (AREP) for both options. The reliability indices were then used to calculate the annual frequency and annual duration of loss of supply to customers. It is expected that circuits B23C/M29C will have similar reliability indices, if not better, due to comparable characteristics and load as circuits H24C/H26C.

5.2 Reliability Results

Currently, the four circuits collectively supply eastern Ontario for 120–300km. In spite of this long distance, the reliability and security of the transmission lines in this part of the province has been exceptional based on the historical performances. Given that these 230kV circuits will now be terminating at Clarington TS, the exposure will reduce to 26km, the region's security and reliability is expected to improve substantially. Table 8 illustrates the reliability indices for the loss of supply to customers considering both types of overlap events: Forced-Forced and Planned-Forced.

Table 8 **Reliability Indices, Overlap Line Outages**

Options	Annual Frequency of Loss of Supply	Annual Duration of Supply Interruptions
Option 1a	0.01	0.12h or 7.02m
Option 1b	0.0008	0.007h or 26.60s
Option 2, Whitby TS DESN 1	0.0001	0.0003h or 1.26s
Option 2, Thornton TS/CTSs	0.0004	0.002h or 8.47s

For each reliability index above, two sets of reliability indices were considered: one due to the overlap of forced outages (Forced-Forced) only and one with the overlap of planned and forced outages (Planned-Forced). In the course of the overlap outages' assessment, it was observed that the Planned-Forced type outages had the dominant impact on the final reliability indices when compared to Forced-Forced type outages.

Further, two types of outages in each set, namely the permanent outages and the switching outages, were computed. In the permanent outage, the supply to customers is restored after repairing the failed components while in the switching outage; the supply to customers is restored by switching off the failed components and restoring the healthy ones to service. The switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour except in the case of Option 2 where MDSs are expected to operate within 30 minutes.

It is observed in Table 8 that with the commissioning of Clarington TS in 2018, the reliability improves by over 92% while an additional investment in MDSs of over $24 million yields another increment of only 7% to the system reliability. With Clarington TS in service, Option 1b, the reliability indices improve significantly when compared to the reliability of the existing supply system. Also, the annual duration of supply interruption is reduced to just 26.6 seconds from 7 minutes with Clarington TS in the region.

5.3 Cost Results

The capital (carrying) cost and outage cost components were evaluated for the both options using the formulae stated earlier and the results are shown in Table 9. These costs are mainly dependent on the annual duration of supply interruption in Table 8. Since the annual duration of supply interruption in the region is expected to be reduced to merely 26.6s with Clarington TS soon to be in service, the annual expected outage cost has dropped by almost 94%.

Table 9 illustrates that the annual benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The performance of H24C/H26C is expected to be exceptionally good following the commissioning of Clarington TS with an expected annual cost of $15.37k-$46.12k, a very well improvement from the current system and at least 13 times more economical than the annual cost with the switches. With the inclusion of Clarington TS by 2018, the system is projected to be most cost-effective and reliable.

Table 9 **Cost Results, Overlap Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a	$0.00	$263.52-$790.56	$263.52-$790.56
Option 1b	$0.00	$15.37-$46.12	$15.37-$46.12
Option 2	$600.00	$3.66-$10.97	$603.66-$610.97

6 Conclusion

6.1 Common Mode Outages

The following concluding remarks can be made regarding the impact of the common mode outages:

i) All options have the same frequency of supply interruptions to customers.
ii) Only one common mode outage, relative to this assessment, has occurred in the eastern Ontario in the past 25 years. This event occurred in 1992 due to high winds toppling multiple towers.
iii) The reliability and cost analysis show that it is not justifiable to invest $24M for marginal improvement.

6.2 Overlap Outages

The following concluding remarks can be made regarding the impact of overlap outages:

i) A significant improvement in reliability is observed after the commissioning of Clarington TS in 2018, Option 1b. However, the installation of MDS, Option 2, does not result in a substantial improvement in the reliability indices for an additional cost of approximately $24M.
ii) The result of reliability/cost analysis for circuits B23C/M29C is expected to be similar to H24C/H26C due to similar regional characteristics and loading conditions, therefore, same conclusion can be drawn for both pairs.

6.3 Summary

Based on historical data and a technical analysis on how outages impact the loads supplied by the GTA East 230kV corridor currently, post-Clarington TS, and with MDS, Table 10 illustrates that Clarington TS alone improves the reliability in the region by 77.8% while with additional investment of $24M in MDS, further reliability improvement is insignificant (less than 4%).

Table 10 **Summary of Results**

Options	Total Annual Cost ($k)	Annual Frequency of Interruption	% Reliability Improvement
Option 1a, Current System	$632.16-$1,896.49	0.02364	-
Option 1b, post Clarington TS	$101.28-$303.87	0.00524	77.8%
Option 2, MDS post Clarington TS	$1,211.47-$1,234.37	0.00444	81.2%

In conclusion, the performance of all 4 circuits has been very good over the last 20 years. With Clarington TS in service in 2018 the risk exposure on these circuits will be significantly less; therefore, it is not justifiable to further invest $24M.

Finally, these costs will have to be recovered from the customers or rate payers consistent with the TSC. Furthermore, MDS were considered to be ideal and 100% reliable in the course of this assessment but in reality introduce a weak link in the system.

WG is recommending that based on this assessment, Option 1b is considered to be the most economical and reliable state of the system. No further action is required at this time.

7 Next Steps

Hydro One will continue with the Clarington TS and keep the LDCs informed of any delays with the project. The finding of this study will be included in the GTA East RIP report expected to be completed in Q4 2016.

8 References

[1] Line Switches Reliability Study by Gomaa HAMOUD, Hydro One – May, 2016
[2] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May, 2013
[3] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
[4] GTA East Needs Assessment Report – April, 2013
[5] GTA East Integrated Regional Resource Plan (IRRP) Report – June, 2016

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NEEDS ASSESSMENT REPORT

GTA East Region

Date: August 15, 2019

Prepared by: GTA East Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA East Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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Executive Summary

REGION GTA East Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: JUNE 23, 2019 **END DATE:** August 15, 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting from Needs Assessment ("NA"). The purpose of this NA is to identify any new needs and/or to reaffirm needs identified in the previous GTA East Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for GTA East Region.

3. SCOPE OF NEEDS ASSESSMENT

The assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA East Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment methodology include review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their useful life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Previously identified need as part of the regional planning

The NA reaffirms previously identified needs –

a. Additional transformation capacity in Pickering-Ajax-Whitby sub-region:
Seaton MTS is being built by Elexicon with an in-service date of Q1 2020. No further action is required.
b. Additional transformation capacity in Oshawa-Clarington sub-region:
Enfield TS went in-service in March 2019. No further action is required.

II. Newly identified needs in the region

a. Line / Station Capacity

No new supply capacity needs have been identified by Study Team.

b. System Reliability & Operation

No new System Reliability and Operation needs have been identified by Study Team.

c. Aging Infrastructure Transformer replacements

i. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase) (2027)
ii. Cherrywood TS – MV Switchyard Refurbishment (2025)
iii. Wilson TS – T1/T2 & Switchyard Refurbishment (2025)

7. RECOMMENDATIONS

The Study Team's recommends that following end of life high voltage equipment should be replaced with similar equipment and it does not require further regional coordination (see further details in Section 7.1).

a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
b. Cherrywood TS – MV switchyard Refurbishment
c. Wilson TS – T1/T2 & Switchyard Refurbishment

The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous GTA East regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA East Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team 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: GTA East Region Study Team Participants

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the GTA East region, the 2nd 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 the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

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 boundaries of the GTA East Region are shown below in Figure 1.

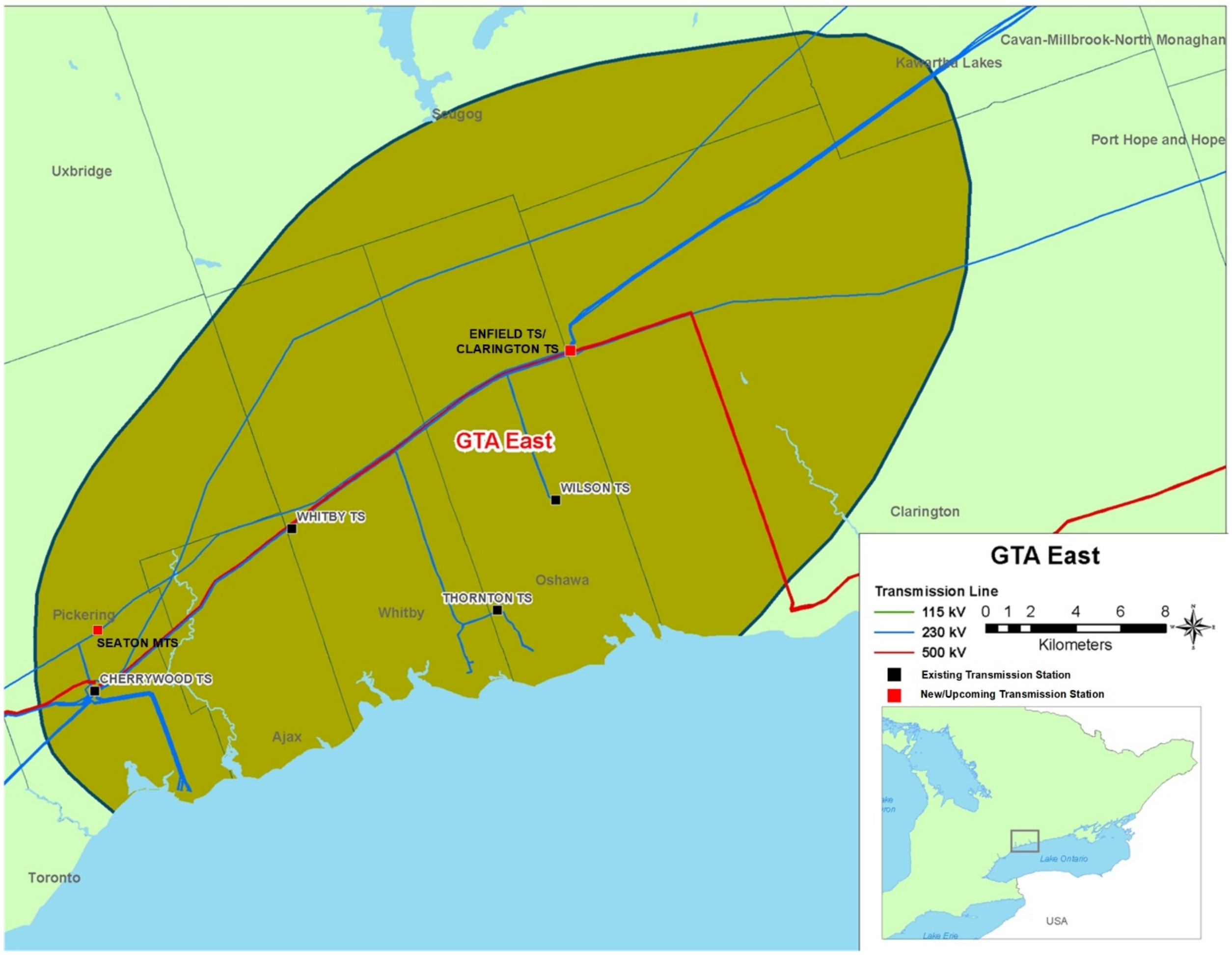

Figure 1: Geographical Area of GTA East Region with Electrical Layout

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and five 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are four Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Screening:

- Cherrywood TS is the major transmission station that connects the 500kV network to the 230kV system via four 500/230kV autotransformers.
- Five step-down transformer stations supply the GTA East load: Cherrywood TS, Whitby TS, Wilson TS, Thornton TS and Enfield TS.
- Three customer transformer stations (CTS) are supplied in the region.
- Five 230kV circuits (T23C, T29C, T24C, T26C, T28C) emanating east from Cherrywood TS provide local supply to the GTA East Region. They extend from Cherrywood in the City of Pickering to Clarington TS.
- The Pickering Nuclear Generating Station (NGS) consists of 6 generating units with a combined output of approximately 3000 MW. It is connected to the 230kV system at Cherrywood.
- CGS D is a 60 MW gas-fired cogeneration facility that connects to circuit T26C.

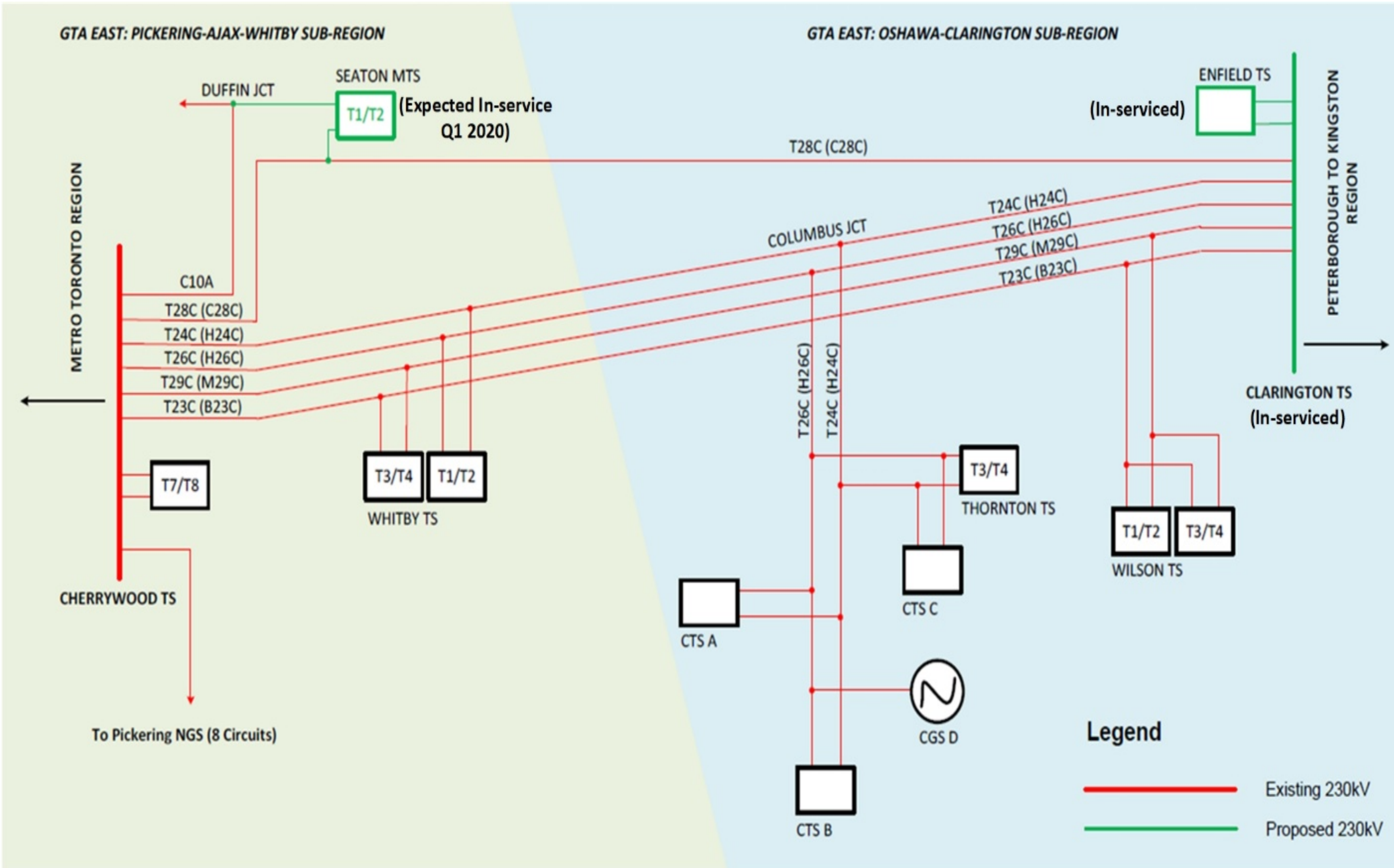

Figure 2: Single Line Diagram of GTA East Region

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA East Region NA. The information provided includes the following:

- GTA East Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the GTA East Region.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the GTA East region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the GTA East region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the GTA East region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

In addition, Hydro One has reviewed the Community Energy Plans in the region. There are currently no active Community Energy Plans in the region which can have any direct impact on the needs identified by the Study Team.

7 NEEDS

This section describes emerging needs identified in the GTA East Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle. The recent load forecast prepared for this report is higher than that of the previous cycle of regional planning. This is attributed to the load growth at Enfield TS and Seaton MTS. A contingency analysis was performed for the region and no new system needs were identified.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	Whitby T1/T2 27.6 kV was expected to be loaded to capacity by 2020 and additional transformation capacity was required for the expected load growth in the area.	Seaton MTS is in construction with an expected in-service date of Q1 2020
Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Wilson TS T1/T2 & T3/T4 was loaded pass its LTR rating and that immediate action was needed to address the overloading issue and expected load growth in the area	Enfield TS is currently in-service.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, following major high voltage equipment has been identified as approaching its end of useful life over the next 10 years and assessed for right sizing opportunity.

a. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project)

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. The age, condition and lack of parts present significant difficulties in maintaining these breakers and the associated high pressure air system.

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2022. The Study Team recommended continuation of these end of life asset replacement as per the plan.

b. Cherrywood TS – LV DESN Switchyard Refurbishment

The MV DESN switchyard, with the exception of step-down transformers T7 and T8, at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

c. Wilson TS – T1, T2 and Switchyard Refurbishment

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through Oshawa Power feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2025.

The Study Team has assessed downsizing and/or upsizing a need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the best “right sizing”. The Study Team recommends continuation of these end of life asset replacement as per the plan.

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

7.2 Station and Transmission Capacity Needs in the GTA East Region

The following Station and Transmission supply capacities needs have been identified in the GTA East region during the study period of 2019 to 2028.

7.2.1 New Seaton MTS

The Pickering-Ajax-Whitby sub-region is being supplied by two step-down transformer stations, Cherrywood TS at 44 kV and Whitby TS at 27.6 kV and 44 kV. A new residential and mixed use commercial developing area, called Seaton, will result into significant 27.6 kV demand in the sub-region. The previous Regional Planning cycle as well as current submitted load forecast identified need for additional 27.6 kV capacity in the area.

Figure 3: Location of Seaton MTS

As recommended in the previous regional planning cycle, Elexicon has initiated installation of a new step down transformer station, called Seaton MTS. The station will be built and owned by Elexicon. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. No further action is required.

7.2.2 Enfield TS

Wilson TS is located within the city of Oshawa and has four 230kV / 44kV (T1/T2 & T3/T4) step down transformers that supplies OPUC and Hydro One Dx customers. Wilson TS normal supply capacities were exceeded due to significant growth over the time. The previous Regional Planning cycle recommended a new TS, now named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located adjacent to Clarington TS and will supply OPUC through four (4) feeders and Hydro One Dx through two (2) feeders. The station went in-service March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS. No further action is required.

Figure 4: Location of Clarington TS and Enfield TS

7.3 Other Planning Considerations in the GTA East Region

As all the needs in the previous planning cycle are already addressed OR being addressed, and no new needs have arisen in the latest load forecast, no other consideration is needed.

8 CONCLUSION AND RECOMMENDATIONS

In conclusion, the capacity needs identified in the previous planning cycle are being addressed with projects under execution. All the new loads are expected to be accommodated by Enfield TS and Seaton MTS. It is recommended that Hydro One and the LDCs continue to monitor the loading of the existing facilities and new facilities over the next five (5) years to ensure adequate capacity is available for the new load in the region.

The Study Team recommendations are as follows:

A. Replacement of end of life component with similar equipment does not require further regional coordination. The Study Team considered these end of life asset replacement for right sizing opportunity and recommended continuation of replacing these assets with similar equipment. The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs:

   a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
   b. Cherrywood TS – MV DESN Switchyard Refurbishment
   c. Wilson TS – T1/T2 Replacement / Refurbishment

9 REFERENCES

[1] Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[2] IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[3] Needs Assessment Report GTA East – August 2014

[4] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[5] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: GTA East Region Non-Coincident Summer Load Forecast

Transformer Station		Summer 10 Day LTR (MW)	Type	Actual	Forecasted										
Name	DESN ID			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cherrywood TS	T7/T8	175	Gross	N/A	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
			DG	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	N/A	1.8	3.0	3.2	3.6	4.2	4.6	5.1	5.4	6.0	6.3	6.6
			Net	161.1	164.2	163.0	162.8	162.4	161.8	161.4	160.9	160.6	160.0	159.7	159.4
Seaton MTS	T1/T2	153	Gross	0.0	0.0	1.0	4.0	20.0	28.0	36.0	43.0	50.0	57.0	65.0	74.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.0	0.1	0.4	0.7	1.0	1.3	1.6	2.0	2.5	3.0
			Net	0.0	0.0	1.0	3.9	19.6	27.3	35.0	41.7	48.4	55.0	62.5	71.2
Thornton TS	T3/T4	160	Gross	N/A	138.5	131.3	133.5	135.8	136.8	137.8	138.8	139.8	140.9	141.9	143.0
			DG	N/A	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
			CDM	N/A	1.5	2.4	2.6	3.0	3.5	3.8	4.3	4.6	5.1	5.4	5.7
			Net	138.3	136.4	128.3	130.4	132.2	132.7	133.4	133.9	134.6	135.2	135.9	137.2
Whitby TS	T3/T4	187	Gross	142.4	143.3	151.0	155.8	161.7	166.7	168.7	170.7	172.8	175.0	177.1	179.2
			DG	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	0.0
			CDM	0.0	1.5	2.7	3.0	3.6	4.2	4.7	5.2	5.6	6.3	6.7	7.2
			Net	123.4	122.8	129.3	133.8	139.1	143.5	145.0	146.5	148.2	149.7	151.4	172.1
Whitby TS	T1/T2 (27.6kV)	90	Gross	56.0	59.0	74.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
			CDM	0.0	0.6	1.3	1.7	2.0	2.3	2.5	2.8	2.9	3.2	3.4	3.6
			Net	56.0	57.9	72.2	87.8	87.5	87.2	87.0	86.7	86.6	86.3	86.1	86.4
Whitby TS	T1/T2 (44kV)	90	Gross	43.7	57.7	59.5	61.2	63.1	64.3	65.6	66.9	68.3	69.6	71.0	72.4
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0

			CDM	0.0	0.6	1.1	1.2	1.4	1.6	1.8	2.1	2.2	2.5	2.7	2.9
			Net	43.7	56.6	57.9	59.5	61.2	62.2	63.3	64.3	65.6	66.6	67.8	69.5
Wilson TS	T1/T2	161	Gross	153.6	153.6	155.3	154.1	156.7	159.4	161.2	163.8	165.6	167.4	168.3	169.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	1.6	2.8	3.0	3.4	4.0	4.5	5.0	5.4	6.0	6.4	6.8
			Net	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	162.4
Wilson TS	T3/T4	134	Gross	N/A	169.2	143.3	144.2	152.8	154.7	156.5	158.4	160.2	162.1	163.9	165.7
			DG	N/A	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
			CDM	N/A	1.5	2.1	2.2	2.7	3.2	3.5	3.9	4.2	4.7	5.1	5.4
			Net	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.4
Enfield TS	T1/T2	157	Gross	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.2	1.5	2.1	2.4	2.9	3.3	3.7	4.1	4.7	5.1	5.6
			Net	0.0	18.8	82.0	106.8	109.0	112.1	115.2	118.2	122.3	125.2	129.3	133.5
CTS A			Net	25	25	25	25	25	25	25	25	25	25	25	25
CTS B			Net	95	95	95	95	95	95	95	95	95	95	95	95
CTS C			Net	21	21	21	21	21	21	21	21	21	21	21	21
CGS D			Net	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltage Level	Supply Circuits
1.	Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
2.	Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
3.	Whitby TS T3/T4	230/44kV	T23C/T29C
4.	Wilson TS T1/T2	230/44kV	T23C/T29C
5.	Wilson TS T3/T4	230/44kV	T23C/T29C
6.	Thornton TS T3/T4	230/44kV	T24C/T26C
7.	Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
8.	Seaton MTS	230/44kV	C10A/T28C

Appendix C: Lists of Transmission Circuits

Sr. 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: Lists of LDCs in the GTA East Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Oshawa PUC	TX
2.	Elexicon Energy Inc.	TX / DX
3.	Hydro One Distribution	TX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
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
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

GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

hydro one

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan ("RIP") report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

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

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EXECUTIVE SUMMARY

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

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

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

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

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

Table of Contents

List of Figures

List of Tables

1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

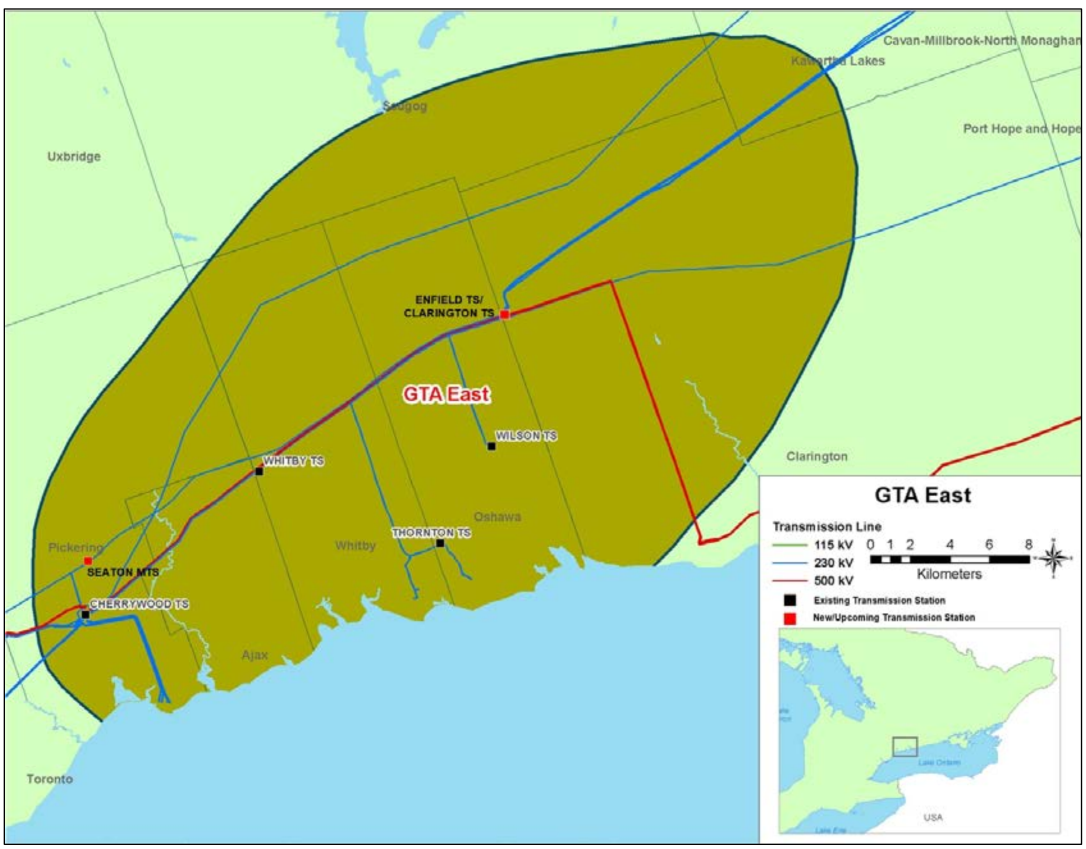


Figure 1-1: GTA East Region

1.1 Objective and Scope

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

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

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

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

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

[1] Also referred to as Needs Screening

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

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

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

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

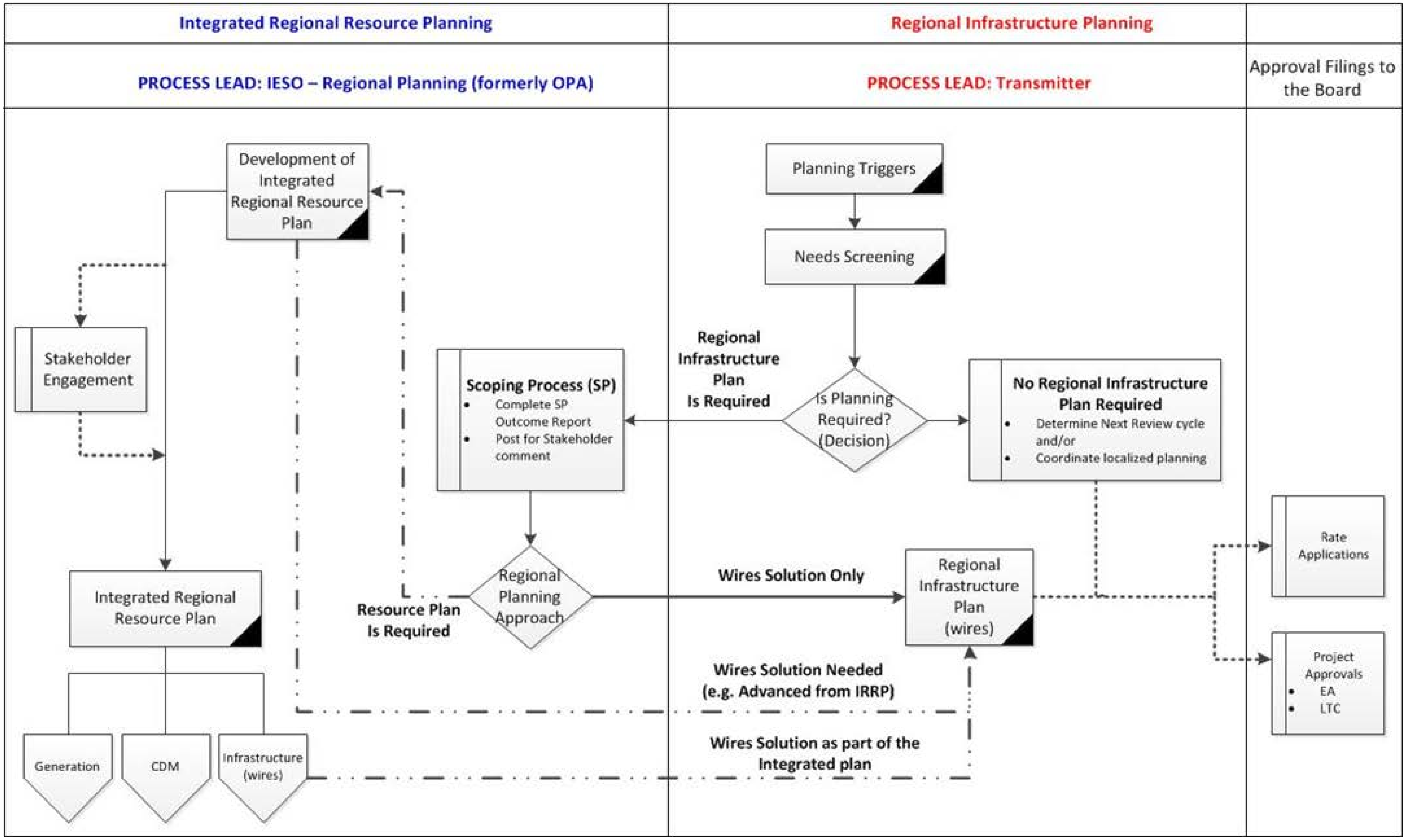


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

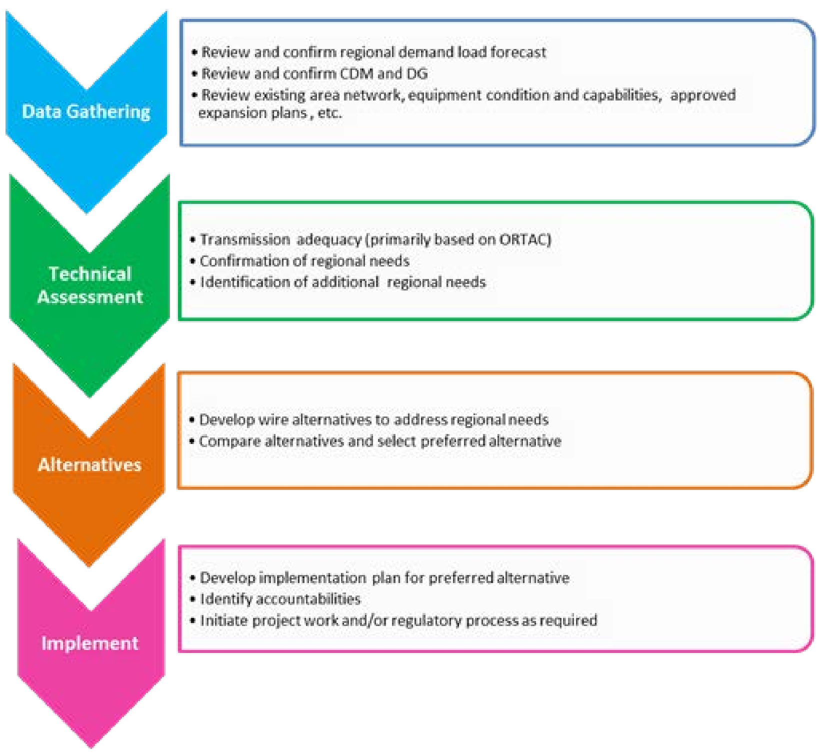


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

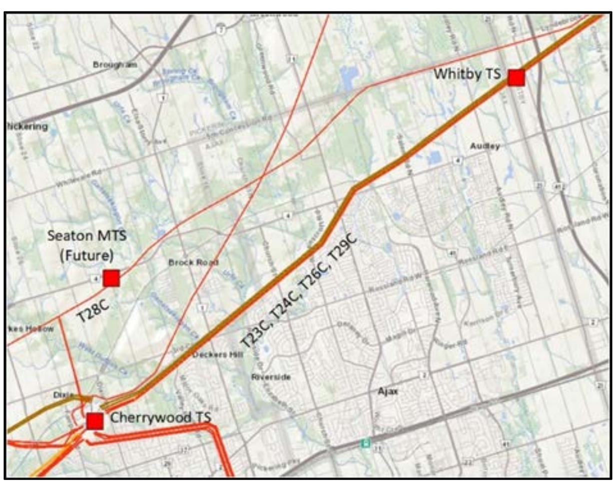


Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.

Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

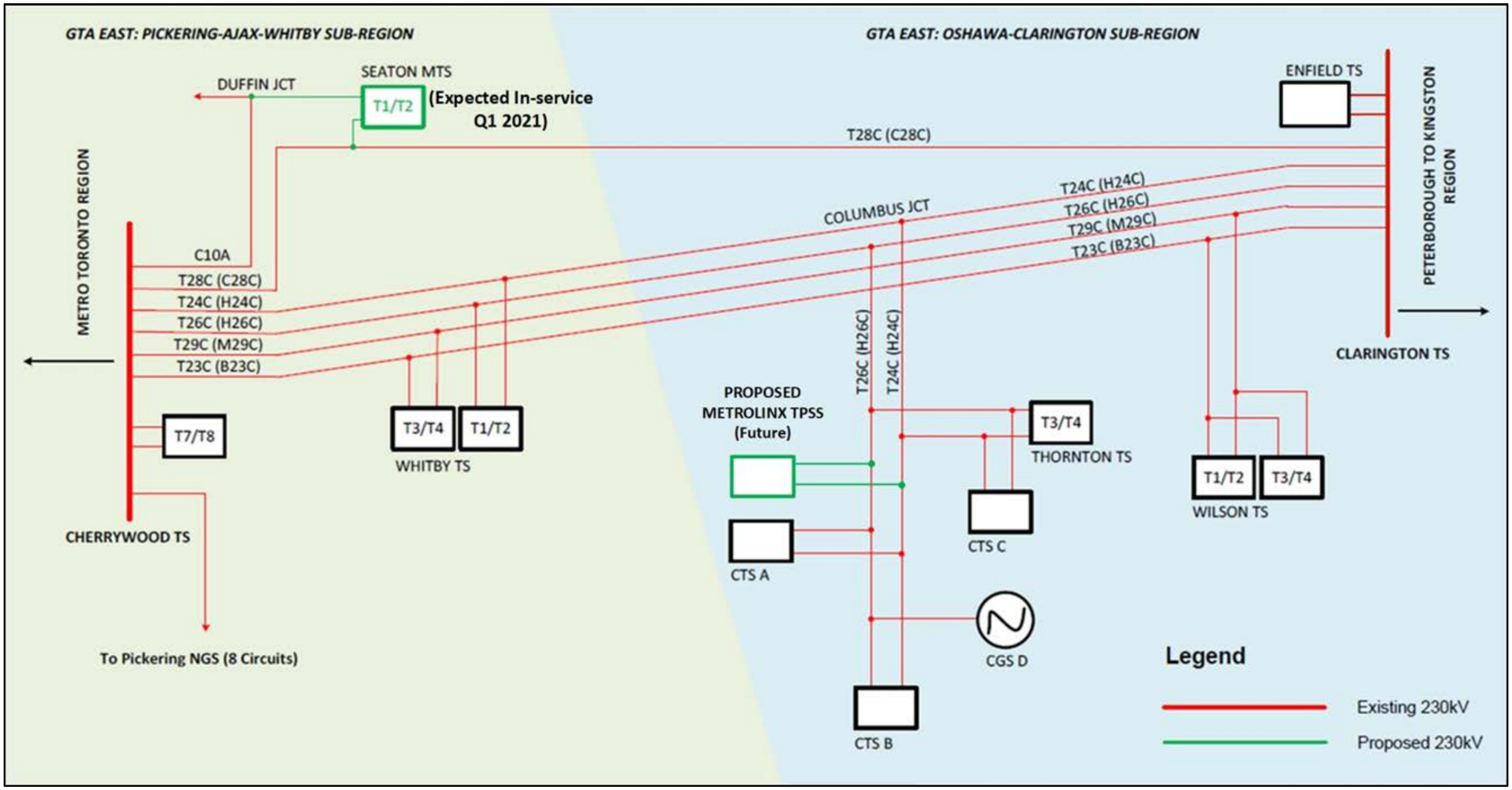


Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.
- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.
- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.
- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.
- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

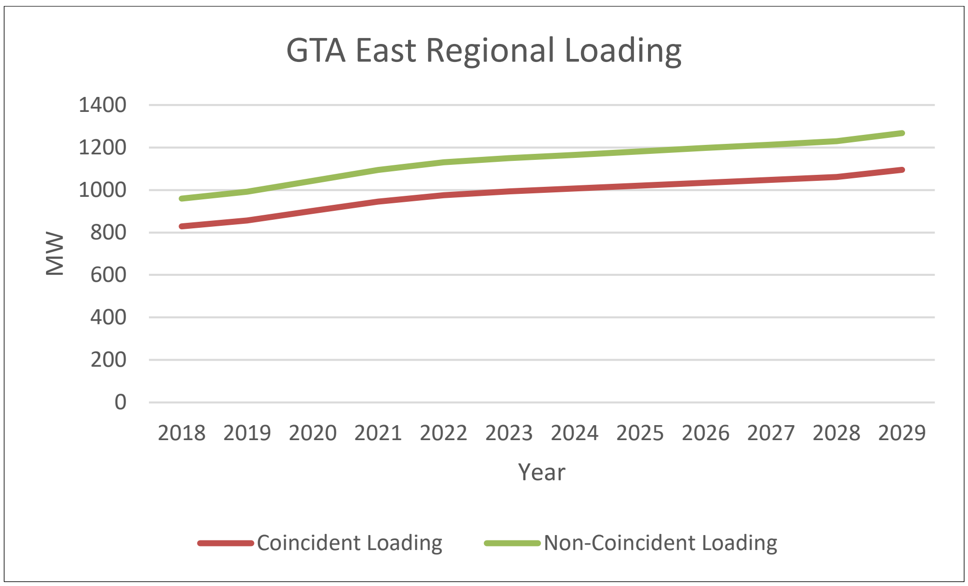


Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

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

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

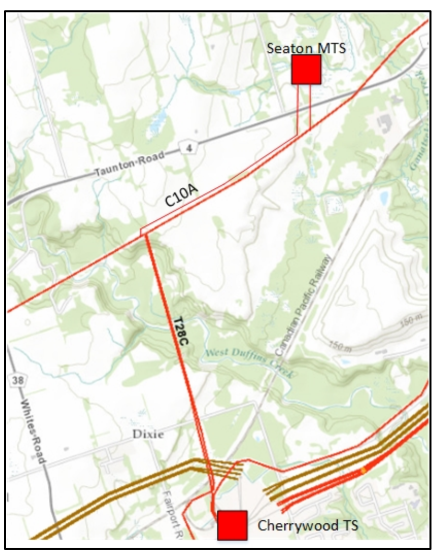


Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

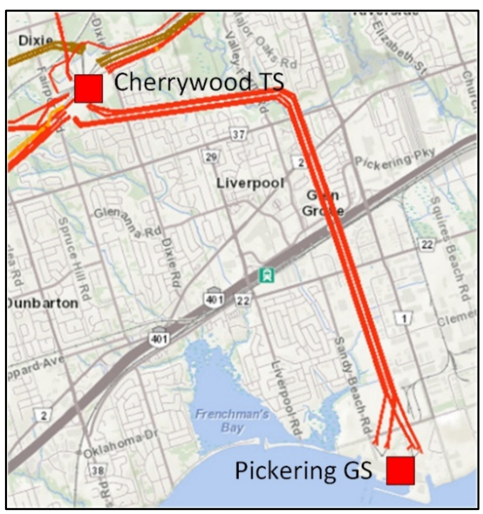


Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

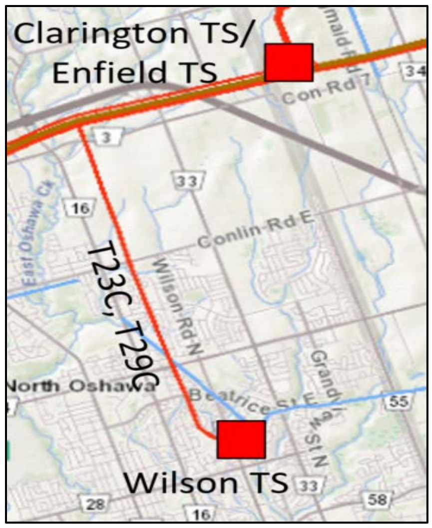


Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only "right sizing" option.

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Wilson TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

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

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

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, "Needs Assessment Report, GTA East Region", 15 August 2019

[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[4]. Needs Assessment Report GTA East – August 2014

[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	Station Name	Connection Type
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
GATR	Guelph Area Transmission Reinforcement
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
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
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Budget Category	Standards Equipment Reliability and Compliance
OEB Investment Category	System Service
Primary Driver	Reliability
Secondary Driver(s)	Safety

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.30M	**$0.30M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Standards Equipment Reliability and Compliance ("SERC") investments are made by Elexicon Energy Inc. ("Elexicon") to review equipment reliability and recommend changes to be made to standards or equipment that would address reliability and safety. New changes to distribution standards are made on a needs basis when identifying areas of the territory that may need further improvements. The results of this program produce the analysis and reports geared towards further improvement investments around the distribution system. Internal engineering needs, external committees and conferences, and reliability statistics drive investments into this program.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.30	0.33	0.30	0.30	0.30	0.30	0.30	0.30
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	0.30	0.33	0.30	0.30	0.30	0.30	0.30	0.30

Supporting Summary Statements:

With the merger of Veridian Connections Inc. (“Veridian”) and Whitby Hydro Electric Corporation (”Whitby Hydro”) into Elexicon, standards have been identified that are the best takeaways from both pre-existing companies. Examples of opportunities afforded by the SERC program include continuous improvement by adopting products such as condu-discs to build greater grounding design schema. Considerations for climate change from the program include system hardening, adaptation planning, environmental contaminates, and arrester implementation to adjust to increased lightning.

Over the years, reliability measures of System Average Interruption Duration Index (“SAIDI”) and System Average Interruption Frequency Index (“SAIFI”), adjusted for loss of supply and major events, shows a decreasing trend. The SERC program aims to continue the momentum and maintain or improve reliability performance. Safety is continuously considered by the SERC program to ensure the safety of crews and workers alongside the public. As the effects of climate change have become more prevalent, the SERC program has implemented various measures to ensure that the Elexicon grid is ready for climate adaptation. Additionally, as more disruptive technologies like Electric Vehicles (“EVs”) and Distributed Energy Resources (“DER”) impact the grid, the SERC program will evaluate these effects and make continuous improvements to standards and practices.

The alternative for the status quo is not applicable as Elexicon has a responsibility to its system and customers to ensure improvements for the system to maintain customer service, operational efficiency, and continuity of service. The merger has provided the SERC program with additional responsibilities which requiring consolidation of the two former distribution design standards of Whitby and Veridian. However, the opportunities in consolidation and the collective experiences of the program and the committee will improve Elexicon as a whole. Lessons learned from both the former Veridian and Whitby Hydro side will assist in creating a better grid in the combined Elexicon territory.

2. Basis for Action

2.1 Performance Trends:

To identify SERC, reliability statistics are utilized to reflect the reliability trends year over year. As seen from the SAIDI and SAIFI numbers with the Loss of Supply and Major Event adjusted from 2014 to 2019, they have shown a decreasing trend. Improvements will continue to be identified and implemented throughout the system using reliability analysis and changes from the Standards Equipment Reliability and Compliance Committee. SERC improvements are completed in conjunction with other System Service programs to address performance measures year over year. Additionally, many System Renewal programs are supported through the SERC program at Elexicon. Other drivers to the SERC program include internal Standards Committees that involve a multitude of departments and external industry committees made of standards groups of other utilities. In this case, continuous improvement is driven by internal design needs and through a review of external designs and discussions.

Table 2: System Reliability Statistics (2014 to 2019)

Metric	2014	2015	2016	2017	2018	2019
Total Outages						
SAIDI (hrs)	2.38	2.43	1.72	1.89	5.30	1.63
SAIFI	2.82	2.74	1.78	2.01	2.59	1.26
Loss of Supply Adjusted						
SAIDI	1.94	1.55	1.17	1.14	3.84	1.33
SAIFI	1.85	2.00	1.28	1.50	1.57	1.03
Loss of Supply and Major Event Adjusted						
SAIDI	1.94	1.55	1.17	0.98	1.34	1.33
SAIFI	1.85	2.00	1.28	1.18	1.17	1.03

Figure 1: SAIDI performance with Trend - Loss of Supply and Major Event Adjusted

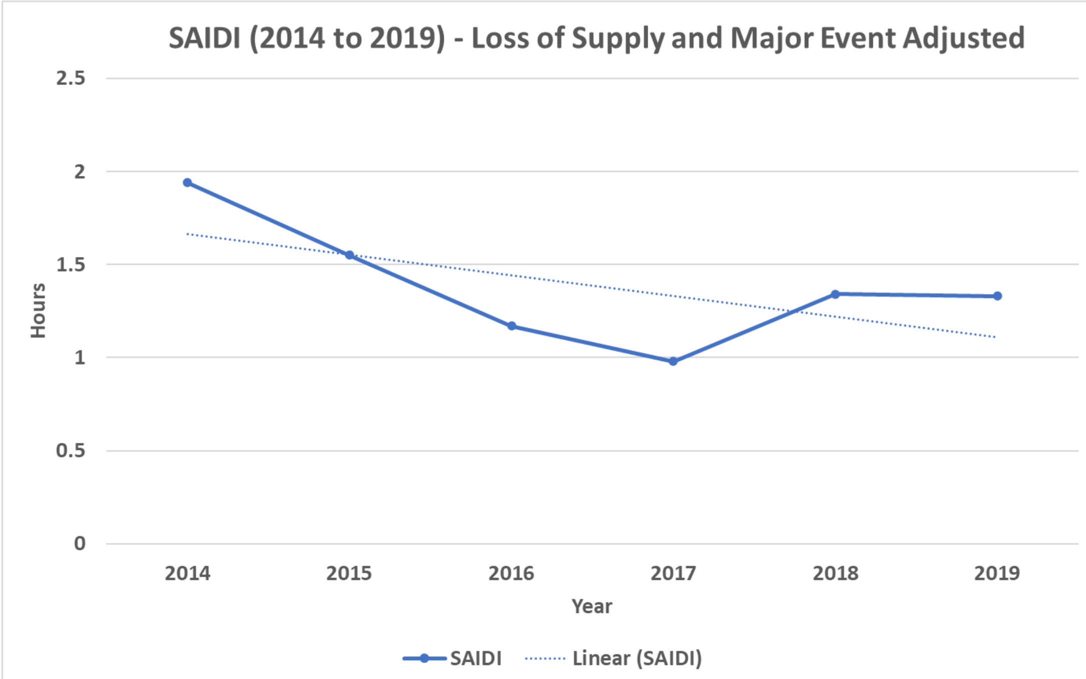
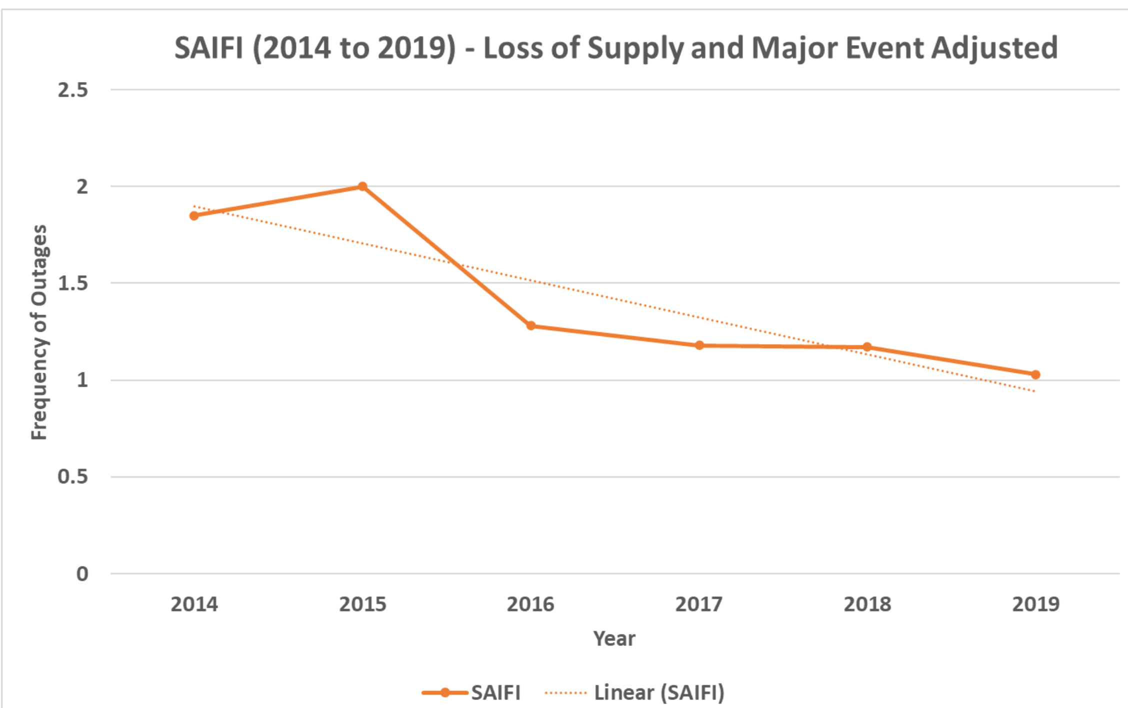


Figure 2: SAIFI performance with Trend - Loss of Supply and Major Event Adjusted



2.2 Current-State Analysis:

-C.c.2 (SS) Where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs

Distribution Standards Improvements from the SERC program

Current Elexicon standards are created using the best takeaways from both companies. Initiatives introduced include ensuring equipment reliability for climate change adaptation through system hardening, reducing environmental contaminates, and increasing lightning protection. Recently, overhead distribution standards across Elexicon's Service Area were upgraded from CSA Medium Loading B to CSA Heavy Loading to improve system hardening. All new construction from Elexicon moving forward to greater reliability and resiliency to outside elements. Software managed by the standards division is also continually updated to match the latest CSA overhead standards C22.3 that are adjusted to climate effects.

Standard Equipment Approvals at Elexicon are also trending towards heavy-duty designs. For example, a new design standard was introduced which increased the cross-arm load capacity per wire from 6000 lbs to 10000 lbs. The standards committee has also introduced a set of formal lightning arresters and a new requirement where arresters are implemented every 10 pole spans to mitigate lightning strikes. Elexicon has recently also investigated an enhanced ground plate that is installed on every distribution pole. This will help reduce the expected equipment failures on newly constructed pole lines.

Distribution Equipment Failure Analysis and Initiated Investments

Past reliability and equipment failure analysis of cables at former Veridian from the SERC program led to Cable Injection practices at the former utility. Veridian had realized benefits through the extension of asset life and health throughout the area and lower costs compared to replacement. Elexicon has budgeted annual cable injection procedures in the system renewal program as a result of these historical benefits. Additionally, porcelain cut-outs and insulators have been identified as safety concerns by the SERC program. Porcelain cutouts and insulators replacements will continue to be an annual investment across the future DSP period.

Overall, the SERC program is a combination of internal standards development and investigations into potential solutions that can increase the safety and reliability of the system. The program has initiated various system renewal and reliability investments alongside the improvement of internal design standards. Elexicon and the SERC program is committed to the continuous improvement of its distribution system to serve its customers.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.
-C.c.3 (SS) Description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met

SAIDI and SAIFI

Numerous initiatives are made from the SERC program to help improve system reliability. Examples of the work include support for SAIDI/SAIFI initiatives in conjunction with the Distribution Automation, Planning, and IT group. Standard FCI deployment is also performed by the group to help crews identify faults using FCIs to reduce the duration of outages that affect the SAIDI score. Improvements and initiatives produced from the SERC program can contribute to improvements in SAIFI metrics.

O.Reg 22/04 – Electrical Distribution Safety

New Distribution Standards needs to follow the regulations and rules as outlined in O.Reg 22/04 concerning electrical distribution safety. Examples of sections impacted include Safety Standards, when safety standards are met, the approval of electrical equipment, and approval of plans, drawings, and specifications for installation work. The SERC group must ensure that distribution standards maintain and can even improve the safety of the public and workers. The approval of electrical equipment is crucial in ensuring the system is compliant with regulatory compliances and in introducing new changes to distribution standards and improvements on the system. Lastly, the approval of plans, drawings, and specifications is a commitment by the SERC group to ensure all plans are safe for installation. Distribution Standards assist designers in making informed decisions when designing new distribution systems for Customers. Initiatives such as storm hardening and porcelain replacements at the Utility look to improve the safety of Elexicon's Distribution System.

Leave to Construct Approval

Leave to Construct approval is not required for this program.

New Technology, Inoperability, and Cyber-Security

Elexicon is required to comply with the *Ontario Cyber Security Framework* and new investments in the SERC will leverage advanced technology while complying with standards for interoperability and cybersecurity.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Safety: As reliability and standards compliance is continually improved upon, safety is taken into consideration through each development. These upgrades can prove to improve the safety of current designs through the development of new standards and the introduction of new equipment.

Reliability: The SERC program is meant to evaluate existing standards and the equipment reliability at Elexicon to increase reliability. By only employing the status quo, reliability may stay the same or even decrease. New opportunities are evaluated by investigating equipment reliability and compliance and continuous improvement of distribution standards.

Operational Effectiveness: Revaluating standards equipment reliability and compliances from the two former utilities allows operational efficiencies from creating one standard. Additionally, changes to standards that increase the reliability of service may prove new installations to be operationally effective.

Customer Service: Engaging in new developments and introducing new standards to improve service provide benefits to customers. Continuous improvement in standard designs ensures that Elexicon is providing a service to the customer that seeks to evaluate new opportunities for improvement. Elexicon Customers expect consistent and excellent electrical service; SERC investments look to improve current systems and practices to ensure greater reliability of service. SERC initatives such as storm hardening, reliability studies, and cable injections directly improve the grid which provides benefits to Elexicon customers.

Public Policy Responsiveness: Public policy initiatives in reliability measures, climate change, and safety are addressed when the SERC program performs evaluation work. Reliability is evaluated based upon current metrics and for climate change adaptation. Reliability statistics for equipment, areas, and designs are taken into consideration when planning and adapting to climate change.

2.5 Merger-Related Objectives:

The status quo of consolidating standards from both utilities is optimal from the perspective of the merger as combined standards utilize the benefits of experiences from the two former utilities. Additionally, combined standards help with the facilitation of consistent operations for inside workers and crews. One consistent standard in the company promotes an operationally efficient process and affects all aspects of the company related to distribution infrastructure. Through the SERC program, Elexicon evaluates and seeks opportunities for improvement through reliability analysis and stakeholder collaboration. From the perspective of a merger, a combined group of stakeholders from both previous organizations working together enables lessons learned. Work produced from the SERC program is intended to improve service continuity for customers. Through the program, Elexicon has introduced reliability initiatives directed towards climate change and system reliability.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.c.1 (SS) An assessment of both the benefits of the project for customers based on achievement of the project objectives and the cost impact to customers of the investment

Number	**1**	**2**	**3**
Scenario Description	Budgeted Investment Across the DSP Period	25% More Investment into the SERC Program	25% Less Investment into the SERC Program
Annual Program Scope	The SERC program is budgeted with an annual amount intended to maintain analytical and standard design improvement work across the future DSP period.	In this case, the program is continued but 25% more investment is placed into the program.	In this case, the program is continued but 25% less investment is placed into the group.
Annual Gross CAPEX	$0.300	$0.375	$0.225
Annual Net CAPEX	$0.300	$0.375	$0.225
Annual Program Benefits	This alternative will ensure continuation of further improvement or maintaining of the reliability metrics. At the same time, the program will continue to implemented various measures to ensure that the Elexicon grid is ready for adaptation of more disruptive technologies like EVs and DERs.	Increasing the level of investment into the SERC Program by 25% will increase the level of reliability metrics improvement results, which in recent years were at adequate levels.	Decreasing the level of investment into the SERC Program by 25% will decrease the level of reliability metrics improvement results, which in recent years were at adequate levels.
Program Economics	The level of investment into the SERC Program will remain at approximately the same level compared to the historical spend, to continue further improvement or maintaining of the reliability metrics.	Increasing the level of investment into the SERC Program by 25% is currently deemed unnecessary as the proposed spend in Preferred Alternative 1 is aligned to the historical level of investment which continues to provide the required reliability	Decreasing the level of investment into the SERC Program by 25% is currently insufficient as the proposed spend in Preferred Alternative 1 is aligned to the historical level of investment which continues to provide the required reliability

		metrics improvement results.	metrics improvement results.
Customer Feedback	In Elexicon's Customer Survey, 262 customeres were surveyed online and 600 customers were surveyed by phone. The results of online and phone surveys indicate that majority of customers (73.3% or 632 of the 862 customers) are very satisfied or somewhat satisfied with the service reliability over the last few years. At the same time the results of online and phone surveys indicate that largest group of customers (52.1% or 449 of the 862 customers) are satisfied with the planned allocation of investment. This is based on information provided in the survey indicating that aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability.		
Other Constraining Factors	Problems may arise in the distribution system that will involve further investigations from the SERC program to address new standards, reliability improvements, and practices. Elexicon shall utilize budgets from other System Service programs to allocate to the SERC program if required.	Current Investments would increase by 25%. As the program is investments into people and knowledge, additional staffing would be added or further opportunities for improvement could be identified. However, the budget has been set historically at the number that has benefited Elexicon.	Current Investments in the program have stayed consistent across the past years. Less investment in the program could affect continuous improvement.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.c.4 (SS) Identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system

Reliability: Reliability of Elexicon service will stay stagnant or decrease if Elexicon continues with the status quo. Failure to adapt to challenges such as climate change adaptation and new distribution technology can lead to a more unreliable grid. An evaluation of the standards and reliability statistics across the territory can help improve reliability.

Grid Resiliency: Resiliency will not improve if Elexicon is comfortable only with the status quo and not making changes to standards to account for the environment. For example, Elexicon has identified the need for composite poles in Gravenhurst due to the advent of woodpeckers which cause damage to wooden poles. Additional measures have been initiated to address the increasing concerns on climate change.

Operational Efficiency and Cost Effectiveness: The SERC program allows for improvements to standards and distribution equipment which produces operational efficiency and the cost-effectiveness of new designs. Standardized designs are made for new connections and construction to ensure that cost is as effective as possible. New standards also provide a rejuvenation of service areas through improvements of new distribution equipment specifications as compared to legacy equipment.

Safety: Safety will stay the same or worsen if the Status Quo is maintained. The SERC program constantly evaluates the safety of equipment and the environment to ensure outside workers and the public are not affected. Safety improvements to processes of installation and design as well as materials that are utilized. For instance, porcelain insulators have been identified as a safety concern and Elexicon is actively replacing older porcelain insulators with polymer insulators to protect workers and the public.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: The Status Quo will not allow for increased coordination and interoperability internally within Elexicon and externally with other parties. Elexicon consistently is involved with external committees in discussions over improvements and work towards greater standards. New improvements to Elexicon's grid should also provide positive impacts to other third parties such as municipalities, and Hydro One.

Conservation and Demand Management: N/A

Net Customer Benefits: The Customer will not experience benefits if the status quo to standards is kept. Continuous improvement and analysis of data and equipment are utilized to help improve the reliability and safety of the distribution network in a cost effective manner. New improvements are realized as customer benefits such as public safety are increased alongside the reliability of service.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.c.5 (SS) Identification and explanation of the factors affecting implementation timing/priority

Inquiries to current distribution standards and practices are made throughout the company. If a need does materialize from a request to update a standard, the SERC committee shall evaluate and determine the best course of action. Ultimately, the SERC program helps serve all departments across Elexicon. As the SERC program performs internal reliability tracking and equipment failure analysis, it represents a proactive approach by Elexicon in identifying possible improvements into the future. Investment budgets for this program are set annually across the future DSP period. As the program is a catalyst to many programs of System Renewal and System Service, it will not be reduced. A continuous improvement program internally at Elexicon like the SERC program is beneficial in identifying opportunities where the company can do better.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Whitby and Veridian have historically collaborated with regards to design standards and staff have also moved from one utility to the other. This staffing history has helped benefit Elexicon in establishing design standards as a newly consolidated company. As ideas from the two companies were shared and some staff have experience in both utilities, each predecessor had some understanding of each others' practices. The territory proximity of the former Ajax-Pickering and Whitby territories also assists in the consolidation of distribution system design. Both service territories are urban and represent mirroring neighbourhoods and the use of land and area. Opportunities, where improvements have been made in both former territories, can be utilized in the combined Elexicon territory.

Moving forward, a Standards Committee has been created with a mixture of former Whitby Hydro and Veridian Connections staff. Distribution Standards have been evaluated and consolidated for Elexicon. An assortment of departments from stations, lines, distribution design, planning, and asset management are involved as stakeholders to the committee.

Equipment Failure Data – Analysis, Investigations, Reports

Equipment Failure data is utilized to perform analysis and investigations. Records of equipment failures are kept with monthly reports and trends are captured through analysis. These metrics and findings drive the decisions by the SERC group to invest in new assets within the service territory and to evaluate and consider improvements to existing distribution standards and equipment.

Good Utility Practice

Good Utility Practice is followed by the SERC committee at Elexicon in ensuring new equipment is integrated into existing distribution standards. Good Utility Practice is defined as any practice, method, or act engaged in or approved by a significant portion of the electric utility industry in which reasonable judgment in light of facts known at the time of the decision was made. Consultation with other utilities helps enable and provide support to standards development at Elexicon. In ensuring due diligence, Elexicon evaluates the standards and reliability of the equipment alongside the experience that other utilities may have when engaging in standard changes and improvements.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Material Differences

The material differences between the two systems have been adjusted accordingly by consolidating the two former distribution standards into one Elexicon standard. Whitby Hydro did not use cable injection processes before whereas Veridian engaged in cable injection practices. Cable Injection processes shall continue and annual cable injection investments in the System Renewal- Rebuilds program have been budgeted. The two former utilities used porcelain insulators, and there is now a transition to replace porcelain insulators with polymer replacements. This change was suggested to improve the safety of crews and the public due to the shrapnel like behavior when it fails. These annual replacements for porcelain arresters and insulators are present in the System Renewal-Others program. Climate change adaptation has also been integrated into Elexicon's practices and distribution standards.

Operations Feedback

Operational feedback is also taken as an input into the decisions and initiatives that the SERC team engages in. As crews perform the physical installation and troubleshooting of the system, any new changes to standards and equipment have a major impact.

External and Internal Coordination

External and Internal resources are utilized through the SERC program. Utility forums and third parties are also consulted to provide ideas that could be used as initiatives piloted by the SERC program. Internal stakeholders utilize the feedback from internal staff and external committees to plan and perform work. For the most part, for more specialized SERC influenced investments, external third parties are used to perform the work such as cable injection. For more routine work, internal Elexicon operational staff are utilized.

4.3 Scale Increase Considerations

Currently Merged Standards and Practices:

A committee of the two former utilities reviewed all standards from both utilities, and a consensus agreement on the best practices from both locations was formed. Influences from both utilities were present in the former standards which made the consolidation easier. The combined skillsets and increase in resources from the two former utilities will help with serving the different areas under Elexicon. Experiences with different assets will also be influential in determining new standards and Elexicon's asset management practices.

The increased service territory will benefit Elexicon in implementing SERC related initiatives. As both Whitby and the Ajax-Pickering area are similar in terms of land use and urban infrastructure, any previous related SERC programs could be translated to each other. Furthermore, the combined operational staff will help assist in implementing these initiatives in both territories.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

The Standards Equipment Reliability and Compliance program was created to improve the reliability of the system by making optimal investments through analysis of failure data and for the continuous improvement of standard designs. Opportunities for efficiencies can be realized as the standards groups of both former utilities will assist in the SERC program. Additionally, investigations into new equipment or designs can implement cost savings related to reactive work or for the ability of the system to be climate change adaptive. Savings can be realized from programs initiated by the SERC program such as through cable injection practices where cable lives are extended. Over the DSP period, the SERC program will continue with its historical investment into the program.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX	Priority
2021-1001	Standards Equipment Reliability & Compliance	2021	$0.30M	27.7

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.c.7 (SS) An analysis of project benefits and costs comparing the proposed project to a) doing nothing and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.
Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these qualitative factors in relation to the proposed project and all alternatives, including how these factors affected the selection of the proposed project.
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.

<table>
<tr><th>Project name</th><td colspan="5">Standards Equipment Reliability and Compliance (SERC)</td></tr>
<tr><th>Project numbers</th><td colspan="5">2021-1001</td></tr>
<tr><th>Job numbers</th><td colspan="5">Several</td></tr>
<tr><th>Project District</th><td colspan="5">General</td></tr>
<tr><th>Project Location</th><td colspan="5">General</td></tr>
<tr><th>Investment Category</th><td colspan="5">SYSTEM SERVICE</td></tr>
<tr><th>Budget Category</th><td colspan="5">S3 - Standard Equipment Reliability & Compliance</td></tr>
<tr><th>Project Driver</th><td colspan="5">System Operational Objectives: Reliability</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021 JAN 01</td></tr>
<tr><th>Required In-Service Date</th><td colspan="5">2021 DEC 31</td></tr>
<tr><th>Scope of Work</th><td colspan="5">Standards – Produce hydro distribution reference documents for construction purposes; Mainly concerned with CSA compliance for clearances and O.Reg 22/04 for safety. Also, produce policies and procedures for Engineering / Planning.
Equipment – Produce Equipment Approval Sheets to ESA requirements. Introduce new equipment to Elexicon engineers.
Reliability – Analysis trouble report data for capturing equipment failure trending including underground cable faults. These reports are considered for the purpose of future capital projects.
Compliance –Ensure compliance with CSA, ESA, O.Reg 22/04 as related to the above. Ensure Engineering and Planning are up to current regulations (i.e. Construction Act 2019), overlap with Regulatory.</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td colspan="2">Gross: $300,000</td><td colspan="2">Contribution: $0</td><td>Net: $300,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$27,000</td><td>$30,000</td><td>$51,000</td><td>$192,000</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">The project is required to ensure compliance of standards and equipment with CSA, ESA, and regulation 22/04. System reliability will be improved by analysis of the equipment failure and initiating the projects to remedy these troubles, which will be achieved by introducing new equipment to system inventory and/or updating maintenance procedure of the equipment.</td></tr>
<tr><th>Criteria Score</th><td colspan="5">27.7</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">Not Applicable</td></tr>
<tr><th>Intervention Options</th><td colspan="5">There is no alternative. The project is required to ensure compliance with CSA, ESA, O.Reg 22/04 as related to standard, and equipment. The project will ensure engineering and planning are up to current regulations (i.e. Construction Act 2019), overlap with Regulatory.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">The project will reduce cost of the O&M. Part of the project is to investigate equipment failure. The equipment failure trends are captured and corrective actions will be implemented to prevent similar accident/failures in the system, which will improve system reliability and reduce the O&M costs.</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">The project addresses the RRF objectives of Public Policy Responsiveness, customer focus, and Operational Effectiveness.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">The average cost of the project based on historical data is $275,000.</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">Not Applicable</td></tr>
</table>

Budget Category	System Reliability Improvements
OEB Investment Category	System Service
Primary Driver	System Operational Objectives: Reliability
Secondary Driver(s)	System Efficiency; Safety; Customer Service

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$1.02M	**$1.08M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Elexicon Energy Inc ("Elexicon") plans to continue investing in the reliability of its system through the introduction of new assets. Historically and currently, these investments include single-phase line reclosers ("Tripsavers"), three-phase "SCADA Mate", and "IntelliRupter" switches, Faulted Circuit Indicators ("FCI") (standard and smart), and other SCADA improvements. The historical value of reliability measures for the SAIFI has all demonstrated a decreasing trend whereas SAIDI numbers have stagnated in the years of 2018 & 2019. Reliability statistics and analysis such as SAIDI and SAIFI alongside Worst Performing Feeder Analysis drive investments of the System Reliability Improvement program.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	1.02	1.02	1.12	1.74	1.05	1.05	0.75	0.75
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Expenditures	1.02	1.02	1.12	1.74	1.05	1.05	0.75	0.75

Supporting Summary Statements:

New proposed projects aim to continue improving reliability for customers, remove complacency with the status quo and explore new grid technologies. The potential benefits arising from system reliability improvement investments include remote fault location and switching, increased operational efficiencies from troubleshooting, and increases in reliability for customers through reductions in outage duration, and occurrences. Reliability measures of SAIFI within Elexicon have exhibited a decreasing (improving) trend. SAIDI numbers have stayed consistent over the past two years despite a decreasing trend over the past six years. New System Reliability improvement projects are proposed to increase performance within the reliability measures. Installation of new SCADA Mate Switches, Smart and Standard FCIs, Trip Savers and SCADA upgrades have the potential to improve these measures. Worst performing feeder analysis is performed to address specific locations within the distribution system where reliability is poor.

System Reliability projects will enable the merged utility to perform more efficient operational work and standardize reliability improvements for the foreseeable future. Operational efficiencies will be increased as faulted circuit indicators will provide crews with remote detection, and alerts thus reducing the amount of duration and coordination needed in troubleshooting outages. TripSavers will provide reclosing capabilities on specific overhead laterals that have been targeted by Elexicon. Additionally, new investments into SCADA upgrades will be performed to merge and improve the current SCADA system that will be used as one merged utility.

Elexicon aims also to improve its operational efficiency when addressing outages or faults. Crews will be able to identify the specific locations of faults through faulted circuit indicator implementation. Smart and standard FCIs will be utilized and constant communication with the control room will be established. Applying TripSaver technology will reduce outage duration and reduce the number of calls required for crews to respond. Cost savings should result from these system reliability improvements.

2. Basis for Action

2.1 Performance Trends:

Historically, System Reliability Improvements were meant to target and improve reliability measures such as SAIDI and SAIFI. New additions to the grid were utilized to target areas where reliability performance was poor or had a significant number of outages.

SAIDI and SAIFI numbers are provided for three categories in Table 1:

1. Total outages
2. Total outages excluding Loss of Supply (LOS"); and
3. Total outages excluding LOS and Major Event Days ("MEDs") removed.

Table 2: Historical SAIDI and SAIFI performance

Metric	2014	2015	2016	2017	2018	2019
Total Outages						
SAIDI	2.38	2.43	1.72	1.89	5.3	1.63
SAIFI	2.82	2.74	1.78	2.01	2.59	1.26
LOS Adjusted						
SAIDI	1.94	1.55	1.17	1.14	3.84	1.33
SAIFI	1.85	2.00	1.28	1.50	1.57	1.03
LOS and MED Adjusted						
SAIDI	1.94	1.55	1.17	0.98	1.34	1.33
SAIFI	1.85	2.00	1.28	1.18	1.17	1.03

Figure 1: Elexicon SAIDI (LOS and MED Adjusted) Metric 2014 to 2019

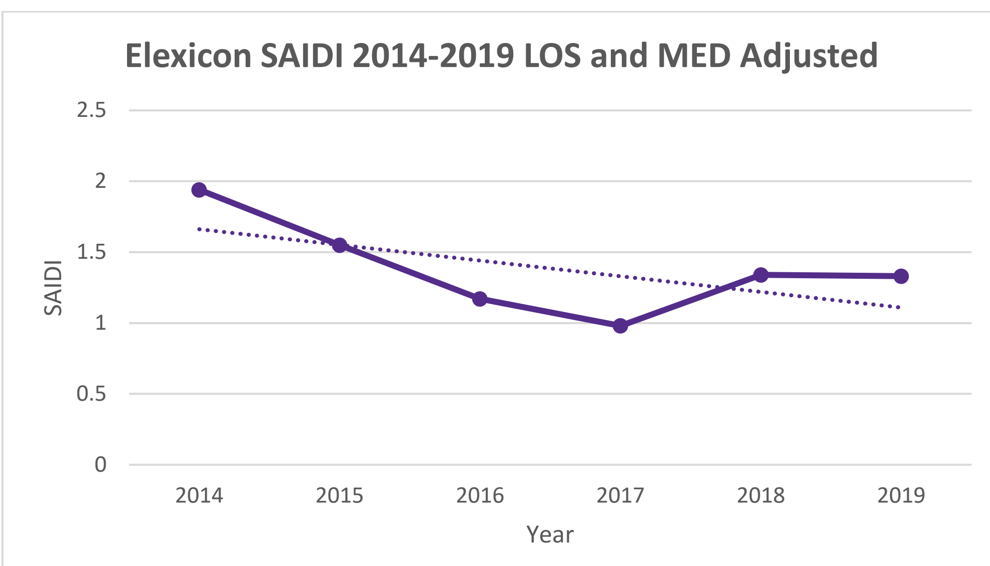
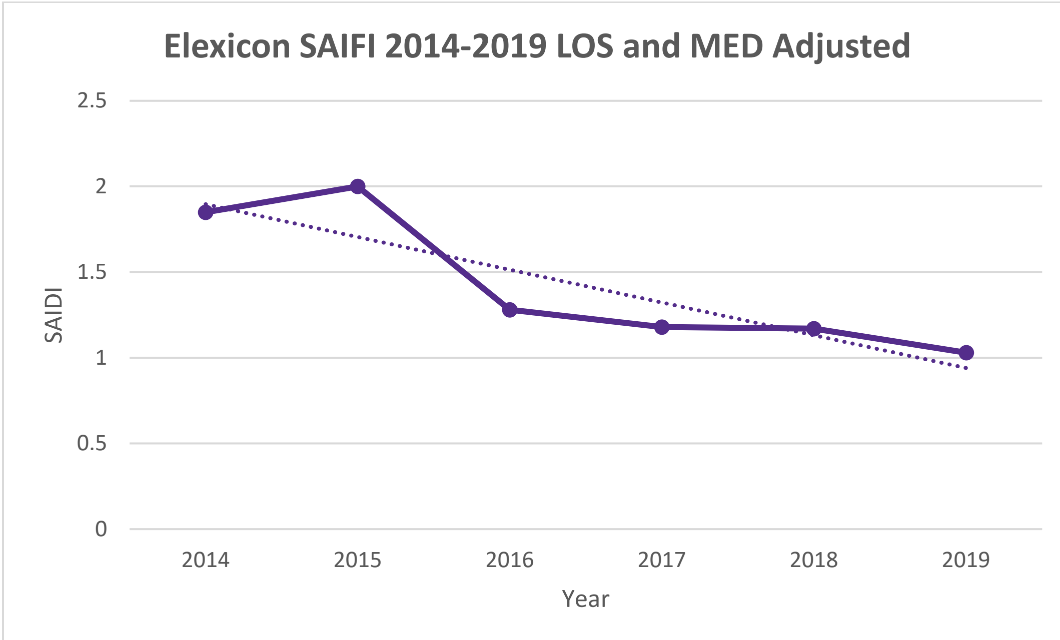


Figure 2: Elexicon SAIFI (LOS and MED Adjusted) Metric 2014 to 2019



The year 2018 was a significant outlier in terms of poor SAIDI performance, with and without LOS events, when not adjusted for MEDs. The SAIFI numbers follow a decreasing trend from 2014 to 2019. Although the SAIDI numbers exhibit a decreasing trend, it is found that 2018 and 2019 performance stayed constant. Further System Service investment specifically in improving System Reliability will continue this improved performance in reliability for the years to come. When adjusted for LOS and MED, both SAIDI and SAIFI show a decreasing trend from 2014 to 2019. However, SAIDI numbers have stayed consistent from 2018 and 2019 at 1.33 and 1.34 whereas from 2014 to 2017, SAIDI decreased each year. SAIFI has consistently decreased year over year across the 2014 to 2019 period. System Reliability Improvements such as FCIs and TripSavers can potentially assist in decreasing SAIDI numbers in the future.

Interruption results are provided for three categories:

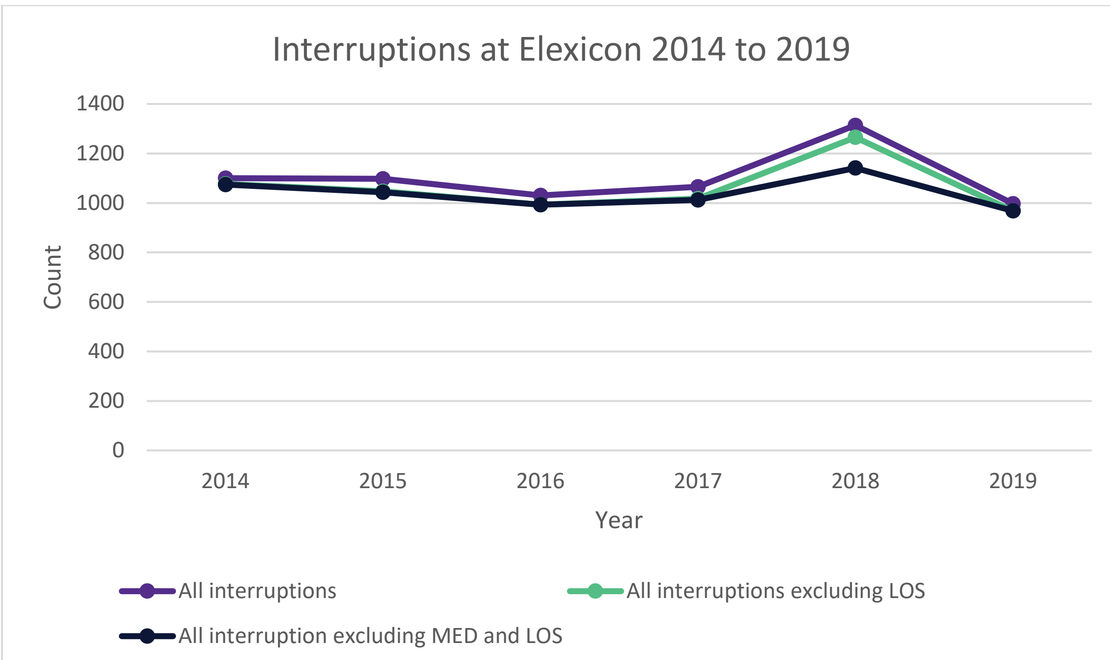
1. All Interruptions;
2. All Interruptions excluding LOS; and
3. All Interruptions excluding MEDs and LOS.

MEDs severely impact the historical interruption numbers alongside the loss of supply. As the numbers are adjusted to exclude MEDs and LOS, 2018 still presents a major increase in interruptions. The 2019 numbers however fall more in line with the historical records of interruptions. This is reflective of the company's initiatives of System Reliability Improvements and other system service programs like the program.

Table 3: Interruption History

Categorization	2014	2015	2016	2017	2018	2019	2020
All interruptions	1,100	1,098	1,031	1,065	1,314	997	
All interruptions excluding LOS	1,077	1,047	993	1,017	1,265	968	
All interruption excluding MED and LOS	1,075	1,044	993	1,012	1,141	968	

Figure 3: Elexicon Interruptions 2014 to 2019



2.2 Current-State Analysis:

-C.c.2 (SS) Where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs

The current system has steadily incorporated smart and standard FCIs since its introduction in 2013. Improved FCIs now communicate back to the SCADA network which can reduce the number of time operations needs to troubleshoot calls. Additionally, they enable remote fault detection which helps improve power restoration. Smarter FCIs reduce equipment damage, reduce costs, and improve reliability. FCIs are deployed at longer feeders with a lack of SCADA telemetries such as HONI feeders by Gravenhurst and Clarington.

TripSaver technology has been implemented at Elexicon to address temporary faults at specific overhead lateral locations through reclosing capabilities. Past locations where TripSavers have been installed include Southwest Pickering, Northwest Pickering, Ajax, and Whitby. The TripSaver recloser will attempt to reclose the circuit three times before it considers the problem permanent. Sustained outage and truck rolls can be avoided when power is restored automatically following a momentary interruption. TripSavers are also implemented where a fault can be cleared faster and in other areas where coordination is difficult.

Worst performing feeder analysis is also carried out within the Elexicon territory to identify specific feeder locations where reliability has been poor. These locations are identified to analyze how system reliability projects could potentially reduce the amount of sustained and monetary outages within the grid. Given the location, Elexicon planners will evaluate the performance of the feeder for sustained and momentary outages to determine improvements that will fix the poor performance of feeders. A summary of the Worst Performing feeders for both sustained and momentary outages are found in Table 3 and Table 4. Feeders that are highlighted in red are feeders that appear in multiple categories in either sustained or monetary outage performance.

Table 4: Worst Performing Feeder by Sustained Outages

Sustained Outages								
Rank	Feeder	# of Outages	Rank	Feeder	CI	Rank	Feeder	CHI
1	JAMSF1	225	1	SHEPM4	93224	1	JAMSF1	127278
2	WHITM48	213	2	ORILM6	86775	2	ORILM6	122503
3	SHEPM4	167	3	40M8	80197	3	WHITM46	111855
4	11F4	155	4	SHEPM2	55764	4	WILSM12	69433
5	MALVM35	153	5	WILSM11	47908	5	SHEPM4	65099
6	BAYRF1	141	6	MALVM35	47749	6	BAYRF1	61044
7	MONAF4	106	7	WILSM17	42133	7	WILSM11	58743
8	PICBF6	102	8	WHITM46	38908	8	GRAVF1	55509
9	GRAVF1	102	9	BAYRF1	33307	9	WILSM14	46144
10	NOTIF2	91	10	52M7	29250	10	PICBF6	44530

Table 5: Worst Performing Feeders by Momentary Outages

Sustained Outages								
Rank	Feeder	# of Outages	Rank	Feeder	CI	Rank	Feeder	CHI
1	12F2	43	1	40M27	135554	1	SHEPM4	398
2	SHEPM4	41	2	SHEPM4	123745	2	WHITM22	278
3	7F4	41	3	ORILM6	107702	3	WILSM11	266
4	JAMEF1	36	4	WILSM11	93663	4	BEAVM24	231
5	BAYRF1	35	5	BAYRF1	89880	5	CHERM4	153
6	10F1	32	6	12F2	78245	6	CHERM8	144
7	10F6	31	7	CHERM5	75507	7	SPRYF2	103
8	7F2	31	8	MALVM35	68739	8	WHITM23	97
9	SPRYF4	30	9	40M25	65699	9	7F1	91
10	FAIRF1	29	10	10F1	63462	10	WHITM24	86

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.
-C.c.3 (SS) Description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met

Reliability Measures: Reliability Measures are annually provided and an assessment of the LDC's performance by the OEB is undertaken. Without continued investment into the grid and of new reliability technologies, Elexicon can potentially run the risk of decreased performance in reliability measures. The OEB sets the reliability and quality of service standards for distributors each year concerning SAIDI and SAIFI.

O.Reg 22/04: Any System reliability improvements will follow *O.Reg 22/04*, Electrical Distribution Safety when projects are incorporated in new installations and standard designs. As System Reliability Improvements can be found in critical sections servicing customers, the implementation needs to be safely completed.

Leave to Construct Approval: Leave to Construct approval is not required for this program.

New Technology, Interoperability, and Cyber-Security: Elexicon is required to comply with the *Ontario Cyber Security Framework* and new investments into System Reliability Improvements will leverage advanced technology while complying with standards for interoperability and cybersecurity.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service: Reliability of the grid is representative of the customer service Elexicon provides to customers. New improvements in system reliability such as FCIs, Smart TripSaver Switches, and SCADA upgrades can potentially improve SAIDI, SAIFI, and other reliability measures. FCIs can help improve operational efficiencies, and reduce troubleshooting time which as a result can potentially reduce outage durations (SAIDI). Current legacy equipment at best maintains the current reliability performance of Elexicon. If System reliability improvements are not pursued, customers may experience worse service. Customers expect excellent and consistent electrical service for their daily purposes. Elexicon's investments in this program seek to improve the reliability of electrical service. Customers will directly benefit by as this program evaluates and seeks continuous improvement where reliability is lower on the network.

Operational Excellence: System Reliability improvements offer numerous benefits to operations within Elexicon. Reductions in outage duration from remote fault location assist operations in troubleshooting and restoring power to customers. If System Reliability improvements are not pursued, operational excellence of Elexicon will stagnate. Additionally, as a recently merged utility, improvements to operational efficiencies can lay the foundations of improved operational excellence into the future.

Financial Performance: Making more advanced investments into the grid can reduce financial constraints on assets, and operations. A decrease in labour time through reliability improvements saves the utility money to engage in other projects. Assets being protected or prolonged through reliability improvements reduces the need to utilize money on an unexpected basis and rather as carefully timed investments.

Public Policy Responsiveness: The ongoing development of smart grids will be satisfied through smart technology investments related to the improvement of reliability. The OEB also requires that Elexicon report its reliability performance each year. These investments are aimed at improving reliability measures year over year for customers. The OEB uses reliability measures to assess Elexicon on its distributor scorecard and decreased performance would negatively affect Elexicon as a whole.

Asset Management: New IntelliRupter implementation will extend and help protect substation transformer assets. Reclosers have been used historically in addressing temporary outages but have the potential to apply high mechanical strain on the substation transformer. New IntelliRupter switches have pulse closing technology which mitigates the effects of reclosing and can extend the useful life of transformers. This will be initially tested in the Whitby service area but will be crucial to Elexicon's future goals as a utility that embraces asset management.

2.5 Merger-Related Objectives:

Historically, Elexicon has invested in TripSaver and FCI (Smart and Standard Type) technologies to improve the system reliability of the grid. Combined with the other system service programs such as Feeder Enhancements via Voltage Conversion and the Standards Equipment and Reliability program, Elexicon has made investments to continually improve its reliability. The current investment strategy is optimal from the perspective of the merger. Elexicon will continue to implement these measures to reduce the number of outages and reduce the number of hours required for reactive crews to identify faulted locations. Considering the non-contiguous territory of Elexicon, any initiatives aimed at reducing the number of labour hours needed to perform reactive work will be important.

System Reliability improvements provide high value for commitments made to service continuity as it is mandated by or regulatory requirements. New Reliability improvements that lead to a reduction in outages also serve as a labour-saving capital investment. As noted in the performance trends for System Reliability, Elexicon has demonstrated a historical decreasing trend for SAIDI and SAIFI numbers. As current System Reliability Improvements have assisted in improving these numbers, Elexicon will continue to implement consistent investments into FCIs and TripSavers.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.c.1 (SS) An assessment of both the benefits of the project for customers based on achievement of the project objectives and the cost impact to customers of the investment

Number	***1***	***2***	***3***
Scenario Description	Status Quo: Budgeted System Reliability Improvements	Increased Pacing (100% more investment)	Slower Pacing (50% less investment)
Annual Program Scope	The current Budget for System Reliability Investments is optimized as they target areas where reliability is poor.	Increased investment in reliability improvements than the current plan. SAIDI and SAIFI could potentially be improved further by investigating new areas where System Reliability Improvements could be made.	Decreased investments into reliability improvements than current plans. SAIDI and SAIFI can improve but lesser so than the current proposed solution. Reliability Improvements may not be as great if less investment is made.
Annual Gross CAPEX	$0.99M	$1.98M	$0.50M
Annual Net CAPEX	$0.99M	$1.98M	$0.50M
Annual Program Benefits	Worse risk and reliability performance than Scenario 2, better risk and reliability performance than Scenario 3.	Better risk and reliability performance than Scenarios 1 and 3.	Worse risk and reliability performance than Scenarios 1 and 2.
Program Economics	Projected Defective Equipment (“DE”) SAIDI of 0.828 and residual risk of $18.4M in 2029.	Projected reduction in DE SAIDI of -2.1% and residual risk by -1.1% by 2029 compared to Scenario 1.	Projected increase of DE SAIDI of 1.9% and residual risk by 1.6% by 2029 compared to Scenario 1.
Customer Feedback	40.5% (349 of the 862 surveyed) of customers believe that either Elexicon should maintain or spend more in reliability in specific areas requiring improvement if it could avoid bill increases and does not raise prices.	47.1% (406 of the 862 surveyed) of customers would accept a gradual increase to maintain reliability or a larger increase to monthly bills for Elexicon to invest more into reliability.	1.7% (15 of the 862 surveyed) of Customers believe Elexicon should invest less in outage protection to reduce the impact of future bill increases, even if potentially longer and more outages result.

Other Constraining Factors	If reliability becomes worse in a specific service area, the budget may need to be shifted from other System Service programs or future years in the System Reliability Improvements will be reduced. Contingencies to reliability requirements shall be planned.	Increased investment would allow Elexicon to produce benefits throughout the service area. However, the current plan is optimized for the requirements in the area.	By decreasing investment, reliability may not be improved as much in certain service areas. The current status quo is a balanced budget with optimal investments of adequate return.
Preferred Alternative	**X**		

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.c.4 (SS) Identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system

Reliability: Reliability could improve but be less than optimal if fewer smart solutions are used to improve system reliability. For instance, smart FCIs could be replaced with standard FCIs but the performance and capabilities of Smart FCIs are preferred. Additionally, TripSavers and IntelliRupters could be substituted by traditional switching and fuses. However, TripSavers can reclose and decrease momentary faults that the classic switches cannot perform. Current TripSavers support three reclosing operations before the device permanently remains open. This provides immense benefits to reliability as temporary faults and outages would occur. The duration of outages would decrease from these measures. FCI investments will allow crews to identify where specific faults have occurred in the system during trouble calls.

Grid Resiliency: The preferred alternative will provide Elexicon with reliability improvements but may not create a more resilient grid. As the effects of climate change, development, and new technologies impact the grid, smarter solutions will allow the grid to become more resilient and stable to outside effects.

Operational Efficiency and Cost Effectiveness: Operational Efficiency would be increased with the introduction of System Reliability improvements. Reliability measures such as FCI deployment and TripSaver implementation should reduce the duration of outages and the amount of work that crews will be required to perform.

Safety: The safety benefits of System Reliability improvements is the reduction in the amount of work required for operations to respond to outages. New FCIs and TripSavers reduce the amount of work that crews must partake in. If less tasks are required from Personnel, then there will be fewer opportunities for unsafe moments.

Cyber-Security/Privacy: Adding smarter components that can be remotely controlled can introduce Cyber-security and Privacy concerns. With the introduction of new technology, opportunities for malpractice from third parties could be possible. Elexicon will ensure that System Reliability improvements are safe from cyber-attacks.

Environmental Benefits: N/A

Coordination/Interoperability: Coordination to switch off a certain segment of the grid from new Reliability improvements would be quicker and more efficient because of the SCADA switches and other assets. The TripSaver recloser offers remote communication options that leverage existing infrastructures such as AMI, Distribution Automation, and SCADA. IntelliRupters can also be integrated into Utility systems.

Conservation and Demand Management: N/A

Net Customer Benefits: Current reliability assets would only maintain the status quo for reliability measures. Customers can experience more reliable service through potential reliability improvements in the reduction of outage durations, frequency of outages, number of outages, and number of customers effected.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.c.5 (SS) Identification and explanation of the factors affecting implementation timing/priority

If reliability within certain locations is deemed to be poor or decreasing substantially, Elexicon will consider options in performing system reliability improvements. A preliminary assessment of the distribution system in the area will be conducted. Worst performing feeder analysis will ideally be performed to identify the feeders which have experienced the most induced outages. Locations with a high number of temporary faults are identified when implementing Trip Savers. If locations demonstrate an increasing number of temporary faults, Elexicon will analyze and plan for system reliability improvements in these sections.

An assessment of how the projects have improved system reliability will also be conducted. If results from new projects prove successful, Elexicon will evaluate the pacing of system reliability improvements.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Reliability statistics, and the tracking of momentary and sustained interruptions, are the primary data used to plan and justify System Reliability Improvements. New reliability improvements will be evaluated based on effectiveness in decreasing outages within a geographic span of the grid. As previously discussed for FCIs, they are deployed on feeders without SCADA telemetry. TripSavers are placed onto service areas where there are a high number of temporary faults.

Historically, reclosers and a few TripSavers have been utilized on Elexicon's system which has led to system reliability improvements. In 2021, Elexicon plans to install IntelliRupters in the Whitby Service Area and analyze the benefits that will result from the new implementation.

TripSavers are an annual investment across the future DSP period that Elexicon will continue to be implemented on the grid. One added benefit to the TripSaver is that it can be newly installed or retrofitted to existing present-production cut-out mountings. When implementing TripSavers, Elexicon identifies areas with a high number of temporary faults such as South West Pickering, North West Pickering, Ajax, and Whitby. Where coordination is difficult, trip savers are utilized as it can clear a fault faster than the relay and Recloser and breaker. The TripSaver reclosers prevent temporary faults from becoming sustained outages and avoid momentary interruptions on feeders by only signaling the affected lateral. As these temporary faults are prevented from becoming permanent outages, the requirements for trucks and reactive work can be avoided.

The quantitative benefits of new system reliability improvements and its effects on outage durations, frequencies, interruptions, and total customers affected will be analyzed. If reliability improvements are deemed beneficial within an area and if the track record indicates improvements, work will be carried out at the specific location.

4.2 Legacy Work Execution Approaches vs. Combined Operations

In more rural areas, System Reliability improvements like FCIs are installed to assist operational staff with identifying locations of faults. Areas with Momentary outages are targeted with TripSavers and these areas are typically urban. Urban areas within Elexicon demonstrate higher frequencies of momentary outages and the concentration of customers within urban areas could become a problem if an outage were to arise. Elexicon will continue to utilize the same approach to addressing system reliability improvements as in the past. As noted in the performance trends, reliability metrics have been trending down. For switches, inspection procedures were contracted out to external third-party inspectors for both Veridian and Whitby. Forms were provided in excel and word format for users to fill in based upon what was seen. Elexicon will evaluate new reliability improvements implemented across the grid concerning the effectiveness it provides. Moving forward, Elexicon will continue to implement TripSavers throughout the system. IntelliRupter Self Healing Networks will be trialed in Whitby in 2021 and the effects and benefits shall be studied and collected. As Elexicon continues to serve customers, the company shall leverage new reliability improving technologies to provide greater customer service.

4.3 Scale Increase Considerations

Evaluating reliability improvements and the effects produced can set the benchmark for other reliability improvements for the rest of the Elexicon territory. New system reliability upgrades will provide an ability to consolidate new distribution equipment standards to the utility. Elexicon can set the benchmark for new reliability improvements into the future in this upcoming DSP period. With Whitby being a more urban area like that of Pickering and Ajax, lessons learned from the past can be utilized in all service areas. Furthermore, reliability project experience from staff can consolidate expertise. If Reliability Improvement projects are close in distance, work can be coordinated more efficiently. Elexicon systems will need to account for new reliability improvement assets moving forward.

4.4 Impact of Consolidation Period / Rate Freeze on lifecycle management approach and volumes

With regards to the rate freeze, Elexicon will continue to implement reliability measures that are cost-efficient and will help the utility with reliability metrics. For instance, the installation of technology such as the IntelliRupters, TripSavers, and FCIs will assist operational crews in performing restoration and fault detection. These investments will reduce the number of trucks and time required to perform reactive work given service interruptions or outages. Additionally, experiences to savings and cost-efficient investments can be shared between the two former utilities. As one technology may produce benefits for one Service Area, the utility can also aim to achieve benefits through the implementation of the technology to another service area.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Where applicable, reference the priority of the project within the program, as well as the overall priority within the investment category.

Project ID	Project Name	Year	Net CAPEX	Priority
2020-4405A	Whitby Smart IntelliRupters Self-Healing Network	2021	$0.50	85.2

5.2 Individual Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.c.7 (SS) An analysis of project benefits and costs comparing the proposed project to a) doing nothing and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.
Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these qualitative factors in relation to the proposed project and all alternatives, including how these factors affected the selection of the proposed project.
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.

<table>
<tr><td>Project name</td><td colspan="5">Whitby Intellirupters Smart Self-Healing Network Ph2</td></tr>
<tr><td>Project numbers</td><td colspan="5">2020-4405A</td></tr>
<tr><td>Job numbers</td><td colspan="5">Several</td></tr>
<tr><td>Project District</td><td colspan="5">Whitby</td></tr>
<tr><td>Project Location</td><td colspan="5">Whitby</td></tr>
<tr><td>Investment Category</td><td colspan="5">SYSTEM SERVICE</td></tr>
<tr><td>Budget Category</td><td colspan="5">S5 - System Reliability Improvement</td></tr>
<tr><td>Project Driver</td><td colspan="5">Improve system reliability in the area by remote fault isolation and service restoration</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021 JAN 01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 DEC 31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Install five (5) SCADA-Mates Switches along with the wood poles</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $600,000</td><td colspan="2">Contribution: $0</td><td>Net: $600,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$82,781</td><td>$91,979</td><td>$156,364</td><td>$588,666</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon Energy is currently looking to make system improvements for distribution automation. Remote fault isolation and service restoration can be achieved by installation of SCADA-mate switches. Additionally, these automates switches will improve the efficiency for planned maintenance operations.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">85.2</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">Not Applicable</td></tr>
<tr><td>Intervention Options</td><td colspan="5">No alternatives to the project are technically feasible or cost effective. The status quo (do nothing) is not recommended. The overhead distribution system requires automated switches for better system outage response.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">The project will reduce the cost of O&M by better management of the system outage response. Additionally, these automates switches will improve the efficiency for planned maintenance operations.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">This project addresses the RRF objectives of customer focus, Financial Performance, and Operational Effectiveness.</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">Based on historical projects, the average cost of SCADA-Mate switch is $41,000. The average labour cost for switch installation is $25,000. Average cost of wood pole installation is $25,000.</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Normally the poles that the switches are to be installed on will be replaced.</td></tr>
</table>

Budget Category	P1-Facilities
OEB Investment Category	General Plant
Primary Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Non-system physical plant

Average Annual Program Spend – Historical	**Average Annual Program Spend – Forecast**
$0.83M	**$0.94M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Facilities investments by Elexicon Energy ("Elexicon") in the General Plant category pertain to the upkeep and purchases of new offices/operation centres and other non-system physical plant such as furniture, back-up generators, and HVAC systems. Facilities are crucial for inside and outside staff responsible for maintaining and providing Elexicon's customers with a reliable supply of electricity. As staff from the two former utilities of Whitby Hydro Electric Corporation ("WHEC") and Veridian Connections ("Veridian") merge, improvements to current facilities are required to house the consolidated workforce. Regular facilities investments are required as interior building systems and exterior infrastructure deteriorates. The purchase of new land and an operations centre in Belleville is required since the lease on the current facility is expiring and cannot be renewed.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.89	0.79	3.58	0.74	0.60	0.24	0.24	0.24
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	0.89	0.79	3.58	0.74	0.60	0.24	0.24	0.24

Supporting Summary Statements:

Elexicon's facilities investments are designated for the upkeep and upgrade of existing buildings and other non-system physical plant. Facilities investments:

1. Preservation;
2. Improvements;
3. Furniture;
4. Energy Efficiency; and
5. Roof Replacements.

Projects to note in the facilities portfolio include planned roof replacements, annual investments into furniture and energy efficiency, improvements of satellite facilities, and the construction of an operations centre in Belleville.

All facilities investments will comply with the *Ontario Building Code* and the *Ontario Fire Code*. If more staff members are moved to an existing facility, capacity within the building will be ensured for safety. Investments in energy efficiency will provide savings to electricity expenses within Elexicon's offices. Operational efficiencies shall be increased alongside safety, and comfort for Elexicon staff. Projects such as Locker Room renovations and ergonomic furniture will provide quality of life benefits to staff. Elexicon staff will be provided with a safe and comfortable environment for staff to perform work. If facilities conditions worsen and are not taken care of, shut down of critical facility functionality can affect customer service and reliability statistics.

Due to the merger, Elexicon has experienced more significant investment in recent years to consolidate and improve facilities for the combined workforce. As buildings from both former utilities are consolidated, staff will be shuffled throughout the operations centres depending on their role in the company. Improvements will be made to ensure all facilities are up to standard.

2. Basis for Action

2.1 Performance Trends:

Building/Systems Preservation: Preservation investments are meant to replace or refurbish existing facility components that have experienced deterioration or are experiencing declining performance. Annual monthly inspections are performed by Facilities staff to identify opportunities. These investments are required to maintain existing functionality. Washroom refurbishment, air conditioning, and paving of facilities are examples of preservation projects conducted by Elexicon.

Building/Systems Improvements: Elexicon looks to continue investments into improving facilities for its consolidated workforce. In 2019, Elexicon invested heavily as compared to previous years due in part to the merger and consolidation of staff. These investments are related to facility expansions and/or increased functionality/capacity of existing facilities. Historical investments into this category include security upgrades, tube heaters for garages, truck restraints, and building automation systems.

Furniture: Annually, Elexicon invests in office furniture for its staff. Opportunities to improve the equipment are evaluated annually alongside investigations into ergonomic options. Furniture investments include sit/stand desks, linesmen workstations, and other furniture.

Energy Efficiency: Elexicon looks to achieve energy efficiency in its facilities and identifies opportunities annually which they can invest in. LED lighting installations have been historical investments by Elexicon that seek to improve the efficient use of energy in buildings.

Roof Replacement: Roof replacements are a major facilities investment consideration since the roof condition is crucial to the longevity of a building. Elexicon performs due diligence in ensuring inspections are performed alongside condition analysis to identify roofs that require improvements or replacement. Condition analysis and inspections are outsourced to third-party roofing consultants. Historical roof replacements were made for the Ajax operations centre and head office. Throughout the DSP period, three roof replacement projects will take place in Beaverton, Clarington, and Gravenhurst.

Throughout the historical period, facility improvements have been the biggest portion of investments followed by roof replacements. Elexicon is committed to the continuous improvement of facilities to ensure adequate working space for all employees. Roof replacements are not annual investments but are considerable in dollar amount when required. Elexicon actively looks to improve its facilities year over year. In the year 2019, a considerable amount of investment was made by the utility towards facilities due to the merger. The 2019 year featured the highest total of investment across the historical period.

Figure 1: Percentage Makeup of Historical Facilities Investments

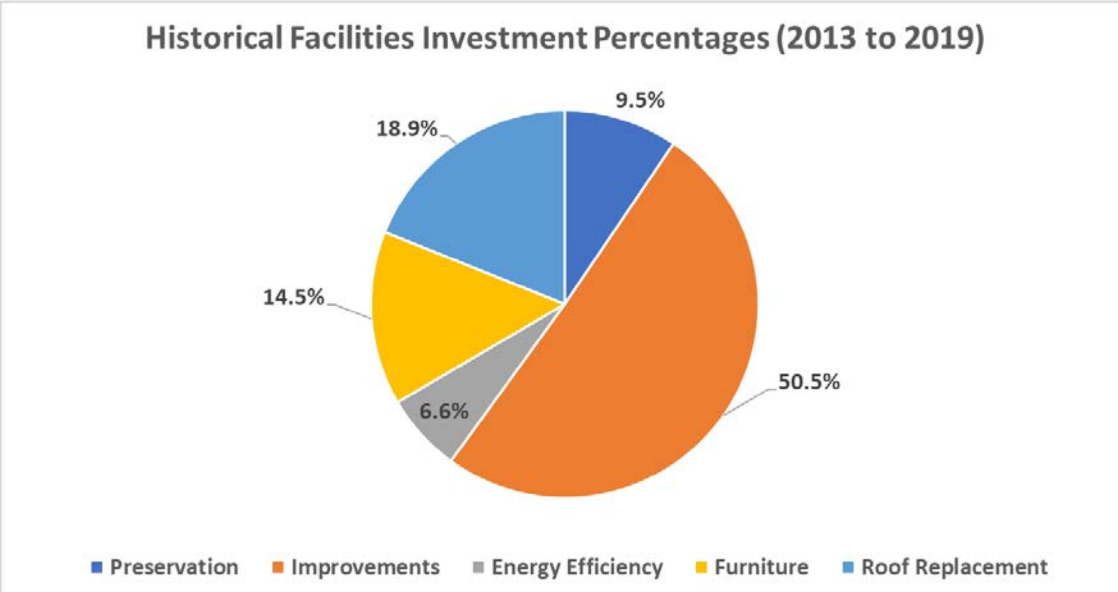


Figure 2: Historical Facilities Expenditures for Veridian

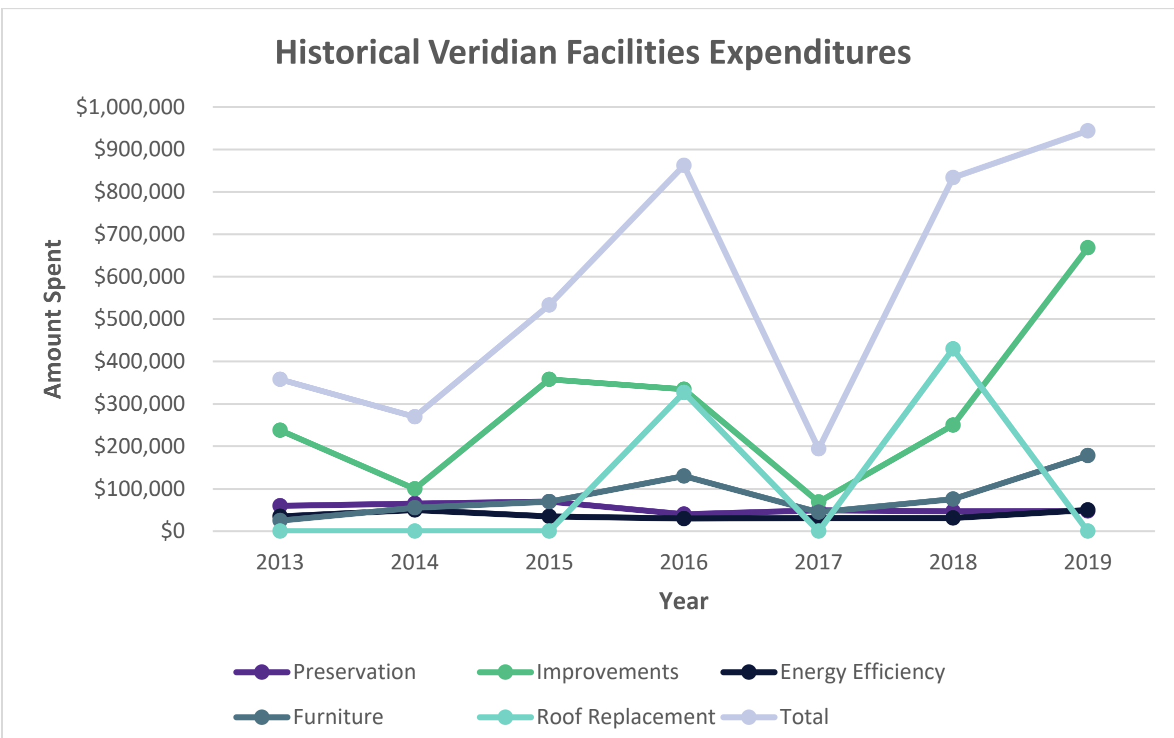


Table 2: Historical Facilities Investments (2013 to 2019) for Veridian

Investment Category	2013	2014	2015	2016	2017	2018	2019
Preservation	$60,000	$65,000	$70,000	$40,000	$49,000	$47,000	$48,000
Improvements	$238,000	$100,000	$358,000	$335,000	$69,000	$250,000	$668,000
Energy Efficiency	$35,000	$50,000	$35,000	$30,000	$31,000	$31,000	$50,000
Furniture	$25,000	$55,000	$70,000	$130,000	$45,000	$76,000	$178,000
Roof Replacement	$0	$0	$0	$327,000	$0	$430,000	$0
Total	$358,000	$270,000	$533,000	$862,000	$194,000	$834,000	$944,000

As noted in the past spending from the Facilities department, the recent years of 2016, 2018, and 2019 have been the biggest spending years. This is due in part to roof replacements during 2016 and 2018. 2019 did not have any roof replacements, but as a result of the consolidation of facilities and required improvements from the merger had the highest spend.

2.2 Current-State Analysis:

List of current Facilities of Elexicon Energy

Elexicon currently owns seven different facilities across its service territory. It should be noted that the Belleville office will change locations as the lease will expire. Planned investments into a new building and land in Belleville have been planned for the future DSP period.

Table 3: Elexicon Energy Facilities

Location	Function(s)	Ownership Status
55 Taunton Road East Ajax	Corporate Head Office Main Operations Centre Main Warehouse	Owned – built in 1992 and expanded in 2010
100 Taunton Road East	Finance and Regulatory Departments Elexicon Group Main Operations Centre Main Warehouse	Owned – built in 1990
459 Sidney Street Belleville	Office Staff Local Operations Centre Local Warehouse	Leased- The lease is expired and Elexicon will move to another location in Belleville in 2021
195 Progress Avenue Gravenhurst	Office Staff Local Operations Centre Local Warehouse	Owned – built in 1994

Location	Function(s)	Ownership Status
2849 Hwy #2 Clarington	Local Operations Centre Local Warehouse	Owned – built in 1984
Hwy 12 Beaverton Township of Brock	Local Operations Centre Local Warehouse	Owned – built in 1962
1885 Clements Road, Unit 275 Pickering	High Availability Site	Owned – built in 1998

Belleville Building Relocation and Purchase

Elexicon's lease for the Belleville facility will be expiring in October 2021 and there is no option to extend. The procurement of land will be conducted by Elexicon and a completed build and relocation is aimed for 2021. The current Belleville building is shared with the City of Belleville's public water utility. Relocation options for the new facility are between six- and ten-minutes driving time from the current location within the Belleville service area. It is preferred that the facility remains south of Highway 401 to the Bay, between Avondale to the west and Farley to the East to respond to customer sites and maintain customer service.

At the current Belleville building, Elexicon does not control the mechanical systems and the HVAC systems only operate from 7:00 am to 5:00 pm. Security is compromised since it is shared between the two utilities. Internet connectivity in the building is poor and there is no customer service counter in the building for customers to pay bills or ask questions. In the areas used by lines crews, air exchange is poor, locker rooms are small, and there is a lack of drying room for outside gear. The Belleville Water Utility also shares the garage with Elexicon, which poses challenges during winter months for access. No storage space exists either on the platform for any hooks or shelves. Stored transformers are placed on the ground on outside parking which makes it difficult to access during winter months. There is also a requirement to provide indoor parking for Elexicon's largest service vehicles; indoor and outdoor parking will be considered to compare costs and benefits.

The future Belleville building shall be built to the Ontario Building Code and to LEED standards. New workstation areas shall be incorporated for GIS, Engineering, Administration and visitors. Lunchrooms, SCADA rooms, Line's areas, warehousing, garage space and Metering areas will also be built within the building. Outside Storage will also be incorporated on platforms instead of the current storage on ground practice.

Roof Replacements

Roof replacements are scheduled for Beaverton, Clarington, and Gravenhurst over the forecast period of the DSP. As these buildings age, roof replacements are required to replace the deterioration. Additionally, leaks can result that cause additional costs such as clean-up, loss of the roof space, damage to the interior, mold, and mildew. Heat losses are also prevalent with roofs that are not up to standard. Roof inspections and condition analysis are performed by external consultants to identify the conditions of roofs at Elexicon facilities. The planned replacements coincide with the details found within the reports and are meant to be replaced due to roofs being at end of life. Elexicon will monitor roof leak interruptions for locations of roofs identified.

Roof Replacement: Beaverton

The Beaverton facility roof replacement has been scheduled for 2022. Active leak conditions were reported within the interior building space under the sloped roof deck. Other deficiencies include deteriorated sealant at one ridge vent detail, backout of mechanical fasteners, clogged downspouts and gutters, damaged gutter straps, redundant pipe penetration detail, stack flashing concerns, deteriorated wall penetration sealants, and organic debris. The roof is approximately 29 years of age. Deficiencies were observed on the second slop canopy such as missing sidewall flashing, deteriorating sealant at vertical termination, and missing metal fascia and gable trim. The following images illustrate the deteriorating sealant and corrosion of metal roof panels found on the Beaverton roof.

Figure 3: Images of Beaverton Roof Defects

Roof Replacement: Clarington

The Clarington facility roof replacement has been scheduled for 2022, when replacement and removal construction of all roof assemblies are to be completed. While there are no current active leak conditions, the main roof is approximately 25 years old and the sloped roof deck is approximately 19 years old. For the sloped roof deck, the deficiencies at the time of inspection include staining and a small amount of organic growth on one slope, and organic debris in the gutter.

Roof Replacement: Gravenhurst

The Gravenhurst facility roof replacement has been scheduled for 2023. Roof decks inspected did not have reported active leak conditions or significant deficiencies but are approximately 25 years of age. For sloped roof decks, they do not have any reported active leak deficiencies but display staining and a small amount of organic growth on one slope and organic debris in the gutter. The sloped roof decks are approximately 19 years of age.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

Ontario Building Code: Elexicon facilities must follow O.Reg 332/12, the *Ontario Building Code*. The Building Code outlines the fundamental requirements (technical and administrative) that all buildings require for occupancy or use across various categories. These requirements govern functions such as renovation, change of use, and construction of buildings in Ontario.

Ontario Fire Code: Elexicon facilities must also follow O.Reg 213/07, the *Ontario Fire Code*. Occupancy and fire safety implementation must be up to standard to the Fire code. The *Ontario Fire Code* sets the minimum requirements respecting fire safety within facilities and buildings.

OEB Metrics: Facilities conditions and capabilities can affect Elexicon's performance with regards to annual OEB Scorecard metrics. For instance, a working facility will allow the utility to have adequate capacity and comfort for customer care to respond to calls and settlements. The operation and design of the grid can also be maintained if facilities housing staff are performing well. In cases where facility outages or problems arise, this could negatively impact a variety of measures. Garage and gates for fleet vehicles need to be in good operating condition and reliable. If for some reason, the gate or facility does not open and allow fleet vehicles to efficiently move onto roads, SAIDI could be impacted greatly.

COVID-19: With the recent occurrence of COVID-19, new facilities practices will be updated, and positioning of seating locations and areas will be changed. This is to ensure adequate safe working distance from operational staff is followed such that transmission may not be possible. New maintenance procedures will need to be developed and implemented to ensure facility health and safety excellence.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Facilities contribute to Elexicon's housing for all departments and allow for inside and outside workers to safely and more efficiently work at designated locations. Improvements to facility assets ensure that employees have the necessary ergonomics and safety while performing work. Operational efficiencies are realized by the upkeep and improvements of facility components. If facilities are unsafe or insecure, they could contribute to potential injuries and security incidents within the workplace.

Customer-focused metrics that are impacted by facilities investments include Service Quality and SAIDI. If facilities are not optimal or run into issues for access, fleet vehicles will not be able to leave facilities and address troubleshoot calls. Furthermore, suboptimal control room operations due to facility negligence would lead to operational issues and delays to grid response. Facilities must be adequately safe, secure, and ergonomic due to the criticality that facilities have on control room activities and other utility operations. Elexicon customers expect consistent and excellent customer service especially with respect to customer requests, new connections and in restoring power. Insufficient facilities would lead to disruptions to customer service quality which would impact the daily lives of customers.

2.5 Merger-Related Objectives:

The status quo is optimal for investments as Elexicon has consolidated facilities from the two previous utilities. As facility assets deteriorate and reach the end of life, Elexicon will make prudent investments to renew its non-system physical plant. The combined facilities budget will be directed at upgrading some of the satellite operations facilities throughout the Elexicon service territory. As investments are made into the consolidated facility portfolio, realized benefits will arise in savings and performance improvements of building and staff. Elexicon will uphold satellite offices due to the non-contiguous service area it is responsible for. Satellite offices allow for better response times and dedicated staff to each territory.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.d.1 (GP) The results of quantitative and qualitative analyses of the proposed project/program, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable

Number	1	2	3	4
Scenario Description	Status Quo; Budgeted Investments in Facilities	Greater Investment (25% more)	Smaller Investment (25 % less)	Invest only in upgrades when deterioration is found
Annual Program Scope	The current budgeted investments into facilities are an optimal balance between refurbishment, improvements, and upgrades.	Greater Investment into facilities upgrades and consolidations will be completed. About 25% more of the budget will be added on.	Less Investment into facilities upgrades and consolidations will be completed. About 25% less of the budget will be added on.	In this scenario, new upgrades are the only action performed when discovering deterioration. The facility asset will be completely replaced with a greater functioning replacement.
Annual Gross CAPEX	$0.94	$1.18	$0.71	$1.88
Annual Net CAPEX	$0.94	$1.18	$0.71	$1.88
Annual Program Benefits	The budgeted plan is paced such that Elexicon has sufficient resources to execute the program. Projects are prioritized such that the most beneficial projects are completed first while accounting for interdependencies between projects. See Section 3.2 for the program benefits and Section 5.1 for the	It is anticipated that there will be limited incremental benefits to increasing the pace of investments. Roof replacement and energy efficiency projects could be expedited with a higher budget; however, faster execution amidst the Belleville office relocation would compound the difficulty of doing so.	Smaller investment into the facilities program would produce less benefits and contribute to compounding requirements of facilities. Investments are made to address any issues current Elexicon facilities are facing. Underinvestment would require future higher spending to address	In this case, Elexicon will realize more benefits from completing an entire upgrade over maintenance or prolonging the expected life of facility assets. In doing so, expenditures to this program would increase. Elexicon believes that the mixture of upgrading and maintaining existing facility

	prioritized list of material projects in the 2021 Bridge Year.		the issues that were not addressed earlier.	assets is the most cost-effective approach.
Program Economics	The average forecasted program spend is approximately that of the historical expenditures. However, it is expected that in 2021, Elexicon will be spending a majority of that forecasted spend on the new Belleville Operations Centre. These investments are made to ensure service continuity for customers and improve operational effectiveness within the region.	Increasing the level of investment into the facilities program by 25% is currently deemed unnecessary in comparison to the proposed spend of the Preferred Alternative. The first alternative aligns to historical levels, satisfies the operational requirement of a new center, and addresses the current issues identified in the program.	Decreasing the level of investment into the facilities program by 25% is insufficient in comparison to the proposed spend of the Preferred Alternative. Under-investments in the program will delay and may bring about more required investments in the future for the facilities program. This could affect service quality and operational effectiveness of Elexicon.	Upgrading facility components only instead of also being able to maintain components would increase the spending in this program. Compared to historical expenditures, the forecasted expenditures would double. The current Preferred Alternative is the most efficient and optimal investment strategy. Elexicon should be able to upgrade and maintain facility assets, not one or the other.
Customer Feedback	Elexicon Customers (262 from online, 600 from phone) were surveyed about Elexicon's request for funding for the new Belleville Operations Center. 72.3% (623 of the 862) of customers felt that the proposed investments to the centre were appropriate. 83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.			
Other Constraining Factors	If further degradation is found in the DSP period, a shift in the investment budget for facilities will need to occur. Budgets from other General Plant programs could fulfill the resource need as well.	Greater Investments are not preferable as Elexicon has budgeted an adequate amount of investment into facilities. Marginal returns are made with greater facilities investments. Investments that are required have been planned.	Less investment in facility assets will negatively impact Elexicon. Investments have been planned for Elexicon to have service and business continuity. The decreased investment could also affect staff morale.	Upgrading only as an action is not operationally efficient and would cost Elexicon significantly more than refurbishing, replacing, and upgrading.
Preferred Alternative	X			

3.2 Rationale for the Preferred Alternative.

> *-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.*
> *-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.*
> *For proposed distribution rate funded CDM programs the following details are required:*
> *• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers*
> *• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred*

Reliability: SAIDI numbers decrease if facility investments are not made as planned. Gates, entrances, and any facilities related to operations need to be high-performing to allow crews to react to outages and interruptions. Any facilitates related to the control room need to be particularly high-performing so that system operators can respond to incidents in the field and facilitate planned switching operations.

Grid Resiliency: When Elexicon experiences Major Event Days or events regarding extreme weather, facilities will need to be able to perform adequately in these situations. Key utility facilities include control rooms, back-up generators, and incident command centres. Facilities must have the appropriate systems to respond to adverse events.

Operational Efficiency and Cost Effectiveness: Operational efficiency is affected greatly by facility investments made by Elexicon. Fleet and operations require facility investments into locker rooms, garages, and supplies. Any sub-optimal facilities prevent the operational efficiencies for outside workers. Facility investments into interior furniture also help inside workers more optimally approach and perform work. New facilities equipment such as HVAC systems tend to be more efficient than legacy models, supporting the cost-effectiveness of Elexicon as an organization.

Safety: Facility investments help ensure a safe and secure workplace for all Elexicon staff. This is paramount to ensuring safe daily operations of the grid are met. Regular facility investments reduce the risk of a safety event for staff and customers visiting Elexicon's customer service desks.

Cyber-Security/Privacy: N/A

Environmental Benefits: Environmental benefits are realized from any facilities projects geared towards energy efficiency. A decrease in emissions and wasted energy can be produced from further facility investments. Currently, Elexicon engages in energy efficiency initiatives to decrease the amount of energy consumption within facilities.

Coordination/Interoperability: N/A

Conservation and Demand Management: CDM can be realized within the Elexicon facilities by incorporating facility components that help conserve and manage the demand of the buildings. As noted above, Elexicon actively looks to implement energy efficiency initiatives that would increase the efficiency of non-system physical plant including LED lighting.

Net Customer Benefits: Based on the proposed plan, customers will benefit from the continued operation of Elexicon's service centres, which serve as primary dispatch points for Elexicon's crews and front-line customer service desks. These service centres are critical to provide reliable service across a large and non-contiguous service area. Elexicon's facilities also benefit customer experience by hosting Elexicon's call centres, grid operations, and engineering staff who provide services for customer-requested work and new connections.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

If more severe deterioration is found within the facilities assets, the problems will be addressed with the current budget. Any other items which are not as pressing will be moved to the next calendar year. A comparison between the quickly deteriorating facility asset and the planned replaced asset will be produced to ensure that the most pressing or emergency facility investments are addressed.

COVID-19 has introduced numerous contingencies towards facilities planning and investments. As staff will need to be socially distant and workstations need to be sanitized, new upgrades and changes to current seating arrangements are made. Elexicon will evaluate the requirements to ensure current working facilities are suitable and safe for essential staff who require usage of facilities.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Typical Lifecycles and sustainment strategy for facilities

Elexicon has historically and currently designated lifecycles and action guidelines when facilities plant has reached end-of-life. This approach to facility asset management and investments will be utilized moving forward. The referenced facilities assets are listed below in Table 4. Asset typical useful lives based on International Financial Reporting Standards values are also provided in Table 5.

Table 4: Elexicon Facility Asset Typical Life Cycle

Asset	Typical Life Cycle	Replace / Refurbish Guideline	Comment
Furniture	10 years	Replace when damaged	Standardization of furniture across all locations addresses the following criteria: aesthetics, durability, maintenance, sustainability, and warranty
HVAC Systems	15 years	Refurbish/Replace	Many system components can be refurbished to extend the life cycle
Generator Systems	25 years	Refurbish/Replace	Existing generators are in the early stage of their life cycle
Security System	15 years	Replace	System upgrade in 2013/2014
Fire Systems	20 years	Refurbish	Many system components can be refurbished to extend the life cycle
Roof Structures	20-30 years	Replace	Replace upon the end of life
Parking Lot, Driveways	15 years	Replace	Replace upon the end of life

Table 5: IFRS Facility Typical Useful Life

Facility Component	TUL (IFRS Documentation)
Building Exterior	25
Building Interior	15
Structure	50
HVAC	25
Land Rights	50
Office Furniture	10

Elexicon currently has an inventory of major equipment that includes the date of install and maintenance plan. Condition Tracking is a work in progress for the Facilities department which will assist Facility planners in making investments.

The facilities department continually seeks opportunities to invest in energy efficiency for HVAC and lighting systems. If the business cases for energy efficiency retrofit opportunities produce positive value, the energy-efficient investment is pursued.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Regular maintenance of equipment is performed by the facilities department to prevent equipment breakdown and extend the useful life of facilities asset. Inspections, testing, lubrication, cleaning, and filter changes are the preventive measures used in facilities maintenance at Elexicon. Every month, the following facility components are inspected and maintained which include:

- HVAC systems;
- Generator equipment;
- Water management systems;
- Fire systems;
- Security systems;
- Yard gates; and
- Lifting devices (e.g., fork lifts, elevators)

Figure 4 demonstrates the monthly planned inspections that Elexicon performs facilities. The colours demonstrate the year-to-date status of the maintenance practice as of Oct. 31, 2020; any issues are highlighted to be resolved. Elexicon is diligent in ensuring facilities are run smoothly and without trouble.

Figure 4: Elexicon Facility Maintenance Schedule

	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Carpet Cleaning				✓								✓
Window Washing							✓					
Daily Janitorial Services	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Fire Alarm Tests	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sprinkler Test			✓									
Generator Testing (bi-weekly)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Generator Maintenance		✓			✓			✓				
HVAC Maintenance		✓				✓		✓				
Fire Extinguisher Certification											✓	
Elevator Testing	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Elevator Certification	✓											
Elevator Inspection	✓	✓	✓	✓	✓	✓	✓	✓	✓			
Backflow Prevention Testing			✓									
Fire Hydrant Testing										✓		
Clarington Water Testing	✓		✓		✓		✓		✓		✓	
Overhead door/Gate Inspections	✓		✓						✓			

Minor repairs are completed using internal resources. If a project is specialized or too large for Elexicon's staff, contracted resources are used. For instance, roofing replacements and inspections are carried out by third-party consultants.

4.3 Scale Increase Considerations

As a result of the merger, facility assets and staff have been consolidated. Veridian's main operations centre has been transformed into the main operations centre for Elexicon Energy. The two individual control rooms of WHEC and Veridian are now combined into one main control room of Elexicon. Operational efficiencies are realized from the combination of both facilities. Satellite operations centres from Veridian will continue to operate for service territories far from the main operations center. The maintenance budget from WHEC is carried over to Elexicon Energy allowing further improvements to current facilities.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Elexicon will ensure that facilities will be consolidated from the two former utilities. For instance, the main operations center shall house the main control room and integrate many of the core functions of Elexicon. Any new additions to current facilities will be assessed and determined if required. Satellite offices are maintained so that operational staff can respond to issues more efficiently. More efficient use of spending will be utilized to house the combined staff of the former utilities.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year (End)	Net CAPEX	Priority Score
2016-2012	Belleville Relocation building	2021	$2.6	57

5.2 Individual Material Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.d.2 (GP) Where the capital cost of a project substantially exceeds the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.

Project name	Belleville Relocation Building
Project numbers	2016-2012
Job numbers	N/A
Project District	General
Project Location	Belleville
Investment Category	General Plant
Budget Category	Facilities
Project Driver	Non-system physical plant
Proposed Start Date	December 1st 2020
Required In-Service Date	December 31st 2021
Scope of Work	Construction of new Belleville Operations Centre. See Appendix D in the attached Cresa report for the design-build specifications.

<table>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $2,600,000</td><td colspan="2">Contribution: $000</td><td>Net: $2,600,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$234,000</td><td>$260,000</td><td>$442,000</td><td>$1,664,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The City of Belleville has provided notice to Elexicon that the current lease arrangement at 31 Wallbridge Cres will not be extended as they intend to move another City department into the space occupied by Elexicon. The lease expires in October 2021.

In 2016, Elexicon hired an external consultant (Cresa) to conduct an assessment of the current situation of the previous shared building at 459 Sidney Street, the future needs of the Belleville location, conceptual alternatives and a financial lease/buy analysis. This report is appended to this document and forms a core part of the business case.

The assessment also identified the requirement of the facility to be located within the Elexicon service territory, and in close proximity to the existing facility in order to maintain current outage response times. To that degree, Elexicon has negotiated a land exchange with the City of Belleville for the vacant land on Coleman street, which is adjacent to the existing property. The land transfer was completed in November 2020.

A local contractor will be selected for the design/build of the new building and property with construction beginning in December 2020.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">57</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">All employees at the Belleville location.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">No option available to extend the existing lease with the City of Belleville beyond a couple of months for construction delays. Elexicon has reviewed available properties for sale/lease in the area and none met the needs assessment for the facility. See Appendix A of the attached Cresa report for a detailed review of the survey options. See Appendix C of the attached Cresa report for a detailed review of the implementation options.</td></tr>
<tr><td>Effect on System O&M Costs</td><td colspan="5">Increase O&M costs as Elexicon will be responsible for all maintenance costs related to the building and property.</td></tr>
<tr><td>Targeted Outcomes</td><td colspan="5">Operational Effectiveness</td></tr>
<tr><td>Cost Benchmarks</td><td colspan="5">2010 & 2011 – Ajax building expansion – $8.02M
2011 – Ajax building renovations and control room relocation - $2.12M</td></tr>
<tr><td>Value-Added Approach</td><td colspan="5">Per the Cresa report, the design-build option was the preferred approach compared to the “Design bid build” option, since the project can be completed quicker and cost efficiencies can be achieved with a single design-build team.</td></tr>
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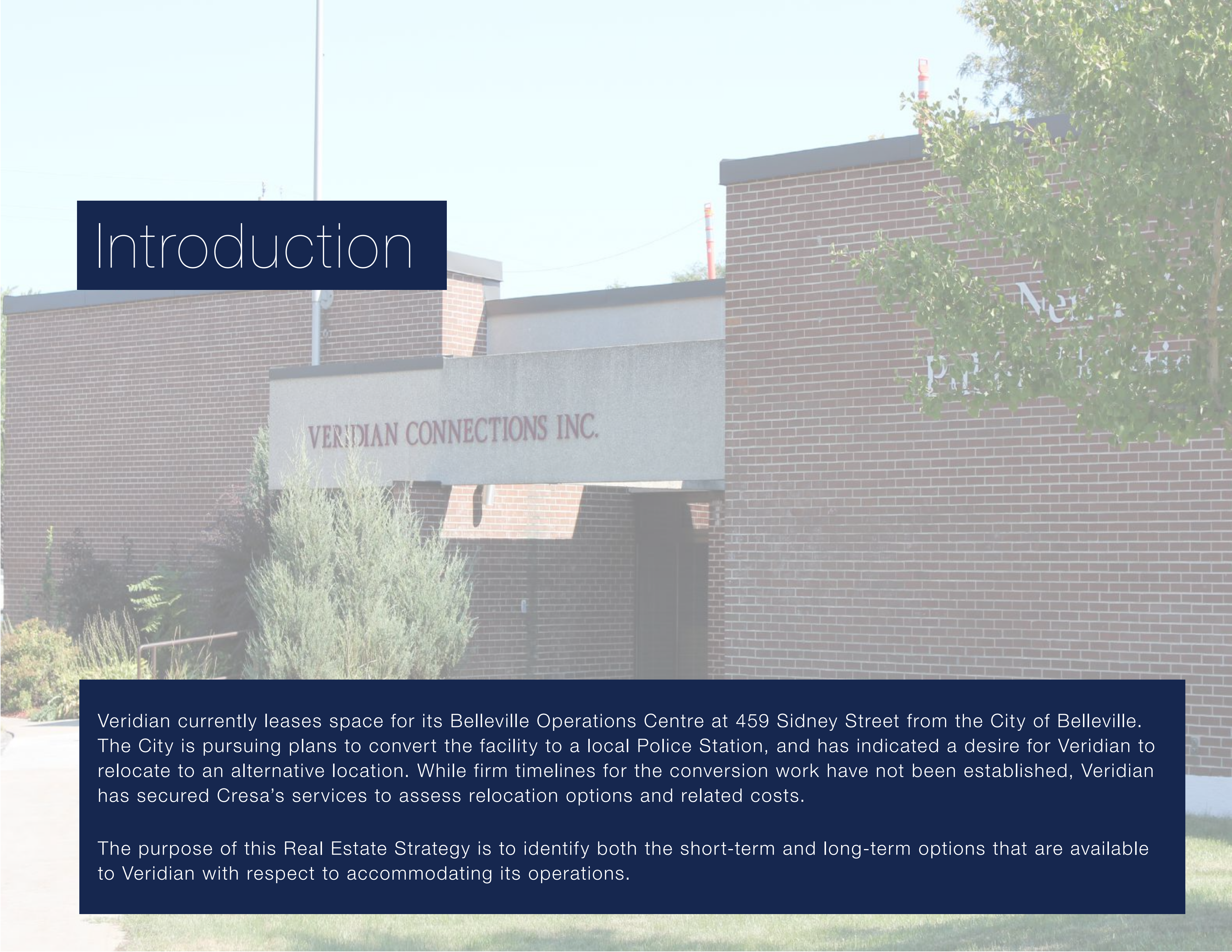
Veridian Connections Inc.
Belleville Operations Centre

REAL ESTATE STRATEGY

December 12, 2016

cresa
The Tenant's Advantage

Table of Contents



Introduction

Veridian currently leases space for its Belleville Operations Centre at 459 Sidney Street from the City of Belleville. The City is pursuing plans to convert the facility to a local Police Station, and has indicated a desire for Veridian to relocate to an alternative location. While firm timelines for the conversion work have not been established, Veridian has secured Cresa's services to assess relocation options and related costs.

The purpose of this Real Estate Strategy is to identify both the short-term and long-term options that are available to Veridian with respect to accommodating its operations.

Objectives of Report

- Confirm future requirements for Veridian Connections' Belleville Operations Centre
- Develop a Strategic Facilities Plan aligning real estate with Veridian's business goals
- Identify relevant options, including leasing or ownership of existing buildings or greenfield sites for a purpose built facility
- Provide budget estimate of the cost to implement various options
- Highlight next steps and the associated timeline for implementation

Sources

- The information contained within this report has been compiled from the following:
  - Identification of needs by way of interview with Veridian's Steering Committee on August 19, 2016 and subsequent meeting with the Belleville User Group on August 26
  - Tours of Veridian's Belleville, Clarington and Ajax Operations Centres
  - Property tours on September 2, 2016
  - Space programming analysis prepared by Cresa, based upon information provided by Veridian
  - Data collected through independent market research
  - Steering Committe Review on October 14, 2016

Section 1

Where are we today?

Lease Highlights

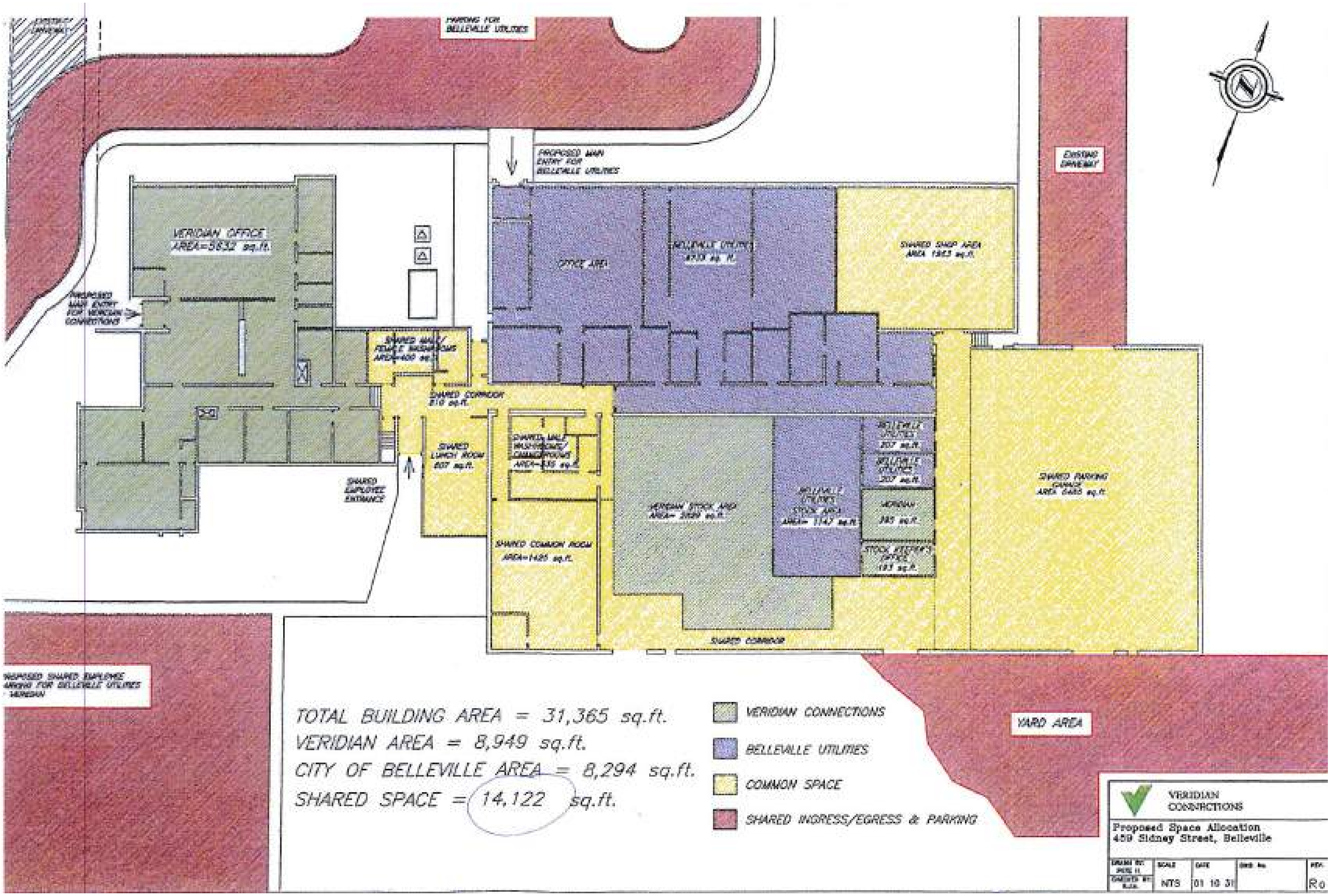
Lease Date:	October 22, 2001	**Expiry Date**	September 30, 2021
Tenant:	Veridian Corporation	**Remaining Term:**	None
Subtenant:	City of Belleville Water Utility	**Net Rent:**	$30,000 Per Annum
Landlord	The Corporation of the City of Belleville	**Additional Rent**	$137,773.73
Building:	459 Sidney Street, Belleville		

Occupancy Cost Summary

OCCUPIED AREA:	VERIDIAN CONNECTIONS	BELLEVILLE WATER	TOTAL
Dedicated Area	8,949 SF	8,294 SF	17,243 SF
Shared Area:	5,997 SF*	8,125 SF*	14,122 SF*
TOTAL OCCUPIED AREA:	**14,946 SF**	**16,419 SF**	**31,365 SF**
* Note that because some areas are shared, the allocations above are estimates only and have not been verified through measurement.			
VERIDIAN OCCUPANCY COSTS			
OCCUPANCY COSTS	**Total Building**	**Dedicated Area 8,949 SF ($ PSF)**	**Dedicated + Shared Area 14,946 SF ($ PSF)**
Basic Annual Rent[1]:	$30,000.00	$3.35 PSF	$2.00 PSF
Additional Rent[2]:			
Property Taxes	$54,237.00	$6.06 PSF	$3.63 PSF
Utilities	$34,523.95	$3.86 PSF	$2.31 PSF
Grounds Maintenance	$4,053.51	$0.45 PSF	$0.27 PSF
Building Maintenance	$42,229.03	$4.72 PSF	$2.83 PSF
Other (Insurance, etc.)	$2,690.24	$0.30 PSF	$0.18 PSF
TOTAL ESTIMATED OCCUPANCY COST PER ANNUM	$167,773.73	$18.74 PSF	$11.22 PSF

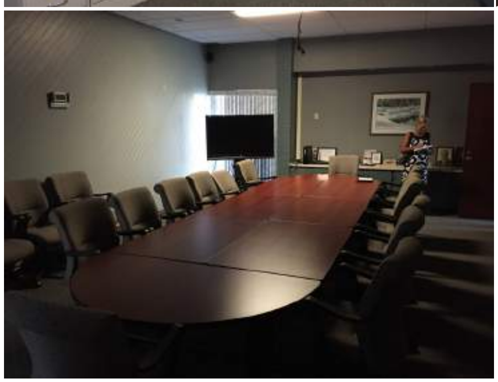
1. Sublease recovery from Belleville Water Utility = $1 PA
2. Includes Veridian's share of Additional Rent (excluding Belleville Water Utilities)

459 Sidney Street Building Layout



Current Premises - Office Area





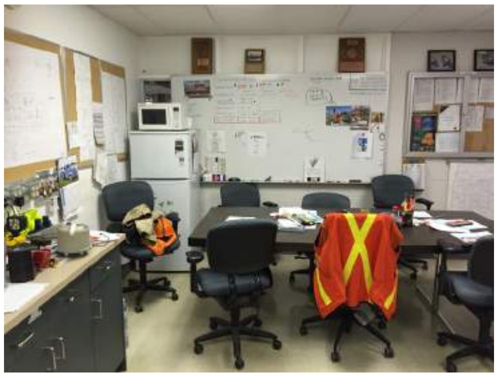

WHAT'S WORKING

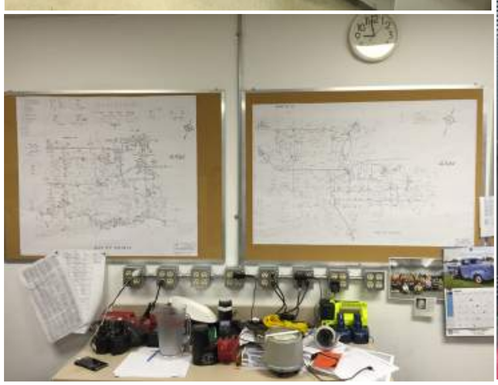
- Office area is well laid out and spacious
- Veridian workstation standards have been employed, providing uniformity with other facilities.
- Main boardroom is well sized and frequently utilized.
- Dedicated computer training room is well set up and frequently utilized.
- Lunch room is well equipped and adequately sized for the building population.

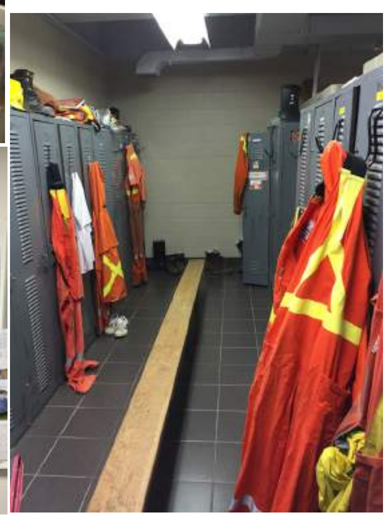
WHAT'S NOT WORKING

- Internal travel distances are excessive due to the size of the building relative to Veridian's occupied space.
- Veridian does not control the mechanical systems in the building; as a result the interior environment, including air quality, is not optimal.
- HVAC systems operate 7:00 a.m. - 5:00 p.m., resulting in the building being poorly heated or cooled at beginning and end of the work day. Thermostats do not override base building settings.
- Security is compromised due to sharing of the facility.
- Building does not have fibre or WiFi and bandwidth is limited. Connectivity is inconsistent.
- Parking lots are not adequately plowed in winter.
- Customers frequently try to access the building to pay bills or ask questions. Building is not staffed for these functions.

Current Premises - Lines Area







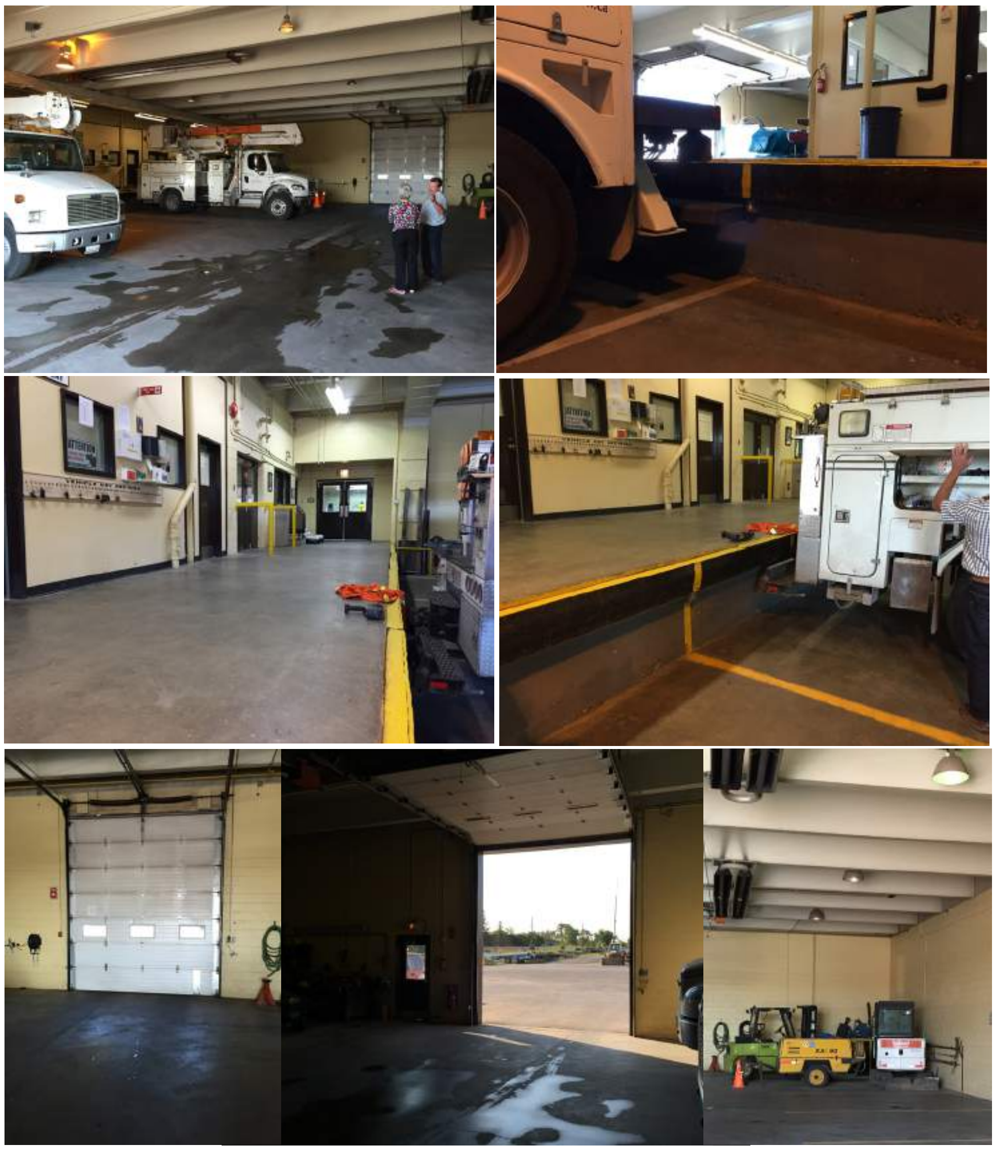
WHAT'S WORKING

- Sufficient meeting space for Lines Crew adjacent to Lead Hand.
- Ample wall space to display maps, etc.

WHAT'S NOT WORKING

- Lack of proper drying room for outside gear.
- Air exchange in locker room is poor.
- Individual lockers are small for the amount of equipment to be stored.

Current Premises - Garage



WHAT'S WORKING

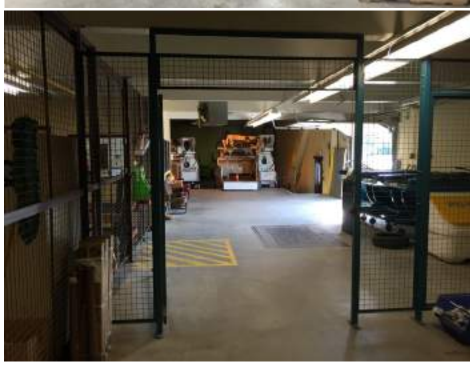
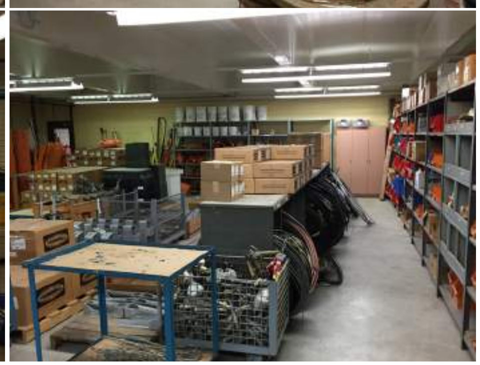
- Dual access from front and rear of garage provides good traffic flow and flexibility in the event the rear gate is inoperable or there are other traffic issues.
- Elevated platform in garage area provides good space for loading / unloading.
- Good open space provides space for truck washing.

WHAT'S NOT WORKING

- Access to the garage, especially during winter months, can be challenging due to the sharing arrangement with Belleville Water Utility.
- There is no storage space on platform (hooks or shelves).

Current Premises - Warehouse



WHAT'S WORKING

- Warehouse is well sized to accommodate both Veridian and Belleville Water Utility.
- Shipping / receiving doors are adequate.

WHAT'S NOT WORKING

- Low height restricts ability to store inventory on higher racks and reduce floor space.
- Couriers do not have access to back door unless they come through the gate.
- There is no visual contact with the gate.

Current Premises - Outside Storage





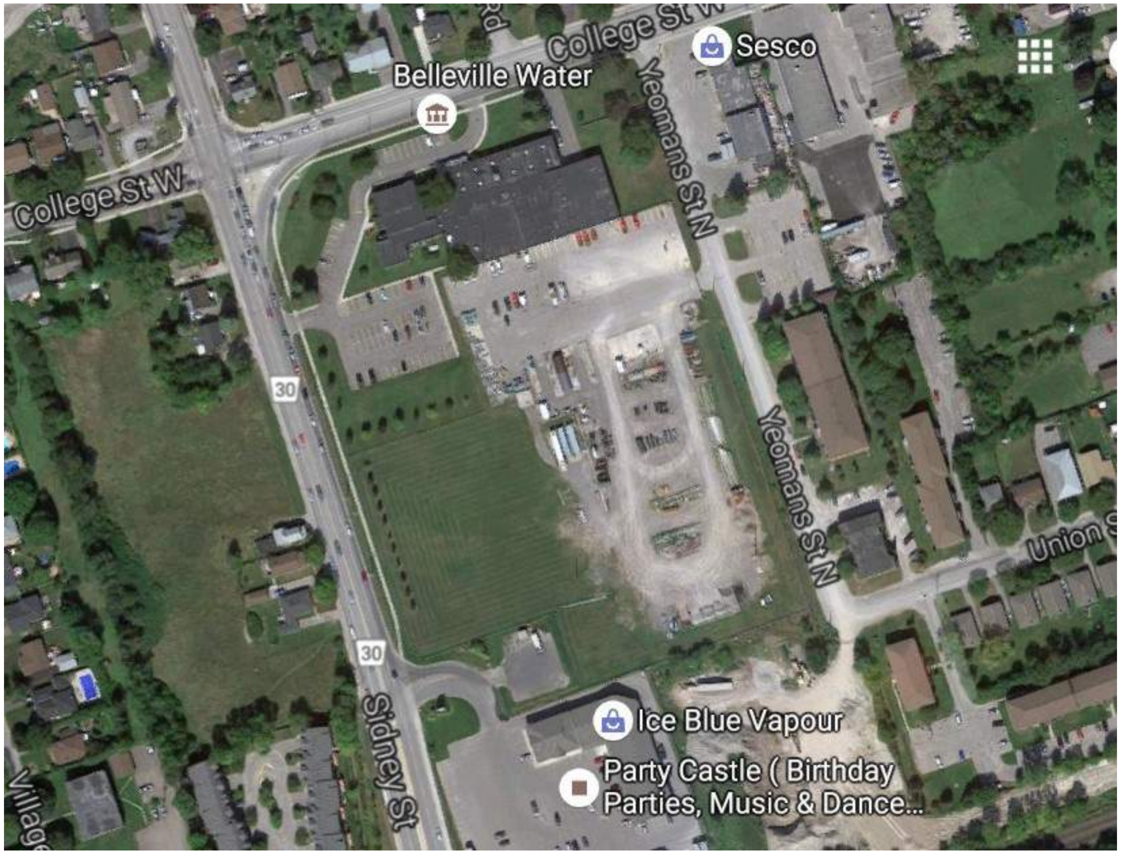

WHAT'S WORKING

- More than adequate storage space.
- Access to fuel pumps is convenient.

WHAT'S NOT WORKING

- Transformers set on ground; difficult to access in winter months.
- Snow is not cleared properly.
- Sliding gate frequently out of service. Note: Gate was damaged by lightning some time ago; Veridian determined that it would not be fixed with relocation pending.

Location



WHAT'S WORKING

- Current location is ideal for servicing Veridian's customer base.
- Good access into and out of the site.

Section 2

What are our future needs?

Space Calculation

OFFICE & WORKSTATION REQUIREMENTS		Staff #	O1 130 SF	WS 1 49 SF	WS 2 15 SF	Qty	SF	Total Functional
GIS / Engineering / Admin		4	0	4	0	4	196	
Lines		9	1	1	2	4	209	
Stores (WS Included in WH Area)		1	0	1		1	0	
Metering		3	0	3	0	3	147	
Olameter		1	0	0	2	1	30	
TOTAL OFFICE & WORKSTATIONS			1	9	3	13		582
DEPARTMENTAL SUPPORT								
GIS / Engineering / Admin								
Admin Storage	Locked Storage for supplies, cameras, petty cash					1	100	
GIS Filing	10 total cabinets					1	50	
Layout Table	6 filing cabinets with transaction top					1	50	
Plotter Room	HP DesignJet T1100ps + paper storage					1	100	
Copier / Scanner	Standalone multi-function machine					1	18	
Lines								
Crew Area (Open)	Open meeting area with seating for 8-10					1	300	
Locker Room	18-20 lockers (24” wide) with 2’ bench and 4’ aisles					1	260	
Shower / Washroom (Male)	2 showers / 2 urinals / 2 WCs					1	225	
Locker / Shower / Washroom (Female)	4 lockers + shower + single WC					1	120	
Drying Room / Mud Room						1	150	1,373
CENTRALIZED SUPPORT								
Meeting Room / Lunch Room / Training Room	Divisible Lunch / Meeting / Training Room with seating for 20					1	750	
AODA Washroom	AODA Compliant Unisex Washroom					1	120	
SCADA / Radio Room	Located in proximity to tower					1	100	
IT Room	Centrally located with adequate AC					1	80	1,050
TOTAL WORKSPACE & CENTRALIZED SUPPORT								**3,005**
CIRCULATION	General circulation, corridors, etc. (40%)							**1,200**
TOTAL OFFICE AREA								**4,205**

INDUSTRIAL COMPONENTS	Qty	SF (Incl, Circulation)
Garage	1	8,000
Warehouse	1	2,000
Metering	1	500
TOTAL INDUSTRIAL AREA (circulation included)		**10,500**

SUMMARY	
Total Staff (Including Growth)	18
Departmental Office Requirements	582 SF
Departmental Support	1,373 SF
Centralized Support	1,050 SF
Sub-Total Office & Centralized Support	3,005 SF
Circulation (40%)	1,200 SF
Total Office Area	4,205 SF
Garage	8,000 SF
Warehouse & Metering	**2,500 SF**
Total Industrial Area	10,500 SF
Uplift (Corridors, etc.) - 6%	1,000 SF
TOTAL EST. BUILDING AREA	**15,705 SF**

Future Premises Requirements

BASE BUILDING

- Cost-effective, functional building
- Compliant with current Codes, including AODA
- Built to LEED standards; certification would be dependent on additional cost
- Natural light throughout occupied office and support areas
- Energy efficient lighting; on occupancy sensors with manual override
- Quality HVAC systems with optional BAS, remotely controlled
- No public access or reception area required; external drop box for customer use
- First aid stations (2) with First Aid Kit, Stretcher, Eye Wash and AED
- Adequate power, properly distributed
- Genset (75 kW) to support Operations activities in the event of power outage
- Fire protection throughout; dry system in IT area, wet system through remainder of building
- Adequate employee parking (outside of fenced compound)
- Security system with access control, intrusion alarm, PA system, POE camera system and monitoring
- Security gate at main entrance to yard

OFFICE AREA

- Open workstation area for 4 staff (1 each GIS, Engineering, Admin and Visitor/Hoteling)
- 7' x 7' workstations (with double station) for Admin and 7'x9' workstations for techs
- Desktop printers at each workstation to be reconsidered; network printer at Admin Station
- Space to accommodate free-standing multi-function machine for work orders (currently leased through the City)
- Anticipate re-use of existing workstation furniture with the addition of sit/stand desks in selected locations
- Adequate filing and layout space (transaction top preferred)
- Locked storage room for supplies, cameras, petty cash, wall mounted key cabinets
- Space to accommodate engineering plotter and rolls of paper (currently HP DesignJet T1100ps)
- Space to accommodate 10 file cabinets (7 @ 4-5 drawers; 15 @ 3 drawers)
- Layout table / transaction top (5' x 10')
- Minimum 1 large meeting room; 20 seat capacity; located for easy access by all staff (to be combined with Lunch Room as multi-function space)
- Training room to accommodate 8-10 computer training stations, located for easy access by all staff
- Meeting / training rooms to be flexible to accommodate Health & Safety training
- Washrooms of proper size and quantity to meet current and projected staff needs and code requirements (including AODA)
- Good quality but modest level of finishes (generally paint and carpet throughout office area)

Future Premises Requirements

LUNCH ROOM	• Seating capacity for 16 • Centrally located and accessible to all staff • Equipped with refrigerator, microwaves (2) and dishwasher • Provide sufficient counter space and clearance for coffee machines, kettle, toaster, etc. • Room for 2 vending machines (pop and snacks)	• Floor mounted water dispenser • Recyling stations • Wall mounted / ceiling hung LCD screen • Consider combining lunch room, meeting room and computer training room as multi-function space • Recommend industrial grade vinyl flooring throughout multi-function space
TECHNOLOGY	• Centrally located IT Room with sufficient AC (approximately 80 SF) • Separate SCADA / Radio Room (approximately 100 SF) • Radio room to be located near tower • Ensure access to fibre / cable with wireless throughout building. SCADA and Radio Communication to share fibre with IT	• SCADA requires desk to be available for Forward Operating Control Centre (emergency preparedness). Spare desk will be available in Admin Area. • Updated AV in meeting rooms, lunch room • VOIP system does not require telephone room or backboard • SCADA / Radio Communication requires line of sight to the Belleville Water Tower for signal transmission. In the event line of sight is not available, a repeater can be installed at an additional cost of approximately $50,000 (per Veridian)
LINES AREA	• 1 Supervisor Office located adjacent to Lines Area • Open Lines Area with 1 Lead Hand workstation (with desktop printer) • 1-2 hoteling stations • Open meeting area with seating for 8-10 and wall mounted Smart Board	• Layout table for maps (ideally with storage below) • Charging station for radios, tablets, etc. • Drying Room to accommodate 18 Lines personnel with proper exhaust / ventilation. Consider infrared drying as an option. • Recommend industrial grade vinyl flooring throughout Lines Area (with possibility of ceramic tile in Shower Area & Washroom)

Future Premises Requirements

METERING	• Approximately 700 SF adjacent to warehouse but secured (500 SF storage/workshop + 200 SF office) • 3 workstations (7’ x 7’)	• Olameter station (15 SF). Note: may be located elsewhere in building • Recommend industrial grade vinyl flooring in Metering area
WAREHOUSE / STORES	• Approximately 2,000 SF (including 500 SF caged tool crib) • 1 Stores Office with workstation, printer, filing, shelving • Level with truck docks for easy movement of parts to Lines Trucks • 1 Drive-in door • 20’ clear height (level with garage)	• Assume new racking to take advantage of height • New spool rack to hold 9 reels of cable • Area for scrap bins; weigh scale not required • Consider entrance to warehouse area for couriers (outside of fenced compound)
GARAGE	• Drive through configuration with 16’ motorized OH doors; ensure adequate turning radius. (An optional garage configuration that may result in less square footagewould be a 1-deep garage with individual OH doors where trucks back into place.) • Provide signal (traffic) lights at doors • Minimum 20’ clear height • 9 indoor parking spaces (14’ x 30’) for 5 Line Trucks, 2 Tensioners, 1 U/G Pulling Machine , 1 Forklift • Truck wash area with pressure washer (integrated with garage rather than separate wash bay)	• Trench drains, minimum 12-16” wide with proper slope • Oil separators; CO2 extraction • Heated to 62 deg F; cooling not required • Small parts storage within garage area • Ideally treated slab to protect against oil / grease **NOTE: As an option, consider outside covered storage for Lines trucks in lieu of garage environment**
OPTIONAL FEATURES	• Photovoltaic panels (roof mounted)	

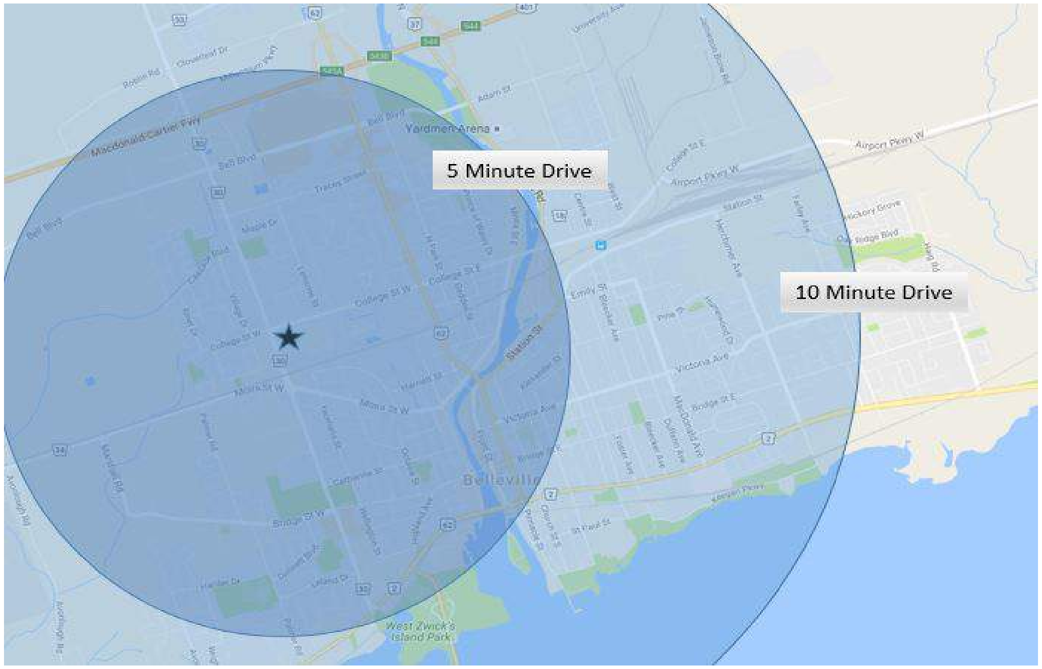
Future Premises Requirements

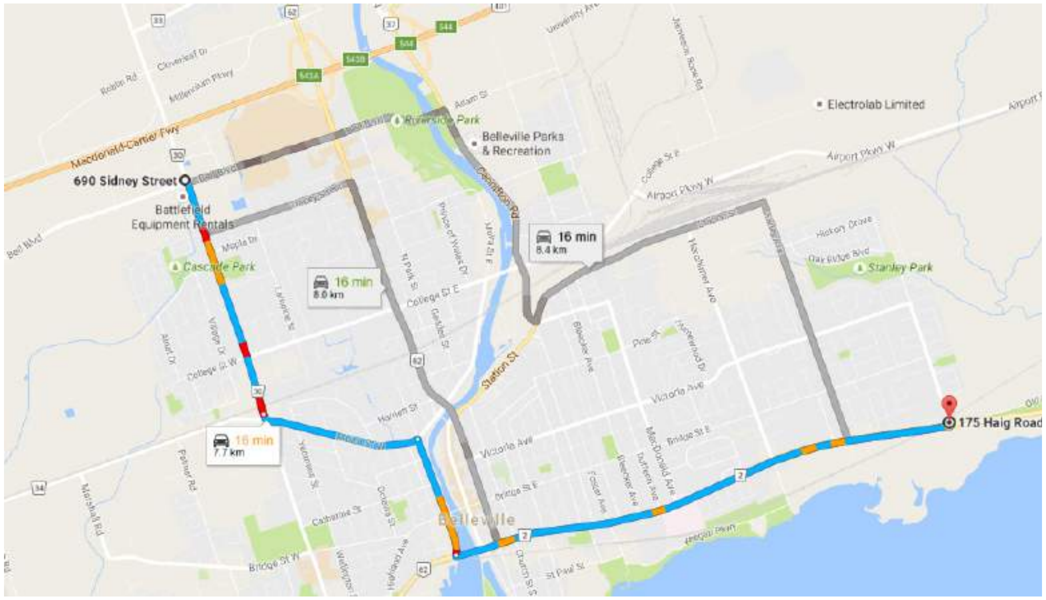
OUTSIDE STORAGE	• Approximately 1-1.5 acres • Preference for transformers and other equipment to be stored on racks versus on ground • Traffic areas to be paved to edge of storage • 2 pole cribs for emergency stock (for planned work, poles are shipped to site) • Location for 2 digger trucks with plug-in stations • Parking for 8-10 Veridian vehicles within fenced compound; covered parking to be considered	• Seacan storage (1) for Substations • Seacan storage (2) for kitted jobs awaiting delivery to site • Approximately 500 SF outside storage for Metering • Bunker for propane storage, etc. • Fully fenced yard with controlled access • Fuel pumps not required on site
PARKING	• 20 Employee and visitor parking spaces outside fenced compound • At least 1 vehicle charging station	
LOCATION	• Current location is ideally situated to service the current client base and future expansion • Preference is to remain south of Highway 401 to the Bay, between Avondale to the west and Farley to the east	• Ideal location will be central, allowing Veridian to respond to all customer sites within similar time frames

Location Map

RELOCATION PARAMETERS

- Within Service Area
- Adjacent map demonstrates 5 and 10 minute drive radii from Veridian's current location.
- The map below demonstrates that Veridian's entire service area is within a 20 minute drive (corner to corner), so any reasonably accessible location will be acceptable.





Section 3

Conceptual Alternatives

Conceptual Alternatives

CONCEPTUAL ALTERNATIVE 1

Relocate to a New Purpose Built Facility to be Owned (or Leased) by Veridian

- Identify site(s) that are available for purchase within the desired boundaries and negotiate a purchase agreement. Construct a building to be owned by Veridian **or** to be built and owned by a third party private investor and leased to Veridian.
- Alternatively, the land component may result from an exchange with the City of Belleville for lands already owned by Veridian.

CONCEPTUAL ALTERNATIVE 2

Relocate to an Existing Building for Purchase or Lease. Renovate to meet Veridian's needs.

- Identify sites with existing buildings of appropriate size (approximately 15,000 - 20,000 SF) that are available for purchase or lease and reasonably suitable for reconfiguration to suit Veridian's use.
- Negotiate a purchase or long-term lease agreement (15+ years).
- Proceed to have building renovated to meet Veridian's specific requirements, including interior improvements

Conceptual Alternatives

NOTES AND ASSUMPTIONS

- Conceptual Alternatives are outlined based on current program requirements. The garage size has been provided by Veridian based on a drive-through structure. Final size of building will be subject to formal planning.
- Conceptual block plan has been prepared to demonstrate a potential building layout based on the program. Final layout will be subject to site configuration.
- High level construction and ancillary budgets are provided. Construction budget includes a 10% contingency.
- A draft outline specification for a new design-build facility has been prepared and is included in Appendix C. The outline specification is subject to final refinement based on feedback from Veridian.
- A new building can be commissioned using one of several approaches: Design Build and Design Bid Build being the most common. The building cost estimates included herein are based on a Design Build approach, (which is typically less expensive than Design Bid Build). A comparison of the Design Build and Design Bid Build approaches are included in Appendix C.
- Land values and taxes are estimates until alternatives can be finalized and details confirmed.

Conceptual Alternative 1

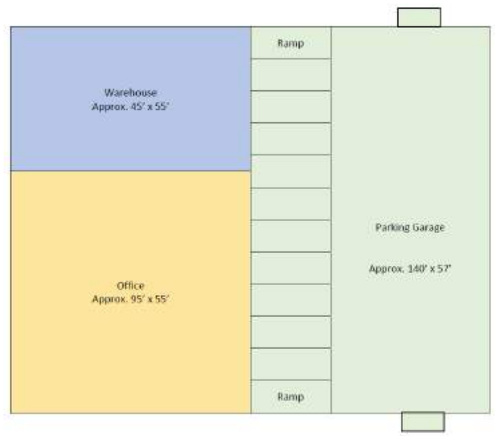
RELOCATE TO A NEW PURPOSE BUILT FACILITY TO BE OWNED (OR LEASED) BY VERIDIAN

OPTION 1: CONSOLIDATED OFFICE / WAREHOUSE / GARAGE WITH INDOOR TRUCK PARKING

Construct a building of approximately 15,700 SF with indoor parking for 8-10 hydro vehicles and 1 acre of outside storage	
Land:	2.5 - 3 Acres
Land Price:	$180,000 - $380,000 / Acre
Preliminary Construction Bud-	$2.36 Million (excluding Land)
Preliminary Ancillary Budget:	$140,000 - $150,000

Comments:

- Meets Veridian's operational requirements
- There are limited sites of appropriate size available for purchase. Refer to Survey included in Appendix A.
- May be opportunity to negotiate with the City of Belleville to exchange Veridian's lands adjacent to the Riverside for a 3.5 acre site located at Coleman & Ridley Streets
- There have been no sites identified where an owner would be willing to build for lease. It may be possible to identify a private investor who would buy and lease back on a long-term basis.
- Preliminary construction and ancillary budgets are included on the following page



Potential Building Configuration
 - Drive Through Garage with Indoor Parking

Optional Garage Configuration
 - Single Depth Parking -
Trucks Back In

Conceptual Alternative 1

RELOCATE TO A NEW PURPOSE BUILT FACILITY TO BE OWNED (OR LEASED) BY VERIDIAN

OPTION 1: CONSOLIDATED OFFICE / WAREHOUSE / GARAGE WITH INDOOR TRUCK PARKING

Budget Estimate (Building Only)			
Item	**Area (SF)**	**Unit Price**	**Total**
Building Shell	15,700 SF	$75.00	$1,177,500
Finished Office	4,200 SF	$60.00	$252,000
Corridors/Uplift Areas	800 -1,000 SF	$60.00	$48,000
Warehouse / Truck Area Upgrades			
12" Slab on Grade	8,000 SF	$20.00	$160,000
Wash Bay (Open Area Within Garage)			
Trench Drains		Lump Sum	$30,000
Exterior			
Light Duty Asphalt		Lump Sum	$100,000
Heavy Duty Asphalt at Building		Lump Sum	$60,000
Heavy Duty Asphalt at Outside Storage		Lump Sum	$35,000
Fencing for Storage Area		Lump Sum	$20,000
75kW Generator		Lump Sum	$80,000
Estimated Building Cost			**$1,962,500**
Development Charges (est)		$4.25	$66,725
Soft Costs		7%	$137,375
Contingency		10%	$196,250
Total Estimated Building Cost			**$2,362,850**

Assumptions
- 3 Acre Site (cost of land not included)
- Site serviced to lot line
- Site relatively flat with minimum cut and fill
- No site remediation required (i.e., good environmentals)
- Simple site plan approval needs

Ancillary Budget			
Item	**Qty**	**Unit Price**	**Total**
Furniture			
Office	1	$5,500	$5,500
Workstations	9 4	$3,500 $1,000	$31,500 $4,000
Training / Meeting / Lunch Room	1		$20,000
Lockers + Benches	24		$10,000
Security	Lump Sum		$25,000
Cabling / IT	Lump Sum		$10,000
Appliances	Lump Sum		$10,000
Audio Visual	Lump Sum		$20,000
Building & Site Signage	Lump Sum		$10,000
Total Ancillary Budget			**$146,000**

Assumptions:
- Budget represents new furniture throughout; existing furniture may be relocated to reduce budget
- Assumes existing servers, UPS, and other specialty equipment will be relocated
- Special communications equipment by Veridian
- Audio Visual includes smart board for Lines area
- No warehouse racking or equipment is included
- Moving costs not included

Conceptual Alternative 1

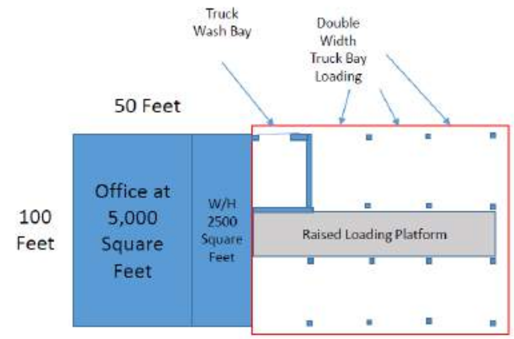
RELOCATE TO A NEW PURPOSE BUILT FACILITY TO BE OWNED (OR LEASED) BY VERIDIAN

OPTION 2: CONSOLIDATED OFFICE / WAREHOUSE / WITH OUTDOOR COVERED PARKING & WASH BAY

Construct a building of approximately 7,500 SF with outdoor covered parking for 8-10 hydro vehicles and 1 acre of outside storage	
Land:	2.5 - 3 Acres
Land Price:	$180,000 - $380,000 / Acre
Preliminary Construction Budget:	$2.25 Million (excluding Land)
Preliminary Ancillary Budget:	$140,000 - $150,000

Comments:

- Meets Veridian's operational requirements but may impact operating efficiencies during inclement weather.
- This is modeled with covered parking as a less expensive option for Veridian's consideration.
- There are limited sites of appropriate size available for purchase. Refer to Survey included in Appendix A.
- May be opportunity to negotiate with the City of Belleville to ex-change Veridian's lands adjacent to the Riverside for a 3.5 acre site located at Coleman & Ridley Streets.
- There have been no sites identified where an owner would be willing to build for lease. It may be possible to identify a private investor who would buy and lease back on a long-term basis.
- Preliminary construction and ancillary budgets are included on the following page.



Sample Massing Plan with covered parking

HONI Covered Parking

Conceptual Alternative 1

RELOCATE TO A NEW PURPOSE BUILT FACILITY TO BE OWNED BY VERIDIAN

OPTION 2: CONSOLIDATED OFFICE / WAREHOUSE / WITH OUTDOOR COVERED PARKING & WASH BAY

Budget Estimate (Building Only)			
Item	**Area (SF)**	**Unit Price**	**Total**
Building Shell	7,500 SF	$75.00	$562,500
Finished Office	4,200 SF	$60.00	$252,000
Corridors / Uplift	800 - 1,000 SF	$60.00	$48,000
Covered Truck Parking			
Open Building Shell	8,000 SF	$60.00	$480,000
Raised Concrete Platform		Deleted	
Heavy Duty Asphalt		Lump Sum	$75,000
Trench Drains		Lump Sum	$35,000
Exterior			
Light Duty Asphalt		Lump Sum	$100,000
Heavy Duty Asphalt at Building		Lump Sum	$60,000
Heavy Duty Asphalt at Outside Storage		Lump Sum	$35,000
Fencing for Storage Area		Lump Sum	$20,000
75 kW Generator		Lump Sum	$80,000
Estimated Building Cost			**$1,747,500**
Development Charges (est)		$4.25	$63,750
Soft Costs		7%	$122,325
Contingency		10%	$174,750
Total Estimated Building Cost			**$2,108,325**

Assumptions
- 3 Acre Site (cost of land not included)
- Site serviced to lot line
- Site relatively flat with minimum cut and fill
- No site remediation required (i.e., good environmentals)
- Simple site plan approval process

Ancillary Budget			
Item	**Qty**	**Unit Price**	**Total**
Furniture			
Office	1	$5,500	$5,500
Workstations	9 4	$3,500 $1,000	$31,500 $4,000
Training / Meeting / Lunch Room	1		$20,000
Lockers + Benches	24		$10,000
Security	Lump Sum		$25,000
Cabling / IT	Lump Sum		$10,000
Appliances	Lump Sum		$10,000
Audio Visual	Lump Sum		$20,000
Building & Site Signage	Lump Sum		$10,000
Total Ancillary Budget			**$146.000**

Assumptions:
- Budget represents new furniture throughout; existing furniture may be relocated to reduce budget
- Assumes existing servers, UPS, and other specialty equipment will be relocated
- Special communications equipment by Veridian
- Audio Visual includes smart board for Lines area
- No warehouse racking or equipment is included
- Moving costs not included

Conceptual Alternative 3

RELOCATE TO AN ALTERNATE EXISTING BUILDING (FOR LEASE OR PURCHASE)

Identify existing standalone or multi-tenant buildings for lease or purchase that can accommodate Veridian's requirement of approximately 20,000 SF (including indoor covered parking) and outside storage. Renovate as needed.	
Land:	2.5 - 3 Acres
Preliminary Construction Budget:	TBD
Preliminary Ancillary Budget:	$140,000 - $150,000
Comments:	

- Only one existing building, at 85 Davy Road, has been identified that can accommodate Veridian (see Survey in Appendix A)
- Multi-tenant building; formerly Canada Post distribution warehouse
- Can be demised to provide Veridian with approximately 20,000 SF
- Currently offered for lease at $4.50 PSF
- Extensive renovation likely required including addition of drive in doors and creation of indoor garage
- Landlord can add parking on north side of lot
- Outside storage permitted
- Further evaluation required to determine cost to repurpose building

Financial Comparison of Lease vs Own

- Veridian will complete a Financial Comparison of Lease vs Own on a Revenue Requirement Basis

Section 4

What do we do next?

Recommendations

- The City has not provided a definitive timeline for the Police Department's move to 459 Sidney Street but they are reportedly in the process of procuring architectural services, which will be followed by a design phase prior to tendering construction.

- While further discussion will be required to determine the actual timing for the transition, it is recommended that Veridian continue with the process of identifying and procuring a future site to ensure that it can make a smooth transition at the appropriate time. If a new building is to be commissioned on land to be acquired by Veridian, a timeframe of 16 to 22 months should be anticipated, depending on the design and construction process to be undertaken. The shorter timeframe would accommodate a design build solution, while a traditional design bid build approach would typically be of longer duration. In the event that Veridian is able to purchase an existing building, a lead time of 16 months will also allow for any required renovations to be completed.

- Concurrently, Veridian should determine whether there is any benefit to an early termination of the existing lease.

- Veridian has indicated that ownership and leasing of its future location will both be considered, the key driver being the desire to achieve a solution at the lowest overall cost to customers (on a revenue requirement basis). If there is no material difference in cost between the two approaches, ownership would be preferred. Given the lack of existing buildings that offer reasonable potential for Veridian, a new greenfield solution would appear to be the most likely outcome, but will be subject to final costing.

- From an operations perspective, there is a desire to provide indoor parking for Veridian's largest service vehicles. While the capital cost to provide indoor covered parking represents a premium of approximately $250,000, this will be partially offset by lower labour and fuel costs and increased efficiency for crews versus costs that would be incurred if trucks are parked outside during the winter months. Veridian will conduct a separate analysis on the potential labour, fuel cost and vehicle maintenance differentials.

Recommendations

- The labour and fuel cost savings achieved through the provision of indoor parking will be partially offset by the cost to heat the indoor garage. The cost to heat the garage will be dependent on the frequency and duration for which the doors are opened but, at a winter temperature of 62F degrees, a conservative estimate of heating costs would be $0.50 - $0.60 PSF of garage area.

- It is recommended that pricing be solicited for both indoor and outdoor covered parking to determine the actual cost differential so Veridian can make a fully informed decision.

- The Survey included in Appendix A highlights the various sites that have been identified as potential purchase and relocation options together with existing buildings that may be repurposed. Of these, two sites are considered well suited to Veridian's use with respect to size and location. However, neither site is currently entirely zoned industrial; discussions with the City will be required to clarify the potential to rezone.

- Some sites are City owned, while others are privately held. Pricing for all sites has not been obtainable; however, based on Cresa's research and discussions with owners, privately held lands are being valued between $180,000 and $380,000 per acre. The City has been unwilling to provide a price for their lands; however Veridian was previously advised that they would be priced at $40,000 - $60,000 per acre. This would need to be validated through a formal Offer to Purchase process.

- Through discussion, the City has also indicated that it may be interested in a land exchange, whereby Veridian could take ownership of a 3.5 acre site at Coleman & Ridley Streets (or possibly another City owned site) in exchange for Veridian's lands at the Riverside Substation, is a location that the City has been utilizing for some time.

- Next steps would be to identify the preferred location options from the Survey included in Appendix A, and proceed immediately to negotiate purchase agreements with vendors or, alternatively, a land exchange with the City of Belleville.

Recommendations

- With respect to a short-term strategy, Cresa's research has not identified any buildings that would be ideally suited to Veridian's use on a short-term basis. The most suitable short-term option would be the existing Canada Post distribution facility at 85 Davy Road, which is currently available for lease. While the building provides 20,000 SF of available space to accommodate the office and warehouse functions the parking of service vehicles, inside or under cover, will be difficult to achieve. As such, it is Cresa's recommendation that Veridian engage the City immediately to confirm timing and ensure there will be adequate notice to allow for a smooth transition to a new building.

- In the event the City (or Police Department) requires access to 459 Sidney Street prior to lease expiry in 2021 (or before Veridian's future premises can be prepared), it should be determined whether there is an opportunity to retain the garage, warehouse and outside storage for an extended term while the remainder of the building is renovated. In this instance, Veridian could locate short-term office accommodation elsewhere, or potentially place portable office units on the site, providing reasonable proximity for all staff to the key operations functions.

Next Steps (Relocation - Based on New Build)*

ACTIVITY	
Analyze Needs and Develop Space Programme	4 Weeks
Deliver Executive Summary	1 Week
Confirm Objectives	1 Week
Tour and Shortlist Sites	1 Week
Identify Preferred Sites	1 Week (concurrent with Touring and Shortlisting)
Prepare and Negotiate Offer(s) to Purchase*	10 - 12 Weeks
Conditional Offer*	
Due Diligence Period*	
Close Land Purchase*	
Prepare and Issue Design Build RFP	2 Weeks
Receive and Analyze Design Build RFP Responses	5 Weeks (Including Response Period)
Award Design Build Contract	1 Week
Design, Working Drawings and Permitting	12 - 14 Weeks
Construction of Building & Interiors	42 - 45 Weeks
Relocation / Occupancy	2 - 3 Weeks

*** Note: If an existing building can be identified that will suit Veridian's needs, the process will be modified to exclude the land purchase. It should be anticipated that the Design, Working Drawings, Permitting and Construction activities will remain necessary in order to prepare a building for Veridian's use.**

Section 5

Appendices

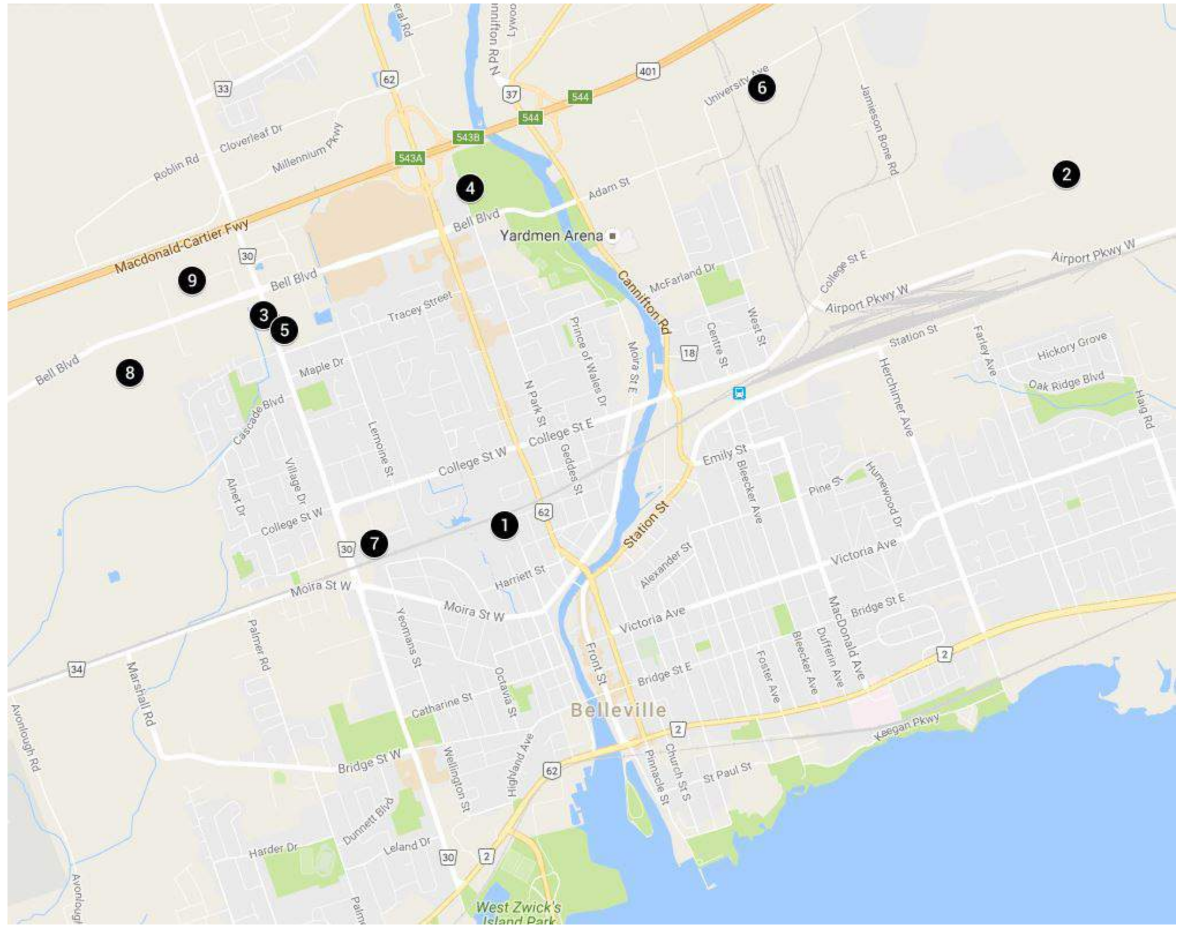
Appendix A - Survey

The following land and buildings have been identified as potential relocation options for Veridian. In an effort to "rank" the desirability of each site or building, they have been evaluated on a scale of 0-5 on the basis of (i) the potential to work with the City of Belleville to achieve a land exchange, (ii) cost, (iii) location, and (iv) readiness (meaning servicing, zoning, etc.)						RANKING SCALE				
Option#	**Address**	**Owner**	**Acreage**	**Asking Price**	**Current Zoning**	**Potential Land Ex-**	**Cost**	**Location**	**Readiness**	**Total**
1	400 Coleman Street	City of Belleville	3.5	$40,000 - $60,000/ Acre*	Mixed (O2/M1)	5	5	5	3	18
2	College Street East	City of Belleville	4+	$40,000 - $60,000 /Acre*	Industrial	5	5	1	1	12
3	Sydney Street Lot #1	John Royle (Private)	2.47	$380,000/Acre	Commercial	0	1	5	3	9
4	259 North Park Street	Belleville Parks Dept.	4 +/-	$40,000 - $60,000 / Acre*	O2 (Open Space)	2	5	1	1	9
5	Sydney Street Lot #2	Dennis Hawley (Private)	5	$180,000 / Acre	Residential	0	2	5	1	8
6	321 University Avenue	TBD (Private)	5	TBD	Industrial	0	3	2	2	7
7	240 Yeoman Street (adjacent to Veridian's current location)	Dondeb Inc. (Private)	2.2	$227,000 - $272,000/Acre	Residential	0	2	4	1	7
8	Bell Boulevard West	Belanger Family (Private)	>200	TBD	Commercial	0	2	3	0	5
Existing Buildings		Description	Size	Rental Rate	TMI					
9	85 Davy Road	Former Canada Post Distribution Centre	20,000 SF	$4.50 PSF Net	$5.00 PSF (incl. Utilities)	0	2	3	3	8

* Verbal estimate only provided to Veridian by City representative; final pricing to be confirmed

Appendix A - Survey Map

Option#	Location
1	400 Coleman Street
2	College Street East
3	Sydney Street Lot #1
4	259 North Park Street
5	Sydney Street Lot #2
6	321 University Avenue
7	Yeoman Street (adjacent to Veridi-an's current location)
8	Bell Boulevard West
9	85 Davy Road



Survey Option 1

400 Coleman Street Lot

Availability
TBD

LOT INFORMATION

Location	Coleman & Ridley	**Serviced**	Yes
Owner	City of Belleville	**Zoning**	Mixed (O2/M1)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE (per acre)
3.5	$40,000 - $60,000 (Verbal)

COMMENTS

- Ownership: City owned - good potential for land exchange
- Location: Prime central location; on main thoroughfare with good access to all points in service territory.
- Cost: Potential low cost option (to be confirmed)
- Readiness:
  - Serviced
  - Partially zoned O2 for open space; zoning will have to be clarified with the City
  - Lot entrance is not at grade with the street, would require some landscaping to allow for truck entrance
  - Large lot with ample room for building and outside storage
  - Borders the rail corridor on the north side. Building and storage will likely require setback from the rail corridor (TBD).

Survey Option 2

College Street East Lot

Availability
TBD

LOT INFORMATION

Location	College Street East
Owner	City of Belleville

Serviced	Yes
Zoning	Industrial (M2-1)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE (per acre)
4+	$40,000 - $60,000 (Verbal)

COMMENTS

- Ownership: City owned - potential for land exchange
- Location: Sub-prime location; most eastern lot and at furthest point from Veridian's primary service area; area of future development
- Cost: Potential low cost option (to be confirmed)
- Readiness:
  - Serviced and Zoned Industrial
  - Land would require extensive site prep before construction could begin

Survey Option 3

Sydney Street Lot #1

Availability
TBD

LOT INFORMATION

Location	Sydney & Bell
Owner	Private (John Royle)

Serviced	Yes
Zoning	Commerical (R6-2)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE	ASKING PRICE (per acre)
2.47	$940,000	$384,615

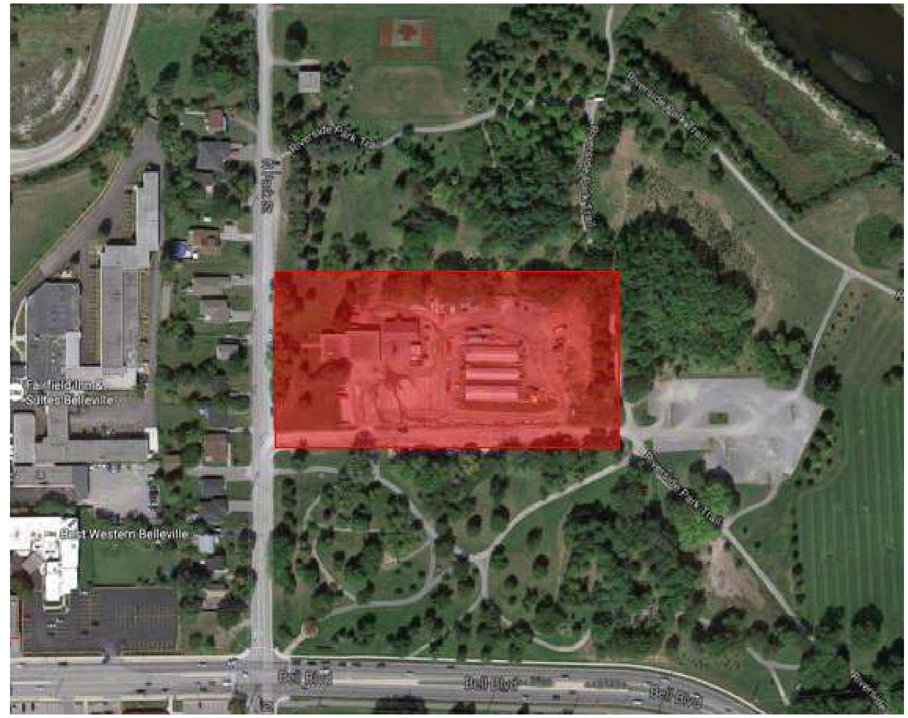
COMMENTS

- Ownership: Private - no potential for land exchange
- Location: Prime central location on main thoroughfare; close to existing location
- Cost: Highest asking price per acre
- Readiness:
  - Currently zoned for commercial
  - Surrounding area zoned industrial; rezoning to M1 requires clarification from the City
  - Requires an additional $50,000 for demolition of existing buildings
  - Owner prefers to sell the land outright; would only do build to suit for lease on very favourable lease terms

Survey Option 4

259 North Park Street

Availability
TBD



LOT INFORMATION

Location	Bell & North Park
Owner	Belleville Parks Department (City)

Serviced	Yes
Zoning	Open Space (O2)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE (per acre)
~4	$40,000 - $60,000 (Verbal)

COMMENTS

- Ownership: City Owned by Parks & Rec; potential (but unlikely) land exchange due to surrounding use
- Location: Adequate location toward north side of the service terrirtory
- Cost: Potential low cost option
- Readiness:
  - Zoned O2 for open space, rezoning may be difficult
  - City trying to consolidate municipal operations on Wallbridge crescent, may vacate this site
  - Building too small, requires heavy repurposing

Survey Option 5

Sydney Street Lot 2 (East Side)

Availability

Immediately

LOT INFORMATION

Location	Sydney & Bell
Owner	Private (Dennis Hawley))

Serviced	Yes
Zoning	Residential (RH)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE	ASKING PRICE (per acre)
5	$900,000	$180,000

COMMENTS

- Ownership: Private - no potential for land exchange
- Location: Prime central location on main thoroughfare; close to existing location
- Cost: At mid range per acre; Owner has received a certified appraisal for $900,000
- Readiness:
  - Serviced but Zoned for Residential; will be difficult to get approval for rezoning
  - More land than needed; would require severance. Owner may be willing to divide.
  - Power lines crossing the property

Survey Option 6

321 University Avenue

Availability
TBD

LOT INFORMATION

Location	University & Adam
Owner	Private (TBD) Listed by Bayshore Groups (Frank Salvatore)

Serviced	Yes
Zoning	Industrial (M2-1)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE	ASKING PRICE (per acre)
6	TBD	TBD

COMMENTS

- Ownership: Private - no potential for land exchange
- Location: Sub-prime location; in industrial park on eastern part of Veridian's service territory
- Cost: TBD
- Readiness:
  - Serviced and Zoned industrial
  - Part of larger site. Severance required. Owner willing to parcel out approximately 6 acres at front of site
  - Former Exxon Mobil plant takes up majority of the property

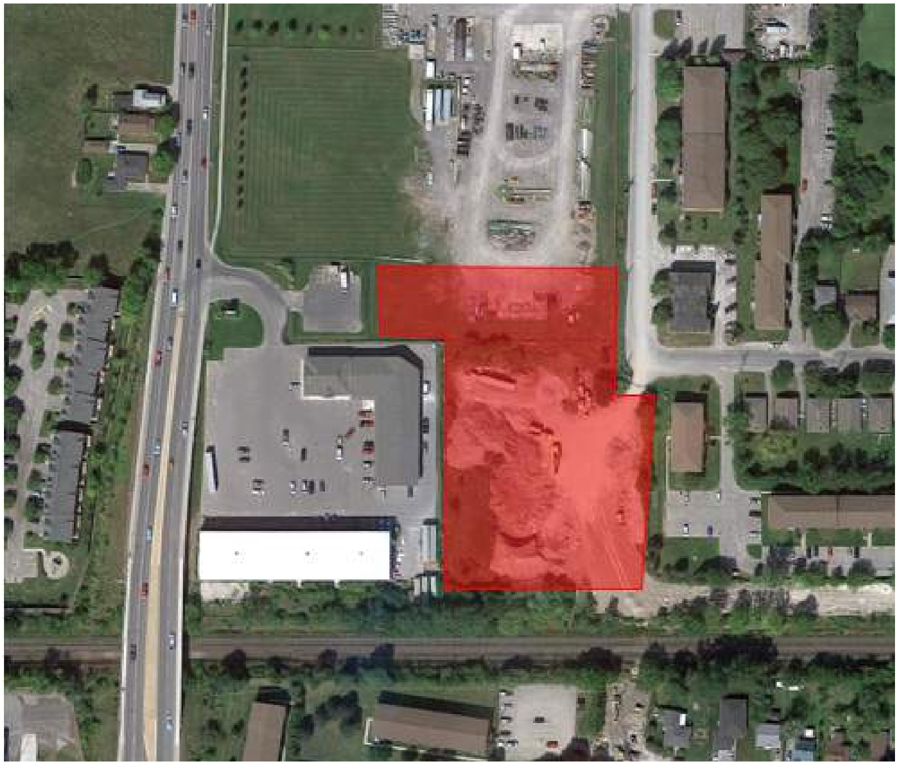
Survey Option 7

240 Yeoman Street
(Behind Current Location)

Availability

Location	Yeoman & Union
Owner	Dondeb Inc.

Serviced	Yes
Zoning	Residential (R6)



PRICE SUMMARY

SIZE (acres)	ASKING PRICE	ASKING PRICE (per acre)
2.2	$500-600,000	$227,000 - $272,700

COMMENTS

- Ownership: Private - no potential for land exchange
- Location: Prime location behind existing building. Good entrance and exit point onto Yeoman Street with identical response times as current location.
- Cost: Toward the higher side per acre
- Readiness:
  - Currently zoned residential; **in receivership**; gaining access to title may be complicated due to legal situation
  - Acquiring the back portion of Veridian's existing lot would likely require a land exchange with the City and potential severance

Survey Option 8

Bell Boulevard West

Availability

TBD

LOT INFORMATION

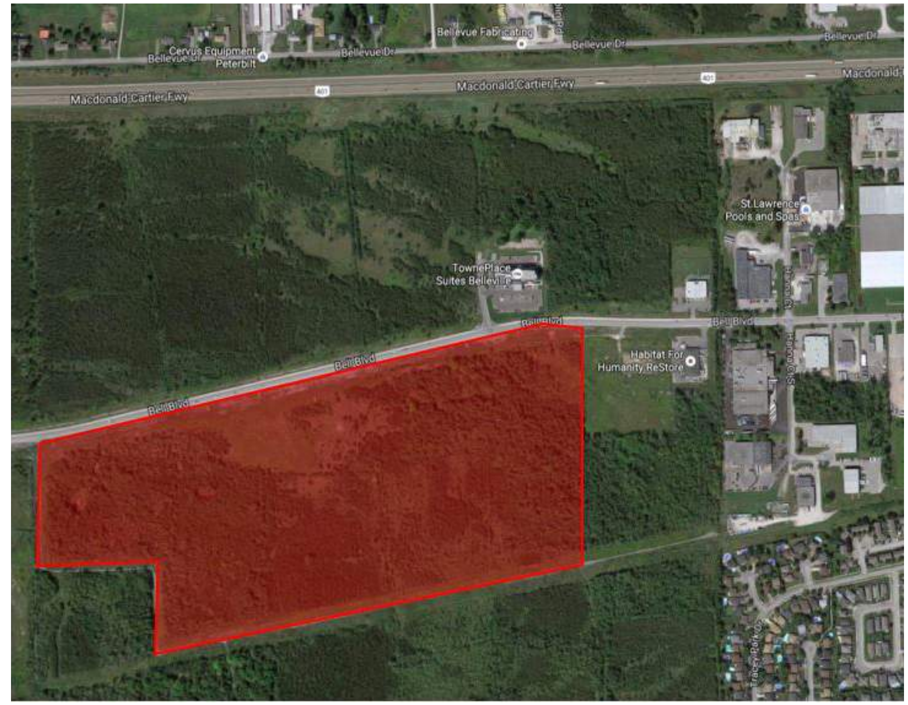
Location	Bell Boulevard
Owner	Private (Belanger family)

PRICE SUMMARY

SIZE (acres)	ASKING PRICE	ASKING PRICE (per acre)
>200	TBD	TBD

COMMENTS

- Ownership: Private - no potential for land exchange
- Location: Adequate location on western side of service territory. in area of future development
- Cost: TBD
- Readiness:
  - Zoning to be confirmed
  - Lot can be parceled out to any size; would require severance
  - Land would require extensive clearing and site prep before construction could begin



Survey Option 9

85 Davy Road (Leasing Option)

Availability
IMMEDIATE

BUILDING INFORMATION

Building Size:	~20,000 SF	**Clear Height:**	16'
Office Area (Divisible):	TBD	**Loading Doors:**	2
Industrial / WH Area:	TBD	**Sprinklers:**	TBD
Parking:	TBD	**Zoning:**	Commercial

RENTAL SUMMARY

NET RENT	EST TMI	EST GROSS RENT
$4.50 PSF	$5.00 PSF	$9.50 PSF

COMMENTS

- Ownership: Private owner; leasing option only
- Location: Adequate location on main thoroughfare at north side of service territory
- Cost: Estimated Gross Rent appears on the high end of market
- Leasehold Improvements: Allow $50-$60 PSF for office and $20-$25 PSF for garage
- Readiness:
  - Vacant. Could be suitable short-term option (i.e., 1 year lease with option to extend)
  - Former Canada Post distribution warehouse
  - No drive in doors or interior garage, would require extensive repurposing and site prep for outside storage. Landlord willing to add parking on the north side of the lot

Appendix A - Survey “B” List

In addition to the Survey Options identified above, the following sites are currently available for purchase. They have been eliminated from further consideration by Cresa for the reasons listed below.

Address	Comments
McFarland Drive at Centre Street	• 9 Acre Site; will not subdivide • Zoned Residential with approval for 54 lots • Adjacent to School (not suitable neighboour for Veridian’s use)
University Avenue south of Highway 401	• 18 Acre site; will not subdivide • Lot would require extensive preparatory site work

Appendix B - Lease Review

ITEM	DETAILS
LEASE DATE	October 22, 2001 (Original Lease) (Note Lease has been extended for 3 additional 5 year terms under same terms and conditions as original lease). Lease Amending Agreements have not been provided
TENANT	Veridian Corporaiton
LANDLORD	The Corporation of the City of Belleville
BUILDING	459 Sidney Street, Belleville
AREA	31,365 SF (Shared between Veridian Connections and City of Belleville Water Utility)
EXPIRY DATE	September 30, 2021
REMAINING TERM	None
NET RENT (2016)	$30,000 per annum payable quarterly (Note: Sublease Recovery = $1 Per Annum)
ADDITIONAL RENT:	All costs payable directly by the Tenant (Note: Subtenant pays proportionate share of all Additional Rent)
LEASE TERMS:	
ASSIGNMENT & SUBLETTING	Tenant may assign or sublet all or a portion of the Property with prior consent of the Landlord, not to be unreasonably wittheld (Orig. Lease Article 5)
REPAIR & MAINTENANCE	Landlord is to maintain the property and make all needed repairs and all necessary replacements (Original Lease, Article 7.1)
ALTERATIONS & ADDITIONS	Tenant may make alterations with prior written approval by Landlord of Tenant's plans and subject to compliance with all applicable building codes. (Original Lease, Article 8(a))
RESTORATION	There is no restoration provision in the Lease. Upon expiry or other termination of the lease, the Tenant may remove its Trade Fixtures and will make necessary repairs to any resulting damage. (Original Lease, Article 8.3 and 8.5)
SIGNAGE	The Tenant is permitted to erect its signage on the Property, in location(s) determined by the Landlord and subject to compliance with all applicable bylaws and regulations. The Lease is silent on the need to remove signage and repair damage. (Original Lease, Article 9)
TERMINATION (OVERHOLDING)	If the Tenant remains in possession of the Property following termination of the lease it shall create a monthly tenancy on same terms and conditions as the Lease, except for the Term. (Original Lease, Article 13(3)
ENVIRONMENTAL INDEMNITY	Tenant is responsible for any environmental contamination as defined in the Envioronmental Protection Act (Ontario) or any successor legislation, resulting from its occupancy of the Property. Its obligations under the Lease will survive expiry of the Term of the Lease. (Original Lease, Article 20)

Appendix C - Design Build vs Design Bid Build

DESIGN BUILD

The Design Build process typically begins with a competitive RFP, whereby multiple Design Build teams are invited to submit proposals for the design, construction and commissioning of a building once a site has been identified. This may or may not involve a small honorarium to cover each proponent's costs.

Considerations:

- There is a single point of responsibility for both design and construction activities. By combining design and construction under a single entity, co-ordination, constructibility, cost of change and project timelines should all be improved upon over the Design Bid Build methodology.
- Design Builders will be prequalified and invited based on their experience with similar buildings and their ability to deliver on time and on budget.
- The design builder assembles a consulting team (architect, structural, mechanical, eletrical and other engineers) that is tied together by contract with all fees bundled into the overall pricing. The team will typically have prior experience working together toward successful delivery of a project.
- A key component of the RFP requires proponents to provide a design concept based on the outline specification provided by the Client. The requirements are incorporated into a customized design concept by each Design Build proponent.
- The outline specification becomes a "performance spec". The design build team interprets the requirements and develops the details in conjunction with the client but the client does not maintain control over the design details. The end result is a building that meets the client's requirements, but may not be exactly what you would receive in a Design Bid Build scenario.
- Key to achieving an optimal Design Build result will be the ability of Veridian's internal team to define and detail the requirements as completely as possible so that the Design Build submission is comprehensive.
- The Design Build submission will include pricing based upon the outline specification provided. Through negotiation of the agreement, modifications to the preliminary design can be incorporated and a final guaranteed maximum price agreed upon.
- Once drawings are sufficiently advanced, the Design Builder applies for Site Plan Approval to ensure construction can commence as quickly as possible.
- The construction approach is accelerated as construction of the structure can proceed in advance of finalizing all finishing details. A foundation permit can be secured, allowing construction to proceed in advance of a full permit.

DESIGN BID BUILD

The Design Bid Build approach is the traditional method of project delivery whereby an architect is commissioned to design and fully detail a building for tender.

Considerations:

- The Client will have the opportunity to interview a number of architects and select a design partner based on their past experience and perceived "fit" with the Client's team.
- Following selection of an architect, the Client will be required to engage the remaining engineering consultants. While these individual consultants will work under the direction of the architect, they will typically be bound by contract directly to the Client. This contractual relationship may be less conducive to teamwork.
- This process allows for a fully customized building, designed to the Client's specific requirements, including final fit and finish. Prior to proceeding to tender, the building will be fully designed and detailed, including fully co-ordinated drawings for structural, mechanical, electrical, landscape, etc.
- Once drawings are complete, the package is issued for tender, typically to a number of pre-qualified contractors, who will respond with a fixed price lump sum quotation, which will then be converted to a Stipulated Sum construction agreement.
- Although drawings may be fully co-ordinated, in the Design Bid Build approach, the entire design is typically completed with little or no input from the constructor, which often results in construction and co-ordination issues in the field that need to be dealt with by change orders, often at a premium cost.
- The Design Bid Build methodology is usually of a longer duration than Design Build as all drawings must be fully detailed and co-ordinated prior to tendering in order to minimize post-tender changes which can impact both cost and schedule. In this instance, it may be preferable for the architect to apply for the permit so that construction can begin immediately upon award of the contract.

Appendix C - Design Build vs Design Bid Build

DESIGN BUILD

Pros:

- Design Build can produce a project more quickly than a conventional Design Bid Build.
- There is a single point of accountability for design and construction.
- Cost efficiencies can be achieved since the contractor and designer are working together throughout the entire process.
- Change orders would typically arise primarily from “owner” changes.

Cons:

- Less design control and involvement by the owner and stakeholders.
- Owner must be highly responsive in its decision making to take full advantage of the speed of Design Build.
- The owner does not receive the benefit of the checks and balances that exist when it contracts separately with a designer and a general contractor.
- This approach can be problematic when there is a need for multiple agency design approvals.
- May be inappropriate if the owner is looking for an unusual or iconic design.

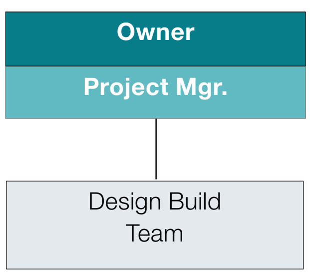
DESIGN BID BUILD

Pros:

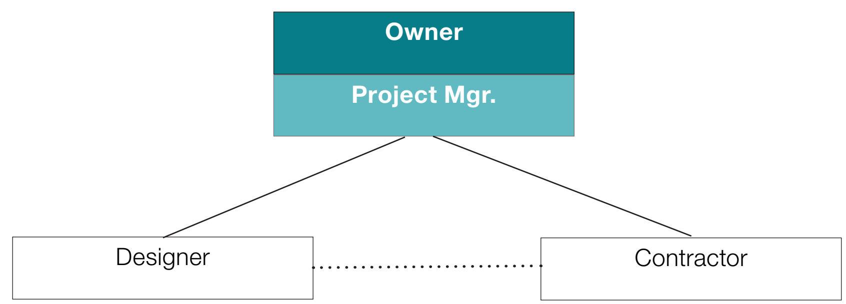
- This method is widely applicable, well understood and has well-established and clearly defined roles for the parties involved.
- The owner has a significant amount of control over the end product, particularly since the facility’s features are fully determined and specified prior to selection of a contractor.

Cons:

- Process may have a longer duration when compared to Design Build since all design work must be completed prior to tendering of the construction contract.
- The designer may have limited ability to assess scheduling and cost ramifications as the design is developed, which can lead to a more costly final product.
- This traditional approach, in some cases, may promote more adversarial relationships rather than co-operation or co-ordination among the contractor, designer and owner.
- The absence of construction input into the project design may limit the effectiveness and constructibility of the design. Important decisions affecting both the types of materials specified and the means and methods of construction may be made without full consideration from a construction perspective.



Design Build
With Project Mgr.



Design Bid Build
With Project Mgr.

Appendix D - Preliminary Design Build Outline Spec

Building Class:	• Offfice / Industrial Building: • Major Occupancy: Group F, Division 3 (storage, garage, warehouse) • Subsidiary Occupancies: Group D (office) and Group A, Division 2 (meeting rooms in office space, lunch room, fitness) • Construction Type: ISO Class 3 IBC Type 11B (Light Non-combustible Steel Frame) • Single user building • 1 storey above grade • AODA and Code compliant
Building Size:	• 17,700 SF comprised of: • approximately 4,800 SF finished Office and Centralized Support space + 800 - 1,000 SF of corridor and uplift space • approximately 10,000 SF indoor garage • approximately 2,500 SF warehouse / storage • plus building gross up of approximately 6% • Estimated staff complement: 18 FTE
Land (Acreage):	• Estimated 2.5 - 3 acres
Building Envelope:	• Durable exterior materials; simple standard structural steel construction with steel siding • Energy efficient design to minimize tenant's ongoing operating costs • Aluminum frame windows throughout office area; sufficient in quantity to allow ample natural light into office premises • Flat inverted ballasted roof • Clean, modern design
Parking:	• 20 staff and visitor parking spaces outside of fenced compound • Space for 1 vehicle charging station (by Owner) outside of fenced compound • HC parking as per code requirements • 10 parking spaces for Hydro vehicles within fenced compound (covered parking as an option)
Truck Access:	• 53' Trailer access to loading docks • No permanent trailer parking required
Landscaping / Exterior:	• Landscaping to be suitable to suburban industrial facility • Some green space with patio preferred (in proximity to lunch room) • Adequate site lighting • Exterior space at warehouse for dumpster • Light duty asphalt for staff parking with concrete curbs and minimal sidewalk • Heavy duty asphalt to overhead doors and building side for thoroughfare • Heavy duty asphalt to outside storage • Fenced storage compound

Appendix D (cont'd)

HVAC:	• Energy efficient HVAC systems • Standard RTU for office areas • Flexible zones and controllability • Sized and designed as appropriate for different functional spaces • Integrated BAS system for all HVAC (optional) • Humidification as required • Ensure adequate ventilation • Optional infrared drying in Drying Room
Fire Protection	• Fully sprinklered • Wet systems in office and warehouse • Dry system in IT / Server Room and SCADA / Radio Room • Dry system in garage
Plumbing:	• Ensure adequate domestic water access • Ensure adequate drainage and sanitary services • Designed to meet occupant load with flexible shower and washroom layouts • Kitchen equipped for typical appliances
Electrical:	• Minimum 400 AMP / 600 V / 3 Phase service • Flexible and adequate secondary power distribution • Energy efficient lighting throughout with occupancy sensors (with manual overrides) • Integrated BAS lighting control system (subject to pricing) • 75 kW genset required
Security:	• Intrusion Alarm and Access Control systems • POE camera system • Cameras strategically positioned in outside areas
IT:	• Demarc properly located for easy access to IT / Server Room and SCADA/Radio Room • EMT from source to IT / Server Room • Sufficient space for distribution of IT infrastructure using CAT 6 cabling throughout • Wireless technology throughout • Radio tower (by Owner) to be located in proximity to SCADA/Radio Room

Appendix D (cont'd)

BUILDING INTERIOR SPACES	
Office Areas:	• Refer to space program for requirements • 2 hour fire separation from Warehouse / Garage • Standard 5" slab on grade • Mainly open office concept with meeting rooms and common support areas • Glass fronts on offices and meeting rooms with applied film to approximately 75% of glass area • No reception area required • Good quality, moderate level finishes throughout • Carpet throughout office / workstation /boardroom areas • Industrial grade vinyl flooring throughout corridors, Lines Area and multi purpose Lunch/Meeting Room • Mechanical / electrical / storage and service rooms to have sealed or painted concrete floors and painted walls • Paint finish throughout • T-bar ceilings with lay-in acoustic tile throughout office areas and lunch room • All partitions between offices and meeting rooms to be insulated • Offices and meeting rooms to have sound attenuation continued above ceiling to eliminate sound transmission room to room • Kitchen / lunch room to be complete with good quality upper and lower cabinets, stainless steel sinks and faucets. Provide power at counter height, spaced appropriately. Provide power for refrigerator(s), microwave(s), dishwasher, vending machines and water dispenser
Washrooms / Locker Rooms / Drying Room:	• Provide 1 AODA compliant unisex washroom • Men's Washroom / Shower / Locker Room to have 2 showers, 2 urinals, 2 wcs • Men's Locker Room to have • Women's Washroom / Shower / Locker Room to have single shower and 1 wc • Ceramic / porcelain tile floors in all washrooms • Industrial grade vinyl flooring in men's locker rooms and drying room • Wall tile to 48" on all wet walls • Prefinished metal or plastic laminate, ceiling hung toilet partitions for each W/C stall. • Urinal partitions between all urinals • Washroom vanities with integrated backsplash in all washrooms; mounted at barrier free height with open space for wheelchair access • Washroom accessories to meet local Code requirements • Mirrors above all vanities including one barrier free mirror • Ceilings to be gypsum board on metal furring channels; flat painted • General lighting in washroom area with supplementary vanity lighting • GFI power receptacle at each vanity

Appendix D (cont'd)

Warehouse:	• 2,500 SF, including air conditioned warehouse office (100 SF) and secured Metering area of 500 SF • 20' clear height (level with garage) • 1 overhead door with door seals and dock leveler • 1 drive-in door with door seal • 1 mandoor to exterior (accessible from outside of fenced compound) • 2-ton crane • Fully sprinklered • Heated to 62 deg. F • Good lighting • Adequate staging area
Garage:	• Drive through structure with 16' x 16' overhead doors • Traffic control lights on interior and exterior of both doors • 20' clear height • 10 interior parking spaces adjacent to Warehouse to accommodate hydro trucks (bays 14' x 30') • Enhanced 12" reinforced slab on grade for truck driving area • CO2 system with makeup air, exhaust and controls • 12"-16" trench drains full length of garage with proper slope • Heated to 62 deg. F by unit heaters • Internal hose bib for power washing machine
Covered Parking (Option 2):	In lieu of indoor garage parking, provide covered parking attached to main building: • Open building shell: structural steel and standing seam roof (approximately 9,000 SF) • Parking for 10-12 Hydro vehicles, 14' x 30' bays (including 1 wash bay) • 36" high concrete platform, 8'-10' wide with bays evenly spaced on both sides • 1 - 8' wide x 10' high loading door from warehouse to raised concrete platform • Hose bib for wash bay and proper drainage • Heavy duty asphalt

170 University Avenue • Suite 1100 • Toronto, ON • M5H 3B3
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Budget Category	Fleet
OEB Investment Category	General Plant
Primary Driver	Capital/Maintenance Support
Secondary Driver(s)	Business Operations Efficiency

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$1.29M	**$1.39M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

General Plant investments in the Fleet category are designated to maintain/upgrade older fleet assets and introduce new fleet assets to ensure vehicle operations and performance for various departments under Elexicon Energy ("Elexicon"). Vehicles are of crucial importance for operational staff to perform routine and unplanned work. Historical data demonstrates that Elexicon's fleet assets are aging and are nearing the refurbishment and replacement categories. Condition data for fleet assets suggest that the investments into fleet refurbishments and replacements are continuing to improve the overall condition of fleet assets.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	1.29	0.80	1.86	1.41	1.41	1.41	1.41	0.81
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	1.29	0.80	1.86	1.41	1.41	1.41	1.41	0.81

Supporting Summary Statements:

Fleet vehicles are evaluated annually to identify required refurbishments and replacements. Vehicles are assessed for age and mileage to identify those that need further evaluation. Once a vehicle has been identified, it is inspected to assesss the need for investment. A letter grade is assigned to represent the condition of the vehicle and those requiring immediate intervention are assessed for refurbishment and replacement options. Vehicles are also added or upgraded in the fleet to address new changes in the system or if an operational need is fulfilled by a new vehicle purchase.

The separate fleets of the legacy utilites Whitby Hydro Electric Corporation (“WHEC”) and Veridian Connections (“Veridian”) have combined all vehicles into one fleet inventory under Elexicon. The consolidation of fleet operations and expertise will prompt a more operationally efficient practice. As a majority of Elexicon territories are in Durham Region, the former WHEC’s fleet can also be used for broader Durham operations. The combined budgets of the two former utilities helps address the investment requirements and the comined experience of staff with different vehicles is beneficial for Elexicon.

Fleet investments are vital to Elexcion’s customer service commitments since they are crucial for front-line staff to travel to customer and system locations. For instance, SAIDI could be impacted if a vehicle is unavailable or breaks down when responding to an outage. Thus, regular maintenance and investment into fleet assets are crucial activities for a utility. Additionally, fleet vehicles allow staff to perform the work necessary to improve, maintain, and construct the distribution system. The loss of function of a bucket truck arm would impact the ability to perform work, and in the worst-case scenario, endanger operational staff. Vehicles need to be maintained and vehicles with newly added functionality can assist in ensuring work is performed safely and adequately at Elexicon.

2. Basis for Action

2.1 Performance Trends:

Elexicon uses various metrics to understand how fleet assets have been performing and if investments are needed. These metrics include:

1. Vehicle age;
2. Vehicle condition;
3. Maintenance history and historical maintenance costs; and
4. Vehicle utilization.

Figure 1: Average Veridian Fleet Asset Age 2013 to 2017

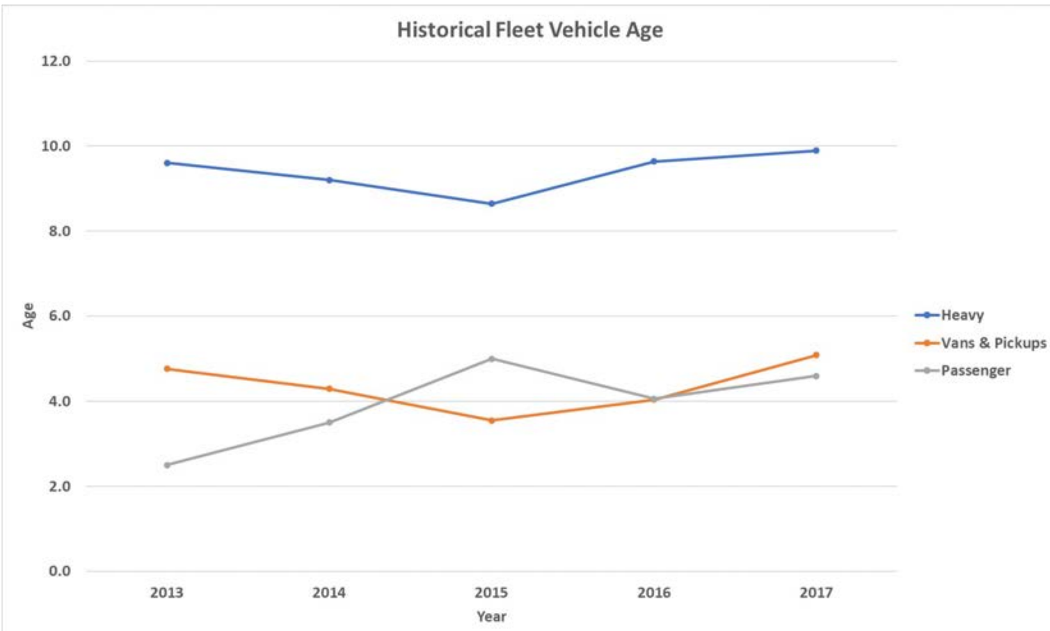


Table 2: Average Fleet Asset Age – Veridian (2013 to 1017)

	Vehicle Type	2013	2014	2015	2016	2017
Average Age	Heavy	9.6	9.2	8.6	9.6	9.9
	Vans & Pickups	4.8	4.3	3.6	4.0	5.1
	Passenger	2.5	3.5	5.0	4.1	4.6

Throughout recent history (2013 to 2017), fleet vehicle assets on average have aged across all categories. As vehicles reach a certain threshold of age and mileage, Elexicon evaluates the vehicle and determines if a replacement is needed. The threshold for replacement or refurbishment for fleet vehicles may vary. Elexicon will need to evaluate the condition of a larger pool of assets resulting from the merger.

Veridian Condition of Fleet Vehicle Assets

Fleet condition is assessed annually by the Fleet department. Elexicon first identifies the vehicle's mileage and age to determine if refurbishment or replacement is needed. Once a candidate has been identified, a comprehensive inspection and evaluation of the vehicle's mechanical condition is completed. Letter grades are then assigned to the vehicle, with “A” being the highest priority for investment and “C” being the lowest priority. Table 8 in the inspections and work execution section of the business case describes Elexicon’s fleet condition in further detail and illustrates these letter grade definitons. A historical makeup of conditions across 2013 to 2017 is provided in Figure 2.

Figure 2: Veridian Historical Condition Makeup of Fleet Assets 2013 to 2017

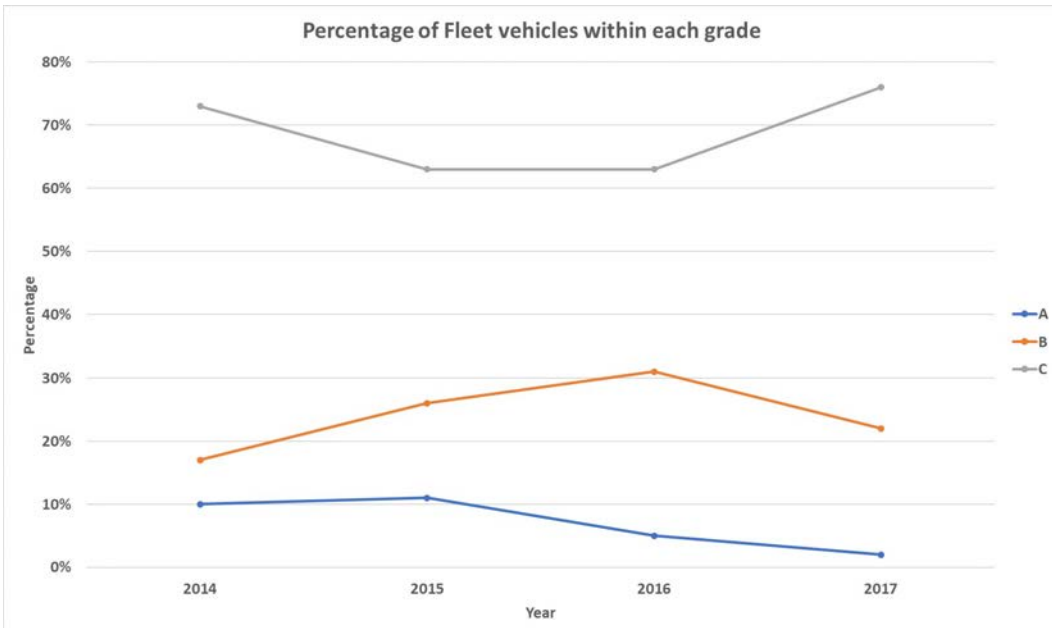


Table 3: Condition of Fleet Assets Historically – Veridian (2013 to 1017)

	Condition	2013	2014	2015	2016	2017
Condition	A	N/A	10%	11%	5%	2%
	B	N/A	17%	26%	31%	22%
	C	N/A	73%	63%	63%	76%

As per the historical condition year over year (2014 to 2017), the percentage of vehicles with an “A” grade has trended downward, reflective of recent investments made. The number of vehicles with a “B” grade has trended slightly upwards, while the number of vehicles with a “C” grade has varied between years and has increased slightly since 2014.

Veridian Historical Maintenance Costs

The historical maintenance costs are tracked and have trended downwards. Vehicle condition – which has improved historically – contributes heavily to the annual maintenance costs. Records are available up to 2016.

Table 4: Total Maintenance Costs Historically by Fleet Asset – Veridian (2013 to 2016)

Maintenance Costs per Vehicle – average including labour ($ '000)	Vehicle Class	2013	2014	2015	2016
	Heavy	272.97	373.40	322.33	144.19
	Vans & Pickups	216.80	230.70	214.99	115.42
	Passenger	9.12	8.18	5.62	20.56
	Total	**498.89**	**612.28**	**542.94**	**280.17**

Over the years 2014 to 2016, the maintenance costs for vehicles has decreased for heavy vehicles, vans, and pickups. Passenger vehicle maintenance costs have increased. Overall, the program has reduced maintenance costs from 2013 to 2016.

Elexicon Vehicle Utilization Rate (Fleet Utilization)

The vehicle utilization rate is also calculated for all fleet assets. This rate is calculated for the Fleet Committee and owners to monitor and maximize vehicle utilization. The vehicle utilization rate is the ratio of billed hours for the vehicle versus the number of business hours in the reporting period. For each year, the Fleet Committee sets a goal for its utilization rates across the whole fleet portfolio.

Elexicon Fuel Efficiency Metrics

Protractor and Geotab GPS are used as a recordkeeping system to track vehicle records such as odometer, and engine-hour readings. Elexicon tracks fuel efficiency over time as the ratio of fleet fuel usage to annual distance travelled. Fuel usage rate has trended upward, meaning efficiency has trended downward historically.

Figure 3: Fuel Efficiency by Year

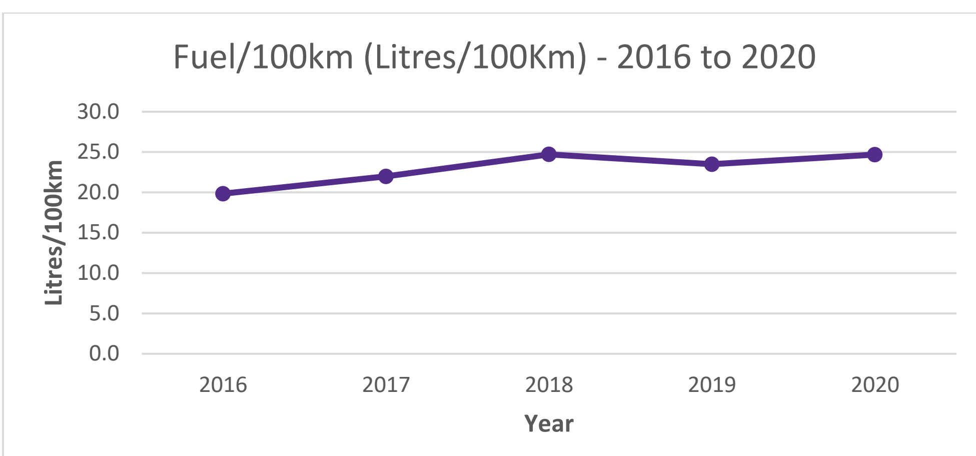


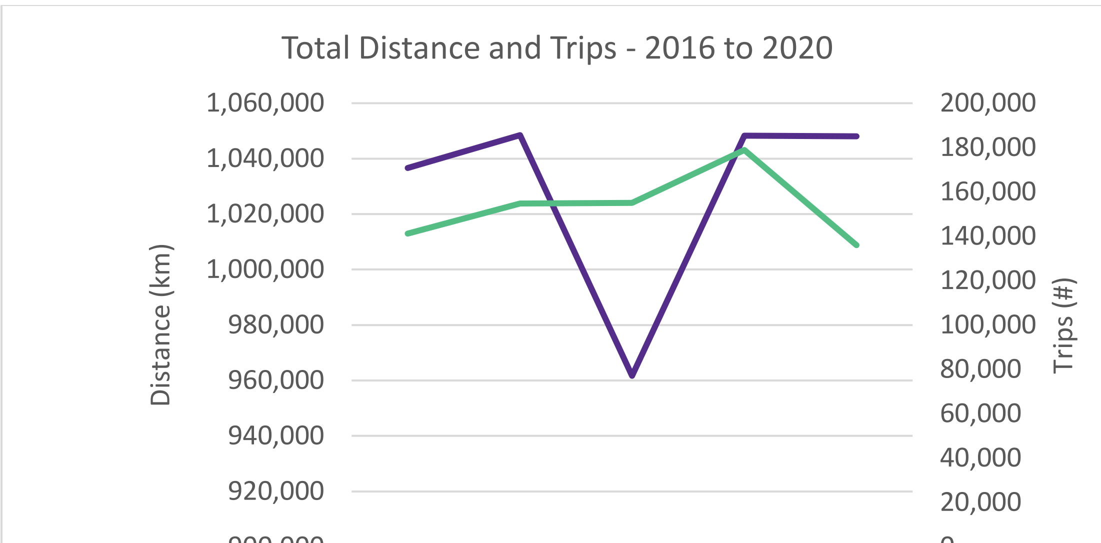
Table 5: Fuel/100 KM– Elexicon (2016 to 2020)

Year	2016	2017	2018	2019	2020
Total Distance	650,492	752,232	688,308	793,331	1,071,335
Fuel (total Litres)	129,087	165,478	170,072	186,450	264,284
Fuel (L)/100 KM	19.8	22.0	24.7	23.5	24.7
Total Vehicles measured	49	52	52	81	126

Total Distance and Trips - Elexicon

The total distance and trips that Vehicles undego annually are also taken into consideration when assessing the utilization and wear that assets undergo. In Elexicon's Maintenance practices, specific vehicles are required to undergo an condition assessment if the odometer passes a certain threshold. As the vehicles continue to accumulate distance, more assessments are required to evaluate investment requirements or maintenance practices.

Figure 4: Elexicon- Fleet Total Distance and Trips



	2016	2017	2018	2019	2020
Total Distance (km)	1036692	1048481	961689	1048329	1048097
Total Trips (Counts)	141198	154799	155129	178905	136007

2.2 Current-State Analysis:

Elexicon's fleet investments are broken down into the following categories listed in Table 5. These categories are also utilized when performing condition assessments on fleet assets annually. Mutliple Fleet Assets are found in each department at Elexicon depending on the nature of work that the group partakes in.

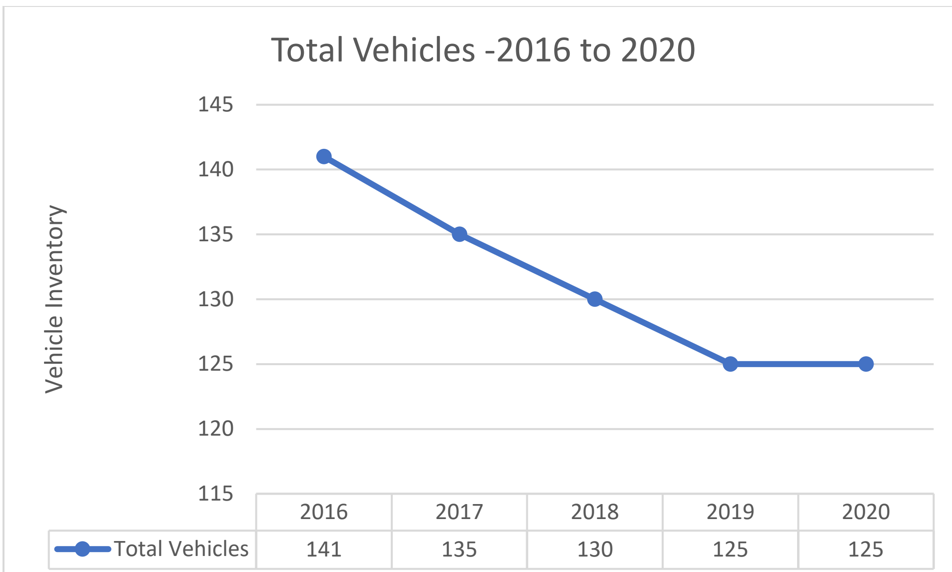
Table 6: Fleet Asset Type Descriptions

Budget Name	Description
Fleet - Large	Large fleet vehicles are predominantly bucket trucks used for overhead and line work.
Fleet - Medium	Medium-sized fleet assets are vans.
Fleet - Other	Other miscellaneous fleet assets are found in this investment category.
Fleet - Repairs	Fleet repairs are any expenditures into repairing current fleet assets including emergency repairs.
Fleet - Small	Smaller fleet vehicles include passenger vehicles used to inspect and manage work.
Fleet - Specialized	These vehicles are used for more specialized tasks such as pole digging, traversing through the snow with snowmobiles, and pulling cable.
Fleet - Substations	These fleet assets are specifically designated for the Substations department at Elexicon.
Fleet - Tools	Tools are an annual investment to renew mechanics tools to ensure the daily operation, inspection, and maintenance of fleet vehicles and assets.
Fleet - Trailers/Trucks	Trailers and Trucks are used to transport the more heavy-duty assets to locations. These trailers are designated specifically to transport cable reels, poles, transformers, and various other distribution equipment that cannot be housed on normal vehicles.

Historical Makeup of Fleet Vehicles - Elexicon

Due to the consolidation of the two former utilities, the fleet inventory from WHEC and Veridian has been combined to form the mixed inventory for Elexicon. COVID-19 has impacted fleet operations at Elexicon as there is less vehicle sharing which consequently requires more vehicles in circulation. This initiative is currently being followed to ensure the health and safety of all operational staff during the pandemic. It remains to be seen how changing health and safety considerations because of the pandemic could affect fleet utilization in the future. Historically, the number of fleet assets across the types of vehicles Elexicon has remained consistent. Over the course of the last five years, the total vehicle count has gone down from 141 to 125 vehicles.

Figure 5: Total Fleet Vehicles by Type (2016 to 2020)



Overall, the amount of vehicles that Elexicon possesses has trended downwards. Vehicles in use at Elexicon are tracked with Geotab software and hardware to evaluate various metrics. As the territory has increased in size and the fleet has absorbed numerous vehicles, numbers may grow into the future.

Figure 6: Fleet Vehicles by Department

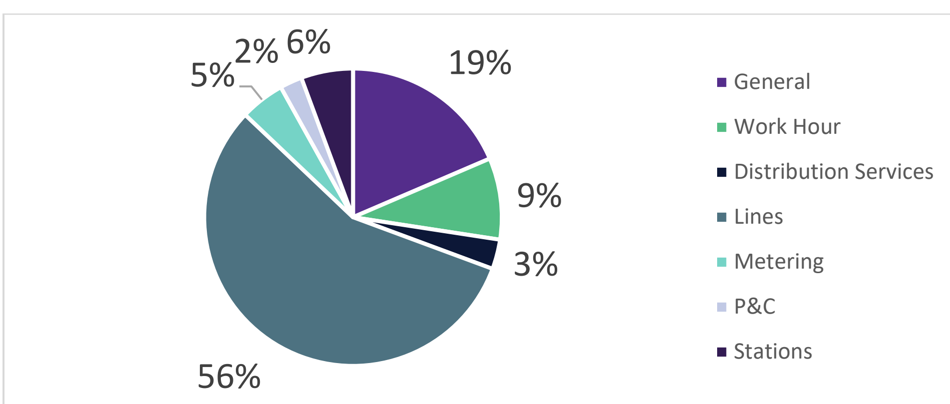


Table 7: Percentage Share of Fleet Vehicles by Department

Department	Total Vehicles	Percentage
General	23	19%
Work Hour	11	9%
Distribution Services	4	3%
Lines	70	56%
Metering	6	5%
P&C	3	2%
Stations	7	6%

As seen in the percentage share of vehicles for departments, the majority of Vehicles are utilized and found in the operations division at Elexicon. About 81% of registered vehicles are utilized for Distribution Operations which places wear and tear after continued usage.

Average Odomoter Reading by Department

Of the departments that make up the fleet vehicles, 56% or 70 of the 125 vehicles in inventory belong to the Lines (Underground and Overhead) Crews. Much of the operational departments at Elexicon are found to have higher average odometer readings than other departments. The Lines Department undergoes the largest general investment due to the sheer size of the fleet inventory for that department. It's importance cannot be understated and Elexicon continues to invest into new lines vehicles where applicable. Thus, the average odometer reading of Lines Vehicles is found to be in the bottom three. However, continued investments into newer vehicles helps decrease this average.

Figure 7: Average Odomoter Reading by Department

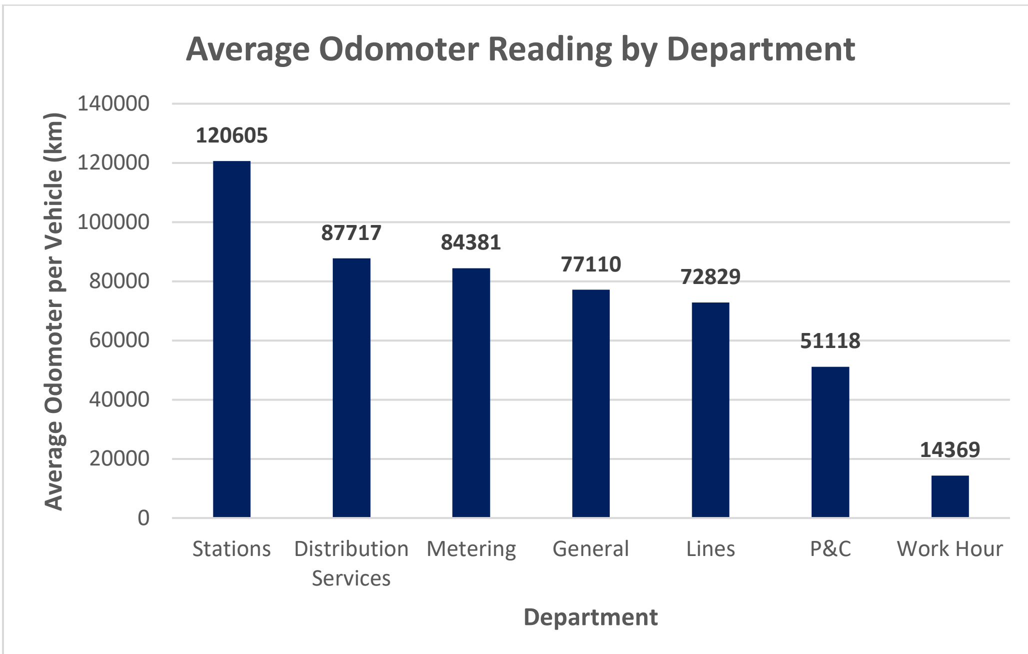


Table 8: Average Odomoter Readings by Department

Department	Total Vehicles	Average Odometer (km)
Stations	7	120,605
Distribution Services	4	87,717
Metering	6	84,381
General	23	77,110
Lines	70	72,829
P&C	3	51,118
Work Hour	11	14,369

2020 Fleet Utilization Rate

As discussed in performance trends, Elexicon performs a calculation of the Fleet Utilization Rate of each vehicle. In this case, a fleet utilization rate is calculated for each department. Note that the total trip hours is utilized and divided by the total amount of business hours for that year. As seen from the graph, Operational Departments such as Lines, P&C, and Substations demonstrate higher utilization rates for vehicles as the utilization rates for all three groups are greater than 50%.

Figure 8: Elexicon Fleet Utilization Rate across Departments

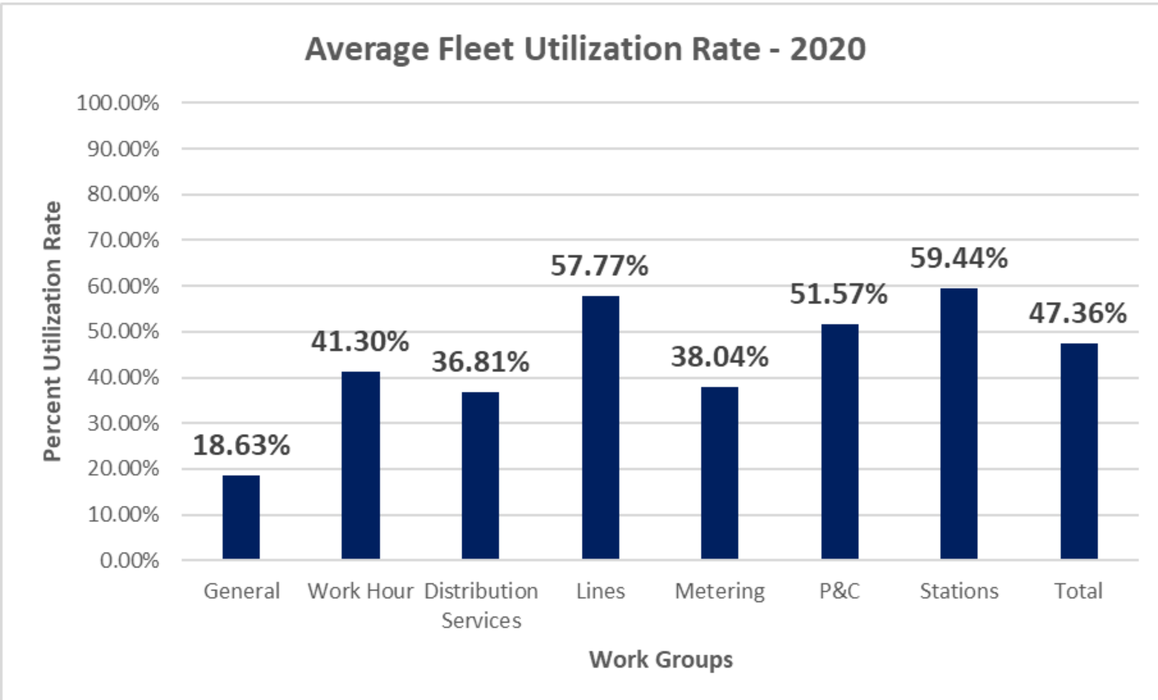


Table 9: Fleet Utilization Rate by Department

Group	Vehicles	Hours	Utilization Rate
General	23	8,055	18.63%
Work Hour	11	8,541	41.30%
Distribution Services	4	2,768	36.81%
Lines	70	76,026	57.77%
Metering	6	4,290	38.04%
P&C	3	2,909	51.57%
Stations	7	7,822	59.44%
Total	124	110,411	47.36%

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.*

OEB Scorecard Metrics and the Distribution System Code

Fleet vehicles are critical to grid operations, maintenance and capital work. They are also relied on to allow Elexicon to provide front-line customer service. Key scorecard metrics that pertain to fleet investments include system reliability in terms of SAIDI, safety in terms of lost-time injuries, and service quality in terms of connection of new services and appointments met. SAIDI numbers may increase if fleet vehicles that are used to address outage calls are unavailable or break down when responding to an outage. Safety incidents can also arise from vehicles, which are mitigated by regular maintenance and upkeep. Fleet investments ensure work performed also addresses the safety of the grid to the public. Fleet vehicles must be maintained in adequate condition for operational work on the grid. Additionally, as various service quality requirements need to be met within an adequate time, issues with fleet vehicles could prove to affect these numbers and the performance of this metric. In particular, the *Distribution System Code* specifies the time window to connect new customers and meet appointments – including underground locate requests.

Highway Traffic Act

Elexicon fleet assets shall follow the rules laid out by the *Highway Traffic Act*, which lays out many of the regulatory rulings and compliances regarding weight, equipment, load, and dimensions. This legislation regulates the administration of loads, classification of vehicles, and other transport-related issues. New vehicles purchased must comply with this Act and maintenance programs must ensure upkeep to the requirements.

Electric Utility Safety Rules: 123 Aerial Devices/Boom Trucks

Rule 123 of the *Electrical Utility Safety Rules* – set forth by the Infrastructure Health and Safety Association ("IHSA") – pertain to aerial devices and boom trucks. These rules must be followed when utilizing these vehicles for operational work. In particular, there are clauses related to the operational value of these assets such as structural, mechanical, and hydraulic defects, that must be met. Elexicon ensures that all aerial devices and boom trucks are adequate and up-to-standard to perform the work necessary to serve customers and protect the safety of workers.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

If fleet vehicles are not maintained or replaced at an adequate time, vehicles run the risk of failing prematurely and at crucial times. Fleet vehicles are used daily by many departments at Elexicon including Lines Services, Metering, Substations, Distribution Services, and Facilities. Heavy vehicles such as bucket trucks are essential for crews to perform daily work on lines and in times of emergencies. Lighter vehicles are available for supervisors and leads to monitor and inspect work. Furthermore, the deterioration of a vehicle's condition can lead to major safety problems. For instance, the bucket truck's arm needs to be evaluated consistently due to its importance for line work. Vehicles need to be checked consistently for safety to ensure that Elexicon staff do not endanger themselves or the public while on the job. Lastly, due to vehicles responding to troubleshooting calls, if a vehicle fails during a truck roll-out, they run the risk of bringing down SAIDI numbers. Elexicon customers expect excellent and consistent electrical service in order to utilize electricity in their daily lives. In situations where response is required, fleet vehicles must be in good shape to address troubleshooting and outages. Where new construction or maintenance work is required, fleet vehicles must also be in good shape to allow Elexicon to build a system that can be utilized by new and existing customers.

Operational Efficiencies: Inadequate fleet investments into sub-par vehicles may cause operational efficiencies of workers to stay stagnant or decrease. Any vehicle equipment or asset that does not perform to its capacity can dramatically increase the amount of work required from staff.

2.5 Merger-Related Objectives:

The fleet size of WHEC and Veridian was combined to consolidate operations. Due to the larg, non-contiguous service area of Elexicon, the fleet size may need to be increased in the future. To maintain reliability, customer service, and safety performance, Elexicon continues to refurbish fleet assets and make proactive investments into vehicles. These investments are of high value to service continuity and utility integration since they integrate core operations of legacy utilities and improves operational capabilities relative to both predecessors. The current status quo of the combined inventory is optimal but new investments planned for the future DSP period will assist in rounding out the fleet inventory and satisfying operational needs.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.d.1 (GP) The results of quantitative and qualitative analyses of the proposed project/program, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable

Number	***1***	***2***	***3***	***4***
Scenario Description	Current Planned Fleet Investments (Balance Refurbishment Practices and New Purchases)	Faster pace – 25% more annually	Slower pace – 25% less annually	Invest only into new replacements; no Refurbishment performed
Annual Program Scope	The planned investments in the Business Case made at Elexicon ensure optimal spending and balance between replacement, refurbishment, and new vehicle purchases	Faster pace of fleet refurbishment and replacement, constituting 25% more annual CAPEX on average	Slower pace of fleet refurbishment and replacement, constituting 25% less annual CAPEX on average	In this investment, the refurbishment of existing vehicles is not made. Elexicon shall only replace vehicles and purchase new vehicles when required.
Annual Gross CAPEX	\$1.39M	\$1.74M	\$1.04M	\$2.78M
Annual Net CAPEX	\$1.39M	\$1.74M	\$1.04M	\$2.78M
Annual Program Benefits	The budgeted plan is paced such that Elexicon has sufficient resources to execute the program. Projects are prioritized such that the most beneficial projects are completed first while accounting for interdependencies between projects. See Section 3.2 for	It is anticipated that there will be limited incremental benefits to increasing the pace of investments. More investments into fleet assets could be expedited with a higher budget; however, administrative and organizational work to fit the fleet asset to	Smaller investment into the fleet program would produce less benefits and contribute to compounding requirements of the entire fleet. Investments are made to address any issues current Elexicon fleet are facing. Underinvestment would require future higher	In this case, Elexicon will realize more benefits from completing an entire replacement over maintenance or prolonging the expected life of fleet assets. In doing so, expenditures to this program would increase. Elexicon believes that the

	the program benefits and Section 5.1 for the prioritized list of material projects in the 2021 Bridge Year.	company objectives would be required. The current investment is sufficient for the travel uses of the company.	spending to address the issues that were not addressed earlier.	mixture of replacing and maintaining existing fleet assets is the most cost-effective approach.
Program Economics	The average forecasted program spend is approximately that of the historical expendtiures. These investments are made to ensure service continuity for customer and to improve operational effectiveness within the region.	Increasing the level of investment into the fleet program by 25% is currently deemed unnecessary in comparison to the proposed spend of the Preferred Alternative. The first alternative aligns to historical levels, and addresses the current issues identified in the program.	Decreasing the level of investment into the fleet program by 25% is insufficient in comparison to the proposed spend of the Preferred Alternative. Under-investments in the program will delay and may bring about more required investments in the future for the fleet program. This could affect service quality and operational effectiveness of Elexicon.	Purchasing new fleet assets only, instead of also being able to maintain, would increase the spending in this program. Compared to historical expenditures, the forecasted expenditures would double. The current Preferred Alternative is the most efficient and optimal investment strategy. Elexicon should be able to replace, upgrade and maintain fleet assets, not one or the other exclusively.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable. Fleet equipment is re-evaluated based upon it's condition year over year depending on if it satisfies certain criteria warranting inspection. Equipment is replaced if the condition is deemed to be un-suitable for future purposes. When Customers were asked about power outages,46.7% (403 of the 862) selected that the length of the outages was the most inconvenient. Fleet investments ensure that vehicles utilized to respond to outages are in good shape such that SAIDI will not increase due to vehicular complications.			
Other Constraining Factors	One constraining factor with the planned option is the further degradation of assets that could occur for the fleet inventory. In this case, an adjustment will need to be made for future	Further investments into fleet assets could assist Elexicon; however, fleet utilization has been identified to be adequate by Elexicon. Any fleet assets that are not utilized fully	Fewer investments into fleet assets would negatively affect Elexicon. Fleet investments have been planned to ensure service continuity and to address operational needs.	By only introducing new fleet assets, Elexicon maintains service continuity; however, as fleet assets are continually invested in with no refurbishment, the costs of

	year fleet budgets or other programs in the General Plant category.	would reduce the operational efficiency and usefulness of the investment.	Less investment would disrupt the service continuity of the fleet department.	such practice are very high. To ensure cost and operational efficiency, refurbishments should also be performed.
Preferred Alternative	**X**			

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies. *-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.* *For proposed distribution rate funded CDM programs the following details are required:* *• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers* *• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred*

Reliability: Service reliability can suffer if fleet investments are not made. As vehicles are used by operations to reduce trouble calls, SAIDI numbers could increase if vehicles fail. As durations of outages are reduced by reactive crews, the increased risk of vehicle breakdown could jeopardize and impact SAIDI numbers substantially. Fleet investments are paced to support the desired level of system reliability.

Grid Resiliency: Resiliency is the ability to respond to adversity. Fleet vehicles allow Elexicon to proactively invest in its system to improve it resiliency. They also allow staff to reactively respond to issues such as outages and storm clean-up. Investments are paced to support a resilient grid.

Operational Efficiency and Cost Effectiveness: Fleet investments are paramount to the operational efficiency of Elexicon's work. Any vehicle that experiences performance issues or outright breaks down in the field would increase the amount of work-hours required by staff. This is especially true for vehicles such as bucket trucks and Radial Boom Derricks "(RBDs") that contain many complex, moving components. As vehicle replacement costs are high, Elexicon makes prudent investment decisions in this area, including assessing refurbishments options when considering vehicle replacement. Vehicle refurbishment and replacements should be balanced as part of a fleet life-cycle management approach.

Safety: Safety is impacted by fleet investments as operational crews rely on fleet assets to transport material and people to work locations. If fleet assets are in deteriorating or poor condition, it could prove to be a safety risk. Special vehicles such as bucket trucks serve additional purposes in housing tools and bucket capabilities for overhead workers. Harnesses are also prevalent for fall-arrest systems.

Cyber-Security/Privacy: There is no effect on cyber-security or privacy.

Environmental Benefits: Newer vehicles have improved fuel efficiency compared to older and deteriorated vehicles. Where possible, Elexicon evaluates the opportunity to replace conventional vehicles with electric vehicles at a manageable rate.

Coordination/Interoperability: As a member of the Utilities Standard Forum, Elexicon has access to shared standards with other utilities in Ontario. This includes standard purchasing of heavy work vehicles that reduces the overall investment cost.

Conservation and Demand Management: There is no effect on energy conservation and demand management.

Net Customer Benefits: Customers will experience benefits if fleet investments are made for deteriorating vehicles. If less reliable fleet assets are used, measures of operational efficiency and reliability are affected. Customers benefit from operational efficiencies and the reduction of outage durations.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

If a vehicle exhibits significant deterioration, resources shall be allocated into investments geared towards replacing or refurbishing the asset. An annual allocation of budget is also provided for emergency repairs of fleet assets. If the budget has been surpassed already, Elexicon has two options:

1. Budgets from other General Plant programs could be shifted to the fleet category; or
2. A reduction in the future budget of fleet investments could be made such that a fleet investment could be made in the year needed.

If an operational need has been identified by operational departments with regards to fleet capabilities, Elexicon will take note of this requirement. The fleet committee at Elexicon will evaluate the request and ensure that gird operations are equipped with fleet resources that provide safe environments for staff to work in.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Vehicles are assessed each year in two categories based on age and mileage. If a vehicle exceeds a threshold in at least one of these categories, a condition assessment is performed. These condition categories are described in Table 7. Any vehicles assigned an "A" grade are deemed to be the most critical for proactive investment. Replacement and refurbishment options are then assessed.

When purchasing new vehicles, Elexicon provides vehicle specifications and assesses proposals for the supply of vehicles. These vehicle specifications apply to pickup trucks, bucket trucks, RBDs, and passenger vehicles. The bid assessment for all vehicles considers price, safety ratings, lifetime operating cost (including fuel usage), functionality, and ergonomics.

Vehicles that have exceeded the recommended age threshold, have high maintenance and repair costs, or are unsafe are considered at the end of their life cycles. Fleet assets that do not have safety issues are identified as potential vehicles to auction off. Legacy vehicles are sold to a broker in an auction or traded in, depending on the method that provides the greater return for Elexicon.

Elexicon also utilizes in-vehicle and/or portable computing devices to improve its ability to manage vehicle fleet assets. The types of data that are recorded include:

- Vehicle speed;
- Vehicle idle time;
- Average fuel usage;
- Average driving times for routine trouble calls; and
- Vehicle or equipment limits being exceeded.

These data are utilized to manage assets, provide long-term work planning, and support budgeting and asset allocation for the fleet inventory. This is crucial in ensuring the longevity and maintenance of fleet vehicles.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Historically and currently, Elexicon's inspections of vehicles are determined by two metrics which are age and mileage. At least one of these thresholds must be met before a detailed assessment is conducted. This approach will be carried moving forward and was originally the fleet asset management strategy of former Veridian.

Table 10: Elexicon Fleet Asset Threshold for Condition Assessment

Vehicle Category	Assessment Threshold	
	Age (years)	Mileage (km)
Heavy Vehicles	>10	>200,000
Light Vehicles	> 5	>150,000
Trailers	>12	N/A
Special Purpose	>15	N/A

During June and July each year, the Corporate Services department completes a formal assessment of each vehicle that meets or exceeds the thresholds of Table 7. A review of category A and B vehicles will be led to determine refurbishment or replacement investments planned for the next year's budget cycle. At the end of July of each year, an overall summary of proposed fleet investments for the following fiscal year will be provided.

Table 11: Fleet Asset Investment Priority and Condition

Category	Interpretation	Definition
A	High Investment Priority	The level of deterioration is severe and planned replacement or refurbishment is critical for the coming calendar year.
B	Medium Investment Priority	The vehicle is mechanically and structurally sound at present, but the condition is at risk of deterioration during the coming calendar year.
C	Low Investment Priority	The vehicle is mechanically and structurally sound. Planned replacement or refurbishment is not necessary for the coming calendar year.

The key aspects of the vehicle that are assessed include the engine, drive train, chassis, tires, body, paint, condition of aerial device, hydraulic system controls and hoses, and general appearance. Comments, conditions, and costs of the refurbishment or replacement are provided on each fleet vehicle inspection form. Mechanics maintain records of all vehicle inspections. Preventative maintenance scheduled by mechanics is based on engine-hours and odometer readings (mileage). Inspections include fluid replacements, tire inspection, and brake inspection.

In addition to mechanic inspections, crews must perform pre-trip inspections using the logbook equipped to each vehicle. Each vehicle shall be subject to a circle check to complete the log requirements for each trip. Any defects are then brought to the attention of supervisors to determine vehicle safety and operability.

Elexicon's vehicles are assigned to several user groups where each manager holds responsibility for ensuring the optimal use of fleet vehicles under their care. Activities regarding fleet asset management that managers are responsible for include scheduling, accurate project time allocations, maximizing efficient utilization, general cleanliness and good housekeeping, accident, and incident reporting.

4.3 Scale Increase Considerations

Due to the large territory of the combined utility, work execution can be consolidated in fleet services. Benefits are realized through more efficient resource utilization by consolidation. As most of the service municipalities are within the Durham region, adding the WHEC fleet capabilities further improves the execution and utilization of resources in Durham. Higher purchasing power is also realized through the combination of both utilities.

The combined skills and experience of fleet workers also benefits Elexicon. As the larger service territory requires further utilization of fleet resources, the experience in identifying deteriorating fleet assets and the ability to refurbish vehicles will improve Elexicon's operational efficiencies across its service territory.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

To ensure the consolidation of merged operations, all existing vehicles were taken from both former inventories of the two utilities. A condition assessment was performed and an identification of the required investments for the combined fleet inventory was identified. As further development or projects are built up from the development in the Elexicon territory, additional operational functionality of fleet assets may be required. In these cases, the fleet department and fleet utilization group will determine the necessary investments to assist operational staff.

Operational synergies which were identified in the merger apply to the fleet group and pertain to O&M savings for the most part.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

Project ID	Project Name	Year	Net CAPEX ($M)	Priority
2021-3007	Vehicles, Large (1 RBD) V573 Digger	2021	$0.50	57.6
2021-3025	Large RBF V579 (Digger)	2021	$0.50	57.6

5.2 Individual Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.d.2 (GP) Where the capital cost of a project substantially exceeds the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.

<table>
<tr><td>Project name</td><td colspan="5">Vehicles, Large (1 RBD) V528 Digger</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-3007</td></tr>
<tr><td>Job numbers</td><td colspan="5"></td></tr>
<tr><td>Project District</td><td colspan="5">Gravenhurst</td></tr>
<tr><td>Project Location</td><td colspan="5">Gravenhurst</td></tr>
<tr><td>Investment Category</td><td colspan="5">General Plant</td></tr>
<tr><td>Budget Category</td><td colspan="5">Fleet</td></tr>
<tr><td>Project Driver</td><td colspan="5">Capital/Maintenance Support</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">JAN 1st 2021</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">DEC 31st 2021</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Replace V528 – 1997 Freightliner 47’ RBD Digger Derrick Truck</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $500,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $500,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$45,000</td><td>$50,000</td><td>$85,000</td><td>$320,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Vehicle conditions are assessed year over year by the Fleet department. Elexicon first identifies the vehicles mileage and age to determine if refurbishment or replacement should be considered. Once a candidate has been identified, a comprehensive inspection and evaluation of the vehicles mechanical conditions is completed. Letter grades are then assigned to the vehicle asset with A being the highest priority of investment and C being the lowest, and a determination is made on whether the vehicle should be refurbished or replaced

V528 has been assigned the A Grade and requires replacement. This vehicle is also at risk of not passing the MTO Safety Inspection as the frame has delaminated more than 10mm.
- Age - 1997
- Mileage – 5,224
- Hours - 115
- Mechanical Condition – Engine replaced in 2010
- Physical Condition – Fair (frame rails deflection at 14mm)
- Maintenance Costs
o 2020 - $3K
o 2019 - $6K
o 2018 - $4K</td></tr>
<tr><td>Criteria Score</td><td colspan="5">57.6</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">All customers in the Gravenhurst district.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">Continuing to maintain the existing vehicle will be costly and increases risk of failure in the field. By not replacing the asset, potential repercussions would be vehicle failure and the inability to work on the lines. A temporary replacement vehicle would be required either from another district (if available) or via rental.</td></tr>
</table>

	Refurbishment of this vehicle will prolong the asset for a short period of time, but does not guarantee the complete repair of the unit over an extended period of time. This will require a complete re-chassis of the vehicle.
Effect on System O&M Costs	Reduced maintenance costs as a result of replacing the aging vehicle.
Targeted Outcomes	Operational Effectiveness
Cost Benchmarks	Historical purchases: 2014 – 55' Double Bucket Truck - $290K 2014 – 88'Double Bucket Truck - $408K 2016 – 55' Single Bucket Truck - $415K 2016 – 47' RBD Truck - $371K 2019 – 47' RBD Truck - $355K 2019 – 52' RBD Truck – 412K Costing does not include additional upfit requirements or tools which would be added to the first cost of the vehicle for a total initial capital outlay.
Value-Added Approach	N/A

<table>
<tr><td>Project name</td><td colspan="5">Large RBD V579 (Digger)</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-3025</td></tr>
<tr><td>Job numbers</td><td colspan="5"></td></tr>
<tr><td>Project District</td><td colspan="5">Brock</td></tr>
<tr><td>Project Location</td><td colspan="5">Brock</td></tr>
<tr><td>Investment Category</td><td colspan="5">General Plant</td></tr>
<tr><td>Budget Category</td><td colspan="5">Fleet</td></tr>
<tr><td>Project Driver</td><td colspan="5">Capital/Maintenance Support</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">JAN 1st 2021</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">DEC 31st 2021</td></tr>
<tr><td>Scope of Work</td><td colspan="5">Replace V579 – 1997 Freightliner 47’ RBD Digger Derrick Truck</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $500,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $500,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$45,000</td><td>$50,000</td><td>$85,000</td><td>$320,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Vehicle conditions are assessed year over year by the Fleet department. Elexicon first identifies the vehicles mileage and age to determine if refurbishment or replacement should be considered. Once a candidate has been identified, a comprehensive inspection and evaluation of the vehicles mechanical conditions is completed. Letter grades are then assigned to the vehicle asset with A being the highest priority of investment and C being the lowest, and a determination is made on whether the vehicle should be refurbished or replaced

V579 has been assigned the A Grade and requires replacement. This vehicle is also at risk of not passing the MTO Safety Inspection as the frame has delaminated more than 10mm.
- Age - 1999
- Mileage – 74,943
- Hours – 4,766
- Mechanical Condition – Fair
- Physical Condition – Poor (frame rails over 10mm)
- Maintenance Costs
  o 2020 - $3K
  o 2019 - $6K
  o 2018 - $2K</td></tr>
<tr><td>Criteria Score</td><td colspan="5">57.6</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">All customers in the Brock district.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">Continuing to maintain the existing vehicle will be costly and increases risk of failure in the field. By not replacing the asset, potential repercussions would be vehicle failure and the inability to work on the lines. A temporary replacement vehicle would be required either from another district (if available) or via rental.</td></tr>
</table>

	Refurbishment of this vehicle will prolong the asset for a short period of time, but does not guarantee the complete repair of the unit over an extended period of time. This will require a complete re-chassis of the vehicle.
Effect on System O&M Costs	Reduced maintenance costs as a result of replacing the aging vehicle.
Targeted Outcomes	Operational Effectiveness
Cost Benchmarks	Historical purchases: 2014 – 55' Double Bucket Truck - $290k 2014 – 88'Double Bucket Truck - $408k 2016 – 55' Single Bucket Truck - $415k 2016 – 47' RBD Truck - $371k 2019 – 47' RBD Truck - $355k 2019 – 52' RBD Truck – $412k Costing does not include additional upfit requirements or tools which would be added to the first cost of the vehicle for a total initial capital outlay.
Value-Added Approach	N/A

Budget Category	P3-Information Technology
OEB Investment Category	General Plant
Primary Driver	System Capital and Maintenance Investment Support
Secondary Driver(s)	Business Operations Efficiency; Functional Obsolescence

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$2.42M	**$3.64M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Elexicon Energy ("Elexicon") invests in information technology ("IT") and operational technology ("OT") systems to support the daily operations and long-term plans of the distribution grid and organization. These investments are currently split into initiatives such as the consolidation of various legacy systems and upgrades of current systems for future and current needs. Drivers such as operational needs, cost savings, operational efficiencies, grid modernization, cyber security, and customer centricity are catalysts to the planned IT/OT investments across the future Distribution System Plan ("DSP") period. These investments are intended to benefit Elexicon as a newly merged company now and into the future.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Capital Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross CAPEX	2.42	4.31	6.46	4.16	3.04	2.82	2.42	2.95
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net CAPEX	2.42	4.31	6.46	4.16	3.04	2.82	2.42	2.95

Supporting Summary Statements:

Elexicon's technology investments will allow for the consolidation and streamlining of various duties and systems under one company. The importance of consolidation cannot be understated as it serves as a fundamental foundation of Elexicon's operations and capabilities as a combined organization moving forward. Currently, various legacy systems are in place from the two former utilities such as the Customer Information Systems ("CIS"), Geographical Information Systems ("GIS"), financial systems, outage management systems, SCADA systems, payroll systems, and human resources information systems. Continued Consolidation of IT and OT assets will be performed which will introduce cost savings, increased capabilities, and operational efficiencies. A list of opportunities for technology-related cost savings was identified as potential merger synergies prior to merging. These opportunities can be achieved through consolidation.

Technology investments also serve to benefit Elexicon in other measurable ways. For example, service quality and system reliability performance measures will be improved as new systems will allow for enhanced fault location, enabling crews to more quickly locate faults. This will facilitate greater operational efficiency as fleet and labour utilization can be increased, with less time being spent on line patrols. A planned CIS system upgrade will offer streamlined call-centre operations and benefits to current Elexicon customers over the legacy systems. Third-party penetration testing will also be performed to ensure hardening and resiliency of Elexicon IT and OT systems. If weaknesses are discovered, additional cyber-security investments will be planned. Other investments in cyber security such as training, policy development, and software updates will continuously improve Elexicon's security posture in an effort to be fully compliant with the *Ontario Cyber Security Framework*. Elexicon is also making investments into new technologies in preparation for the future grid. Projects such as micro-grid advancements and behind-the-meter analysis will allow Elexicon to adapt to new disruptive technologies while providing a high-quality service. Elexicon will also continue in-house efforts around machine learning, analytics, and data science to achieve operational efficiencies and plan data-driven optimization investments.

Elexicon will be moving forward with a proactive approach where technology investments are problem-driven and solutions-oriented. Elexicon seeks to solve problems with investments that will provide defined value to the organization. Duplicate systems from the legacy utilities were analyzed, and the best technology of each legacy utility will be brought forward, utilized, and enhanced. This allows Elexicon to use the momentum and investments of its predecessors while also improving existing systems and capturing benefits. In addition, various initiatives that are new to both utilities have also been started, such as the implementation of an IT Help Desk and Configuration Management Database ("CMDB").

Initiatives such as these will improve Elexicon's use of systems and resources and provide increased operational excellence within the organization.

2. Basis for Action

2.1 Performance Trends:

IT infrastructure Issues

In 2020, Elexicon experienced multiple prolonged outages due to aging equipment and systems, overprovisioning, and legacy configurations. IT outages are defined as problems that occur during work hours for a service that an employee is required to use. Because Elexicon has a 24/7 System Control Centre, many after-hours outages also fit this definition. To mitigate these issues, Elexicon has begun multiple methodical enhancement projects such as hardware upgrades, capacity increases, and software implementations. For example, Elexicon implemented a help desk in early 2020 to assist the IT department in understanding the magnitude and quantity of IT-related issues. Elexicon also upgraded its server infrastructure and backup system. Moving forward, the help desk will be used to track and understand where some IT infrastructure is failing. This will provide tools for greater asset management of technology assets in the company.

Renewable Energy Generation Connections

In considering innovative technology investments, Elexicon also notes customer plans and trends regarding Renewable Energy Generation ("REG") investments and the general behaviour of Electric Vehicles and REG adaptation within the Elexicon territory. Projects related to energy storage, net metering, and microgrids are assessed and evaluated by the utility to prepare for the future grid. Examples of this work include a Community Microgrid project that helps model the network and identify deficiencies. Utilization of this pilot will provide strategic planning, understanding of the technical difficulties, and test out the investments needed to ensure a safe and secure grid among ongoing modernization initiatives. Moving forward, Elexicon will evaluate opportunities to utilize existing technology assets and new disruptive technologies to plan the future grid.

Figure 1: Generation Connections Historically

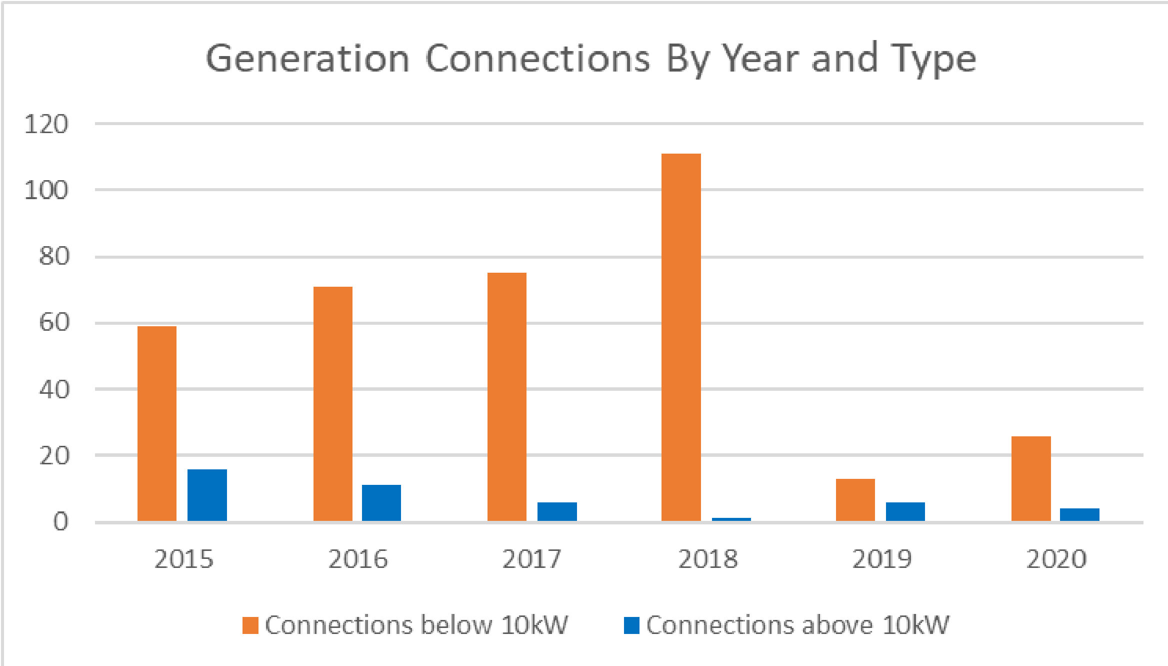


Table 2: REG Connections by Type (2015 to 2019)

Year	2015	2016	2017	2018	2019	Total (2015 to 2019)
Connections below 10 kW	59	71	75	111	13	329
Connections above 10 kW	16	11	6	1	6	40

The historical number of REG connections peaked in 2018 due to the cancellation of the FIT program, which accelerated approvals of applications. Elexicon has forecasted expected REG investments into the future in its REG forecast sent to the IESO. These will be taken into consideration by the technology division at Elexicon. As more innovative and disruptive technologies penetrate the distribution system, Elexicon will ensure a framework and reliable system is in place.

Configuration Management Database

Elexicon has recently implemented a new CMDB to track the lifecycles of IT hardware. IT/OT software lifecycles will also be managed in this database in the future, allowing Elexicon to perform tracking and trending of a variety of metrics related to IT/OT.

Reliability Impacts of Operational Technology

Investments into new software systems within the OT category can have positive impacts on the reliability measures. For instance, the new Advanced Distribution Management System ("ADMS") platform will include outage-reduction technologies such as fault location and isolation and automatic switch-order creation. These and other similar functions are expected to reduce both the System Average Interruption

Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") through their use. Both SAIDI and SAIFI have been trending downwards, as shown in Figure 2 and Figure 3, respectively. The new ADMS is aimed at streamlining operations, improving customer communications, and improving (or maintaining in turbulent conditions) outage statistics in the future.

Figure 2: Elexicon SAIDI Trend and Performance 2014 to 2019

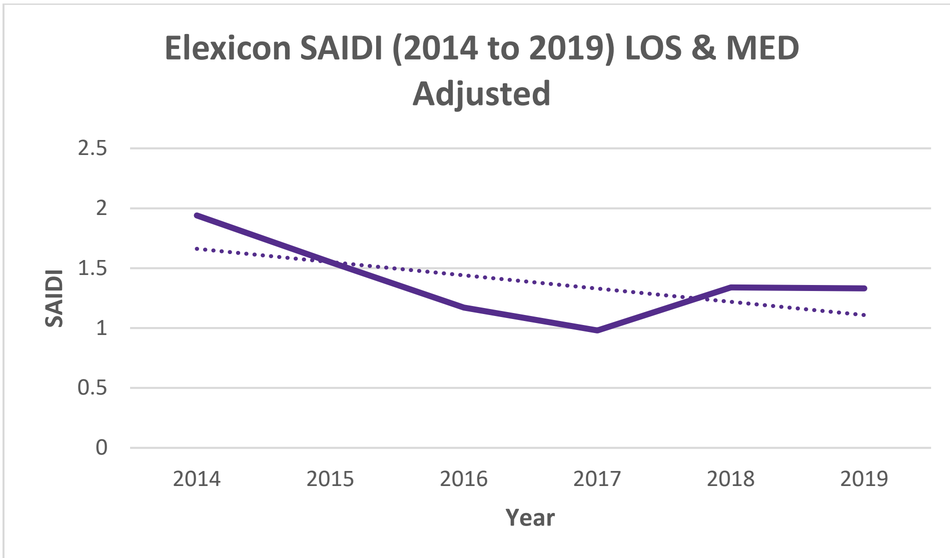


Figure 3: Elexicon SAIFI Trend and Performance 2014 to 2019

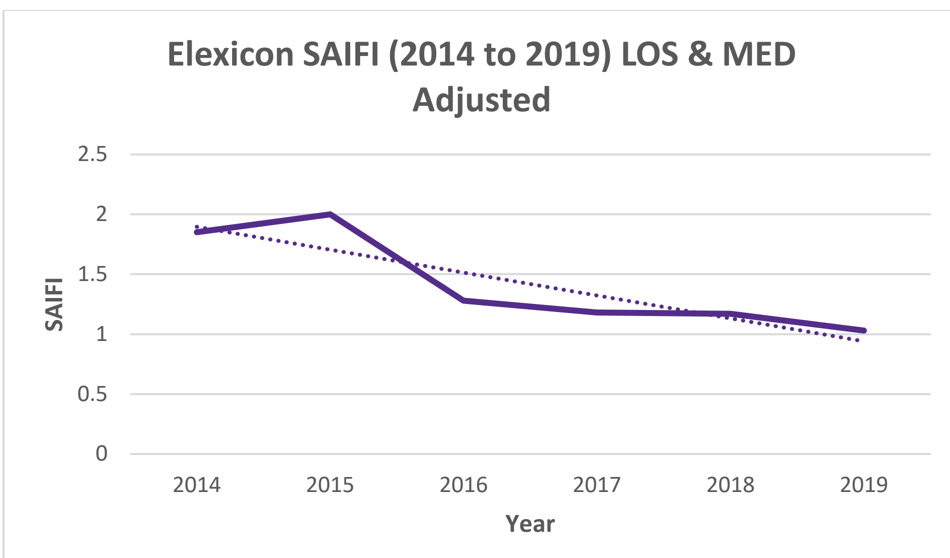


Table 3: Elexicon System Reliability Statistics

Metric	2014	2015	2016	2017	2018	2019
SAIDI	2.38	2.43	1.72	1.89	5.3	1.63
SAIFI	2.82	2.74	1.78	2.01	2.59	1.26
SAIDI	1.94	1.55	1.17	1.14	3.84	1.33
SAIFI	1.85	2.00	1.28	1.5	1.57	1.03
SAIDI	1.94	1.55	1.17	0.98	1.34	1.33
SAIFI	1.85	2.00	1.28	1.18	1.17	1.03

2.2 Current-State Analysis:

Elexicon's IT/OT investments fall into various categories which include: the consolidation of IT/OT systems, upgrades to IT/OT systems, investments into Cyber security, and investments into Grid Modernization and Innovation.

Consolidation of OT/IT Systems:

Some of the current legacy utility systems are either duplicates of each other, or sufficient for the corporate needs, operational efficiencies, or grid performance needed for Elexicon Energy. For instance, Veridian's legacy Outage Management System ("OMS") was built for reporting and tracking of outages and communicating with customers. Whitby's legacy OMS provided real-time outage identification (via Advanced Metering Infrastructure – "AMI") and communication to customers. Elexicon cannot operate effectively with two separate systems and require a company-wide ADMS, the requirements of which neither legacy system can satisfy. For example, the legacy Veridian OMS does not have the capability to identify fault locations or calculate the network state. New fault identification capability can reduce fault patrol times by using fault currents to calculate probable fault locations. Similarly, the legacy Whitby OMS does not have the capability of an ADMS and cannot perform advanced network functions such as energy management. The proposed ADMS will provide a platform to perform basic outage management tasks, and much more advanced functions as required in the future.

Continued consolidation of various systems such as the GIS for both former Veridian Connections and Whitby Hydro is expected. The GIS is used in the design, planning, and operations departments at Elexicon. The two GIS were combined in 2020, offering significant cost savings, cohesion between the two former utilities, and a centralized data repository for asset data.

Similarly, Elexicon is currently consolidating its two CIS, one from each of the former utilities. The consolidation of the two CIS enables alignment of business processes, enhances operational excellence, and delivers a unified customer experience. Other consolidation of software and hardware includes network replacements and enhancements, server application and software upgrades, Great Plains upgrades for financial reporting, vehicle radio system consolidation and improvement, mobile workforce management software harmonization, and SCADA system consolidation.

Technology Upgrades:

Elexicon's technology upgrades can be split into two categories: Software and Hardware. Software upgrades include upgrades to Kinetiq (the metering portal for the region), AutoCAD, SCADA, and other OT and IT software enhancements. It is expected that in 2022, the Elexicon SCADA system will be upgraded, refreshing end-of-life and deprecated software and systems.

Hardware upgrades include new office equipment such as laptops, printers, scanners, and operational hardware. As the life cycles for IT/OT hardware and software are evaluated and deemed at the end-of-life, new IT/OT investments are made. For example, Elexicon's data centre is tracking to reach capacity within a few years and so it will be expanded in the future DSP period to ensure adequate and reliable data centre operations. As the two utilities have now merged into Elexicon, a robust infrastructure must exist to handle existing and new data and systems. Over the next five years, Elexicon expects the need for additional storage capacity will continue to increase as demand for technologies and data increases. Network, storage and backup systems will be upgraded/enhanced in accordance with the upcoming IT capacity plan, which will also be developed.

Cyber-Security Investments:

The current security state of Elexicon's IT and OT systems is continually evaluated, both by internal and external parties. Gaps in IT/OT infrastructure, along with *Ontario Cyber Security Framework* drive investments to improve Elexicon's cyber-security posture. Elexicon routinely engages security experts to perform penetration testing and security audits to ensure that its systems are hardened against cyber-security threats. Additional investments are planned for cyber security, including new equipment and software installation, staff cyber-security training, enhanced cyber-security monitoring, and policy development. These investments will ensure that Elexicon can become compliant with the *Ontario Cyber Security Framework*. They will also ensure that Elexicon will be proactive in protecting against cyber-security threats as opposed to the traditional reactive posture. Cyber-security projects are prioritized to have the broadest effect of increasing overall maturity under the *Ontario Cyber Security Framework*.

Innovation & Grid Modernization:

Changes within the distribution utility sector are occurring rapidly. Technologies such as demand response, distributed energy resources, small-scale REG, energy storage, virtual power plants, microgrids, demand-side resources, and electric vehicles will continue to capture the headlines – but these terms often mean very different things to different people. Identifying and understanding the overall trends and plan to address challenges to Elexicon's operations is very important.

The disruptive technologies introduced into the utility grid are being driven not only by the electricity industry with new energy generation and storage technologies, but also by external factors, both from macroscopic processes based on societal and regulatory changes as well as innovations in operations and Information and Communication Technology, which are enabling customers to make more of their own decisions about how they consume or, in some cases, produce electricity. These drivers, commonly referred to as "the five Ds" are decarbonization, decentralization, deregulation, democratization, and digitalization.

Elexicon bases its investments into Innovation and Grid Modernization on the current-state of its technology and the expected evolution of drivers. Elexicon regularly evaluates trends with regards to Electric Vehicles and DER. Historically, Elexicon has employed microgrid pilot projects to understand the impact on the distribution network and operations. Other innovative projects levy the expertise found within the technology division at Elexicon by performing data analytics across the grid and in the organization. These projects evaluate and seek opportunities where the utility can become more operationally efficient. In the past, analytics projects were utilized to optimize vegetation management at the former Veridian Connections.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

Ontario Cyber Security Framework: Elexicon is required to comply with the *Ontario Cyber Security Framework*. The former Veridian Connections staff were part of the original Cyber Security Working Group that helped develop the framework for the power sector. The framework was based on the *NIST Cybersecurity Framework*, with influences from the U.S. Department of Energy *Cybersecurity Maturity Model*, privacy by design principles, and other stakeholders. Each year, Elexicon submits a report to the OEB outlining its cyber-security posture and identifying any gaps. Elexicon will analyze the discovered gaps and continue to implement cyber-security initiatives to decrease the cyber-security risk of the utility. Elexicon is working towards becoming compliant with the *Ontario Cyber Security Framework* over the forecast period

EB-2014-0189 Distribution System Reliability Performance Targets: With the ADMS potentially improving the reliability of the system, system reliability measures and expectations can be improved upon as outlined in EB-2014-0189 *Distribution System Reliability Performance Targets*. In particular, system-reliability measures of SAIDI and SAIFI are impacted by Elexicon's IT/OT investments. Elexicon aims to maintain or decrease reliability measures in the future. OT and Innovation investments will assist in improving reliability.

Ontario Regulation 425/06: Criteria and Requirements for Meters and Metering Equipment, Systems, and Technology: Under Ontario Regulation 425/06, there are requirements and criteria for meters, metering equipment, systems and technology specified in the document titled *Functional Specifications for Advanced Metering Infrastructure*. This document sets forth the minimum required level of functionality for AMI in the province of Ontario for residential and small General Service customers. Elexicon uses Connexo advanced metering infrastructure headend software to ensure the functionalities of existing Elster infrastructure and provide further insights into smart meters deployed on Elexicon's grid. As of now, Elexicon has two AMI systems and does not have plans to consolidate across the DSP forecast period. However, both AMIs will be maintained with high quality to ensure service and accuracy.

OEB Service Quality Requirements: Elexicon is required to continue to seek opportunities to improve or maintain customer service levels as set out by the OEB. Consolidation of and improvements to the CIS will ensure that customer service measures are maintained or improved moving forward. Also, Elexicon is looking to expand paperless billing to adapt to new customers expectations. Continued improvement and consolidation of Elexicon IT systems will help maintain and improve Service Quality (e.g., customer appointments and telephone accessibility) and customer satisfaction (e.g., billing accuracy and first contact resolution). The customer survey results indicate that 86% of customers are interested in automated outage notifications, indicating the need to improve services.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

If IT and OT investments were not undertaken at the pace contemplated, the following consequences are expected:

Customer Service: Customer satisfaction may stagnate or reduce as the multiple legacy systems continue to age and experience technical issues. Outage times and fault identification can be improved based upon new implementation; thus, improving customer satisfaction. Centralized and coherent systems also achieve greater operational efficiency, reduce error potential, provide greater opportunity for analysis, and improve response times. An improved and merged CIS will help maintain or improve customer service measures outlined by the OEB. Customers expect excellent electrical and customer service from the utility in responding to concerns and ensuring the reliability and operation of the grid. Improvements to software that interact with customers creates a more efficient and effective outlet for customer service. Operational Technology investments seek to improve operational effectiveness thus decreasing the amount of time customers may face when encountering outages. Overall, IT and OT systems ensure the safe daily operation of the grid which ensures electrical service to customers that use electricity in their daily lives.

Operational Effectiveness: As the complexity of the distribution system increases with the proliferation in mobile loads, distributed generation, and other modern changes in the electricity system, Elexicon must adapt to increase in sophistication to suit. Not investing in systems such as an ADMS will limit Elexicon's ability to maintain a high level of operational excellence, keeping response times high, analytics low, and real-time adjustments impossible in an increasingly real-time grid. For example, station switching typically needs to be analyzed using engineering knowledge and offline analysis, but systems such as the ADMS can enable System Operators to make decisions in real-time and reduce changes of damage to equipment or outages. Without such investments in mobile workforce management, ADMS, SCADA, and IT infrastructure in general, Elexicon will be unable to adapt to new developments in the electricity sector and will lag the operational excellence of the industry and, more importantly, the expectation of the customer to perform. In addition, consolidating and streamlining systems such as the GIS, CIS, ADMS, Quadra, Great Plains, and other such systems reduces the operational expenses associated with effectively distributing electricity to customers. Furthermore, as new technology opportunities become available, initiatives such as Enterprise Data Analytics projects and innovation projects seek to find operational efficiencies using in-house data or new technologies.

Elexicon has identified numerous cost-saving opportunities with the merger through a report and evaluation of merger synergies. For instance, consolidation of systems such as GIS and Radio System will be completed. GIS software maintenance was previously outsourced by Whitby, but the system will be moved to using in-house expertise of existing legacy Veridian staff instead, providing immediate savings. Similarly, the legacy Whitby Hydro vehicle radio system was merged into the legacy Veridian radio at negligible extra cost, providing another immediate cost savings. Further savings will be realized as maintenance will no longer be required for two SCADA systems. Costs of a legacy Whitby phone system upgrade, and its subsequent maintenance, were deferred due to the merger and extension of the existing legacy Veridian phone system.

Public Policy Responsiveness: Elexicon is mandated by the OEB to become compliant with industry cyber-security measures, namely the *Ontario Cyber Security Framework*. Penetration testing, auditing, and increased cyber-security investment will improve Elexicon's compliance level over the forecast period. Looking into the future, Electric Vehicles and Distributed Energy Resources will continue to develop and impact the nature of Elexicon's grid. The new extensible ADMS platform will enable to adaption to these technologies over time.

Consequences of inaction may also negatively impact Cyber Security and Grid Modernization. Without investments into new initiatives and innovation at Elexicon, the utility may not be as adequately prepared for future problems and opportunities such as increased uptake of Electric Vehicles and microgrids, or new and creative cyber threats.

Financial Performance: Not needing to pay for once-duplicate existing legacy systems will lower the overall cost of operating at Elexicon. Consolidating software, upgrading technology, and investing in new technologies will increase efficiency, resiliency, and allow for continual improvement with minimized overhead. Financial system upgrades such as those of Prophix and Great Plains will enable more streamlined workflows, improved interoperability, and more visibility into financial reporting.

Reliability: The new ADMS software will house information on operational counts of network and switching devices, real-time grid management, and instantaneous loading. Recommendations for transfers based on past and historical loading will also be automated. New software systems and maintenance of existing systems promote stability of the reliability of the grid.

2.5 Merger-Related Objectives:

The existence of many legacy systems from both Whitby and Veridian's systems is operationally inefficient. By incrementally and methodically consolidating and upgrading legacy systems, Elexicon can focus improvements and investments, enabling more effective operational excellence. Continued use of software systems from legacy utilities leads to inefficiencies and non-uniform work procedures and processes.

Cyber-security vulnerabilities of the two former utilities are still present as Elexicon has merged, and in some cases compounded. One of Elexicon's major IT initiatives is to improve its compliance with the *Ontario Cyber Security Framework* by over the forecast period.

With respect to grid modernization, Elexicon's general approach is to use active problem solving and find targeted, innovative and efficient solutions to existing problems. The approach is problem and value driven rather than technology driven to analyze what the company can most benefit from. The three major drivers to investments in Grid Modernization include (1) data-driven Investments, (2) trend-driven investments, and (3) non-discretionary investments. Proof-of-concept projects will be investigated by Elexicon and planned investments are intended to prepare for the future dynamic utility customer.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.d.1 (GP) The results of quantitative and qualitative analyses of the proposed project/program, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable

Number	1	2	3
Scenario Description	Current Budgeted IT/OT Plan	A faster pace of investment into new IT/OT systems (10% more)	A slower pace of investment into new IT/OT systems (10% less)
Annual Program Scope	The current IT/OT plan is described in the business case. Consolidation and Upgrades to IT/OT assets are performed with balance kept in mind.	Improved pacing for the consolidation and upgrade of current technologies.	Continued consolidation of technology assets and upgrades at a slower pace.
Annual Gross CAPEX	$3.64M	$4.01M	$3.28M
Annual Net CAPEX	$3.64M	$4.01M	$3.28M
Annual Program Benefits	The budgeted plan is paced such that Elexicon has sufficient resources to execute the program. Projects are prioritized such that the most beneficial projects are completed first while accounting for interdependencies between projects. See Section 3.2 for the program benefits and Section 5.1 for the prioritized list of material projects in the 2021 Bridge Year.	With a larger budget, it is anticipated that no incremental benefits will be achieved, as program execution is limited by available IT and OT resources. Project interdependencies only limit Elexicon's ability to ramp up its investment plan beyond the forecast amount.	With a lower budget, Elexicon would achieve the same benefits as the proposed plan but over a longer period of time, since several planned projects would be deferred to future years. See Section 3.2 for the program benefits and Section 5.1 for the prioritized list of material projects in the 2021 Bridge Year.
Program Economics	The budgeted plan is paced such that Elexicon's IT and OT resources are efficiently and effectively used for executing the capital program while maintaining day-to-day operations.	With a 10% higher budget, Elexicon would lack the IT and OT resources to execute the capital plan.	With a 10% lower budget, Elexicon's IT and OT resource would be underutilized.
Customer Feedback	Key customer preferences and priorities pertaining to the IT/OT investment program include:		

	• When asked to identify their top two priorities, the top choices identified by Elexicon's customers were "improving the grid's resilience to major weather events, like storms, floods, or freezing rain" and "preparing the grid for new types of uses, like electric vehicles and renewable generation". The consolidation of IT/OT systems supports investments into the ADMS, AMI, and SCADA which relate to the former objective. Grid Modernization and Innovation investments support the latter objective. • When asked for their support of "investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage", 75.5% (651 of the 862) of customers surveyed online expressed their support for these investments, which pertain to the Grid Modernization and Innovation portion of the IT/OT budget. • From the survey, 87% (750 of the 862) of customers are interested in receiving outage notifications by phone either via text/and or voice to landline about the cause and anticipated restoration time. This initiative falls under the IT/OT investment program.		
Other Constraining Factors	Current budget is constrained by the operational needs of system investments and other non-system investments.	A faster pace of investment would reduce the budget available for system investments and other non-system investments.	A slower pace of investment would increase the budget available for system investments and other non-system investments.
Preferred Alternative	X		

3.2 Rationale for the Preferred Alternative

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Elexicon's reliability performance will deteriorate if new investments into new merged systems are not made. Without these investments, the technical issues arising from the legacy OMS will make it difficult to respond to outages. The planned ADMS implementation will provide incremental reliability benefits through the capability to estimate fault location based on the measured fault current. New investments targeted at emerging technology implementations would ensure improvements in reliability measures through the ability to incorporate new functionality and communication with equipment.

Operational Efficiency and Cost Effectiveness: If the status quo is maintained, the level of operational efficiency and cost-effectiveness would not improve and would likely deteriorate over time. The duplication of systems and functionality comes with increased complexity and cost that should be avoided. Furthermore, failing to introduce new consolidated technologies will lead to lost opportunities for improving operational efficiencies. For instance, by having fault location capabilities in an ADMS, crews could significantly reduce the time needed to restore some outages.

Grid Resiliency: Analytics projects and new technology investments by Elexicon will improve its ability to respond to adverse grid conditions – such as multiple outages during storms – supporting a more resilient grid. SCADA upgrades will ensure that controllable devices are able to respond when needed to support planned/reactive switching and other operations. Real-time loads recorded through the ADMS and upgrades to the Kinetiq metering data platform will allow Elexicon to better plan for a more resilient grid in the future that is able to better respond to dynamic operating conditions.

Safety: With the added complexity of having disparate systems that overlap in function, there is an increase in the potential for error or oversight. Consolidated systems and improved situational awareness will ultimately lead to better and safer decision-making, especially in emergency situations.

Cyber-Security/Privacy: With multiple disparate systems and infrastructures, complexity is greatly increased, leading to a much greater likelihood of security risks and privacy breaches. Consolidation of infrastructure, harmonization of cyber-security practices and policies, and tightening of points of entry will lead to a lowered likelihood of undesired security incidents or breaches. Dedicated investments into cyber-security will be undertaken over the forecast period.

Environmental Benefits: Investments within this program promote greenhouse gas reduction technologies such as Electric Vehicles and in the reduction of Elexicon's carbon footprint through more efficient operations.

Coordination/Interoperability: Existing technology assets will enable current coordination and interoperability levels with stakeholders. Coordination with Hydro One/IESO and neighboring LDCs improved due to the reliability of software, new data collected for insights, and added potential functionality. Elexicon also engages with multiple utility committees in identifying IT trends, innovation, and experiences throughout the sector.

Conservation and Demand Management: Smart Meters and other Grid Modernization technologies allow customers to better manage their energy usage.

Net Customer Benefits: The customer will realize benefits across the different technology investments planned by Elexicon from improving and consolidating customer-facing software, improved operational performance through new technology implementation, and potential improvements in addressing outages. Consolidating the CIS from Whitby and Veridian into one system will enable synergies in customer service, billing, credit and collections, metering payment processing, and new service setup and upgrades. A new Elexicon customer bill and website will also be created, aided by the merged CIS and Customer Portal.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

When new functions are needed in the ADMS, new upgrades will be added on a per-use basis or when requirements are identified. Modular software will be chosen such that new advancements and upgrades to the software are more easily implemented, especially considering new technologies impacting the grid. After implementation, the results of the benefits of more advanced ADMS functions will be considered in the context of changes in the electricity sector and customer requirements.

If security audits and penetration testing exposes previously unknown high-level cyber-security risks, more prioritization and investment into existing cyber-security measures to IT and OT software will be required. Year over year, Elexicon investigates into cyber-security gaps that exist. If any gaps present concerning problems, prioritization will be placed into ensuring the problem is remedied.

Elexicon also evaluates proof-of-concept projects related to innovation and analyzes how disruptive technologies like Microgrids, REG, and Electric Vehicles should be responded to. If the trend of new REG investments shows an increasing amount, Elexicon will ensure system investments will be made to prepare for its increased implementation.

Any licensing issues or software issues that arrive on OT and IT systems will also be prioritized. For example, vendors who have deprecated software versions or exited a business may prompt sooner than end-of-life conditions. Elexicon will have to shift in resources from one planned investment to the new investment to adapt.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Elexicon IT investments are driven by multiple drivers which include:

- Asset life-cycles; and
- Operational needs.

Elexicon follows IFRS useful life values to predict lifetimes of IT/OT hardware and software. Laptop life-cycles typically last three years and desktop cycles last for four years. By the year 2020, there will be a large number of devices that will need to be replaced as they will reach end of life. Elexicon currently has incorporated hardware life-cycles in the new CMDB. Software and OT assets will be also be maintained in the CMDB in the future to further enhance asset management of technology assets at Elexicon.

Table 4: IFRS IT typical useful life

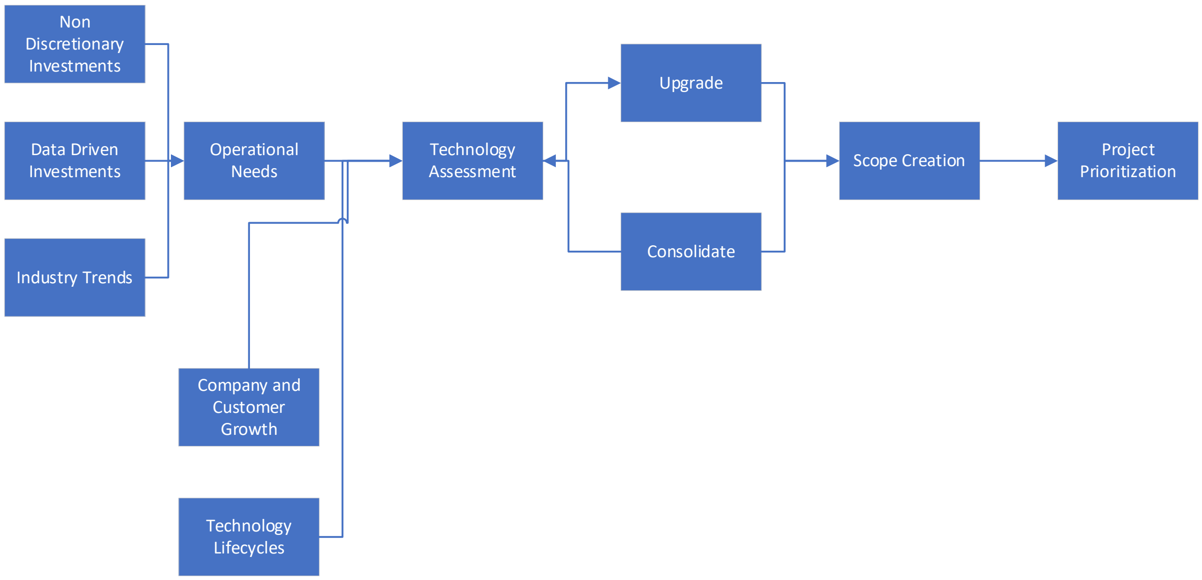
IT Asset	Components	IFRS Useful Life
Computer Hardware	Others	5 years
	Desktop	4 years
	Laptop	3 years
Computer Software	Acquired	3 years
	Internal	5 years

At the legacy Veridian Connections, the OMS software was purpose-built mainly for tracking and reporting of outages and communication with customers. The legacy Whitby Hydro OMS featured real-time outage identification via AMI and communication with customers. Both former utilities had issues with the software that will be addressed by the new ADMS. With Quadra, there will be a consolidation of systems to perform new project estimates, bills, and create scopes. Combined information from different systems that is more easily accessible can promote fundamental changes to the planning, analytical, and life-cycle management of processes. For example, loading data of new assets can be acquired alongside GIS coordinates and condition data. The mixture of data allows planners at Elexicon to perform a more granular analysis in terms of distribution system projects.

Both legacy utilities used NorthStar for their respective CIS. A consolidated platform for Elexicon would increase the operational efficiency of the Customer Care department at Elexicon. Additionally, the GIS are being consolidated into one system. The general consolidation of many of Elexicon's software systems will improve the operations as a combined front of the two former utilities.

Operational needs are identified from various inputs such as industry trends, the need for non-discretionary investments, and data-driven research and analysis. A simplified process diagram found in Figure 4 details a typical technology investment procedure at Elexicon.

Figure 4: Typical Elexicon Technology Investment Cycle



An assessment is made based upon the needs and drivers found in the technology portfolio. If the assessment deems that the need is warranted, a project will be defined by a project lead. The project is then initiated and weighed against other technology projects. These projects are weighed against each other for a multitude of considerations which include safety, reliability, asset life, the criticality of the investment, and operational efficiency. Projects are then prioritized and assigned a completion year depending on when the project is required to be in service.

4.2 Legacy Work Execution Approaches vs. Combined Operations

The legacy Whitby Hydro IT and OT was fully outsourced and, in some cases, hosted by external resources. Legacy Veridian Connections leveraged mostly in-house expertise of IT and OT systems, utilizing contractors for specialized knowledge only. Moving forward, Elexicon will capitalize on the existing infrastructure and skills to save on outsourcing costs.

An emerging approach to performing work at Elexicon is to automate or digitize the manual processes within the company. Over the next five years, many manual or paper-based processes will be automated and digitized. Examples include trench inspections, movement forms, cable testing, cable injections, pole testing, cyclical maintenance, tree trimming, switch order execution, trouble call data collection among others.

In the future, there will be more flexibility in performing work for Elexicon whether it be internal or external development. When evaluating a technology investment, Elexicon will consider outsourcing or in-house ownership. If cost savings and efficiencies are realized from one option over the other, Elexicon will look towards making the best economic decision.

4.3 Scale Increase Considerations

Due to the scale increase of the merger, Elexicon will continue to perform consolidation of existing technology systems. The consolidation of multiple systems into a single system produces significant efficiencies of scale where an entire system can effectively be replaced by a few licenses. This is the case with the GIS, the CIS, the ADMS, mobile workforce management, CYME, Great Plains, Prophix, Quadra, and several other systems.

In addition, the combined skill sets of IT personnel from the different utilities will be beneficial in sustaining the legacy systems for the time being and utilizing their experiences within the new consolidated and upgraded systems across the company. The in-house expertise in technology from the Veridian side will be utilized for Elexicon in place of contracted labour or consultants with minimal overhead.

A larger service territory will require Elexicon to evaluate the best software currently in place to serve its customers. Further SCADA points will need to be integrated into the existing system and an understanding of the gaps and differences between legacy systems was conducted. As the former Whitby Territory is a neighboring area to Ajax and Pickering, efficiencies for OT may be realized which will also produce efficiencies for crews in responding to calls. A larger service territory also affords Elexicon to adapt for the changing grid throughout the region. As EVs and DERs become more popular, evaluations of disruptive technologies throughout the region can be performed.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Employees will be trained and introduced to the new software but will utilize legacy systems until all personnel can be transferred. Once all employees are trained, a transition to new software will occur and the legacy systems will not be maintained. However, Elexicon needs to ensure whatever previous important information from the two legacy systems needs to be transferred to the new systems. For example, if new functions are needed in the ADMS, new upgrades will be added on a per-use basis or when requirements are identified. As a merged utility this removes the upkeep/costs of maintaining and tuning the legacy systems.

Data centre upgrades will be made to ensure enough data storage will be achieved now and into the future for the utility.

With the introduction and upgrades of various software systems, Elexicon will look to improve cyber-security compliance. If cyber-security weaknesses are found within the existing IT and OT framework, Elexicon will ensure that these weaknesses are removed.

The merger has identified numerous merger synergies that are expected to produce cost savings through the reduction of certain technologies in use at Elexicon. These cost savings will be utilized to reinvest into other aspects of the company.

5. Individual Material Projects Comprising the Program

5.1 Overview of Projects

Project ID	IT Customer Service Project Name	Year	Net CAPEX ($M)	Priority Score
2020-4034	CIS Merge Project	2021	0.974	89.5
2021-4081	Mobile Office - Field Staff (70)	2021	0.556	84.6
2021-4057	General 2-way Radio Upgrade	2021	0.300	62.5
2021-4020	Data Centre infrastructure Annual Addition	2021	0.600	50.9
2021-4040	ADMS Purchase and Implementation	2021	0.800	47.9
2021-4022	Server Application Software Upgrade/Modifications	2021	0.300	22.1

5.2 Individual Project Scopes

-A.4 Start date, in-service date and expenditure timing over the planning horizon
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.
-A.3 Related customer attachments and load, as applicable
-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.
[Continued below under Value-Added Approach]
-C.d.2 (GP) Where the capital cost of a project substantially exceeds the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).
-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.

<table>
<tr><td>Project name</td><td colspan="5">CIS Merge (including Customer Portal transition)</td></tr>
<tr><td>Project numbers</td><td colspan="5">YCI200100, YCI190107</td></tr>
<tr><td>Job numbers</td><td colspan="5">PO #0000166, PO # 0000094</td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">General Plant</td></tr>
<tr><td>Budget Category</td><td colspan="5">Information Technology</td></tr>
<tr><td>Project Driver</td><td colspan="5">Business Operations Efficiency</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2020 JAN 27</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021 FEB 01</td></tr>
<tr><td>Scope of Work</td><td colspan="5">The scope of the project includes:
Creation of a production version of the NorthStar CIS, merging Whitby Hydro and Veridian customer history and harmonized setups and processes
Development of a merged customer-facing portal for all Elexicon customers
Consolidated reporting abilities</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $974,000</td><td colspan="2">Contribution: $0</td><td>Net: $974,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$99,900</td><td>$111,000</td><td>$188,700</td><td>$710,400</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">The project will merge the former Veridian and Whitby Hydro CIS’ into one instance, the Harris NorthStar product which both former utilities operated with. To merge the systems, a number of changes to business processes, system configuration and data are required. The project will also merge the existing customer portals into a single site where all Elexicon customers can view their bills and manage their account details.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">89.5</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">The CIS merge should be seamless to customers. They will continue to receive bills from Elexicon as usual.

Former Whitby Hydro customers will be transitioned to the former Veridian Connections Customer Portal, they will see a difference in the eBill notifications they receive and the presentment of information in the portal, however the content of the information will be similar to before.

All Customer Experience staff and others who use the current NorthStar CIS’ instances will benefit as all customers will be housed in one CIS; however, the systems are similar and will be familiar to users. Further benefits include reduced maintenance release costs in operating a single system, the ability to align processes. Moving to a single customer portal will provide consistency to customers across the Elexicon Service territory and all customers will be able to view the same information related to their accounts. There will also be reduced costs in maintaining a single customer portal.</td></tr>
</table>

Intervention Options	Development of a new CIS for a large utility like Elexicon would require a system such as SAP or CC & B. These systems were all considered, however have significantly higher implementation costs. Both Veridian Connections and Whitby Hydro used the Harris NorthStar application as their CIS. Merging this system into one instance reduces the risk of introducing a new CIS with new functionality that would require development of new processes at cutover. Training on a brand-new system would be expensive. Maintaining status quo would require the former utilities to continue to operate separately and independently. This would require additional resources to manage and maintain two systems. The Veridian instance includes more functionality and custom modifications. In order to merge processes and provide similar customer experiences, the existing Whitby Hydro instance would need substantial upgrades and custom modifications to enhance functionality and match the functionality available in the Veridian instance.
Effect on System O&M Costs	A merged CIS is strategically important to Elexicon as it will allow the Customer Experience department (and others that use it), to operate with unified processes. Prior to the merge of the CIS, departments have continued to operate with multiple variations of the same processes. A merged CIS will help departments operate as one with single process flows and will align customer experiences. The CIS merge will create the efficiency of only having to manage, support and maintain a single instance. Merging the CIS' will allow the two former utilities to leverage the benefits of each system, including automation, single source reporting, and document storage.
Targeted Outcomes	Customer Focus - provides for the ability to manage customers consistently across Elexicon Energy Operational Effectiveness – allows for unified processes Financial Performance – a merged CIS will allow for merged contracts with vendors
Cost Benchmarks	No Benchmarks available.
Value-Added Approach	Utilizing the Veridian Connections NS instance as the base for the Elexicon Energy instance has reduced costs related to developing new processes, training, and testing, as many of the existing Veridian set-ups and processes have been adopted.

Project name	Mobile Office Project				
Project numbers	2021-4081				
Job numbers					
Project District	All Districts				
Project Location	All Locations				
Investment Category	General Plant				
Program Category	IT				
Project Driver	IT/OT – Business Operations Efficiency				
Proposed Start Date	2021 JAN 01				
Required In-Service Date	2021 MAR 31				
Scope of Work	This project involves the purchase of approximately 70 'mobile offices' consisting of rugged laptops and/or tablets, plus vehicle mounts and associated accessories and software to work remotely in the field.				
Preliminary Estimate: Total Capital Cost	Gross: $556,000	Contribution: $0		Net: $556,000	
Expenditure Timing	**Quarter**	**Q1**	**Q2**	**Q3**	**Q4**
	Gross CAPEX	$50,040	$55,600	$94,520	$355,840
Rationale for Intervention	Many positions at Elexicon Energy have field duties ranging from metering and inspections, to stations repairs and traditional line work. As forms and reports increasingly become digitized and information is expected to flow from field to office faster through various applications, the need for field staff to communicate and work electronically is essential to working efficiently. Furthermore, with current pandemic recommendations that include physical distancing and working from home/remotely to minimize contact through sharing of equipment and accessing shared spaces (ie office buildings), providing staff with the necessary hardware, software and accessories to perform work safely and efficiently from the field is more important than ever.				
Criteria Score	84.6				
Impacted Customers and Entities	Outfitting 70 employees in the select roles identified (metering, engineering inspectors, stations technicians, lead linespersons, supervisors) with this equipment will benefit all 168,000+ Elexicon customers across all service areas through faster and more efficient completion of repairs and upgrades.				
Intervention Options	The options are either to outfit them with the necessary hardware and software to work remotely, or to continue with status quo, where staff would continue to complete their work in hard copy, and then travel to the office to enter it electronically, either personally or by an administrative support person. Status quo is highly inefficient in terms of both time and cost. Furthermore, the risk of contracting/transmitting COVID-19 is increased when staff need to travel between field and office to drop off/pick up paperwork, and should be avoided to the fullest extent possible during periods of active pandemics.				
Effect on System O&M Costs	The start-up OM&A costs are estimated at $82k to increase the number of licenses for already procured software, and $10k thereafter for annual license renewals.				

Targeted Outcomes	Increased productivity and zero transmission of COVID-19 between employees through contact tracing.
Cost Benchmarks	No benchmarking available. Competitive procurement to be undertaken to ensure best value received.
Value-Added Approach	This project advances the Operational Excellence and Customer-Centricity strategic pillars in the 2020 Strategic Plan. Capital costs are offset by increased productivity, which should be seen in an increased number of OM&A and capital projects completed in 2021 over 2020, improved customer service feedback and increased employee satisfaction.

<table>
<tr><th>Project name</th><td colspan="5">2021-4057 General 2-Way Radio Upgrade</td></tr>
<tr><th>Project numbers</th><td colspan="5"></td></tr>
<tr><th>Job numbers</th><td colspan="5"></td></tr>
<tr><th>Project District</th><td colspan="5">General</td></tr>
<tr><th>Project Location</th><td colspan="5">General</td></tr>
<tr><th>Investment Category</th><td colspan="5">General Plant</td></tr>
<tr><th>Program Category</th><td colspan="5">Information Technology</td></tr>
<tr><th>Project Driver</th><td colspan="5">Business Operations Efficiency</td></tr>
<tr><th>Proposed Start Date</th><td colspan="5">2021-03-01</td></tr>
<tr><th>Required In-Service Date</th><td colspan="5">2021-12-31</td></tr>
<tr><th>Scope of Work</th><td colspan="5">This project will aim to replace an aging field radio system used by crews and the system control centre for reliable, secure and recordable communications.</td></tr>
<tr><th>Preliminary Estimate: Total Capital Cost</th><td colspan="2">Gross: $300,000</td><td colspan="2">Contribution: $0</td><td>Net: $300,000</td></tr>
<tr><th rowspan="2">Expenditure Timing</th><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$27,000</td><td>$30,000</td><td>$51,000</td><td>$192,000</td></tr>
<tr><th>Rationale for Intervention</th><td colspan="5">The current vehicle radio system is using deprecated and unsupported hardware. It is currently being held together but upon equipment failure is very difficult to maintain and bring back up. An upgrade to the system is required.</td></tr>
<tr><th>Criteria Score</th><td colspan="5">62.5</td></tr>
<tr><th>Impacted Customers and Entities</th><td colspan="5">All Field Staff and Control room staff rely on a robust and resilient radio system. Having such a system will affect all customers, especially in major outage situations</td></tr>
<tr><th>Intervention Options</th><td colspan="5">There are multiple options around which system to purchase, however the existence of such a system is a requirement. As we are a mission-critical utility that requires open communications between office and field staff, there is no other reliable communication method that can be used apart from a dedicated radio or similar technology network. Cellular communications cannot be relied upon as there is currently no guarantee of service or priority for utilities.</td></tr>
<tr><th>Effect on System O&M Costs</th><td colspan="5">O&M costs should remain constant if we purchase an additional system. There is the option to use ‘radio as a service’, which would shift the burden from Capital to Operating. This is not favoured but will be considered, and would cost approximately $150k/year</td></tr>
<tr><th>Targeted Outcomes</th><td colspan="5">Reliable communications between field staff and back office.</td></tr>
<tr><th>Cost Benchmarks</th><td colspan="5">None available currently</td></tr>
<tr><th>Value-Added Approach</th><td colspan="5">N/A</td></tr>
</table>

<table>
<tr><td>Project name</td><td colspan="5">Data Centre Infrastructure Annual Addition</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-4020</td></tr>
<tr><td>Job numbers</td><td colspan="5"></td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">General Plant</td></tr>
<tr><td>Program Category</td><td colspan="5">Information Technology</td></tr>
<tr><td>Project Driver</td><td colspan="5">Business Operations Efficiency</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021-01-01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021-12-31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">
Network Infrastructure: Replacement of aging network devices, including network redesign, implementation and integration and consolidate Whitby and Veridian VLANs into a single Elexicon Energy network.
Legacy network: Integration of legacy Whitby Hydro network and server infrastructure into the new Elexicon Energy landscape.
Domain Name Service (DNS) Consolidation: The current DNS layout has brought on challenges with the merger resulting in name resolution issues. In order to remediate these challenges Elexicon needs to consolidate the Whitby Hydro and Veridian DNS domains into one single Elexicon DNS domain and will require Vendor expertise to conduct an assessment of the DNS services and identify the gaps. The assessment will guide Phase 2 to rollout a single domain structure for the entire organization.
Active Directory Integration: As a result of the merger there have been challenges creating secure Active Directory TRUST zones which allows end users across domains to share calendars, scheduling, servers, file sharing and folder access across the domains. This initiative will collapse the three domains into a single unified AD domain. Elexicon users will be migrated using a phased approach from the old domains into the new consolidated domain.
Exchange Mail: There have been numerous challenges with the emails flowing between the three domains due to setup of trust relationships. Elexicon users are currently unable to view calendars between end users across domains and integration challenges with DNS and AD. The plan is to migrate 350 users and 150 shared mail boxes once the Active Directory Trust zones and DNS consolidation is completed.
</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $600,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $600,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$63,000</td><td>$70,000</td><td>$119,000</td><td>$448,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">
Network Infrastructure: Aging equipment has reached End of Life (EOL) and cannot be patched or supported by the Vendor, needs to be replaced to mitigate any potential support issues or hardware failures.
</td></tr>
</table>

	• **Legacy network:** Aging equipment hosted at the Whitby Hydro site needs to be consolidated into one single consolidated network managed by Elexicon IT and provide for BCP, economies of scale and eliminate monthly hosting charges. • **Domain Name Service (DNS) Consolidation**: The current DNS setup is creating all sorts of challenges for Name Resolution due to the merger of the two companies. Consolidation on the Domain Naming Service into a single Elexicon Energy domain will alleviate these issues. • **Active Directory Integration:** The creation of trust relationships between the three zones and the final migration of Active Directory users should mitigate all server, file sharing and folder access and calendars issues across the domains. • **Exchange Mail**: It is anticipated the migration of 350 user mail boxes and 150 shared mail boxes would mitigate email, calendaring and scheduling issues.
Criteria Score	50.9
Impacted Customers and Entities	The entire business will be impacted by these network upgrades, domain changes and mail migrations. These disruptions would require careful coordination between teams. In addition, customers will be affected by external-facing changes including inbound emails during the transition. The benefits include a single Elexicon Energy domain, consolidated DNS and bring additional resiliency in our network hardware infrastructure. All internal stakeholders will be hosted on a single consolidated mail domain.
Intervention Options	There is no alternative to replacing End OF Life (EOL) or out of support network hardware. It must be kept updated and aligned with the asset lifecycle. Consolidation of systems is also not discretionary to achieve merger synergies and bring about a single domain entity. Other benefits to be gained include improved security, efficiency and complexity.
Effect on System O&M Costs	Upgrade of aging hardware will have no impact on O&M Consolidation of systems will save approx. $263,000 over 5 years – see merger synergies for more details.
Targeted Outcomes	Public Policy Responsiveness: Abiding by Cyber Security Framework Disaster recovery and resiliency Merger synergies Financial Performance Merger Synergies Decreasing O&M costs Operational Effectiveness Consolidated system Resiliency Cyber Security Reduced complexity

Cost Benchmarks	No Benchmarks available at this time
Value-Added Approach	All of the legacy Whitby Hydro systems are being absorbed into legacy Veridian (now Elexicon) infrastructure with minimal incremental increase.

<table>
<tr><td>Project name</td><td colspan="5">ADMS Purchase and Implementation</td></tr>
<tr><td>Project numbers</td><td colspan="5">2021-4040</td></tr>
<tr><td>Job numbers</td><td colspan="5"></td></tr>
<tr><td>Project District</td><td colspan="5">General</td></tr>
<tr><td>Project Location</td><td colspan="5">General</td></tr>
<tr><td>Investment Category</td><td colspan="5">General Plant</td></tr>
<tr><td>Program Category</td><td colspan="5">Information Technology</td></tr>
<tr><td>Project Driver</td><td colspan="5">Business Operations Efficiency</td></tr>
<tr><td>Proposed Start Date</td><td colspan="5">2021-01-01</td></tr>
<tr><td>Required In-Service Date</td><td colspan="5">2021-12-31</td></tr>
<tr><td>Scope of Work</td><td colspan="5">This project involves the purchase and implementation of an ADMS, the first phase of which – this portion – is a functioning outage management system to provide interfacing with GIS, SCADA, AMI and outage communications, replacing the legacy Whitby Hydro and Veridian outage systems. See 2021-4040: Appendix A – Project description for more information</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td colspan="2">Gross: $800,000</td><td colspan="2">Contribution: $000</td><td>Net: $800,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$72,000</td><td>$80,000</td><td>$136,000</td><td>$512,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">Elexicon does not currently have a system capable of satisfying our requirements for the future, nor a robust enough system to satisfy current requirements. The legacy Veridian OMS was purpose-built at a time when it was deemed unnecessary to have a full OMS and was intended to satisfy the need to track and report on outages, and for communicating with customers. However, there is now a business need for a formal OMS beyond the practical capability of in-house development.
See 2021-4040: Appendix B – Rationale for more details.</td></tr>
<tr><td>Criteria Score</td><td colspan="5">47.9</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">All customers and stakeholders will be impacted by this as this will increase operational excellence around outage management, response and communication.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">ADMS technologies will provide Elexicon with greater ability to observe and control distribution systems so as to address rising operational complexities while ensuring reliable and resilient operations. An ADMS differs from a traditional distribution management system (DMS) in that it integrates operations across the numerous systems and applications that are typically isolated or, at best, loosely coupled.

As such, considering present industry needs, there is no alternative for ADMS. However, as mentioned above, there are short-term, non-viable, patched approaches available; such as, continue to use existing OMS software or continue building upon in-house-built OMS software.
These alternatives will not be able to meet current and future industry requirements.</td></tr>
</table>

	See 2021-4040: Appendix C – Alternatives for more details.
Effect on System O&M Costs	Estimated $100,000/year less in maintenance costs than the current cost of the legacy Whitby Hydro outage management system
Targeted Outcomes	- Improved situational awareness - Faster response to outages - Improved system management (feeder balancing, etc…) - Improved resiliency of SCC operations by eventually becoming paper-less
Cost Benchmarks	No Benchmarks available. Competitive process to be followed
Value-Added Approach	N/A

2021-4040: Appendix A – Project description

The US Department of Energy (DOE) defines an advanced distribution management system (ADMS) as a software platform capable of integrating current and emerging distribution utility data, measurement, and control applications from varying vendors, and utilizing real-time, spatial data of all connected devices, to manage and optimize distribution utility operations for improved reliability, resiliency, efficiency, asset protection, and integration of distributed energy resources (DERs).

ADMS integrates operations across the numerous systems and applications that are typically isolated or, at best, loosely coupled. These systems and applications include, but are not limited to: Energy Management Systems (EMS), Distributed Energy Resource Management System (DERMS), Supervisory Control and Data Acquisition (SCADA), Outage Management Systems (OMS), Graphical Information Management Systems (GIS), Advanced Metering Infrastructure(AMI) and Meter Data Management Systems (MDMS), Customer Information Systems (CIS), Fault Location Isolation and Service Restoration (FLISR), mobile workforce tools, feeder load balancing and optimization, voltage optimization control, and distribution state estimation. By integrating operations across all of these systems and applications, ADMS technologies provide utilities with greater ability to observe and control distribution systems so as to address rising operational complexities while ensuring reliable and resilient operations.

At present, the distribution system faces key technical challenges in managing and optimizing a modernized grid. ADMS provides key solution to these challenges including managing the complexity of operating the distribution systems with increasing levels of variability in both generation and load assets; implementing a holistic approach to coordinate and manage grid operations within distribution grid, and to local energy networks such as microgrids, distributed energy resources (solar PV, wind, combustion engines, combined heat and power, micro turbines, micro hydro power, and fuel cells, electric vehicles, responsive building loads, energy storage, and demand response); utilizing real-time, spatial data of all connected devices in determining the grid state for improved operational planning, protection, control, and optimization; and achieving interoperable and integrated operations between legacy and new and emerging systems and applications.

It is recommended that Elexicon adopt a growing and increasingly necessary trend among utilities by implementing an advanced distribution management system (ADMS). The ADMS implementation modular approach will closely coordinate with Elexicon Energy's grid modernization initiative activities undertaken. Furthermore, it is recommended that Elexicon purchase and implement a robust, open source and interoperable ADMS system from industry recognized and established ADMS vendor in a modular way, starting with OMS, to ensure that Elexicon can meet the demands of the changing landscape today, and that prepared for the coming changes.

Initially, this project will be implemented in two phases:

1. The first phase involves an implementation of a new enterprise OMS to replace the two legacy systems. This OMS will be part of a larger, established ecosystem of an ADMS and will be incrementally added to as needs arise. This portion is estimated to cost approximately $800,000 in 2021.
2. The second phase involves implementing limited ADMS functionality to help streamline or improve current utility processes and is currently estimated to cost approximately $500,000 in 2022.

In subsequent years, as technology continues to disrupt the electricity distribution industry, more advanced functionalities will be added incrementally that is available in an ADMS as needs and their solutions arise.

2021-4040: Appendix B – Rationale

Elexicon does not currently have a system capable of satisfying its requirements for the future, nor a robust enough system to satisfy current requirements. The legacy Veridian OMS was purpose-built at a time when it was deemed unnecessary to have a full OMS and was intended to satisfy the need to track and report on outages, and for communicating with customers. However, looming disruptions to the distribution system and given market solutions have become viable and necessary. There is now a business need for a formal OMS beyond the practical capability of in-house development. The legacy Whitby OMS was also purpose-deployed to provide real-time outage identification (via AMI) and communication to customers. While it has been successful in both of those areas, is an aging application (the version was released about ten years ago) and a decision must be made regarding whether to upgrade the application version or to replace the applications.

It is recommended to replace this legacy software, though the cost to do so is likely higher in the short-term than upgrading, for the following reasons:

1. Both legacy utilities have identified recurring issues with the current software vendors for the OMS.
2. The vendors do not have a vision to extend their software into an ADMS platform. They have communicated intent to add a few ADMS-like functions into the software, but to date have no customers using these functions.

It is recommended to not continue with the existing systems as reinforced by the industry trend in developing a vendor agnostic interconnection layer so that various DMS systems, their peripheral systems, and other applications can be more effectively interconnected. Elexicon is envisioning to reduce integration costs and have access to best-of-breed solutions from multiple vendors while avoiding stranding investments in legacy systems.

Finally, implementing ADMS functionality will introduce some significant cost savings and reliability improvements. Consider adding fault location to demonstrate: On average, the Veridian rate zone has experienced about 530 overhead contact outages and auto reclose events per year. While patrols are not always dispatched in the case of auto reclose events, we will assume that they would be if it was not so cost prohibitive. If Elexicon had fault location analysis functionality from an ADMS, it could very quickly deploy field crews to one or two specific locations and identify the cause and location of the outage much more efficiently. Conservatively, consider that half of these outages require a patrol for at least 1.5 hours. This would mean that annual spend on searching for outage locations and causes would be $79,500. If Elexicon reduced that time by just 30 minutes per incident with the help of the ADMS' fault location function, it would see a savings of $133,000 over 5 years just from the one function. This is not considering the improvement in reliability and reduction of future outage causes (by remedying outages that currently have unknown causes).

Consider that this is only one function of dozens in an ADMS system. Additional currently unquantifiable benefits of the ADMS system include:

- Increased safety for field crews as operational situational awareness, especially in crisis situations, is greatly improved by providing crew management, incident management, SCADA management, work order and tagging management, and awareness of distributed generation into plain focus. Reduction of error and restoration time due to automatic loading calculations and automatic generation of switching orders using current, historical and projected system loading, profiling down to the customer.
- Decreased overhead for performing routing operations such as removing a station from service. This is currently an operation that must go to engineering for study. An ADMS will download that decision-making to operators directly, improving overall organizational efficiency.
- Real-time management of loading and recommendation for transfers by the system, reducing overall infrastructure requirements. This is becoming increasingly important as electric vehicles and distributed generation and storage increase.
- Streamlining of switch order creation and execution through digitization of currently paper-based process
  Improved asset management of devices through the inherent switch operation logging ability of the ADMS system. This will allow us to keep track of the number of operations of devices and to proactively maintain them as per specification. Additionally, if devices have not been operated for an extended time period, such systems can provide warnings to add extra steps in order to operate before execution of switching steps, avoiding device failure.

Strategic Rational for ADMS implementation:

- Accommodating growing deployment of DERs.
- Enabling an integrated system approach to electric power system operations and control that spans transmission, distribution, and local energy networks such as buildings and microgrids
- Utilizing real-time, spatial data of all connected devices to manage and optimize grid operations
- Achieving interoperable and integrated operations between legacy and new and emerging systems.
- Accommodating new architectural and operational constructs for distribution networks

2021-4040: Appendix C – Alternatives

ADMS technologies will provide Elexicon with greater ability to observe and control distribution systems so as to address rising operational complexities while ensuring reliable and resilient operations. An ADMS differs from a traditional distribution management system (DMS) in that it integrates operations across the numerous systems and applications that are typically isolated or, at best, loosely coupled.

As such, considering present industry needs, there is no alternative for ADMS. However, as mentioned above, there are short-term, non-viable, patched approaches available; such as continuing to use existing OMS software or continue building upon in-house-built OMS software. These alternatives will not be able to meet current and future industry requirements. The other option is to not use OMS/ADMS software at all. This is not a practical option because Elexicon has a basic organizational obligation to manage the current state of the network, to communicate that state both internally and to customers in real-time, and to perform analysis on the various events. These functions are impossible without an OMS.

In addition, with the onset of the proliferation of distributed generation and moving loads such as EVs, the system is very quickly becoming unmanageable in the traditional manual ways of today: computer aided system management will become a necessity, as is evidenced by the mass migration to ADMS solutions across the industry at large.

Project name	Server Application Software Upgrade/Modifications
Project numbers	2021-4022
Job numbers	
Project District	General
Project Location	General
Investment Category	General Plant
Program Category	Information Technology
Project Driver	Business Operations Efficiency
Proposed Start Date	2021-01-01
Required In-Service Date	2021-12-31
Scope of Work	• **Hyperconverged Storage Area Network Storage (SAN)**: This project was initiated to build, deploy, and configure a Server based vSAN cluster in the Elexicon environment to refresh and increase total storage space to 60Terabytes. This initiative will migrate all critical virtual machines to the new cluster, allow for site fault tolerance and upgrade software versions. Initiative will be done in phases as below: o **Phase I** – Configuration of the server environment o **Phase II** – Storage migration for all Virtual machines from the vSAN 6.0 storage space to vSAN 6.7 Storage space. o **Phase III** - Convert all current Cisco M4 servers in the vSAN 6.0 environment to vSAN 6.7 hosted cluster. • **Integrated Backup Solution**: Elexicon is implementing a VEEAM backup solution for 200 virtual servers and 10 physical servers located across 3 separate geographical locations. The backup solution will consist of 1 virtual server running the core backup and replication software with long term storage being provided by 2 Cisco storage servers. The majority of the virtual servers reside in Ajax and Pickering. • **Develop a secure password vault**: o Passwords are currently hosted across multiple spreadsheets and in various forms and managed by different teams. This initiative will consolidate all passwords into a secure cloud-based solution that allows for passwords to be maintained by separate teams based on role/job function and allows for logging, tracking and auditing any changes to the passwords. • **Develop a secure site for file captures and logging**: o Initiative to develop a central site to allow for secure file transfers, perform automated backups for all server and network device configurations and a create a central repository for tracking, logging and audit which will allow for troubleshooting, configuration retrieval and help facilitate and expedite issue resolution. • **Knowledge base:**

<table>
<tr><td></td><td colspan="5">
<li style="list-style:none">
Build an IT Knowledge base for procedural documentation and resolutions for common problems. This will help with problem resolution, training and support backup.
Information radiators:
Recommend a solution to bring the communication monitors in-house so we can manage and support IT assets effectively and content management. The communication monitors are currently hosted at a vendor site.
</td></tr>
<tr><td>Preliminary Estimate: Total Capital Cost</td><td>Gross: $300,000</td><td colspan="2">Contribution: $0</td><td colspan="2">Net: $300,000</td></tr>
<tr><td rowspan="2">Expenditure Timing</td><td>Quarter</td><td>Q1</td><td>Q2</td><td>Q3</td><td>Q4</td></tr>
<tr><td>Gross CAPEX</td><td>$27,000</td><td>$30,000</td><td>$51,000</td><td>$192,000</td></tr>
<tr><td>Rationale for Intervention</td><td colspan="5">
Hyperconverged Storage Area Network Storage (SAN):
Leverage newer disk space for critical servers
Repurpose older disk space for non-critical and non-production server backups.
Integrated Backup Solution:
Transition backups to newer, higher performance backup infrastructure to ensure data backup reliability.
Develop a secure password vault:
Implement a secure password storage option, thereby improving cyber-security as per OEB framework.
Develop a secure site for file captures and logging:
Increasing visibility into network activity by tracking, logging and reporting all activity, thereby improving cyber-security as per OEB framework.
Could also assist with audit capabilities.
Knowledge base:
Enhancing internal documentation of knowledge to reduce re-work, improve support and increase efficiency
Information radiators:
Lower costs, increase efficiency, better utilize internal expertise, information radiators provide a conduit to promote cyber-security awareness.
</td></tr>
<tr><td>Criteria Score</td><td colspan="5">22.1</td></tr>
<tr><td>Impacted Customers and Entities</td><td colspan="5">The entire business will be impacted by these application upgrades. The benefits include business continuity, cyber security enhancements, secure passwords, enhanced logging and improved support documentation.</td></tr>
<tr><td>Intervention Options</td><td colspan="5">Elexicon must ensure data reliability through proper backups and modernized infrastructure. It must also ensure that passwords are stored security and accessibly and that logging information can be readily retrieved in the event of any incident.</td></tr>
</table>

	Building out a knowledge base allows Elexicon IT to efficiently assist end users to resolve commonly encountered issues quickly and effectively, thereby improving response times.
Effect on System O&M Costs	• **Develop a secure password vault**: o +$2k/year (assuming a cloud-based solution – Dashlane) • **Knowledge base:** o +$12k/year (Assumed Software-As-A-Service (SaaS) tool – HelpJuice) • **Information radiators** o ~8k/year (savings) • **Integrated Backup Solution**: o ~7.5k/year (1h/week savings) resulting from efficiency improvements. Non-Tangible costs include: • Improved data reliability • Automated Backup Schedules • Improved logging (cyber security) • Enhanced knowledge support
Targeted Outcomes	Operational Effectiveness • Improved data reliability • Automated Backup Schedules • Improved logging (cyber security) • Enhanced knowledge support Public Policy Responsiveness • Improved security posture
Cost Benchmarks	No Benchmarks available.
Value-Added Approach	N/A

Budget Category	Tools & Equipment
OEB Investment Category	General Plant
Primary Driver	Capital & Maintenance Support
Secondary Driver(s)	Safety

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.40M	**$0.14M**

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

This category of investments covers General Plant projects focuses on the introduction and replenishment of tools and equipment used by various operational divisions at Elexicon Energy ("Elexicon"). The operational divisions involved in the procurement of tools and equipment include lines, substations, and the health and safety group. Tools and equipment are essential for crews to work safely, efficiently, and perform complex tasks such as construction, maintenance, and testing needed in the field. Distinct annual budgets are set for the Lines and Substation departments for tools and equipment expenditures.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.40	0.16	0.16	0.15	0.14	0.14	0.14	0.14
Contributions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Program Expenditures	0.40	0.16	0.16	0.15	0.14	0.14	0.14	0.14

Supporting Summary Statements:

Tools and equipment investments are made annually by Elexicon to renew and revitalize the existing portfolio to assist operational staff. As tools become worn out or lose functionality, expenditures are made to replace if necessary. Additionally, as new capabilities are required, an investigation into new tools and equipment is performed to assess the benefits or abilities. When investing in new tools and equipment, Elexicon first considers the operational need, followed by the operational efficiency, safety, and ergonomic impacts of the purchase.

Previous tools and equipment from Whitby Hydro Electric Corporation (“WHEC”) and Veridian Connections (“Veridian”) now form the combined inventory at Elexicon. In the future, the organization will evaluate the inventory of tools and consolidate resources and tools under Elexicon. As the two staff utilize the mixed inventory, feedback and use will be provided as engagement for future tools and equipment purchases.

The tools and equipment portfolio addresses various metrics either indirectly or directly. Tools provide essential functions for completing operations, maintenance, and capital work allowing Elexicon to satisfy various service quality requirements including connections of new services and decrease outage frequency and duration. New and existing tools also provide operations with safe limits of approach and an ability to perform work away from the line; operations benefit from a safer environment of work. Elexicon places high importance on safety and is committed to ensuring a safe workplace free from injuries. Better tools provide greater safety margins for workers and reduce the index of accidents for workers. Elexicon is committed to achieving zero injuries now and into the future.

2. Basis for Action

2.1 Performance Trends:

Throughout the DSP period, Elexicon will continue to evaluate its tools and equipment program annually. As the two former utilities had a different combination of tools and equipment, the current inventory is a mixture of the former utilities. Moving forward, Elexicon will consolidate tools under specific brands based on feedback from operational staff. As the two former utilities operational staff utilize the combined tools and equipment pool, it will demonstrate trends to which tools or equipment are valued and preferred under one combined group.

Two one-off purchases are planned for 2021 and 2022 for the substations department where the Compano 100 and Buss Bender are introduced. In the first year, the substation department will spend around $42,000 to consolidate and update inventory from the two former utilities. This will drop down to about $15,000 each year after 2020. Office Equipment shall be procured in 2020 and 2021 for health and safety purposes through the purchase of two defibrillators.

Figure 1: Tools and Equipment Expenditures planned across DSP Period

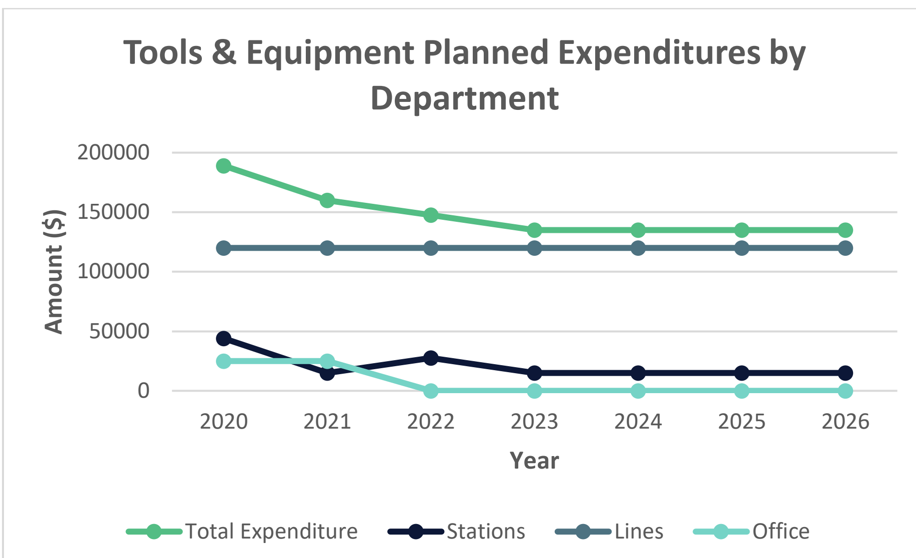


Table 2: Year by Year Expenditures by Department

Year	2020	2021	2022	2023	2024	2025	2026
Stations	$44,000	$15,000	$27,600	$15,000	$15,000	$15,000	$15,000
Lines	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
Office	$25,000	$25,000	$0	$0	$0	$0	$0
Total	**$189,000**	**$160,000**	**$147,600**	**$135,000**	**$135,000**	**$135,000**	**$135,000**

2.2 Current-State Analysis:

The current tools and equipment investment program at Elexicon consists mainly of two operational departments which include Stations and Lines (overhead and underground). As a result of the merger, a combination of tools and equipment from both former WHEC and Veridian were combined to make up the current Elexicon tool inventory. As the two utilities were separate and had different practices, the current tool and equipment makeup is a large and diverse mixture. Looking into the future, Elexicon will consolidate tools and equipment across the company. Tools are purchased such that there are sufficient quantities for operational staff to use and back-up stock for replacing failed equipment.

As the current tools at Elexicon are from past utilities, they are still able to meet the corporate needs of the combined utility. Current crews may need to take note of specific tools that need to be used in each service area, but there are no complications with the newly merged tool inventory. As the Elexicon grid continues to develop and crews experience different tools or realize opportunities to improve, more advanced or efficient tools and equipment shall be procured and utilized. Elexicon will investigate into a procedure or committee to assist in tools and equipment procurement composed of various stakeholders.

Tools and Equipment Investment Specifics:

Within the tools and equipment portfolio for Elexicon, investments are separated into three program buckets.

1) **Tools and Equipment for Lines**

Throughout the DSP period, investments for Lines will be geared towards the renewal and introduction of tools and equipment for overhead and underground crews at Elexicon. These tools and equipment include hot sticks, power tools, gloves, etc.

2) **Tools and Equipment for Substations**

The Substation department has an annual budget of tools and equipment regarding work performed on substations. Specifically, the Compano 100 and BUSS Bender tool will be procured as new station purchases outside the annual budget in 2020 and 2021. The Compano 100 can assist station staff in protection, instrument transformer, circuit breaker/switchgear, and grounding system testing. It is a versatile test instrument capable of producing various test signals of different shapes, frequencies, and magnitudes.

Figure 2: Compano 100 Tool

3) Tools and Equipment – Office Equipment

Investments into tools and equipment for office use across the DSP period include first-aid equipment, such as Zoll Defibrillators. These tools and equipment will be used to ensure the health and safety of staff within facilities.

Impact of COVID-19

Due to the COVID-19 pandemic, personal tools are not shared among crews and are instead designated for individual employees. For certain complex equipment, they are assigned to one crew. To ensure the safety of operational staff, Elexicon will continue to provide personal tools and equipment to staff. Moving forward, Elexicon will take precautions with regards to the sharing of tools and evaluate the future health and safety considerations and changes that COVID-19 will inevitably introduce to the industry even after the pandemic.

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).
-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.
-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

IHSA - Electrical Utility Safety Rules

The Infrastructure Health & Safety Association ("IHSA") is Ontario's trusted health and safety resource, and recognized by the Ministry of Labour, Ministry of Advanced Education and Skills Development, and the Workplace Safety and Insurance Board. The IHSA produces the *Electrical Utilities Safety Rules* which are the foundation for safe work practices including proper usage of tools and equipment. For instance, rubber gloves and line tools must be retested for electrical insulation strength regularly. The procedures and requirements for tools and equipment working on lines and substation equipment are outlined in this rulebook.

CSA Z462

CSA Z462 is the Workplace Electrical Safety Standard by the Canadian Standards Association which addresses electrical safety requirements for PPE. This standard guides Elexicon on the selection of personal protective equipment and protective clothing for protection from electrical arc flash hazards.

Occupational Health and Safety Act, R.S.O 1990 c.O.1

Elexicon has an obligation to comply with the *Occupational Health and Safety Act*. As stated in Section 25(1) employers shall ensure that equipment, materials, and protectives devices are prescribed as provided, maintained in good condition, and used as prescribed. Investments into tools and equipment under this program helps to ensure the safety of inside and outside workers.

O.Reg 22/04 (Electrical Distribution Safety)

All distribution systems and electrical installations shall follow the safety standards outlined in Section (4) of O.Reg. 22/04. Providing safe and effective tools and equipment assists in the safety standards of new installations onto the distribution system.

OEB Scorecard Metrics

This program drives Elexicon's performance of OEB scorecard metrics outlined in the *Recording and Recording Keeping Requirements*. The most direct impacts of these investments pertain to safety metrics. Tools and equipment are used for capital and maintenance support and impact service quality measures such as connection of new services and reliability measures such as SAIDI. Tools and equipment with better safety margins, more efficiency, and ease of use should reduce labor hours during outages.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service

Without sufficient tools and equipment, Elexicon will not be able to perform necessary work to ensure the safety and reliability of the electrical distribution system. Improper tools and equipment could lead to complications with installations which would potentially affect Elexicon's reliability performance and ability to connect new services for customers. For instance, improper connectors that are crimped poorly would disrupt the connections and service of many customers.

Operational Effectiveness

Adequate investment into operational tools and equipment allows Elexicon to be effective when completing project, operations, and maintenance work. Any tools or equipment which are breaking down or cannot perform will push back project completions or require further time dedicated to operational tasks. Advancements in new tools and equipment could also provide operational time savings for crews if introduced to Elexicon. Labor hours can be reduced through more advanced or efficient tools that are introduced.

Financial Performance

Investing in new tools and equipment provides financial savings into the long-term future. Broken tools will require maintenance costs if not remedied. Additionally, investigations or ventures into new technologies of tools and equipment could provide cost savings in the form of labor hours and material purchasing.

Public Policy Responsiveness

Public Policy from various safety acts and initiatives throughout Ontario is affected by the implementation of effective tools and equipment. Safety is paramount in the utility industry and the main priority as outlined in public opinion and policy. If inadequate tools and equipment are provided to operational crews to perform work, there is a major risk of safety issues and damage to Elexicon's image from the potential of safety incidents. Tools and Equipment are critical to the maintenance and construction of the electrical grid. The *Electrical Utility Safety Rules*, *Occupational Health and Safety Act*, and pursuit of zero injuries would be responded to adequately through tools and equipment investments.

2.5 Merger-Related Objectives:

Discussions are currently being held to identify more optimal and efficient processes to introduce tools and equipment at Elexicon. As the merger presented a mixture of former WHEC and Veridian tools to the inventory, an assessment and experience utilizing both tools will be performed and gained. Operational crews and leaders shall provide opinions on the range of tools and equipment which can drive the internal best practices. In December 2020 Elexicon created a committee with stakeholders in departments of supply chain, health and safety, operations, and engineering with regards to new tools and equipment. to drive improvements, efficiencies, and cost savings in the tools and equipment program for Elexicon.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-C.d.1 (GP) The results of quantitative and qualitative analyses of the proposed project/program, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable

Number	***1***	***2***	***3***	***4***
Scenario Description	Budgeted tools and equipment investments across the DSP period.	Faster pace of investment into the tools and equipment portfolio (25% more)	Slower pace of investment into the tools and equipment portfolio (25% less)	Replace tools and equipment like-for-like; no new functionalities are to be introduced.
Annual Program Scope	The current budget is an optimized investment case where new tools with added functionality are introduced and like-for-like replacements are also performed.	Greater spending is present in this option which will add 25% of the planned budget on top.	Less spending is present in this option which will be only 75% of the current planned budget.	In this alternative, no new tools or equipment are procured that can introduce new functionality. Like for like replacements are only introduced.
Annual Gross CAPEX	$0.14M	$0.18M	$0.11M	$0.12M
Annual Net CAPEX	$0.14M	$0.18M	$0.11M	$0.12M
Annual Program Benefits	Optimized purchasing of tools and equipment ensures that all budgeted projects can be completed safely and without delays stemming from lack of available and appropriate tools/equipment	Faster investment in tools does not translate into program benefits (i.e., does not expedite capital or maintenance jobs, as the pace of these projects is controlled by budgets, procurement, and approvals)	Slower investment in replacement tools and equipment has the potential to negatively impact the pace of capital and OM&A work if suboptimal tools are being used, or replacement stock is not available on hand during the course of work.	Replacing only like-for-like with no additional functionality will prevent ergonomic improvements from being realized, which ultimately works to reduce lost time from chronic injuries. The potential to complete work faster as technology improvements

				are introduced is also prevented.
Program Economics	Optimizing the budget ensures a balanced approach to ensuring there is adequate supply of tools and equipment, with funding for strategic investment in advancements that clearly demonstrate a positive cost benefit ratio.	Investment above optimal will result in surplus tools and equipment that that run the risk of becoming out of compliance with current standards before their useful end of life.	A slower pace of investment increases the risk of a tool or equipment shortage. If staff are left with an inadequate supply of tools or equipment and need to share, less jobs can be completed annually, increasing the risk of backlogs over time	Replacing like-for-like increases the risk of a budget shortfall should a legislative or regulatory change require a change in the way work is performed, thereby changing what tools and equipment are required to complete the work.
Customer Feedback	83.4% (719 of the 862) of customers believe that Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable. Tools and Equipment are used by Elexicon staff to build and maintain the grid. It is imperative that Elexicon continues to invest in adequate tools and equipment.			
Other Constraining Factors	If further degradation of assets in the tools and equipment portfolio occurs, a change in the future budget may be required. Additionally, operational needs may arise which require significantly more investment into the program. Elexicon shall ensure optimal investments and decision-making are made in these scenarios.	Increasing the tools and equipment expenditures beyond the forecast needs would leave less remaining budget for other necessary investments over the forecast period.	Less investment into tools and equipment would negatively impact the ability of staff to perform work. This would negatively impact workforce health and productivity, safety, service continuity, and service quality.	Only replacing tools and equipment like-for-like is not the preferred alternative. In many cases it is beneficial to upgrade tools when replacement is necessary to improve the efficiency and safety of work.
Preferred Alternative	**X**			

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred

Reliability: Reliability will be negatively impacted if Elexicon does not sufficiently invest in tools and equipment including replacements and new tools where required. Tools and equipment are relied upon to perform critical field work including operations, emergency power restoration, timely maintenance, and capital work. The pacing of this program supports Elexicon's SAIDI performance going forward.

Grid Resiliency: Sufficient tools and equipment are required to operate a resilient grid. Storm response requires high deployment of field crews to ensure safety of the public and restore power quickly. These field crews need access to the equipment needed to complete the work.

Operational Efficiency and Cost Effectiveness: The budgeted expenditures for tools and equipment serve to improve operational efficiency and cost effectiveness, while not over-investing in this area. In addition, legacy equipment will need to be maintained when it may be more cost-effective to invest in equipment that can readily be maintained.

Safety: Safety would be stagnant if the existing tools and equipment continue to be utilized in the future. Improvements to new tools and equipment can increase the safety of operational staff alongside indices that are measured for Elexicon.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: N/A

Conservation and Demand Management: N/A

Net Customer Benefits: Current tools and equipment provide customers with benefits to service reliability. New investments such as LIDAR would allow for Elexicon to manage and understand their distribution assets further spatially and in terms of condition. Further understanding allows Elexicon to further employ asset management on the distribution system thus improving customer benefits.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated

If more severe deterioration is found in tools and equipment utilized by a group, Elexicon will invest more into one year and budget less for future years. Additional outcomes include increasing the budget for operational tools in the future if advanced degradation is discovered.

As Elexicon evaluates the current mixed tools inventory, operational crews could utilize legacy tools that are deemed operable. However, Elexicon looks to provide crews with tools that are operationally efficient and safe. Practices at Elexicon in the past were to purchase enough tools and equipment for stock in the warehouse in case the in-field tools and equipment failed.

If a significant new purchase for a tool or piece of equipment is required, a business case will be created for the specific investment. Analysis of the cost benefits shall be conducted to determine the feasibility and need of the purchase.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Previous tools and equipment life cycles from WHEC and Veridian had the same practices where tools were utilized until signs of poor condition or end-of-life were present. New tools were then purchased to replace the tools that had become obsolete. Tool capabilities and inventory for Elexicon have become mixed because of the merger. As a result of the merger, the tools from the two former utilities were combined under one umbrella. In the future, Elexicon will evaluate the inventory of tools and consolidate resources across the organization. One such initiative will be the establishment of a formal tools and equipment process and committee to help shape tools and equipment capabilities for Elexicon in the future.

Ergonomics and operational needs are the major drivers of tools investments at Elexicon. Visual inspections of the tools are also utilized to understand if the equipment or tools can remain functional and useful. Elexicon usually runs the tools to failure unless something is notably wrong with the tool. Power tools do not have regular maintenance practices or calibration work done on them. Instead, they are used until they are no longer functional.

Certification data on specific tools are evaluated year over year to determine recertification requirements. Any tools deemed operationally broken or fail certified tests are disposed of correctly. Safety standards are evaluated to ensure the safety of all workers. Recertification of equipment at Elexicon is an operational expenditure, but replacing the tool becomes a capital expenditure. The total useful life as part of the IFRS accounting standards at Elexicon is presented below. These are split into major tools and equipment and measuring and testing equipment.

Table 3: IFRS Tools and Equipment Typical Useful Life

Tools and Equipment	TUL (IFRS)
Major Tools and Equipment	10
Measure and Test Equipment	10

4.2 Legacy Work Execution Approaches vs. Combined Operations

Tools and equipment are inspected when licences and certifications are expired in accordance with the *Electrical Utility Safety Rules*. Tools and equipment are tested consistently to ensure safety and performance. If a tool does not pass qualifying tests, new purchases will be required to replace the tool. Crews also perform a visual inspection of the tool and assess its overall performing condition. If the tool has been deemed to be functionally obsolete, an investment shall be made for a new tool or utilizing a tool that is in the warehouse. New tools and equipment are evaluated to review if the introduction is feasible, training requirements, and operational benefits. Tools may also fail in the field when staff performs work; immediate action is taken to replace the tool.

Before any work is done on the system, crews must complete a tailboard and job safety analysis. This procedure assists employees with integrating accepted health and safety principles and practices into a job operation. By identifying the hazards in place as well as the requirements of the job, tools and equipment are identified to be used for the job.

Physical differences in the makeup or electrical configuration of the two legacy systems could present differences in the tools and equipment utilized by operational crews. As the current tools and equipment inventory is a mixture of two former utilities tools and equipment portfolio, operational crews will be exposed to other tools. As the grid develops and other technology or assets are placed, new tools may be required in the future. Elexicon will consider and evaluate future tools and equipment necessary to perform work.

The resources used to perform work on the grid are a mix of internal and external resources. Any projects that are larger or more complex in nature that require more labour resources are externally contracted. More routine inspections, maintenance, testing, and construction work is carried out by internal staff. For more complex work such as station inspection and testing, external parties are utilized.

4.3 Scale Increase Considerations

Elexicon has higher purchasing power with the merger of the two utilities but also absorbs a larger service territory. Higher purchasing power allows a consolidation and more outlined tools and equipment portfolio. For instance, the Town of Whitby is near many of the other major Durham municipalities served by Elexicon such as Ajax and Pickering.

Tools and equipment are made more efficient through sharing and can be consolidated. However, considering COVID, sharing is now discouraged whereas previously it was encouraged. The practices for tools and equipment will be reviewed by the two utilities and experiences will be shared between the operational teams.

The merger produced a mixture of tools and equipment from the two former utilities. Elexicon will consolidate the current mixed portfolio into one combined portfolio in the future. As staff from both former utilities utilize the combined inventory, input from both sides is considered. Elexicon is evaluating the tools and equipment portfolio via the tools and equipment committee formed in December 2020.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

With the tools and equipment inventory combined from the two former utilities, staff shall continue to use existing tools and equipment until their useful end of life. An annual budget has been set for the future DSP period taking into consideration the rate freeze. The condition of tools and equipment is considered and any candidates that lack functionality are immediately replaced due to safety and operational efficiency impacts.

Any new tools procured such as the Compano 100 will be noted which will introduce new capabilities. As Elexicon also holds an inventory of back-up equipment, the stock shall be filled to ensure adequate back up of tools and equipment are always maintained. Moving forward, if an operational need arises for a specific new tool or equipment, the purchase shall take part in the annual budgets from either the Lines or Stations department. If more budgeting is required, commitments to other General Plant programs could be shuffled to this program. Additionally, a reduction of next year's budgeted amount could be performed to purchase the given tool or equipment for the given year.

5. Individual Projects Comprising the Program

5.1 Overview of Projects

There are no material projects within the Customer Requested Work program in 2021.

5.2 Individual Material Project Scopes

There are no material projects within the Customer Requested Work program in 2021.

APPENDIX B: Customer Survey Results

Customer Engagement Report

Brickworks Communications

Updated February 2021

Table of Contents

Background

Elexicon Energy commissioned Brickworks to oversee an engagement survey of its customers. The purpose of this survey process was to learn more about how Elexicon's investment plans can best reflect the needs and preferences of their customers. The information collected will be used to inform investment decision-making and may also be submitted to the Ontario Energy Board (OEB) as an input into their five-year Distribution System Plan (DSP).

There were two main approaches used in this process, including an open online survey forum which resulted in N=262 completes and a random telephone survey of N=600 customers. Customers were assured that all responses to this survey would be confidential, and only overall or aggregate results would be reported.

Reporting Notes

The survey questions were designed by Elexicon and Brickworks. The role of Oraclepoll Research Ltd was to field the online and telephone surveys and report on the findings.

This report contains an executive summary of the results from both the telephone and online components, as well as the results by question. Findings are presented in the order that they were asked in each survey.

Methodology & Logistics – Online Survey

Survey Method

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was a self-selection survey where respondents connected via a hyperlink to the survey site to complete their interview. Elexicon posted the link on their website homepage, and promoted the survey using e-blasts to their customer base.

Study Sample

In total, N=263 customers completed online questionnaires.

Logistics

Surveys were completed online between October 26th and December 13th, 2020.

Confidence

It is not customary to assign online self-selection samples a margin of error. However, a probability sample of N=262 has a margin of error or is considered accurate ± 6.0%, 19/20 times.

Methodology & Logistics – Telephone Survey

Study Sample

Elexicon provided Brickworks with a database of their residential and business customers to be surveyed. A total of N=524 residential customers, N=70 small business customers, and N=6 large businesses were randomly selected from the database and surveyed by telephone, using person-to-person live telephone interviewing.

Respondents were screened to ensure that they were 18 years of age or older, an Elexicon customer, and were one of the persons either at the business or residence that was a decision maker as related to reviewing utility bills and making payments.

Survey Method

The survey was conducted using computer-assisted techniques of telephone interviewing (CATI) and random number selection. A total of 20% of all interviews were monitored, and Oraclepoll management supervised 100%.

Logistics

Telephone interviews were completed between November 20th and December 4th, 2020. Initial calls for the residential component were made between the hours of 5 p.m. and 9 p.m. Subsequent call backs of no-answers and busy numbers were made on a (staggered) daily rotating basis up to 5 times (from 10 a.m. to 9 p.m.) until contact was made. In addition, telephone interview appointments were attempted with those respondents unable to complete the survey at the time of contact. At least one attempt was made to contact respondents on a weekend. Calls to business customers were first made from 8:30 a.m. to 5:30 p.m. during weekdays. There was at least one follow up call after 5:30 p.m. and one on a weekend. In addition, telephone appointments were accepted and made as per the respondent's time preference.

Confidence

The margin of error for the N=600-respondent survey is ± 4.0%, 19/20 times.

Online Survey Results

Survey participants were shown background information about Elexicon. They were also told that a main objective of the online poll was to learn how Elexicon's investment plans can best reflect the needs and preferences of its customers.

"Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account."

Yes	*N=262*	*100%*

"What is the municipality associated with the Elexicon customer account?"

Whitby	*29%*
Ajax	*23%*
Pickering	*16%*
Belleville	*8%*
Clarington	*7%*
Gravenhurst	*7%*
Port Hope	*4%*
Brock	*3%*
Scugog/Port Perry	*3%*
Uxbridge	*<1%*

The initial set of questions were demographic. First respondents were screened to ensure they were Elexicon customers, then they were probed about where they live, the client segment they belonged to, and if they are responsible for paying the electricity bill.

"To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer."

Residential	*N=262*	*100%*

"In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?"

I am primarily responsible for paying my household's electricity bill	*N=233*	*89%*
I share the responsibility for paying my household's electricity bill	*N=29*	*11%*

General Questions

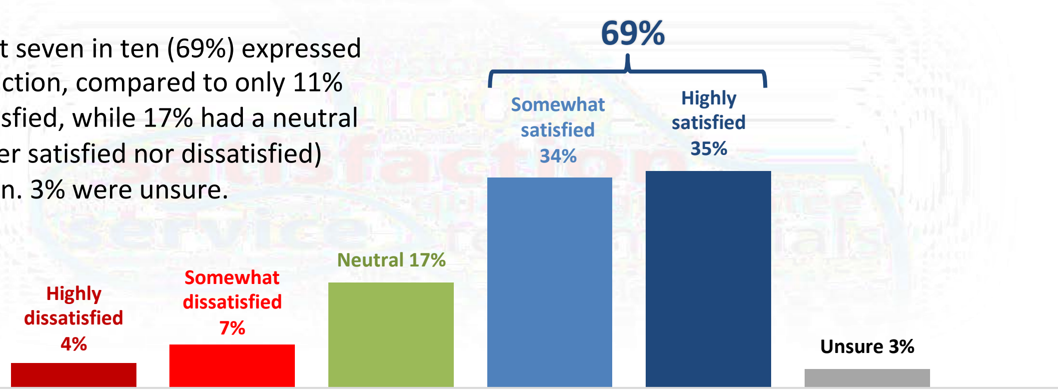
Next, online participants were presented with an explanation of the three major cost components of their electricity bill: Generation, Transmission and Distribution – and the portion retained by Elexicon. They were advised that the information collected in the survey related only to their local electricity distributor Elexicon, after which questions were asked.

"When did you first become aware of the merger between Whitby Hydro and Veridian to create Elexicon?"

Eighty-five percent of customers were aware of the merger prior to the survey.

"Overall, how satisfied are you with the services Elexicon provides you with?"

Almost seven in ten (69%) expressed satisfaction, compared to only 11% dissatisfied, while 17% had a neutral (neither satisfied nor dissatisfied) opinion. 3% were unsure.



Comments were accepted at the end of the question and results have been sorted into the categories below.

"In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?"

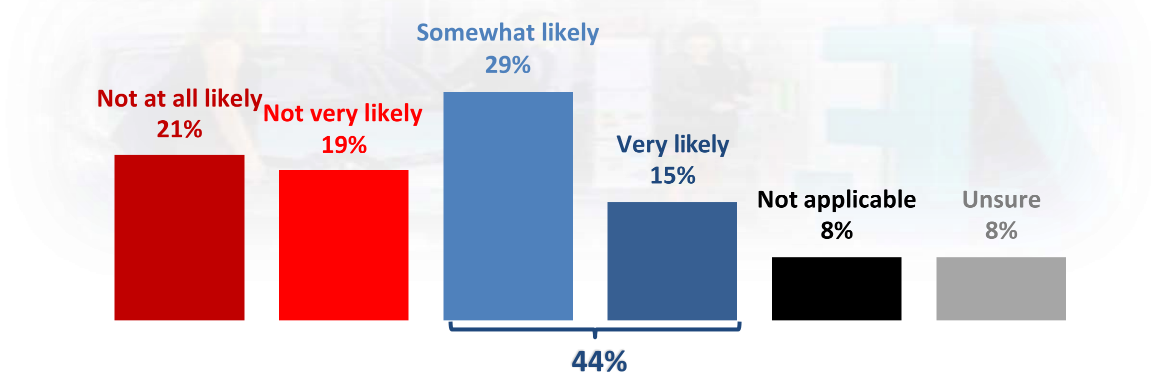
No problems / satisfied	23%	Service has improved	2%
Unsure	21%	Website problems / issues	2%
Reliable / stable service	13%	Simplify billing / payment methods	1%
Poor service / interruptions / outages	11%	Billing problems	1%
Hydro rates are high / expensive	9%	Good customer service	1%
No change	4%	The transition has been seamless	1%
Old / outdated infrastructure	3%	Need alternative energy options	1%
Dislike time of use / simplify / change	2%	Cannot compare due to the monopoly	<1%
No notice for planned outages	2%	Lack of follow up	<1%
No experience / new client / too soon	2%	Give rebates	<1%
Poor costumer service / long waits	2%		

"Please rate your level of agreement with the following statements using a scale from one (strongly disagree) to five (strongly agree)."

	Strongly disagree	Somewhat disagree	Neutral	Somewhat agree	Strongly agree	Unsure	Not applicable
"The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities"	25%	20%	27%	**21%**	**7%**	1%	-
"When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved"	**3%**	**9%**	19%	18%	20%	-	31%

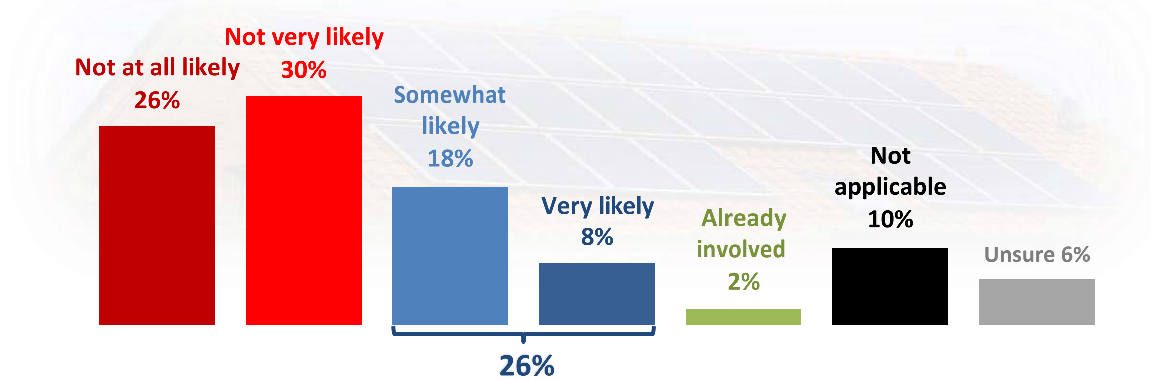
Twenty-eight percent agreed the cost of their bill creates some form of hardship. Total agreement, or being satisfied with how questions or requests were resolved, is 38%, compared to only 12% that disagreed (dissatisfied), while 19% had a neutral opinion. 31% answered not applicable or had no experience.

"If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?"



Interest in EV's is solid at 44%, with 29% somewhat and 15% very likely to consider a purchase.

"How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?"



Slightly more than a quarter or 26% said they are somewhat (18%) or very likely (8%) to become involved in self generation.

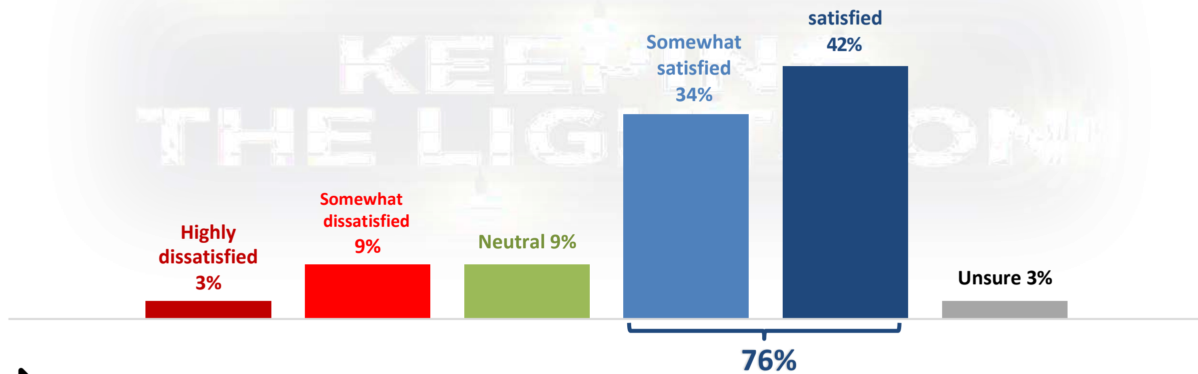
Two questions about outages over the past year were asked, the first about how many times the power has been out, and second related to the length of time the outages lasted.

"In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your home to the best of your recollection?"	
0	8%
1	14%
2	29%
3	13%
More than 3	24%
Not Sure	11%

"In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average? Please select from the following options based on your best estimate:"	
Under 30 minutes	20%
Under 1 hour	22%
Between 1 and 2 hours	22%
Longer than 2 hours	21%
Not Sure	15%

Customers were then asked about reliability starting with an overall satisfaction question.

"Which of the following options best represents your overall satisfaction with service reliability over the last few years?"



Seventy-six percent are satisfied or very satisfied with service reliability.

"When power outages do occur, which aspect of them has been most inconvenient for you?

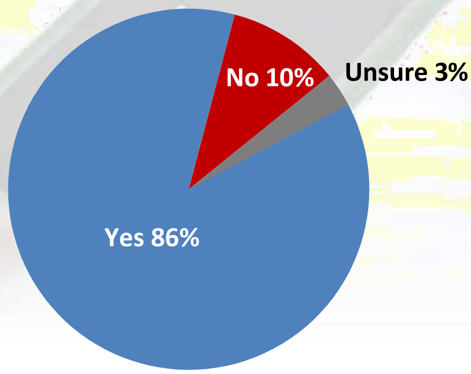
How long the outages have lasted	44%
How often the outages have occurred	20%
Not Sure	16%
Impact it has on my electronics / computers	7%
None / no inconveniences	4%
Getting information from Elexicon / contact with	3%
Both how often & how long	3%
Timing / when they occur	2%
No heat / no cooling / appliances	1%

"When there is a power outage, how do you interact with Elexicon Energy?"

I check the outage map online	37%
I do not take any steps	30%
I phone the outage number posted on the website	19%
I check Twitter	6%
Telephone call	3%
No experience	2%
I use both Twitter and Map	1%
Radio	1%
Unsure	1%

The length of an outage is of most concern to 44%, followed by how often they occur (20%). When asked how they interact with Elexicon during an outage, 37% check the map online and 19% phone the number on the website, while three in ten do not take any actions.

"Please indicate your level of interest in the following: When an outage occurs, are you interested in receiving notifications sent to your phone (via text or voice to landline) about its cause and anticipated restoration time?"



Interest is high at 86% for an outage notification system by text or voice.

"To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?"	
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases.	37%
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term.	32%
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term to achieve this.	12%
Not Sure	11%
Maintain reliability & do not raise prices	4%
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others.	3%
Provide better service overall	1%

There is a split of opinion with the two most selected options being spending more on reliability and less on other areas (to avoid some bill increases) as well as maintaining current reliability, even if it increases monthly bills in the long term.

"Elexicon can prevent more outages caused by aging equipment if it proactively replaces more equipment before it fails. Another option is to wait and replace equipment only after it fails, which potentially causes more service interruptions and leads to extra costs such as staff overtime. Which of the following options best describes your views on this trade-off?"	
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.	81%
Not Sure	10%
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road.	5%
Maintenance on a schedule & no rate increases	4%
Invest in better equipment	1%

A clear majority of 81% feel equipment should be replaced before it fails.

"Elexicon's top spending priority is always to keep its power system and operations safe. With its budget staying nearly flat through 2029, Elexicon will face tough trade-offs when selecting among other investment priorities."

"Please choose two of the following objectives that you think Elexicon should focus its efforts on, in addition to keeping the system safe and accommodating new growth in the coming years."

	First mention	Second mention	Combined
Improving the grid's resilience to major weather events, like storms, etc.	28%	31%	30%
Preparing the grid for new types of uses, like EV's & renewable generation	23%	11%	17%
Investing now in things that will help reduce rate increases after 2029	13%	20%	16%
Minimizing the impact of power outages	7%	19%	13%
Helping customers manage their electricity use	10%	10%	10%
Reducing the environmental impact of Elexicon's operations	12%	5%	8%
Improving power quality	5%	2%	4%
Addressing customer requests faster and more efficiently	2%	1%	2%

➡ While improving the grid's resilience to major events is the number one choice at 30%, results are close for second, with 17% naming preparing the grid for new uses and 16% investing now in things that will help reduce rate increases after 2029.

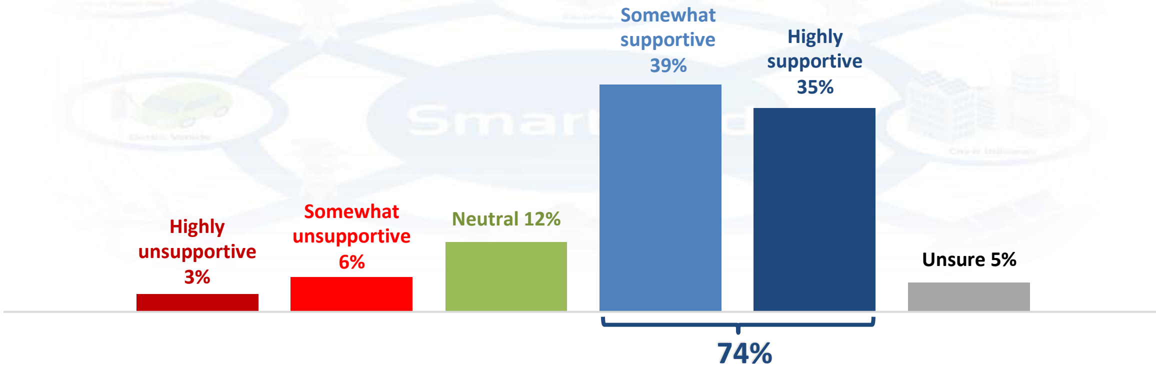
➡ **45% of customers who are dissatisfied with reliability listed minimizing outage impacts in their top two priorities.**

"Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid.
Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?"

I am satisfied with the planned allocation based on what I know	50%
I would prefer to spend more on the technical upkeep of the power grid & less on the other two	18%
Not Sure	16%
I would prefer to spend more on reliability and less on the other two	8%
I would prefer to spend more on efficiency, health, & safety of operations and less on other two	7%

➡ Half are satisfied with the planned allocation, while 16% were unsure. There are 18% that want more spent on technical upkeep, with the remaining responses divided between more spent-on reliability and more on efficiency, health, and safety of operations.

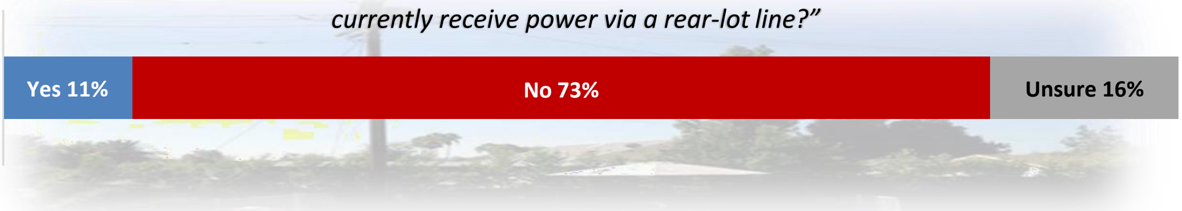
"Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?"



Support for investing in new technologies is at nearly three-quarters or 74%.

Customers were presented with a description of rear-lot overhead power lines, the challenges they face, and the cost of conversion to underground lines. They were then asked the following two questions.

"To the best of your knowledge, does your place of <<residence>>/<<business>> currently receive power via a rear-lot line?"



"Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?"

Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere. While concentrating the work in a single community for a shorter timeframe is less inconvenient to local residents, it could leave vulnerable rear-lot feeders in other communities unaddressed for longer.	38%
Not Sure	23%
Move lines underground and plan work according to worst performing areas. This spreads the work across Elexicon's service territory over time but may mean that there may be multiple construction-related disruptions.	22%
Maintain the status quo – keep the overhead lines in the rear lots, replacing them as they fail. While budgets can be used elsewhere, it will leave area customers vulnerable to longer than average outages.	17%

Only 17% want to maintain the status quo and 23% were unsure as to a preferred option. There were 38% that want to move the lines underground and work geographically. 22% that also want to move the lines underground, but work on the worst performing areas.

ICM Project #1: New Pickering Area Transformer Station

Next, online participants were provided with background information about three projects that Elexicon plans to seek approval for additional rate increases. They were informed that two projects are driven by population growth, and the third is needed to sustain operations in the Belleville area.

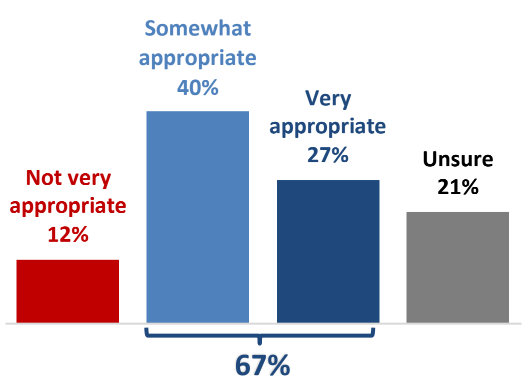
Elexicon will request special rate increases for these projects since it cannot finance them along with its other budgetary priorities. These requests are reviewed by the OEB through a process known as the Incremental Capital Module (ICM).

The first project is a large new Transformer Station in the Pickering area, required to support the residential and commercial growth that is projected to add as many as 32,000 new customers over the next 20 years. Elexicon estimates that to avoid system capacity shortages, the station needs to be in service in 2022.

The project is expected to cost about $40 million, which amounts to an approximate:

- $1.45 - $1.85 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- 2.90 - $3.60 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $280.95 - $343.40 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Transformer Station appropriate?



Two-thirds consider the level of investment appropriate (somewhat & very), only 12% do not feel it appropriate and 21% were undecided.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	70%
Customers affected should pay	6%
Developers should pay a higher portion	6%
Against the proposed project all together	3%
If it is necessary / if needed / get it done	3%
Better cost-efficient solutions are needed	3%
Do not want to pay for other communities	2%
Do not increase rates	1%
Not enough information	1%
Ensure safely / reliability	1%
More renewable solutions needed	1%
Too costly	1%
Make sure there is a backup plan	<1%
Should focus on conservation	<1%

While most (70%) did not have comments to share, those with opinions tended to cite the belief that customers in the communities affected and developers should pay for costs or a larger portion of the price. Some mentions reflected opposition, others the need to get things done. There were also those that felt other options should be pursued.

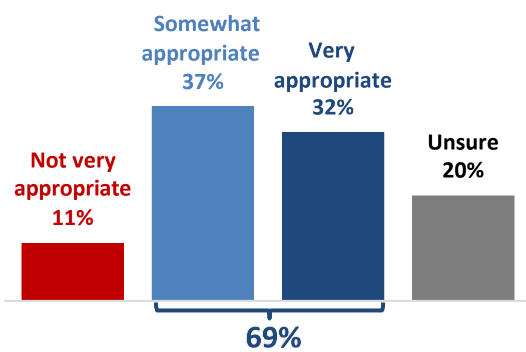
ICM Project #2: Accommodating the Move of the Belleville Operations Centre

The second project for funding is a new Operations Centre in Belleville to accommodate staff and equipment involved in providing customer service and responding to local power outages. The lease on the existing facility is set to expire in 2021 and cannot be renewed. Having considered all feasible options, Elexicon determined that owning a new facility is the most cost-effective option for customers in the long term.

The project is expected to cost about $2.6 million, which amounts to an approximate

- $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $2.6 million, which amounts to an approximate $18.35 - $23.50 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Operations Centre appropriate?"



Sixty-nine percent consider the level of investment appropriate. This compares to a low 11% that do not, while 21% are unsure.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	79%
Customers / communities affected should pay	4%
It is a required investment / reasonable / needed	3%
Refurbish an existing building	2%
Should come from reserve funds not customers	2%
Against project all together	2%
Lack of information to make an informed decision	2%
Build it smart / keep future growth in mind	1%
Compare leasing versus new build	1%
Customers should not have to pay	1%
Lease / rent building	1%
Should have been done years ago	1%
Proposed budget seems too low	<1%
Municipality should help finance	<1%
Savings should be passed onto the customer	<1%
Business / developers should pay	<1%
Should be mortgage financed	<1%

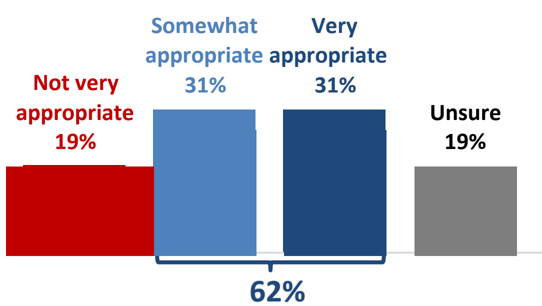
Almost eight in ten had no comment and among those that did, there was a mix of those in support, opposed, or not wanting to pay, and others suggesting alternative solutions for the build and payment.

ICM Project #3: Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit

To enable construction of dedicated Rapid Transit Bus Lanes in the Hwy #2 corridor in Pickering, Elexicon is required to relocate existing underground feeder infrastructure located in the right of way intended for the bus lanes. Elexicon and its customers are responsible for a portion of this cost, estimated to be $2.8 million. While performing this work, Elexicon will have an opportunity to replace or upgrade any equipment, as necessary.

- The project's cost is equivalent to an approximate $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $27.95 - $35.70 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"Do you consider the level of investment proposed for this underground infrastructure project to be very appropriate, somewhat appropriate, or not appropriate? "



Slightly more six in ten said the level of investment is appropriate, less than two in ten not appropriate, and an equal number did not know.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	74%
Residents / communities affected should pay	6%
Should be a priority	3%
Project should be covered by taxpayers	3%
Project not a priority	3%
Need more information / unclear	2%
Costs should be covered by transit users	2%
Municipality should pay	2%
Should be paid for by investors	1%
Will improve reliability	1%
Poor planning	1%
Project should be completed quickly as possible	1%
Disagree with project	1%
Will raise rates	<1%
Should be Elexicon's responsibility	<1%

Nearly three-quarters had no comments, but most of those that did (14%) referenced the belief that costs should be incurred by users, those affected, by ratepayers, or municipalities.

In the final question about the three ICM projects, respondents were asked which of five options presented would give them the most confidence that Elexicon is acting in their best interest.

"What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting in the best interest of their customers in mind?"

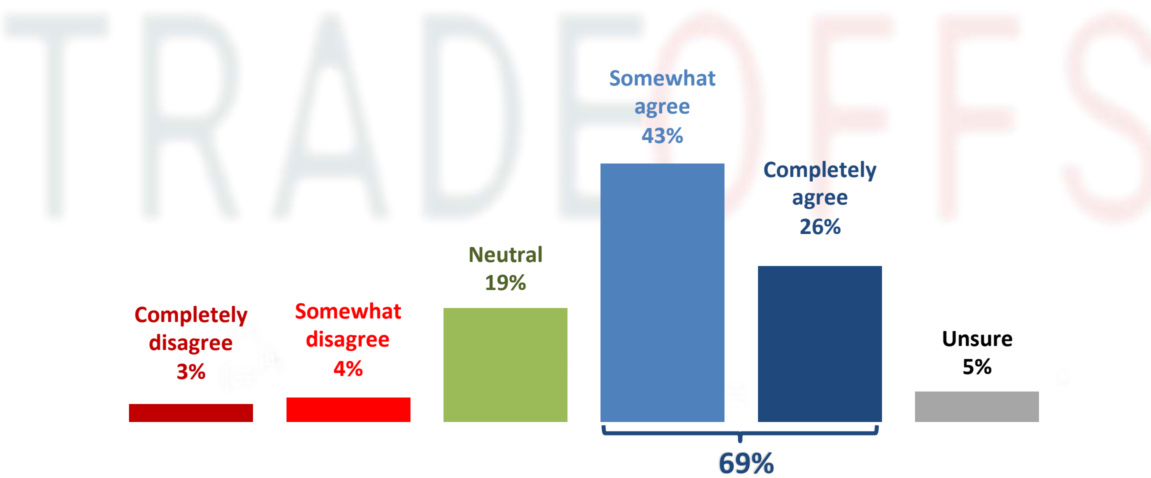
37%	Why Elexicon could not build these projects without seeking rate increases
15%	Why the chosen design and size are optimal
11%	Why the projects cannot be built for less
5%	Why the projects cannot be reasonably delayed
2%	Why these projects could not be built in other areas
29%	Unsure

Most named was why Elexicon could not build these projects without seeking rate increases, followed by why the chosen designs and sizes are optimal and then why they cannot be built for less. Almost three in ten answered do not know or were unsure.

Part D

Elexicon Energy
Part D: Concluding Observations

"As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?"



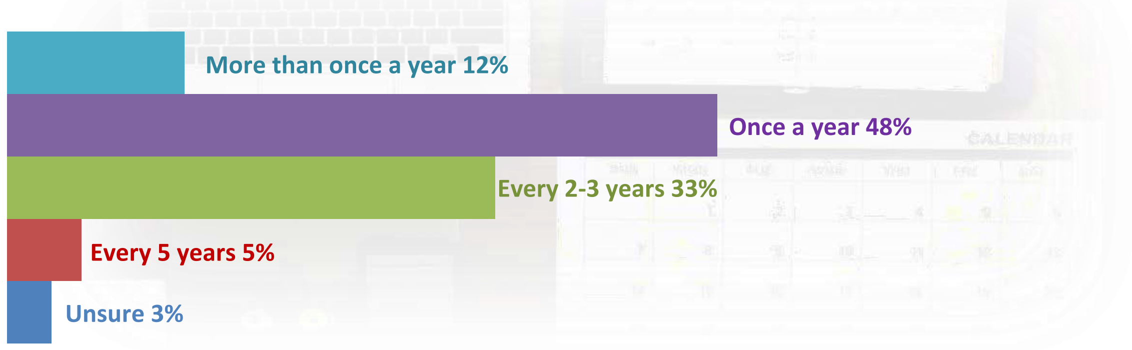
An almost seven in ten majority somewhat or completely agreed that they have a better appreciation of the planning trade-offs that Elexicon needs to consider when making investment plans. This compares to only 7% that somewhat or completely disagreed, while 19% gave a neutral (neither agree nor disagree) response, and 5% were unsure.

Customers were asked about their preferred method to have Elexicon consult with them on similar topics. Below are the percentage of counts or the responses for each category, revealing that by far, most favour online surveys.

"In the future, what is your preferred method to have Elexicon consult with you about topics similar to what we discussed?"

Online Surveys	93%
Live Online Presentations and Q&A Sessions	13%
In-Person Townhall Meetings	8%
In-Person Focus Groups	5%
Phone Surveys	3%
Mail	1%
Bill inserts	1%
General email	<1%
Newspaper	<1%

"How often should Elexicon engage its customers on matters such as those captured in this survey?"



➡ The percentage of customers that want to be engaged on a yearly basis (once & more than once a year) is 60%, while a third named every 2-3 years. Only 5% stated every five years and 3% were unsure.

"Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?"

Unsure / none	N=218	83%
Lower rates	N=12	5%
Promote Green Energy	N=5	2%
Limit increases to most needed projects	N=2	1%
Removal of overhead wires	N=2	1%
Invest in an outage communication system	N=2	1%
App to monitor usage	N=2	1%
More tools to help manage electricity use	N=2	1%
Keep the utilities public / local	N=2	1%
Amount and length of outages too high	N=1	<1%
Support Electric vehicles	N=1	<1%
Stop all investment in Green Energy	N=1	<1%
Communities should cover costs	N=1	<1%
Support upgrades	N=1	<1%
Create jobs	N=1	<1%
Move to online payments only	N=1	<1%
Improve customer service	N=1	<1%
Would like data from Smart Meter	N=1	<1%
Capital costs should've been pre-planned	N=1	<1%
Upgrades should not impact customers	N=1	<1%
Upgrades too costly	N=1	<1%
Should not pay for new subdivisions	N=1	<1%
Trees are being cut down unnecessarily	N=1	<1%
More outreach needed	N=1	<1%

Telephone Survey Results

Elexicon Energy
Part A: Initial Qualification and Segmentation

Telephone respondents were read background information about Elexicon. They were also told that a main objective of the online poll was to learn how Elexicon's investment plans can best reflect the needs and preferences of its customers.

"Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account."

Yes	*N=600*	*100%*

"What is the municipality associated with the Elexicon customer account?"

Whitby	*29%*
Ajax	*18%*
Pickering	*17%*
Belleville	*10%*
Clarington	*8%*
Gravenhurst	*7%*
Port Hope	*5%*
Brock	*3%*
Scugog	*2%*
Uxbridge	*2%*

The initial questions were demographic. First respondents were screened to ensure they were Elexicon customers, then they were probed about where they live, the client segment they belonged to, and if they are responsible for paying the electricity bill.

"To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer."

Residential	*N=524*	*87%*
Small Business (monthly electricity bill below $2,500)	*N=70*	*12%*
Large Business (monthly electricity bill above $2,500)	*N=6*	*1%*

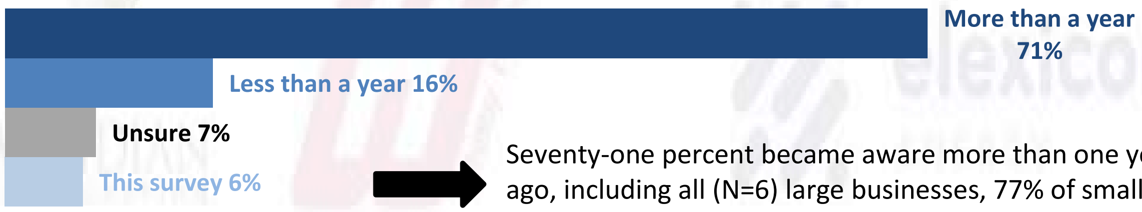
"In your <household / business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?"

I am primarily responsible for paying my household's electricity bill	*N=466*	*78%*
I share the responsibility for paying my household's electricity bill	*N=58*	*10%*
I am the person responsible for managing my organization's electricity bill	*N=42*	*7%*
I am the person overseeing the management of my organization's electricity bill	*N=34*	*6%*

General Questions

Respondents were next read an explanation of the three major cost components of their electricity bill: Generation, Transmission and Distribution – and the portion retained by Elexicon. They were advised that the information collected in the survey related only to their local electricity distributor Elexicon, after which questions were asked.

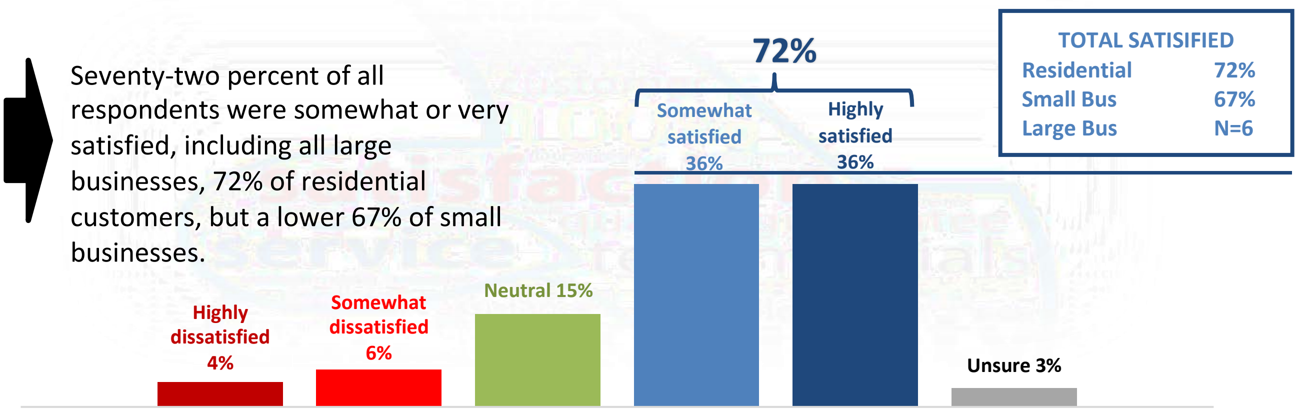
"When did you first become aware of the merger between Whitby Hydro and Veridian to create Elexicon?"



Seventy-one percent became aware more than one year ago, including all (N=6) large businesses, 77% of small businesses, and 70% of residential customers.

"Overall, how satisfied are you with the services Elexicon provides you with?"

Seventy-two percent of all respondents were somewhat or very satisfied, including all large businesses, 72% of residential customers, but a lower 67% of small businesses.



Comments were accepted at the end of the question and results have been coded into the categories below.

"In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?"

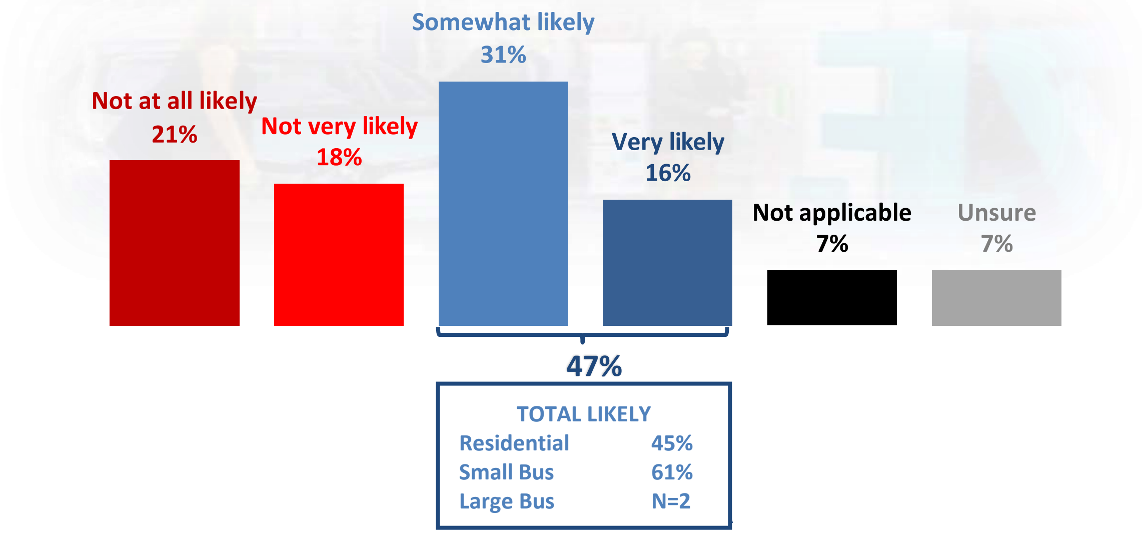
Unsure / none	30%	Good customer service	1%
No problems / satisfied	24%	Poor customer service /long waits	1%
Reliable / stable service	14%	No notice for planned outages	1%
Hydro rates are high / expensive	13%	Simplify billing / payment methods	1%
Poor service / interruptions / outages	10%	Dislike time of use / simplify / change	1%
No experience / new customers	2%	Lack of follow up	1%
Old / outdated Infrastructure	2%	Billing problems	<1%

“Please rate your level of agreement with the following statements using a scale from one (strongly disagree) to five (strongly agree).”

	Strongly disagree	Somewhat disagree	Neutral	Somewhat agree	Strongly agree	Unsure	Not applicable	TOTAL AGREE BY SEGMENT
“The amount of my monthly electricity bill is a major expense item for my family / business and requires me to go without some other important priorities”	20%	24%	22%	**24%**	**9%**	1%	-	*Residential 32%* *Small Bus 43%* *Large Bus N=1*
“When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved”	**4%**	**8%**	19%	21%	20%	1%	27%	*Residential 40%* *Small Bus 45%* *Large Bus N=5*

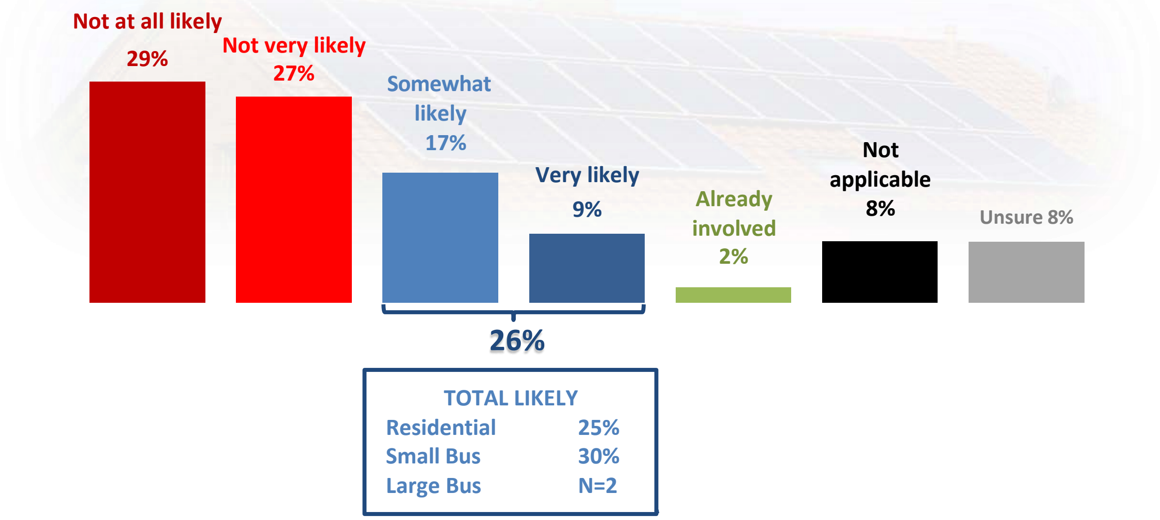
Thirty-three percent of all respondents agreed their monthly bill is a major expense affecting priorities, with small businesses most likely to agree at 43%. More than four in ten or 41% agreed or were satisfied with how their questions were resolved, compared to only 12% that disagreed or were not satisfied – with businesses being more satisfied (total agree).

"If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?"



There is strong overall interest at 47%, with those in the small business cohort showing the strongest interest.

"How likely are you to become involved in self-generation of electricity at your <residence>>/<<business> over the next five years (for example, by installing solar panels)?"



Twenty-six percent said they are somewhat (17%) or very likely (9%) to become involved in self generation, with results higher among small businesses.

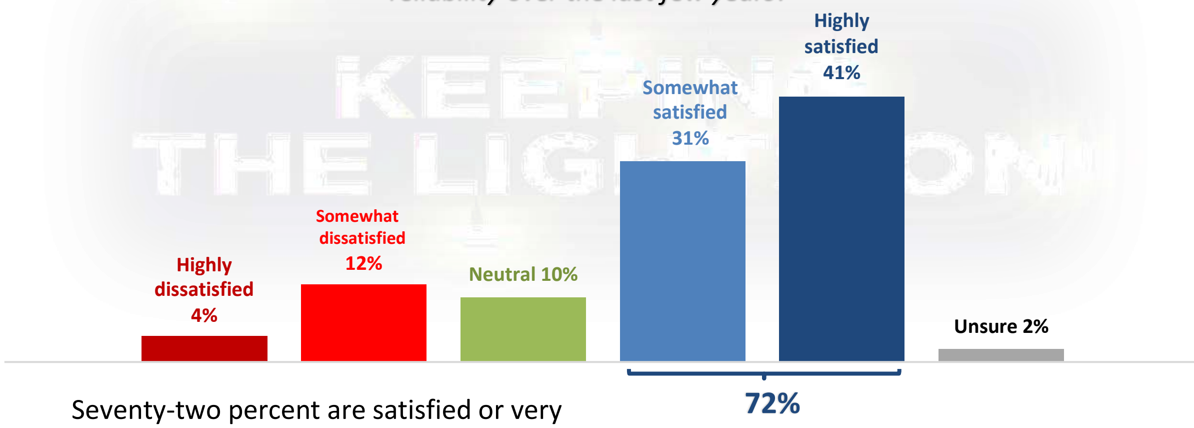
Two questions about outages over the past year were asked, the first about how many times the power has been out, and second related to the length of time they lasted.

"In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your <home / business> to the best of your recollection?"	
0	7%
1	15%
2	31%
3	14%
More than 3	26%
Not Sure	8%

"In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average? Please select from the following options based on your best estimate:"	
Under 30 minutes	23%
Under 1 hour	21%
Between 1 and 2 hours	21%
Longer than 2 hours	25%
Not Sure	10%

Customers were next probed about reliability, starting with an overall satisfaction question. There were then asked two semi-open follow-ups about what most inconvenienced them during outages and how they interact with Elexicon during these events.

"Which of the following options best represents your overall satisfaction with service reliability over the last few years?"



Seventy-two percent are satisfied or very satisfied with service reliability with residential customers (74%), with 4 of the N=6 large businesses being more satisfied than small businesses (62%).

TOTAL SATISFIED	
Residential	74%
Small Bus	62%
Large Bus	N=4

"When power outages do occur, which aspect of them has been most inconvenient for you?"

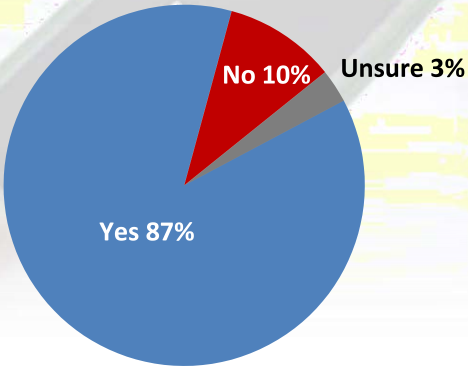
How long the outages have lasted	48%
How often the outages have occurred	19%
Not Sure	15%
Impact it has on my electronics / computers	8%
None / no inconveniences	4%
Both how often & how long	3%
Getting info from Elexicon / contact	2%
Timing / when they occur	1%

"When there is a power outage, how do you interact with Elexicon Energy?"

I check the outage map online	38%
I do not take any steps	29%
I phone the outage number posted on the website	21%
I check Twitter	6%
Telephone call	4%
Unsure	2%
No experience	1%
Radio	<1%

The length of an outage is of most concern to 48%, followed by how often they occur (19%). When then asked how they interact with Elexicon during an outage, 38% check the map online and 21% phone the number on the website, while an additional 4% just said a telephone call.

"Please indicate your level of interest in the following: When an outage occurs, are you interested in receiving notifications sent to your phone (via text or voice to landline) about its cause and anticipated restoration time?"



TOTAL INTEREST	
Residential	86%
Small Bus	94%
Large Bus	N=6

Interest is very high at 87%, and especially among businesses.

"To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?"	
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases	38%
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term	37%
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term to achieve this	12%
Not Sure	10%
Maintain reliability and do not raise prices	3%
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others	1%

An almost equal number support spending more on reliability and less on other areas (to avoid some bill increases) and maintaining current reliability, even if it increases monthly bills in the long term.

"Elexicon can prevent more outages caused by aging equipment if it proactively replaces more equipment before it fails. Another option is to wait and replace equipment only after it fails, which potentially causes more service interruptions and leads to extra costs such as staff overtime. Which of the following options best describes your views on this trade-off?"	
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	85%
Not Sure	7%
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	5%
Maintenance on a schedule and no rate increases	4%

A very strong majority of 85% feel equipment should be replaced before it fails.

“Elexicon’s top spending priority is always to keep its power system and operations safe. With its budget staying nearly flat through 2029, Elexicon will face tough trade-offs when selecting among other investment priorities.”

“Please choose two of the following objectives that you think Elexicon should focus its efforts on, in addition to keeping the system safe and accommodating new growth in the coming years.”

	First mention	Second mention	Combined
Improving the grid’s resilience to major weather events, like storms, floods, or freezing rain	32%	30%	31%
Preparing the grid for new types of uses, like electric vehicles and renewable generation	22%	12%	17%
Investing now in things that will help reduce rate increases after 2029	12%	20%	16%
Minimizing the impact of power outages	6%	20%	13%
Helping customers manage their electricity use	11%	9%	10%
Reducing the environmental impact of Elexicon’s operations	11%	5%	8%
Improving power quality	4%	3%	4%
Addressing customer requests faster and more efficiently	2%	1%	2%

➡ Improving the grid’s resilience to major events is the number one, two, and combined choice. The next highest in terms of combined results is preparing the grid for new uses, followed by investing in things that will help reduce rate increases after 2029.

➡ **45% of customers who are dissatisfied with reliability listed minimizing outage impacts in their top two priorities.**

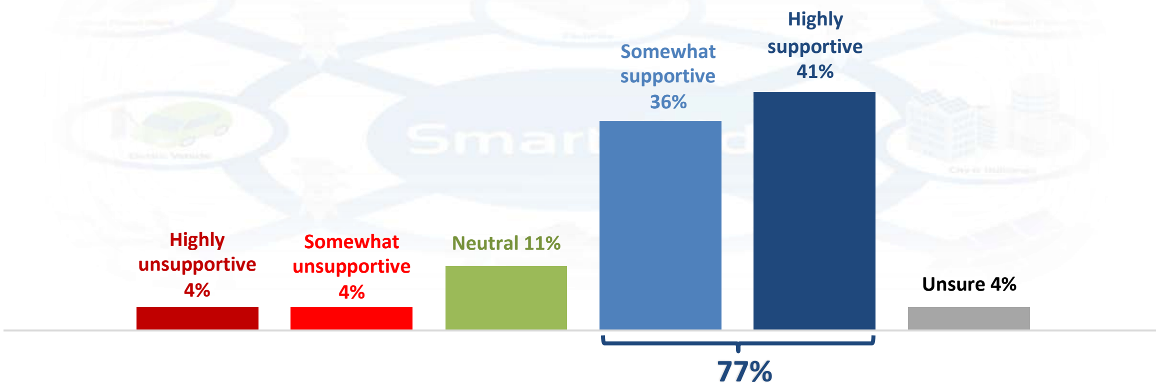
“Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid.”

“Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?”

I am satisfied with the planned allocation based on what I know	53%
I would prefer to spend more on the technical upkeep of the power grid and less on the other two	16%
Not Sure	14%
I would prefer to spend more on reliability and less on the other two	11%
I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	6%

➡ A slim majority or 53% are satisfied with the planned allocation, next followed by those wanting more spent on technical upkeep (16%) and reliability (11%). Only 6% want more spent-on efficiency, health, and safety, while 11% were unsure.

"Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?"

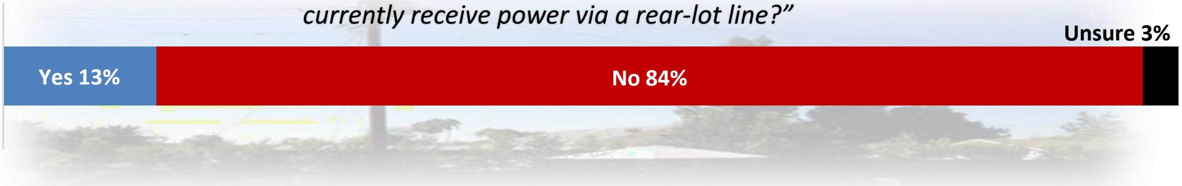


Support for investing in new technologies is at a strong 77%.

TOTAL SUPPORTIVE	
Residential	76%
Small Bus	80%
Large Bus	N=6

Customers were read a description of rear-lot overhead power lines, the challenges they face, and the cost of conversion to underground lines. They were then asked the following two questions.

"To the best of your knowledge, does your place of <residence>/<business> currently receive power via a rear-lot line?"



"Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?"

Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere. While concentrating the work in a single community for a shorter timeframe is less inconvenient to local residents, it could leave vulnerable rear-lot feeders in other communities unaddressed for longer.	39%
Move lines underground and plan work according to worst performing areas. This spreads the work across Elexicon's service territory over time but may mean that there may be multiple construction-related disruptions.	24%
Maintain the status quo – keep the overhead lines in the rear lots, replacing them as they fail. While budgets can be used elsewhere, it will leave area customers vulnerable to longer than average outages.	22%
Not Sure	15%

While no option received majority preference, most named was moving lines underground and working geographically, while the other two alternatives received roughly the same percentage of responses.

ICM Project #1: New Pickering Area Transformer Station

Next, online participants were read background information about three projects that Elexicon plans to seek approval for additional rate increases. They were informed that two projects are driven by population growth and the third is needed to sustain operations in the Belleville area.

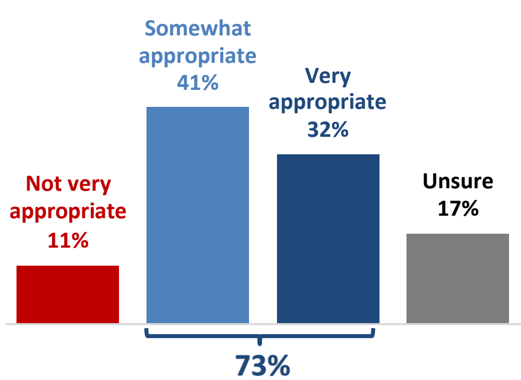
Elexicon will request special rate increases for these projects since it cannot finance them along with its other budgetary priorities. These requests are reviewed by the OEB through a process known as the Incremental Capital Module (ICM).

The first project is a large new Transformer Station in the Pickering area, required to support the residential and commercial growth that is projected to add as many as 32,000 new customers over the next 20 years. Elexicon estimates that to avoid system capacity shortages, the station needs to be in service in 2022.

The project is expected to cost about $40 million, which amounts to an approximate:

- $1.45 - $1.85 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- 2.90 - $3.60 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $280.95 - $343.40 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Transformer Station appropriate?



TOTAL SUPPORTIVE	
Residential	71%
Small Bus	78%
Large Bus	N=5

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	81%
If it is necessary / if needed / get it done	8%
Developers should pay a higher portion of cost	3%
Customers affected should pay	3%
Against the proposed project all together	1%
Do not increase rates	1%
Better cost-efficient solutions are needed	1%
Do not want to pay for other communities	1%
More renewable energy needed	1%
Should focus on conservation	1%
Apply new rates for new customers	<1%
Too costly	<1%

Seventy-three percent consider the level of investment appropriate (somewhat & very), only 11% do not feel it appropriate, and 17% were undecided. More than 80% had no comments, with those that did being split over support and wanting alternative costing options.

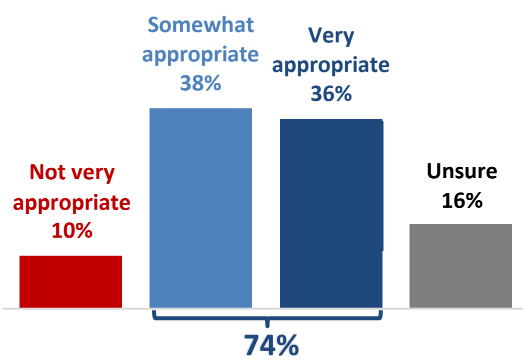
ICM Project #2: Accommodating the Move of the Belleville Operations Centre

The second project for funding is a new Operations Centre in Belleville to accommodate staff and equipment involved in providing customer service and responding to local power outages. The lease on the existing facility is set to expire in 2021 and cannot be renewed. Having considered all feasible options, Elexicon determined that owning a new facility is the most cost-effective option for customers in the long term.

The project is expected to cost about $2.6 million, which amounts to an approximate

- $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $2.6 million, which amounts to an approximate $18.35 - $23.50 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Operations Centre appropriate?"



TOTAL SUPPORTIVE	
Residential	72%
Small Bus	87%
Large Bus	N=6

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	88%
It is a required investment / reasonable / needed	4%
Customers / communities affected should pay	3%
Lack of information to make an informed decision	2%
Refurbish an existing building	2%
Customers should not have to pay	1%
Against project all together	1%
Consider lease / renting building	1%
Build it smart / keep future growth in mind	1%
Business / developers should pay	<1%

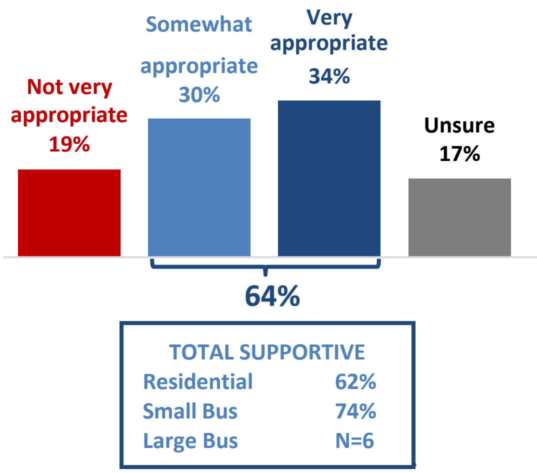
Almost three-quarters consider the level of investment appropriate, with results very strong among businesses. Most had no comments or thoughts to share. Comments were spread among those supporting the project and others opposed to having to pay for it.

ICM Project #3: Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit

To enable construction of dedicated Rapid Transit Bus Lanes in the Hwy #2 corridor in Pickering, Elexicon is required to relocate existing underground feeder infrastructure located in the right of way intended for the bus lanes. Elexicon and its customers are responsible for a portion of this cost, estimated to be $2.8 million. While performing this work, Elexicon will have an opportunity to replace or upgrade any equipment, as necessary.

- The project's cost is equivalent to an approximate $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $27.95 - $35.70 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"Do you consider the level of investment proposed for this underground infrastructure project to be very appropriate, somewhat appropriate, or not appropriate? "



"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	76%
Customers / communities affected should pay	5%
Should be a priority	4%
Project should be covered by taxpayers	3%
Costs should be covered by transit users	2%
Need more information / unclear	2%
Complete as efficiently and quickly as possible	2%
Will improve reliability	1%
Project not a priority	1%
Municipality should pay	1%
Transit is important / needed for growth	1%
Should be paid for by investors	1%
Poor planning	1%
Will raise rates	1%
Disagree with project	1%

Results were lowest for this project with 64% saying the project was somewhat or very appropriate. While some comments expressed support, others reflected the belief that funding or costing should come from others, such as affected users and municipalities.

In the final question about the three ICM projects, respondents were asked which of five options would give them the most confidence that Elexicon is acting in their best interest.

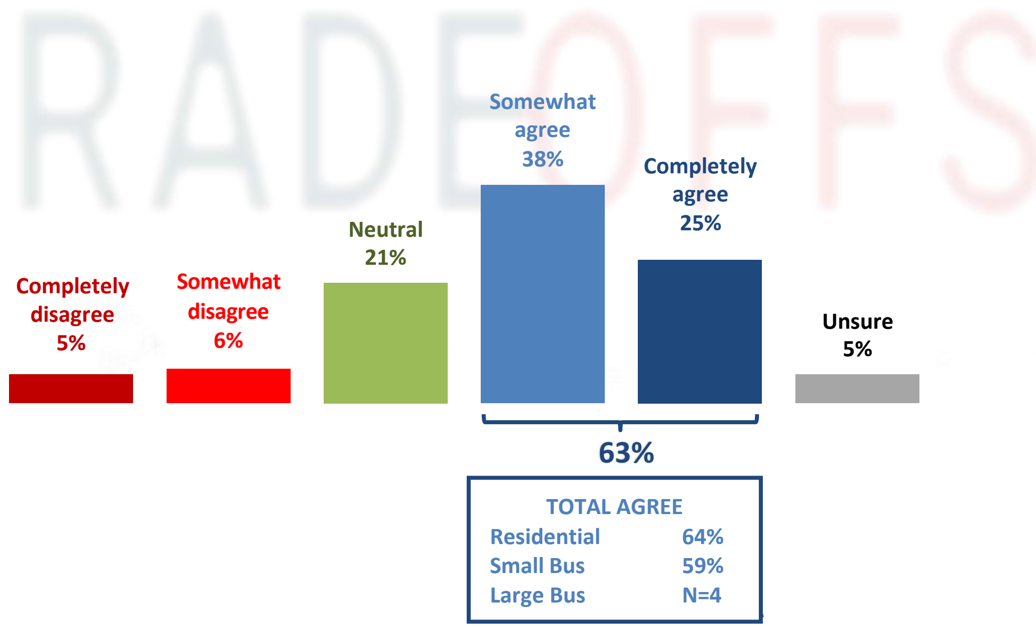
"What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting in the best interest of their customers in mind?"

39%	Why Elexicon could not build these projects without seeking rate increases
16%	Why the chosen design and size are optimal
14%	Why the projects cannot be built for less
6%	Why the projects cannot be reasonably delayed
2%	Why these projects could not be built in other areas
23%	Unsure

Most named was why Elexicon could not build these projects without seeking rate increases, followed by why the chosen designs and sizes are optimal and then why they cannot be built for less. Twenty-three percent answered do not know or were unsure.

Elexicon Energy
Part D: Concluding Observations

"As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?"



Sixty-three percent somewhat or completely agreed that they have a better appreciation of the planning trade-offs that Elexicon needs to consider when making investment plans. This compares to 11% that somewhat or completely disagreed, while 21% gave a neutral (neither agree nor disagree) response and 5% were unsure.

Customers were asked about their preferred method to have Elexicon consult with them on similar topics. Below are the percentage of counts or the responses for each category.

"In the future, what is your preferred method to have Elexicon consult with you about topics similar to what we discussed?"

Live Online Presentations and Q&A Sessions	33%
Email	22%
Online Surveys	20%
Unsure	15%
Bill inserts	14%
In-Person Townhall Meetings	7%
Phone Surveys	2%
In-Person Focus Groups	2%
Mail	1%
Newspaper	1%

"How often should Elexicon engage its customers on matters such as those captured in this survey?"

Once a year is how often a small majority want to be engaged, followed by 31% that named every 2-3 years, 9% more than once a year, and only 4% every five years.

"Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?"

Unsure / none	N=467	78%
Lower rates	N=51	9%
Limit increases to most needed projects	N=18	3%
Promote Green Energy	N=12	2%
Do most needed first	N=10	2%
Upgrades too costly	N=8	1%
Improve customer service	N=6	1%
More energy savings advice	N=5	1%
More outreach needed	N=5	1%
Amount and length of outages too high	N=3	1%
Communities should cover costs	N=3	1%
Support upgrades	N=3	1%
Upgrades should not impact customers	N=3	1%
Support Electric vehicles	N=2	<1%
Removal of overhead wires	N=2	<1%
The projects should have been planned	N=1	<1%
We should not pay for new developments	N=1	<1%

Online Results by Question

Q1.Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account.		
	N	Percent
Yes	262	100.0

Q01B.What is the municipality associated with the Elexicon customer account?		
	N	Percent
Whitby	75	28.6
Ajax	61	23.3
Pickering	43	16.4
Belleville	19	7.3
Clarington (Bowmanville, Orono, Newcastle)	19	7.3
Gravenhurst	19	7.3
Port Hope	11	4.2
Brock (Beaverton, Cannington, Sunderland)	7	2.7
Port Perry	7	2.7
Uxbridge	1	.4
Total	262	100.0

Q02.To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer.		
	N	Percent
Residential	262	100.0

Q03.In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?		
	N	Percent
I am primarily responsible for paying my household's electricity bill	233	88.9
I share the responsibility for paying my household's electricity bill	29	11.1
Total	262	100.0

Q1.When did you first become aware of the merger between Veridian Connections and Whitby Hydro Electric Corporation to form Elexicon?		
	N	Percent
More than a year ago	183	69.8
Less than a year ago	40	15.3
Was not aware until this survey	19	7.3
Not Sure	20	7.6
Total	262	100.0

Q2A.Overall, how satisfied are you with the services Elexicon provides you with?		
	N	Percent
Highly Satisfied	92	35.1
Somewhat Satisfied	90	34.4
Neither Satisfied nor Dissatisfied	45	17.2
Somewhat Dissatisfied	17	6.5
Highly Dissatisfied	10	3.8
Not Sure	8	3.1
Total	262	100.0

Q2B. In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?		
	N	Percent
No problems / satisfied	59	22.5
Unsure	55	21.0
Reliable / stable service	33	12.6
Poor service / interruptions in service	29	11.1
Hydro rates are high / expensive	23	8.8
No change	10	3.8
Old / outdated Infrastructure	7	2.7
Dislike time of use / need to simplify / change	6	2.3
No notice for planned outages	5	1.9
No experience / new customers / too soon to rate	5	1.9
Poor costumer service /long waits	5	1.9
Service has improved	5	1.9
Website problems / issues	4	1.5
Simplify billing / payment methods	3	1.1
Billing problems	3	1.1
Good customer service	3	1.1
The transition has been seamless	2	.8
Need alternative energy options	2	.8
Cannot compare due to the monopoly	1	.4
Lack of follow up	1	.4
Give rebates	1	.4
Total	262	100.0

Q3."The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities."			
		N	Percent
	Strongly Disagree	65	24.8
	Somewhat Disagree	52	19.8
	Neither Agree nor Disagree	71	27.1
	Somewhat Agree	54	20.6
	Strongly Agree	18	6.9
	Not Sure	2	.8
	Total	262	100.0

Q4."When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved."			
		N	Percent
	Strongly Agree	51	19.5
	Somewhat Agree	46	17.6
	Neither Agree nor Disagree	50	19.1
	Somewhat Disagree	24	9.2
	Strongly Disagree	9	3.4
	Not Applicable	82	31.3
	Total	262	100.0

Q5.If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?			
		N	Percent
	Very Likely	40	15.3
	Somewhat Likely	75	28.6
	Not Very Likely	49	18.7
	Not Likely at All	56	21.4
	Not Applicable	22	8.4
	Not Sure	20	7.6
	Total	262	100.0

Q6.How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?			
		N	Valid Percent
	I am already involved in self generation	6	2.3
	Very Likely	22	8.4
	Somewhat Likely	46	17.6
	Not Very Likely	78	29.8
	Not Likely at All	67	25.6
	Not Applicable (e.g., housing situation does not permit)	27	10.3
	Not Sure	16	6.1
	Total	262	100.0

Q7. In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at...			
		N	Percent
	0	21	8.0
	1	37	14.1
	2	77	29.4
	3	33	12.6
	More than 3	64	24.4
	Not Sure	30	11.5
	Total	262	100.0

Q8.In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average?		
	N	Percent
Under 30 minutes	52	19.8
Under 1 hour	58	22.1
Between 1 and 2 hours	57	21.8
Longer than 2 hours	56	21.4
Not Sure	39	14.9
Total	262	100.0

Q9.Which of the following options best represents your overall satisfaction with service reliability over the last few years?		
	N	Percent
Very Satisfied	111	42.4
Somewhat Satisfied	88	33.6
Neither Satisfied nor Dissatisfied	24	9.2
Somewhat Dissatisfied	23	8.8
Very Dissatisfied	8	3.1
Not Sure	8	3.1
Total	262	100.0

Q10.When power outages do occur, which aspect of them has been most inconvenient for you?		
	N	Percent
How long the outages have lasted	114	43.5
How often the outages have occurred	52	19.8
Not Sure	42	16.0
Impact it has on my electronics / computers	19	7.3
None / no inconveniences	11	4.2
Getting information from Elexicon / contact with (duration, restoration, etc.)	8	3.1
Both how often & how long	8	3.1
Timing / when they occur	5	1.9
No heat / no cooling / appliances	3	1.1
Total	262	100.0

Q11.When there is a power outage, how do you interact with Elexicon Energy? Select all that apply.		
	N	Percent
I check the outage map online	98	37.4
I do not take any steps	79	30.2
I phone the outage number posted on the website	51	19.5
I check Twitter	16	6.1
Telephone call	7	2.7
No experience	4	1.5
I use both Twitter and Map	3	1.1
Radio	2	.8
Unsure	2	.8
Total	262	100.0

Q12.Please indicate your level of interest in the following potential service offering: When an outage occurs, are you interested in receiving notifications sent to your phone (via text and/or voice to landline) about its cause and anticipated restoration time?		
	N	Percent
Yes	226	86.3
No	27	10.3
Not Sure	9	3.4
Total	262	100.0

Q13.To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?		
	N	Percent
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases.	97	37.0
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the Long term	83	31.7
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term	32	12.2
Not Sure	30	11.5
Maintain reliability & do not raise prices	11	4.2
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially m	7	2.7
Provide better service overall	2	.8
Total	262	100.0

Q14 Which of the following options best describes your views on this trade-off?		
	N	Percent
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	212	80.9
Not Sure	25	9.5
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	13	5.0
Maintenance on a schedule & no rate increases	10	3.8
Invest in better equipment	2	.8
Total	262	100.0

Q15. Please select two potential objectives from the following list that you think Elexicon should focus its efforts on in addition to keeping the system safe and accommodating new growth in the coming years.

Q15 FIRST CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	74	28.2
Preparing the grid for new types of uses, like electric vehicles and renewable generation	61	23.3
Investing now in things that will help reduce rate increases after 2029	34	13.0
Reducing the environmental impact of Elexicon's operations	31	11.8
Helping customers manage their electricity use	25	9.5
Minimizing the impact of power outages	18	6.9
Improving power quality	13	5.0
Addressing customer requests faster and more efficiently	6	2.3
Total	262	100.0

	Q15 SECOND CHOICE	N	Percent
	Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	82	31.3
	Investing now in things that will help reduce rate increases after 2029	52	19.8
	Minimizing the impact of power outages	51	19.5
	Preparing the grid for new types of uses, like electric vehicles and renewable generation	30	11.5
	Helping customers manage their electricity use	25	9.5
	Reducing the environmental impact of Elexicon's operations	13	5.0
	Improving power quality	6	2.3
	Addressing customer requests faster and more efficiently	3	1.1
	Total	262	100.0

Q16. Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid. Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?

		N	Percent
	I am satisfied with the planned allocation based on what I know	130	49.6
	I would prefer to spend more on the technical upkeep of the power grid and less on the other two	48	18.3
	Not Sure	43	16.4
	I would prefer to spend more on reliability and less on the other two	22	8.4
	I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	19	7.3
	Total	262	100.0

Q17. Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?

		N	Percent
	Highly Supportive	91	34.7
	Somewhat Supportive	102	38.9
	Neither Supportive nor Unsupportive	32	12.2
	Somewhat Unsupportive	15	5.7
	Highly Unsupportive	9	3.4
	Not Sure	13	5.0
	Total	262	100.0

Q18. To the best of your knowledge, does your place of residence / business currently receive power via a rear-lot line?

		N	Percent
	Yes	29	11.1
	No	192	73.3
	Not Sure	41	15.6
	Total	262	100.0

Q19. Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?	N	Percent
Maintain the status quo – keep all the lines overhead in the rear lots, replacing them as they fail.	45	17.2
Move lines underground and plan work according to worst performing areas.	57	21.8
Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere.	100	38.2
Not Sure	60	22.9
Total	262	100.0

Q20.To what degree do you consider the level of proposed investments in the Transformer Station appropriate?	N	Percent
Very Appropriate	72	27.5
Somewhat Appropriate	105	40.1
Not Very Appropriate	31	11.8
Not Sure / Cannot Rate	54	20.6
Total	262	100.0

Q21.Do you have any thoughts you'd like to share with respect to this project?	N	Percent
Unsure / none	184	70.2
Customers affected should pay	17	6.5
Developers should be covering a higher portion of the cost	15	5.7
Against the proposed project all together	9	3.4
If it is necessary / if needed / get it done	9	3.4
Better cost-efficient solutions are needed	9	3.4
Do not want to pay for other communities	5	1.9
Do not increase rates	3	1.1
Not enough information to make a decision	3	1.1
Safely and reliability	2	.8
More renewable energy sources such as solar or wind	2	.8
Too costly	2	.8
Make sure there is a backup plan	1	.4
Should focus on conservation	1	.4
Total	262	100.0

Q22.To what degree do you consider the level of proposed investments in the Operations Centre appropriate?	N	Percent
Very Appropriate	84	32.1
Somewhat Appropriate	96	36.6
Not Very Appropriate	29	11.1
Not Sure / Cannot Rate	53	20.2
Total	262	100.0

Q23.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	207	79.0
Customers / communities affected should pay	11	4.2
It is a required investment / reasonable / needed	8	3.1
Refurbish an existing building	6	2.3
Should come from reserve funds not customers	4	1.5
Against project all together	4	1.5
Lack of information to make an informed decision	4	1.5
Build it smart / keep future growth in mind	3	1.1
Compare leasing versus new build	3	1.1
Customers should not have to pay	3	1.1
Lease / rent building	2	.8
Should have been done years ago	2	.8
Proposed budget seems too low	1	.4
Municipality should help finance	1	.4
Savings should be passed onto the customer	1	.4
Business / developers should pay	1	.4
Should be mortgage financed	1	.4
Total	262	100.0

Q24.To what degree do you consider the level of proposed investments in the Underground System Relocation appropriate?		
	Frequency	Percent
Very Appropriate	81	30.9
Somewhat Appropriate	80	30.5
Not Very Appropriate	51	19.5
Not Sure / Cannot Rate	50	19.1
Total	262	100.0

Q25.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	194	74.0
Customers / residents / communities affected should pay	16	6.1
Should be a priority	9	3.4
Project should be covered by taxpayers	8	3.1
Project not a priority	7	2.7
Need more information / unclear	5	1.9
Costs should be covered by transit users	5	1.9
Municipality should pay	4	1.5
Should be paid for by investors	3	1.1
Will improve reliability	3	1.1
Poor planning	2	.8
Project should be completed as efficiently and quickly as possible	2	.8
Disagree with project	2	.8
Will raise rates	1	.4
Should be Elexicon's responsibility	1	.4
Total	262	100.0

Q26.What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting with the best interest of their customers in mind?			
		N	Percent
	Why Elexicon could not build these projects without seeking rate increases	98	37.4
	Not Sure	76	29.0
	Why the chosen design and size are optimal	39	14.9
	Why the projects cannot be built for less	30	11.5
	Why the projects cannot be reasonably delayed	14	5.3
	Why these projects could not be built in other areas	5	1.9
	Total	262	100.0

Q27.We're almost done – we have only a few more questions to ask you. As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?			
		N	Percent
	Completely Agree	69	26.3
	Somewhat Agree	112	42.7
	Neither Agree nor Disagree	50	19.1
	Somewhat Disagree	11	4.2
	Completely Disagree	7	2.7
	Not Sure	13	5.0
	Total	262	100.0

Q28. To help Elexicon improve on customer engagement in the future, please identify your preferred ways for being consulted in the future on similar topics.

MULTIPLES RESPONSES ACCEPTED		Responses		Percent of Cases
		N	Percent	
	Online Surveys	244	74.8%	93.1%
	Phone Surveys	8	2.5%	3.1%
	In-Person Focus Groups	13	4.0%	5.0%
	In-Person Townhall Meetings	20	6.1%	7.6%
	Live Online Presentations and Q&A Sessions	35	10.7%	13.4%
	Mail	2	0.6%	0.8%
	Newspaper	1	0.3%	0.4%
	Bill inserts	2	0.6%	0.8%
	General email	1	0.3%	0.4%
Total		326	100.0%	124.4%

Q29.How often should Elexicon engage its customers on matters such as those captured in this survey?			
		N	Percent
	Once a Year	126	48.1
	Once Every 2-3 Years	86	32.8
	More Than Once a Year	31	11.8
	Once Every 5 Years	12	4.6
	Not Sure	7	2.7
	Total	262	100.0

Q30.Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?		
	N	Percent
Unsure / none	218	83.2
Lower rates	12	4.6
Promote Green Energy	5	1.9
Limit increases to most needed projects	2	.8
Removal of overhead wires	2	.8
Invest in an outage communication system	2	.8
App to monitor usage	2	.8
More tools to help manage my electricity use	2	.8
Keep the utilities public / local	2	.8
Amount and length of outages too high	1	.4
Support Electric vehicles	1	.4
Stop all investment in Green Energy	1	.4
Communities should cover costs	1	.4
Support upgrades	1	.4
Create jobs	1	.4
Move to online payments only	1	.4
Improve customer service	1	.4
Would like to obtain data from Smart Meter	1	.4
Capital costs should have been pre-planned	1	.4
Upgrades should not impact customers	1	.4
Upgrades too costly	1	.4
The entire ratepayer base should not pay for expansion to new subdivisions.	1	.4
Trees are being trimmed down / cut down unnecessarily	1	.4
More outreach needed	1	.4
Total	262	100.0

Telephone Results by Question

Q1.Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account.		
	Frequency	Percent
Yes	600	100.0

Q01B.What is the municipality associated with the Elexicon customer account?		
	N	Percent
Whitby	173	28.8
Ajax	107	17.8
Pickering	103	17.2
Belleville	60	10.0
Clarington (Bowmanville, Orono, Newcastle)	45	7.5
Gravenhurst	44	7.3
Port Hope	27	4.5
Brock (Beaverton, Cannington, Sunderland)	17	2.8
Scugog	14	2.3
Uxbridge	10	1.7
Total	600	100.0

Q02.To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer.		
	N	Percent
Residential	524	87.3
Small Business (monthly electricity bill below $2,500)	70	11.7
Large Business (monthly electricity bill above $2,500)	6	1.0
Total	600	100.0

Q03.In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?		
	N	Percent
I am primarily responsible for paying my household's electricity bill	466	77.7
I share the responsibility for paying my household's electricity bill	58	9.7
I am the person responsible for managing my organization's electricity bill	42	7.0
I am the person overseeing the management of my organization's electricity bill	34	5.7
Total	600	100.0

Q1.When did you first become aware of the merger between Veridian Connections and Whitby Hydro Electric Corporation to form Elexicon?		
	N	Percent
More than a year ago	426	71.0
Less than a year ago	93	15.5
Was not aware until this survey	36	6.0
Not Sure	45	7.5
Total	600	100.0

Q2A.Overall, how satisfied are you with the services Elexicon provides you with?		
	N	Percent
Highly Satisfied	217	36.2
Somewhat Satisfied	213	35.5
Neither Satisfied nor Dissatisfied	91	15.2
Somewhat Dissatisfied	39	6.5
Highly Dissatisfied	22	3.7
Not Sure	18	3.0
Total	600	100.0

Q2B. In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?	N	Percent
Unsure / none	178	29.7
No problems / satisfied	146	24.3
Reliable / stable service	82	13.7
Hydro rates are high / expensive	75	12.5
Poor service / interruptions / outages	61	10.2
No experience / new customers / too soon to rate	12	2.0
Old / outdated Infrastructure	11	1.8
Good customer service	7	1.2
Poor customer service /long wait times	7	1.2
No notice for planned outages	6	1.0
Simplify billing / payment methods	5	.8
Dislike time of use / need to simplify / change	5	.8
Lack of follow up	3	.5
Billing problems	2	.3
Total	600	100.0

Q3."The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities."	N	Percent
Strongly Disagree	119	19.8
Somewhat Disagree	146	24.3
Neither Agree nor Disagree	135	22.5
Somewhat Agree	143	23.8
Strongly Agree	53	8.8
Not Sure	4	.7
Total	600	100.0

Q4."When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved."	N	Percent
Strongly Agree	117	19.5
Somewhat Agree	127	21.2
Neither Agree nor Disagree	112	18.7
Somewhat Disagree	49	8.2
Strongly Disagree	26	4.3
Not Applicable	163	27.2
Unsure	6	1.0
Total	600	100.0

Q5. If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?	N	Percent
Very Likely	94	15.7
Somewhat Likely	189	31.5
Not Very Likely	107	17.8
Not Likely at All	124	20.7
Not Applicable	41	6.8
Not Sure	45	7.5
Total	600	100.0

Q6. How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?	N	Percent
I am already involved in self generation	15	2.5
Very Likely	56	9.3
Somewhat Likely	100	16.7
Not Very Likely	164	27.3
Not Likely at All	171	28.5
Not Applicable (e.g., housing situation does not permit)	47	7.8
Not Sure	47	7.8
Total	600	100.0

Q7. In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your home to the best of your recollection?	N	Percent
0	42	7.0
1	87	14.5
2	184	30.7
3	83	13.8
More than 3	154	25.7
Not Sure	50	8.3
Total	600	100.0

Q8. In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average?	N	Percent
Under 30 minutes	137	22.8
Under 1 hour	128	21.3
Between 1 and 2 hours	123	20.5
Longer than 2 hours	150	25.0
Not Sure	62	10.3
Total	600	100.0

Q9.Which of the following options best represents your overall satisfaction with service reliability over the last few years?	N	Percent
Very Satisfied	245	40.8
Somewhat Satisfied	188	31.3
Neither Satisfied nor Dissatisfied	61	10.2
Somewhat Dissatisfied	70	11.7
Very Dissatisfied	22	3.7
Not Sure	14	2.3
Total	600	100.0

Q10.When power outages do occur, which aspect of them has been most inconvenient for you?	N	Percent
How long the outages have lasted	289	48.2
How often the outages have occurred	114	19.0
Not Sure	91	15.2
Impact it has on my electronics / computers	46	7.7
None / no inconveniences	24	4.0
Both how often & how long	17	2.8
Getting information from Elexicon / contact with (duration, restoration, etc.)	12	2.0
Timing / when they occur	7	1.2
Total	600	100.0

Q11.When there is a power outage, how do you interact with Elexicon Energy?		
	N	Percent
I check the outage map online	229	38.2
I do not take any steps	171	28.5
I phone the outage number posted on the website	126	21.0
I check Twitter	36	6.0
Telephone call	22	3.7
Unsure	9	1.5
No experience	5	.8
Radio	2	.3
Total	600	100.0

Q12.Please indicate your level of interest in the following potential service offering: When an outage occurs, are you interested in receiving notifications sent to your phone (via text and/or voice to landline) about its cause and anticipated restoration time?		
	N	Percent
Yes	524	87.3
No	58	9.7
Not Sure	18	3.0
Total	600	100.0

Q13.To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?		
	N	Percent
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases	226	37.7
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term	219	36.5
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term	72	12.0
Not Sure	60	10.0
Maintain reliability & do not raise prices	15	2.5
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others	8	1.3
Total	600	100.0

Q14 Which of the following options best describes your views on this trade-off?		
	N	Percent
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	507	84.5
Not Sure	41	6.8
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	30	5.0
Maintenance on a schedule & no rate increases	22	3.7
Total	600	100.0

Q15. Please select two potential objectives from the following list that you think Elexicon should focus its efforts on in addition to keeping the system safe and accommodating new growth in the coming years.

Q15. FIRST CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	192	32.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	133	22.2
Investing now in things that will help reduce rate increases after 2029	73	12.2
Helping customers manage their electricity use	65	10.8
Reducing the environmental impact of Elexicon's operations	63	10.5
Minimizing the impact of power outages	37	6.2
Improving power quality	24	4.0
Addressing customer requests faster and more efficiently	13	2.2
Total	600	100.0

Q15. SECOND CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	182	30.3
Minimizing the impact of power outages	121	20.2
Investing now in things that will help reduce rate increases after 2029	120	20.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	69	11.5
Helping customers manage their electricity use	51	8.5
Reducing the environmental impact of Elexicon's operations	30	5.0
Improving power quality	20	3.3
Addressing customer requests faster and more efficiently	7	1.2
Total	600	100.0

Q16.Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of Its power grid. Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?

	N	Percent
I am satisfied with the planned allocation based on what I know	319	53.2
I would prefer to spend more on the technical upkeep of the power grid and less on the other two	95	15.8
Not Sure	84	14.0
I would prefer to spend more on reliability and less on the other two	65	10.8
I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	37	6.2
Total	600	100.0

Q17.Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?

	N	Percent
Highly Supportive	243	40.5
Somewhat Supportive	215	35.8
Neither Supportive nor Unsupportive	66	11.0
Somewhat Unsupportive	25	4.2
Highly Unsupportive	26	4.3
Not Sure	25	4.2
Total	600	100.0

Q18. To the best of your knowledge, does your place of residence / business currently receive power via a rear-lot line?		
	N	Percent
Yes	79	13.2
No	505	84.2
Not Sure	16	2.7
Total	600	100.0

Q19. Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?		
	N	Percent
Maintain the status quo – keep all the lines overhead in the rear lots, replacing them as they fail.	131	21.8
Move lines underground and plan work according to worst performing areas.	144	24.0
Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere.	234	39.0
Not Sure	91	15.2
Total	600	100.0

Q20.To what degree do you consider the level of proposed investments in the Transformer Station appropriate?		
	N	Percent
Very Appropriate	189	31.5
Somewhat Appropriate	247	41.2
Not Very Appropriate	62	10.3
Not Sure / Cannot Rate	102	17.0
Total	600	100.0

Q21.Do you have any thoughts you'd like to share with respect to this project?		
	N	Percent
Unsure / none	484	80.7
If it is necessary / if needed / get it done	50	8.3
Developers should be covering a higher portion of the cost	18	3.0
Customers affected should pay	16	2.7
Against the proposed project all together	6	1.0
Do not increase rates	6	1.0
Better cost-efficient solutions are needed	6	1.0
Do not want to pay for other communities	4	.7
More renewable energy sources such as solar or wind	3	.5
Should focus on conservation	3	.5
Apply new rates for new customers	2	.3
Too costly	2	.3
Total	600	100.0

Q22.To what degree do you consider the level of proposed investments in the Operations Centre appropriate?		
	N	Percent
Somewhat Appropriate	228	38.0
Very Appropriate	215	35.8
Not Very Appropriate	59	9.8
Not Sure / Cannot Rate	98	16.3
Total	600	100.0

Q23.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	525	87.5
It is a required investment / reasonable / needed	21	3.5
Customers / communities affected should pay	17	2.8
Lack of information to make an informed decision	9	1.5
Refurbish an existing building	9	1.5
Customers should not have to pay	6	1.0
Against project all together	4	.7
Lease / rent building	4	.7
Build it smart / keep future growth in mind	3	.5
Business / developers should pay	2	.3
Total	600	100.0

Q24.To what degree do you consider the level of proposed investments in the Underground System Relocation appropriate?		
	N	Percent
Very Appropriate	206	34.3
Somewhat Appropriate	177	29.5
Not Very Appropriate	113	18.8
Not Sure / Cannot Rate	104	17.3
Total	600	100.0

Q25.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	456	76.0
Customers / residents / communities affected should pay	30	5.0
Should be a priority	22	3.7
Project should be covered by taxpayers	15	2.5
Costs should be covered by transit users	14	2.3
Need more information / unclear	10	1.7
Project should be completed as efficiently and quickly as possible	9	1.5
Will improve reliability	8	1.3
Project not a priority	8	1.3
Municipality should pay	7	1.2
Transit is important / needed for growth	6	1.0
Should be paid for by investors	5	.8
Poor planning	4	.7
Will raise rates	3	.5
Disagree with project	3	.5
Total	600	100.0

Q26.What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting with the best interest of their customers in mind?		
	N	Percent
Why Elexicon could not build these projects without seeking rate increases	234	39.0
Not Sure	137	22.8
Why the chosen design and size are optimal	94	15.7
Why the projects cannot be built for less	86	14.3
Why the projects cannot be reasonably delayed	36	6.0
Why these projects could not be built in other areas	13	2.2
Total	600	100.0

Q27.We're almost done – we have only a few more questions to ask you. As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?			
		N	Percent
	Completely Agree	151	25.2
	Somewhat Agree	227	37.8
	Neither Agree nor Disagree	129	21.5
	Somewhat Disagree	34	5.7
	Completely Disagree	28	4.7
	Not Sure	31	5.2
	Total	600	100.0

Q28. To help Elexicon improve on customer engagement in the future, please identify your preferred ways for being consulted in the future on similar topics.

MULTIPLES RESPONSES ACCEPTED		Responses		Percent of Cases
		N	Percent	
	Online Surveys	121	17.6%	20.2%
	Phone Surveys	9	1.3%	1.5%
	In-Person Focus Groups	10	1.5%	1.7%
	In-Person Townhall Meetings	40	5.8%	6.7%
	Live Online Presentations and Q&A Sessions	195	28.3%	32.5%
	Mail	7	1.0%	1.2%
	Newspaper	5	0.7%	0.8%
	Bill inserts	82	11.9%	13.7%
	Email	132	19.2%	22.0%
	Unsure	87	12.6%	14.5%
Total		688	100.0%	114.7%

Q29.How often should Elexicon engage its customers on matters such as those captured in this survey?			
		N	Percent
	Once Every 5 Years	24	4.0
	Once Every 2-3 Years	184	30.7
	Once a Year	304	50.7
	More Than Once a Year	55	9.2
	Not Sure	33	5.5
	Total	600	100.0

Q30.Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?		
	N	Percent
Unsure / none	467	77.8
Lower rates	51	8.5
Limit increases to most needed projects	18	3.0
Promote Green Energy	12	2.0
Do most needed first	10	1.7
Upgrades too costly	8	1.3
Improve customer service	6	1.0
Energy savings advice	5	.8
More outreach needed	5	.8
Amount and length of outages too high	3	.5
Communities should cover costs	3	.5
Support upgrades	3	.5
Upgrades should not impact customers	3	.5
Support Electric vehicles	2	.3
Removal of overhead wires	2	.3
The projects should have been planned	1	.2
We should not pay for new developments	1	.2
Total	600	100.0

APPENDIX C: Regional Planning Documents

GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

hydro one

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan (“RIP”) report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

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

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EXECUTIVE SUMMARY

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

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

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

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

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

Table of Contents

List of Figures

List of Tables

1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

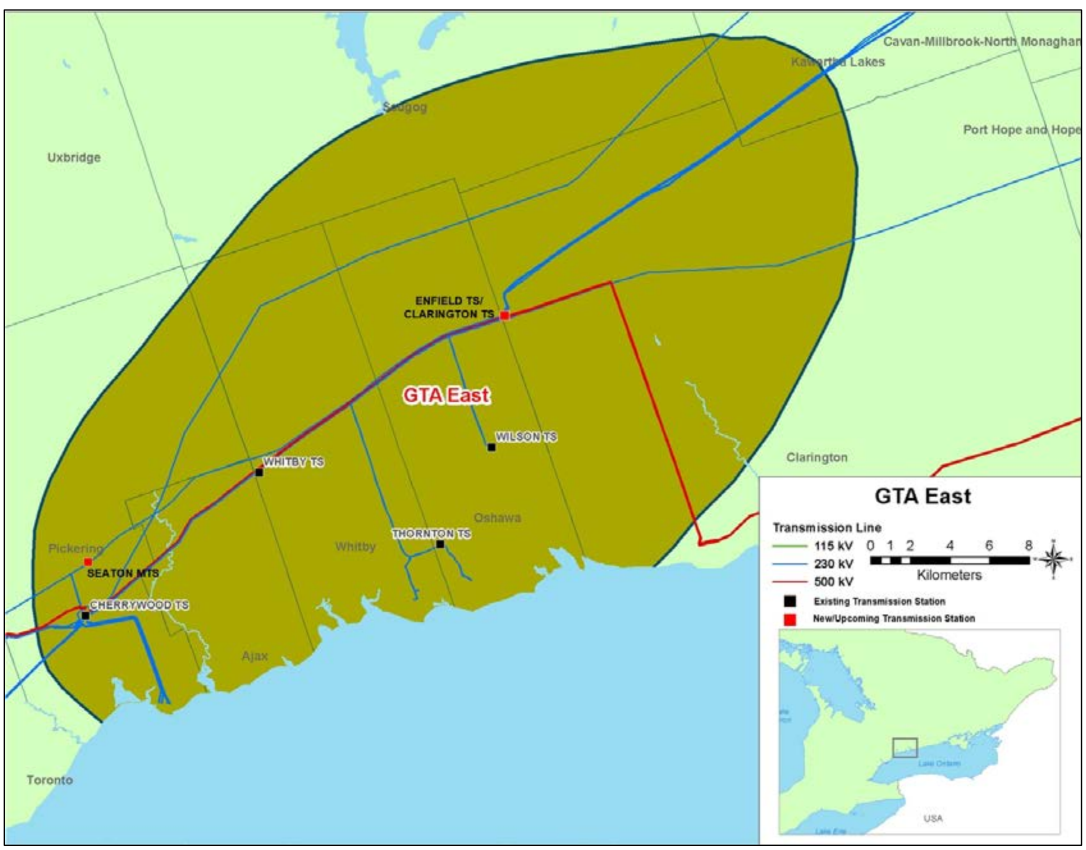

Figure 1-1: GTA East Region

1.1 Objective and Scope

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

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

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

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

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

[1] Also referred to as Needs Screening

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

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

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

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

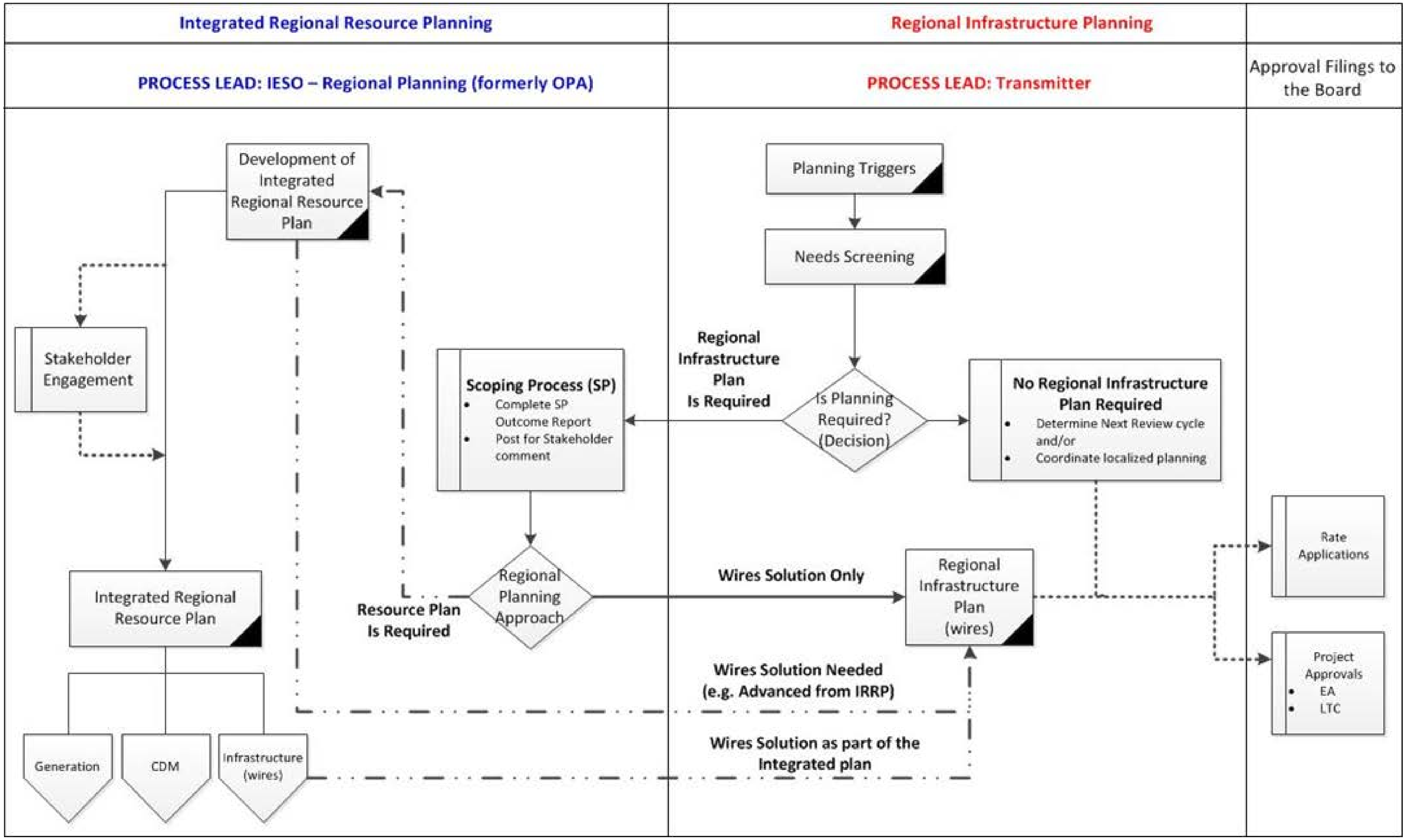

Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

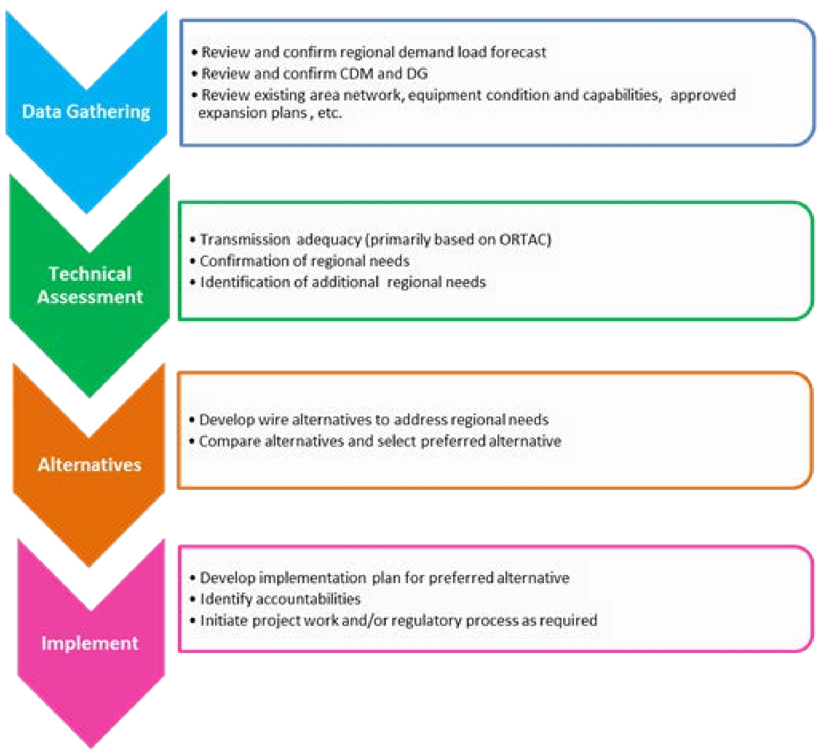

Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

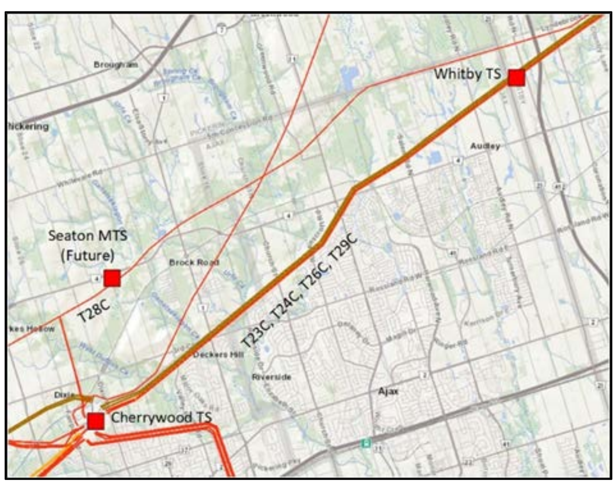

Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.

Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

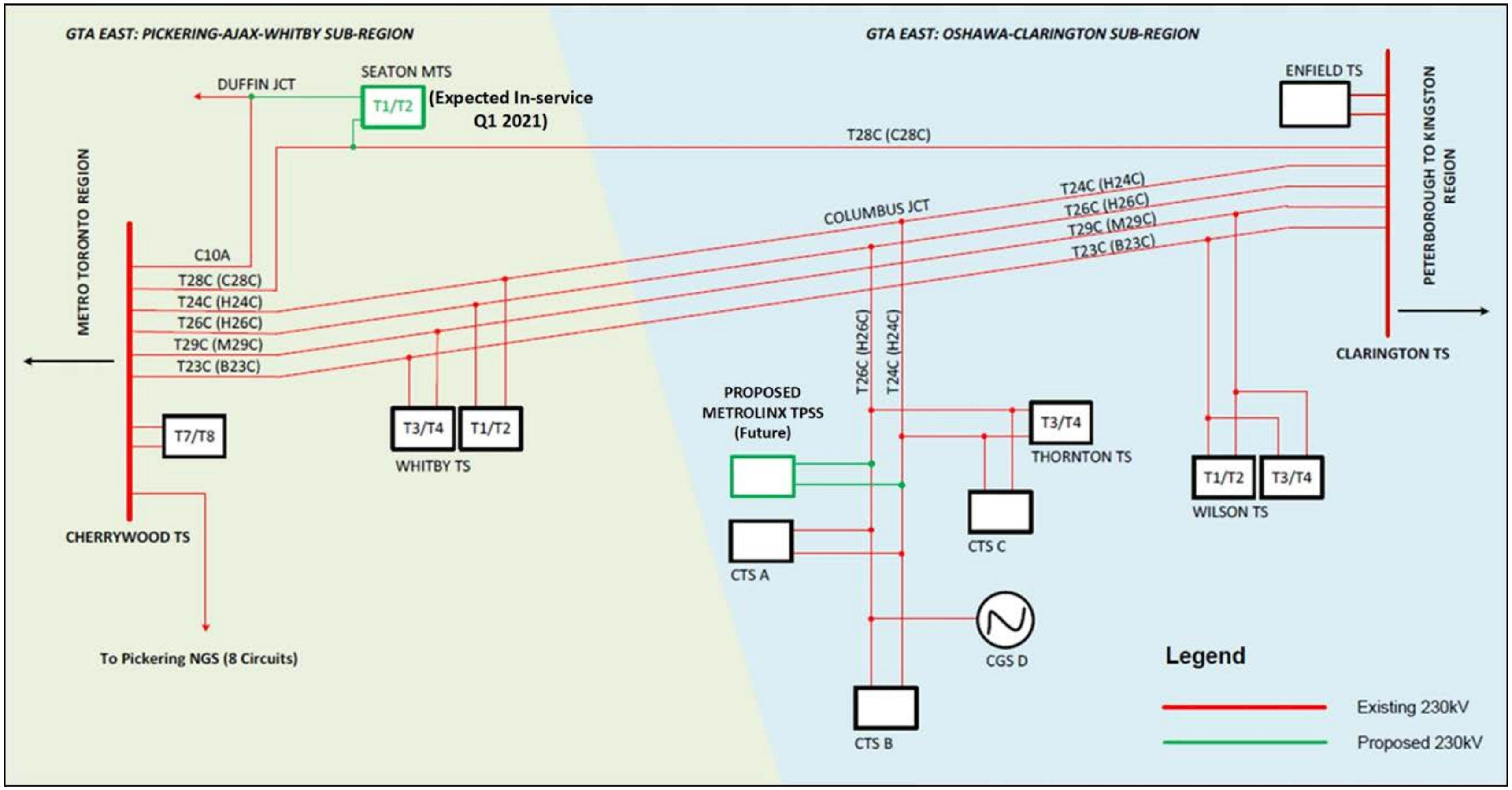

Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.
- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.
- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.
- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.
- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

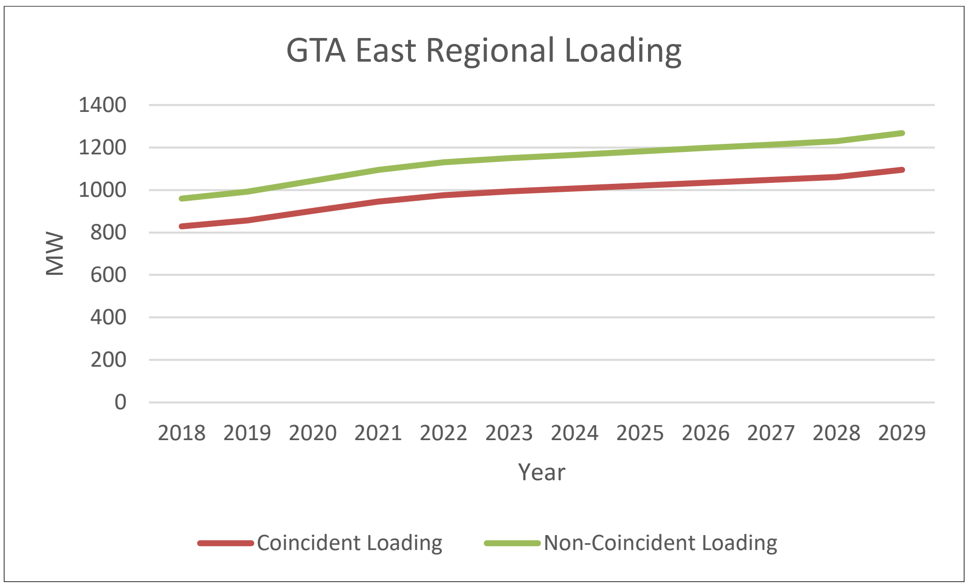

Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

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

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

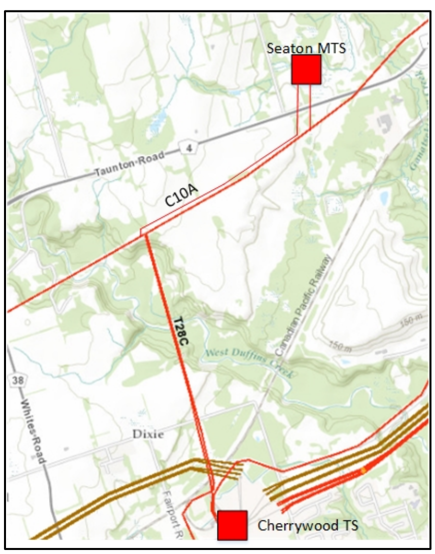

Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

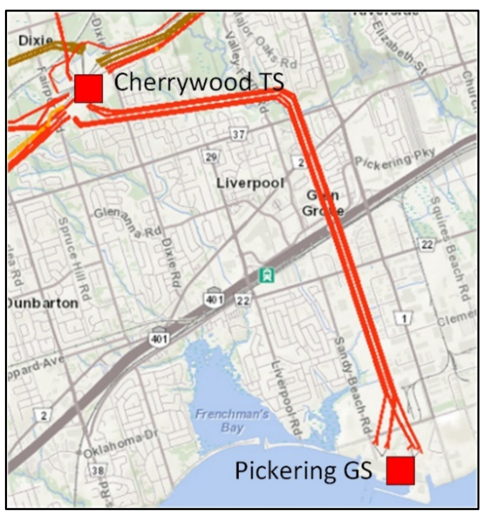

Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

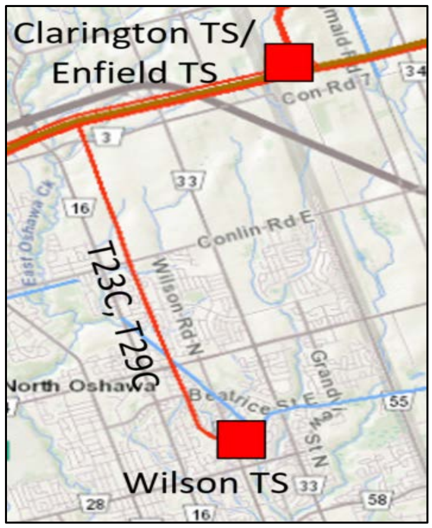

Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only “right sizing” option.

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One’s obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Wilson TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

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

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

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, “Needs Assessment Report, GTA East Region”, 15 August 2019
[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[4]. Needs Assessment Report GTA East – August 2014

[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	**Voltage Level**	**Supply Circuits**
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	**Station Name**	**Connection Type**
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
GATR	Guelph Area Transmission Reinforcement
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
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
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

GTA North

REGIONAL INFRASTRUCTURE PLAN

October 22, 2020

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Prepared by:

Hydro One Networks Inc. (Lead Transmitter)

With support from:

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

DISCLAIMER

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

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

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EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

The Study Team recommends that:

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

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

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

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

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

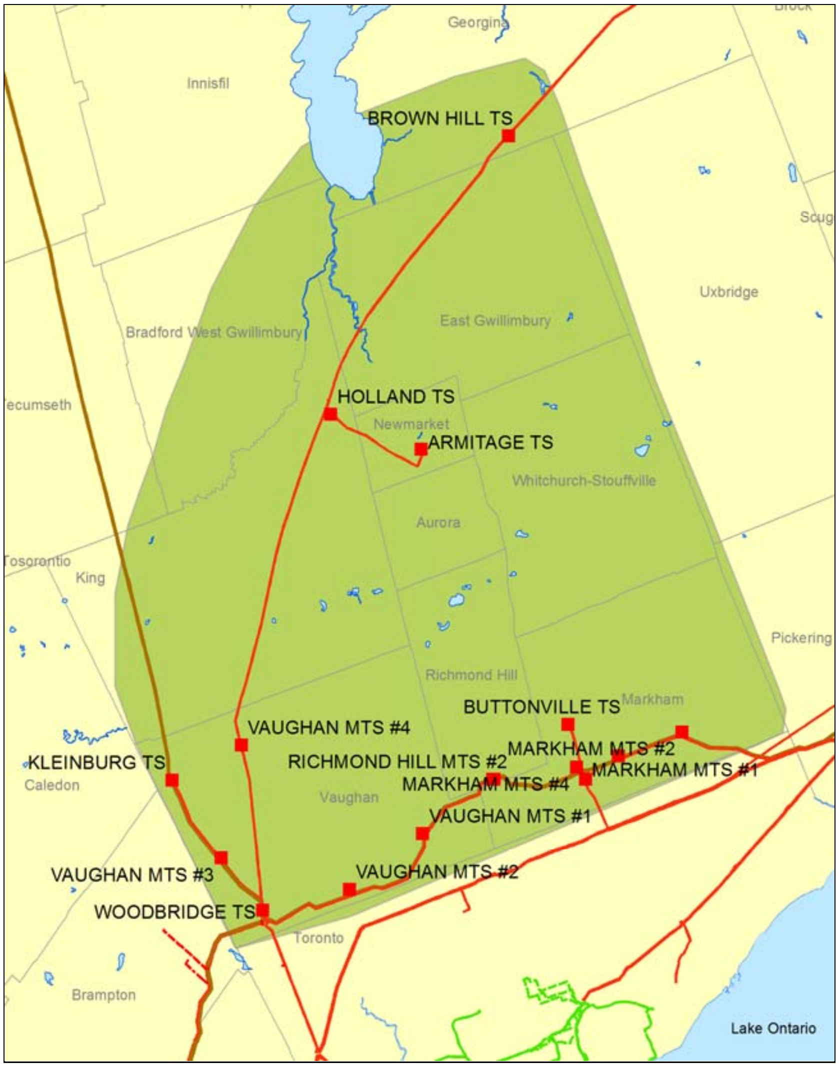


Figure 1-1: GTA North Region Map

1.1 Objectives and Scope

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

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

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

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

[1] Also referred to as Needs Screening

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

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

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

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

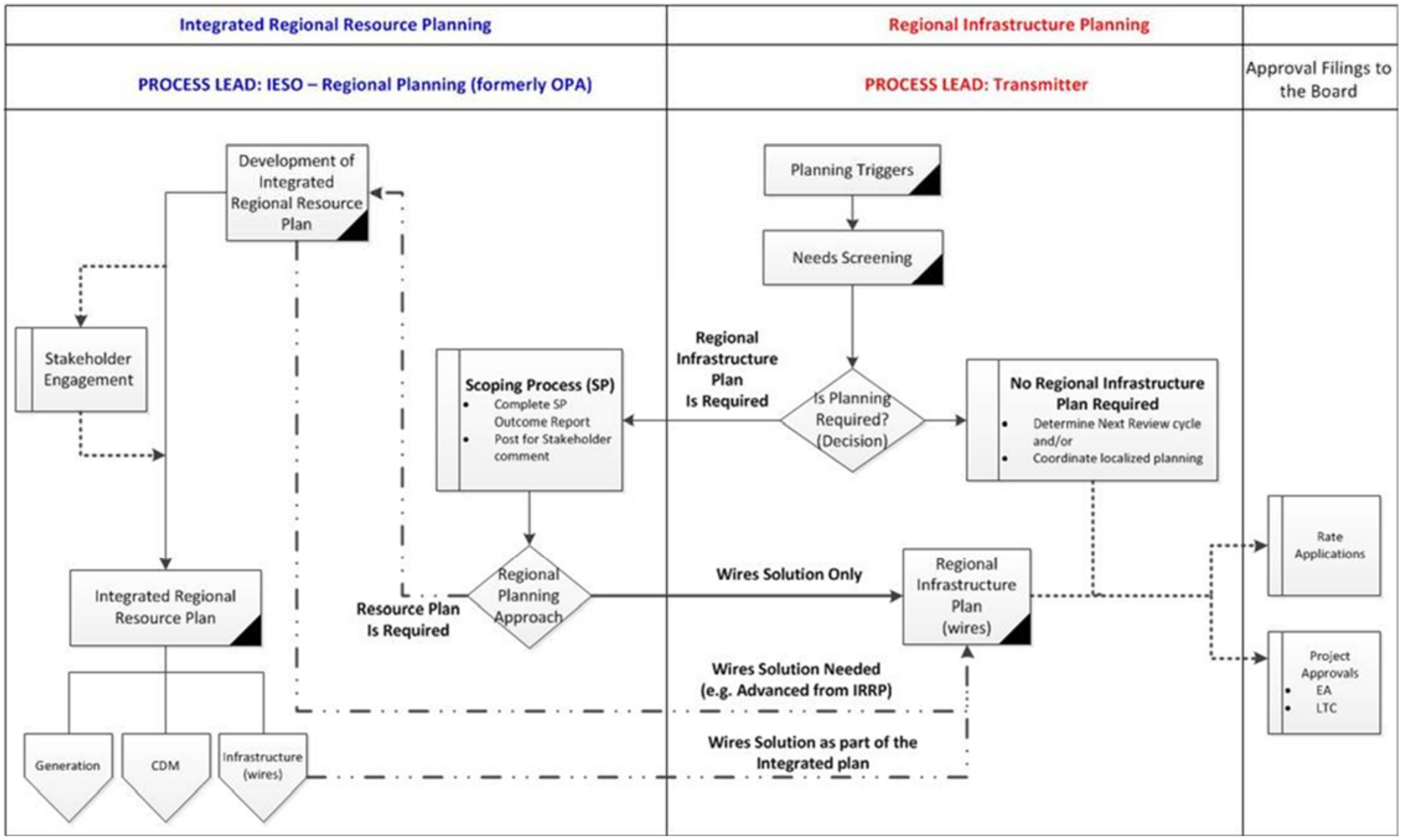


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

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

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

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

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

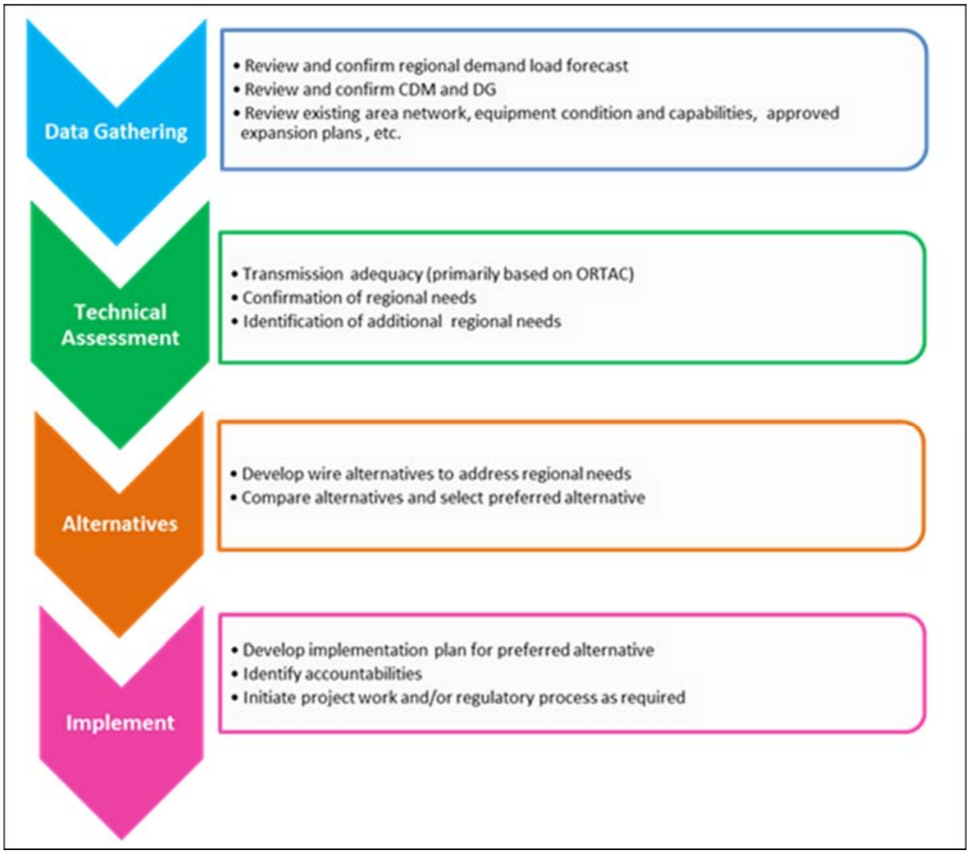


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

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

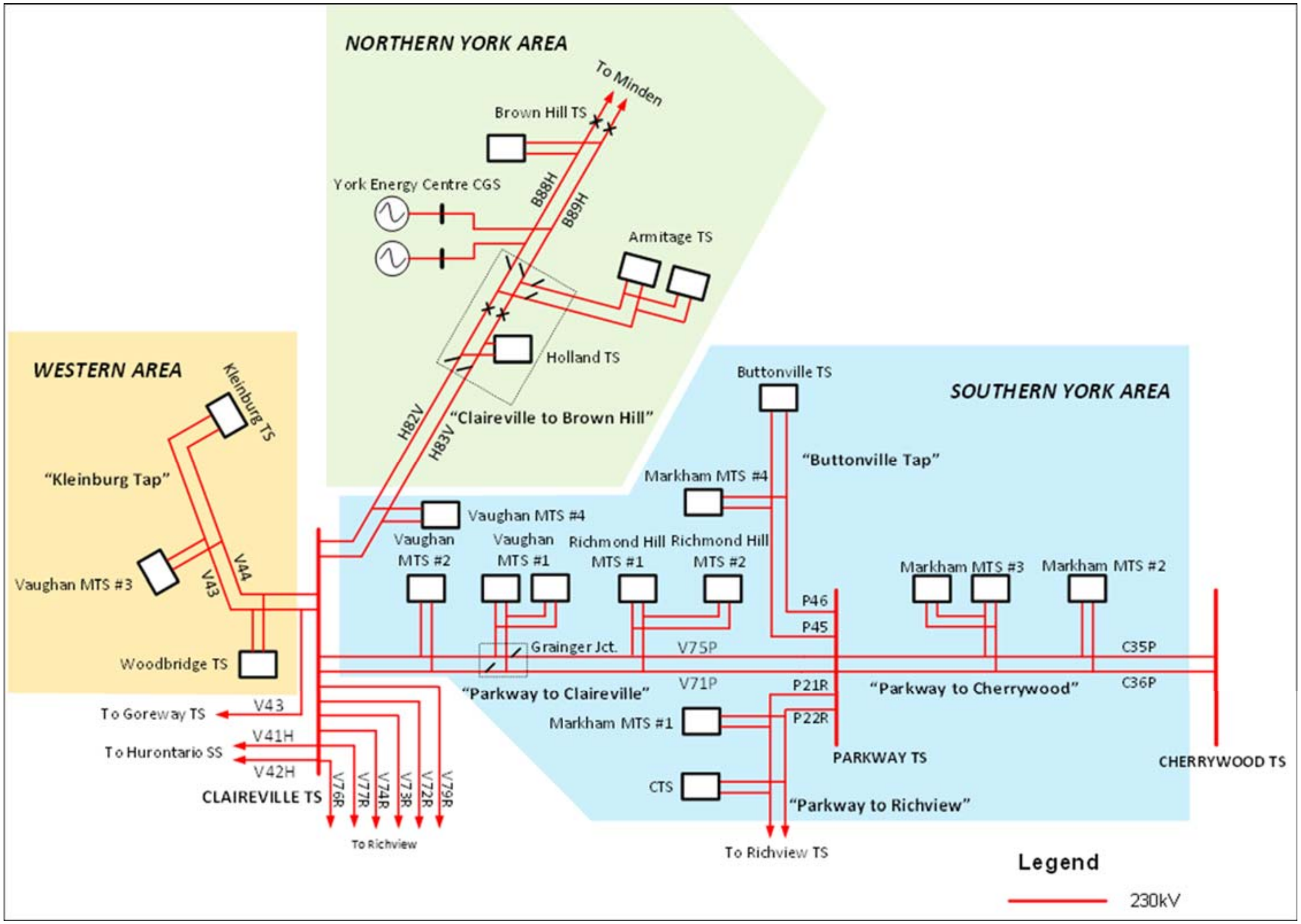
Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the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

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

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

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

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



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

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

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

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

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

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

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

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

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

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

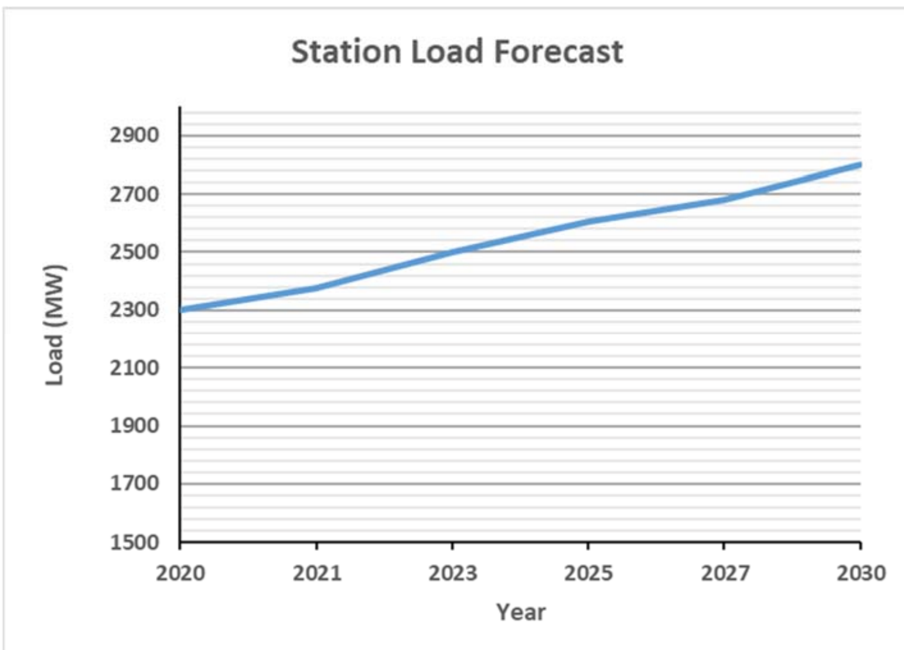


Figure 5-1: GTA North Region Load Forecast

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

5.2 Study Assumptions

The following other assumptions are made in this report.

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

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

6 ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

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

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

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

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

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

6.1 Adequacy of Northern and Southern York Area Facilities

6.1.1 500 and 230 kV Transmission Facilities

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

Southern York Area:

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

Northern York Area:

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

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

6.1.2 Step down Transformer Station Facilities

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

Table 6-1 Step-Down Transformer Stations

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

*Stations owned by Alectra

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

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

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

6.2 Adequacy of Western Area Facilities

6.2.1 230 kV Transmission Facilities

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

6.2.2 Step down Transformation Facilities

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

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

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by Alectra

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

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

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

6.3 Other Needs Identified During Regional Planning

6.3.1 Load Restoration in the Western Area

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

6.3.2 Load Restoration in the Northern York Area

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

6.3.3 Load Security and Restoration in the Southern York Area

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

6.3.4 High Voltages on Circuits M80B/ M81B

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

6.3.5 End of Life of Woodbridge TS- Transformer-T5

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

6.4 Longer Term Regional Needs (2030-2040)

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

Table 6-5: Longer Term Adequacy of Transmission Facilities

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

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

7 REGIONAL NEEDS AND PLANS

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

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

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

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

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

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

7.1 Woodbridge TS: T5 End-of-Life Transformers

7.1.1 Description

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

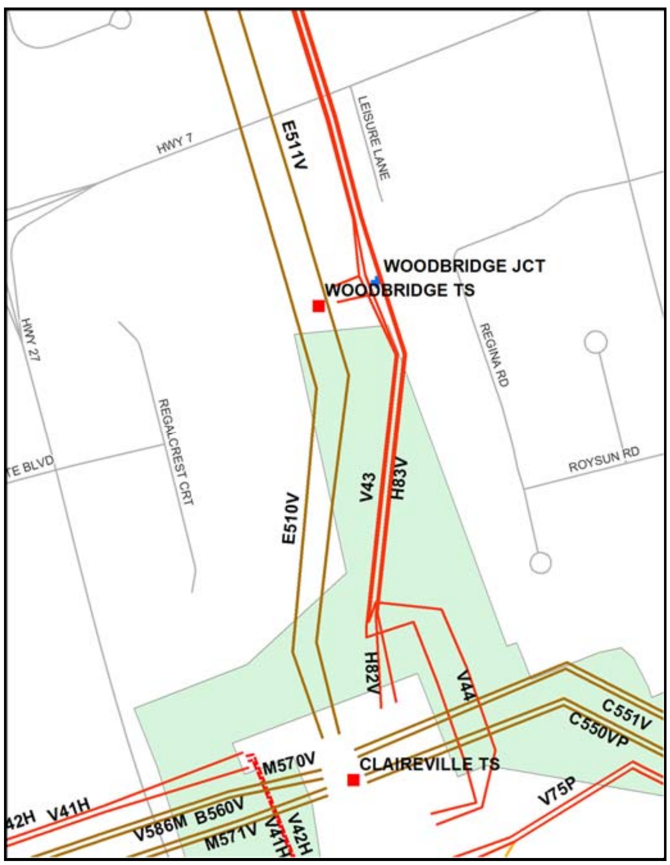


Figure 7-1: Woodbridge TS

7.1.2 Alternatives and Recommendation

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

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

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

7.2 Station Supply Capacity Needs and Plans

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

7.2.1 Markham MTS #5 Transformer Station

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

7.2.1.1 Alternatives and Recommendation

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

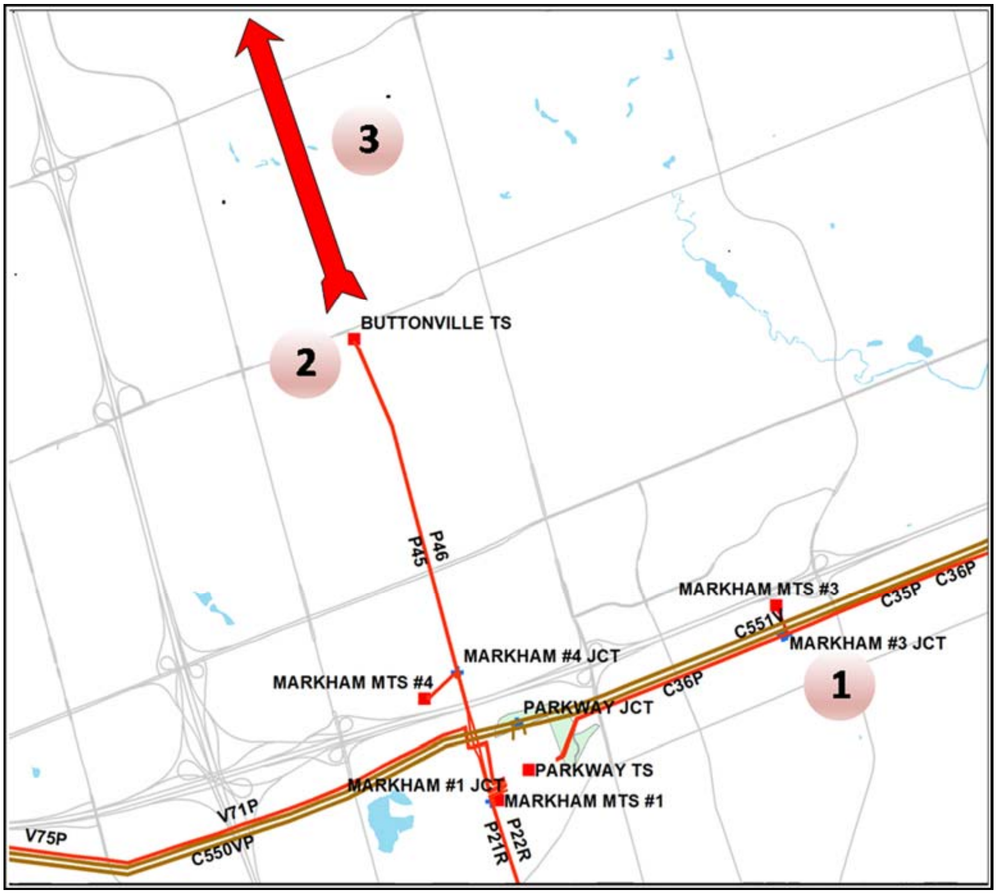


Figure 7-2: Location options for Markham #5 MTS

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

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

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

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

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

7.2.2 Northern York Area Transformer Station

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

Table 7-3: Northern York Area Peak Loading

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

7.2.2.1 Alternatives and Recommendation

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

7.2.3 Vaughan Area Transformer Station

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

7.2.3.1 Alternatives and Recommendation

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

7.3 System Capacity Needs and Plans

The Study Team has identified the following system capacity needs

7.3.1 Transmission Line uprate- P45/P46

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

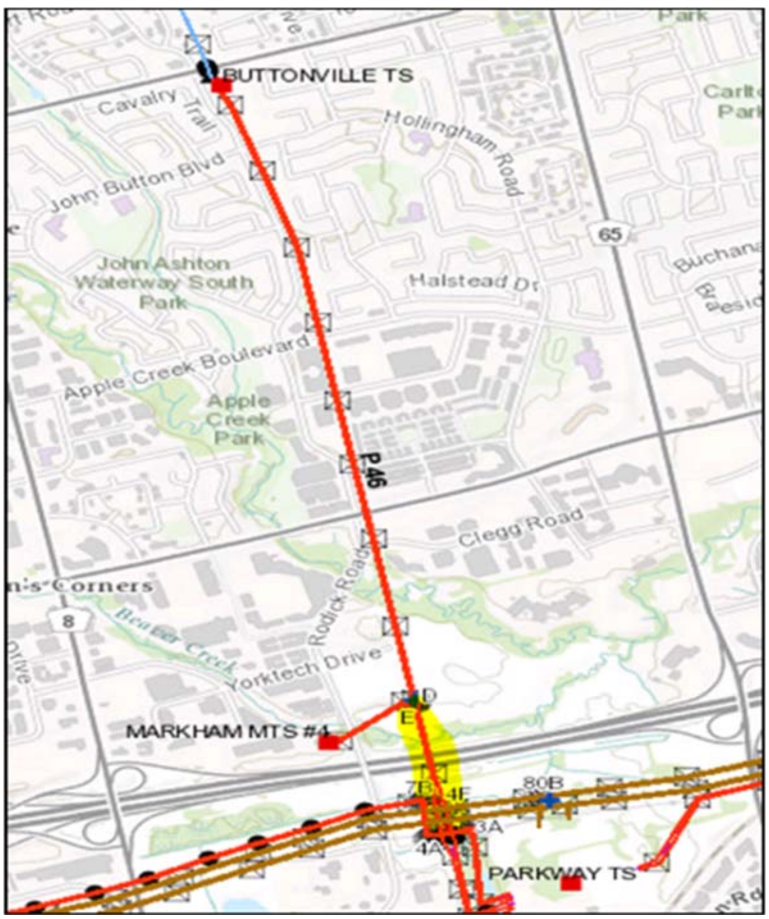


Figure 7-3: Buttonville Tap P45/P46 Limiting Section

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

Table 7-4: Loading on Buttonville Tap Circuits

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

7.3.1.1 Alternatives and Recommendation

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

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

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

7.3.2 High Voltages on M80B/M81B

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

7.3.2.1 Alternatives and Recommendations

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

1- **Alternative 1 – Switch LV caps manually at Beaverton and Lindsay:** The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage (i.e. 262.5 kV) for up to 30 minutes. This capability provides sufficient time for operators to manually adjust the system. Under this alternative the operator will remotely switch out capacitor banks at Beaverton and Lindsay to mitigate high voltages when required.

2- **Alternative 2 - Expanding the York Region Special Protection Scheme (SPS):** The problem of overvoltage can be mitigated by modifying the York Region SPS to automatically remove capacitor banks at Lindsey TS and/or Beaverton TS under high load conditions following specific contingencies.

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

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

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

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

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

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

Thermal Limitations

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

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

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

Voltage Limitations

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

7.3.3.1 Alternatives and Recommendations

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

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

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

7.4 Load Restoration

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

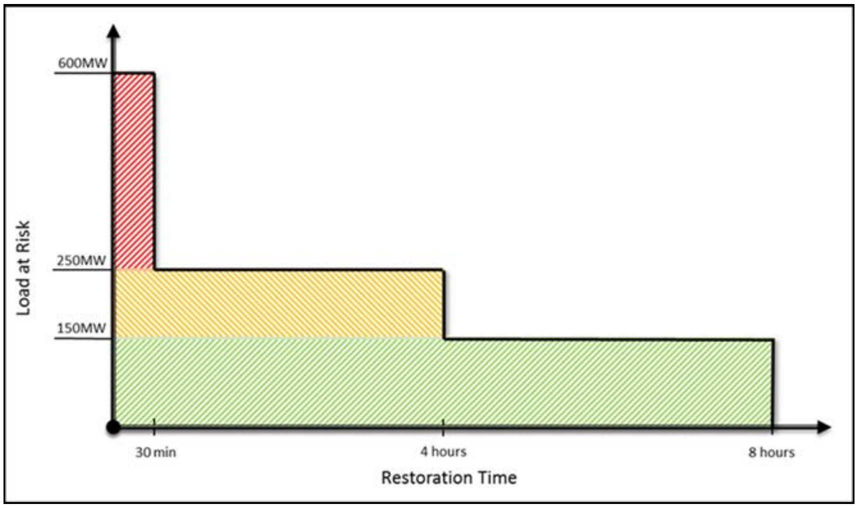


Figure 7-4: Load Restoration Criteria as per ORTAC

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

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

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

Table 7-6: Load Restoration on Kleinburg Radial Tap

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

7.4.1.1 Alternatives and Recommendations

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

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

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

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

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

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

7.4.2.1 Alternatives and Recommendations

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

7.5 Improve Load Security on the Parkway to Claireville Line

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

7.5.1 Alternatives and Recommendations

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

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

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

8 CONCLUSIONS AND NEXT STEPS

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

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

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

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

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

The Study Team recommends that:

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

9 REFERENCES

[1] GTA North Regional Infrastructure Plan – February 2016

[2] GTA North Needs Assessment – March 2018

[3] York Region Scoping Assessment Outcome Report - 2018

[4] Integrated Regional Resource Plan (IRRP) - February, 2020

[5] Integrated Regional Resource Plan (IRRP) - Appendices - March, 2020

[6] IESO Ontario Resource Transmission Assessment Criteria (ORTAC)

10 APPENDIX A. STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
Kleinburg TS T1/T2 44	230/44	V44/V43
Vaughan MTS #3 T1/T2	230/27.6	V44/V43
Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
Woodbridge TS T3/T5 44	230/44	V44/V43
Armitage TS T1/T2	230/44	B88H/B89H
Armitage TS T3/T4	230/44	B88H/B89H
Brown Hill TS T1/T2	230/44	B88H/B89H
Holland TS T1/T2, T3/T4	230/44	H82V/H83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Markham MTS #2 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T3/T4	230/27.6	C35P/C36P
Markham MTS #4 T1/T2	230/27.6	P45/P46
CTS	230/13.8	P21R/P22R
Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V

11 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

12 APPENDIX C. DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Armitage TS	Tx/Dx
	Buttonville TS	Tx
	Holland TS	Dx
	Kleinburg TS	Tx
	Markham MTS #1	Tx
	Markham MTS #2	Tx
	Markham MTS #3	Tx
	Markham MTS #4	Tx
	Richmond Hill MTS #1	Tx
	Richmond Hill MTS #2	Tx
	Vaughan MTS #1	Tx
	Vaughan MTS #2	Tx
	Vaughan MTS #3	Tx
	Vaughan MTS #4	Tx
	Woodbridge TS	Tx/Dx
Distributor Name	**Station Name**	**Connection Type**
Newmarket-Tay Power Distribution Ltd	Armitage TS	Tx/Dx
	Holland TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Hydro One Distribution	Armitage TS	Tx
	Brown Hill TS	Tx
	Holland TS	Tx
	Kleinburg TS	Tx
	Woodbridge TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Toronto Hydro Electric System Limited	Woodbridge TS	Dx

13 APPENDIX D. GTA NORTH REGION LOAD FORECAST

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Armitage	317	302	307	312	312	312	312	312
Brown Hill	184	94	95	95	96	97	98	100
Northern York Area	153	0	0	0	0	12	32	62
B88H/B89H Total		396	402	407	408	421	442	474
Holland	168	142	145	154	166	168	168	168
H82V/H83V Total	168	142	145	154	166	168	168	168
Northern York Area Sub-Total		**538**	**547**	**561**	**574**	**589**	**610**	**642**
Markham #2	101	101	101	101	101	101	101	101
Markham #3	202	202	202	202	202	202	202	202
C35P/C36P Total		303	303	303	303	303	303	303
Markham #1	81	81	81	81	81	81	81	81
P21R/P22R Total		81	81	81	81	81	81	81
Buttonville	166	148	148	147	156	156	156	154
Markham #4	153	99	128	153	153	153	153	153
Markham #5	153	0	0	0	26	77	153	153
P45/P46 Total		247	276	300	335	386	462	460
Richmond Hill	254	246	246	245	250	254	254	254
Vaughan #1	306	265	275	300	306	306	306	306
Vaughan #2	153	142	151	153	153	153	153	153
V71P/V75P Total		653	672	698	709	713	713	713
Vaughan #4	153	54	63	108	153	153	153	153
Vaughan #5	153	0	0	0	0	0	2	147
H82V/H83V Total		54	63	108	153	153	155	300
Southern York Area Sub-Total		**1338**	**1395**	**1490**	**1581**	**1636**	**1714**	**1857**

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Kleinburg	196	144	145	146	147	148	169	170
Vaughan #3	153	132	141	153	153	153	153	153
Woodbridge	160	149	149	150	150	153	154	153
V43/V44 Total		425	435	449	450	454	476	476
Western Area Sub-Total		**425**	**435**	**449**	**450**	**454**	**476**	**476**
GTA North Region Total		**2301**	**2377**	**2500**	**2605**	**2679**	**2800**	**2975**

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NEEDS ASSESSMENT REPORT

Peterborough to Kingston Region

Date: February 10, 2020

Prepared by: Peterborough to Kingston Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase 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 Study Team for this region.

The Study Team 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: December 09, 2019 **END DATE:** February 10, 2020

1. INTRODUCTION

The first cycle of the Regional Planning process for the Peterborough to Kingston (PtoK) Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting from Needs Assessment ("NA"). The purpose of this NA is a) to identify any new needs and/or to reaffirm needs identified in the previous PtoK Regional Planning cycle and b) recommend which need may be a) addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for PtoK Region.

3. SCOPE OF NEEDS ASSESSMENT

The assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region: and
- Develop options for need(s) and/or a preferred plan or recommend which needs require further assessment/regional coordination.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

As per the PPWG Regional Planning Report to the Board (May 2013), the planning horizons of regional facilities are typically considered over the 1-20 years; however, in most situations focus is over the 1 – 10 years.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

In addition, community energy plans in the region have also been scanned and reviewed (Section 9 for references). Federal and Provincial agencies either operate and/or subsidize facilities, such as Canadian Forces Bases, Corrections Institutions and Post-Secondary Institutions in the region and similarly, municipal agencies operate many facilities in the study region; water, wastewater and recreation arenas to name a few. All these agencies are contemplating to reduce Green House Gas (GHG) emissions and to achieve carbon neutrality by no later than 2050 through renewable resources, energy efficiency and/or electrification of heating and transportation. At this time, there is insufficient data available for input into the load forecast for this Needs Assessment study however, the Study Team should monitor the evolving climate action plans of federal, provincial and municipal agencies as they are expected to lead climate action over the next five years.

5. ASSESSMENT METHODOLOGY

The assessment methodology include review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its life.

6. NEEDS

I. Update on plan implementation of identified needs from previous cycle

a. The load supplied by Gardiner TS DESN 1 T1/T2 exceeded its summer 10 day Limited Time Rating (LTR) of 125 MW. As recommended in the previous NA, Hydro One Distribution has completed the transfer of load from DESN 1 to lightly loaded DESN 2 with excess capacity resulting in a load relief for Gardiner TS DESN 1.

II. Newly identified needs in the region

a. Line / Station Capacity

i. The 2018 summer peak loading on Frontenac TS was 113 MW, which is above its 10 day summer LTR of 111 MW. Based on the submitted load forecast, the Frontenac TS will be loaded more than 125 MW by year 2028. Load relief is required at the Frontenac TS in the near term.

ii. As per submitted load forecast, the loading on Gardiner TS DESN 1 will be exceeded by its 10 day summer LTR of 125 MW by year 2025. However the combined capacity of Gardiner TS DESN 1 and DESN 2 is 209 MW and total current load is 154 MW.

iii. The 2018 summer peak loading on Belleville TS is 159 MW, which is close to its 10 day summer LTR of 161 MW. In addition to normal load growth in the area, Elexicon Energy Inc. has recently received approximately 30 MW of load connection inquiries to be connected at the Belleville TS. There is insufficient existing capacity in the area to supply these potential future connections.

b. Aging Infrastructure Transformer replacements

- **i.** Lennox TS – 230kV & 500kV Breaker Replacements (2020)
- **ii.** Port Hope TS: Transformer Replacement (2023)
- **iii.** Havelock TS: Transformer Replacement (2027)
- **iv.** Belleville TS: Transformer Replacement (2021)

7. RECOMMENDATIONS

The Study Team recommends the following -

a. Over loading at Frontenac TS shall be managed by Hydro One Transmission by coordinate with Hydro One Distribution and Kingston Hydro to undertake distribution load transfers between Gardiner TS and Frontenac TS over the near term.

b. An integrated regional resource planning (IRRP) and/or Regional Infrastructure Planning (RIP) process should be undertaken for the Peterborough-Kingston region to further assess the needs discussed above in section a.i), a.ii), and a.iii) as well as any addition needs identified in the area.

c. Replacement of end of life asset with similar equipment does not require further regional coordination (see further details in Section 7.1). The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs:

- i. Lennox TS: 230kV & 500kV Breaker Replacements (Bulk System)
- ii. Port Hope TS: Transformer Replacement - EOL replacement of transformers T3 / T4
- iii. Havelock TS: Transformer Replacement – EOL replacement of transformers T1 / T2
- iv. Belleville TS: Transformer Replacement - EOL replacement of transformer T2

d. IRRP and/or RIP should monitor the potential impact of Federal, Provincial and/or Municipal climate change and/or energy plans for this region.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the Peterborough to Kingston Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous PtoK regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the Peterborough to Kingston Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team 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: PtoK Region Study Team Participants

Company
Elexicon Energy Inc.
Kingston Hydro
Peterborough Distribution Inc.
Lakefront Utilities Inc.
Eastern Ontario Power Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the PtoK region, the 2nd Regional Planning cycle was triggered for the PtoK region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the PtoK region and includes:

- Review the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment (“SA”), Local Planning (“LP”), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The PtoK Region includes Frontenac County, City of Kingston, Hasting County, Northhumberland County, Peterborough County, and Prince Edward County. The boundaries of Peterborough to Kingston Region is shown below in Fig. 1.

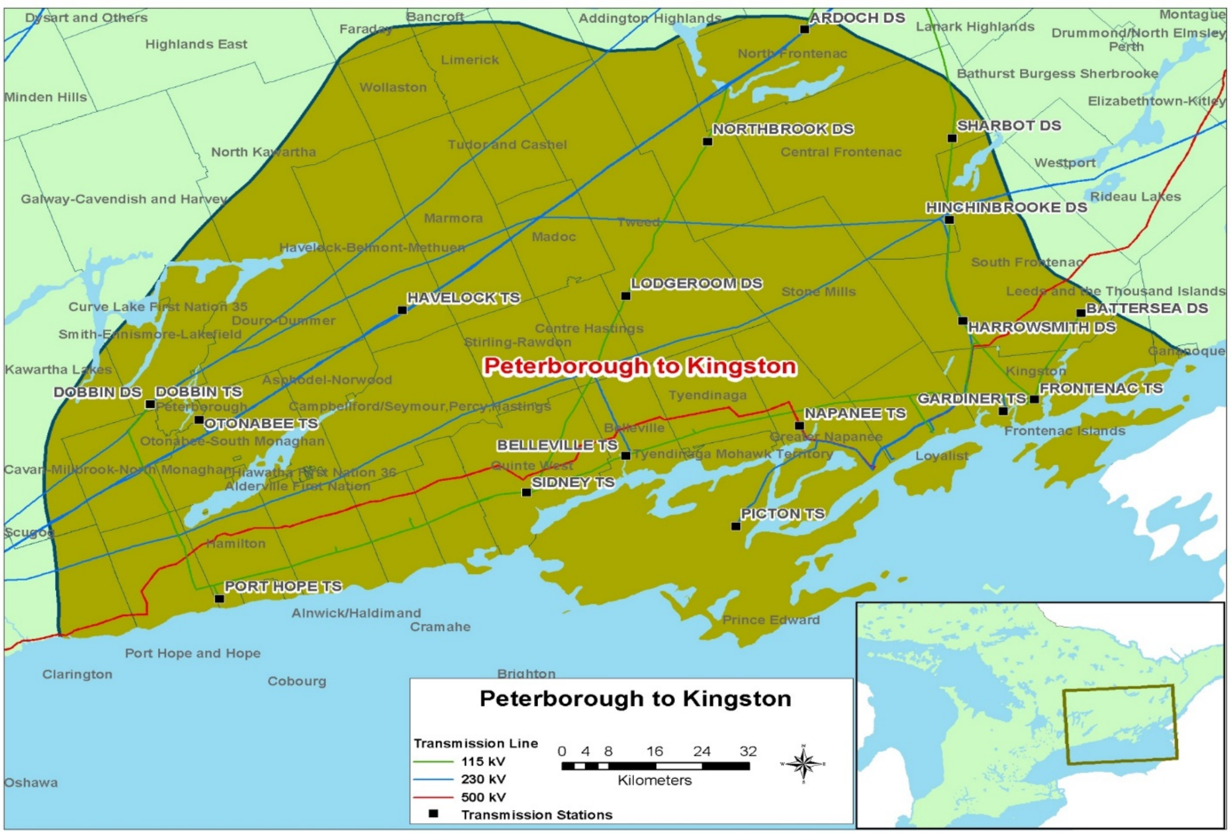

Figure 1: Geographical Area of PtoK Region with Electrical Layout

Electrical supply to the Peterborough to Kingston 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. There are ten Hydro One step-down TS’s, eight high voltage distribution stations (HVDS), and five other direct transmission connected load customers in the Region. The main generation facility in the Region is the 2000 MW Lennox Generation Station (GS) connected to Lennox TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV 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 HVDS 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 at 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 115kV circuit Q6S

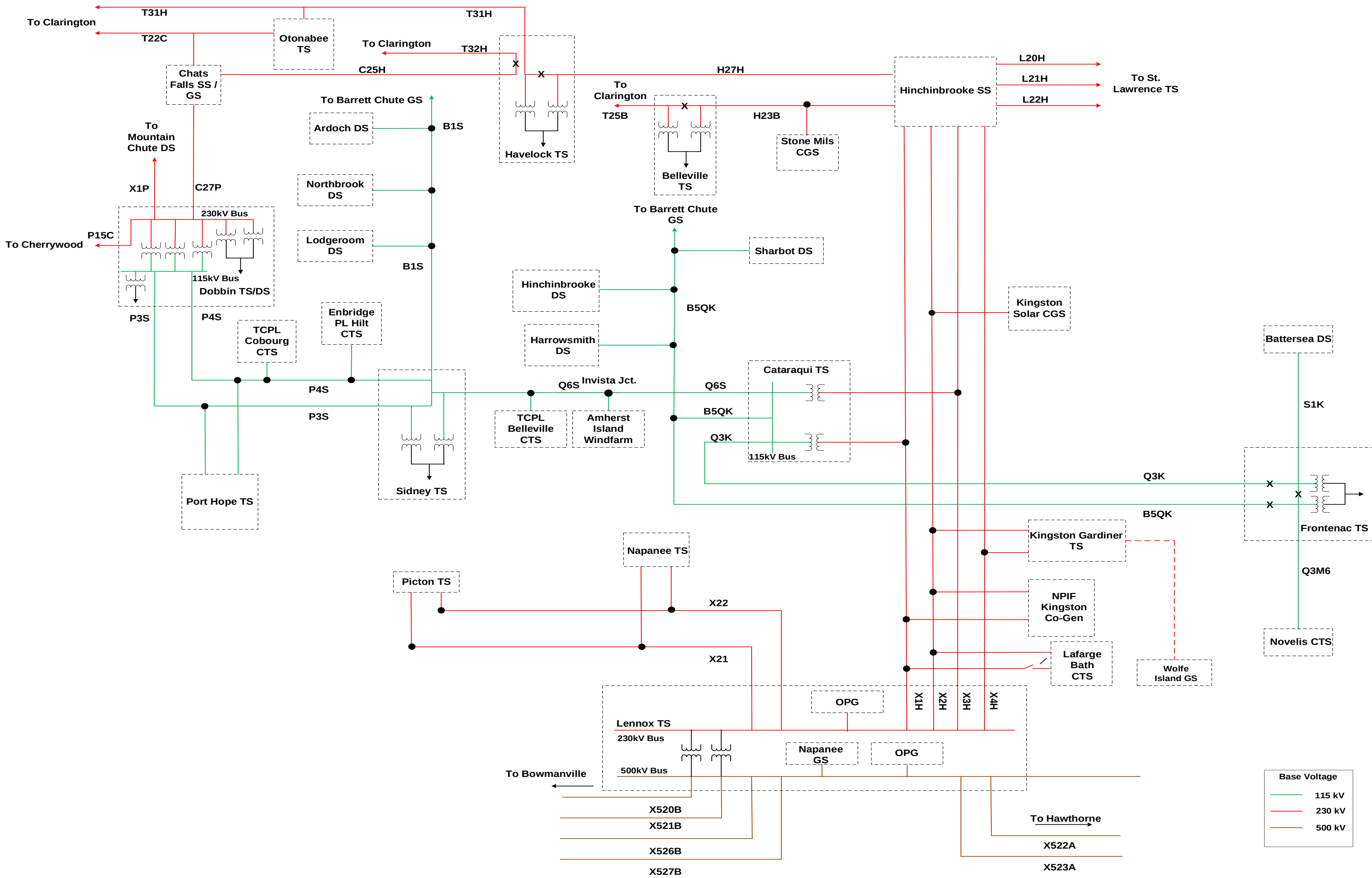

Figure 2: Single Line Diagram of Peterborough to Kingston Region

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Peterborough to Kingston Region NA. The information provided includes the following:

- Peterborough to Kingston Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life (“EOL”); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the PtoK Region.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the PtoK region for the 10 year study period. The IESO provided a Conservation and Demand Management (“CDM”) and Distributed Generation (“DG”) forecast for the PtoK region. The region’s extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer and 2018/19 winter peak extreme weather corrected loads. The extreme summer / winter weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These extreme weather corrected net summer / winter load forecast for the individual stations in the PtoK region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;

- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of life.

7 NEEDS

This section describes emerging needs identified in the Peterborough to Kingston Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle. The recent load forecast prepared for this report is higher than that of the previous cycle of regional planning. This is attributed to the load growth in Belleville, Kingston and other parts of the regions as well as lower CDM and DG targets in the region. A contingency analysis was performed for the region and no new system needs were identified.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Transformation capacity relief at Gardiner TS DESN 1.	Gardiner TS DESN 1 load exceeded its normal supply capacity. Hydro One Dx agreed to transfer load from Gardiner TS DESN 1 to Gardiner TS DESN 2.	The work completed in summer 2019.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

a. Lennox TS – 230 kV & 500 kV Breaker Replacement

This project is outside the scope of regional planning being part of part of Bulk System. A description is provided for information purpose only. Lennox Transformer Station (TS) is located in Eastern Ontario and is a major hub for 500 kV Central-East power flow that forms part of the Hydro One Bulk Power System (BPS). The station also connects 2000 MW of generation from Lennox GS on both the 500 kV and 230 kV systems. Furthermore, it also connects 900 MW of Napanee GS. The 230 kV and 500 kV switchyard at Lennox TS contain 14 X Air Blast Circuit Breakers (ABCBs) and 2 X OIL Circuit Breakers (OCBs). The existing 500kV and 230kV ABCBs are obsolete and at end of life. The age, condition and very poor performance present significant difficulties in maintaining these breakers and the associated high pressure air system.

The scope of this project is to replace the existing six (6) 500kV and eight (8) 230kV air-blast circuit breakers. In addition, 2 X 230 kV oil circuit breakers, AC/DC station service and associated protection, control and telecom facilities will be replaced to meet current standards and to fully comply with NPCC BPS requirements. The targeted in-service for the final phase is in year 2020.

b. Port Hope TS – Transformers Replacement

Port Hope Transformer Station supplies the City of Port Hope, City of Cobourg and other surrounding area via two DESN, T1/T2 & T3/T4. Each transformer is 50/83 MVA in size and step down 115 kV to 44 kV voltages. The Port Hope TS DESN 1 and DESN 2 summer 10 day LTR is 125 MW and 104 MW, respectively. The stations 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 114 MW and is forecasted to be 136 MW in the next 20 years. Transformer T3 / T4 are 61 years old and have reached their end of life. In addition, 44 kV switchyard associated with transformer T3 / T4 is also at the end of life and need to be replaced.

The scope of this project is to replace transformers T3 and T4 and associated 44 kV switchyard assets with the current standard equipment. Replacing transformer with lower size rating is not recommended as the load is increasing. Moreover, the current LTR rating of the transformers is adequate to serve the forecasted load for the next 20 years and therefore, the preferred option is to replace the transformer with the similar size transformer. The targeted in-service for this project is in year 2023.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

c. Havelock TS – Transformers Replacement

Havelock TS is located into Central East Ontario and supplies the surrounding area via T1/T2 DESN. Each transformer is 83.3 MVA in size and step down 230 kV to 44 kV feeder voltages. The station summer 10 day LTR is 88 MW. The stations 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 75 MW and is forecasted to be 90 MW in the next 20 years. Transformers T1/T2 are 56 years old and have reached their end of life and need to be replaced.

The scope of this project is to replace transformers T1 and T2 with new transformers. The newer similar size 50/83 MVA transformer will have a 10 day LTR rating greater than 100 MW and would serve the expected load forecast for the next 20 years

Transformer cost difference based on its size only is minimal. Hence, replacing transformer with lower size rating is not recommended as the load is increasing and downsizing the capacity today and then later upgrading it with larger transformers will be significantly more costly. Moreover, the current LTR rating of the transformers is adequate to serve the forecasted load. Therefore, the preferred option is to replace the transformer with the similar size transformer. The targeted in-service is in year 2027.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

d. Belleville TS – Transformer Replacement

Belleville TS supplies City of Belleville and surrounding area via T1/T2 DESN. Each transformer is 125 MVA in size and step down 230 kV to 44 kV feeder voltages. The station summer 10 day LTR is 161 MW. The stations 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 158 MW and is forecasted to be 189 MW in the next 20 years. Transformer T2 and T1 are 52 years and 45 years old respectively, and have reached their end of life and requires to be replaced. In addition, Station Service Transformers (SSTs), 230 kV switches and associated EOL equipment with transformer T2 and T1 are also require to be replaced.

The scope of this project is to replace the transformer T2 and T1. Replacing them with lower size transformer rating is not recommended as the load is increasing and downsizing the capacity today and then later upgrading it with larger transformers will be significantly more costly. Moreover, these transformers are already the highest standard size transformer, 75/100/125 MVA size, and since the load at Belleville

TS is not expected to decrease in future, the preferred option is to replace these transformer with the similar size transformer. The targeted in-service for transformer T2 is year 2021 and transformer T1 is in year 2025.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

7.2 Station and Transmission Capacity Needs in the Peterborough to Kingston Region

The following Station and Transmission supply capacities needs have been identified in the PtoK region during the study period of 2019 to 2028.

7.2.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are within the thermal limits of the circuits and within the voltage range as per Ontario Resource and Transmission Assessment Criteria (ORTAC) over the study period for the loss of a single 230/115 kV autotransformer in the Region.

7.2.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period for the loss of a single 230 kV circuit in the Region.

7.2.3 115kV Transmission Lines

The 115 kV circuits supplying the Region are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period adequate over the study period for the loss of a single 115 kV circuit in the Region.

7.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

a. Frontenac TS

The 2018 actual non-coincident summer peak load on Frontenac TS was 113 MW which is above its 10 day summer LTR of 111 MW. Based on the submitted load forecast, the Frontenac TS will be loaded more than 125 MW in the mid term.

Upgrading the transformers at Frontenac TS is not economically feasible as the transformers are already the largest size for a 115 kV connection. In addition, preliminary studies indicate that there is voltage and thermal constraints on 115 kV line circuits when adding a new DESN on these lines. Also, the cost of upgrading 115 kV transmission line to 230 kV has been a deterrent due to low load growth in the area. As per the current configuration, Kingston Hydro indicated to Hydro One that it may have up to 12 MW of emergency load transfer capability between Gardiner TS DESN 1 T1/T2 and Frontenac TS T3/T4.

Based on the above, the Study Team recommends that in the near term, Hydro One Transmission work with the Hydro One Distribution and Kingston Hydro for load transfer options to Gardiner TS to provide load relief at Frontenac TS.

b. Gardiner TS DESN 1

The 2018 actual non-coincident summer peak for Gardiner TS DESN 1 T1/T2 was 129 MW. The summer peak for year 2019 was reduced from 129 MW to 119 MW due to load transfer work completed by Hydro One Distribution. As per submitted load forecast, the loading on Gardiner TS DESN 1 will be exceeded by its 10 day summer LTR of 125 MW by year 2025.

Gardiner TS DESN 2 is located in the same area and has 10 day summer LTR of 84 MW. Based on the submitted load forecast, Gardiner TS DESN 2 will have at least 42 MW of excess capacity available by year 2028.

Based on the above, the Study Team recommends that the mid to long-term area supply capacity for city of Kingston and nearby area should be further assessed as part of the IRRP and/or RIP.

c. Belleville TS

The 2018 actual non-coincident summer peak load (adjusted for extreme weather) on Belleville TS T1/T2 was about 159 MW and is at close to its 10 day summer LTR of 161 MW. In addition to normal load growth in the area, Elexicon Energy Inc. has recently received approximately 30 MW of load connection inquiries to be connected at the Belleville TS.

Belleville TS has space for second DESN. However, preliminary studies undertaken by Hydro One indicate that there may be voltage and/or thermal constraints on the transmission lines supplying Belleville TS. Based on these assessments, following options may be available to address the need for additional capacity at Belleville TS -

- Install an additional 3rd 75/125 MVA transformer at Belleville TS and assess transmission line capacity
- Install a new DESN with two 75/125 MVA and assess transmission line capacity

In addition, reactive support may also be required at the station. Study team recommends that further assessment should be undertaken as part of the integrated regional resource planning process and/or RIP to develop a preferred plan. The integrated regional resource planning process, which includes stakeholder and community engagement activities, will examine the technical feasibility, economic implications and required timing of options for long-term, reliable electricity supply to the area based on a demand forecast prepared by the Working Group at the outset of the process.

d. Other TSs and HVDSs in the Region

All the other TSs and HVDSs in the Region are forecasted to remain within their normal supply capacity during the study period and therefore, the capacity needs for these TSs and HVDSs will be reviewed in the next planning cycle.

7.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of circuits X2H and X4H, the load interrupted by configuration at Gardiner TS will exceed 150 MW threshold marginally based on the coincident load forecast. As per the current configuration, Kingston Hydro indicated to Hydro One that it may have up to 12 MW of emergency load transfer capability between 230 kV connected Gardiner TS DESN 1 and 115 kV connected Frontenac TS T3/T4. As such, no action is required at this time and this will be reviewed in the next planning cycle.

There are other operating considerations on the Bulk System related to the 230 kV that may need further assessment as part of Bulk System Planning in the region. For example , the Dobbin TS Auto Transformers are legacy transformers and the tap changers on all 3 units are limited in their voltage regulation capability that prevents the voltage on the 230kV tap of the transformer to be operated at higher voltages up to 264 kV.

7.4 Other Planning Considerations in the Peterborough to Kingston Region

In addition, community energy plans in the region have also been scanned and reviewed (Section 9 for references). Federal and Provincial agencies either operate and/or subsidize facilities, such as Canadian Forces Bases, Corrections Institutions and Post-Secondary Institutions in the region and similarly, municipal agencies operate many facilities in the study region; water, wastewater and recreation arenas to name a few. All these agencies are contemplating to reduce Green House Gas (GHG) emissions and to achieve carbon neutrality by no later than 2050 through renewable resources, energy efficiency and/or electrification of heating and transportation. At this time, there is insufficient data available for input into the load forecast for this Needs Assessment study however, the Study Team should monitor the evolving climate action plans of federal, provincial and municipal agencies as they are expected to lead climate action over the next five years.

8 CONCLUSION AND RECOMMENDATIONS

In conclusion, the Gardiner TS DESN 1 station capacity need identified in the previous planning cycle has already been addressed. It is recommended that the newly identified needs shall be assessed in the current cycle of regional planning.

The Study Team recommends the following -

a. Over loading at Frontenac will be managed by Hydro One Transmission by coordinate with Hydro One Distribution and Kingston Hydro to undertake distribution load transfers between Gardiner TS and Frontenac TS over the near term.

b. An integrated regional resource planning (IRRP) and/or Regional Infrastructure Planning (RIP) process should be undertaken for the Peterborough-Kingston region to further assess the needs discussed above in section 7.2.4 a, b, and c as well as any addition needs identified in the area.

c. Replacement of end of life asset with similar equipment does not require further regional coordination (see further details in Section 7.1). The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs:

i. Lennox TS: 230kV & 500kV Breaker Replacements (Bulk System)
ii. Port Hope TS: Transformer Replacement - EOL replacement of transformers T3 / T4
iii. Havelock TS: Transformer Replacement – EOL replacement of transformers T1 / T2
iv. Belleville TS: Transformer Replacement - EOL replacement of transformer T2

d. IRRP and/or RIP should monitor the potential impact of Federal, Provincial and/or Municipal climate change and/or energy plans for this region. .

9 REFERENCES

[1] RIP Report – Peterborough to Kingston Region – July 2016

[2] Local Planning Report – Gardiner TS Load Balancing – October 2015

[3] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[4] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

[5] 2017 Long Term Energy Plan – Ontario Government

[6] Government of Canada – Excerpts from Greening Government Strategy Website (as of Nov 7, 2019)

[7] Queen’s University - Climate Action Plan dated January 2016

[8] St. Lawrence College 2018-2019 Business Plan & Energy Plan

[9] City of Kingston Municipal Energy Study – June 2018

[10] City of Kingston Declares Climate Emergency – March 2018

[11] City of Kingston – October 2019 Report to Council Number 19-261

Appendix A: Extreme Weather Adjusted Non-Coincident Summer / Winter Load Forecast

Table A.1: Peterborough to Kingston Region Summer Non-Coincident Load Forecast

Transformer Station		Summer 10 Day LTR (MW)	Type	Actual	Forecasted									
Name	DESN ID			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Ardoch DS	T1	12	Gross	3	3	3	3	3	3	3	3	3	3	3
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	T1/T2	12	Gross	8	8	8	9	9	9	9	9	9	9	9
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	8	8	8	8	8	8	8	8	8	8	8
Belleville TS	T1/T2	161	Gross	159	159	160	161	162	163	164	167	168	170	172
			CDM	0	2	3	3	4	5	5	6	6	7	8
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	159	157	157	158	158	158	159	161	162	163	164
Dobbin DS	T1/T2	24	Gross	10	15	15	15	15	15	15	15	15	16	16
			CDM	0	0	0	0	0	0	0	0	0	1	1
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	10	15	15	15	15	15	15	15	15	15	15
Dobbin TS	T3/T4	160	Gross	95	96	98	99	100	101	102	103	104	104	105
			CDM	0	1	2	2	2	2	3	3	3	4	4
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	95	95	96	97	98	99	99	100	100	101	101

Frontenac TS	T3/T4	111	Gross	113	115	118	120	123	124	124	125	125	126	126
			CDM	0	1	2	2	2	3	3	4	4	5	5
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	113	114	116	118	121	121	121	121	121	121	121
Gardiner TS	T1/T2	125	Gross	119*	119	122	123	125	127	128	129	130	131	132
			CDM	0	1	2	2	3	3	3	4	4	5	5
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	119*	118	120	121	122	124	125	125	126	126	127
Gardiner TS	T3/T4	84	Gross	35*	35	41	41	42	42	43	43	43	44	44
			CDM	0	0	1	1	1	1	1	1	1	2	2
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	35*	35	40	41	41	41	41	42	42	42	42
Harrowsmith DS	T1/T2	12	Gross	14	14	15	15	15	15	15	16	16	16	16
			CDM	0	0	0	0	0	0	0	0	1	1	1
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	14	14	15	15	15	15	15	15	15	15	15
Havelock TS	T1/T2	88	Gross	75	76	78	79	80	81	81	82	83	84	84
			CDM	0	1	1	1	2	2	2	2	3	3	3
			DG	0	1	1	1	1	1	1	1	1	1	1
			Net	75	74	75	76	77	78	78	78	79	79	80
Hinchinbrooke DS	T1	6	Gross	6	6	6	6	7	7	7	7	7	7	7
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	6	6	6	6	6	6	6	6	6	7	7
Lodgeroom DS	T1/T2	11	Gross	8	8	8	8	8	8	8	8	9	9	9
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG M	0	0	0	0	0	0	0	0	0	0	0
			Net	8	8	8	8	8	8	8	8	8	8	8

Napanee TS	T1	104	Gross	62	63	65	66	67	69	69	70	71	72	73
			CDM	0	1	1	1	1	2	2	2	2	3	3
			DG	0	0	0	0	0	0	0	0	0	0	-7
			Net	62	62	64	65	66	67	68	68	69	70	78
Northbrook DS	T1	12	Gross	6	6	7	7	7	7	7	7	7	7	7
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	6	6	6	6	7	7	7	7	7	7	7
Otonabee TS	T1/T2 (44kV)	97	Gross	65	60	61	61	66	70	71	73	74	75	76
			CDM	0	1	1	1	1	2	2	2	2	3	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	65	59	59	60	64	68	69	70	71	72	73
Otonabee TS	T1/T2 (27.6kV)	105	Gross	51	53	54	55	51	47	47	48	49	49	50
			CDM	0	0	1	1	1	1	1	1	2	2	2
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	51	53	53	54	50	45	46	47	47	48	48
Picton TS	T1/T2	78	Gross	59	60	62	63	64	65	66	67	68	69	70
			CDM	0	1	1	1	1	2	2	2	2	2	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	59	60	61	62	63	64	64	65	65	66	67
Port Hope TS	T1/T2	125	Gross	44	45	46	46	47	48	48	48	49	49	50
			CDM	0	0	1	1	1	1	1	1	2	2	2
			DG	0	0	1	1	1	1	1	1	1	1	1
			Net	44	44	45	45	46	46	46	46	47	47	47
Port Hope TS	T3/T4	104	Gross	70	70	72	73	73	74	75	76	76	77	78
			CDM	0	1	1	1	1	2	2	2	2	3	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	70	70	71	71	72	73	73	73	74	74	75

Sharbot DS	T1	6	Gross	4	4	4	4	4	4	4	4	4	4	4
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	T1/T2	112	Gross	78	79	81	82	83	84	84	85	85	86	87
			CDM	0	1	1	1	2	2	2	3	3	3	3
			DG	0	0	0	0	0	0	0	-5	-5	-5	-5
			Net	78	78	79	80	81	82	82	88	88	89	89
LaFarge Canada CTS			Net	21	21	21	21	21	21	21	21	21	21	21
Enbridge PL Hilt CTS			Net	2	2	2	2	2	2	2	2	2	2	2
TCPL Cobourg CTS			Net	0	0	0	0	0	0	0	0	0	0	0
TCPL Belleville CTS			Net	0	0	0	0	0	0	0	0	0	0	0
Novelis CTS			Net	9	10	10	10	10	10	10	10	10	10	10

** The 2018 summer peak load adjusted for 10 MW of load transfer from Gardiner TS DESN 1 to DESN 2 by Hydro One Distribution.*

Table A.2: Peterborough to Kingston Region Winter Non-Coincident Load Forecast

Transformer Station		Winter 10 Day LTR (MW)	Type	Actual	Forecasted									
Name	**DESN ID**			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Ardoch DS	T1	12	Gross	2	2	2	2	2	2	2	2	3	3	3
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	T1/T2	12	Gross	11	10	10	10	11	11	11	11	11	11	11
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	11	10	10	10	10	10	10	10	10	10	10

Belleville TS	T1/T2	181	Gross	159	158	160	162	165	167	169	171	173	175	178
			CDM	0	2	3	3	4	5	5	6	6	7	8
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	159	156	157	159	161	162	164	165	167	169	170
Dobbin DS	T1/T2	24	Gross	10	16	17	17	17	17	17	17	17	17	17
			CDM	0	0	0	0	0	0	0	1	1	1	1
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	10	16	16	16	17	17	17	17	17	17	17
Dobbin TS	T3/T4	177	Gross	73	70	72	72	73	74	74	75	75	76	77
			CDM	0	1	1	1	1	2	2	2	2	3	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	73	70	71	71	72	72	72	73	73	73	74
Frontenac TS	T3/T4	122	Gross	117	117	120	123	126	127	128	129	129	130	131
			CDM	0	1	2	2	2	3	3	3	3	4	4
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	117	116	118	121	124	124	125	126	126	126	127
Gardiner TS	T1/T2	143	Gross	128*	128	130	132	133	135	136	137	138	139	140
			CDM	0	1	2	2	3	3	4	4	4	5	5
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	128*	127	128	130	130	132	132	133	134	134	135
Gardiner TS	T3/T4	84	Gross	37*	37	43	43	44	44	44	45	45	45	46
			CDM	0	0	1	1	1	1	1	1	1	2	2
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	37*	37	42	42	43	43	43	43	44	44	44
Harrowsmith DS	T1/T2	12	Gross	18	18	18	18	18	18	19	19	19	19	19
			CDM	0	0	0	0	0	0	0	1	1	1	1
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	18	17	18	18	18	18	18	18	18	18	18

Havelock TS	T1/T2	97	Gross	65	63	64	65	65	66	67	67	68	68	69
			CDM	0	1	1	1	1	2	2	2	2	2	3
			DG	0	1	1	1	1	1	1	1	1	1	1
			Net	65	61	62	62	63	63	64	64	64	65	65
Hinchinbrooke DS	T1	6	Gross	7	6	6	6	7	7	7	7	7	7	7
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	7	6	6	6	6	6	6	6	7	7	7
Lodgeroom DS	T1/T2	11	Gross	10	9	10	10	10	10	10	10	10	10	10
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	10	9	9	9	10	10	10	10	10	10	10
Napanee TS	T1	117	Gross	72	70	72	73	74	75	76	77	78	79	80
			CDM	0	1	1	1	1	2	2	2	3	3	3
			DG	0	0	0	0	0	0	0	0	0	0	-7
			Net	72	69	71	72	73	74	74	75	76	77	85
Northbrook DS	T1	12	Gross	7	6	7	7	7	7	7	7	7	7	7
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	7	6	6	7	7	7	7	7	7	7	7
Otonabee TS	T1/T2 (44kV)	109	Gross	78	75	76	77	77	78	78	79	79	80	80
			CDM	0	1	1	1	2	2	2	2	3	3	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	78	74	75	75	75	76	76	76	76	76	77
Otonabee TS	T1/T2 (27.6kV)	115	Gross	62	60	61	62	62	63	63	63	64	64	64
			CDM	0	1	1	1	1	1	2	2	2	2	2
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	62	60	60	61	61	61	61	61	62	62	62

Picton TS	T1/T2	89	Gross	57	56	57	58	59	60	60	61	62	63	64
			CDM	0	1	1	1	1	1	2	2	2	2	2
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	57	55	56	57	57	58	59	59	60	60	61
Port Hope TS	T1/T2	140	Gross	67	65	66	67	68	68	69	69	70	71	71
			CDM	0	1	1	1	1	2	2	2	2	3	3
			DG	0	0	1	1	1	1	1	1	1	1	1
			Net	67	64	65	65	66	66	67	67	67	68	68
Port Hope TS	T3/T4	116	Gross	76	75	76	77	78	79	79	80	80	81	81
			CDM	0	1	1	1	2	2	2	2	3	3	3
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	76	74	75	76	76	77	77	77	78	78	78
Sharbot DS	T1	6	Gross	4	4	4	4	4	4	4	4	4	4	4
			CDM	0	0	0	0	0	0	0	0	0	0	0
			DG	0	0	0	0	0	0	0	0	0	0	0
			Net	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	T1/T2	112	Gross	84	82	83	84	85	86	87	87	88	89	89
			CDM	0	1	1	1	2	2	2	3	3	3	3
			DG	0	0	0	0	0	0	0	-5	-5	-5	-5
			Net	84	81	82	83	83	84	84	90	90	91	91
LaFarge Canada CTS			Net	21	21	21	21	21	21	21	21	21	21	21
Enbridge PL Hilt CTS			Net	2	2	2	2	2	2	2	2	2	2	2
TCPL Cobourg CTS			Net	0	8	8	8	8	8	8	8	8	8	8
TCPL Belleville CTS			Net	0	5	5	5	5	5	5	5	5	5	5
Novelis CTS			Net	9	9	10	10	10	10	10	10	10	10	10

** The 2018 winter peak load adjusted for 10 MW of load transfer from Gardiner TS DESN 1 to DESN 2 by Hydro One Distribution.*

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Ardoch DS (T1)	115/12.5
2.	Battersea DS (T1/T2)	115/12.5
3.	Belleville TS (T1/T2)	230/44
4.	Dobbin DS (T1/T2)	115/27.6
5.	Dobbin TS (T3/T4)	115/44
6.	Frontenac TS (T3/T4)	115/44
7.	Gardiner TS (T1/T2)	230/44
8.	Gardiner TS (T3/T4)	230/44
9.	Harrowsmith DS (T1/T2)	115/12.5
10.	Havelock TS (T1/T2)	230/44
11.	Hinchinbrooke DS (T1)	115/12.5
12.	Lodgeroom DS (T1/T2)	115/12.5
13.	Napanee TS (T1)	230/44
14.	Northbrook DS (T1)	115/12.5
15.	Otonabee TS (T1/T2)	230/44
16.	Otonabee TS (T1/T2)	230/27.6
17.	Picton TS (T1/T2)	230/44
18.	Port Hope TS (T1/T2)	115/44
19.	Port Hope TS (T3/T4)	115/44
20.	Sharbot DS (T1)	230/12.5
21.	Sidney TS (T1/T2)	115/44
22.	LaFarge Canada CTS	230/13.8
23.	Enbridge PL Hilt CTS	115/4.16
24.	TCPL Cobourg CTS	115/4.16
25.	TCPL Belleville CTS	115/4.16
26.	Novelis CTS	115/13.2

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	X1H, X2H, X3H, X4H	Hinchinbrooke SS	Lennox TS	230
2.	X21, X22	Picton TS	Lennox TS	230
3.	H23B	Belleville TS	Hinchinbrooke SS	230
4.	H27H	Hinchinbrooke SS	Havelock TS	230
5.	X1P	Dobbin TS	Chenaux TS	230
6.	C27P	Dobbin TS	Chat Falls GS	230
7.	T32H	Clarington TS	Havelock TS	230
8.	C25H	Chat Falls GS	Havelock TS	230
8.	T22C	Clarington TS	Chat Falls GS	230
9.	P15C	Cherrywood TS	Dobbin TS	230
10.	T25B	Clarington TS	Belleville TS	230
11.	P3S, P4S	Dobbin TS	Sidney TS	115
12.	Q6S	Cataraqui TS	Sidney TS	115
13.	B1S	Barrett Chute TS	Sidney TS	115
14.	Q3K	Cataraqui TS	Frontenac TS	115
15.	B5QK	Cataraqui TS	Frontenac TS to Barrett Chute TS	115

Appendix D: Lists of LDCs in the PtoK Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Peterborough Distribution Inc.	TX / DX
2.	Elexicon Energy Inc.	TX / DX
3.	Hydro One Distribution	TX
4.	Kingston Hydro	TX / DX
5	Lakefront Utilities Inc.	DX
6.	Eastern Ontario Power Inc.	DX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
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

Figure 5.2-17 below depicts the GTA North region. The participants are currently in the second Regional Planning Process cycle as they completed first cycle with the publication of the RIP report in February 2016. Hydro One initiated the second cycle with the NA phase and the participants subsequently completed the IRRP stage in February 2020 and the RIP phase in October 2020. The latter is the most recently complete phase of the Regional Planning Process for the GTA North region.

Figure 5.2-1: Overview of GTA North Regional Planning Zone

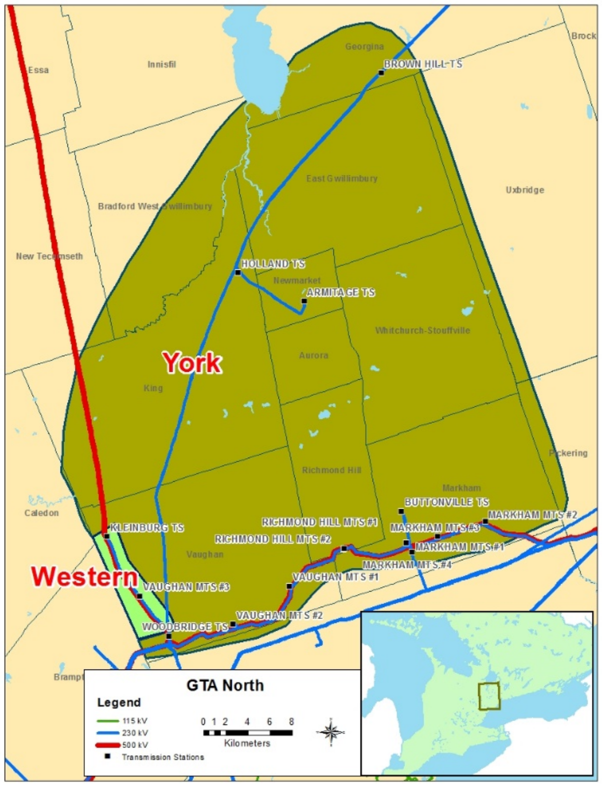

Table 5.2-6 provides a summary of the needs discussed during the consultation and the associated outcomes, none of which impact the current DSP. The study team identified that no actions are required to address needs related to high voltages on the M80B/M81B circuits and Vaughan step-down transformation capacity within this planning cycle. The remaining needs will be addressed by Hydro One in coordination with affected LDCs.

Need	Impact on Elexicon's DSP?	Outcome	Date
Markham Area: Step-down Transformation Capacity	No	Build new Markham #5 MTS at the existing Buttonville TS and connect to P45/P46 circuits – 1.1 km section of line between Parkway TS and Markham MTS #4 Jct needs to be uprated. Hydro One and Alectra to coordinate construction of station and line tap connection.	2025
Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	No	Reconductor circuits P45/P46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS. It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying forecasted load.	2025
High voltages on 230kV circuit M80B/M81B	No	No action required. The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage for up to 30 minutes. This provides sufficient time for operators to manually adjust the system as required.	N/A
Northern York Area: Step-down Transformation Capacity	No	Build new Northern York Station – it is anticipated that the new station will be supplied by circuits B88H/B89H. Further discussions between Hydro One and affected LDCs are required.	2027
Woodbridge TS: End-of-life of transformer T5	No	Replace the end-of-life transformer T5 at Woodbridge TS with a new 75/125MVA 230/44-27.6 kV transformer to maintain reliable supply to the customers in the area. Hydro One to coordinate with affected LDCs.	2027
Vaughan Area: Step-down Transformation Capacity	No	Build new Vaughan #5 MTS – Alectra has sufficient space at Vaughan #4 MTS to accommodate another station, but additional transmission capacity is required. A plan to increase transformation capacity is required before a plan for the new station can be committed.	2030

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NEEDS ASSESSMENT REPORT

South Georgian Bay - Muskoka

Date: April 30, 2020

Prepared by: South Georgian Bay - Muskoka Region Study Team

Transmission & Distribution

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the South Georgian Bay - Muskoka Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase 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 Study Team for this region.

The Study Team 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 (SGB) – Muskoka (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: January 30, 2020 **END DATE:** April 30, 2020

1. INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay (SGB) - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting with a Needs Assessment ("NA"). The purpose of this NA is a) to identify any new needs and/or to reaffirm needs identified in the previous SGB-Muskoka Regional Planning cycle and b) recommend which need may be a) met more directly by distributors or other customers and their respective transmitter b) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for SGB-Muskoka Region.

3. SCOPE OF NEEDS ASSESSMENT

This assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region: and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.
- Identify needs that will require further coordination at the regional level and those which can be met more directly by distributors and other customers as their respective transmitter.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

As per the PPWG Regional Planning Report to the Board (May 2013), the planning horizons of regional facilities are typically considered over 1-20 years; however, in most situations focus is over the 1 – 10-year timeframe.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment methodology includes review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its life.

6. NEEDS

I. Needs Identified from Previous Cycle – Implementation Plan Update

i. Barrie TS transformer supply capacity will be exceeded, and consequently result in thermal violation of the radial supply circuits (E3B/E4B). The majority of equipment at Barrie TS as well as the Essa TS 115kV yard have also been assessed at being end of life and in need of replacement due to asset condition. This resulted in creation of the Barrie Area Transmission Reinforcement (BATU) project to address these needs. This investment in presently underway with an in-service date scheduled for 2022.

ii. Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to asset condition. Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs. The In-service is scheduled for 2024.

iii. Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load forecast. To adhere to the criteria, Hydro One will be installing 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time. The In-service is scheduled for 2021.

iv. Minden TS – Replace 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units. These transformers have been assessed at being end of life and in need of replacement due to asset condition. The In-service scheduled is for 2021.

v. Orangeville TS – Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. These transformers and associated low voltage equipment has been assessed at being end of life and in need of replacement due to asset condition. This is presently underway with an In-Service scheduled for 2023.

II. Newly Identified Needs in the region

i. Waubaushene TS - This station will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. An immediate solution is required to address the summer loading concern and shall be coordinated with a permanent solution to address long term supply capacity needs. As well, the transformers are expected to be at the end of the study period and require replacement by 2030.

ii. Everett TS – Load growth at this station is restricted due to a limiting component within the low votage yard. This will be need to be corrected by 2026 to allow load to continue growing as per demand forecast.

iii. Barrie TS - This station will exceed its normal summer and winter supply capacity in 2024 and 2026 respectively, based on the existing 115/44kV transformers installed. The Barrie Area Transmission Project (BATU) will be completed in 2022, and help to address existing capacity, and end of life issues that have been identified in the first RP cycle. Although supply capacity appears to be available post-BATU, Hydro One Distribution and its embedded LDC (InnPower) will be constrained at the 44kV feeder supply level in 2025. A plan is required to address the supply capacity need from InnPower beyond what Barrie TS can provide.

iv. Parry Sound TS - This station will exceed supply in 2020 based on the winter demand forecast. Hydro One will be upgrading the transformers with two new 230/44kV 83MVA units in 2024. A solution is required to address the immediate station capacity need.

v. Sections of M6E/M7E are at end of life and in need of replacement – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Falls JCT – In-Service 2024

Sections of E8V / E9V are at end of life and in need of replacement – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT – In-Service 2027

Sections of D1M / D2M are at end of life and in need of replacement – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT - In-Service 2028

vi. M6E/M7E (Essa TS x Midhurst TS) thermal overloading - With four Des Joachims GS units out of service the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE (Long

Term Emergency) rating on the line section from Essa TS x Midhurst TS. This overload occurs as early as 2023.

7. RECOMMENDATIONS

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio setting on the low voltage bushing of the transformer breaker can be modified to allow full transformer LTR capability. Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

TABLE OF CONTENTS

List of Tables and Figures

2 INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous SGB-Muskoka regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the South Georgian Bay - Muskoka Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team 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: SGB-Muskoka Region Study Team Participants

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator ("IESO")
Hydro One Networks Inc. (Distribution)
Alectra Utilities
InnPower
Orangeville Hydro
Elexicon Energy
Lakeland Power
EPCOR Electricity Distribution Ontario Inc.
Newmarket-Tay Power Distribution Ltd
Orillia Power Distribution Corp.
Wasaga Distribution Inc.

3 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the SGB-Muskoka region, the 2nd Regional Planning cycle was triggered for the SGB-Muskoka region.

4 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the SGB-Muskoka region and includes:

- Review the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

5 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The geographical area of the South Georgian Bay/Muskoka Region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the North-East, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. This region is divided into two sub-regions:

- Barrie/Innisfil Sub-region: This area encompasses the City of Barrie, the Towns of Innisfil, New Tecumseth and Bradford West Gwillimbury, and the Townships of Essa, Springwater, Clearview, Mulmur, and Adjala-Tosorontio.

- Parry Sound/Muskoka Sub-region: This area encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County.

The boundaries of South Georgian Bay - Muskoka Region is shown below in Fig. 1.

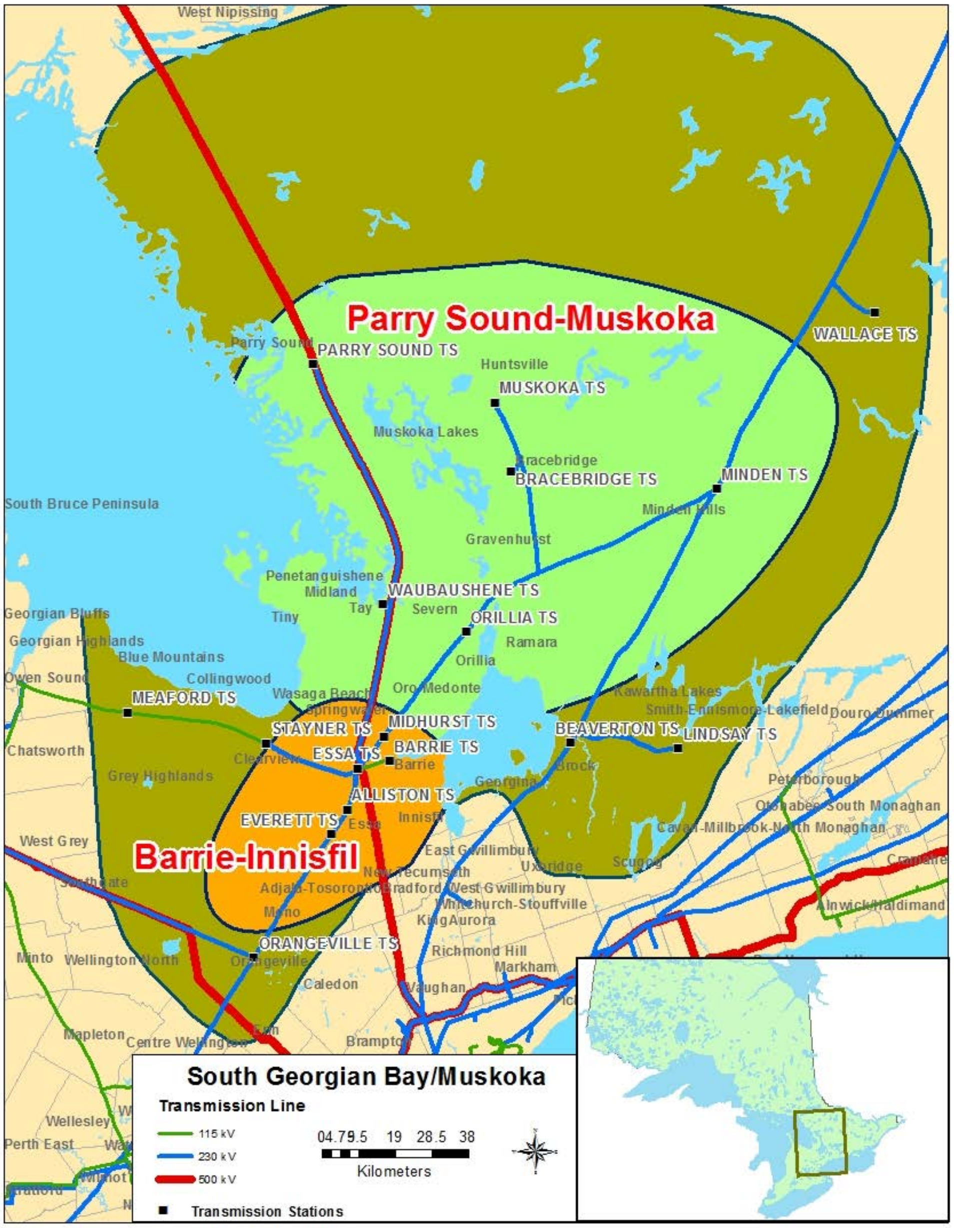

Figure 1: Geographical Area of SGB-Muskoka Region with Electrical Layout

Electrical supply to the 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) HONI 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 following circuits are not included in the South Georgian Bay/Muskoka Region:

• The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
• The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

• Essa TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230kV auto-transformers. Essa TS also supplies the 115kV system towards Barrie TS via two 230/115kV auto-transformers.

• Eleven step-down transformer stations supply load to the north and east areas of the Region (north and east of Essa TS): Barrie TS, Beaverton TS, Bracebridge TS, Lindsay TS, Midhurst TS, Minden TS, Muskoka TS, Orillia TS, Parry Sound TS, Wallace TS, and Waubashene TS.

• Five step-down transformer stations supply load to the south and west areas of the Region (south and west of Essa TS): Alliston TS, Everett TS, Meaford TS, Orangeville TS, and Stayner TS.

• Eight 230kV circuits (E8V, E9V, E20S, E21S, E26, E27, M6E, and M7E) radiating outward from Essa TS provide local supply to the Region. These circuits are essential to the Region and will be included in the study to ensure long-term reliability. Four 230kV circuits (D1M, D2M, D3M, and D4M) entering the region from the east are also a major supply path for the Region and will be analyzed in this study.

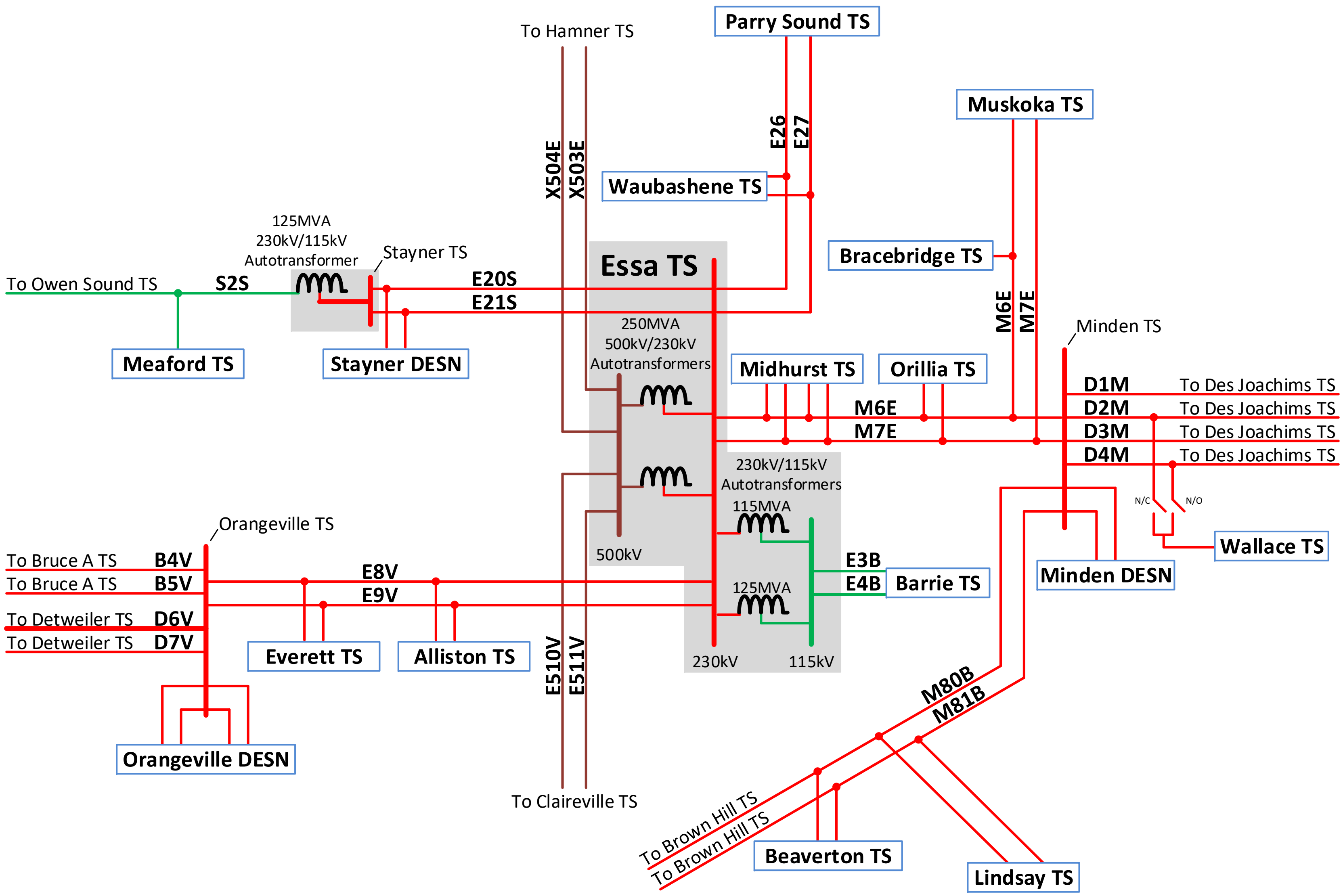

Figure 2: Single Line Diagram of South Georgian Bay - Muskoka Region

6 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the South Georgian Bay - Muskoka Region NA. The information provided includes the following:

- South Georgian Bay - Muskoka Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the SGB-Muskoka Region.

7 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the SGB-Muskoka region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the SGB-Muskoka region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2019 summer and winter peak weather corrected loads. The summer / winter weather correction factors were provided by Hydro One. The net weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These load forecasts for the individual stations in the SGB-Muskoka region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of life.

8 NEEDS

This section describes emerging needs identified in the South Georgian Bay - Muskoka Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Needs identified in the previous RP cycle	Needs Details	Current Status	In-Service
Supply Capacity & End-Of Life	Barrie TS transformer supply capacity will be exceeded and has consequently overload the supply circuits (E3B/E4B) InnPower is an embedded LDC supplied from a single 44kV feeder from Barrie TS and requires an additional feeder to supply its loads.	Hydro One's Barrie Area Transmission Reinforcement (BATU) project is underway This investment will address the needs identified in the last RP cycle.	2022
	Parry Sound TS supply capacity has been exceeded, and in need of upgrading. Transformers have also been assessed at being end of life and in need of replacement due to asset condition.	Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs.	2024
Load Restoration	Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load	Hydro One is installing 230kV motorized disconnect switches on the M6E and M7E circuits. This will improve load restoration time. Underway	2021
End of Life Asset Replacement	Minden TS – Replacement of 230/44kV (T1/T2) transformers	Underway	2021
	Orangeville – Replacement of 230/44/27.6 (T1/T2) and 230/44 (T3/T4) transformers, low voltage switchyard	Underway	2023

8.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
- Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

a. Barrie TS – Replace and Upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

b. Minden TS -Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

c. Orangeville TS - Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

d. Parry Sound TS – Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

e. M6E/M7E – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Fls JCT (In-Service 2024)

f. E8V / E9V – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT * (In-Service 2027)

g. D1M / D2M – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT * (In-Service 2028)

*- further conductor samples/testing to be performed to confirm need.

8.2 Station and Transmission Capacity Needs in the South Georgian Bay - Muskoka Region

The following Station and Transmission supply capacities needs have been identified in the SGB-Muskoka region during the study period of 2020 to 2029.

8.2.1 230/115 kV, & 500/230kV Autotransformers

230/115 kV autotransformers at Essa TS(T1/T2) and Stayner TS (T1) remain within limits for the study period based on both and summer and winter demand forecast. Note: The existing Barrie area transmission upgrade project (BATU) will remove the Essa TS (T1/T2) autotransformers as part of its scope of work in 2022.

500/230kV autotransformers at Essa TS (T3/T4) remain within limits for the study period based on both and summer and winter demand forecast.

8.2.2 230 kV Transmission Lines

The 230kV M6E/M7E circuits from Essa TS to Midhurst TS exceed the Long-Term Emergency (LTE) rating within the study period. With four out of eight Des Joachims GS units are out of service (approx. 200MW) the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE rating. This overload occurs as early as 2023 and continues until the end of the NA study period.

8.2.3 115kV Transmission Lines

With the loss of E4B, the companion E3B circuit will exceed its summer Long-Term Emergency (LTE) rating within the study period. The scope of the Barrie Area Transmission Upgrade (BATU) project will address this finding with an expected 2022 in-service date.

8.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using both summer and winter station peak load forecasts provided by the study team. The results are as follows:

a. Waubaushene TS

Waubaushene TS has a summer 10-day LTR of 94MW and will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. Summer overloading at this station has been increasing becoming a concern and the forecast in this NA further reinforces the need for an immediate solution.[1] Initial distribution studies have shown that up to 10MW of load can be permanently transferred to Midhurst TS. This solution in combination with additional CDM/DG initiates may provide the capacity relief needed and its effectiveness will be confirmed in the next stage. While these initiatives are being explored, it is important to note that the existing 230/44kV transformers (T5/T6) are scheduled for replacement in 2030, and if needed can be upgraded to larger units to permanently alleviate supply capacity constraints. This investment can be advanced with agreement from connected LDCs if it needs to be coordinated with shorter term solutions.

b. Everett TS

Everett TS has a summer and winter 10-Day LTR of 86MW. The station supply capability is limited by a CT ratio setting on the low voltage bushing of the transformer breakers, thereby restricting the ability to utilize the full supply capability of the transformers. This restriction can be alleviated by adjusting the CT ratio of the transformer breakers, and must be completed by 2026 to allow station load to continue growing.

c. Barrie TS

Barrie TS presently has a 10-Day LTR of 109MW which will exceed its normal supply capacity in the year 2024 based on the summer demand forecast. The Barrie Area Transmission Project (BATU) project currently underway and once completed will see two new 230/44kV 125MVA transformers increasing the supply capacity of the station (170MVA in the summer), even with the new units installed, station LTR will exceed in the summer 2029. Although capacity does appear to be available for the near and mid-term, Hydro One distribution and its' embedded LDC (InnPower) will see a supply capacity constraint at the 44kV feeder level in 2025. Minor capacity increases can be accommodated on the 44kV system but only on an emergency basis, and can not be used as a permanent supply solution for increased load growth.

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[1] Waubaushene TS experienced station loading in excess of 100MVA in July 2018. Although this load occurred for 2hrs and both T5/T6 were in-service, Hydro One operations were ready to initiate control actions to shed load in the event of a transformer outage.

The working group agreed that for this station, it would be reasonable to use the explicit MW values provided by the LDCs, to coincide with ongoing regulatory proceeding related to the aforementioned BATU project. [2] As such, the load forecast for each connected LDC (Shown in Appendix A) at Barrie TS is explicitly shown to provide the working group greater transparency and help to identify individual LDC needs within the study period. A near term solution is required to address this need from InnPower and should be incorporated with any long-term solutions to supply their study forecast of 93MW. InnPower will need new supply capacity into the Innisfil service territory to be provided by 2025 to service its load growth. This growth is consistent with the forecasted growth identified in the 2016 Barrie/Innisfil IRRP.

d. Parry Sound TS

Parry Sound TS has a 10-day winter LTR of 51MW and will be exceeded at the end of 2020 based on the winter demand forecast.
Parry Sound TS presently has 230/44kV 42MVA transformers (T1/T2) that have approached end of life. Hydro One will be right sizing these transformers and replacing these with two new 230/44kV 83MVA units which will provide the supply capacity needed for future load growth. These transformers are scheduled to be in-service 2024. Based on the immediate need for capacity relief at the station, Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers.

e. Other TSs in the Region

All the other transmission stations (TS) in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

8.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

[2] The forecast provided in IR response (January 9, 2020) with respect to BATU Leave to construct application (EB-2018-0017) illustrates Alectra's assigned capacity of 90MW at Barrie TS.

9 CONCLUSION AND RECOMMENDATIONS

The Study Team recommends the following –

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio on the low voltage bushing of the transformer breaker can be changed to allow full transformer LTR capability.
Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

Appendix A: Weather Adjusted Non-Coincident Summer Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Summer Peak Load												
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				44.0	44.3	44.6	44.9	45.2	45.5	45.9	46.2	46.5	46.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.3	1.6	1.8	1.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	41.0	38.5	43.7	43.6	43.8	44.0	44.1	44.2	44.4	44.5	44.5	44.7	45.0
Alliston TS	T3/T4	111	N	100	Gross Peak Load				71.1	73.2	75.4	77.7	80.1	82.5	85.0	87.5	90.2	92.9
					CDM (MW)				0.6	0.8	1.0	1.4	1.7	2.1	2.4	3.1	3.4	3.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	76.7	61.8	69.0	70.5	72.5	74.4	76.3	78.3	80.3	82.5	84.4	86.8	89.2
Barrie TS	T1/T2	115	Y	109	Gross Peak (Alectra)				65.1	67.1	69.2	71.3	73.5	75.5	77.4	79.4	81.5	83.6
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				84.1	90.3	99.3	111.2	122.3	132.2	142.8	155.0	165.8	176.5
					CDM (MW)				0.7	0.9	1.4	2.0	2.7	3.4	4.1	5.5	6.3	7.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	93.9	119.5	127.9	83.4	89.4	97.9	109.1	119.7	128.8	138.8	149.5	159.5	169.5
Beaverton TS	T3/T4	203	Y	193	Gross Peak Load				60.2	60.8	61.3	61.9	62.4	63.0	63.5	64.1	64.7	65.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.4	1.6	1.8	2.3	2.4	2.6
					DG (MW)				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					Net Load Forecast	52.9	55.7	59.7	59.5	59.9	60.3	60.5	60.9	61.2	61.5	61.7	62.0	62.5
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	13.0	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Everett TS	T1/T2	95	N	86	Gross Peak Load				74.6	76.8	79.0	81.3	83.7	86.2	88.7	91.3	94.0	96.8
					CDM (MW)				0.6	0.8	1.1	1.5	1.8	2.2	2.5	3.2	3.6	3.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	82.0	70.9	72.5	73.9	76.0	77.9	79.9	81.9	84.0	86.2	88.1	90.4	92.9
Lindsay TS	T1/T2	169	Y	161	Gross Peak Load				79.9	80.9	82.0	83.0	84.1	85.2	86.3	87.4	88.5	89.7
					CDM (MW)				0.7	0.8	1.1	1.5	1.8	2.2	2.5	3.1	3.3	3.5
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	72.3	72.9	78.9	79.1	80.0	80.7	81.4	82.2	82.9	83.7	84.2	85.1	86.0
Meaford TS	T1/T2	55	Y	52	Gross Peak Load				26.8	27.0	27.1	27.3	27.5	27.7	27.8	28.0	28.2	28.4
					CDM (MW)				0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	30.2	33.4	26.6	26.6	26.7	26.8	26.8	26.9	27.0	27.0	27.0	27.1	27.2
Midhurst TS	T1/T2	171	Y	162	Gross Peak Load				120.6	122.9	125.3	127.7	130.2	132.7	135.3	137.9	140.6	143.3
					CDM (MW)				1.0	1.3	1.7	2.3	2.8	3.4	3.9	4.9	5.3	5.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	122.0	122.5	118.3	119.5	121.6	123.6	125.4	127.4	129.3	131.4	133.1	135.3	137.6
Midhurst TS	T3/T4	166	N	149	Gross Peak Load				99.7	102.5	105.4	108.4	111.4	114.6	117.8	121.1	124.6	128.1
					CDM (MW)				0.9	1.1	1.4	2.0	2.4	2.9	3.4	4.3	4.7	5.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	110.1	97.2	97.0	98.8	101.5	104.0	106.4	109.0	111.6	114.5	116.9	119.9	123.0
Minden TS	T1/T2	58	N	52	Gross Peak Load				42.9	43.2	43.5	43.9	44.2	44.5	44.8	45.1	45.4	45.8
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.1	1.3	1.6	1.7	1.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	39.9	39.5	42.6	42.6	42.8	42.9	43.1	43.2	43.3	43.5	43.5	43.7	44.0
Muskoka TS	T1/T2	178	Y	169	Gross Peak Load				131.0	133.1	135.1	137.2	139.4	141.6	143.8	146.0	148.3	150.6
					CDM (MW)				1.1	1.4	1.9	2.5	3.0	3.6	4.1	5.1	5.6	6.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.0	-1.2	-1.2
					Net Load Forecast	118.8	132.7	129.0	129.8	131.6	133.2	134.6	136.2	137.8	139.5	141.9	143.8	145.8

Orangeville TS	T1/T2	103	N	93	Gross Peak Load				58.2	58.8	59.5	60.2	60.8	61.5	62.2	62.9	63.6	64.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.3	1.6	1.8	2.2	2.4	2.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	50.7	52.7	57.5	57.7	58.2	58.7	59.1	59.5	59.9	60.4	60.9	61.4	62.0
Orangeville TS	T3/T4	106	Y	101	Gross Peak Load				75.4	76.3	77.1	78.0	78.9	79.7	80.6	81.5	82.4	83.4
					CDM (MW)				0.7	0.8	1.1	1.4	1.7	2.1	2.3	2.9	3.1	3.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	70.2	69.9	74.6	74.8	75.5	76.1	76.6	77.1	77.7	78.3	78.8	79.5	80.2
Orillia TS	T1/T2	162	Y	154	Gross Peak Load				116.7	118.3	119.9	121.5	123.2	124.9	126.6	128.4	130.1	131.9
					CDM (MW)				1.0	1.2	1.6	2.2	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	96.1	107.4	115.1	115.7	117.1	118.3	119.3	120.5	121.7	123.0	123.9	125.2	126.7
Parry Sound TS	T1/T2	52	N	47	Gross Peak Load				45.1	45.5	45.9	46.3	46.8	47.2	47.6	48.0	48.4	48.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.4	1.7	1.8	1.9
					DG (MW)				0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	-0.2	-0.2
					Net Load Forecast	41.0	42.5	44.8	44.8	43.6	43.9	44.1	44.3	44.5	44.8	44.9	46.7	47.1
Stayner TS	T3/T4	191	Y	181	Gross Peak Load				119.5	120.7	122.0	123.2	124.5	125.8	127.0	128.3	129.7	131.0
					CDM (MW)				1.0	1.2	1.7	2.3	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	108.0	112.4	118.3	118.5	119.4	120.2	120.8	121.6	122.4	123.3	123.7	124.6	125.7
Wallace TS	T3/T4	54	N	49	Gross Peak Load				39.8	40.1	40.4	40.8	41.1	41.5	41.8	42.2	42.5	42.9
					CDM (MW)				0.3	0.4	0.6	0.7	0.9	1.1	1.2	1.5	1.6	1.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	27.0	37.5	39.4	39.4	39.7	39.9	40.0	40.2	40.4	40.6	40.7	40.9	41.2
Waubaushene TS	T5/T6	99	Y	94	Gross Peak Load				99.0	100.0	100.9	101.9	102.9	103.9	104.9	105.9	107.0	108.0
					CDM (MW)				0.9	1.0	1.4	1.9	2.2	2.7	3.0	3.7	4.0	4.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	85.3	92.2	98.0	98.1	98.9	99.5	100.0	100.7	101.2	101.9	102.2	102.9	103.8

Appendix A: Weather Adjusted Non-Coincident Winter Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Winter Peak Load												
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				31.3	31.5	31.7	31.9	32.1	32.3	32.5	32.7	32.9	33.1
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	35.9	36.2	31.1	31.1	31.3	31.5	31.6	31.7	31.8	32.0	32.2	32.3	32.5
Alliston TS	T3/T4	128	N	115	Gross Peak Load				73.7	75.9	78.2	80.6	83.0	85.5	88.1	90.8	93.5	96.4
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.2	1.4	1.4	1.5	1.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	57.3	71.6	73.3	75.5	77.7	79.8	82.0	84.3	86.8	89.4	92.1	94.8
Barrie TS	T1/T2	127	Y	121	Gross Peak (Alectra)				54.7	56.4	58.2	60.0	61.8	63.4	65.1	66.8	68.5	70.3
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				73.7	79.6	88.2	99.8	110.6	120.2	130.5	142.3	152.8	163.2
					CDM (MW)				0.4	0.5	0.6	1.0	1.3	1.7	2.0	2.3	2.4	2.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	95.1	78.4	80.9	73.3	79.2	87.6	98.8	109.3	118.5	128.5	140.1	150.4	160.6
Beaverton TS	T3/T4	224	Y	213	Gross Peak Load				83.7	84.4	85.1	85.8	86.5	87.2	87.9	88.7	89.4	90.2
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.4	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	79.2	78.4	83.0	83.2	83.9	84.5	84.9	85.5	86.0	86.6	87.3	88.0	88.7
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Everett TS	T1/T2	95	N	86	Gross Peak Load				81.6	82.2	82.9	83.6	84.3	85.0	85.7	86.4	87.1	87.9
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.3	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	78.2	76.4	80.9	81.1	81.8	82.3	82.8	83.3	83.8	84.4	85.0	85.7	86.5
Lindsay TS	T1/T2	192	Y	182	Gross Peak Load				95.5	96.7	97.9	99.1	100.3	101.5	102.8	104.0	105.3	106.6
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.7	1.7
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	88.7	91.5	94.4	94.9	96.0	97.1	98.0	99.0	100.0	101.1	102.3	103.6	104.8
Meaford TS	T1/T2	62	Y	59	Gross Peak Load				34.4	34.7	34.9	35.1	35.4	35.6	35.8	36.1	36.3	36.5
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	33.8	30.2	34.2	34.2	34.5	34.7	34.8	34.9	35.1	35.3	35.5	35.7	36.0
Midhurst TS	T1/T2	193	Y	183	Gross Peak Load				98.8	101.8	105.0	108.2	111.6	114.5	117.5	120.5	123.6	126.9
					CDM (MW)				0.6	0.6	0.7	1.1	1.3	1.6	1.8	1.9	2.0	2.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	103.5	100.5	100.6	98.2	101.2	104.2	107.2	110.3	112.9	115.6	118.6	121.7	124.9
Midhurst TS	T3/T4	191	N	172	Gross Peak Load				119.4	122.8	126.3	129.8	133.5	137.3	141.1	145.1	149.2	153.4
					CDM (MW)				0.7	0.7	0.9	1.3	1.6	1.9	2.2	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	123.6	91.5	116.1	118.7	122.1	125.4	128.5	131.9	135.3	138.9	142.8	146.9	151.0
Minden TS	T1/T2	64	N	58	Gross Peak Load				55.3	55.7	56.0	56.4	56.8	57.1	57.5	57.9	58.3	58.6
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	53.3	55.0	55.0	55.4	55.6	55.8	56.1	56.3	56.6	57.0	57.3	57.7
Muskoka TS	T1/T2	209	Y	199	Gross Peak Load				164.3	166.8	169.4	172.1	174.7	177.4	180.2	183.0	185.8	188.7
					CDM (MW)				0.9	1.0	1.2	1.7	2.1	2.5	2.8	2.9	2.9	3.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.2	-1.3	-1.3
					Net Load Forecast	163.7	157.8	161.8	163.2	165.7	168.1	170.2	172.5	174.8	177.2	181.2	184.2	187.0

Orangeville TS	T1/T2	121	N	109	Gross Peak Load				50.3	50.8	51.4	51.9	52.5	53.0	53.6	54.1	54.7	55.3
					CDM (MW)				0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5
					Net Load Forecast	49.6	47.2	49.8	50.0	50.5	51.0	51.4	51.8	52.3	52.7	54.8	55.3	55.9
Orangeville TS	T3/T4	123	Y	117	Gross Peak Load				89.1	90.0	91.0	91.9	92.9	93.9	94.8	95.8	96.9	97.9
					CDM (MW)				0.5	0.5	0.6	0.9	1.1	1.3	1.5	1.5	1.5	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.4	-1.4	-1.4
					Net Load Forecast	76.1	83.4	88.1	88.6	89.5	90.3	91.0	91.8	92.5	93.4	95.8	96.8	97.8
Orillia TS	T1/T2	184	Y	175	Gross Peak Load				127.2	128.9	130.6	132.4	134.1	135.9	137.8	139.6	141.5	143.4
					CDM (MW)				0.7	0.8	0.9	1.3	1.6	1.9	2.2	2.2	2.2	2.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	119.4	118.6	125.5	126.4	128.1	129.7	131.0	132.5	134.0	135.6	137.4	139.3	141.1
Parry Sound TS	T1/T2	57	N	51	Gross Peak Load				56.5	56.9	57.4	57.9	58.4	58.9	59.4	59.9	60.4	60.9
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	1.0	1.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.8	-1.8
					Net Load Forecast	57.0	53.3	56.0	56.1	56.6	57.0	57.3	57.7	58.0	58.4	58.9	61.2	61.7
Stayner TS	T3/T4	213	Y	202	Gross Peak Load				140.0	141.1	142.1	143.2	144.3	145.3	146.4	147.5	148.7	149.8
					CDM (MW)				0.8	0.8	1.0	1.4	1.7	2.1	2.3	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	138.4	132.7	139.0	139.2	140.2	141.1	141.8	142.5	143.3	144.2	145.2	146.3	147.4
Wallace TS	T3/T4	60	N	54	Gross Peak Load				37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.3
					CDM (MW)				0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	38.0	35.2	37.3	37.2	37.3	37.3	37.3	37.3	37.4	37.4	37.5	37.6	37.7
Waubaushene TS	T5/T6	109	Y	104	Gross Peak Load				95.2	96.1	97.0	97.9	98.7	99.6	100.5	101.5	102.4	103.3
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.6	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	94.0	90.5	94.4	94.7	95.5	96.3	96.9	97.6	98.2	99.0	99.9	100.8	101.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubashene TS	230/44

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

Appendix D: Lists of LDCs in the SGB-Muskoka Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Networks Inc. (Distribution)	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd	DX
9.	Orillia Power Distribution Corp.	DX
10.	Wasaga Distribution Inc.	DX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
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

Toronto

REGIONAL INFRASTRUCTURE PLAN

March 6, 2020

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Prepared and supported by:

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

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

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

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EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

The Study Team recommends that:

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

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

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

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

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

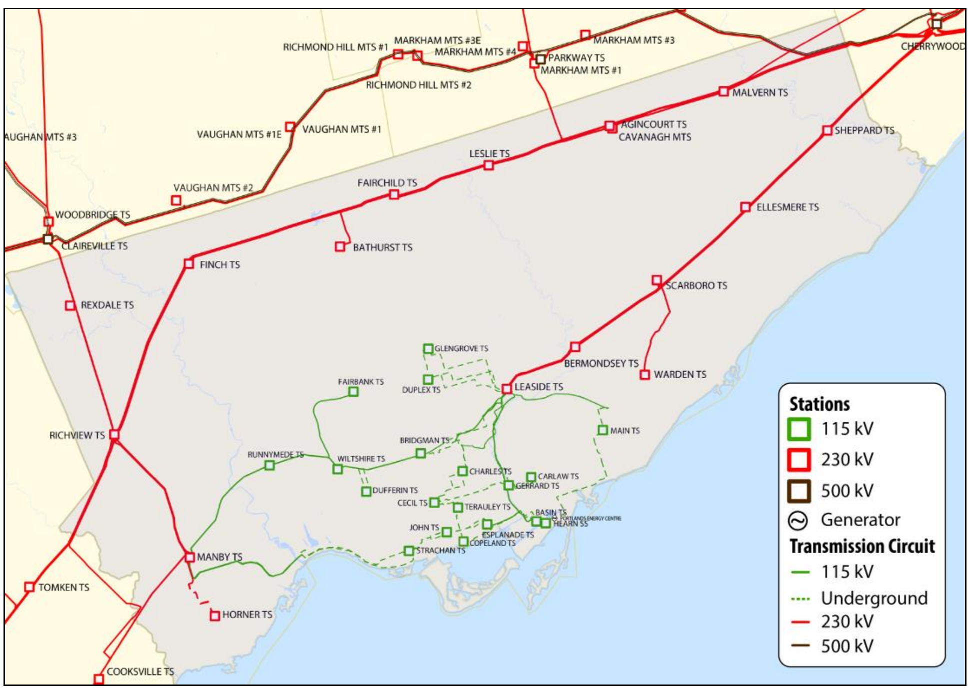


Figure 1-1: Toronto Region Map

1.1 Objectives and Scope

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

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

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

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

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

[1] Also referred to as Needs Screening

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

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

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

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

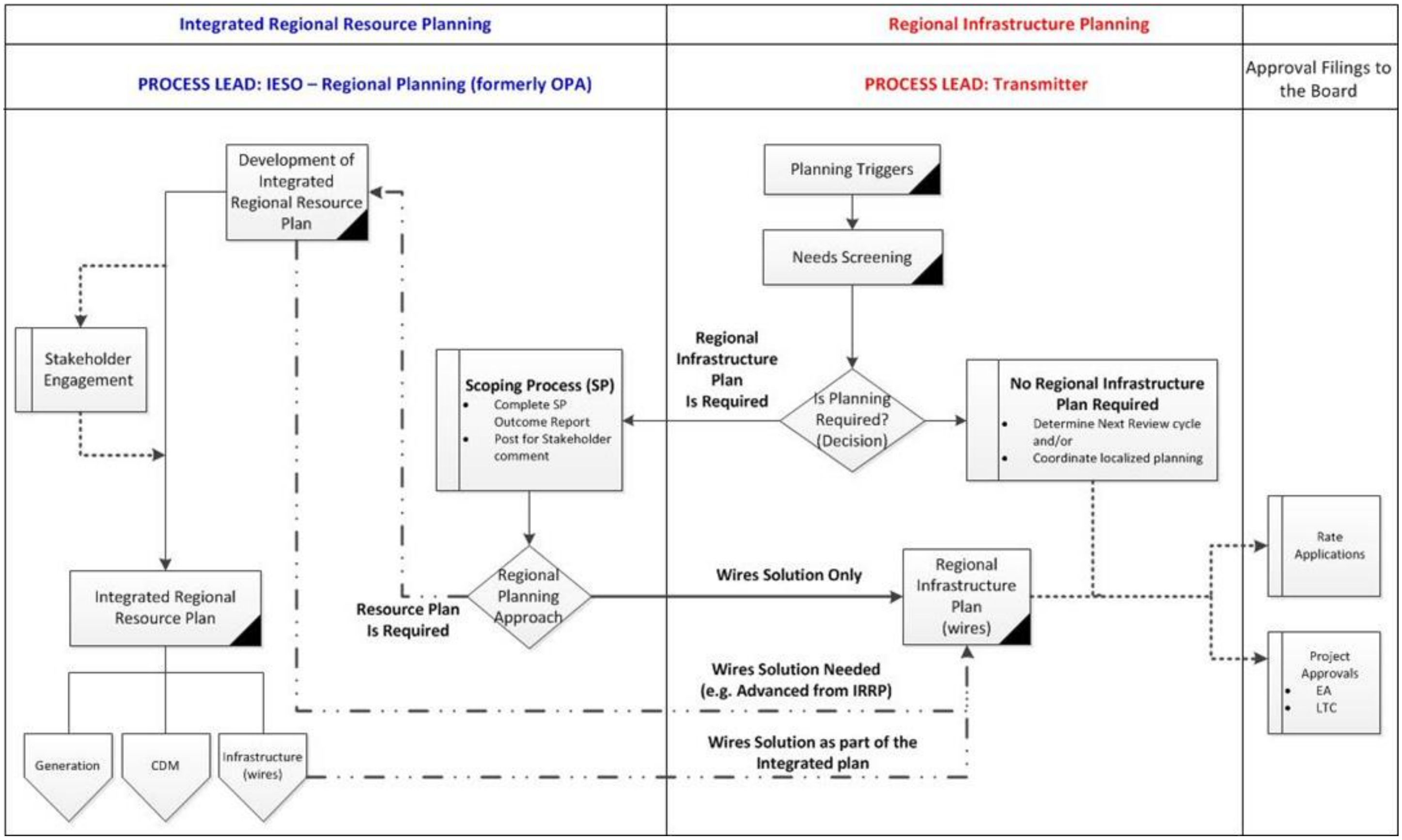


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

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

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

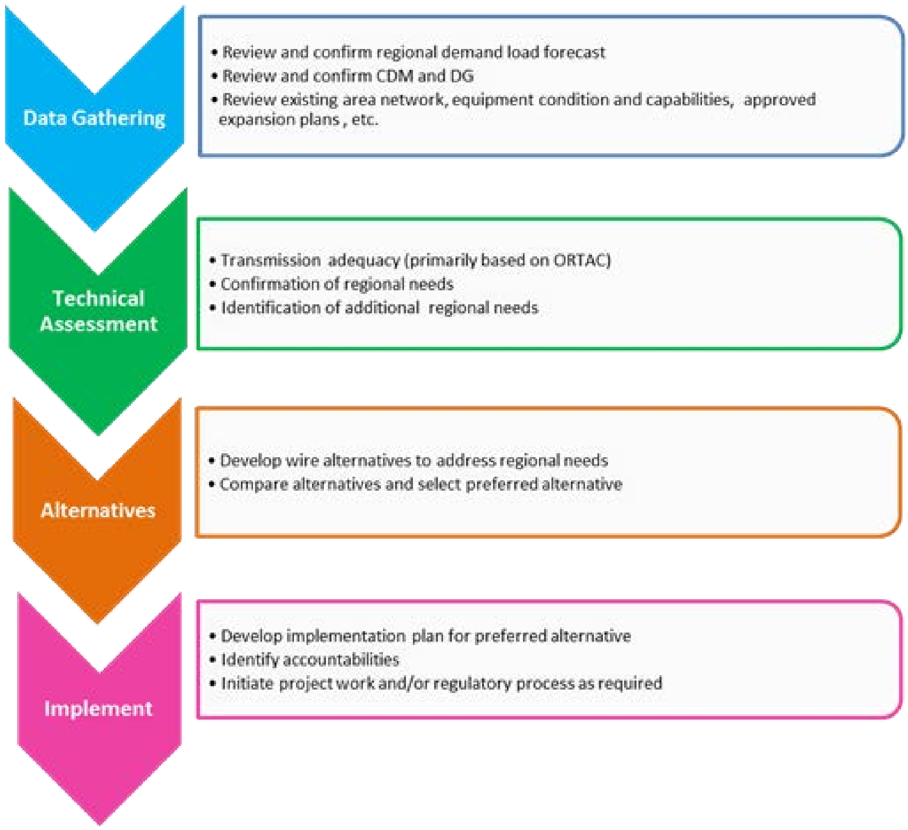


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

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

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

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

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

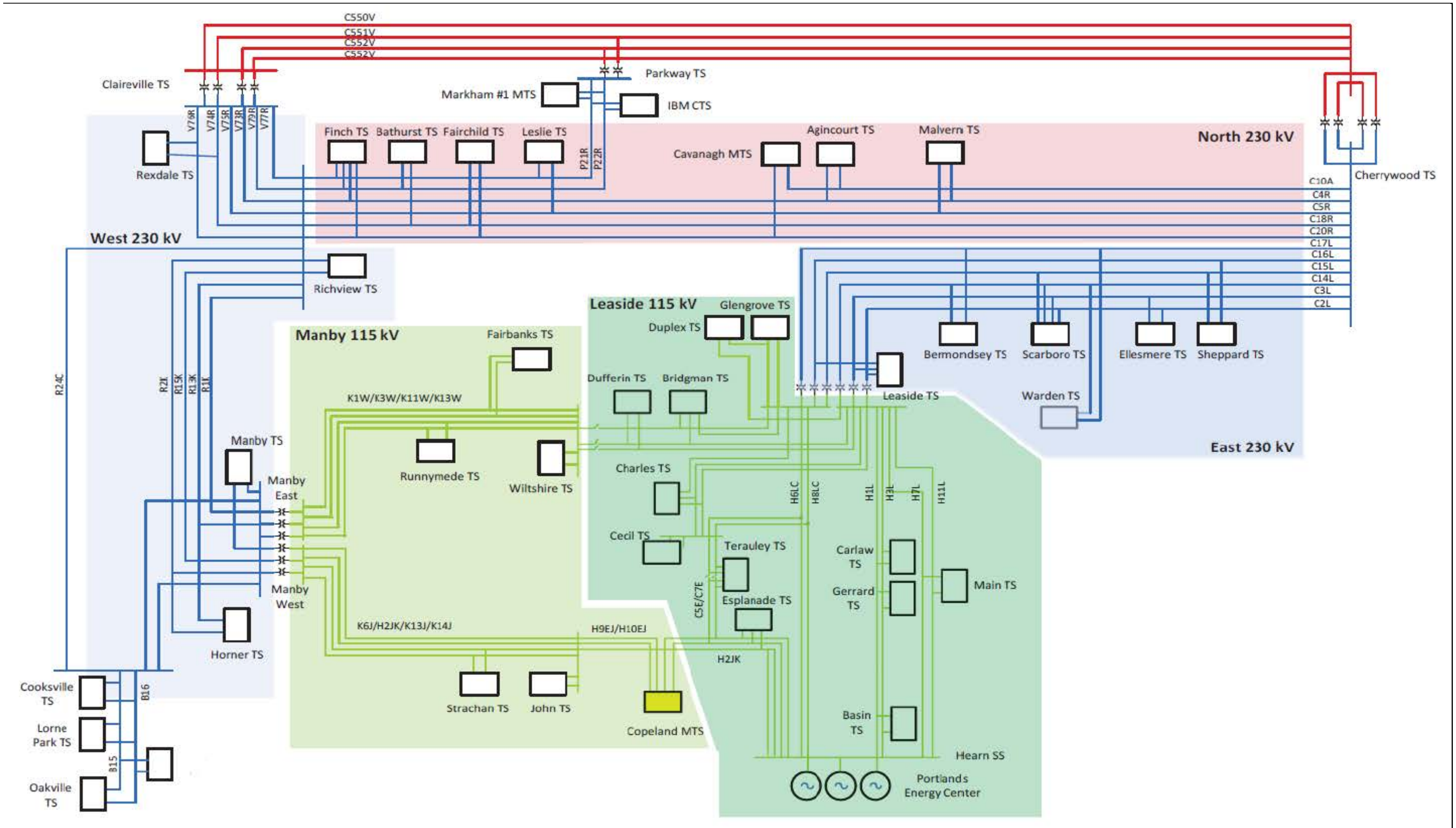


Figure 3-1: Single Line Diagram of Toronto Region's Transmission Network

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

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

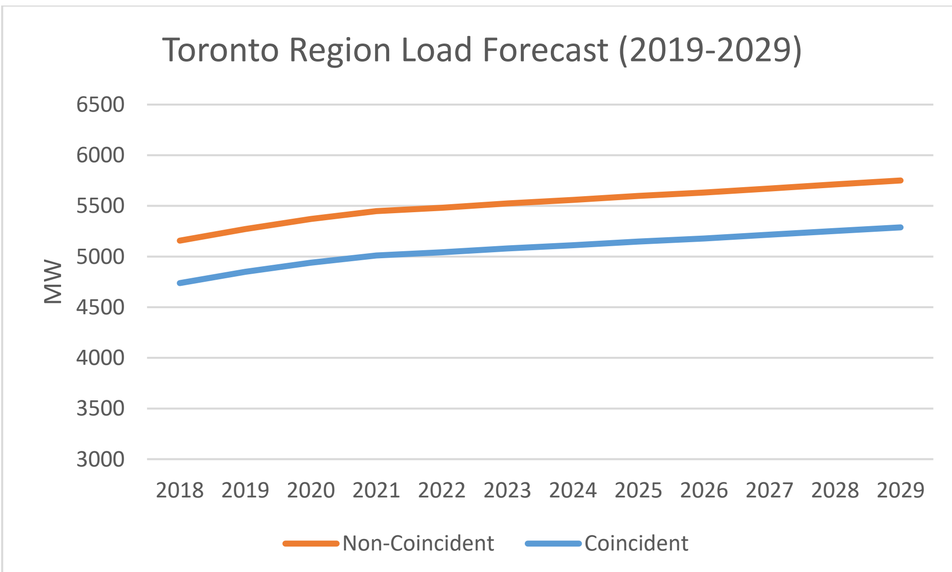


Figure 5-1: Toronto Region Load Forecast

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

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

5.2 Study Assumptions

The following other assumptions are made in this report.

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

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

6 ADEQUACY OF EXISTING FACILITIES

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

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

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

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

Table 6-1: New Facilities Assumed In-Service

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

6.1 230 kV Transmission Facilities

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

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

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

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

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

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

6.2 230/115 kV Autotransformers Facilities

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

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

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

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

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

6.3 115 kV Transmission Facilities

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

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

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

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

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

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

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

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

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

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

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

6.4 Step-Down Transformer Station Facilities

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

Table 6-2: Toronto Step-Down Transformer Stations

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

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

6.5 Longer Term Outlook (2030-2040)

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

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

Table 6-3: Longer Term Adequacy of Transmission Facilities

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

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

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

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

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

7 REGIONAL NEEDS AND PLANS

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

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

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

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

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

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

7.1 Main TS: End-of-Life Transformers

7.1.1 Description

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

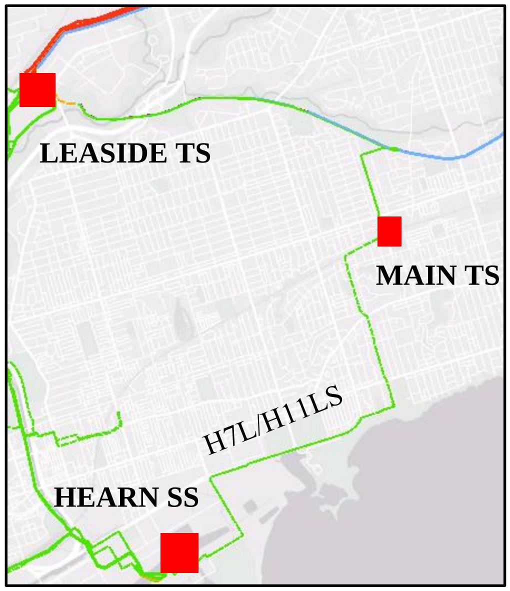


Figure 7-1: Main TS

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

7.1.2 Alternatives and Recommendation

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

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

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

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

7.2.1 Description

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

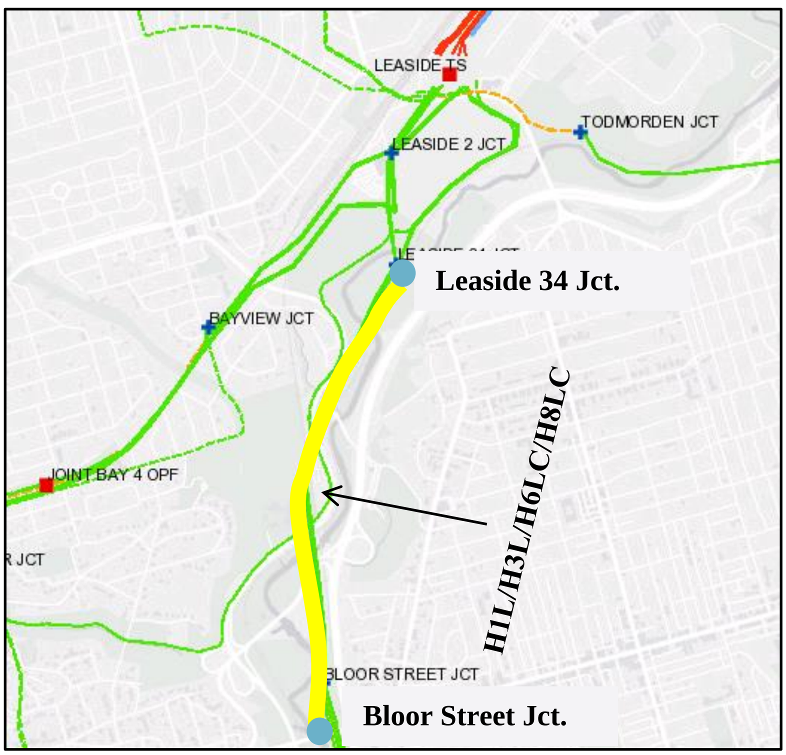


Figure 7-2: H1L/H3L/H6LC/H8LC Section between Leaside 34 Jct. and Bloor St. Jct.

7.2.2 Alternatives and Recommendation

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

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

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

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

7.3.1 Description

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

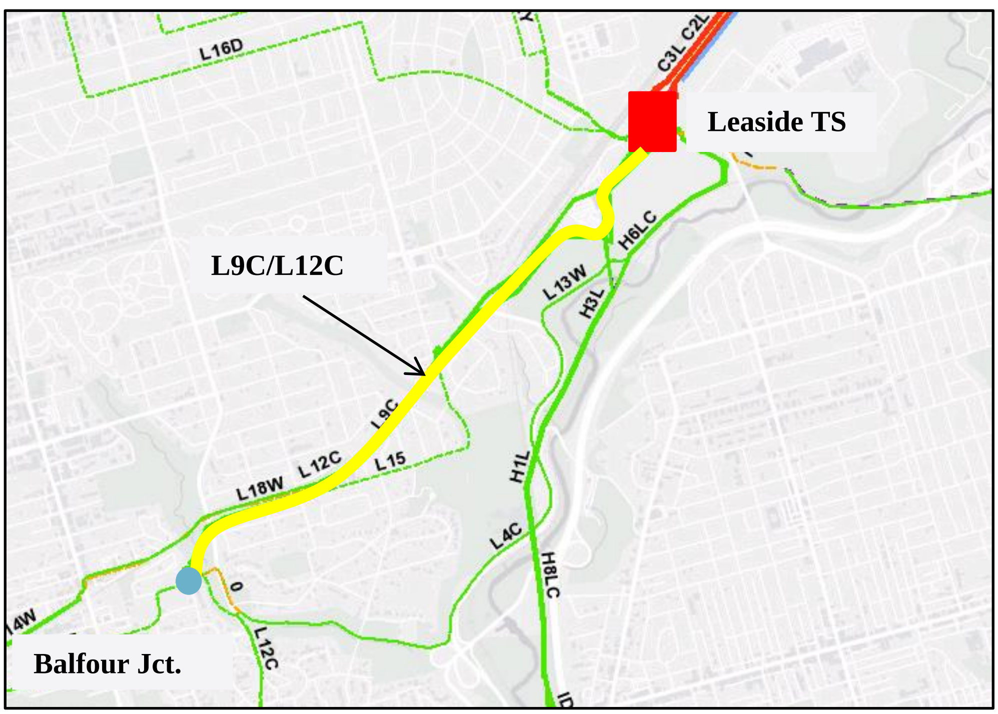


Figure 7-3: L9C/L12C Section between Leaside TS and Balfour Jct.

7.3.2 Alternatives and Recommendation

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

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

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

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

7.4.1 Description

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

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

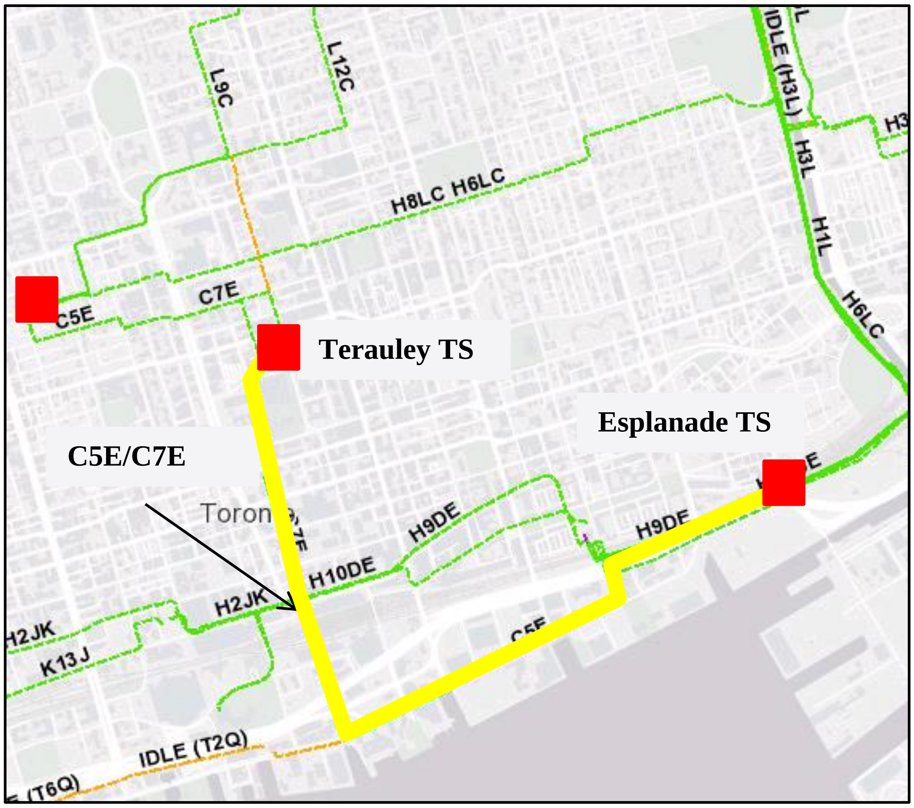


Figure 7-4: C5E/C7E Underground Cable Section between Esplanade TS and Terauley TS

7.4.2 Alternatives and Recommendation

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

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

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

7.5 Richview TS to Manby TS 230 kV Corridor

7.5.1 Description

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

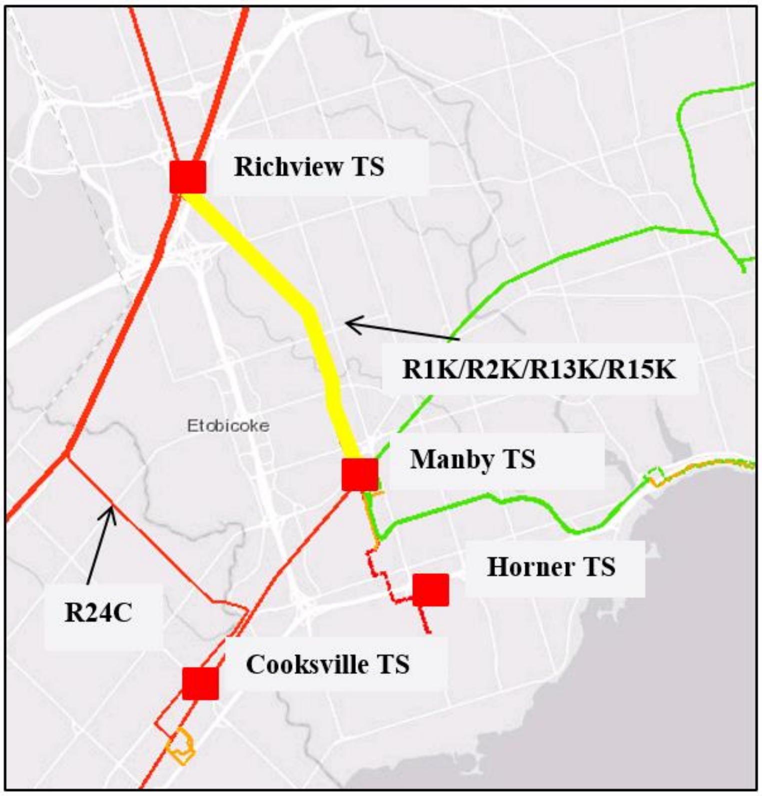


Figure 7-5: Richview TS to Manby TS 230 kV Corridor

7.5.2 Alternatives and Recommendation

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

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

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

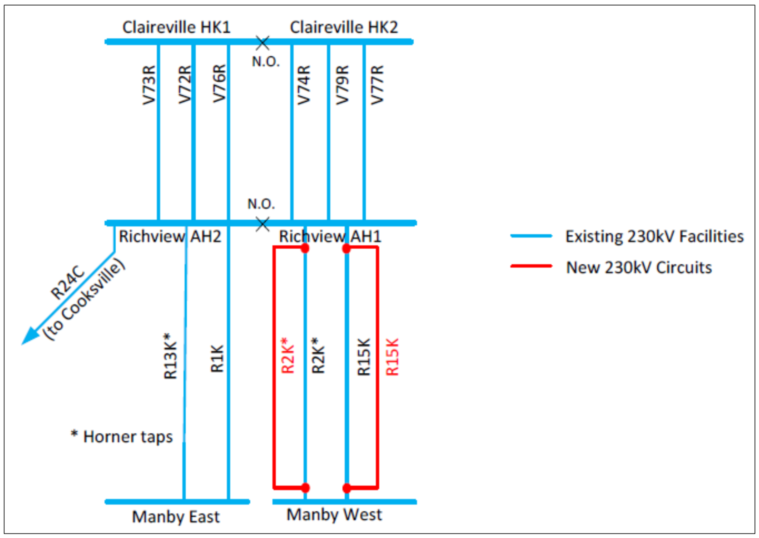


Figure 7-6: Richview TS to Manby TS 230 kV Corridor – Phase 1

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

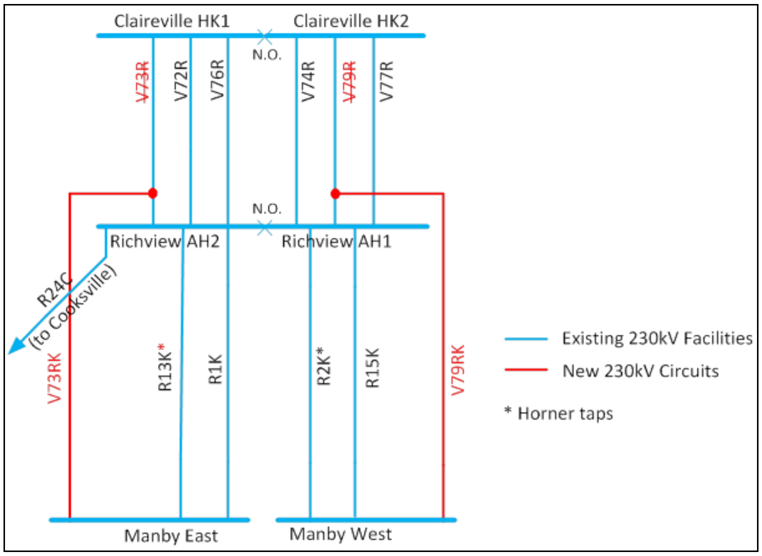


Figure 7-7: Richview TS to Manby TS 230 kV Corridor – Phase 2

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

7.6.1 Description

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

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

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

Figure 7-8: Manby TS

7.6.2 Alternatives and Recommendation

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

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

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

7.7 Bermondsey TS: End-of-Life Transformers

7.7.1 Description

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

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

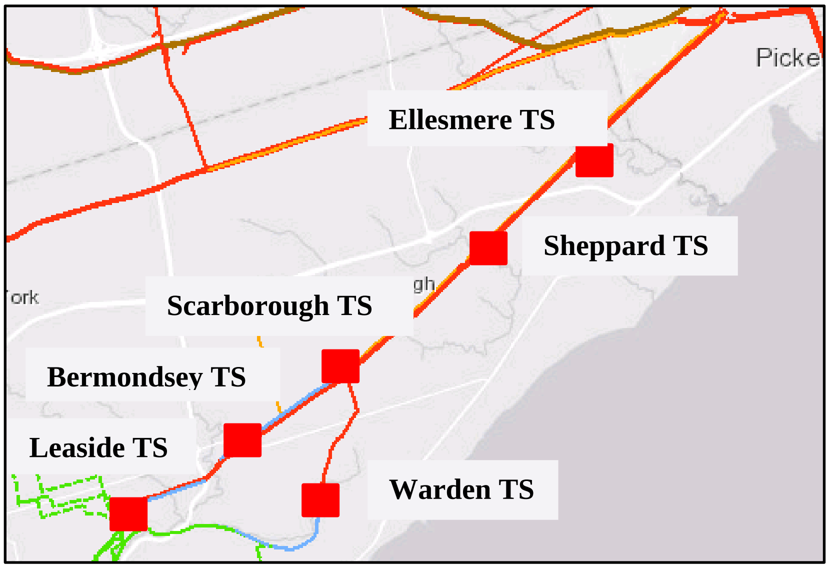


Figure 7-9: Bermondsey TS and Surrounding Stations

7.7.2 Alternatives and Recommendation

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

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

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

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

7.8.1 Description

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

Figure 7-10: John TS

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

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

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

7.8.2 Alternatives and Recommendation

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

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

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

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

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

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

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

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

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

7.9 Long-Term Capacity Needs

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

7.9.1 Fairbank TS Capacity Need

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

7.9.2 Sheppard TS Capacity Need

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

7.9.3 Strachan TS Capacity Need

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

7.9.4 Basin TS Capacity Need

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

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

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

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

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

7.9.5 Manby West TS to Riverside Jct. Corridor Capacity Need

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

7.9.6 Manby West TS Autotransformers T12 Capacity Need

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

7.9.7 Leaside TS to Wiltshire TS Corridor Capacity Need

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

7.9.8 Leaside TS Autotransformers T16 Capacity Need

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

8 CONCLUSIONS AND NEXT STEPS

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

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

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

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

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

The Study Team recommends that:

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

9 REFERENCES

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

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

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

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

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

APPENDIX A. STATIONS IN THE TORONTO REGION

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

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

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

APPENDIX B. TRANSMISSION LINES IN THE TORONTO REGION

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

APPENDIX C. DISTRIBUTORS IN THE TORONTO REGION

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

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

APPENDIX D. TORONTO REGION LOAD FORECAST

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

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

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

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

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

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

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

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

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

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

APPENDIX D: REG Investments Plan

Renewable Energy Generation Investment Plan

28 Sep. 2020

Per: OEB Chapter 5 Consolidated Distribution System Plan
Filling Requirements – Section 5.2.2(d)

Executive Summary

Elexicon Energy Inc. ("Elexicon") has completed its Renewable Energy Generation ("REG") investment plan to provide information to the Ontario Energy Board ("OEB"), the Independent Electricity System Operator ("IESO"), and other interested stakeholders, regarding Elexicon's ability to connect REG projects to its distribution system. Elexicon is requesting a Comment Letter from the IESO regarding:

i. Whether Elexicon has consulted with the IESO, or participated in planning meetings with the IESO;
ii. The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
iii. Whether the REG investments proposed in the Distribution System Plan ("DSP") are consistent with any Regional Infrastructure Plan.

There are currently 594 REG connections on Elexicon's system with a combined generation capacity of 17.03 MW. The breakdown of these REG connections is summarized in Table 1. Of those 594 connections, 532 are micro-generators with a nameplate capacity not exceeding 10 kW, with a total generation capacity of 4.38 MW. There are 47 generation connections sized higher than 10 kW, with an aggregate nameplate capacity of 9.43 MW. The remaining fifteen REG connections are net-metered, of which ten have a generation capacity greater than 10 kW and five have a generation capacity that is 10 kW or lower. The total generation capacity for net metering connections with generation greater than 10 kW is 3.2 MW, while for connections that are 10 kW or less it is 22.14 kW.

Table 1: Summary of REG connection type and size

REG Connection Type	Size	#	Nameplate Capacity (MW)
Generator	≤10 kW	532	4.38
	>10 kW	47	9.43
Net-Metered	≤10 kW	5	0.02
	>10 kW	10	3.20
Total		**594**	**17.03**

Up until 2018, there has generally been a year-over-year increase in the number of new REG connections as a result of programs supported by the government. However, after the programs were cancelled by the end of 2018, there is an evident drop in the number of new connections in 2019 and 2020.

Elexicon uses a multi-constraint approach to assess the ability to connect a new generator to the system and to plan for the overall capacity of the system based on industry standards IEEE 1547 and CSA C22.3. No.9. The key constraints are the minimum load capacity of the feeder, upstream thermal capacity, short-circuit capability, and system voltage characteristics.

1. The defining constraint on the distribution system is typically the minimum load of the feeder, which should be more than the connected generation capacity to prevent unintentional islanding. Since minimum load of a feeder is not directly known, the total capacity of the feeder is used as a proxy. When the connected generation capacity exceeds 25% of the feeder's maximum rated capacity, the feeder is flagged and will be monitored from that point on. The sum of the feeder's connected generation capacity should not exceed 50% of the feeder's maximum rated load capacity.

2. Elexicon reviews thermal capacity limits to ensure that power transformers can operate without causing any safety concerns and impediment to operations. The thermal capacity limit is defined as 60% of the nameplate rating of the power transformer upstream of the feeder.

3. Prior to the connection of generation, the short-circuit capacity of the equipment is also reviewed. Adding new connections increases short-circuit current on the feeder, which can lead to a catastrophic failure if it exceeds a piece of equipment's rated short-circuit capacity.

4. The last constraint to new connections is the voltage profile of a feeder. New connections can impact the voltage profile of a feeder, so the addition is assessed to check if the feeder would have any voltage issues.

Elexicon is currently a part of the following regional planning process groups: GTA East, GTA north, Metro Toronto, Peterborough to Kingston, and South Georgian Bay/Muskoka. Regional planning between utilities facilitates coordination on future and ongoing projects and allows for better communication with the public to meet regional power needs. Consultations with HONI have noted that Cherrywood Transformer Station T7/T8 in the GTA East Region has reached its short-circuit capacity limit. This prevents any new REG connections on downstream feeders. There are no other constraints preventing new REG connections on Elexicon's system.

Table of Contents

Introduction

Elexicon Energy Inc.'s ("Elexicon") legacy utilities, Whitby Hydro Energy Corporation ("Whitby Hydro") and Veridian Connections Inc. ("Veridian"), filed an application to the OEB seeking approval to amalgamate and continue operations as a single corporation. The OEB approved this decision as summarized in the Decision and Order published on December 20th, 2018 (Case EB-2018-0236). Elexicon is preparing and filing a Distribution System Plan ("DSP") to comply with the requirements of the decision which dictate that Elexicon must file a combined DSP within 24 months of the merger.

This Renewable Energy Generation ("REG") Investment Plan provides information to the IESO, OEB, and interested stakeholders regarding the readiness of Elexicon's distribution system to connect REG, including any expansion or reinforcement necessary to remove grid constraints to accommodate the connections of REG for the DSP forecast period 2022 to 2026.

Distribution System Overview

Elexicon is an electric utility company that distributes electricity to the towns of Whitby and Gravenhurst, the cities of Pickering, Ajax, and Belleville, the townships of Brock, Scugog, and Uxbridge, and the municipalities of Clarington and Port Hope. Elexicon distributes electricity to its customers through 57 substations in the areas of Ajax, Belleville, Brock, Clarington, Port Hope, Gravenhurst Table 2 summarizes the count of stations throughout Elexicon's service area by voltage level.

Table 2: Number of stations owned by Elexicon by voltage, area, and municipality

Area	Municipality	kV	# of Stations
Whitby	Whitby	13.8	11
Ajax	Ajax	13.8	6
Ajax	Pickering	13.8	5
Belleville[1]	Belleville	13.8	4.5
Belleville[1]	Belleville	4.16	6.5
Brock	Beaverton	4.16	3
Brock	Brock	8.32	2
Brock	Scugog	4.16	3
Brock	Uxbridge	4.16	2
Clarington	Bowmanville	13.8	3
Clarington	Newcastle	13.8	2
Port Hope	Port Hope	27.6	2
Port Hope	Port Hope	4.16	4
Gravenhurst	Gravenhurst	12.47	1
Gravenhurst	Gravenhurst	4.16	2

[1] Edgehill Substation, located in Belleville, has two transformers, one being 13.8 kV and the other being 4.16 kV.

REG Connections

There are currently 594 REG connections on Elexicon's system, totaling a generation capacity of 17.03 MW. These 594 connections are made up of generator connections and net-metering connections (consisting of a generator and a load). Generator connections were more common prior to 2019 when the government-funded FIT and microFIT programs were active.

Of the 594 active REG connections, 532 are micro-generators with an individual nameplate capacity of 10 kW or less. The combined nameplate capacity of the micro-generators connected to Elexicon's system is 4.38 MW. There are currently 47 generator connections with an individual nameplate greater than 10 kW. The combined nameplate capacity of these generators is 9.41 MW.

Net-metering connections have been available to customers of Elexicon (and Elexicon's predecessors) since 2007 but have seen an increase in the last two years after the termination of the government's support for FIT and microFIT projects. There are currently fifteen net-metering connections, of which ten are above 10 kW and five are 10 kW or less. The net-metering connections above 10 kW have a combined nameplate capacity of 3.2 MW, while the connections that are 10 kW or less have a combined nameplate capacity of 22.14 kW.

Generation Connections over 10 kW

There are currently 47 generation connections above 10 kW on Elexicon's system, all of which utilize solar energy. These connections have a combined generation capacity of 9.41 MW and are scattered across eight different regions of Elexicon's services area: Whitby, Ajax, Belleville, Bowmanville, Gravenhurst, Newcastle, Pickering, and Port Hope. A summary of the connections found in each service area, grouped by their respective connected feeder, can be seen in Table 3.

Table 3: Number and nameplate capacity of generation connections above 10 kW

Area	Feeder	#	Nameplate Capacity (kW)
Ajax	40M-22	2	1000
	40M-45	2	350
	40M-48	2	635
	APPL-F4	1	250
	PICB-F6	1	100
Belleville	8M-8	2	480
	BELL-F2	2	200
	CASC-F1	2	190
	EDGE-F3	1	80
	HERC-F3F4	1	13.3
	JRDS-F1	1	250
	RIVE-F2	1	75

Area	Feeder	#	Nameplate Capacity (kW)
	SIDN-F2	1	40
Bowmanville	SPRY-F3	1	250
Gravenhurst	BAY-F2	1	225
	JAMS-F1	1	100
	MSFL-F3	2	270
Newcastle	CLAR-F1	1	15.5
Pickering	40M-48	1	100
	47M-2	4	733.23
Port Hope	JAME-F1	1	48
Whitby	40M-25	1	130
	40M-27	5	1150
	40M-7	3	660
	40M-8	1	433
	52M-1	4	1075
	52M-6	1	78
	52M-8	1	500

Micro-Generation Connections

There are 532 micro-generation connections, each with a capacity of 10 kW or less. The micro-generation connections have a combined capacity of 4.38 MW. These connections are spread across the following areas: Whitby, Ajax, Beaverton, Belleville, Bowmanville, Cannington, Gravenhurst, Newcastle, Orono, Pickering, Port Hope, Port Perry, Sunderland, and Uxbridge. Table 4 summarizes the number of connections found in each service area along with their connected feeders and generation capacity.

Table 4: Number and nameplate capacity of micro-generation connections (10 kW and below)

Area	Feeder	#	Nameplate Capacity (kW)
Ajax	40M-45	28	250.19
	40M-46	3	29.75
	40M-48	10	93.39
	APPL-F1	3	30
	APPL-F3	3	21.84
	APPL-F4	1	10
	BELL-F1	1	10
	DOWT-F2	2	20
	DOWT-F4	3	27.88
	GREW-F1	3	22.66
	NOTI-F2	1	2.28
	PICB-F1	2	16
	PICB-F2	2	15.75

Area	Feeder	#	Nameplate Capacity (kW)
	PICB-F3	14	124.23
	PICB-F4	1	3
	PICB-F5	4	31.9
	PICB-F6	6	51.4
	WESH-F3	2	16
	WESH-F4	5	42.76
Beaverton	MAIN-F1	1	7
	WILL-F1	1	10
Belleville	8M-4	1	10
	BELL-F2	2	20
	CASC-F2	1	10
	CASC-F3	3	22.535
	CHUR-F2	3	30
	EDGE-F2	2	20
	EDGE-F4	1	10
	GRAV-F1	1	10
	HERC-F1F2	2	19.765
	HERC-F3F4	3	30
	JONE-F3	3	15.178
	JONE-F4	2	20
	JONE-F5	1	6
	REID-F1	9	80
	RIVE-F3	2	18
	SIDN-F1	10	88.93
	SIDN-F2	5	42.87
Bowmanville	54M-11	1	10
	BELL-F2	1	10
	BRAD-F1	2	14.4
	BRAD-F2	10	76.48
	BRAD-F3	2	19.9
	LIBN-F1	6	57.3
	LIBN-F2	12	90.2
	LIBN-F3	3	30
	SPRY-F1	5	36.5
	SPRY-F2	3	30
	SPRY-F4	6	48.3
Cannington	LAID-F2	1	2.3
Gravenhurst	BAY-F1	1	10
	BAY-F3	1	10
	BAY-F4	1	6.87
	FIRS-F2	1	10
	GRAV-F1	3	29.8
	GRAV-F2	2	19.7

Area	Feeder	#	Nameplate Capacity (kW)
	GRAV-F3	1	7.7
	JAMS-F1	1	5
	JAMS-F2	1	7.6
	JRDS-F1	4	37.2
	JRDS-F3	2	20
Newcastle	CLAR-F1	3	26.56
	TORO-F2	5	38.405
	WILM-F1	6	53.2
	WILM-F2	2	10.96
Orono	ORON-F3	2	13.77
Pickering	26M-35	8	66.14
	40M-46	6	40.405
	40M-47	3	23
	40M-48	9	88.42
	47M-2	7	47.61
	47M-4	6	54.26
	BAYR-F1	1	4
	GREN-F1	5	45.32
	GRER-F3	1	10
	GREW-F1	1	9.6
	GREW-F3	3	30
	SAND-F2	2	8.02
	TOWN-F1	1	2.1
Port Hope	CAVN-F1	1	2.82
	CAVN-F3	2	16
	CAVS-F1	2	14.9
	CAVS-F3	2	18.1
	HOWA-F2	1	8
	JAME-F1	6	54.86
	JAME-F2	2	15.95
	PEAC-F2	3	29.8
	SHUT-F1	3	15.84
Port Perry	BIGE-F1	1	10
	BIGE-F3	1	5.87
	CRAN-F2	2	15.16
	MABL-F2	1	10
	PICB-F3	1	10
Sunderland	SUND-F1	1	10
	SUND-F2	1	10
Uxbridge	UXBE-F1	1	10
	UXBE-F2	2	20
	UXBW-F1	2	12.2
	UXBW-F2	1	10

Area	Feeder	#	Nameplate Capacity (kW)
Whitby	10F1	8	60.6
	10F2	1	10
	10F3	3	30
	10F4	3	24.06
	10F6	8	65.92
	11F1	6	47.42
	11F2	9	71.42
	11F3	3	19.7
	11F4	21	171.86
	12F1	3	16.83
	12F2	5	38.85
	13F1	2	17.6
	13F2	3	20.52
	14F1	4	30.52
	14F2	10	71.28
	14F3	8	64.6
	15F1	4	32.6
	15F2	10	89
	15F3	11	90.07
	5F1	11	98.7
	5F2	4	23.2
	5F3	6	52.1
	6F1	2	15
	6F2	12	83.15
	6F3	4	30.47
	7F1	7	43.84
	7F3	4	25.64
	8F1	4	25.53
	8F2	2	20
	8F4	6	44.55
	9F1	2	15.42
	9F3	11	91.22
	9F4	11	86.28

Net Metering

Currently, there are fifteen net-metering connections within Elexicon’s service area, of which ten have a nameplate capacity above 10 kW and five have a nameplate capacity of 10 kW or less. The combined capacity of the net-metering connections above 10 kW is 3.2 MW, while the 10 kW or less connections have a combined nameplate capacity of 22.14 kW. These connections are summarized by areas and feeder in Table 5 and Table 6.

Table 5: Number and nameplate capacity of net-metering connections above 10 kW

Area	Feeder	#	Nameplate Capacity (kW)
Ajax	40M-23	2	740
	DOWT-F2	2	290
	DOWT-F4	2	385
Belleville	8M-8	1	450
	EDGE-F2	1	135
	REID-F1	1	250
	REID-F2	1	950

Table 6: Number and nameplate capacity of net-metering connections 10 kW or less

Area	Feeder	#	Nameplate Capacity (kW)
Whitby	14F3	1	7.6
	5F1	2	5.17
	9F1	1	5.5
	8F4	1	3.87

Applications in Hand

In addition to the currently connected REG, there are several pending applications for new generators (including REG) and energy storage connections. Elexicon has six applications in hand for battery energy storage systems connections which will total 21.14 MW. There is one application for an engine-driven synchronous generator connection in the Whitby service area with a capacity of 800 kW. There are six applications in hand for new solar generation connections totaling 1.39 MW. Finally, there are three applications for combined heat and power generator connections, totaling 1.715 MW. A summary of the applications that describes the connections' type, feeder, and nameplate capacity can be seen in Table 7.

Table 7: Summary of the applications in hand for new connections

Connection Type	Feeder	#	Nameplate Capacity (kW)
Battery Energy Storage System	52M8	1	4
Battery Energy Storage System	81M7	2	2.3
Battery Energy Storage System	8M3	2	12.434
Battery Energy Storage System	8M4	1	2.4
Combined Heat & Power	8M4	2	1.52
Combined Heat & Power	8M8	1	0.195
Engine-Driven Synchronous Generator	40M21	1	0.8
Renewable Generation	54M11	1	0.8
Renewable Generation	REID-F2	1	0.035
Renewable Generation	MSFL-F3	1	0.1
Renewable Generation	SQUI-F4	1	0.2
Renewable Generation	JONE-F4	1	0.06
Renewable Generation	JONE-F5	1	0.135

REG Capacity Assessment

Elexicon evaluates the safety and viability of connecting a new generator to a feeder based on multiple constraints to help ensure the connection does not affect the reliability and safe operation of the distribution system. The inclusion of a new generation connection affects the current flow along the feeder and voltage profile, especially for connections with a nameplate capacity exceeding 10 kW which require a Connection Impact Assessment ("CIA"). The equipment on the distribution system must be assessed to ensure it can handle the stresses during normal operation and short-circuit conditions. Other notable factors include the impact on the voltage profile of the feeder and avoiding unintentional islanding. Elexicon adheres to industry standards IEEE 1547 and CSA C22.3 no.9 in evaluating the impacts of new REG connections.

The defining constraint on the distribution system is typically the minimum load of the feeder, which should be more than the connected generation capacity to prevent unintentional islanding. Since the minimum load of the feeder is not generally known, the maximum capacity of the feeder is used as a proxy. When the total generation capacity connected to a feeder exceeds 25% of the feeder's load, the feeder is flagged and is monitored. The total connected REG capacity on a feeder should not exceed 50% of the feeder's maximum capacity to serve load. No new connections can be added to any feeder which exceed this criterion.

Elexicon also takes into consideration the thermal capacity limits of the system when assessing the viability of adding a new connection. Thermal capacity limits are defined as 60% of the power transformer's nameplate rating associated to the feeder. Adding a new connection affects the current flow on the system; therefore, equipment thermal limits may be exceeded. By performing this check during the connection impact assessment for new connections above 10 kW, Elexicon reduces the risk of losing its assets to damages resulting from overheating, which preserves the safety and reliability of the system.

New generation connections also impact the voltage profile of the feeder in many ways. Elexicon has an obligation to provide electricity to customers at an acceptable quality with limited voltage excursions during normal and switching operations. To maintain a feeder's voltage profile, Elexicon follows the CSA 235 standard, which establishes service levels based on the rated voltage and operating conditions. The CIA checks for voltage issues along the feeder due to the addition of a new connection above 10 kW.

Lastly, new generators contribute short-circuit current to the feeder during fault conditions. Excessive short-circuit current above a piece of equipment's rated short-circuit capacity can lead to catastrophic failure. The CIA performed for proposed connections above 10 kW ensures that feeder and equipment short-circuit limits are not exceeded due to the addition of a new generator.

Since the defining factor limiting new REG connections on the distribution system is typically the minimum load threshold of the feeder, Table 8**Error! Reference source not found.** summarizes the load capacity of each distribution feeder and the 25% and 50% thresholds used as a proxy for minimum load. There are currently no constraints on Elexicon's system that would prevent the connection of new REG. There are, however, constraints on the upstream transmission system that prevent downstream connection of new REG on certain Elexicon feeders. Hydro One's Cherrywood Transformer Station T7/T8 has reached its short circuit capacity limits and no new downstream generation connections can be added. Table 9 summarizes the load capacity and thresholds for transmission feeders in Elexicon's territory.

Table 8: REG connection capacity by MS Feeder

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
Armitage TS	UXBE-F1	4.16	1	0.01	1.95	0.49	0.97	5	3
Armitage TS	UXBE-F2	4.16	2	0.02	1.95	0.49	0.97	5	3
Armitage TS	UXBE-F3	4.16	0	0.00	1.95	0.49	0.97	5	3
Armitage TS	UXBW-F1	4.16	2	0.01	1.95	0.49	0.97	5	3
Armitage TS	UXBW-F2	4.16	1	0.01	1.95	0.49	0.97	5	3
Armitage TS	UXBW-F3	4.16	0	0.00	1.95	0.49	0.97	5	3
Beaverton TS	BEAW-F1	4.16	0	0.00	3.02	0.75	1.51	5	3
Beaverton TS	BEAW-F2	4.16	0	0.00	3.02	0.75	1.51	5	3
Beaverton TS	LAID-F1	8.32	0	0.00	7.21	1.80	3.60	5	3
Beaverton TS	LAID-F2	8.32	1	0.00	7.21	1.80	3.60	5	3
Beaverton TS	MAIN-F1	4.16	1	0.01	6.48	1.62	3.24	5	3
Beaverton TS	SUND-F1	4.16	1	0.01	1.69	0.42	0.84	5	3
Beaverton TS	SUND-F2	4.16	1	0.01	1.69	0.42	0.84	5	3
Beaverton TS	WILL-F1	4.16	1	0.01	3.60	0.90	1.80	5	3
Belleville TS	BELL-F1	13.80	1	0.01	11.95	2.99	5.98	20	12
Belleville TS	BELL-F2	13.80	5	0.23	11.95	2.99	5.98	20	12
Belleville TS	CASC-F1	4.16	2	0.19	3.02	0.75	1.51	7.5	4.5
Belleville TS	CASC-F2	4.16	1	0.01	3.06	0.77	1.53	7.5	4.5
Belleville TS	CASC-F3	4.16	3	0.02	3.06	0.77	1.53	7.5	4.5
Belleville TS	CASC-F4	4.16	0	0.00	3.06	0.77	1.53	7.5	4.5
Belleville TS	CATH-F4	4.16	0	0.00	3.31	0.83	1.65	5	3
Belleville TS	CHUR-F1	4.16	0	0.00	2.11	0.53	1.05	7.5	4.5
Belleville TS	CHUR-F2	4.16	3	0.03	2.11	0.53	1.05	7.5	4.5
Belleville TS	EDGE-F1	13.80	0	0.00	8.60	2.15	4.30	20	12
Belleville TS	EDGE-F2	13.80	3	0.16	8.60	2.15	4.30	20	12
Belleville TS	EDGE-F3	4.16	1	0.08	3.02	0.75	1.51	5	3

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
Belleville TS	EDGE-F4	4.16	1	0.01	3.02	0.75	1.51	5	3
Belleville TS	HARD-F1	13.80	0	0.00	10.15	2.54	5.08	10	6
Belleville TS	HERC-F1F2	4.16	2	0.02	3.06	0.77	1.53	7.5	4.5
Belleville TS	HERC-F3F4	4.16	4	0.04	3.06	0.77	1.53	7.5	4.5
Belleville TS	JONE-F3	4.16	3	0.02	3.02	0.75	1.51	7.5	4.5
Belleville TS	JONE-F4	4.16	2	0.02	3.02	0.75	1.51	7.5	4.5
Belleville TS	JONE-F5	4.16	1	0.01	3.02	0.75	1.51	7.5	4.5
Belleville TS	JONE-F6	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Belleville TS	JONE-F7	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Belleville TS	REID-F1	13.80	10	0.33	10.15	2.54	5.08	20	12
Belleville TS	REID-F2	13.80	1	0.95	10.15	2.54	5.08	20	12
Belleville TS	RIVE-F1	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Belleville TS	RIVE-F2	4.16	1	0.08	3.02	0.75	1.51	7.5	4.5
Belleville TS	RIVE-F3	4.16	2	0.02	3.02	0.75	1.51	7.5	4.5
Belleville TS	RIVE-F4	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Belleville TS	SIDN-F1	13.80	10	0.09	11.95	2.99	5.98	20	12
Belleville TS	SIDN-F2	13.80	6	0.08	11.95	2.99	5.98	20	12
CherryWood TS	APPL-F1	13.80	3	0.03	10.00	2.50	5.00	10	6
CherryWood TS	APPL-F2	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	BAYR-F1	13.80	1	0.00	11.95	2.99	5.98	15	9
CherryWood TS	FAIR-F1	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	FAIR-F2	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	FAIR-F3	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	FAIR-F4	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	MONA-F1	13.80	0	0.00	11.95	2.99	5.98	10	6
CherryWood TS	MONA-F2	13.80	0	0.00	11.95	2.99	5.98	10	6
CherryWood TS	MONA-F3	13.80	0	0.00	11.95	2.99	5.98	15	9
CherryWood TS	MONA-F4	13.80	0	0.00	11.95	2.99	5.98	15	9
CherryWood TS	NOTI-F1	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	NOTI-F2	13.80	1	0.00	10.00	2.50	5.00	15	9
CherryWood TS	NOTI-F3	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	NOTI-F4	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	SAND-F1	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	SAND-F2	13.80	2	0.01	10.00	2.50	5.00	15	9
CherryWood TS	SAND-F5	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	SAND-F6	13.80	0	0.00	10.00	2.50	5.00	15	9
CherryWood TS	SQUI-F1	13.80	0	0.00	10.00	2.50	5.00	10	6

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
CherryWood TS	SQUI-F2	13.80	0	0.00	11.11	2.78	5.56	10	6
CherryWood TS	SQUI-F3	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	SQUI-F4	13.80	0	0.00	11.11	2.78	5.56	10	6
CherryWood TS	TOWN-F1	13.80	1	0.00	10.00	2.50	5.00	10	6
CherryWood TS	TOWN-F2	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	TOWN-F3	13.80	0	0.00	10.00	2.50	5.00	12	7.2
CherryWood TS	TOWN-F4	13.80	0	0.00	10.00	2.50	5.00	12	7.2
CherryWood TS	WESH-F1	13.80	0	0.00	10.00	2.50	5.00	10	6
CherryWood TS	WESH-F2	13.80	0	0.00	10.00	2.50	5.00	10	6
Malvern TS	GREN-F1	8.32	5	0.05	7.21	1.80	3.60	1.5	0.9
Malvern TS	GRER-F3	8.32	1	0.01	7.21	1.80	3.60	1.5	0.9
Malvern TS	GREW-F1	8.32	4	0.03	7.21	1.80	3.60	5	3
Malvern TS	GREW-F3	8.32	3	0.03	7.21	1.80	3.60	5	3
Muskoka TS	JRDS-F1	12.47	5	0.29	9.04	2.26	4.52	6	3.6
Muskoka TS	JRDS-F2	12.47	0	0.00	9.04	2.26	4.52	6	3.6
Muskoka TS	JRDS-F3	12.47	2	0.02	9.04	2.26	4.52	6	3.6
Muskoka TS	MSFL-F3	12.47	2	0.27	10.80	2.70	5.40	4.6	2.76
Orillia TS	BAY-F1	4.16	1	0.01	3.31	0.83	1.65	6	3.6
Orillia TS	BAY-F2	13.80	1	0.23	10.97	2.74	5.49	6	3.6
Orillia TS	BAY-F3	13.80	1	0.01	10.97	2.74	5.49	6	3.6
Orillia TS	BAY-F4	13.80	1	0.01	6.45	1.61	3.23	6	3.6
Orillia TS	FIRS-F1	4.16	0	0.00	2.53	0.63	1.26	5	3
Orillia TS	FIRS-F2	4.16	1	0.01	2.53	0.63	1.26	5	3
Orillia TS	FIRS-F3	4.16	0	0.00	2.53	0.63	1.26	5	3
Orillia TS	FIRS-F4	4.16	0	0.00	2.53	0.63	1.26	5	3
Orillia TS	GRAV-F1	12.47	4	0.04	10.80	2.70	5.40	4.3	2.58
Orillia TS	GRAV-F2	12.47	2	0.02	10.80	2.70	5.40	4.3	2.58
Orillia TS	GRAV-F3	12.47	1	0.01	10.80	2.70	5.40	4.3	2.58
Orillia TS	JAMS-F1	12.47	2	0.11	7.58	1.90	3.79	7.5	4.5
Orillia TS	JAMS-F2	12.47	1	0.01	7.58	1.90	3.79	7.5	4.5
Orillia TS	JAMS-F3	12.47	0	0.00	7.58	1.90	3.79	7.5	4.5
Orillia TS	JAMS-F4	12.47	0	0.00	7.58	1.90	3.79	7.5	4.5
Port Hope TS	CAVN-F1	4.16	1	0.00	3.02	0.75	1.51	7.5	4.5
Port Hope TS	CAVN-F2	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Port Hope TS	CAVN-F3	4.16	2	0.02	3.02	0.75	1.51	7.5	4.5
Port Hope TS	CAVN-F4	4.16	0	0.00	3.02	0.75	1.51	7.5	4.5
Port Hope TS	CAVS-F1	4.16	2	0.01	3.60	0.90	1.80	3	1.8

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
Port Hope TS	CAVS-F3	4.16	2	0.02	3.60	0.90	1.80	3	1.8
Port Hope TS	HOWA-F2	4.16	1	0.01	3.60	0.90	1.80	5	3
Port Hope TS	JAME-F1	27.60	7	0.10	20.01	5.00	10.00	10	6
Port Hope TS	JAME-F2	27.60	2	0.02	20.01	5.00	10.00	10	6
Port Hope TS	PEAC-F2	4.16	3	0.03	3.60	0.90	1.80	5	3
Port Hope TS	SHUT-F1	27.60	3	0.02	20.01	5.00	10.00	10	6
Port Hope TS	SHUT-F2	27.60	0	0.00	20.01	5.00	10.00	10	6
Thornton TS	6F1	13.80	2	0.02	10.00	2.50	5.00	6	3.6
Thornton TS	6F2	13.80	12	0.08	10.00	2.50	5.00	6	3.6
Thornton TS	6F3	13.80	4	0.03	10.00	2.50	5.00	6	3.6
Thornton TS	6F4	13.80	0	0.00	10.00	2.50	5.00	6	3.6
Thornton TS	7F1	13.80	7	0.04	10.00	2.50	5.00	6	3.6
Thornton TS	7F2	13.80	0	0.00	10.00	2.50	5.00	6	3.6
Thornton TS	7F3	13.80	4	0.03	10.00	2.50	5.00	6	3.6
Thornton TS	7F4	13.80	0	0.00	10.00	2.50	5.00	6	3.6
Whitby TS	10F1	13.80	8	0.06	10.00	2.50	5.00	20	12
Whitby TS	10F2	13.80	1	0.01	10.00	2.50	5.00	20	12
Whitby TS	10F3	13.80	3	0.03	10.00	2.50	5.00	20	12
Whitby TS	10F4	13.80	3	0.02	10.00	2.50	5.00	12	7.2
Whitby TS	10F5	13.80	0	0.00	0.00	0.00	0.00	12	7.2
Whitby TS	10F6	13.80	8	0.07	10.00	2.50	5.00	12	7.2
Whitby TS	11F1	13.80	6	0.05	11.95	2.99	5.98	20	12
Whitby TS	11F2	13.80	9	0.07	11.95	2.99	5.98	20	12
Whitby TS	11F3	13.80	3	0.02	11.95	2.99	5.98	20	12
Whitby TS	11F4	13.80	21	0.17	11.95	2.99	5.98	20	12
Whitby TS	12F1	13.80	3	0.02	10.00	2.50	5.00	6	3.6
Whitby TS	12F2	13.80	5	0.04	10.00	2.50	5.00	6	3.6
Whitby TS	12F3	13.80	0	0.00	0.00	0.00	0.00	6	3.6
Whitby TS	12F4	13.80	0	0.00	0.00	0.00	0.00	6	3.6
Whitby TS	13F1	13.80	2	0.02	10.00	2.50	5.00	6	3.6
Whitby TS	13F2	13.80	3	0.02	10.00	2.50	5.00	6	3.6
Whitby TS	14F1	13.80	4	0.03	7.96	1.99	3.98	6	3.6
Whitby TS	14F2	13.80	10	0.07	7.96	1.99	3.98	6	3.6
Whitby TS	14F3	13.80	9	0.07	7.96	1.99	3.98	6	3.6
Whitby TS	15F1	13.80	4	0.03	11.95	2.99	5.98	6	3.6
Whitby TS	15F2	13.80	10	0.09	11.95	2.99	5.98	6	3.6
Whitby TS	15F3	13.80	11	0.09	11.95	2.99	5.98	6	3.6

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
Whitby TS	16F3	13.80	0	0.00	10.00	2.50	5.00	6	3.6
Whitby TS	16F4	13.80	0	0.00	10.00	2.50	5.00	6	3.6
Whitby TS	5F1	13.80	13	0.10	10.00	2.50	5.00	6	3.6
Whitby TS	5F2	13.80	4	0.02	10.00	2.50	5.00	6	3.6
Whitby TS	5F3	13.80	6	0.05	10.00	2.50	5.00	6	3.6
Whitby TS	8F1	13.80	4	0.03	12.15	3.04	6.08	12	7.2
Whitby TS	8F2	13.80	2	0.02	10.00	2.50	5.00	12	7.2
Whitby TS	8F3	13.80	0	0.00	12.15	3.04	6.08	12	7.2
Whitby TS	8F4	13.80	7	0.05	10.00	2.50	5.00	12	7.2
Whitby TS	9F1	13.80	3	0.02	12.15	3.04	6.08	12	7.2
Whitby TS	9F2	13.80	0	0.00	12.15	3.04	6.08	12	7.2
Whitby TS	9F3	13.80	11	0.09	12.15	3.04	6.08	12	7.2
Whitby TS	9F4	13.80	11	0.09	12.15	3.04	6.08	12	7.2
Whitby TS	APPL-F3	13.80	3	0.02	10.00	2.50	5.00	15	9
Whitby TS	APPL-F4	13.80	2	0.26	10.00	2.50	5.00	15	9
Whitby TS	DOWT-F1	13.80	0	0.00	11.11	2.78	5.56	10	6
Whitby TS	DOWT-F2	13.80	4	0.31	11.11	2.78	5.56	10	6
Whitby TS	DOWT-F3	13.80	0	0.00	11.11	2.78	5.56	12	7.2
Whitby TS	DOWT-F4	13.80	5	0.41	11.11	2.78	5.56	12	7.2
Whitby TS	PICB-F1	13.80	2	0.02	10.00	2.50	5.00	15	9
Whitby TS	PICB-F2	13.80	2	0.02	10.00	2.50	5.00	15	9
Whitby TS	PICB-F3	13.80	15	0.13	10.00	2.50	5.00	15	9
Whitby TS	PICB-F4	13.80	1	0.00	10.00	2.50	5.00	15	9
Whitby TS	PICB-F5	13.80	4	0.03	10.00	2.50	5.00	15	9
Whitby TS	PICB-F6	13.80	7	0.15	10.00	2.50	5.00	15	9
Whitby TS	WESH-F3	13.80	2	0.02	10.00	2.50	5.00	15	9
Whitby TS	WESH-F4	13.80	5	0.04	10.00	2.50	5.00	15	9
Wilson TS	BIGE-F1	4.16	1	0.01	1.95	0.49	0.97	5	3
Wilson TS	BIGE-F2	4.16	0	0.00	1.95	0.49	0.97	5	3
Wilson TS	BIGE-F3	4.16	1	0.01	1.95	0.49	0.97	5	3
Wilson TS	BRAD-F1	13.80	2	0.01	10.00	2.50	5.00	10	6
Wilson TS	BRAD-F2	13.80	10	0.08	10.00	2.50	5.00	10	6
Wilson TS	BRAD-F3	13.80	2	0.02	10.00	2.50	5.00	10	6
Wilson TS	CLAR-F1	4.16	4	0.04	3.60	0.90	1.80	1.5	0.9
Wilson TS	CRAN-F1	4.16	0	0.00	1.95	0.49	0.97	5	3
Wilson TS	CRAN-F2	4.16	2	0.02	1.95	0.49	0.97	5	3
Wilson TS	CRAN-F3	4.16	0	0.00	1.95	0.49	0.97	5	3

TS	MS Feeder	Voltage (kV)	# of Connections	Connected Generation (MW)	Capacity (MW)	0.25	0.50	MS TX ONAN Capacity (MVA)	Thermal Capacity Limits (MVA)
Wilson TS	LIBN-F1	13.80	6	0.06	10.00	2.50	5.00	15	9
Wilson TS	LIBN-F2	13.80	12	0.09	10.00	2.50	5.00	15	9
Wilson TS	LIBN-F3	13.80	3	0.03	10.00	2.50	5.00	15	9
Wilson TS	MABL-F1	4.16	0	0.00	1.95	0.49	0.97	5	3
Wilson TS	MABL-F2	4.16	1	0.01	1.95	0.49	0.97	5	3
Wilson TS	MABL-F3	4.16	0	0.00	1.95	0.49	0.97	5	3
Wilson TS	SPRY-F1	13.80	5	0.04	10.00	2.50	5.00	10	6
Wilson TS	SPRY-F2	13.80	3	0.03	10.00	2.50	5.00	10	6
Wilson TS	SPRY-F3	13.80	1	0.25	10.00	2.50	5.00	15	9
Wilson TS	SPRY-F4	13.80	6	0.05	10.00	2.50	5.00	15	9
Wilson TS	TORO-F1	13.80	0	0.00	10.00	2.50	5.00	10	6
Wilson TS	TORO-F2	13.80	5	0.04	10.00	2.50	5.00	10	6
Wilson TS	TORO-F3	13.80	0	0.00	10.00	2.50	5.00	10	6
Wilson TS	WILM-F1	13.80	6	0.05	11.95	2.99	5.98	10	6
Wilson TS	WILM-F2	13.80	2	0.01	11.95	2.99	5.98	10	6
Wilson TS	ORON-F3	8.32	2	0.01	7.21	1.80	3.60	3.3	1.98

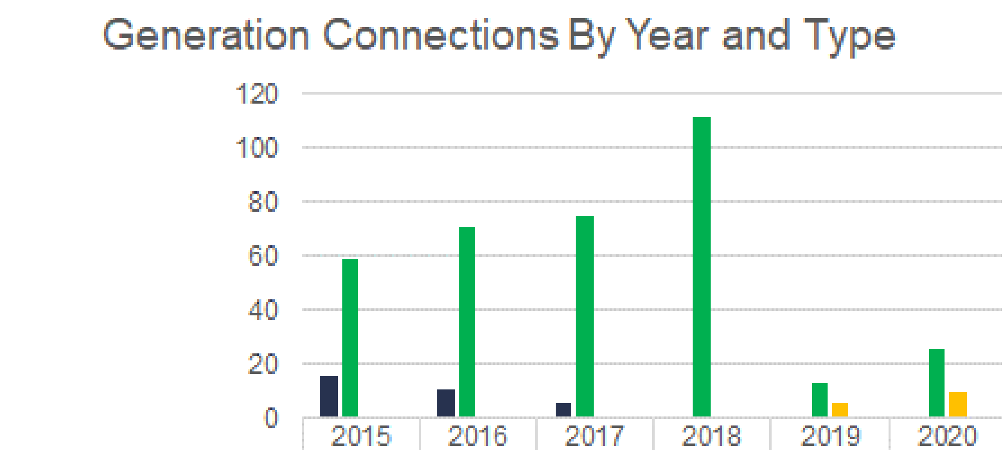
Table 9: REG connection capacity by TS Feeder

TS	TS Feeder	Voltage (kV)	# of Connections	Total Generation (MW)	Capacity (MW)	0.25	0.50
Malvern TS	26M-35	27.60	8	0.07	23.90	5.98	11.95
Sheppard TS	47M-2	27.60	11	0.78	23.90	5.98	11.95
Sheppard TS	47M-4	27.60	6	0.05	23.90	5.98	11.95
Thornton TS	52M-1	44.00	4	1.08	45.72	11.43	22.86
Thornton TS	52M-6	44.00	1	0.08	45.72	11.43	22.86
Thornton TS	52M-8	44.00	1	0.50	45.72	11.43	22.86
Whitby TS	40M-22	44.00	2	1.00	45.72	11.43	22.86
Whitby TS	40M-23	44.00	2	0.74	45.72	11.43	22.86
Whitby TS	40M-25	44.00	1	0.13	45.72	11.43	22.86
Whitby TS	40M-27	44.00	5	1.15	45.72	11.43	22.86
Whitby TS	40M-45	27.60	30	0.60	28.68	7.17	14.34
Whitby TS	40M-46	27.60	9	0.07	28.68	7.17	14.34
Whitby TS	40M-47	27.60	3	0.02	28.68	7.17	14.34
Whitby TS	40M-48	27.60	22	0.92	28.68	7.17	14.34
Whitby TS	40M-7	44.00	3	0.66	45.72	11.43	22.86
Whitby TS	40M-8	44.00	1	0.43	45.72	11.43	22.86
Wilson TS	54M-11	44.00	1	0.01	45.72	11.43	22.86
Belleville TS	8M-4	44.00	1	0.01	45.72	11.43	22.86
Belleville TS	8M-8	44.00	3	0.93	45.72	11.43	22.86

Distribution System REG Forecast

Since 2019, all new connections above 10 kW are net metering connections, while connections whose generation is 10 kW or less could either be Micro FIT or net metering. The number of connection requests has dropped significantly following the cancellation of the FIT program in 2018. Figure 1 illustrates the number of new REG connections each year, assuming that the six applications in hand for new net-metering connections will be connected in 2020. From 2015 to 2018, micro-generation connections (below 10 kW) increased every year. The surge in connections made in 2018 was due to the impending end to the FIT program. Micro-generation connections were significantly less in the years of 2019 and 2020 after FIT was cancelled.

Figure 1: Historical REG connections by year



	2015	2016	2017	2018	2019	2020
Generation >10 kW	16	11	6	1	0	0
Micro-generation	59	71	75	111	13	26
Net-Metering >10kW	0	0	0	0	6	10
Net-Metering ≤ 10kW	0	0	1	0	1	0

Based on historical data, a forecast of the number of new connections is made for each generation type. For Micro FIT and net metering above 10 kW, the average number of new connections for 2019 and 2020 were used to forecast the number of new connections moving forward. For net-metering with a generation of 10 kW or less, it is assumed that there will be one new connection every year. The total generation capacity produced by new connections are calculated by using the forecasted number of new connections multiplied by the historical average connection output of that generation type. Figure 2 and Table 10 show the REG connection forecast for each connection type. Figure 3 and Table 11 show the forecast cumulative REG capacity produced from these connections.

Figure 2: Cumulative historical & forecasted REG connections year over year

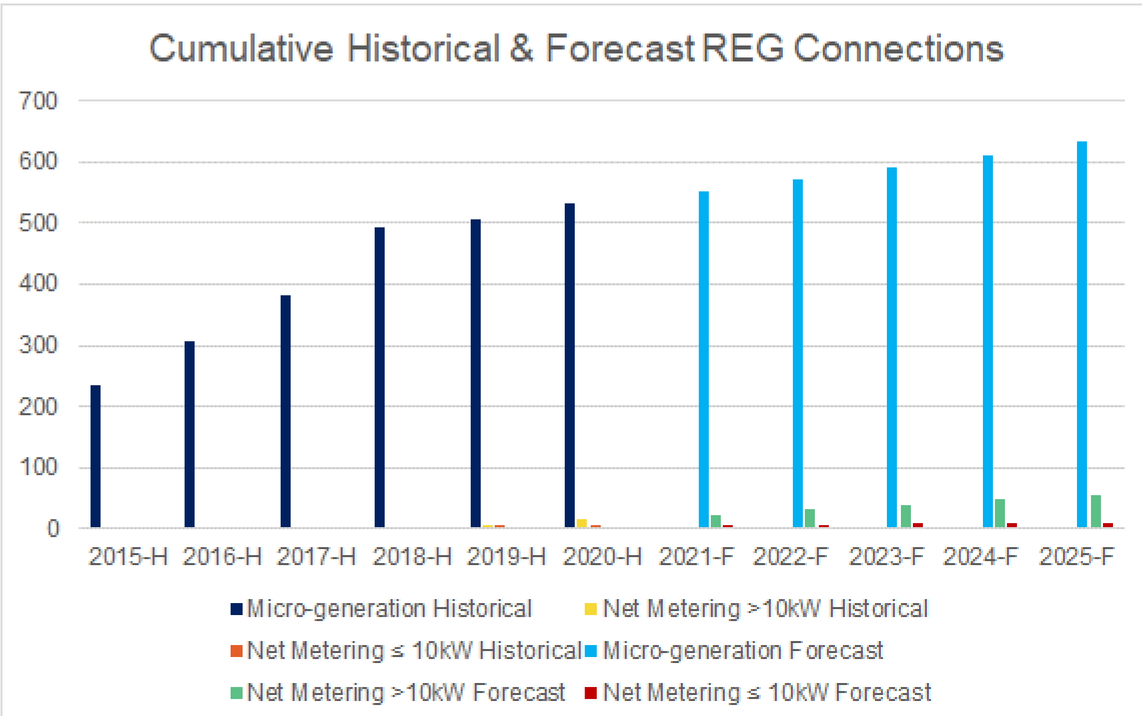


Table 10: Forecast number of new REG connections by type and size

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	20	20	20	20	20
Net Metering >10 kW	8	8	8	8	8
Net Metering ≤10 kW	1	1	1	1	1

Figure 3: Historical and forecast REG capacity

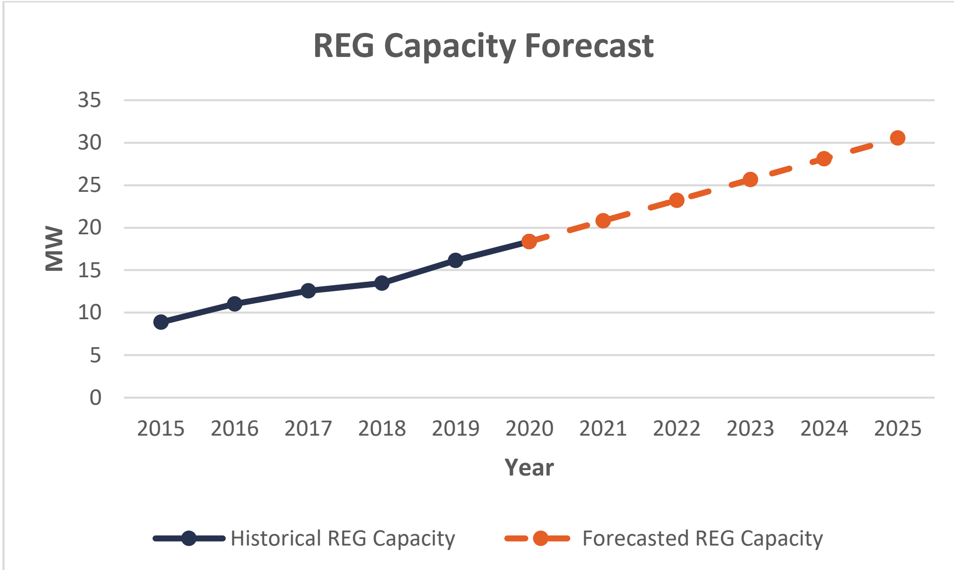


Table 11: Forecast increase of generation capacity in the coming years (in MW)

Forecast Connections	2021	2022	2023	2024	2025
Micro-generation	0.164	0.164	0.164	0.164	0.164
Net Metering > 10kW	2.264	2.264	2.264	2.264	2.264
Net Metering <10kW	0.044	0.044	0.044	0.044	0.044

Planning and Consultation

Elexicon is currently a part of the following five Regional Planning Process ("RPP") groups: GTA East, GTA north, Metro Toronto, Peterborough to Kingston, and South Georgian Bay/Muskoka. Regional planning between utilities allows for closer coordination when planning for future and ongoing projects as well as better engagement with the public to meet regional power needs. A summary of the RPP groups can be seen in the below table along with the partner utilities.

Table 12: summary of the regional planning process groups as well as its members.

RPP Group	Members
GTA East	Elexicon
	Oshawa PUC Networks Inc.
	Hydro One Networks Inc.
GTA North	Elexicon
	Alectra Utilities Co.
	Hydro One Networks Inc.
	Newmarket-Tay Power Distribution Ltd.
	Toronto Hydro Electric System Limited

RPP Group	Members
Metro Toronto	Elexicon
	Alectra Utilities Co
	Hydro One Networks Inc.
	Toronto Hydro Electric System Limited
Peterborough to Kingston	Elexicon
	Eastern Ontario Power
	Kingston Hydro
	Lakefront Utilities
	Peterborough Utilities
	Hydro One Networks Inc.
South Georgian Bay/Muskoka	Elexicon
	Alectra Utilities
	Hydro One Distribution
	InnPower
	Lakeland Power
	Midland PUC
	Newmarket-Tay Power
	Orangeville Hydro
	Orillia Power
	PowerStream COLLUS
	Wasaga Distribution

Regional planning is a continuous process that ensures a reliable supply of electricity to Ontario's electricity planning regions. The first step in the RPP is an assessment that looks at changes in demand in a given area to determine the needs in the region. The Needs Assessment is carried out by the transmitter with data supplied by the IESO and the other local distribution companies. The Scoping Assessment stage, which is led by the IESO and helps determine the best planning approach, produces a Scoping Assessment Outcome Report. If the report determines that an Integrated Regional Resource Plan ("IRRP") is required, then the IESO, the transmitter, and the local distribution companies work together to develop a plan to address the electricity needs of the region. The final step is to produce the Regional Infrastructure Plan ("RIP"), which could occur if the Scoping Assessment determined that needs cannot be met by alternative resources, if an analysis determines that a wires-only solution is part of the near-term solution during the IRRP, or if upon the completion of the IRRP process it is determined that a wires-only solution is a part of the overall integrated solution for the region. This process is led by the transmitter.

The RPP groups for Peterborough to Kingston and GTA North are both in the Needs Assessment stage, having nine and eight needs/projects respectively. The RPP groups for GTA East, Metro Toronto, and South Georgian Bay/Muskoka are all currently in the RIP stage, having four, eight, and six needs/projects. Respectively.

A key issue that relates to Elexicon's ability to facilitate new REG connections is Cherrywood Transformer Station, located in the GTA East region. Hydro One's

Cherrywood Transformer Station T7/T8 has reached its short-circuit capacity limit, which prevents the downstream connection of new REG.

Investments to Facilitate REG

There are currently no constraints on Elexicon's distribution system that would prevent the connection of the REG applications in hand and those forecast over the next five years. As a result, Elexicon has not planned any investments to accommodate new REG connections to its distribution system.

There are, however, constraints on the upstream transmission system that prevents downstream connection of new REG. Hydro One's Cherrywood Transformer Station T7/T8 has reached its short-circuit capacity limit which prevents new additions of downstream REG connections. Elexicon will continue to work with Hydro One through the RPP and various consultations outside of the RPP to alleviate upstream constraints that prevent new REG connections to Elexicon's distribution system.

APPENDIX E: IESO Comment Letter

IESO response to Elexicon Energy Inc.'s REG Investment Plan 2021 – 2025

In accordance with the Ontario Energy Board's (OEB) Chapter 5 filing requirements to submit a Distribution System Plan (DSP) with its Cost of Service application, on October 1, 2020, Elexicon Energy Inc. (Elexicon) sent its Renewable Energy Generation (REG) Plan as part of its DSP, to the Independent Electricity System Operator (IESO) for comment. The IESO has reviewed Elexicon's REG Plan and notes that it contains no investments specific to connecting REG for the Plan period 2021 - 2025.

The IESO notes that Elexicon's service territory is within five regional planning groups: GTA East, GTA North, Metro Toronto, Peterborough to Kingston, and South Georgian Bay/Muskoka. For all of these regions the IESO confirms that Elexicon has been a participating member of the Working Groups[1]. The status of regional planning activities for these regions can be found on the IESO's website.

Elexicon's REG Plan states: "There are currently no constraints on Elexicon's distribution system that would prevent the connection of the REG applications in hand and those forecast over the next five years. As a result, Elexicon has not planned any investments to accommodate new REG connections to its distribution system."

The IESO submits that as Elexicon has no REG investments during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties [2].

The IESO appreciates the opportunity provided to review the REG Plan of Elexicon, and looks forward to working together further throughout the regional planning processes.

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[1] Working Group members along with the IESO and Hydro One (Distribution and Lead Transmitter): **GTA East** – Elexicon, and Oshawa PUC Networks Inc.; **GTA North** – Elexicon, Alectra Utilities Corporation, Newmarket-Tay Power Distribution Ltd., and Toronto Hydro Electric System Limited; **Metro Toronto** – Elexicon, Alectra Utilities Corporation, Toronto Hydro Electric System Limited, and Tillsonburg Hydro Inc.; **Peterborough to Kingston** – Elexicon, Eastern Ontario Power, Kingston Hydro, Lakefront Utilities, former Peterborough Distribution Inc. (now Hydro One Distribution); **South Georgian Bay/Muskoka** - Elexicon, Alectra Utilities Corporation (includes former Collus PowerStream Corporation), InnPower Corporation, Lakeland Power Distribution Ltd., Newmarket-Tay Power (includes former Midland PUC), Orangeville Hydro Limited, Orillia Power Distribution Corporation, and Wasaga Distribution Inc.

[2] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

APPENDIX F: Asset Condition Assessment Report

METSCO

MAKING IT POSSIBLE

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ASSET CONDITION ASSESSMENT REPORT 2019/2020

Prepared by

P-19-205 R3

March 2021

Disclaimer

This report has been prepared by METSCO Energy Solutions Inc. (“METSCO”) for Elexicon Energy Inc. (“Elexicon”). Neither Elexicon, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by Elexicon or METSCO.

Asset Condition Assessment for Elexicon Energy Inc.

Report & Conclusions

March 2021

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Version History

Version	Date	Description
IFR	January 28, 2020	First Complete Draft
R0	March 22, 2020	Ready for Acceptance
R1	January 17, 2021	Updated with new inspection and test results
R2	February 25, 2021	Updated asset counts based on comments on R1
R3	March 10, 2021	Changed chart and added footnotes to ACA summary results in Exec. Summary

Executive Summary

This report relays the findings of an Asset Condition Assessment ("ACA") of the major electrical and select civil assets of the recently incorporated 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 discussion 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 enhancements to 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 retained METSCO Energy Solutions Inc. ("METSCO") to conduct an inaugural ACA study for the recently merged entity. Comprised of the former assets of Whitby Hydro Electric Corporation and Veridian Connections Inc., Elexicon is in the process of preparing its first integrated Distribution System Plan and defining the merged company's new 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 establishment of a comprehensive and sustainable AM practice over time.

Having operated as two separate entities until 2019. Elexicon's predecessors had distinct approaches to AM, including the scope and manner of asset data collection and analysis. As such, METSCO's ability to create unified Health Index ("HI") formulations for the newly merged asset base relied on the degree of consistency and completeness of information available at the time of the study. As a result, we present our findings for a number of asset classes as separate sub-populations of legacy Veridian and Whitby assets, with full expectation that the merged utility will take steps to consolidate the data collection and analysis practices across its service territory, enabling it to undertake consistent asset health analysis in future ACA iterations. As of 2020, the inspection and maintenance program areprograms are combined and the 2020 data included in this report reflects asthat 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 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, METSCO clearly identified these assets as having an "Invalid 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, however, we note that the scope of available asset data employed in our study (and by extension, the comprehensiveness of its results) exceeds the previous ACA iterations prepared by both Elexicon's predecessors. While ample room for continuous improvement remains, we note the progress relative to the prior studies is material and deserves commendation.

Scope of the Study

Our study covers thirteen electrical and two civil asset classes, which collectively represent the bulk of material assets owned by the merged utility and cover all the essential equipment directly involved in the delivery of electricity distribution service.

- Overhead system assets:
    - Wood poles;
    - Concrete poles;
    - Overhead conductor;
    - Pole mounted transformers; and
    - Overhead switches.
- Underground system assets:
    - Underground cable;
    - Pad mounted transformers;
    - Pad mounted distribution switchgear;
    - Vault transformers.
- Station assets:
    - Station power transformers;
    - Station circuit breakers;
    - Station batteries;
    - Station protection relays;
    - Station fences; and
    - Station buildings.

As METSCO gleaned from its conversations with Elexicon throughout the course of this study, the utility is currently articulating the fundamental tenets of its long-term AM strategy, including the interim approaches to account for the ongoing pace of consolidation activities and the impact of the ten-year distribution rate freeze period, which will limit its ability to seek incremental rate funding until its first rebasing as a consolidating entity in 2028. As such, the scope of this report goes beyond the traditional asset health analysis approach and contains an extended discussion on the role of asset health data in mature AM frameworks, special considerations associated with merger-related activities, and suggestions as to potential approaches for closing the existing data gaps in a sustainable manner. We suggest adopting advanced AM measures that would help the utility make informed trade-offs as to its upcoming asset intervention decisions and track the progress of its overall AM maturity level.

Methodology and Findings

For all asset classes that underwent assessment, METSCO 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 HI formulations 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 0-1.

Table 0-1: 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

The relative contribution of various Condition Parameter scores on the aggregate HI results is a function of weighting – assigned by an engineer to each HI subcomponent prior to commencing calculations. Using this methodology, METSCO calculated HI results for every asset class in the scope of our assessment. METSCO's findings for each asset class developed using this methodology provided in Figure 0-1 and are described in more detail in Section 4.

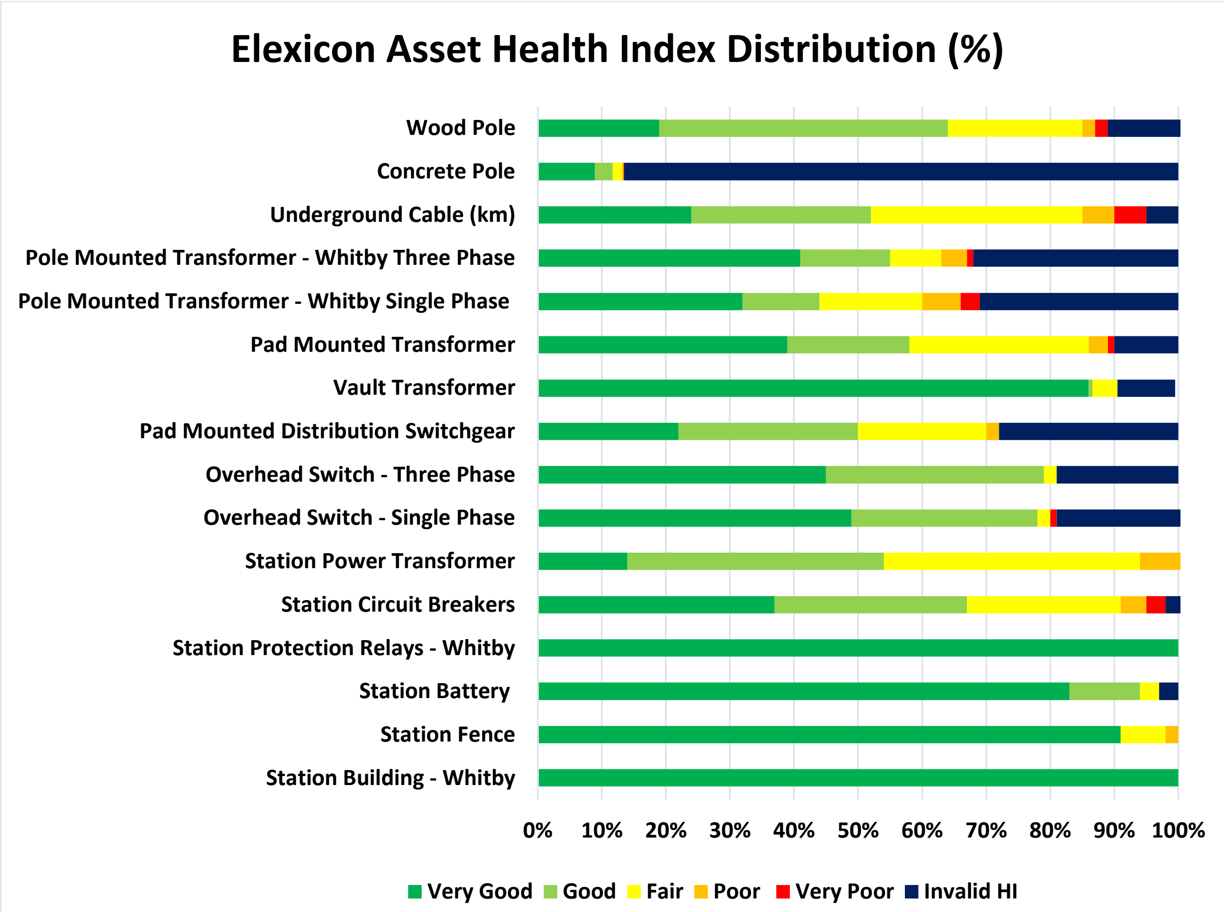


Figure 0-1: Overall Asset Condition Assessment Results[1]

As the above figure indicates, the vast majority of Elexicon's assets are in Fair condition or better based on our assessment, with relative contributions of Poor or Very Poor components being relatively minor and not indicative of extensive deterioration across the system or any concerns with the manner in which assets have been managed in the past.

We note the presence of assets classified as having an Invalid HI corresponding to the individual units where the amount of available data inputs was below the required threshold

[1] Asset classes specifically referencing Whitby region refers asset classes where Veridian region data was insufficient and therefore omitted from this analysis.

– below which the HI cannot be reliably calculated. Importantly, however, the asset classes most affected by data availability issues fall into three groups that contextualizes the observed data availability:

1. Equipment where one or both of Elexicon's predecessors 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).

Section 4 of this report provides an extensive discussion of the HI calculations for each asset class, outlines the assumptions underlying our interpretation of the data provided by Elexicon, and provides recommendations for future enhancements.

Elexicon's Current Health Index Maturity and Continuous Improvement

In a number of 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. In some cases, only the age data is available for a given type of equipment. Overall, however, 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 wood poles and station power transformers, we were able to construct relatively advanced multi-factor health indices. While comparatively less information is available for a number of 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, METSCO 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 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.

Table of Contents

List of Figures

List of Tables

1 About this Report

Elexicon Energy Inc. ("Elexicon" or "the utility") engaged METSCO Energy Solutions Inc. ("METSCO") to prepare an Asset Condition Assessment ("ACA") study for the assets comprising Elexicon's distribution system. The ACA is a critical input for preparation of the utility's Distribution System Plan to be filed with the Ontario Energy Board ("OEB") at a later date.

Elexicon is a regulated electricity distributor in Ontario and a product of a recent merger between the former Whitby Hydro Electric Corporation and Veridian Connections Inc., approved by the OEB in late 2018.[2] Given the recency of the merger, this ACA represents the first instance of an integrated asset condition study where the distribution assets of the two former utilities undergo analysis with a single capital asset portfolio. While in select few cases METSCO had to make methodological adjustments to account for the data gaps between the two sets of legacy utility data, such instances are clearly identified within the body of the report, and the two separate sub-sets of results are provided. To assist Elexicon with further asset condition data integration efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

In preparation of this report, METSCO relied on the following data sources:

- Asset inspection and testing data collected by Elexicon staff or external contractors;
- Trouble reports for certain types of equipment completed by employees;
- Interviews with Elexicon's engineering and asset management ("AM") staff;
- Past deliverables pertaining to specific undertakings prepared by staff or consultancies.

Overall, Elexicon's predecessor utilities possessed a material amount of information regarding their core electricity system assets, which enabled us to compile asset Health Index ("HI") formulations that are broadly consistent with those employed by other Ontario electricity distributors. Given the relative recency of the advanced AM methodologies being implemented in Ontario and elsewhere in North America, both legacy utilities' datasets contained a series of significant gaps related to inspection data for many asset types. In such instances, METSCO 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 HI calculation as per the broadly accepted methodology. As such and by way of foreshadowing our recommendations to management, METSCO

[2] Ontario Energy Board, Decision and Order, "EB-2018-0236 Veridian Connections Inc. and Whitby Hydro Electric Corporation: application for approval to amalgamate and continue operations as a single electricity distribution company," December 20, 2018

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 in its ongoing work to define the scope and nature of its future asset management strategy, this report contains a number of recommendations identifying specific types of data to be collected for the asset classes examined. We also outline options for Elexicon to pace its efforts in collecting additional data parameters we recommend and/or rectifying the existing data gaps within specific datasets.

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 on the basis of 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 in the Distribution Utility Industry

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 a number of 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 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 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 which 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 2-1 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.

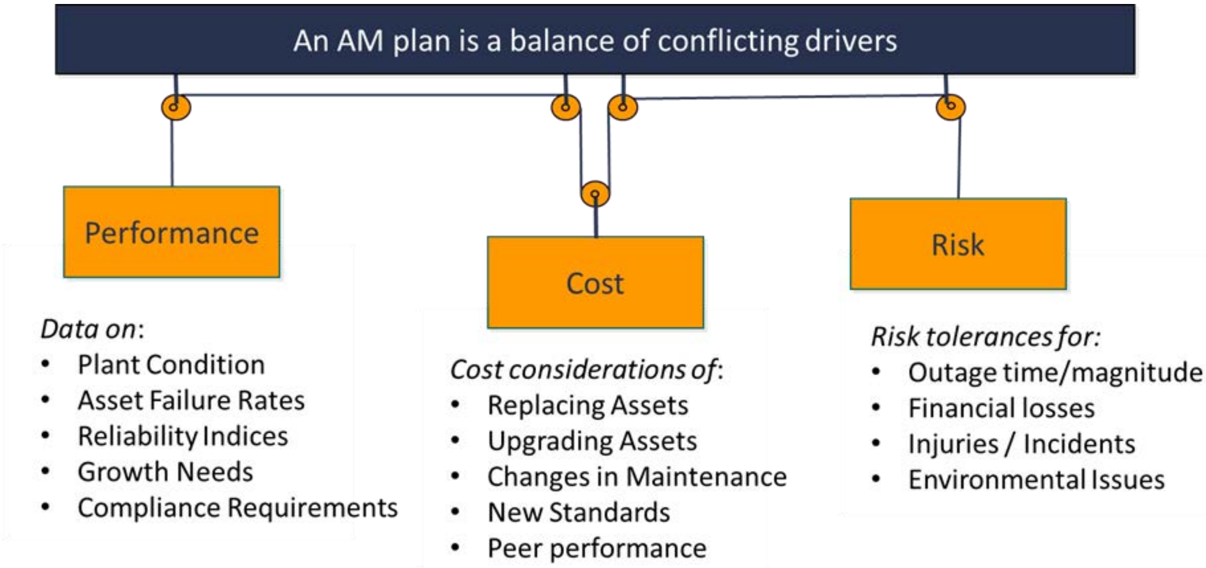


Figure 2-1: Key AM Plan Inputs and Considerations

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 continued development of engineering and economic science. The knowledge and experience of utility subject matter experts continues to play an important role in the development and 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 positions it to collect and leverage the information consistent with the first of the three major types of AM decision-making inputs categorized in section 2.1. 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.

2.2 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 a number of 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 into 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 contemplated as a part of strategic discussions towards 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. We discuss a number of ways in which Elexicon can leverage their ACA findings beyond the generation of the Asset Replacement Plan ("ARP") in Section 5.3 of this report.

2.3 Asset Condition Assessments in the Context of Mergers and Acquisitions

An important consideration giving this particular ACA document added significance is the fact that it is the first instance where asset condition is being evaluated for the combined assets of the recently merged utility. Accordingly, the results of this report can be expected to have a material bearing on the scope and nature of the near-term replacement plans and longer-term asset intervention strategies for the new entity. While both predecessor utilities have been using ACA as a planning tool in the past, this integrated ACA may provide additional insights for the formation of a unified asset strategy for the merged entity over the longer term.

A natural complication of completing the ACA for newly merged entities is the fact that each predecessor utility operated using its own set of asset maintenance and equipment testing practices and asset record-keeping systems. Moreover, the differences in information collection practices naturally led to the predecessor utilities using distinct methodologies for calculating asset HI in their previous ACA iterations. To address these expected discrepancies while making the most of the available information, METSCO relied on a new set of HI that is somewhat different from the methodologies used by either utility in the past.

In some cases, doing so involved dropping a single Condition Parameter available to and used in prior studies by one of the utilities. In others, we adjusted the relative weighting of one of the Condition Parameters relative to what one of the predecessor utilities used to account for additional data that was available to both predecessors but not used by one of them. Of all the Health Indices calculated as part of this report, there are, nevertheless, a number of instances where data availability discrepancies required METSCO to use separate methodologies for the former Veridian and Whitby assets, and then combine the results on the basis of the calculated condition grade for the purposes of presentation.

It is notable that using a new set of indices for a merged entity that deviates somewhat from either of the former utilities' ACA formulations impacts the asset managers' ability to review the year-over-year continuity in asset health trends in the short term. In METSCO's view, however, this temporary disadvantage is offset by the benefit of employing a broadly consistent approach for the entire asset base from the very outset of the integrated operations. In doing so (and notwithstanding the few discrepancies in approaches noted above) the newly merged utility establishes a common outlook on its assets using an independent methodology grounded primarily in the asset data availability, rather than a legacy approach used historically by one of the utilities. A common starting point should then enable the planners to identify the scope and nature of the most immediate asset intervention priorities and provide ample inputs for the broader deliberations around the new utility's AM framework.

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. 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 3-1 presents the HI ranges and the corresponding asset condition.

Table 3-1: 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 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	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on 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 degradation and eventual failure of that particular asset type. A weight is assigned to each Condition Parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 provides an example of an HI formulation table.

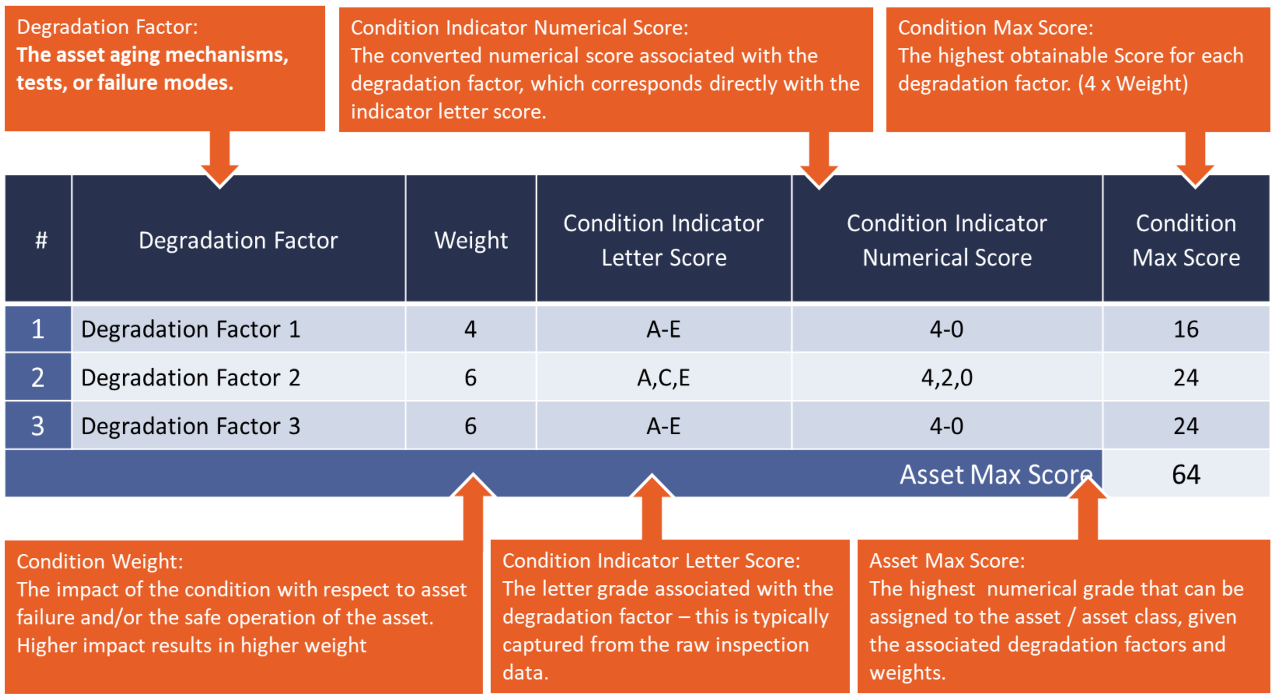


Figure 3-1: HI Formulation Components

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 assets health from being covered up by averaging processes during the HI calculation.

The conversion from alphabetic ranking to numerical grade and a brief characteristic description of the grade is provided in Table 3-2.

Table 3-2: 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 on the basis of following formula:

$$HI = \left(\frac{\sum_{i=1} W_i * CI_i}{CI_{max.}}\right) x\ 100\%$$

where:

- i corresponds to the Condition Parameter number within the HI formulation;
- 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 towards the asset's overall failure probability;
- CI_{max} represents the highest numerical grade that can be assigned to the asset and is be 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 Availability Index

The 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:

$$DAI = \left(\frac{\sum_{i=1} W_i * \alpha_i}{\sum_{i=1} W_i}\right) x\ 100\%$$

where:

- i iterates through the Condition Parameters within the HI formulation;
- W_i 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.

3.2.1 Data Gaps

The HI formulations calculated in this study are based only on available data provided by Elexicon. In almost all instances, additional Condition Parameters or tests exists 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. Depending on the asset class in question, the DAI threshold is either 70% or 66.7%. 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 calculating 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 the passage of 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 period of time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO 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 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 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 METSCO 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 HI formulation for each asset class, the calculated HI scores, and the data available to perform the study.

This report is the first ACA of the combined legacy Whitby and Veridian operations. The most recent ACA report for the Whitby assets is the 2018 ACA report prepared by METSCO and the most recent Veridian ACA is the 2018 ACA report prepared by Kinectrics Inc. We understand that neither document was published publicly as both were the background to filing processes that were not completed when the new Elexicon utility was created.

The datasets of the two legacy utilities are substantially different; many of the less material assets were not reported in the Veridian report, and as such, a different dataset was collected. The result of this report is that, for some assets, the DAI is relatively low. There was an option to only report those assets with mature processes in both areas, but it was deemed useful to highlight those assets where data improvements are expected to show progress in future reports.

For most of the assets, an HI was 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. While two data points are not sufficient for a rigorous HI (which requires a minimum of three input parameters to qualify as a full HI), the availability of some condition data is significantly better than none. In these cases, the comment is made that a two-parameter assessment was conducted. For the sake of consistency in reviewing the study's results, however, all of our findings are presented in the same visual distribution format – separating assets into five condition bands between "Very Poor" and "Very Good" with the sixth category of "No Valid HI" to identify the number of assets where data availability was insufficient to meet the threshold.

Table 4-1 and Figure 4-1 present the results of our ACA study in the numerical and graphical format respectively.

Table 4-1: Summary Results

Asset Category	Population – Note 1	HI Distribution (%) – Note2						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Wood Pole	34,111	19%	45%	21%	2%	2%	12%	88%
Concrete Pole	2,447	9%	3%	2%	0%	0%	87%	20%
Underground Cable (km)	2,336	24%	28%	33%	5%	5%	5%	94%
Overhead Conductor (km)	4,317	-	-	-	-	-	-	Note 3
Pole-Mounted Transformer- Single Phase	1,274	32%	12%	16%	6%	3%	31%	30%
Pole-Mounted Transformer- Three Phase – Note 4	191	41%	14%	8%	4%	1%	32%	
Pad-Mounted Transformer	13,599	39%	19%	28%	3%	1%	10%	95%
Vault Transformer	154	86%	1%	4%	0%	0%	9%	54%
Pad-Mounted Distribution Switchgear	439	22%	28%	20%	2%	0%	28%	72%
Overhead Switch – Three-Phase	3,387	45%	34%	2%	0%	0%	19%	84%
Overhead Switch – Single-Phase	14,315	49%	29%	2%	0%	1%	20%	86%
Station Power Transformer	94	14%	39%	39%	7%	0%	0%	99%
Station Circuit Breaker	175	37%	30%	24%	4%	3%	3%	98%
Station Battery	35	83%	11%	3%	0%	0%	3%	Note 3
Station Protection Relay – Whitby	34	100%	0%	0%	0%	0%	0%	Note 3
Station Fence	46	91%	0%	7%	2%	0%	0%	Note 3
Station Building – Whitby	14	100%	0%	0%	0%	0%	0%	Note 3

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: DAI not meaningful given the type of available data. Assets with poor DAI have recommendations for improvement within the body of the report.

Note 4: One three-phase pole-mounted transformer refers to a group of three individual assets.

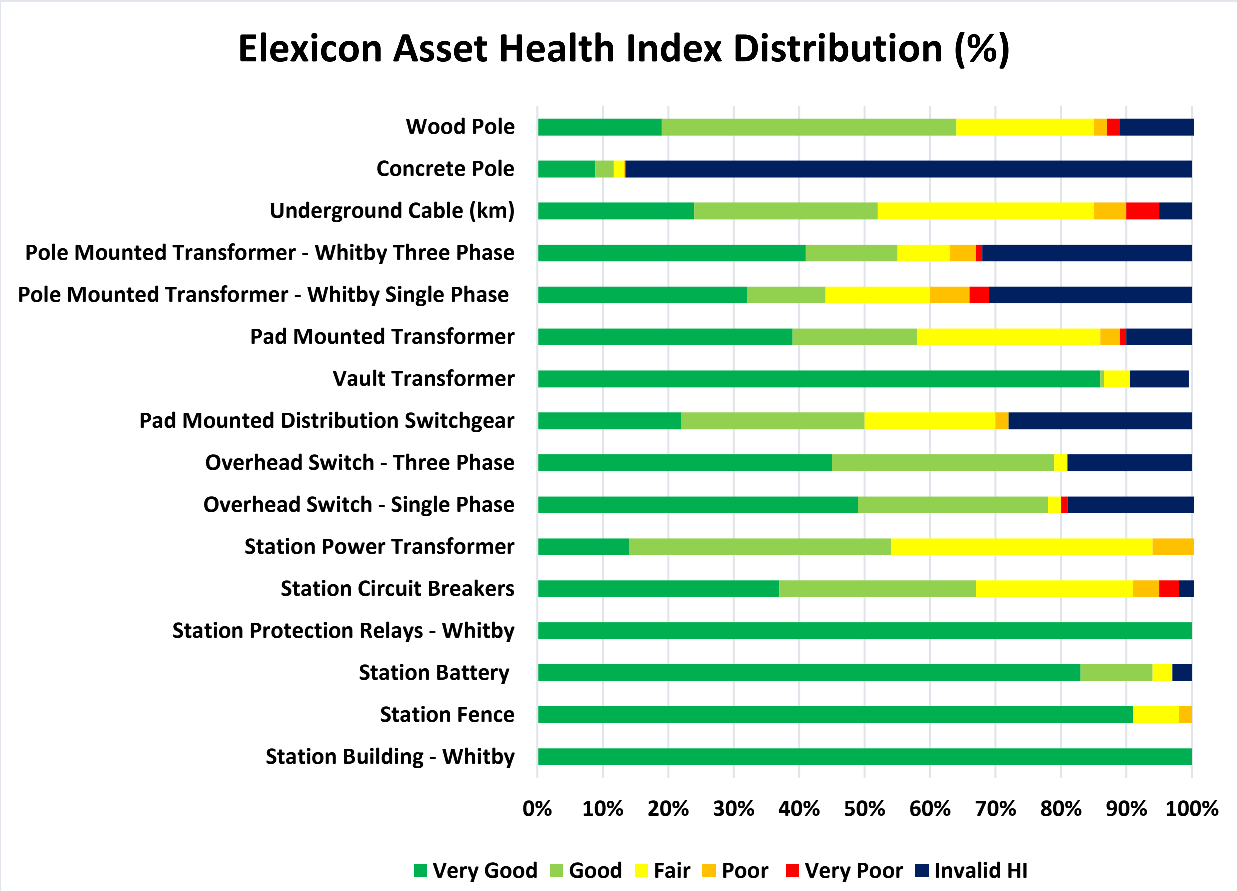


Figure 4-1: HI Summary

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. While the portions of assets with No Valid HIs are significant for some asset classes, in most cases this is a function of the past 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. The number of assets with an Invalid HI has decreased since previous revisions of the report due to additional data collected for poles, overhead conductors, station transformers, station circuit breakers, and station protective relays.

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.

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

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 or twenty 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.

The HI for wood poles is calculated based on end-of-life criteria summarized in Table 4-2. Appendix 6B.1 provides grading tables for each Condition Parameter.

Table 4-2: Wood Pole HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Defects/Overall Condition	7	A,B,C,D,E	4,3,2,1,0	28
Wood Rot	6	A,B,C,D,E	4,3,2,1,0	24
Remaining Strength*	8	A,B,C,D,E	4,3,2,1,0	32
Out of Plumb	2	A,E	4,0	8
			Total Score	**96**

**wood poles newer than ten years are not strength tested; this parameter is removed.*

Data Collection and Assumptions

There are two cycles of data collection at Elexicon. Wood poles are visually inspected every three years as part of the inspection process mandated in the Distribution System Code. In addition, poles are tested by an approved pole testing contract service on a cyclical nature or as needed. This process results in two sets of annual test files that are combined and sorted for the latest data, and then parsed for relevant condition information.

Data collection was executed using physical inspections and tablets for data input. Data files were not parsed into consistent Condition Parameters and imported to the asset registry. Manual conversion took place which is time-consuming and inhibits updating of data. Where conflicting data for age existed between the asset registry and the field notes, the asset registry information was taken as correct.

A number of assumptions were made to process the raw data files. Strength testing is not conducted for newer poles (10 years in service or less). For these poles, the algorithm is modified to not include the remaining strength data. Percent remaining strength was calculated where the remaining strength is given as a total strength rather than a percentage. Where poles are known to have been visually inspected, and there are no notes given about poles leaning, or exhibiting rot, these those poles are assessed a grade of A for the respective data fields. If the pole is not known to have been inspected, these assumptions are not made. In future iterations, all wood poles will receive a designation to clarify if missing test data is consistent with expectations.

The DAI for wood poles across Elexicon is 88% and is expected to continue to improve.

<u>Demographics</u>
Elexicon owns 34,111 wood poles within its service territory. Installation date is unknown for approximately 10% of the total in-service population. Figure 4-2 presents the age distribution for in-service wood poles.

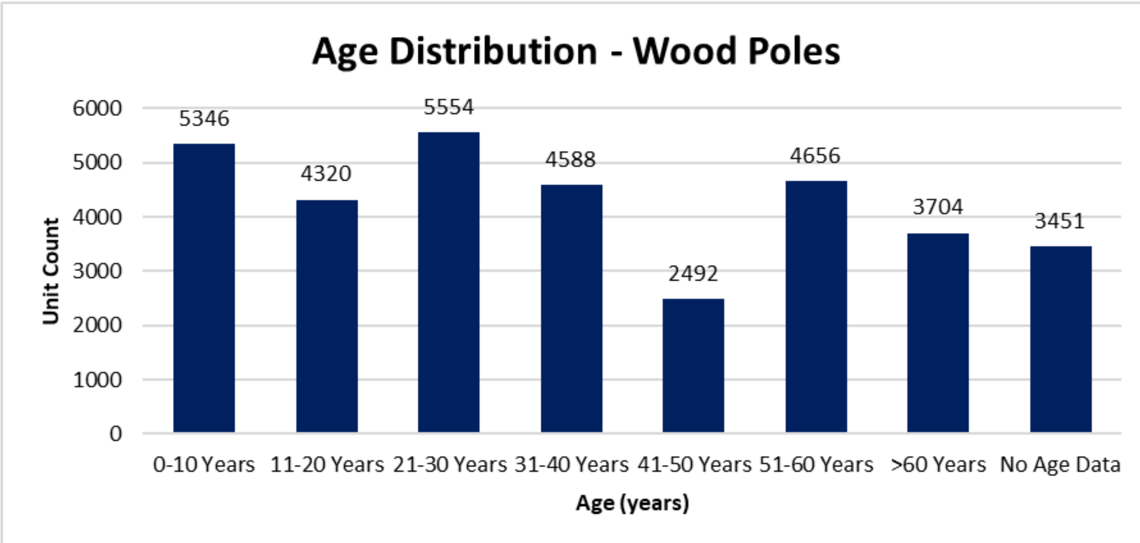


Figure 4-2: Wood Pole Age Distribution

<u>HI Results</u>

The overall HI distribution is presented in Figure 4-3. Most of the poles are in Very Good to Fair condition with approximately 4% of the total population being in Poor or Very Poor condition.

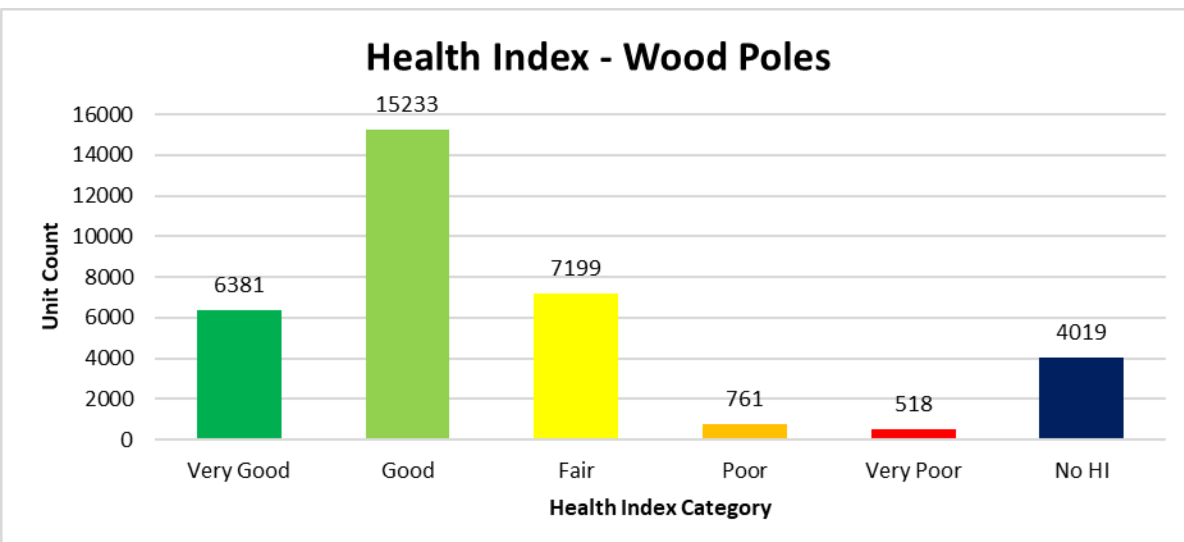


Figure 4-3: Wood Pole HI Results

Recommendations for Future Improvements

It would be beneficial for future assessments if the datasets for poles are aligned and the data gaps are rectified. The asset registry should contain a complete set of the most recent visual inspection and testing data. Poles that are not scheduled for testing (i.e., newer poles) should be designated as such and the requirement for that data removed from the calculation.

In some cases, a wood pole is identified for replacement during the visual inspection without a pole test being performed. To account for this in the analysis, the DAI threshold for wood poles was adjusted from 70% to 66.7% (all parameters except remaining strength present). Pole testing should be completed for all wood poles over ten years of age to verify the condition.

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). Asset registry unique identifiers should be matched up with inspection reports for historical inspection reports, and all data should be parsed into condition codes.

Inspection services should be advised to give consistent reporting of remaining strength, preferably as a percentage of remaining life. Physical condition data should be collected in the same format as the visual inspection process. Other data points such as overall condition should be better documented for intent.

4.1.2 Concrete Poles

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 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.

Table 4-3 below provides the concrete pole HI algorithm. Additional details about these Condition Parameters and how they are graded can be found in Appendix 6B.2.

Table 4-3: Concrete Pole HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Defects/Overall Condition	8	A,B,C,D,E	4,3,2,1,0	32
			Total Score	**44**

Data Collection and Assumptions

In previous ACA reporting for the legacy Veridian, 1,913 concrete poles were not captured. This is a common occurrence due to the different inspection programs for poles as, in general, the poles that undergo physical testing have the best data records.

Approximately 20% of the legacy Veridian concrete poles have age values in the asset registry and 4% have condition data. There is age data for most of the legacy Whitby Hydro's approximately 490 concrete poles, but a large part of those (47%) lack inspection data. As a result, the DAI for concrete poles is very low at 20% overall.

Demographics

Elexicon owns 2,477 concrete poles, of which 1,590 do not have age data all but two of which are in the legacy Veridian area. Figure 4-4 and Figure 4-5 present the age distribution for in-service concrete poles.

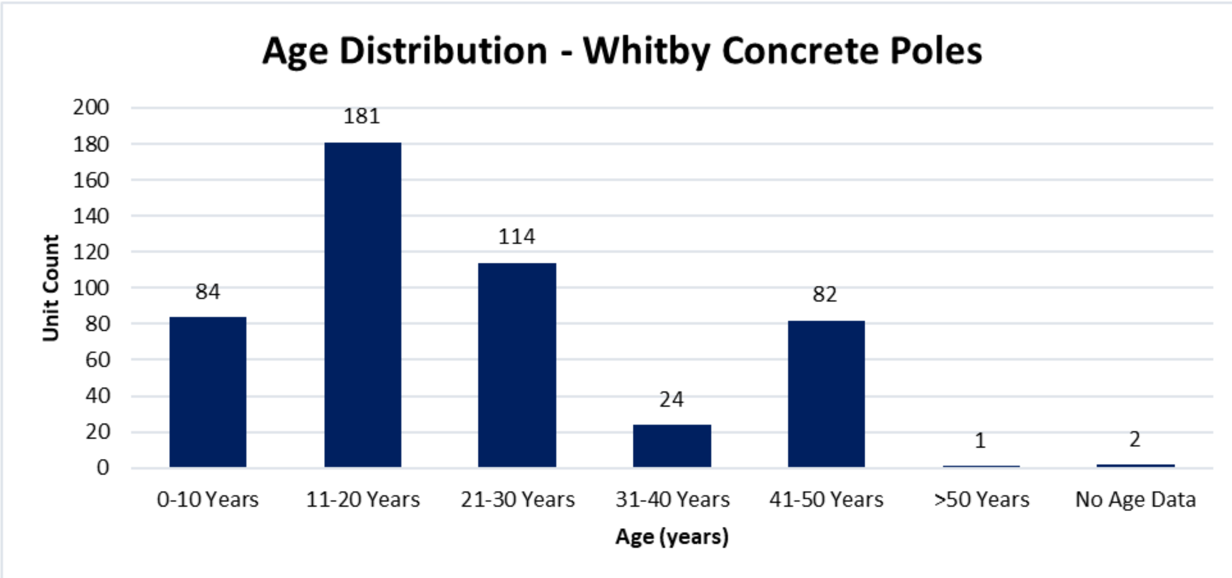


Figure 4-4: Whitby Concrete Pole Age Distribution

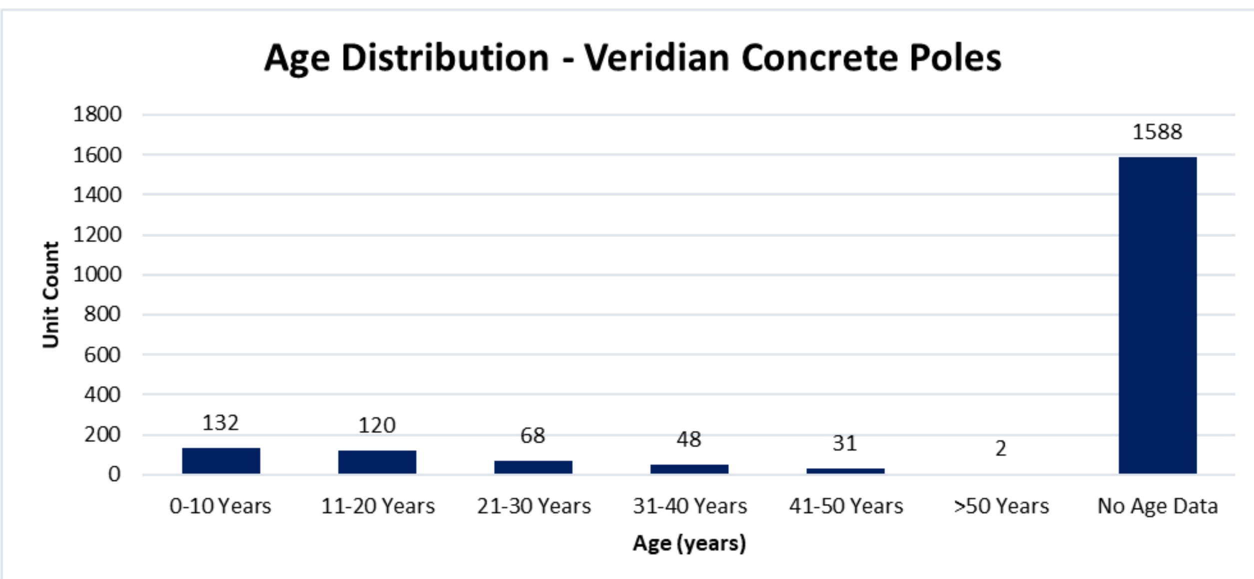


Figure 4-5: Veridian Concrete Pole Age Distribution

<u>HI Results</u>

For this asset class, a two-parameter assessment was conducted. The overall HI distribution for legacy Whitby area concrete poles is presented in Figure 4-6. Most of the known poles are in Very Good to Good condition with approximately 1% of the total population being in Poor or Very Poor condition. However, almost 50% of the population does not have a valid HI.

The concrete poles in the legacy Veridian area are not presented due to only 4% of the population having valid HI information.

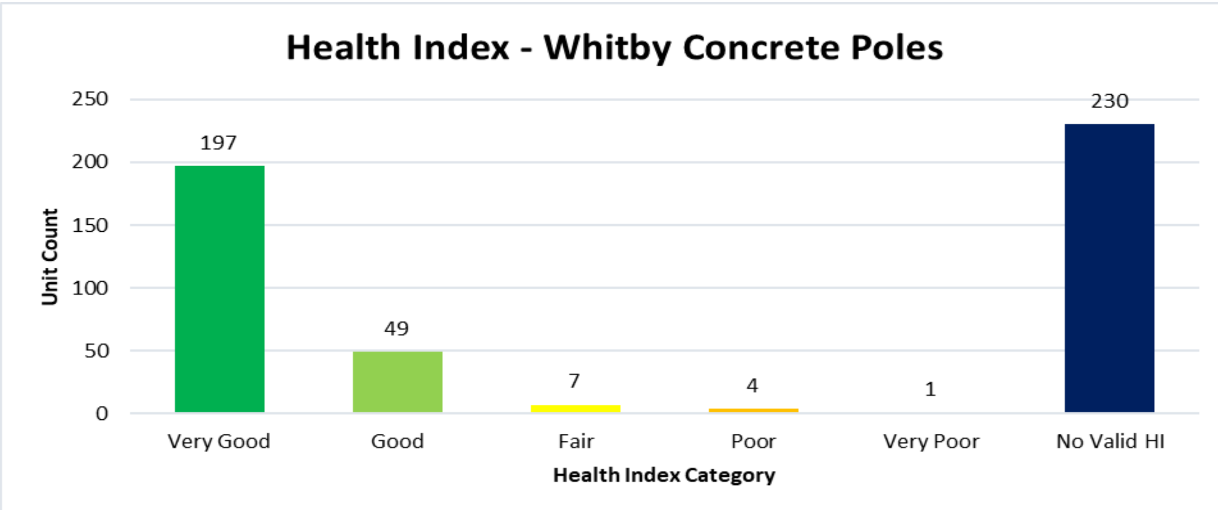


Figure 4-6: Concrete Pole HI Results (Whitby Area)

Recommendations for Future Improvements

While the DAI for concrete poles is very low and needs to be improved, it should also be noted that concrete poles makeup only 5% of the pole population, and therefore, have a minimal impact on renewal planning.

In the legacy Veridian area, demographic data such as installed date and pole type should be established for every pole and a full visual inspection should take place. In the legacy Whitby area, inspection data should be collected for the remaining poles.

Recognized HI guides recommend more than a two-parameter formulation to develop a robust index. A best-practice formulation would consider additional Condition Parameters such as:

- Rust/corrosion and spalling;
- Other defects;
- Out of plumb; and
- Service age.

4.1.3 Underground Cables

Condition Assessment Methodology

Distribution underground 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. The asset health results for primary underground 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 comparison of a given cable segment to other cables of similar vintage. In the legacy Veridian area, a cable injection program has been initiated. For cable sections that are known to have received such treatment, the HI is modified to reflect the life extension.

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 underground cable segments, we applied the "Splice Fault Risk" criterion on a binary scale – where the presence of a splice resulted in the segment being assigned a score of 1, whereas the lack of information regarding a splice was assumed to indicate that no splices exist on that segment. In the latter situation, the cable segment received a score of 4.

Table 4-4 below provides the HI algorithm for underground cables. The relatively high weighting assigned to age is a function of the fact that it represents the only parameter available for the majority of the system. Additional details about these Condition Parameters and their manner of grading can be found in Appendix 6B.3.

Table 4-4: Underground Cable HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Faulted Section	4	A,D	4,1	16
			Total Score	**48**

Data Collection and Assumptions

Given their below-grade location and the associated access difficulties, the information on the condition of underground cables is notoriously difficult and costly to obtain. Data for this asset is limited to records of age and splice locations as taken from the GIS and asset registry. A cable without a splice noted in the section is assumed to be an 'A'.

The DAI measures the percentage of assets for which the data used in the HI formulation is available. The DAI for the underground cables across all voltages is 94%.

Within Elexicon's asset base, 67 km of underground cables have been injected with a product that is designed to extend cable life. Injected cables only exist in the Veridian service area. For the purposes of this study, cable injection is noted, but not incorporated in the HI. The approximate demographics (units in cable length, not circuit length) of the injected cables are:

- Total injected length – 67 km;
- Age category D or E, (36+ years) – 46 km;
- Age category C or higher – 16.4 km; and
- Age unknown – 4.6 km.

Demographics

The Elexicon system features underground primary voltage cables with a combined length of approximately 2,336 km, operating at voltages between 44 kV and 2.4 kV. Age records were not available for approximately 121 km (5%) of Elexicon's total underground cable assets. While it represents a relatively minor portion of all cables by length, it is notable that the missing age data constitute a material portion of cable length across several voltages. For instance, age data is not available for 27% of 44 kV cables and 22% of cables in the 8.0-13.8 kV range.

Table 4-5 provides a breakdown of cable length by voltage, grouping several categories of cables of similar voltage for ease of presentation.

Table 4-5: Length of Cable by Voltage Class

Voltage	Length (circuit km)
44 kV	23.6
27.6 kV	429.4
13.8/8.32/8.0 kV	1710.6
12.47 kV	68.62
4.16/2.4 kV	103.85
Total	**2,336.2**

Figure 4-7 shows the overall age distribution of Elexicon's underground cables by length.

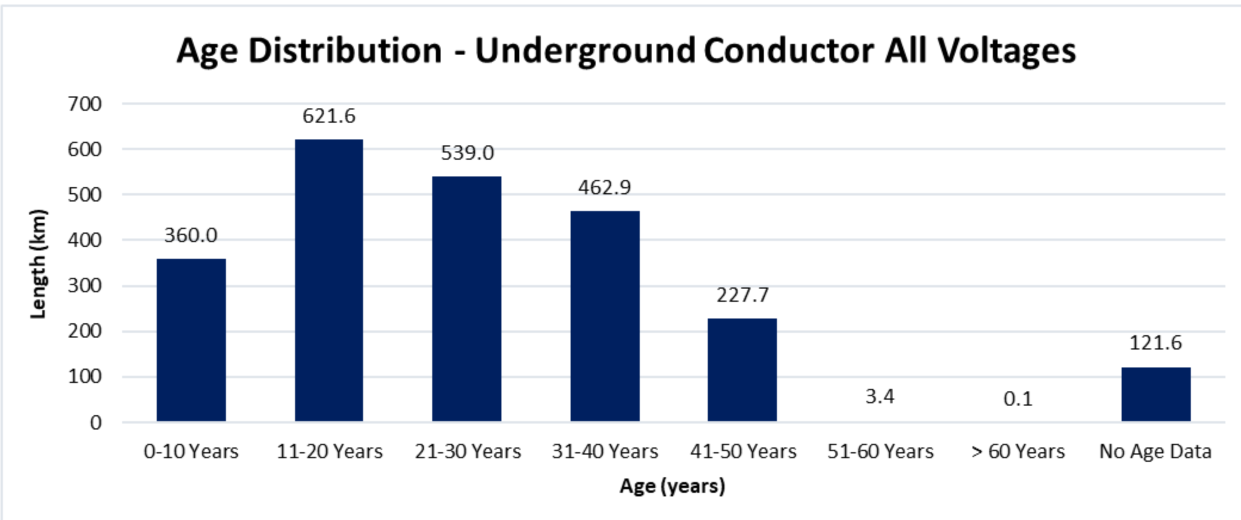


Figure 4-7: Underground Conductor Age Demographics

<u>HI Results</u>

For this asset class, a two-parameter assessment was conducted. The HI indicates that 5% of the underground cables do not have a valid HI. In many cases these assets would be extrapolated over the asset pool; however, since the data availability is closely related to cable type, the assets without a valid HI continue to be shown separately.

Overall, there are 224 km of cables scored as Poor or Very Poor which is about 9% of the asset base with a particular concentration in the 12.47 kV, 4.16 kV, and 2.4 kV voltages, where a combined 28 km of cables (23% of the combined population across these voltages) are in Poor and Very Poor condition. Figure 4-8 provides HIs for underground cable in aggregate.

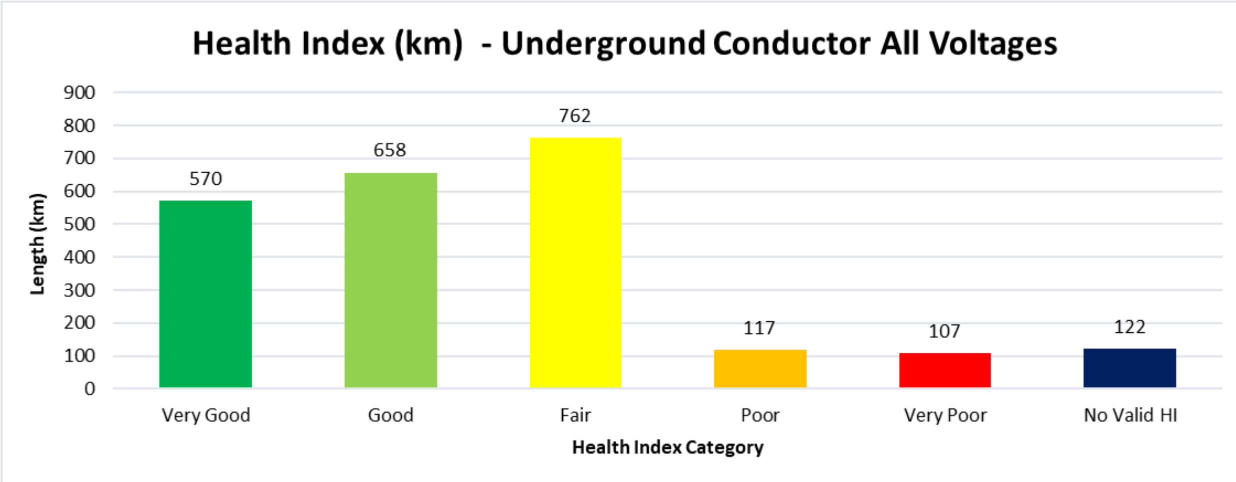


Figure 4-8: Overall Underground Cable HI Results

Recommendations for Future Improvements

It is recommended that Elexicon develop a full 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 in an attempt to correlate age and type with life expectancy.

There is a block of cables, particularly in the 12.5 kV class that should be examined to determine age and type within the Gravenhurst area.

The cable injection program should be unified across the legacy utilities and impact of cable injections will be incorporated into the HI algorithm in future iterations. As of this time, it is practical to assume that the cable injection program has effectively extended the life of 46 km of Poor and Very Poor conductor, 16.4 km of Fair conductor, and 4.6 km of unknown age conductors from their existing scores to at least "Good".

Recognized HI guides recommend employing Condition Parameters in addition to the current two-parameter formulation to develop a more robust index. A best practice-formulation would consider additional Condition Parameters such as:

- Treatment history;
- Field-testing results;
- Fault history;
- Load history;
- Condition of concentric neutral; and

- Visual inspection of terminations and splices.

4.1.4 Overhead Conductors

Condition Assessment Methodology

Overhead 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. In previous iterations of the ACA reporting, "small-conductor" risk was presented as a Condition Parameter. In this version, it was deemed more useful to consider small conductors as a distinct sub-class of overhead conductors.

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.

Data Collection and Assumptions

While the conductor data for 3800 km was accessible in the GIS system, age data is available for a small subset of the total population only. Given these circumstances, METSCO deemed it impractical to calculate a DAI for this asset class.

Demographics

Elexicon has approximately 4,300 km of overhead conductors; however, age data is missing for over 25% of the population. There is known to be 22 km of small conductors which, regardless of age, should be examined in detail for replacement needs. Figure 4-9 and Figure 4-10 present the age distribution for large and small overhead conductors, respectively.

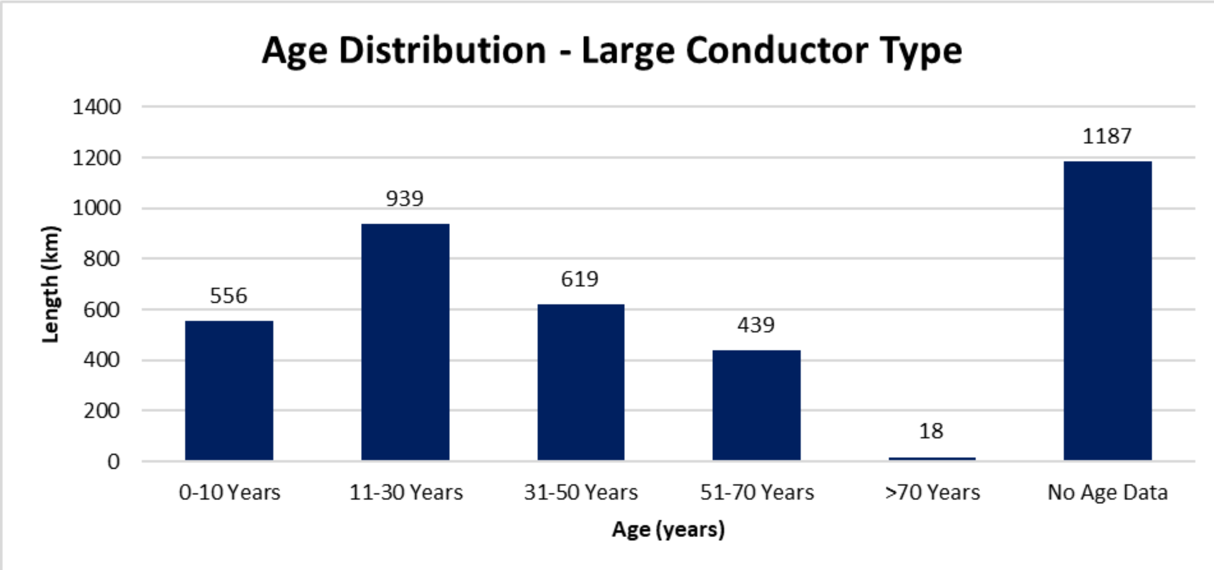


Figure 4-9: Large Conductors Age Distribution

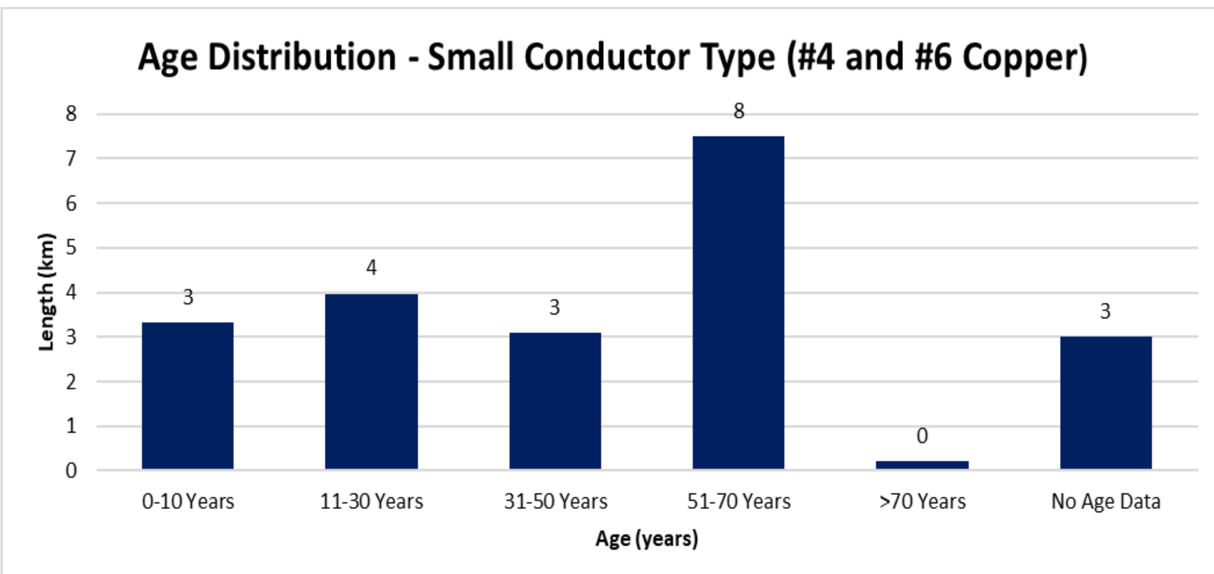


Figure 4-10: Small Conductors Age Distribution

HI Results

Considering the amount of missing data, conductors are not given an HI. Historically, Veridian has not attempted to produce an HI for conductors, whereas Whitby has historically collected some condition data on conductors to illustrate the health of the asset category.

Recommendations for Future Improvements

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 make a useful estimate. Overhead conductor condition rarely drives reinvestment, and therefore, a common-sense approach to data collection is warranted including estimates and broad assumptions.

The data provided accounts for about 3800 km of conductor (88% of the population); therefore, further investigation should take place to align quantities in future iterations.

Best-practice formulations do not generally recognize the need for the additional data collection on distribution overhead conductors. Accordingly, METSCO does not suggest that Elexicon consider the collection of any additional Condition Parameters for this asset class.

4.1.5 Pole-Mounted Transformers

Condition Assessment Methodology

Pole-mounted transformers are another large asset class within the utility system. This asset category is made up of a large number of 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.

The HI for distribution transformers is a two-parameter formulation consisting of age and overall condition with the dominant factor being condition. Table 4-6 below the HI algorithm for pole-mounted transformers. Additional details about these Condition Parameters and how they are graded can be found in 6B.5.

Table 4-6: Pole Mounted Transformer HI Algorithm

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**

Data Collection and Assumptions

Elexicon has about 6,465 single-phase and 767 three-phase pole-mounted transformers. Within that total are approximately 1,465 transformers in the legacy Whitby area that have recorded visual inspection data. There was no condition data recorded in the Veridian legacy area; however, transformer degradation is noted on an exception basis in routine inspection processes. Single-phase and three-phase installations are recorded separately within the analysis therefore each count of a three-phase unit represents three individual units.

The DAI for pole-mounted transformers is 30% largely due to the exception-based approach to overhead transformer inspections in the legacy Veridian area.

Demographics

Approximately 51% (3,715) of the units (7,232) have recorded age data. Almost all of the transformers in the legacy Whitby area have age data and about 2,250 out of 5,700 in the legacy Veridian area. Figure 4-11 and Figure 4-12 show the age distributions for the pole-mounted transformers, separating the single-phase and three-phase units.

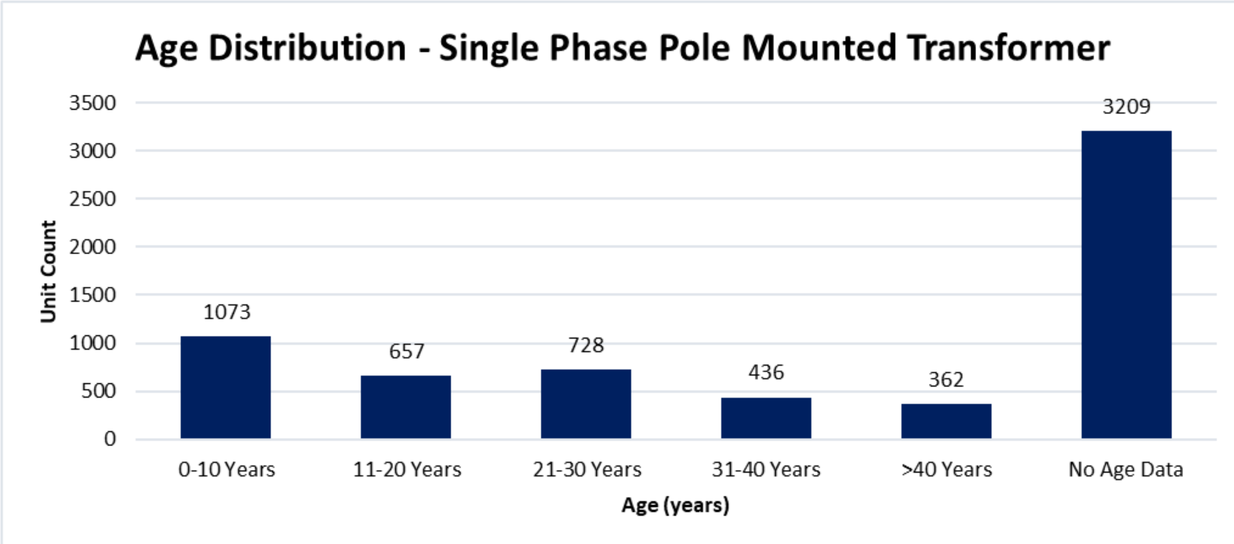


Figure 4-11: Single-Phase Pole-Mounted Transformer Age Distribution

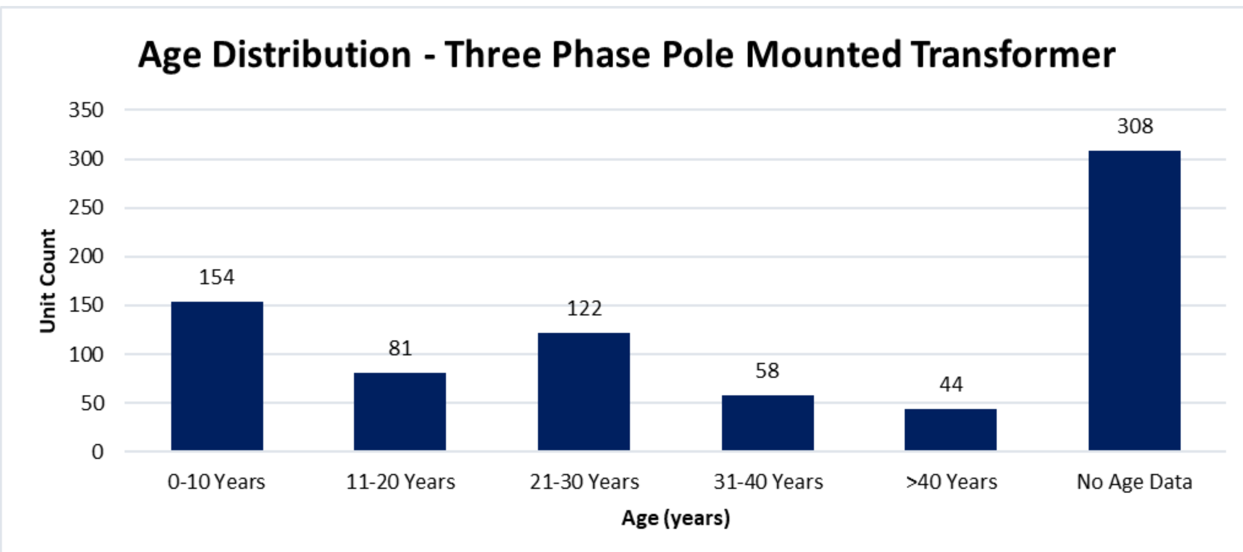


Figure 4-12: Three-Phase Pole-Mounted Transformer Age Distribution

<u>HI Results</u>

Due to a lack of condition data for the legacy Veridian pole-mounted transformers, an HI was calculated for only the units in the legacy Whitby area. For this asset class, a two-parameter assessment was conducted.

Figure 4-13 and Figure 4-14 shows the HI for pole-mounted transformers, with most of the transformers being Very Good to Fair and 125 units being ranked Poor or Very Poor. For 450 units it was not possible to calculate a valid HI.

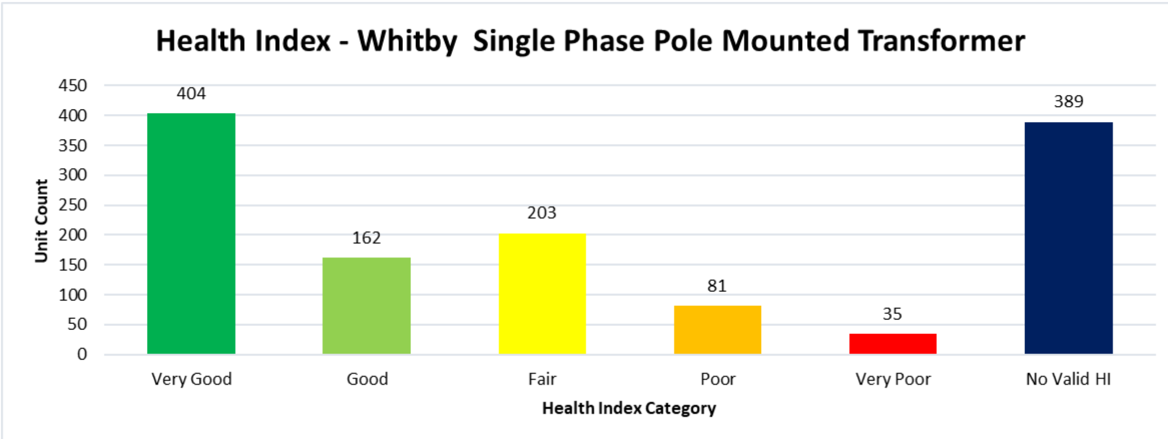


Figure 4-13 Single-Phase Pole-Mounted Transformer HI Results (Whitby)

Figure 4-14 shows the HI for three-phase transformers. In this diagram, each unit represents three transformer units in service.

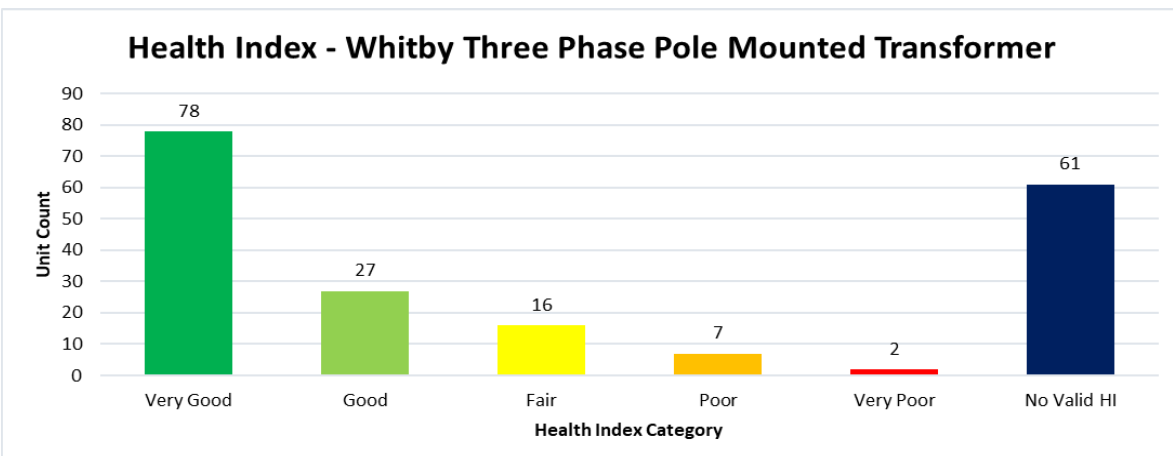


Figure 4-14 Three-Phase Pole-Mounted Transformer HI Results (Whitby)

<u>Recommendations for Future Improvements</u>

Transformer condition data should be collected for all transformers in the legacy Veridian area and the missing 450 units in the Whitby area. Age information should be collected for assets missing age data, predominantly in the legacy Veridian dataset.

Because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number. The GIS of the legacy Whitby area has this functionality. 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.

Recognized HI guides recommend more than a two-parameter formulation to develop a robust index. Best-practice formulations would consider some additional Condition Parameters, including:

- Peak loading history;
- Visual inspections; and
- Infrared scan results.

4.1.6 Pad-Mounted Transformers

<u>Condition Assessment Methodology</u>

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.

Table 4-7 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 6B.6.

Table 4-7: Pad-Mounted Transformer HI Algorithm

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**

Data Collection and Assumptions

Approximately 402 (3%) single-phase and 350 (22%) three-phase transformers do not have recorded condition data, whereas approximately 550 single-phase and 250 three-phase transformers are missing age data. The absence of either data point results in an invalid HI.

When an asset is designated as a three-phase pad-mounted installation it is assumed to be a single unit with a three-phase tank.

The DAI for pad-mounted transformers is 95%. Note that during the process of this project additional data files were presented with up-to-date inspection data that improved the data availability of approximately 2000 single-phase pad-mounted transformers. Similar files were presented for three-phase pad-mounted transformers but did not offer any significant improvement.

Demographics

Elexicon has about 12,012 single-phase and 1,587 three-phase pad-mounted transformers. The installation date is unknown for approximately 7% of the total in-service population. Figure 4-15 and Figure 4-16 present the age distribution for in-service pad-mounted transformers.

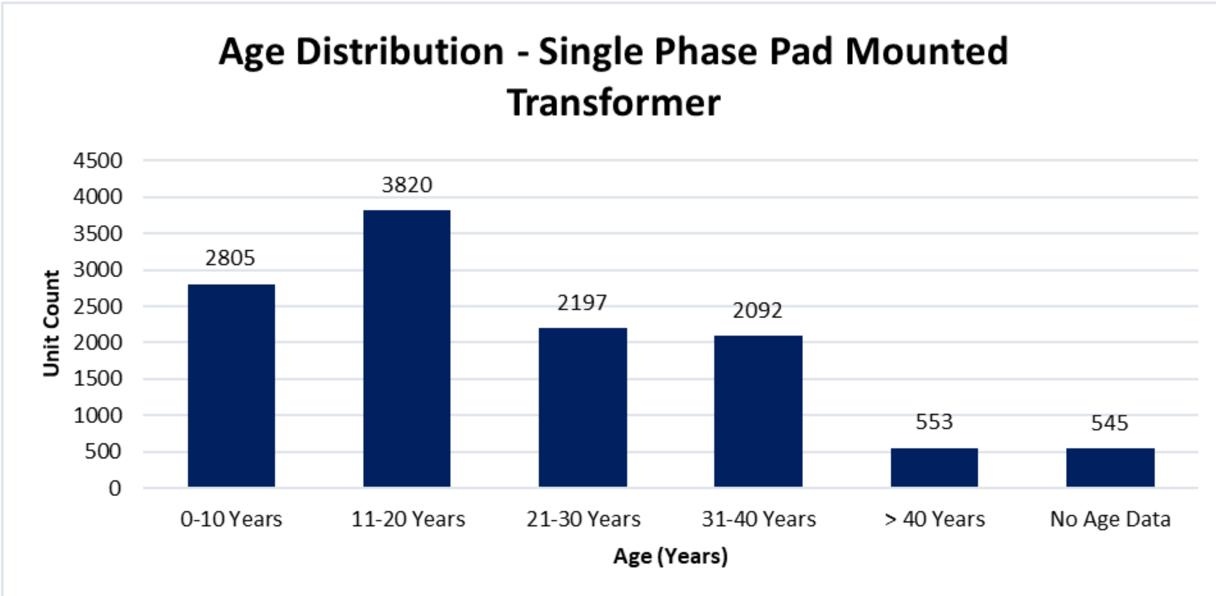


Figure 4-15: Single-Phase Pad-Mounted Transformer Age Demographics

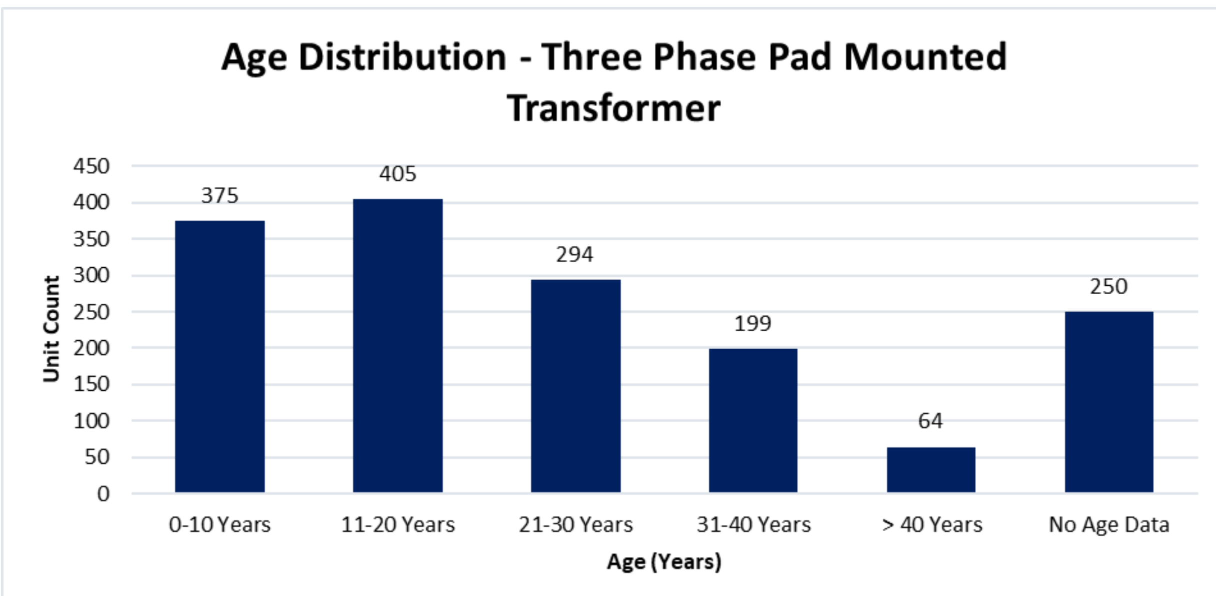


Figure 4-16: Three-Phase Pad-Mounted Transformer Age Demographics

<u>HI Results</u>

For this asset, a two-parameter assessment was conducted. The HI results for single-phase pad-mounted transformers are shown in Figure 4-17. There are 476 single-phase units (4%

of the population) in Poor or Very Poor condition. Approximately 7% of single-phase transformers do not have a valid HI.

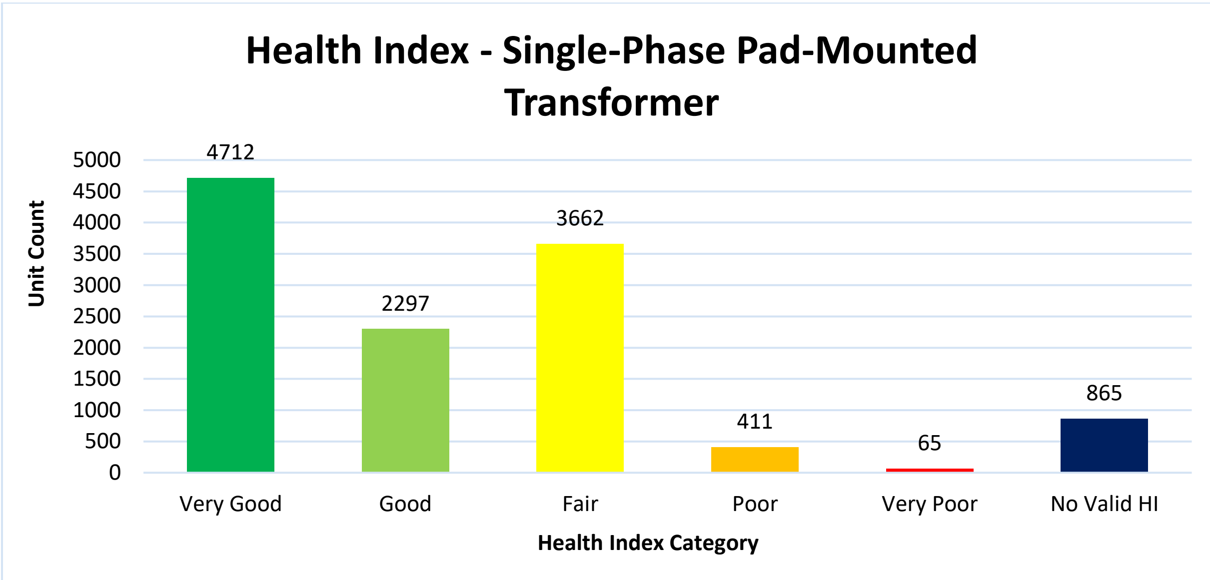


Figure 4-17: Single-Phase Pad-Mounted Transformer HI Results

The HI results for three-phase pad-mounted transformers are shown in Figure 4-18. There are 21 three-phase units in Poor or Very Poor condition (1.5% of the population). Approximately one-third of three-phase transformers do not have a valid HI.

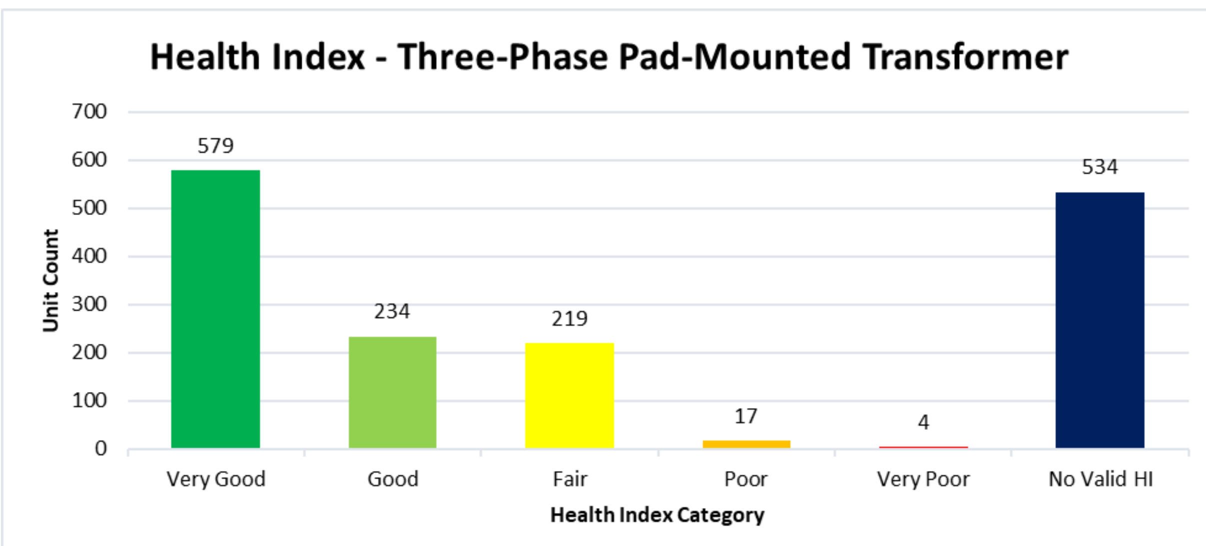


Figure 4-18 Three-Phase Pad-Mounted Transformer HI Results

Recommendations for Future Improvements

Data collection for pad-mounted transformers should be rationalized across the entire utility. 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 switchgear assets would give a better indication of asset health. Suggested additional parameters include, as a minimum, condition of structures/pads and IR scan results.

In addition to rectifying the data gaps across the Condition Parameters already being collected, METSCO encourages Elexicon to consider collecting some of the incremental condition information associated with advanced AM practices:

- Peak loading history
- IR scan
- Condition of enclosure; and
- Condition of civil structure.

4.1.7 Vault Transformers

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 infrastructure, such as the doors and vents, contribute 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.

The HI formulation for vault transformers is a single-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.

Table 4-8 below provides the HI algorithm for vault transformers. Additional details about the Condition Parameters can be found in Appendix 6B.7.

Table 4-8: Vault Transformer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**16**

<u>Data Collection and Assumptions</u>

Vault transformers were not previously addressed in either of the legacy utilities' ACA reports. However, due to the uniqueness of the installations, it was deemed worthy to highlight the asset class separately. As a result, the cycle of data improvement is in the early stages and can be expected to increase.

In this case, each location is reported as a single vault transformer given the format of data reporting, whereas in reality, an installation may be made up of three individual units inside the vault.

Elexicon has 154 vault transformer locations. In the legacy Whitby area, there are nine vault transformers in three locations that have only age data in the registry. In the legacy Veridian area there are 151 installations with condition information for 140.

The DAI for vault transformers is 54%.

<u>Demographics</u>

There is age data for 9 of 160 vault transformers, making the demographic presentation of little value. For completeness purposes, Figure 4-19 shows the age distributions for the known in-service vault transformers.

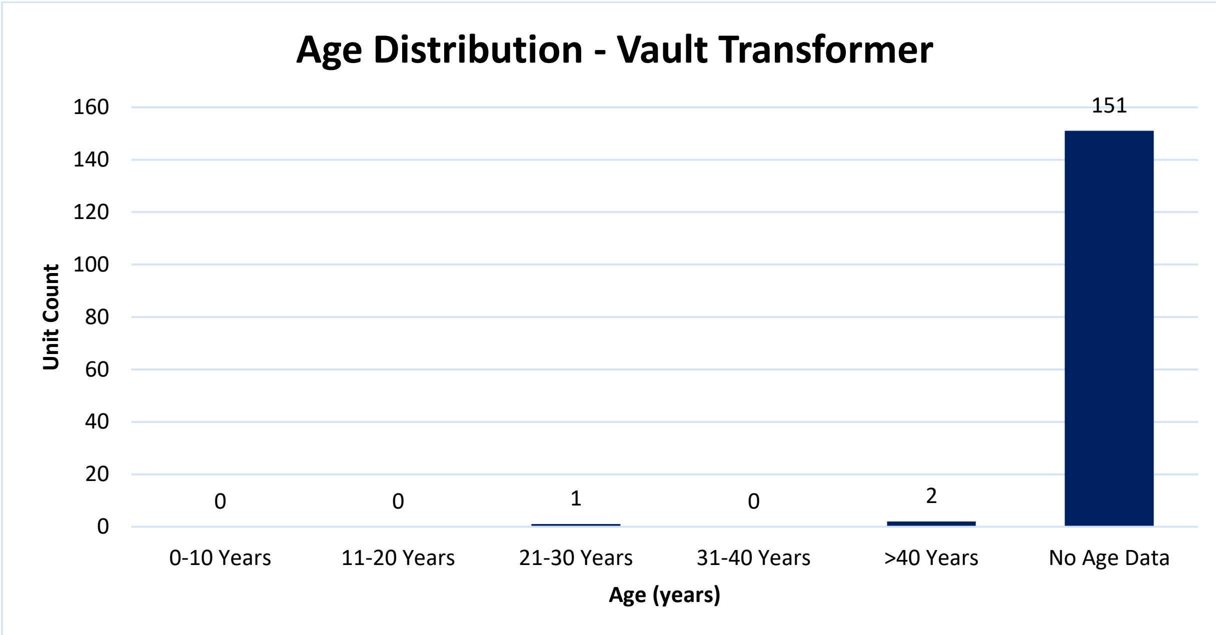


Figure 4-19: Vault Transformer Age Demographics

<u>HI Results</u>

The ACA results for this asset class consist of a one-parameter assessment, which is a simplified view of asset health. Nevertheless, considering that the parameter is derived from field observations, it does provide some valid information on the health of the asset. Most of the installations are in Very Good or Good condition. The HI results for vault transformers are shown in Figure 4-20.

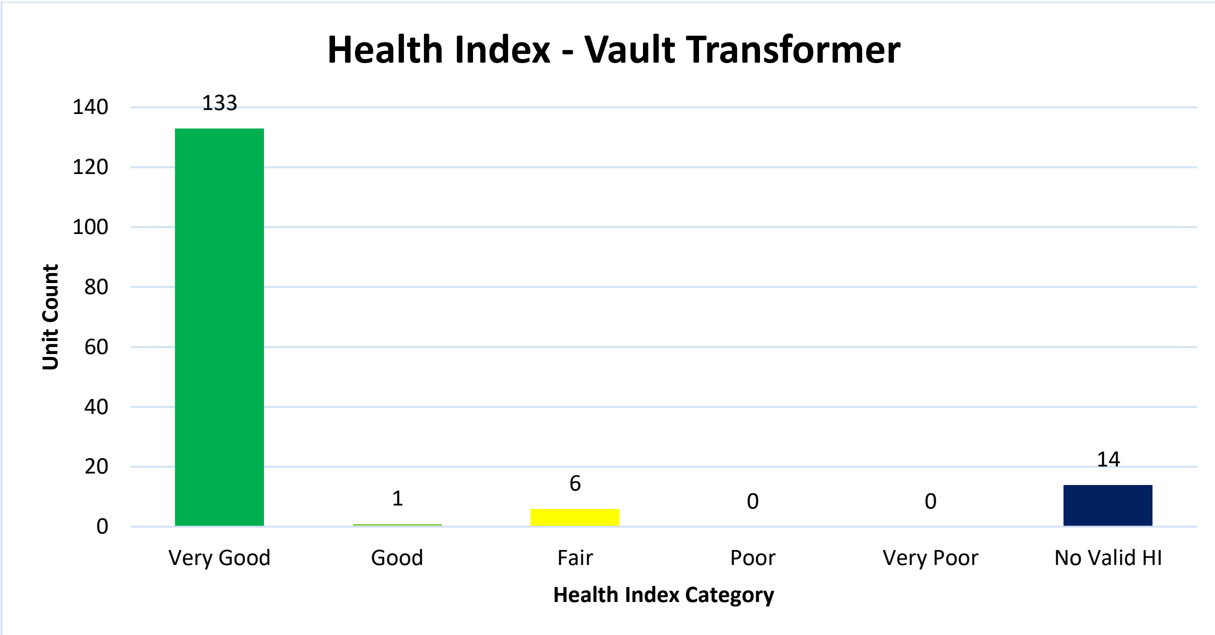


Figure 4-20: Vault Transformer HI Results

<u>Recommendations for Future Improvements</u>

Data collection for vault transformers should be rationalized across the entire utility. 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. It is understood that the Whitby GIS has this module in place.

As part of the Asset Management Plan, an enhanced formulation based on criteria similar to pad-mounted switchgear assets would give a better indication of asset health. Suggested additional parameters include, as a minimum, 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.

Among the additional HI parameters that Elexicon may consider for future collection are the following:

- Transformer age;
- Peak loading history;
- IR scan; and
- Condition of civil structure.

4.1.8 Pad-Mounted Distribution Switchgear

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 replacement of components such as interphase barriers, arc chutes, and high-pressure cleaning.

The HI formulation for switchgears typically uses service age, visual inspections, and IR scan results as Condition Parameters. Elexicon's distribution switchgear HI formulation consists of four parameters, with the combination of visual inspection and IR scan results accounting for two-thirds of the total maximum health score. The remaining one-third is comprised of the results of the enclosure condition inspection and the units' service age.

Table 4-9 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 6B.8.

Table 4-9: Pad-Mounted Distribution Switchgear HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	4	B,C,D,E	3,2,1,0	12
Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Enclosure	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**44**

Data Collection and Assumptions

Some assumptions have been made to complete the dataset for this assessment. The switchgear units in the legacy Whitby area are known to have been scanned with IR technology and exceptions have been reported. Therefore, those assets with no score for IR scanned have been rated as a "B". In the legacy Veridian area, IR scans have a specific coding; therefore, where there is no data it is assumed there have been no scans as opposed to the Whitby exception reporting. The DAI for the pad-mounted switchgear is 72%.

Demographics

Elexicon owns 439 pad-mounted distribution switchgear within its service territory. The installation date is unknown for approximately 28% of the total in-service population. Figure 4-21 presents the age distribution for in-service pad-mounted switchgear.

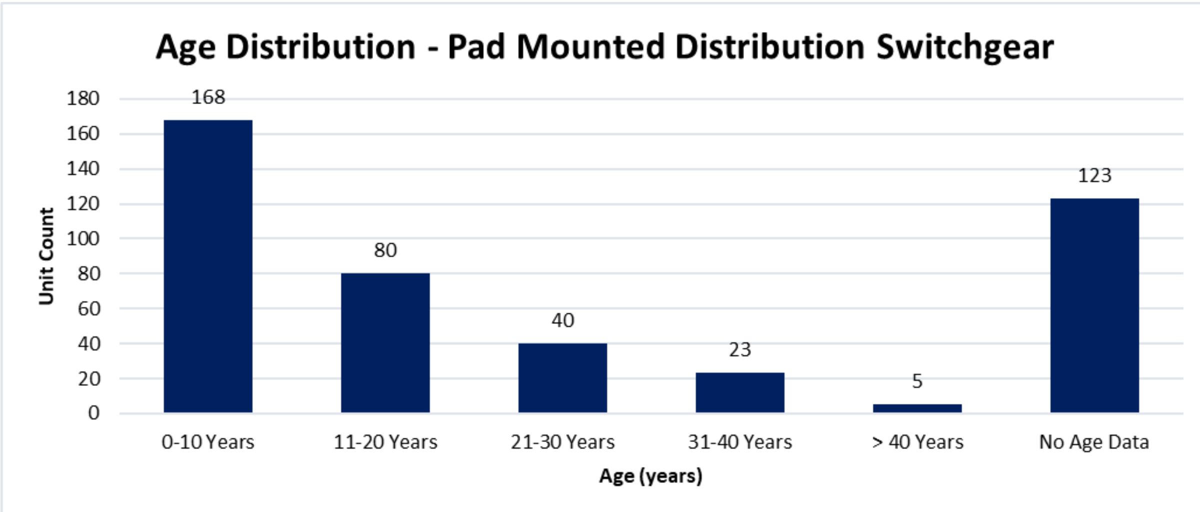


Figure 4-21: Pad-Mounted Distribution Switchgear Age Demographics

HI Results

The overall HI distribution is presented in Figure 4-22. Almost all of the units are in Very Good to Fair condition, with only 2% of the population (nine switchgear) in Poor condition.

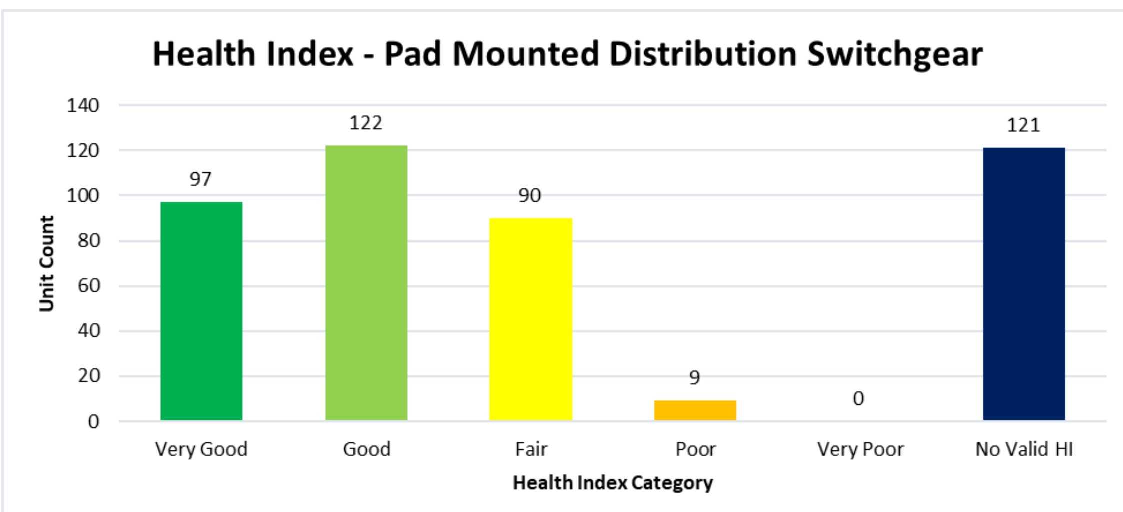


Figure 4-22: Pad-Mounted Distribution Switchgear HI Results

Recommendations for Future Improvements

Data collection for pad-mounted switchgear should be rationalized across the entire utility. At a minimum, age, IR scans, and overall condition data should be made available for all installations. Because of the potential for switches to be removed from one location, rehabilitated and then installed elsewhere, pad-mounted switchgear is often tracked by serial number.

Due to technical differences between gas-insulated, air-insulated, and solid dielectric switchgear, a specific Asset Management Plan, with dedicated formulations for each sub-type would be of value, along with the above-noted enhancements to the overall data collection. Suggested additional parameters include:

- Condition of enclosure;
- Condition of terminations;
- Condition of pad;
- Condition of interphase barriers (if applicable);
- Condition of blades (if visible);
- Condition of operating mechanism (if applicable); and
- SF6 pressure/leaks.

4.1.9 Overhead Switch – Three-Phase

Condition Assessment Methodology

This asset class includes three-phase, gang-operated, pole-mounted, and load interrupter switches. Switches may be operated manually or using a motor and may be controlled via automation schemes or SCADA. Switches that are not operated under load are called air-break switches, whereas switches with load-breaking capability are called load-break switches and switches that can break under fault current are called fault-interrupter switches. Solid-blade riser switches are used to isolate underground cable sections and do not break load.

Three-phase pole-mounted switches represent critical infrastructure for a distribution utility. The primary means of inspecting and maintaining switches are to visually identify dirt and corrosion and to use IR scans to find “hot” connections. Traditional air-insulated, handle-operated switches are highly maintainable and can often be extended indefinitely and nearly completely rebuilt on the pole. Newer “single-piece” devices can also be maintained but would generally be removed from the pole and maintained in a shop setting.

The HI formulation for distribution switches typically uses service age, visual inspections, and IR scan results as Condition Parameters. In this case, the dataset of the legacy Veridian area does not include IR scanning results; however, it is known that switches are regularly inspected and problems would have been reported by exception. Therefore, rather than overly penalizing the process, separate HI formulations for the Whitby and Veridian sub-populations were created.

The resulting formulations are captured in Table 4-10 and Table 4-11 below. Additional details about the Condition Parameters above and they are graded can be found in Appendix 6B.9.

Table 4-10: Whitby Area Three-Phase Overhead Switch HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**40**

Table 4-11: Veridian Area Three-Phase Overhead Switch HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**24 ***

***Note: IR Scans to be added to future assessments**

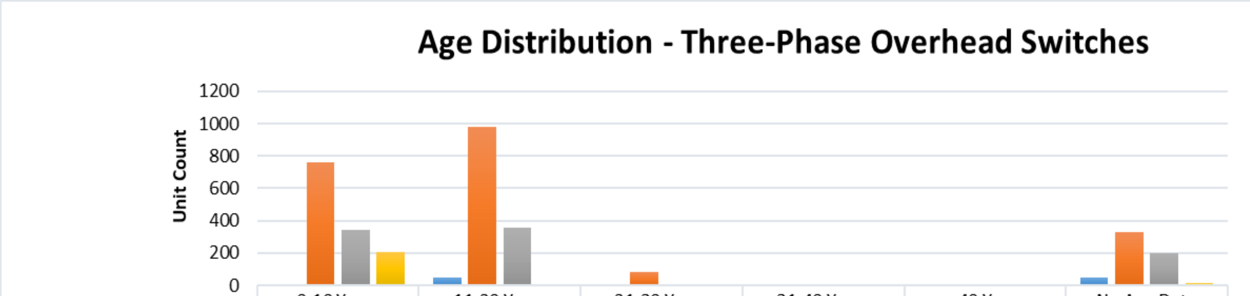
<u>Data Collection and Assumptions</u>

As a follow-up to the ACA data collection, it was discovered that IR scan data for switches in the legacy Veridian are available in hard-copy format. It was deemed too time-consuming to convert this data for this process. Despite missing the IR scan results, the service age and visual inspections results provide enough to detect switches in need of maintenance.

There are about 3,387 three-phase overhead switches in the Elexicon area with age and condition data available for 2,791 (82%). The DAI for this asset is 84% (accepting that for Veridian switches, useable IR scanning data are not expected).

<u>Demographics</u>

Elexicon has 3,387 three-phase overhead switches. Approximately 82% of the switches across the Whitby and Veridian datasets have age data available. Most of the known switches are less than twenty years old; however, almost 600 devices do not have recorded age data. Figure 4-23 shows the age distributions for the in-service three-phase overhead switches.

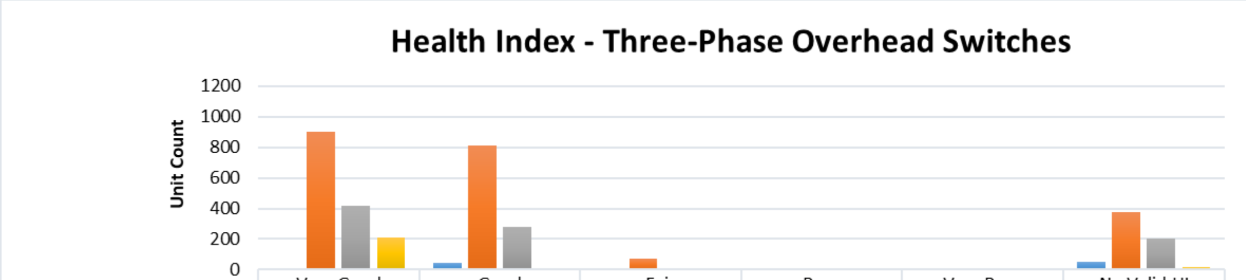


	0-10 Years	11-20 Years	21-30 Years	31-40 Years	> 40 Years	No Age Data
Air-Break Switch	3	48	3	0	0	51
Load Interrupter Switch	762	979	85	4	0	330
Solid-Blade Riser Switch	342	355	0	0	3	200
Fault Interrupter Switch	207	0	0	0	0	15

Figure 4-23: Three-Phase Overhead Switch Age Demographics

<u>HI Results</u>

Figure 4-24 shows the combined HI of the legacy Whitby dataset and the legacy Veridian dataset for all three-phase overhead switches. There is a total of 3,387 three-phase overhead switches, all of which are Very Good to Fair condition except for 641 (19%) which do not allow us to generate a valid HI. For the Veridian area, a two-parameter assessment was conducted.



	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Air-Break Switch	9	45	0	0	0	51
Load Interrupter Switch	903	813	69	0	0	375
Solid-Blade Riser Switch	420	277	0	0	3	200
Fault Interrupter Switch	207	0	0	0	0	15

Figure 4-24: Three-Phase Overhead Switch HI Results

Recommendations for Future Improvements

Considering the value of the three-phase overhead switch asset to the operation of the utility, all missing data should be collected which includes the collecting or estimating of age data. This should include a common definition of switch types. For instance, Whitby uses solid-blade riser devices but does not code them separately.

Condition data including IR scan data 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 insulators;
- Condition of blades;
- Condition of mechanism;
- Condition of terminations; and
- Markers and indicators.

Moreover, as overhead 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 leakers;
- Vacuum bottle integrity;
- SF6; and
- Technical obsolescence.

4.1.10 Single-Phase Switches, Blades and Cut-outs

Condition Assessment Methodology

This asset class is a large pool of relatively minor assets. In many utilities, single-phase switches are considered to be a part of "line hardware" and are, therefore, not proactively managed. This asset class includes devices designated as fused switches (K or E Type), solid-blade disconnects, Trip Savers, in-line disconnect switches, in-line fused switches, fuse riser switches, fused cut-outs, power fuses, and switchgear fuses. Single-phase switches provide means of load disconnection and isolation for equipment, such as overhead or underground laterals and services or transformers.

Degradation factors are generally limited to physical corrosion, insulator tracking, and/or heat generated by loose connections. Occasionally a manufacturing defect will result in accelerated loss of life for an entire type or sub-type of devices. Examples of this might include cut-outs with porcelain insulators, etc.

The HI formulation for distribution switches typically uses service age, visual inspections, and IR scan results as Condition Parameters. In this case, the dataset of the legacy Veridian area does not include IR scanning results; however, it is known that switches are regularly inspected and problems would have been reported by exception. Therefore, separate HI formulations for the Whitby and Veridian sub-populations were created.

The resulting formulations are captured in Table 4-12 and Table 4-13 below. Additional details about these Condition Parameters and how they are graded can be found in Appendix B.10.

Table 4-12: Whitby Area Single-Phase Switch HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**40**

Table 4-13: Veridian Area Single-Phase Switch HI Algorithm

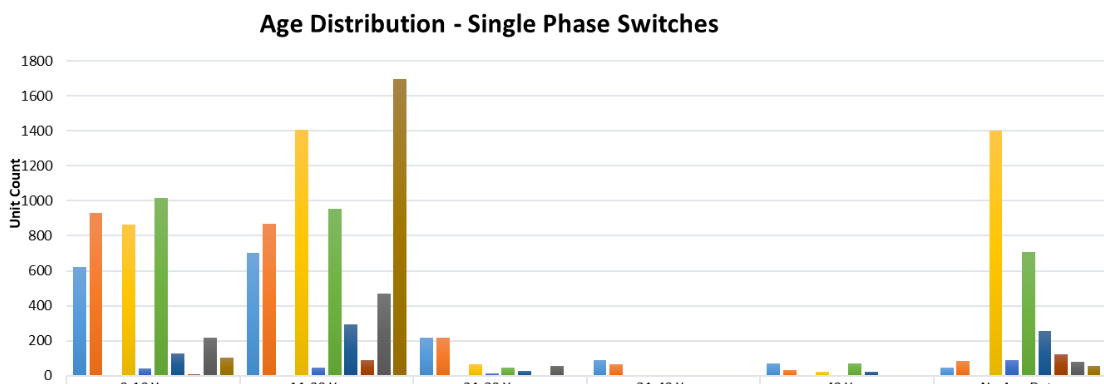
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**24**

Data Collection and Assumptions

In the legacy Whitby area, IR scans are recorded for each switch. In the legacy Veridian area, IR scans are limited to exception-based reporting for units where the scans indicate the need for intervention. The DAI for this asset is 86% (accepting that for Veridian switches, useable IR scanning data are not expected).

Demographics

Approximately 80% of the 14,315 switches have age data available. Most of the known switches are less than twenty years old; however, nearly 2,850 devices do not have recorded age data. Figure 4-25 shows the age distributions for single-phase switches.



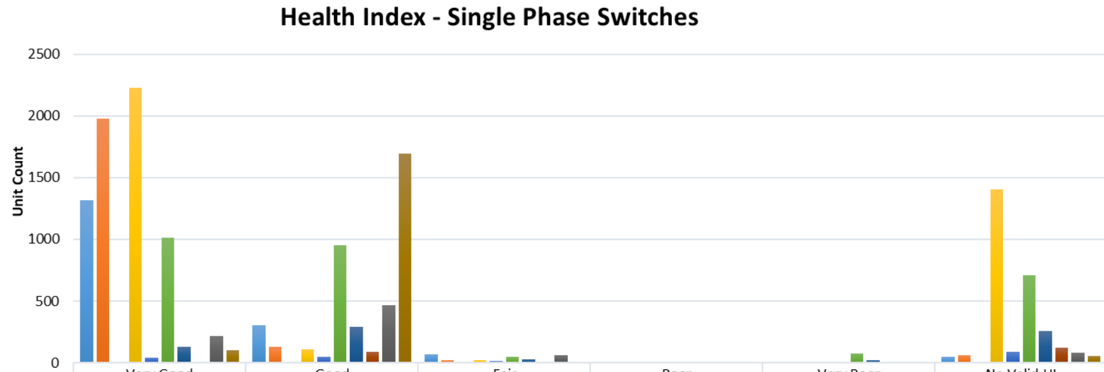
	0-10 Years	11-20 Years	21-30 Years	31-40 Years	> 40 Years	No Age Data
Fused Switch (K or E)	621	702	218	88	68	47
Solid Blade Disconnect	932	868	216	66	33	84
Trip Saver	3	0	0	0	0	5
In-Line Disconnect Switch	866	1407	66	0	21	1403
In-Line Fused Switch	39	47	12	0	0	87
Fuse Riser Switch	1014	953	45	4	72	706
Fused Cutout	129	293	29	1	20	257
Power Fuse	6	90	0	0	0	120
Switch Gear Fuse	218	469	58	0	0	79
UNKNOWN	101	1696	0	0	0	56

Age (years)

Figure 4-25: Single-Phase Switch Age Demographics

HI Results

Figure 4-26 illustrates the combined HI results of the legacy Whitby dataset and the legacy Veridian dataset for all single-phase switches. For this asset, a two-parameter assessment was conducted. There is a total of 14,315 single-phase switches, all of which are Very Good to Fair condition except for 110 units that are in Poor or Very Poor condition and require attention. A further 2,820 do not have a valid HI, largely due to missing age data.



	Very Good	Good	Fair	Poor	Very Poor	No Valid HI
Fused Switch (K or E)	1317	306	68	6	0	47
SOLID BLADE DISCONNECT	1980	129	24	6	0	60
Trip Saver	2	0	0	1	0	5
In-Line Disconnect Switch	2229	110	21	0	0	1403
In-Line Fused Switch	39	47	12	0	0	87
Fuse Riser Switch	1014	953	45	0	76	706
Fused Cutout	129	293	29	0	21	257
Power Fuse	6	90	0	0	0	120
Switch Gear Fuse	218	469	58	0	0	79
UNKNOWN	101	1696	0	0	0	56

Health Index Categories

Figure 4-26: Single-Phase Switch HI Results

Recommendations for Future Improvements

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 or estimating age data. This will also include a common definition of switch types as, for instance, Whitby does not track switchgear fuses as devices. If common definitions and terms are not possible, then separate HI formulations may be developed where the distinction is warranted. However, these are generally minor assets and the most effort should be placed where reinvestment plans are driven by asset degradation.

Condition data including IR scan data should be collected and incorporated into the condition (A,B,C,D,E) and consolidated in the asset registry. Recognized HI guides recommend a multi-parameter formulation that can include the following Condition Parameters that we invite Elexicon to consider:

- Condition of terminations;
- Condition of insulators;
- Condition of blades; and
- Condition of operating mechanism (if applicable).

4.2 Stations 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 or unique assets such as the single regulator located at Pine Ridge MS or the hydraulic recloser at James MS which does not warrant assessment at this time.

4.2.1 Station Transformers

Condition Assessment Methodology

Station 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 of utility assets and reliable indicators of the impending need for maintenance or replacement include dissolved gas analysis ("DGA") and power factor ("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.

Table 4-14 below provides the HI algorithm for station transformers. Additional details about these Condition Parameters and how they are graded can be found in Appendix 6B.11.

Table 4-14: Station Transformer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
DGA	10	A,B,C,D,E	4,3,2,1,0	40
Insulation PF	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	8	A,C,E	4,2,0	32
Service Age	6	A,B,C,D,E	4,3,2,1,0	24
Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
Bushing Condition	5	A,B,C,D,E	4,3,2,1,0	20
Cooling Equipment	2	A,B,C,D,E	4,3,2,1,0	8
Grounding Condition	1	A,B,C,D,E	4,3,2,1,0	4
Foundation Condition	1	A,B,C,D,E	4,3,2,1,0	4
Gasket Condition	1	A,B,C,D,E	4,3,2,1,0	4
Connections Condition	1	A,B,C,D,E	4,3,2,1,0	4
Oil Leaks	1	A,B,C,D,E	4,3,2,1,0	4
			Total Score	**208**

Data Collection and Assumptions

Data was provided for 94 station transformers which include a spare unit and two units at customer premises (Shandex and Mason Windows) owned by Elexicon. Elexicon also owns two brand-new Station Transformers at MS-16 substation for which data was not provided and therefore excluded from this analysis.

Substations are inspected frequently – in many cases as often as on a three-month cycle – and data is typically collected on detailed inspection forms. For the purposes of this study, data are parsed into condition codes (A,B,C,D,E) and the duplicate entries are removed.

The DAI for this asset class is 99%.

Demographics

Figure 4-27 presents the age distribution of Elexicon's station transformers. As the figure indicates, approximately 27% of station transformer units have been in service for 40 years or longer.

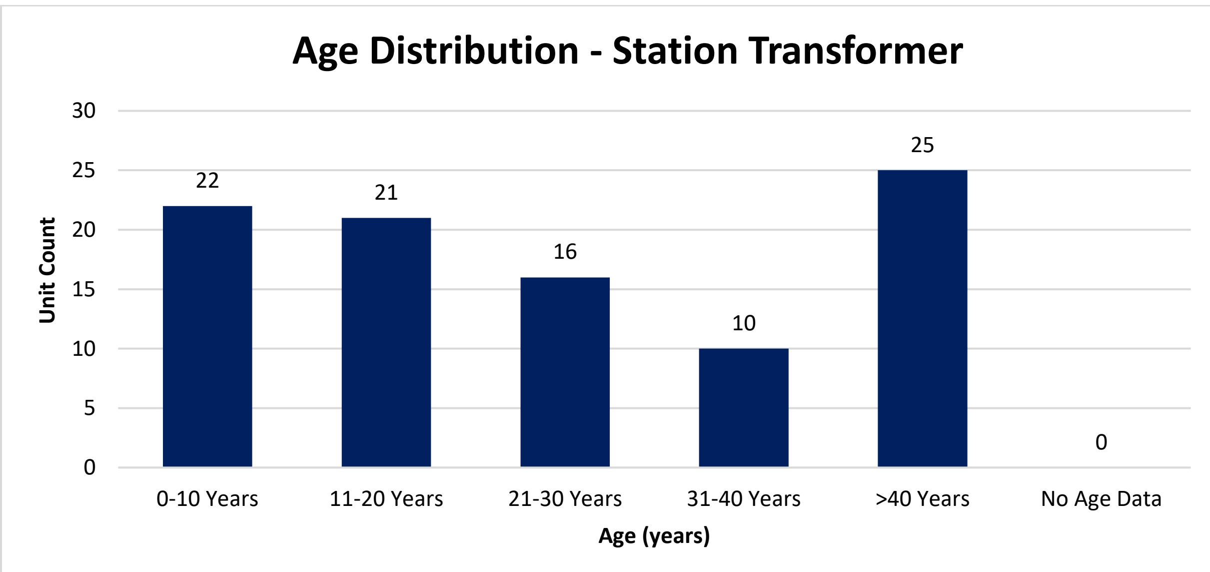


Figure 4-27: Station Transformer Age Demographics

HI Results

The overall HI distribution is presented in Figure 4-28. Most of the transformers are in Very Good to Fair condition; however, seven of the units are in Poor condition.

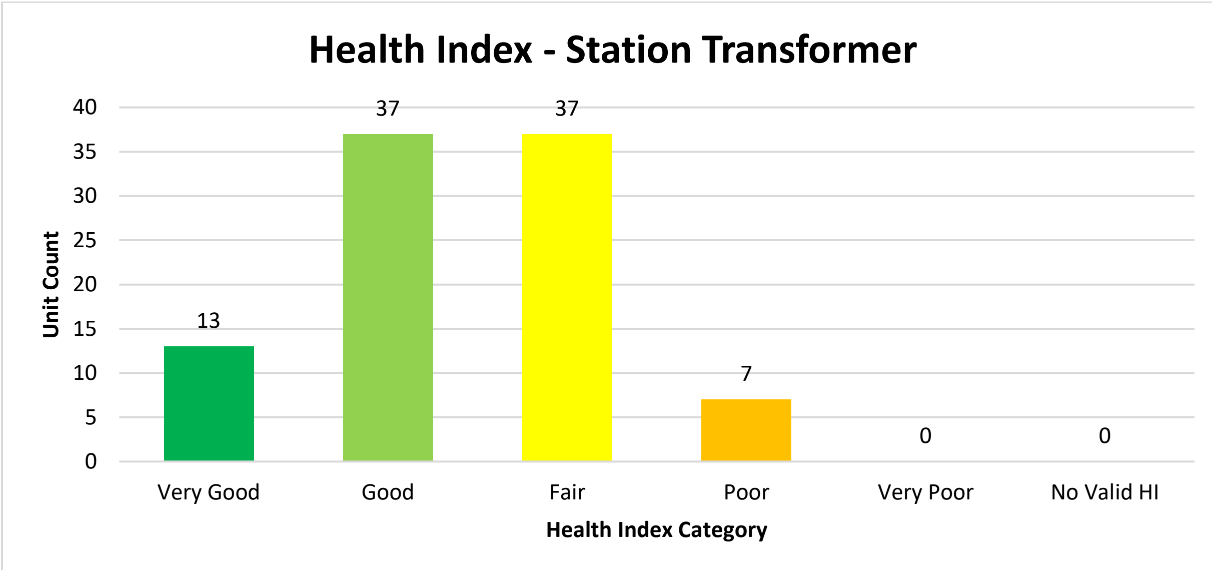


Figure 4-28: Station Transformer HI Results

The HI formulation is heavily weighted to the technical test criteria of DGA, PF, and oil quality ("OQ"). The station transformers assessed in Poor condition are listed below in the format "Station Name (age, unsatisfactory criteria)":

- Applecroft (30 years, DGA/OQ);
- Edgehill (59 years, PF/OQ);
- First (45 years, PF/OQ);
- Harder (48 years, DGA/OQ);
- Jones (56 years, OQ);
- Squires Beach (33 years, OQ); and
- Spare 10 (40 years, DGA).

<u>Recommendations for Future Improvements</u>

Station transformers should be managed under the context of a thorough AM Plan. There are no specific recommendations for improvement based on this ACA process in light of the data that Elexicon already collects except for the collection of data for the two Station Transformers located at the MS-16 substation.

This report includes data on two customer-owned sites, as testing and inspection data was provided, but did not include other customer-owned facilities. It is recommended to flag all customer-owned facilities for common data handling.

The condition data currently being collected for station transformers is both comprehensive and detailed. In addition to the data currently being collected, a best-practice formulation may consider some additional Condition Parameters that we invite Elexicon to review:

- Load history;
- IR scan;
- Insect infestation;
- Degree of polymerization;
- Main tank corrosion;
- Oil tank corrosion;
- Foundation condition; and
- Oil level.

4.2.2 Station Circuit Breakers

Condition Assessment Methodology

Station circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. Breakers 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 degradation occurs 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 which can be maintained by cleaning carbon by-products from the oil, vacuum-bottle insulated with SF6 gas, or solid-dielectric insulation.

Table 4-15 below provides the HI algorithm for station circuit breakers. Additional details about these Condition Parameters and how they are graded can be found in Appendix 6B.12.

Table 4-15: Station Circuit Breaker Health Index Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Test Results	8	A,B,C,D,E	4,3,2,1,0	32
Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
Functional Obsolescence	8*	A,E	4,0	32
			Total Score	**112**

* The weight of 8 is only applied if the asset scores an "E", otherwise this parameter is weighted 0.

Data Collection and Assumptions

Data collected in this section refers only to stations with circuit breakers and does not include stations with fuses and hydraulic reclosers.

The DAI for this asset is 98%.

Demographics

Elexicon owns 175 circuit breakers and has age data for all of them. Figure 4-29 presents the age distribution for in-service station circuit breakers.

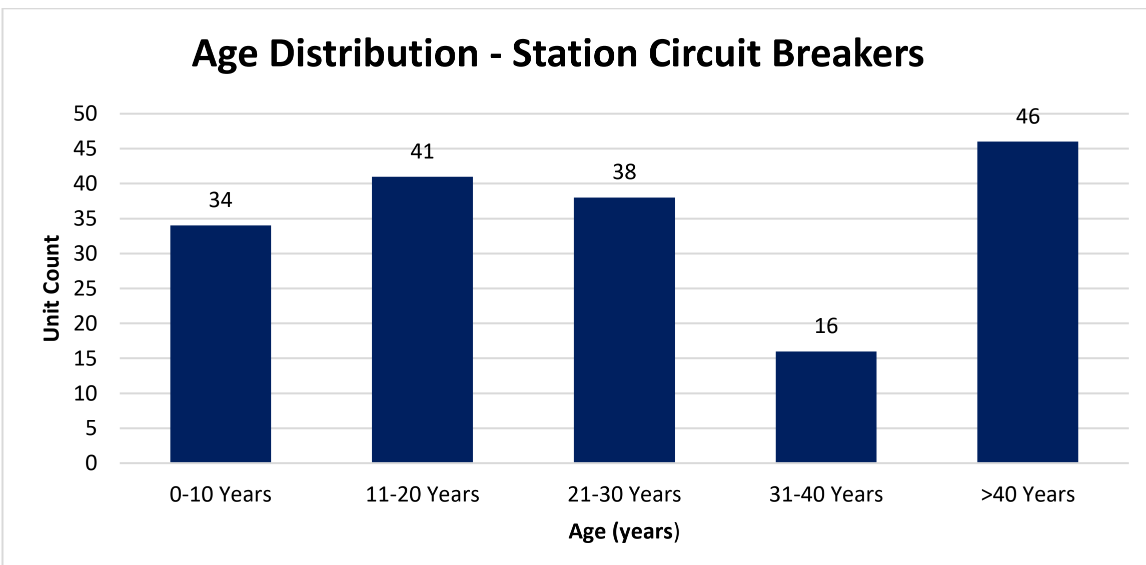


Figure 4-29: Station Circuit Breaker Age Demographic

HI Results

Elexicon owns 175 circuit breakers, of which valid HI results are calculated for 170 (97%). Most of the breakers are in Very Good to Fair condition; however, twelve breakers require attention. Additionally, there are five breakers without a valid HI which should be assessed further. The HI results for station circuit breakers are presented in Figure 4-30.

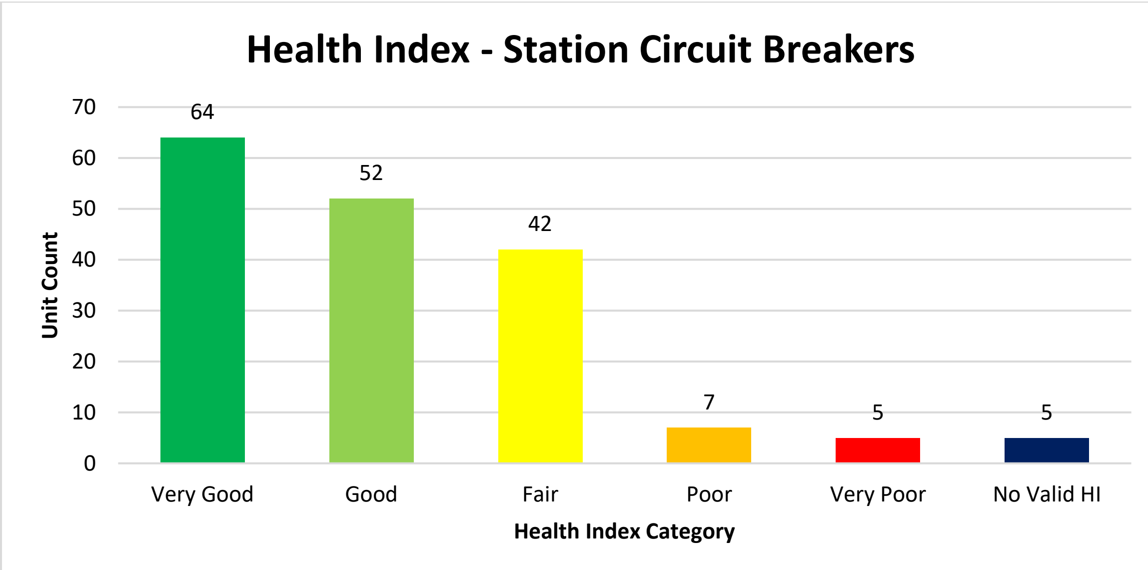


Figure 4-30: Station Circuit Breaker HI Results

<u>Recommendations for Future Improvements</u>

The assets with missing age and condition data should be reviewed and populated.

Condition data is being provided on Inspection forms. For repeatability, future data should be collected in condition coded format, and existing data should be quantized into the consistent criteria codes (A, B, C, D, E)

As station breakers are renewed over time and new stations built, new technology is likely to be introduced into the system, warranting formulation of more comprehensive and/or sub-asset class-specific HI formulations. In addition to the data currently being collected, additional Condition Parameters that Elexicon can consider collecting are:

- Condition of control box;
- Condition of battery/charger system;
- Condition/operability of the communications system;
- Condition of bushings and support structures;
- Condition of bushings;
- Condition of mechanism;
- Condition of foundations and structures;

- Time/travel tests;
- Hydraulic spring recharge time;
- Contact resistance tests;
- Counter readings/operations;
- Vacuum bottle integrity (if applicable);
- Tank and mechanism boxes;
- Oil leaks (if applicable);
- SF6 leaks (if applicable);
- Oil analysis (if applicable);
- Gas analysis (if applicable); and
- Condition of the enclosure.

4.2.3 Station Batteries

Condition Assessment Methodology

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 electrolyte 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.

The differences in the data collection methods of the two areas make it useful to develop separate Health Indices in the legacy Whitby and Veridian areas. Both formulations are based on the important end-of-life indicators and give useful predictions. For this asset, a two-parameter assessment was conducted. Table 4-16 and Table 4-17 provide the HI algorithms for Whitby and Veridian station batteries, respectively. Additional details about the Condition Parameters and how they are graded can be found in Appendix 6B.13.

Table 4-16: Whitby 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
Test Results	4	A,C,E	4,2,0	16
			Total Score	**32**

Table 4-17: Veridian Station Batteries HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
Test Results	4	A,C,E	4,2,0	16
			Total Score	**32**

Data Collection and Assumptions

Data exist in an electronic format for stations in the Whitby region. For the Veridian region, there are inspection forms with no specific condition rating for battery systems other than exception reporting of condition issues. For the purposes of this analysis, where a battery is known to have been inspected but no condition information is provided, the battery is assumed to be in like-new or 'A' condition.

The DAI for this asset is 100% in the Whitby area and 98% in the Veridian area.

Demographics

Demographics are known for battery sets in the legacy Whitby area but the Veridian area data is limited to visual inspection. Since Whitby replaces battery sets regularly, all of the assets are in fairly new condition (less than ten years old). Figure 4-31: Station Battery Age Demographic presents the age distribution for in-service station batteries.

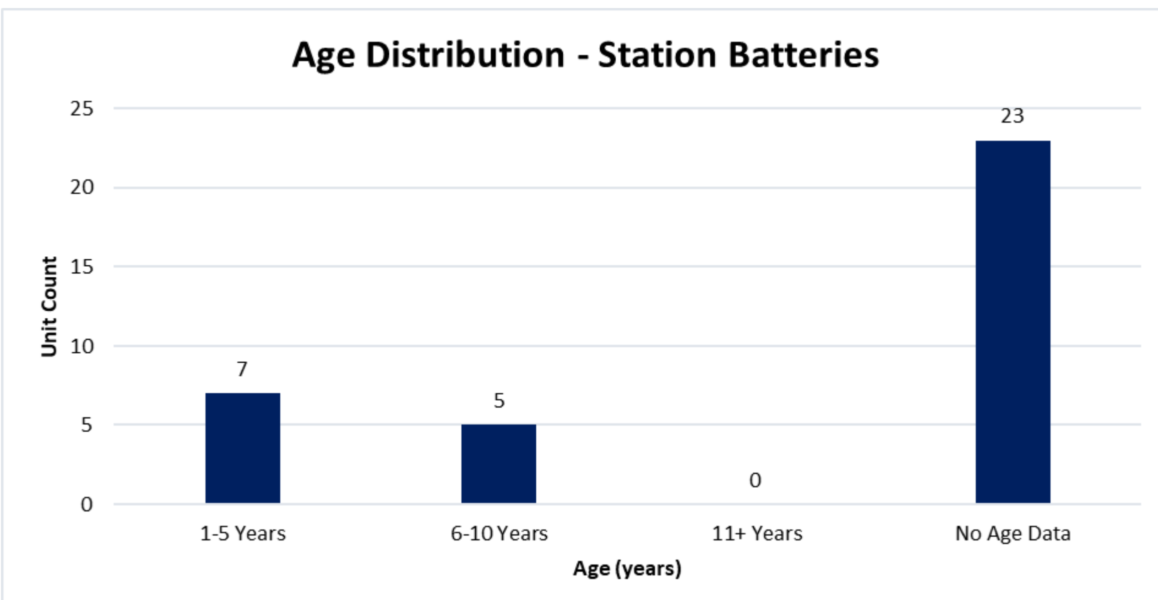


Figure 4-31: Station Battery Age Demographics

HI Results

Most of the installations are in Very Good or Good condition. The battery set at Riverside Substation received a 'C' for condition and should be monitored for further degradation. Figure 4-32 present the combined HI results for station batteries at Whitby and Veridian regions.

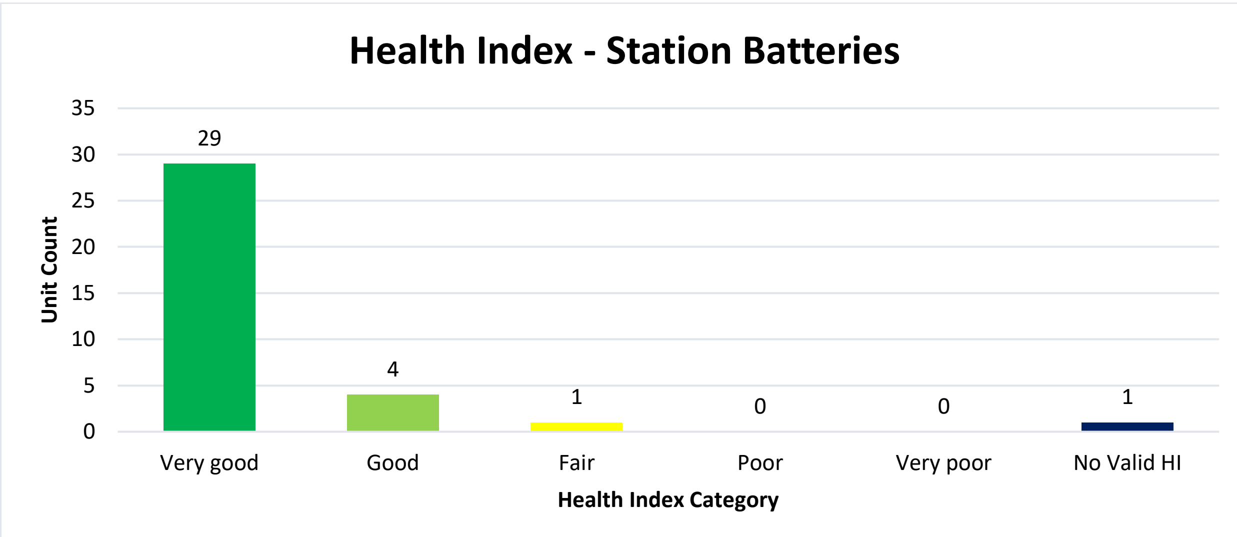


Figure 4-32: Whitby Station Battery HI Results

Recommendations for Future Improvements

As part of the AM planning procedures, a unified practice for station batteries should be developed and aligned between the two areas. Once the practice is set, an HI should be formulated that tracks end-of-life indicators.

In addition to completing the data currently being collected – particularly service age – a best-practice formulation for this asst class includes the following Condition Parameters that Elexicon may wish to incorporate into its station inspection process:

- Charger condition; and
- Redundancy availability.

4.2.4 Station Protective Relays

Condition Assessment Methodology

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.

Protective relays are more likely to become obsolete based on functionality and communication needs rather than physically deteriorating due to environmental conditions.

Table 4-18 below provides the HI algorithm for station protective relays. Additional details about the Condition Parameters can be found in Appendix 6B.14.

Table 4-18: Station Protective 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,E	4,3,2,0	16
Overall Condition	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**44**

Data Collection and Assumptions

Detailed demographics, testing, and visual inspection data were provided for stations in the Whitby region. For the Veridian region, inspection forms, include the type and calibration reports, comprise the only information source available. It is reasonable to assume there are no imminent concerns associated with the units for which these inspection forms are filed; however, the lack of objective data inputs implies that an HI cannot be calculated in the Veridian area.

The DAI for this asset is 100%; this DAI is calculated based on data for the Whitby area only.

Demographics

Age data are available for all protective relays in the legacy Whitby area. All reported installations are less than twenty years old. Figure 4-33 provides the age distributions for the Whitby area station protective relays.

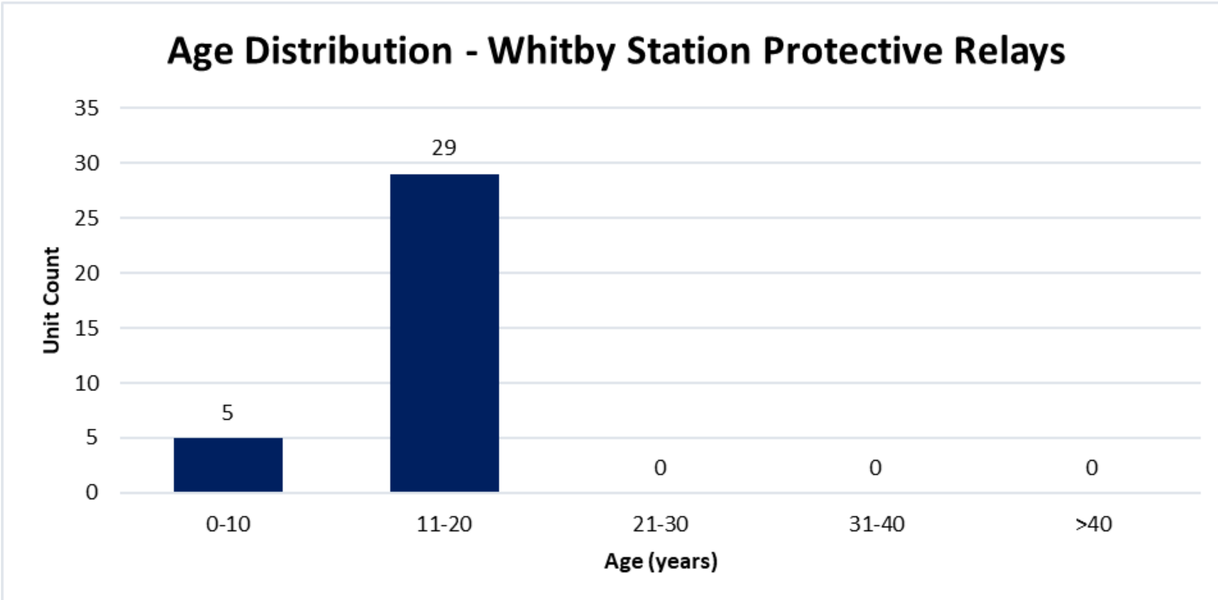


Figure 4-33: Whitby Station Protective Relay Age Demographics

<u>HI Results</u>

The HI results were calculated for relays in the legacy Whitby area only. HI results indicate that all the relays surveyed (34) are in Very Good condition. This is an expected result, as relays do not experience very much physical degradation and are often replaced when they fail the testing procedures or become obsolete due to the vendor discontinuing support for a particular model. It is also an indicator that the protective relays in use are of the newer microprocessor type of relay.

Figure 4-34 provides the HI results for in-service Whitby area station protective relays.

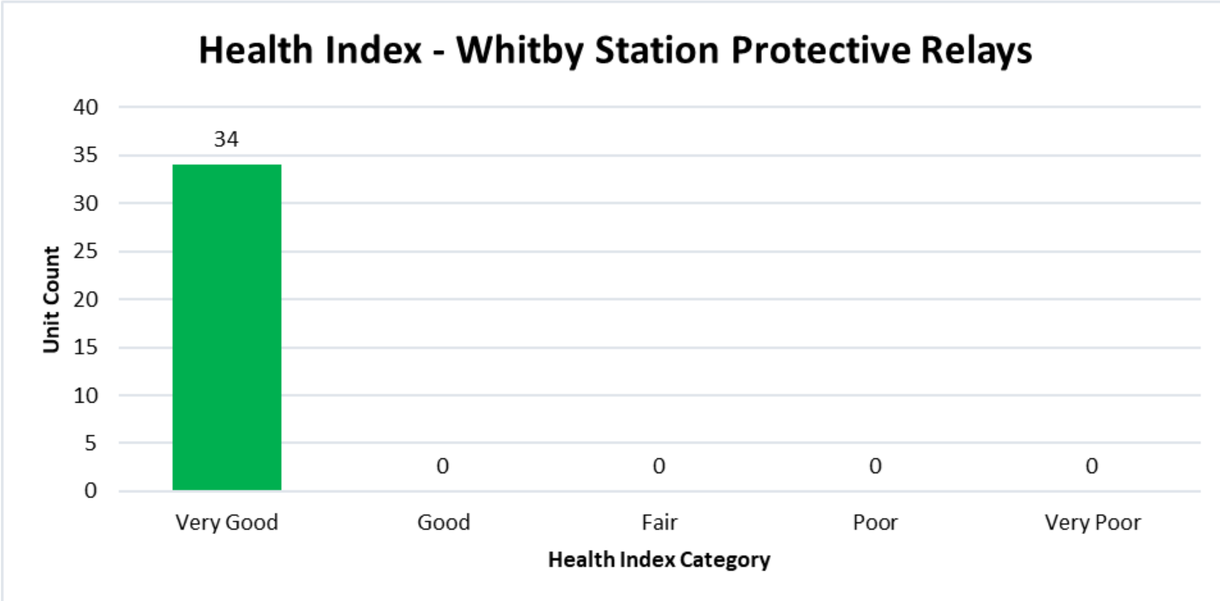


Figure 4-34: Whitby Station Protective Relay HI Results

<u>Recommendations for Future Improvements</u>

In the initial steps, demographics (age and type), test results, and physical condition data should be collected and translated into condition codes (A,B,C,D,E) for all relays not yet reported (which are largely located in the legacy Veridian area).

Some of the legacy Veridian relays are of the mechanical type (Herchimer and Catherine) and should be assessed separately based on typical parameters such as age, visual condition, test results, failure results, and obsolescence factors.

As part of the AM planning, Elexicon should consider how to manage its protective relays. As the end-of-life indicators are established, a more advanced HI for protective relays can be established that is built on more than physical condition.

Other parameters that can be included in future HI formulations include the following:

- Mean time between failures (per relay type); and
- Discretionary or non-discretionary obsolescence.

We also note that Elexicon operates a number of potential and current transformers that form the part of the station protective systems. These assets are often given their own HI scores. Condition Parameters for these units may include (as applicable):

- Condition of insulators;
- Condition of primary connections;
- Condition of secondary connections;
- Condition of foundations and grounds;
- Overall condition;
- Turns ratio tests;
- IR scan results;
- Oil leaks and gaskets;
- Oil analysis;
- Condition of the tank, and terminal boxes; and
- SF6 leaks.

While the Veridian inspection reports include ratio test results, there is insufficient inspection data available to develop an HI at this time.

4.2.5 Station Fences and Buildings

Condition Assessment Methodology

Station buildings – which refer to the walls, roof, floors, doors etc. of the station – and fences 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 and fences are inspected monthly and are maintained as issues arise. In some cases, these assets 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, gates are repaired, and buildings are patched up as needed to remain functional.

Table 4-19 below provides the HI algorithm for station fences and buildings. Additional details about these Condition Parameters above can be found in Appendix 6B.15.

Table 4-19: Station Fence HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	8	A,C,E	4,2,0	32
			Total Score	**32**

Data Collection and Assumptions

For substation fences, simplified condition data were provided in the form of monthly inspection reports for 46 stations across both the legacy Veridian and Whitby areas. Condition data were provided for fourteen substation buildings all located in the legacy Whitby area.

In addition, records are indicating that regular inspection visits take place, however, there is no specific condition data provided. In these records issues are recorded on a "by exception" basis, meaning that no information is captured if an inspector finds the infrastructure to be in an inadequate state. Accordingly, it is reasonable to assume there are no imminent concerns associated with the assets for which the inspection records are available. However, the lack of discrete Condition Parameter records means that an HI cannot be calculated in most cases.

For these assets, a DAI is not meaningful given the manner in which the information is presented and the resulting assumptions of our analysis. However, fence information was provided for 100% of the stations in both areas and buildings information was provided for 100% of the buildings in the Whitby area.

Demographics

Demographic information for stations and fences was not part of the dataset provided and is not deemed critical in assessing the health of these assets.

HI Results

The HI formulation for both stations and fences is a one-parameter assessment, which provides a simplified view of asset health. However, considering they are condition-based assessments derived from field inspections, they pose some incremental value to planners in providing relative ranking across the units. The majority of the installations are in Very Good or Good condition. Valid HI results for buildings are only possible in the legacy Whitby area given the data available at this time. Figure 4-35 presents the HI results of all station fences, whereas Figure 4-36 presents the HI results of station buildings within the Whitby region.

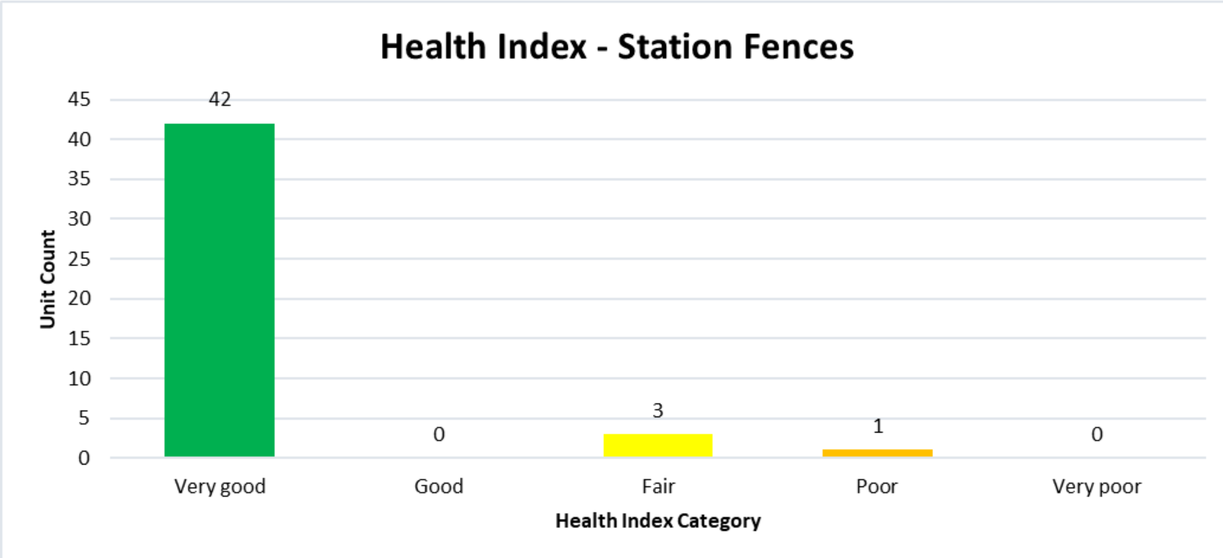


Figure 4-35: Station Fence HI Results

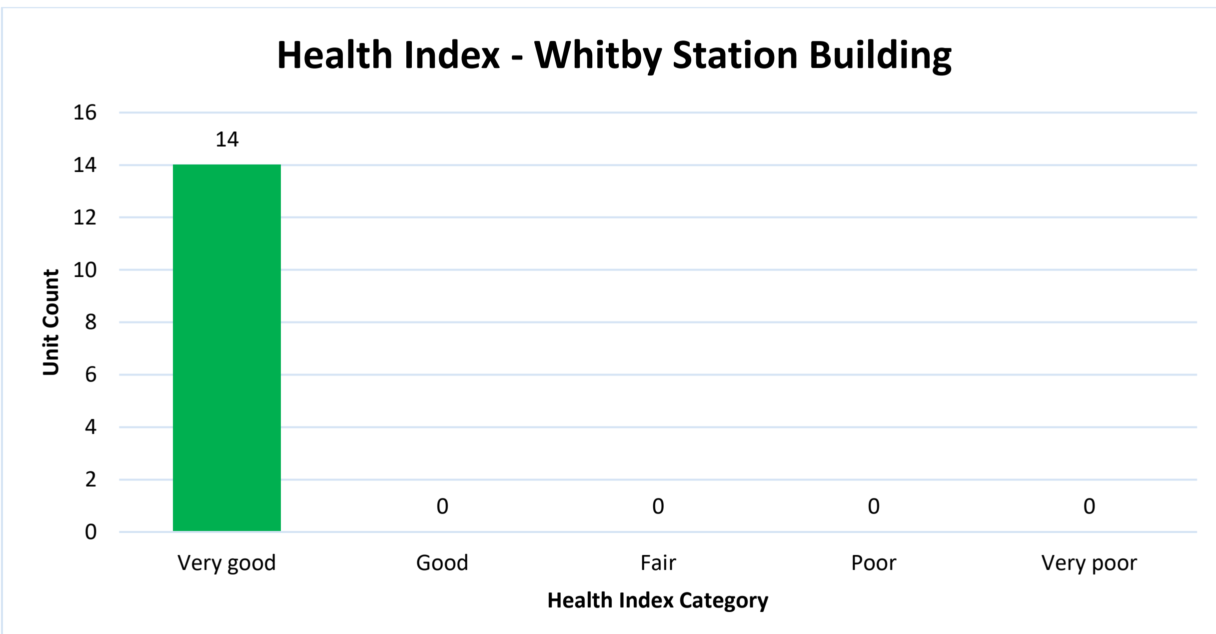


Figure 4-36: Whitby Station Building HI Results

Recommendations for Future Improvements

As it evaluates its approach to AM for station assets overall, we encourage Elexicon to review whether and to what extent its planning functions would derive incremental value from a more granular approach to station ancillary AM, including buildings, fences, ground grids, structures, security systems etc. In deciding among the asset classes where capturing additional condition information may be warranted, Elexicon may wish to concentrate on the asset features capturing which may enable it to perform preventative maintenance.

It may also be useful to create an overall station HI, which would guide renewal investment over the longer term. Additional information that this index could capture may include the following:

- Condition of the roof;
- Condition of walls;
- Condition of doors/windows/louvres;
- Condition of foundations and floors;
- Condition of lighting and HVAC; and
- Condition of the overall building.

An HI formulation for station ancillary systems may include the following parameters:

- Condition of fences;
- Condition of gates;
- Condition of security systems;
- Condition of phones and LAN services;
- Condition of lanes and parking;
- Condition of plumbing and electrical;
- Condition of drainage systems;
- State of surrounding vegetation;
- Grounding/bonding of ancillaries; and
- Access and safety concerns (such as snow pile-up).

Finally, we recommend that Elexicon consider establishing an HI for station ground grids. An HI formulation for ground grids can be comprised of various combinations of the following factors:

- Ground grid installation (technical design and specifications);
- Risers and bonds to structures and attachment connections;
- Buildings, fences, and gates;

- Condition of surface stone;
- Resistivity of surface stone;
- Grid and bonding integrity; and
- Current injection test.

5 Recommendations

5.1 Asset Data Management Improvement in a Strategic Context

As the preceding ACA results indicate, data gaps remain a major consideration for many asset classes, where we were either unable to derive uniform health indices for both sub-populations, where material portions of assets could not be assigned an HI, or where the condition scores were comprised of only one or two parameters, failing to meet the ISO 5500x threshold for being considered an HI. Fundamentally, asset data gaps represent an organizational risk, insofar as the asset health information calculated using this data feeds into the organization's asset intervention planning work.

The magnitude of this risk is a function of the probability of data gaps leading to suboptimal investment allocation decisions and the impact of these under-informed decisions (e.g., the cost of avoidable outages and/or the opportunity cost of other initiatives foregone in the short term to rectify these outages). We do not expect Elexicon to quantify this risk given the magnitude of these current gaps, nor do we see it as a major priority relative to other organizational undertakings associated with the ongoing consolidation of operations. Nevertheless, it is METSCO's recommendation that the risk associated with asset data gaps be articulated, added to the utility's corporate risk register, and mitigated and tracked on an ongoing basis relative to other corporate risk considerations.

Closing the Gaps: Selecting Among the Parameters to Track Going Forward

Notably, managing data availability risk need not be synonymous with rectifying all the data gaps in the shortest possible timeline. As with other continuous improvement undertakings, utilities have a relatively finite number of resources available at any given time. The decision to invest in continuous improvement in one area usually comes at the opportunity cost of enhancing one's capabilities elsewhere. As such, the decision of whether, how, and to what extent to rectify the data gaps is a matter of informed trade-off analysis that should proceed in the following manner:

- Prioritizing among the identified data gaps by their magnitude and significance;
- Estimating the cost and timeline of their rectification; and
- Considering estimated costs and criticality against those of other asset management continuous improvement undertakings being contemplated.

Among the potential factors to use in prioritizing the rectification of data gaps are the criticality rankings for additional Condition Parameters we provide in the following section.

These represent the asset Condition Parameters that most commonly form the basis of advanced asset condition assessments. The higher-ranked parameters typically represent the measurements associated with equipment degradation processes known to be most detrimental to the normal operation of electrical assets over time. We note, however, that these rankings represent the relative significance of parameters within the confines of a single asset class, but not across asset classes. As such, in considering which incremental Condition Parameters should be prioritized over a given timeframe, Elexicon should prioritize the collection of incremental Condition Parameters both within and across the various asset classes.

While collecting the information on the parameters listed below should be seriously considered, it is nevertheless METSCO's recommendation that priority be given to closing the gaps within the data records for the Condition Parameters that are already being collected to some degree. Unlike the new parameters that we suggest below, the organizational processes and knowledge required for collecting and interpreting the parameters already available for some assets should already be in place within the merged organization. Accordingly, we expect that closing of the gaps within the Condition Parameters already being recorded would amount to a "low-hanging fruit" that the organization could proceed to addressing with relative ease.

In closing these gaps associated with the parameters already being collected, it is critical for Elexicon to revisit the definitions and scales underlying these data collection practices, as similarly defined parameters could be interpreted differently by the two merger predecessors' field crews and/or contractors. This is especially critical for qualitative visual assessments such as "Overall Condition" – where the scales of degradation corresponding to a given score can be expected to be different between two predecessor organizations. Doing so can be accomplished by way of developing common reference documents with photographed examples that illustrate asset degradation associated with a given visual assessment score. In developing such materials, it is preferable to involve the field crews as subject matter experts in the early stages. Doing so enables them to develop a sense of ownership in the recalibrated assessment frameworks going forward.

In making these observations, METSCO assumes that Elexicon's future inspection and maintenance practices will emphasize proactive condition data collection to a material degree – as opposed to an exception-based approach where condition information is typically recorded only if an inspected asset exhibits features indicative of imminent failure. We state this assumption particularly because Elexicon's predecessors appear to have relied on exception-based asset condition recording approach for at least some of its asset classes. While such an approach is arguably more economic in the near-term, we believe that it detracts from the asset managers' ability to maintain a comprehensive view of the system and may limit the degree of granularity with which they can evaluate future investment trade-offs. Notwithstanding our views however, using an exception-based approach represents a strategic option that Elexicon may still consider on the balance its priorities across the various asset classes in its care.

5.2 Recommendations for Potential Data Collection Enhancements

The following set of recommendations consolidate METSCO's suggestions provided throughout Chapter 4. The recommendations target additional Condition Parameters or the means of collecting and storing the data already being utilized. The recommendations are based on the advanced ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted.

5.2.1 Wood Poles

Elexicon should take steps to consolidate the data sets with a single structure and consistent parameter reporting for their entire population of wood poles. Doing so will amount to developing an asset registry that should contain a complete set of the most recent visual inspection and testing data.

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). Asset registry unique identifiers should be matched up with inspection reports for historical inspection reports and all data should be parsed into condition codes.

Inspection services should be advised to give consistent reporting of remaining strength, preferably as a percentage of remaining life. Physical condition data should be collected in the same format as the visual inspection process. Other data points such as "Overall Condition" should be better documented for intent with a single methodology document spelling out the various physical manifestations corresponding to a particular grading level and a reference guide containing actual examples to be used for crew training and support.

We note that aside from the gaps in the data records, Elexicon collects a substantial number of data parameters that enable production of a relatively advanced HI formulation. Should the utility consider expanding the scope of inspection data collection, additional Condition Parameters for this asset class may include:

- Cross-arm condition;
- Pole-top condition;

- Insect infestation;
- Woodpecker damage;
- Shell condition; and
- Pole treatment.

5.2.2 Concrete Poles

While the DAI for concrete poles is low and needs to be improved, it should also be noted that concrete poles make up 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 significant number of concrete poles for the foreseeable future. As such, near-term enhancements to the current data collection and tracking practices are in order. In the legacy Veridian area, demographic data, such as installed date and pole type, should be established for every pole and a full visual inspection should take place. In the legacy Whitby area, inspection data should be collected for the remaining poles.

Recognizing that Elexicon is in the process of phasing out this asset class over time, we nevertheless believe that tracking some condition information for these assets' remaining lives may be beneficial from a near-to-medium term planning perspective. To this end, we recommend that Elexicon consider collection the following concrete pole condition data:

- Evidence of rust/corrosion and spalling;
- Evidence of other defects;
- Out of plumb; and
- Service age.

5.2.3 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 in an attempt to correlate age and type with life expectancy.

There is a block of cables, particularly in the 12.5-kV class that should be examined to determine age and type within the Gravenhurst area.

The following types of condition information may assist Elexicon in its efforts to plan its replacement needs with additional confidence:

- Treatment history;
- Field testing results;
- Fault history;
- Load history;
- Condition of concentric neutral; and
- Visual inspection of terminations and splices.

5.2.4 Overhead Conductors

Conductor age should be populated with best available information. Typically, conductors can be assumed to have been installed at the time the original pole lines were built; in this case, the typical pole age for the neighborhood or feeder can make a useful estimate.

Overhead conductor condition rarely drives reinvestment; therefore, a practical approach to data collection is warranted, including reliance on estimates and broad assumptions. At this point, we do not recommend that Elexicon invest any additional resources into collection of conductor condition data.

5.2.5 Pole-Mounted Transformers

Transformer condition data should be collected for all transformers in the legacy Veridian area, and the missing 450 in the Whitby area. Age information should be collected for assets missing age data, primarily in the legacy Veridian dataset.

Because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number. 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 regular inspections. Should Elexicon decide to collect or analyze additional data parameters to assess the remaining lives of its overhead transformer population for longer-term planning, the following types of information may provide useful insights subject to the economics of obtaining it:

- Peak loading history;
- Visual inspections; and
- IR scan results.

5.2.6 Pad-Mounted Transformers

Data collection for pad-mounted transformers should be rationalized across the entire utility. As a minimum, age and condition data should be made available for all installations. Transformers are often tracked by serial number because of the potential for transformers to be removed from one location, rehabilitated, and then installed elsewhere.

As part of the AM Plan, an enhanced formulation based on criteria similar to pad-mounted switchgear assets would give a better indication of asset health. Suggested additional Condition Parameters include:

- Peak loading history;
- IR scan results;
- Condition of enclosure; and
- Condition of civil structure.

5.2.7 Vault Transformers

Data collection for vault transformers should be rationalized across the entire utility. As a minimum, age and condition data should be made available for all installations. Transformers are often tracked by serial number because of the potential for transformers to be removed from one location, rehabilitated, and then installed elsewhere.

As part of the AM Plan, an enhanced formulation based on criteria similar to pad mounted switchgear assets would give a better indication of asset health. Suggested additional parameters include as a minimum, condition of other equipment in vault (i.e., switching provisions, terminations) and IR scan results. In some cases, the condition of the vault itself might be a useful indicator if the vault is not customer-owned. Additional data inputs that would enable Elexicon to formulate a comprehensive HI for this asset class include:

- Transformer age;
- Peak loading history;
- IR scan results; and
- Condition of civil structure.

5.2.8 Pad-Mounted Distribution Switchgear

Data collection for pad-mounted switchgear should be rationalized across the entire utility. As a minimum, age and condition data should be made available for all installations. Pad-mounted switchgear are often tracked by serial number because of the potential for switchgear to be removed from one location, rehabilitated, and then installed elsewhere.

Due to technical differences between gas-insulated, air-insulated, and solid-dielectric switchgear, specific AM Plans featuring discrete formulations for each sub-type should be considered in the future. Suggested additional parameters include, as a minimum, overall condition, structures/pads integrity, operations counter, and gas pressure readings. Other parameters may include:

- Condition of enclosure;
- Condition of terminations;
- Condition of pad;
- IR scan results;
- Condition of interphase barriers (if applicable);
- Condition of blades (if visible);
- Condition of operating mechanism (if applicable); and
- SF6 pressure/leaks evidence.

5.2.9 Overhead Switch – Three-Phase

Considering the value of the three-phase overhead switch asset to the operation of the utility, all missing data should be collected, which may include collecting or estimating age data.

Condition data, including IR scan data, should be collected and translated into condition scores (A,B,C,D,E) and consolidated in the asset registry. A number of incremental Condition Parameters may also be collected to enhance the current state of health information for this important component of the electrical system:

- Condition of insulators;
- Condition of blades;
- Condition of operating mechanism;
- Condition of terminations; and
- Markers and indicator readings.

With respect to more advanced automated switches utilizing oil or gas insulation, the following Condition Parameters should be examined for economic opportunities of collection:

- Counter readings/operations;
- Condition of tank/enclosure;
- Condition of control box;

- Condition of battery/charger system;
- Condition/operability of communications system;
- Oil condition or leakers;
- Vacuum bottle integrity;
- SF6 leaks; and
- Technical obsolescence.

5.2.10 Single-Phase Switches, Blades, and Cut-outs

All missing data for single-phase switches, blades, and cut-outs should be collected, which may include collecting or estimating age data. Condition data – including IR scan results – should be collected and translated into condition scores (A,B,C,D,E) and consolidated in the asset registry. Additional parameters that Elexicon can consider collecting to enhance its predictive assessments for this asset class include:

- Condition of terminations;
- Condition of insulators;
- Condition of blades; and
- Condition of operating mechanism (if applicable).

5.2.11 Station Transformers

Station transformers should be managed under the context of a thorough AM Plan. There are no specific recommendations for improvement based on this ACA process given the substantial amount of data that Elexicon already collects. However, additional information that may inform the evolution of its AM practices for this critical asset class can include:

- Load history;
- IR scan results;
- Insect infestation;
- Degree of polymerization;
- Main tank corrosion;
- Oil tank corrosion;
- Foundation condition; and
- Oil level.

5.2.12 Station Circuit Breakers

The assets with missing age and condition data should be reviewed and populated. Condition data is being provided on inspection forms. For repeatability, future data should be collected in condition coded format, and existing data should be translated into the consistent criteria codes (A,B,C,D,E). Moreover, advanced AM practice manuals recommend a number of additional Condition Parameters that present opportunities for enhancing the rigor of Elexicon's assessment of this asset class. These include:

- Condition of control box;
- Condition of battery/charger system;
- Condition/operability of communications system;
- Condition of bushings and support structures;
- Condition of bushings;
- Condition of mechanism;
- Condition of foundations and structures;
- Time/travel tests;
- Hydraulic spring recharge time;
- Contact resistance tests;
- Counter readings/operations;
- Vacuum bottle integrity (if applicable);
- Tank and mechanism boxes;
- Oil leaks (if applicable);
- SF6 leaks (if applicable);
- Oil analysis (if applicable);
- Gas analysis (if applicable); and
- Condition of enclosure.

5.2.13 Station Batteries

As part of the AM planning procedures, a unified practice for stations batteries should be developed and aligned between the two areas. Once the practice is set, an HI should be formulated that tracks end-of-life indicators, including parameters such as battery test results, condition of the charger, and availability of redundancies.

5.2.14 Station Protective Relays

In the initial steps, demographic (age and type), test results, and physical condition data should be collected and parsed into condition codes (A,B,C,D,E) for all relays not yet reported (largely in the legacy Veridian area). Any old relay types, such as electromechanical or those that do not meet current communications needs should be assessed and scheduled for replacement as needed.

As part of the AM planning process, Elexicon should consider how to manage the protective relays. As end-of-life indicators are established a useful HI for protective relays can be established that is built on factors beyond the physical condition, including mean time between failures (tracked for each given 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 refurbishment of in-service units

Of note is also the fact that Elexicon does not appear to collect detailed condition information for its current and potential transformers that form an integral part of the station safety system. We recommend that Elexicon consider collecting results of inspection and testing work of a subset of the following parameters:

- Condition of insulators;
- Condition of primary connections;
- Condition of secondary connections;
- Condition of foundations and grounds;
- Overall condition;
- Turns ratio tests;
- IR scans;
- Oil leaks and gaskets;
- Oil analysis;
- Condition of tank, and terminal boxes; and
- SF6 leaks.

5.2.15 Station Fences and Buildings

As noted in Chapter 4, Elexicon collects a relatively limited amount of data associated with station fences and buildings given the frequency of inspections, reliance on exception-based reporting, and the relatively short turnaround associated with repairs of any deficiencies uncovered through inspection. This approach may be sufficiently rigorous to continue going forward; however, should the ongoing evaluation of future AM strategy determine that enhancements may be warranted to enable near-term planning and improved visibility into the current state of these assets, Elexicon can collect the following types of information and translate them into station building HI formulations:

- Condition of roof;
- Condition of walls;
- Condition of doors/windows/louvres;
- Condition of foundations and floors;
- Condition of lighting and HVAC systems; and
- Overall condition of the building.

An alternative approach may involve constructing an HI framework for the entire station. If this approach is pursued, additional factors to those noted above that can inform such a formulation include:

- Condition of fences;
- Condition of gates;
- Condition of security systems;
- Condition of phones and LAN services;
- Condition of lanes and parking;
- Condition of plumbing and electrical;
- Condition of drainage systems;
- State of surrounding vegetation; and
- Grounding/bonding of ancillaries.

We also encourage Elexicon to consider developing an HI for its station ground grid installations, given their role in ensuring worker and public safety around the station assets. Whether formulated as a standalone index or a subset of a broader station-wide index discussed above, the Condition Parameters underlying such an index can include the following data:

- Ground grid installation (technical design and to specifications);
- Risers and bonds to structures and attachment connections;
- Buildings, fences, and gates;
- Condition of surface stone;
- Resistivity of surface stone;
- Grid and bonding integrity; and
- Current-injection test results.

5.3 Pacing the Data Gap Rectification

Having described the asset-specific Condition Parameters recommended for Elexicon to evaluate the benefits of future collection, it is important to address the reality that the existing gaps will take considerable time to be closed – even under the most aggressive approaches. Asset condition data is gathered by way of regularly scheduled preventative maintenance or inspection activities, where a given portion of system assets is reviewed each year. It is thus reasonable to expect that any material enhancements would take three to four years to materialize at a minimum –potentially longer depending on the frequency of the asset inspection / maintenance cycles for certain types of equipment.

It is possible, however, to implement important enhancements to asset condition data over a shorter timeline – if the near-term data collection efforts are focused on certain geographic areas, asset classes, and/or equipment units meeting certain attributes that qualify them for higher prioritization. In other words, while attaining system-wide improvements in data collection is likely a matter of a longer timeline, Elexicon can derive significant value if sooner if its condition attribute collection efforts are clearly scoped and prioritized in the early years. In making this observation, we are cognizant that Ontario utilities are bound by the Distribution System Code guideline to inspect their assets with certain regularity. As such, the following recommendations assume that these basic requirements are met, and the suggested approaches represent incremental collection efforts.

There are several potential ways of scoping down and prioritizing the allocation of inspection efforts in the early years:

Asset Class Horizon-based Segmentation

For instance, Elexicon can stage its asset condition data improvements efforts over several "horizons" over which a given set of asset classes is prioritized for enhanced data collection efforts. For instance, overhead or underground plant (or their subsets) could become the focus of enhanced condition data collection for a three-year period, at the conclusion of which the next tranche of assets becomes prioritized.

Pursuing such an approach is predicated on an initial prioritization across asset classes, where informed decisions about the relative criticality of different assets can be made and committed to. Equally important to note that such an approach represents a temporary ramp-up period to gain the hereto missing data, to be followed by a more sustainable process that eventually integrates and balances the collection of asset data across asset classes. Using such an approach, the utility could be expected to significantly improve its understanding of a certain part of their asset base over a relatively short timeframe.

Geographic or Electrical Segmentation

In a similar manner, the early year data gap liquidation efforts can prioritize certain geographic or electrical areas (such as trunk feeders, higher-voltage assets, highest load density areas, etc.). By targeting areas identified as relatively more critical in the near term, Elexicon can gather more information regarding the condition of electrical assets associated with these areas. Once this information is completed and analyzed, the focus can shift to the areas seen as comparably lower priorities.

In the interim, the portions of Elexicon's system prioritized earlier can benefit from more comprehensive HI formulations, giving the utility experience of integrating the new data into their asset intervention planning practices. To the extent that the prioritized areas contain a variety of assets in terms of their types and/or vintages, collecting more information on a subset of assets could also enable Elexicon to make more informed extrapolations regarding the remainder of asset population, using conventional statistical sampling techniques or more advanced data science tools.

Demographic Segmentation

Elexicon may also consider prioritizing their near-term data enhancement efforts for the assets over a certain age threshold, or those of certain makes or models with known performance issues. This approach would assume for a certain period of time (aided potentially by random spot verification) that assets under a certain age threshold or other demographic parameters are in a sufficiently good condition (e.g., Fair and above) to forgo detailed recording of Condition Parameters. Based on the detailed insights obtained through the early years of using this threshold-based approach, the utility could consider to either continue using it (with modifications based on any insights obtained in process) or transitioning the advanced / more comprehensive data collection efforts onto the rest of the asset base.

Performance-Based Segmentation

Yet another approach to prioritizing the development of more comprehensive HI formulations could entail the introduction of new data collection practices for the assets in areas experiencing significant performance issues – such as the feeders with the worst reliability record in the system over the past year. There are a number of potential thresholds to define what constitutes sufficiently poor performance under a worst-performing feeder program. The most common approach involves prioritizing a percentage of worst feeders (e.g., 10% of feeders with the worst outage statistics), or feeders with annual outages over a certain number of outages (e.g., feeders experiencing seven or more sustained interruptions in the past twelve months). In this manner, the enhanced condition data collection (if pursued) could proceed in step with addressing the most significant reliability issues, until such time that the utility deems it appropriate to roll out the collection of additional parameters onto the rest of the territory. Another variation of this approach could entail prioritization of feeders / areas of initial focus based on criticality of loads connected to them (e.g., hospitals, municipal water treatment facilities, government offices, sensitive manufacturing loads, etc.).

The above discussion illustrates the range of approaches that Elexicon could consider in advancing its condition data enhancement activities in a structured and prioritized manner that would balance the paced nature of incremental efforts, with the objective of gaining crucial insights in the shortest reasonable timeframe. We note, however, that the above considerations may not be of relevance depending on the nature of strategic decisions in the area of asset data collection that Elexicon makes in the coming years.

5.4 Potential Asset Management Key Performance Indicators for Future Tracking

To conclude our recommendations section, we discuss several metrics that Elexicon can consider incorporating into its AM process for continuous improvement. While the OEB's RRF includes a set of performance measures that all utilities are required to track and report on, it may be of value to Elexicon to consider tracking several additional measures – either for internal purposes or for incremental reporting to the OEB – through its Distribution System Plan filings. In either case, establishing additional measures would allow the utility to derive new operating and strategic insights and challenge itself to close some of the identified gaps.

We note that, to our knowledge, there are no specific regulatory requirements for utilities to implement and/or report additional metrics such as the ones described below. As such, our recommendations should be viewed as optional additions to the existing AM framework and implemented only if Elexicon believes that the incremental value of insights generated is justified by the additional data collection, tracking, and analysis costs.

5.4.1 Percentage of Asset with Complete Health Indices

Definition:

The percentage of Elexicon's assets, either within a single asset class or across the system for which all inputs for utility-approved HI scores are available, adjusted for assets where collection of condition or diagnostic performance is complex or impractical.

$$\left(\frac{\#\ of\ units\ with\ 100\%\ DAI\ Scores}{Total\ \#\ of\ Units}\right) - \#\ of\ "Infeasible"\ \&\ "Impractical"\ Units$$

Depending on whether this metric is applied to a single asset class or a larger portfolio, the complex/impractical units can entail those below a certain demographic threshold below which the asset is not expected to be at risk and by extension – condition information is not collected (e.g., wood poles younger than ten to fifteen years). Additionally, the "Infeasible and Impractical" category can apply to the assets or individual units with known access issues, or units already slated for replacement or other forms of intervention within the current planning horizon.

Discussion:

This measure amounts to an operating progress tracker geared towards improving the DAI for Elexicon's asset base. As noted throughout this report, data availability remains a challenge for the utility across multiple asset classes. The proposed metric is designed to act as an operating progress target, driven by the motivation to have complete data records according to the HI definitions that the merged utility elects to go forward with. Should Elexicon consider adopting this metric for the entire asset base or select asset classes only, we suggest putting it in place after the utility decides as to which combinations of measurements in intends to collect going forward (including on the basis of recommendations contained in this report).

5.4.2 Asset Replacement Value at Risk

Definition:

The aggregate value (in dollars) of assets in a single asset class found to be in Very Poor and Poor Condition, as determined by the results of an asset condition study and best available asset unit costs estimates.

$$(\#\ of\ assets\ in\ Very\ Poor\ Condition + \#\ of\ Assets\ in\ Poor\ Condition) \\ \times Average\ Replacement\ Unit\ Cost$$

Discussion:

This measure directly introduces a financial dimension to the results of ACA analysis – by providing utility planners with a sense of financial volumes of replacement work expected to be performed over the upcoming time horizons. By monitoring the total dollar value of at-risk assets (i.e., in Very Poor and Poor condition) over time, management can track whether and to what extent its current investment levels enable it to keep the pace of replacement work to maintain the system in a condition deemed to be acceptable or desirable. Introducing dollar weighting to ACA results has a number of other beneficial applications:

Creating a Utility-wide HI distribution – while summing up the total number of assets in each condition category does not provide a particularly meaningful picture, introducing the replacement unit costs into the calculation enables planners to showcase a dollar-weighted HI distribution for the entire system, subsystem, or an individual project scope. The simplest manifestation of such an approach would start from the calculation the total replacement value of the system by summing up the costs of all units comprising it.

To determine what percentage of this total replacement value lands in each of the five HI categories between Very Good and Very Poor, the replacement values of all equipment across the asset classes determined to be in one of the five buckets on the basis of an ACA, would be summed up and divided by the total system replacement value calculated in step one. In this manner, the utility could obtain a long-term view of the overall health of its system, enabling it to consider a variety of operational and financial planning strategies.

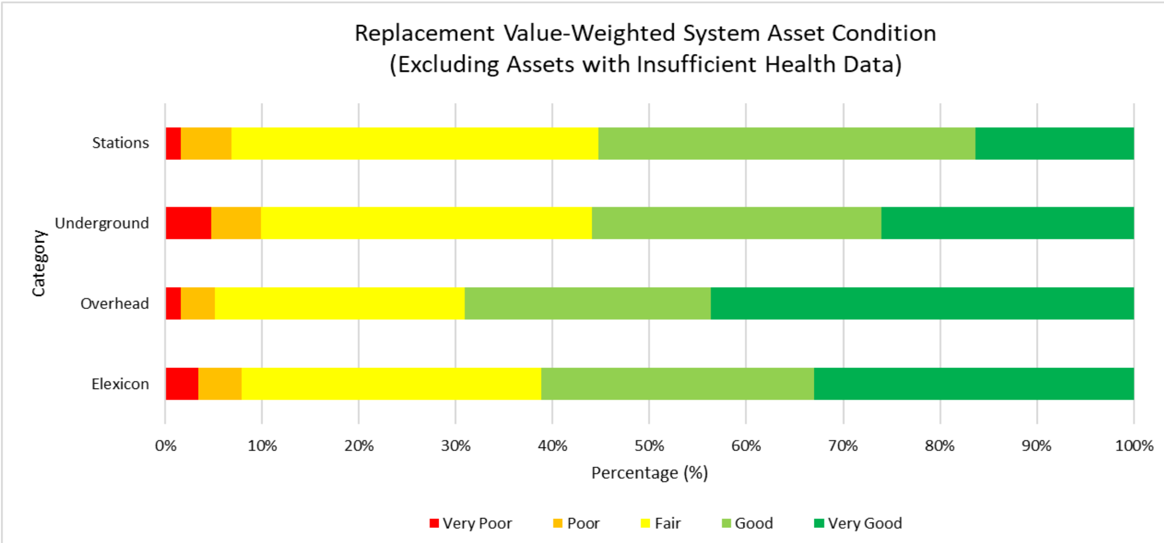


Figure 5-1: Example of Replacement Value Weighted HI Presentation for Major System Components

Figure 5-1 provides a practical example of such an approach, using the condition results of our study and the average unit replacement costs obtained from Elexicon. The figure presents the results for the three major asset sub-systems as well as Elexicon overall. Unlike the unit counts that drive the relative distribution of asset health categories in the traditional (technical) presentation of HI results, it is the relative portion of assumed replacement costs for the assets found to be in a given condition category that drives the presentation in this instance. We note that the above diagram assumes a single average unit costs for each asset type and does not include the assets for which valid HI scores could not be calculated. As such, it represents a relatively high-level assessment that Elexicon can build and refine upon, should it see the value in doing so.

Determining the Value of Asset Intervention Options other than Replacement – planners can also use dollar-weighted HI distributions to determine whether and to what extent asset intervention strategies such as preventative maintenance or refurbishment can provide incremental value relative to replacement costs. To the extent that these types of life-extension interventions (e.g., pole wrapping, stubbing, transformer oil reclamation, etc.) have a favorable impact on the asset HI scores, these activities can defer the need to replace certain assets for a given period of time. In doing so, they are reducing the dollar value of assets in the at-risk condition categories and providing the incremental ratepayer value, where the cost of these operating activities equals or exceeds the deferred replacement value. This analytical approach can be of use when exploring the relative trade-offs between OM&A work and capital investments for various asset classes.

Prioritization of Among Potential Projects – when planners consider multiple projects that propose similar types of investments (e.g., overhead feeder replacements in various parts of the system), a replacement-value weighted average HI of either the specific project scopes, host feeders, or critical asset class can act as an objective dimension along which planners can classify projects as relatively more or less urgent or valuable. Should Elexicon elect to pursue this approach, we suggest using it alongside of other objective prioritization factors, such as criticality, availability of redundancies, reliability performance trends, and others.

METSCO notes that replacement value-weighted asset condition analysis is an activity that can be performed with varying degrees of granularity and financial rigour. For instance, comparatively higher-level approaches can employ a single replacement unit cost for an entire asset class, while more granular methodologies can account for the difference in replacement costs on the basis of various criteria that differentiate the units within an asset class (e.g., pole height, equipment configuration, additional labour required for installation in particular circumstances, and many others. Similarly, more advanced calculation approaches can incorporate the concept of time value of money into the calculation, by making assumptions as to the timeframe before assets in each HI category can be expected to fail, and deflating their asset replacement value accordingly to review the results in resent Value terms.

While we believe that even the simplest manner of calculating replacement value provides opportunities for incremental managerial insights, it is important to be cognizant of the limitations of a given approach when evaluating and/or the implications of its results.

5.4.3 Defective Equipment SAIFI by Major Asset Class

Definition:

Contribution to System Average Interruption Frequency Index ("SAIFI") of outages caused by defective equipment, grouped by major asset class and tracked on a rolling twelve-month basis.

Discussion:

Elexicon is already tracking the reliability statistics by major CEA Cause Code as per the OEB Reporting and Record Keeping Requirements ("RRR"). We also understand that the utility has implemented a tracking process for a number of additional outage cause codes beyond those mandated by the OEB – along with a rigorous "post-mortem" on site analysis of outage codes. As such, tracking this proposed measure would result in a relatively minor incremental effort, aside from categorizing the post-failure field reports and aggregating them with previously collected data. In METSCO's assessment, tracking the magnitude and nature of outages categorized as Defective Equipment can enable Elexicon to obtain additional information with respect to its plant's performance trends across the range of geographical and electrical areas, equipment types, vintages, and models.

The information collected and analyzed through this exercise would contribute to the scope of quantitative content that Elexicon uses to define, scope, and prioritize its individual capital projects and maintenance programs. In addition, once a baseline level of analysis regarding Defective Equipment outage types and trends takes place, the utility will be in a better position to forecast its future reliability levels – both for the purposes of target setting and scenario analysis to supplement capital planning.

5.4.4 Average Age and Health Index at Failure

Definition:

Average numerical age and HI score for assets (by asset class) that experienced operating failure in the field or were flagged for prompt replacement by way of inspection (inspection-based failure). The age information can be established by referencing the specific asset's records contained in Elexicon's GIS. The HI score for a given asset would rely either on referencing the results of the latest asset condition assessment for the asset in question and/or conducting new inspection for all the HI parameters at failure.

Discussion:

Proposed for separate tracking across all major the major asset classes, this measure represents a key input into the formulation of age-based and condition-based failure curves. Failure curves measure the probability of a given asset to fail at different stages of its lifecycle. Age-based probability curves are increasingly common in the industry as inputs into risk-based capital program planning. While condition-based curves are less common given the underlying data collection and tracking requirements, we believe that Elexicon should plan for collection of input data for both types of failure curves at the same time. While conducting the full scope of inspection and testing after the assets have failed or were deemed to have failed is the preferred approach given its precision, it comes at a higher incremental cost. Accordingly, it may be reasonable to simply rely on the most recent HI score available for the failed asset(s).

Aside from enabling Elexicon to forecast their future asset failures with a greater degree of confidence, this measure can also serve as an ongoing benchmark of the effectiveness of the selected HI formulations. To the extent that the most recent HIs of the assets that fail in the field were consistent with the higher likelihood of impending failure, the utility can continue using the existing approach with added confidence. Where consistent and/or material deviations between HI measurements and actual failures occur, these would present opportunities for additional analysis and potential methodological refinements.

The above list represents is a small subset of potential AM metrics that Elexicon can consider implementing for either internal or external tracking and reporting. Irrespective of which metric(s) (if any at all) Elexicon decides to implement beyond the standard OEB Scorecard list, we encourage the utility to do so based on the basis of a fully formed vision for a longer-term AM strategy for the merged utility. In this manner, the selected metrics can act as objective progress gauges towards the outcomes that the utility is targeting – be they grounded in operational or financial performance, or interim steps associated with acquisition of new data or analytical capabilities.

6 Concluding Observations

As we note elsewhere in this report, the amount of asset condition information that Elexicon made available for METSCO in the context of this study exceeded the sum of data that was included in the earlier iterations of its predecessors' ACA studies. This fact alone represents the evidence of continuous improvement efforts over the recent years that we fully expect to continue as the recently merged utility refines its strategic priorities within the AM function and beyond.

While data gaps remain an issue for virtually every asset class, their presence is, in many cases, a function of AM approaches deliberately elected by Elexicon's predecessors. Moreover, the scope of the available data enabled us to construct credible representations of asset health for the majority of Elexicon's asset classes, even where such representations fell short of a full definition of an asset HI.

When examining the HI category distributions across the major asset classes, METSCO sees no evidence that would suggest that any given asset class exhibits deterioration at the scale that would be suggestive of suboptimal approaches to AM in the past. This conclusion is also confirmed by referring to the initial replacement value-weighted asset health distribution presented in section 5.4.2, which suggests that nearly 60% of the system assets by replacement value are in Good or Very Good condition (from among the assets for which some form of health assessment could be formulated as a part of this study).

This report provided Elexicon with a broad range of recommendations with respect to specific types of information that it may choose to collect, the metrics it may deploy to enhance its asset management analytics, or the practical approaches for rectifying the existing asset gaps. As our final recommendation, we suggest that Elexicon invest some time and analytical resources into development of a comprehensive Strategic Asset Management Plan ("SAMP") that would prescribe the utility's unified approach to collection and management of asset data for each asset class.

The asset class-specific data management strategies underlying this document would be formed on the basis of economic analysis that would consider the value of rectifying the existing data gaps and collecting of incremental types of condition data, relative to the incremental value of strategic insights these enhancements could be expected to deliver over time. Updated periodically with the most recent results of system performance analysis, the SAMP document would then act as the central reference source for future inspection work and the objective justification of trade-offs that asset managers are expected to make in order to deliver an optimal balance of system performance and economic sustainability.

This concludes METSCO'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 their ongoing support throughout its development.

Appendix A. METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over 10 years. Our founders are the pioneers of the first-ever Health Index methodology for power equipment in North America as well as the most robust high voltage risk-based analytics on the market today. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified expertise to provide its service to BHI.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

Appendix B. Condition Parameters Grading Tables

B.1 Wood Pole

Table 6-1: Criteria for Service Age

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 6-2: Criteria for Remaining Strength

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 6-3: Criteria for Overall Condition

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 6-4: Criteria for Wood Rot

Condition Rating	Corresponding Condition
A	There is no wood rot
B	Slight wood rot in few areas
C	Slight wood rot present in many area and/or moderate wood rot present
D	Moderate rot present in few locations or Extensive wood rot noted in inspection
E	Wood rot is extensive in many areas

Table 6-5: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	Pole is not leaning
E	Pole is leaning

B.2 Concrete Pole

Table 6-6: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

Table 6-7: Criteria for Overall Condition

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

B.3 Underground Cable

Table 6-8: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	46 years or older

Table 6-9: Criteria for Faulted Section

Condition Rating	Corresponding Condition
A	Splices appear in good condition or are not present on cable segment
D	Splices present on cable segment have a recorded fault

B.4 Overhead Conductor

A health index for overhead conductors has not been created.

B.5 Pole -mounted Transformer

Table 6-10: Criteria for Service Age

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 6-11: 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, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact 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

B.6 Pad Mounted Transformer

Table 6-12: Criteria for Service Age

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 6-13: 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, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact 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

B.7 Vault Transformer

Table 6-14: 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, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact 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

B.8 Pad Mounted Distribution Switchgear

Table 6-15: Criteria for Enclosure Condition

Condition Rating	Corresponding Condition
A	No signs of rust on 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 6-16: Criteria for Overall Condition

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 6-17: Criteria for Service Age

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 6-18: Criteria for IR scan

Condition Rating	Corresponding Condition
B	Minor temperature rise between 0 to 10ºC; continue to monitor switch for further degradation
C	Intermediate temperature rise between 10 to 20ºC; maintenance required at next available outage
D	Serious temperature rise between 20 to 30ºC; maintenance is required as soon as possible
E	Critical temperature rise larger than 30ºC; immediate action is required to correct the issue

B.9 Overhead Switch – Three-Phase

Table 6-19: Criteria for Service Age

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 6-20: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust, no damage to insulators, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Table 6-21: 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 rise between 0 to 10ºC; continue to monitor switch for further degradation
C	Intermediate temperature rise between 10 to 20ºC; maintenance required at next available outage
D	Serious temperature rise between 20 to 30ºC; maintenance is required as soon as possible
E	Critical temperature rise larger than 30ºC; immediate action is required to correct the issue

B.10 Single-Phase Switch

Table 6-22: Criteria for Service Age

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 6-23: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust, no damage to insulators, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Table 6-24: 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 rise between 0 to 10 ºC; continue to monitor switch for further degradation
C	Intermediate temperature rise between 10 to 20 ºC; maintenance required at next available outage
D	Serious temperature rise between 20 to 30 ºC; maintenance is required as soon as possible
E	Critical temperature rise larger than 30 ºC; immediate action is required to correct the issue

B.11 Station Transformer

Table 6-25: Gas Concentration (ppm) to condition rating conversion

Condition	H_2	CH_4	C_2H_2	C_2H_4	C_2H_6	CO	CO_2	TDCG
Condition 1	<100	<120	<1	<50	<65	<350	<2500	<686
Condition 2	101-700	121-400	2-9	51-100	66-100	351-570	2500-4000	687-1879
Condition 3	701-1800	401-1000	10-35	101-200	101-150	571-1400	4001-10000	1880-4585
Condition 4	>1800	>1000	>35	>200	>150	>1400	>10000	>4585

Table 6-26: Gas Rate of Change Limits (ppm/day)

Gas	Lower Limit	Higher Limit
H_2	1.46	4.37
CH_4	1.75	5.25
C_2H_2	0.01	0.04
C_2H_4	0.73	2.19
xC_2H_6	0.95	2.84
CO	5.10	15.31
CO_2	36.4	109
TDCG	10.00	30.00

Table 6-27: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table 6-28: 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 6-29: 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
	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 6-30: Criteria for Service Age

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 6-31: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Station transformer is externally clean and corrosion free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available
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 – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair.

Table 6-32: 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 6-33: Criteria for Cooling Equipment

Condition Rating	Corresponding Condition
A	No 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.
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	Fan and pump enclosures damaged/degraded beyond repair.

Table 6-34: Criteria for Foundation

Condition Rating	Corresponding Condition
A	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two of the above characteristics are unacceptable.
E	Foundation or supports are damaged/degraded beyond repair.

Table 6-35: Criteria for Gasket Condition

Condition Rating	Corresponding Condition
A	No external sign of deterioration of tank gaskets, weld seams, or gaskets on valve fittings.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable – repairable.
E	Two of more of the above characteristics are unacceptable – damaged beyond repair.

Table 6-36: Criteria for Transformer Connection

Condition Rating	Corresponding Condition
A	All primary and secondary connections are in good condition.
B	Normal signs of wear with respect to the primary and/or secondary connectors.
C	Primary or secondary connectors are in unacceptable condition.
D	Both primary and secondary connectors are in unacceptable condition – repairable.
E	Both primary and secondary connectors are in unacceptable condition – damaged beyond repair.

Table 6-37: Criteria for Oil Leaks

Condition Rating	Corresponding Condition
A	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	Minor oil leaks evident, but no moisture ingress is likely.
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.
E	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

B.12 Station Circuit Breaker

Table 6-38: Criteria for Service Age

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 6-39: Criteria for Circuit Breaker Testing

Condition Rating	Corresponding Condition
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and protection relays
B	Normal aging, each of the four indicators within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

Table 6-40: Criteria for Visual Inspection

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.

Table 6-41: 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)

B.13 Station Battery

Table 6-42: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 25% of Effective Life Expectancy
B	Less than 50% of Effective Life Expectancy
C	Less than 75% of Effective Life Expectancy
D	Less than Effective Life Expectancy
E	More than Effective Life Expectancy

Table 6-43: Criteria for Battery Test Results

Condition Rating	Corresponding Condition
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

Table 6-44: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Battery is in new condition
B	Battery has some minor wear
C	Battery has some minor defects
D	Battery has some significant defects
E	Battery is not fit for the service

B.14 Station Protective Relay

Table 6-45: Criteria for Service Age

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 6-46: 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 6-47: Criteria for Overall 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.

B.15 Station Fences and Building

Table 6-48: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No deficiencies
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

APPENDIX G: Asset Replacement Plan

ASSET REPLACEMENT PLAN
2021-2026

Prepared by

METSCO
MAKING IT POSSIBLE

P-19-205-002 R2

February 2021

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Disclaimer

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R2	February 25, 2021	Updated based on latest ACA

Executive Summary

In preparation of this Asset Replacement Plan ("ARP"), METSCO relied primarily on the output of the Asset Condition Assessment ("ACA") combined with raw inspection results, asset failure probabilities, and input from previous planning documents as provided by Elexicon throughout the process.

Asset replacement recommendations are typically met through single asset spot replacements, planned System Renewal projects such as pole line replacements, and to a partial degree System Access and Service projects such as developments and road widenings. Not all assets recommended will be replaced, as some can be maintained such as station transformers and circuit breakers, or rehabilitated such as underground cables, three-phase overhead switches, and pad-mounted switches.

Table 0- 1: Summary of Asset Replacements by Asset Class

Asset / Year	2021	2022	2023	2024	2025	2026
Wood Poles - Pole Replacement Program (#)	350	350	350	350	350	350
Concrete Poles (#)	14	16	16	12	12	12
Underground Primary Cables (km)	50	65	65	82	82	82
Overhead Conductor (km)	60	60	60	60	60	60
Pole-Mounted Transformers: Single-Phase (#)	140	160	180	200	200	200
Pole-Mounted Transformers: Three-Phase (#)	20	20	20	20	20	20
Pad-Mounted Transformers (#)	200	240	280	300	300	300
Vault Transformers (#)	0	0	0	0	0	0
Distribution Switchgear (#)	12	12	12	12	12	12
Overhead Switches – Three-Phase (#)	2	2	2	2	2	2
Single-Phase Switches (#)	250	250	250	250	250	250
Station Transformers (#)	2	2	2	2	2	2
Circuit Breakers (#)	3	3	3	3	3	3
Station Batteries (#)	7	7	7	7	7	7
Station Relays (#)	0	0	0	0	0	0
Station Fences and Buildings (#)	1	0	0	0	0	0

Table of Contents

List of Tables

1 Introduction

1.1 Purpose

Elexicon Energy Inc. (“Elexicon” or “the utility”) engaged METSCO Energy Solutions Inc. (“METSCO”) to prepare an Asset Condition Assessment (“ACA”) study for the assets comprising Elexicon’s distribution system. This Asset Replacement Plan (“ARP”) is a companion document and provides guidance to planning engineers in the development of paced and prioritized asset renewal programs.

In preparation of this ARP, METSCO relied primarily on the output of the ACA combined with input from raw inspection results, asset failure probabilities, and previous planning documents as provided by Elexicon throughout the process including previous ACA documents prepared for the legacy utilities Whitby Hydro and Veridian Connections.

To assist Elexicon in its ongoing work to define the scope and nature of its future asset renewal strategy, this report contains recommendations relating to replacement programs for individual assets as well as identifying specific types of data to be collected for improved planning.

The six-year replacement plan considers expected aging and degradation for each asset and attempts to smooth investment requirements over this time period. Consideration is also given to the system renewal requirements of the next four years (2027-2030) to position investments for a levelized renewal strategy.

1.2 Methodology

The ACA established the Health Index (“HI”) distribution for each class of assets. The HI is a percentage score between 0 and 100, used to assess the condition of an asset with the general implications as summarized in Table 1-1.

Table 1-1: Health Index definition and general implications

Health Index (%)	Condition	Implications
85-100	Very good	Normal Maintenance
70-85	Good	Normal Maintenance
50-70	Fair	Increase diagnostic testing; possible remedial work or replacement needed depending on unit's criticality
30-50	Poor	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very poor	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

In an optimized system, high-risk assets would be scheduled for the renewal program in earlier years, as assets in Very Poor condition (usually higher risk) are considered to be at end of life already. The ACA process is less specific in the longer time spans, therefore renewal programs in the four-to-ten-year planning window blend age, condition, and failure rate information with a focus on renewing assets that would exceed industry expectations. In the case where asset condition is not available, a probabilistic model has been utilized to assess the expected asset failure within a given timeframe. The Weibull distribution function was used to derive the age-based failure probability curves, as it is adaptable to a large range of requirements and can be parametrically controlled to simulate time-variable increasing or decreasing, as well as time-invariant, failure rates. The Weibull distribution is by far the most widely utilized distribution for life data analysis due to its flexibility. The model considers the typical useful life of each asset class based on the OEB's *Asset Depreciation Study*. In all cases, actual asset candidates or replacements should be verified by an in-field assessment of condition and risk.

1.3 Typical Useful Life

In a 2010 study by Kinectrics Inc. called the *Asset Depreciation Study for the Ontario Energy Board*, minimum, maximum ("MaxUL"), and typical useful life ("TUL") values were established that have created a basis for planning and depreciation assumptions. Throughout this report, TUL and sometimes MaxUL are referenced to establish mid to long-term planning needs. Table 1-2 presents the results of this study for various asset classes.

Table 1-2: Assumed useful life (years) for each asset class

Asset Class	Minimum UL	Typical UL	Maximum UL
Wood Pole	35	45	75
Concrete Pole	50	60	80
OH Primary Conductor	50	60	75
UG Primary Cable	35	40	55
Pole-Mount Transformer	30	40	60
Pad-Mount Transformer	25	40	45
Vault Transformer	25	35	45
Switchgear	20	30	45
Overhead Switch	30	45	55
Station Power Transformer	35	45	60
Station Circuit Breaker	35	45	65
Station Battery	10	15	15
Station Protection Relay	10	30	45
Station Buildings	N/A	N/A	N/A
Station Fences	N/A	N/A	N/A

1.4 Interpretation of Replacement Recommendations

For the purpose of planning, this report identifies those assets that need replacement over the planning period absent from any other intervention. This assumption is generally true for run-to-failure assets; however, rehabilitation and maintenance options may be employed for larger maintainable assets such as station transformers, circuit breakers, gang-operated line switches, and pad-mounted switches.

Recommendations for replacement may align with specific budget lines for individual asset renewal. All assets being replaced throughout the planning window are to be considered. For instance, poles being replaced under line reconstruction projects as well as single pole replacements are all being renewed and are to be counted. Sometimes poles are also replaced for System Access or System Service reasons such as new developments or road widenings. These replacements may involve older poles as well as poles that do not require renewal. For these projects, only poles that are in Fair condition or worse should be counted in the renewal totals.

2 Distribution Assets

2.1 Wood Poles

Elexicon owns 34,111 wood poles and age data is known for 30,660 poles. Valid HI Scores were calculated for 30,092 poles. Wood Poles are a pooled asset and poles with missing data can reasonably be assumed to be random. Therefore, results have been extrapolated across the asset class.

During the creation of Elexicon's Distribution System Plan, asset condition data was utilized to identify high-risk assets for the system's wood poles. Wood Poles were assessed based on this condition categories to determine the number of high-risk assets expected to fail over the next ten-year period.

2.1.1 Recommended Replacement Plan

Table 2-1 presents the recommended replacement rates for each year for 2021 to 2026. It is expected that these rates will continue until 2030.

Table 2-1: Wood Poles recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Pole Replacement Program (#)	350	350	350	350	350	350

2.1.2 Rationale for Recommendations

A significant driver of this plan is the approximately 3,562 wood poles that will be expected to fail as of 2030. Elexicon's 2020 ACA results were used for determining the number of spot replacements that would occur under the Pole Replacement Program by identifying assets in Very Poor, Poor as well as Fair condition assets expected to further degrade into Poor condition by 2030.

Pole-line replacement projects are the most effective way to renew the wood pole asset base. Planners typically work to select the feeders suitable for renewal with the highest percentage of poles needing attention. However, a project to replace a section may also be valid if the worst-condition poles across the system are systematically targeted. A "spot" replacement approach may be seen as inefficient relative to a larger project to replace an entire section of the feeder, which also enables the utility to bring the system to the latest standards with respect to pole height, phase spacing, and pole span. Nonetheless, some poles will still end up being replaced on an emergency basis at a higher cost and a lost opportunity for system improvements. A detailed design-level study that considers the relative locations of the poles in the worst condition may be of value to suggest the optimal balance of line section and spot renewal.

2.2 Concrete Poles

Elexicon owns 36,588 poles, of which 2,477 (7%) are concrete poles. There are no field tests to be performed on concrete poles to predict future degradation other than visual inspection of corrosion and evidence of spalling or leaning. Concrete poles are considered to be run-to-failure assets and are replaced when identified at end-of-life based on the visual inspection results. It is Elexicon's practice to replace concrete poles with wood poles in most cases.

In the previous version of the ACA conducted in 2018, concrete poles were considered a minor asset and were not reviewed. New concrete poles are not generally being installed; therefore, the existing population is skewed towards the aged poles. There are 1590 concrete poles of unknown ages, mostly located in the legacy Veridian area.

2.2.1 Recommended Replacement Plan

Concrete poles tend to be replaced on a one-off basis when visual inspections determine them to be compromised. Aged poles that are not exhibiting spalling, corrosion, or stability (leaning) issues do not represent a higher-than-expected risk.

The recommended replacement plan recommends replacement based on the expected deterioration rate of 0.6% for Veridian concrete poles combined with a similar approach to wood poles taken for Whitby concrete poles where inspection data was available and extrapolated. Table 2-2 presents the recommended action plan for concrete poles based on known conditions and some general assumptions for poles that are unknown.

Table 2-2: Concrete Poles recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Concrete Poles (#)	14	16	16	12	12	12

2.2.2 Rationale for Recommendations

Concrete poles represent a small portion of the pole asset class, and replacement levels are approximately 0.04% of the pole population.

It is recommended that condition data should be collected and recorded for concrete poles. This will provide greater certainty to the concrete pole renewal needs. The initial display of corrosion and spalling will indicate a pending need for asset renewal.

2.3 Underground Primary Cables

Elexicon owns approximately 2336 km of underground primary cable, operating at voltages from 4.16/2.4kV to 44kV. Prior to approximately 1990, all underground cable installed of cross-linked polyethylene ("XLPE") type, and after 1990 the predominant cable installed was tree-retardant cross-linked polyethylene ("TRXPLE"). Tree-retardant refers to the insulation's ability to restrict the formulation of tree-shaped defects in the insulation, caused by dielectric breakdown or water ingress. Cables are installed either in direct-buried ducts, concrete-encased ducts, or direct buried in the ground.

Lengths are reported in cable-length, rather than circuit length, meaning that a 1 km length of 3-phase cables is reported as 3 km.

2.3.1 Recommended Replacement Plan

The Health Index formulation is driven mostly by age. For planning purposes, the assets with unknown ages can be reasonably estimated by extrapolation. This results in an expected population of Very Poor cables of 113 km, and a further 124 km of Poor Cables for a total of 237 km of cable. A further 577 km of cables is expected to exceed the TUL of 40 years within ten years resulting in an expected replacement level of 8 2km/year from 2024 to 2030. It is worth noting that some cable injection projects have already taken place. Approximately 63 km of cables identified as Poor or Very Poor have been injected. It is assumed that this process has extended the cable life by approximately 40 years, which is somewhat unproven but, in any case, is well beyond the planning window. The cable replacement plan is reduced by 63 km in Year 1. Table 2-3 presents the recommended replacement rates for each year for 2021 to 2026.

Table 2-3: Underground Primary Cable recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Underground Primary Cables (km)	50	65	65	82	82	82

2.3.2 Rationale for Recommendations

Replacement programs for underground cable are sensitive issues for utilities due to the large quantities of the assets owned, and the relative uncertainty of testing and rehabilitation options. Additionally, cable replacement programs are expensive and have a high impact on residential communities. It is widely considered that when a faulted cable that has been spliced, is at a higher risk of further failures; however, this also is disputed where newer technology splices have been properly installed.

The result of this uncertainty is a recommendation that cable renewal and rehabilitation projects be part of the budgeting process, but that increased efforts on data collection and exploration of rehabilitation options be pursued.

2.4 Overhead Conductors

Overhead primary conductors typically outlive the poles which support them and are replaced when the poles are replaced or when loading drives a feeder upgrade. Overhead conductor lengths are reported in “wire length”, rather than circuit length (i.e., a three-phase line of 1 km is shown as 3 km).

2.4.1 Recommended Replacement Plan

There is no recommended replacement plan for overhead conductors, as conductor age or condition rarely drives reinvestment planning. Overhead conductors are naturally replaced when pole lines are rebuilt or realigned. On the other hand, spot pole replacements do not usually include conductor replacements. In some cases, the conductor is transferred from old to new poles and left in service. Since poles are renewed at a rate of about 1-2% per year, it can be assumed that the conductor is also replaced at a rate of between 0 and 2% per year. For the purposes of illustration, the range is estimated at 1.5%

which is consistent with a 66-year life expectancy. Table 2-4 presents the recommended replacement rates for each year for 2021 to 2026.

Table 2-4: Overhead Conductor estimate plan for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Overhead Conductor (km)	60	60	60	60	60	60

2.4.2 Rationale for Recommendations

Since Elexicon has 3,800 km of conductor and 36,000 poles, each pole would be supporting an average of 100 m of conductor on average. Considering a reasonable estimate for the average distance between poles is 50 m, and a blend of single-phase, three-phase, multi-circuit and secondary-only installations, the numbers for conductor renewal (100 m per pole replaced) would seem to be a reasonable approximation considering the small amount of "small copper conductor" it is reasonable to target replacing those conductors in year 1 if so desired.

2.5 Pole-Mounted Transformers

Elexicon owns 6,465 single-phase and 767 three-phase pole-mounted transformers. A three-phase pole-mounted transformer is reported as a single unit that represents three individual transformers. Of these, about 5,700 are in the legacy Veridian area and 1450 are located in the legacy Whitby area.

The demographic review of the 3,715 transformers with known age data indicates that 406 units have been in service longer than the TUL of 40 years, and a further 568 will pass the TUL in the next ten years. Absent better information it is reasonable to extrapolate these numbers to expect that 1900 pole-mounted transformers will be past their TUL within ten years.

2.5.1 Recommended Replacement Plan

The recommendation for the replacement of pole-mounted transformers is consistent with the planning objectives of Section 1.2 and targets replacing all of the Very Poor assets in year 1 and Poor units in years 2 and 3. Table 2-5 and Table 2-6 presents the recommended replacement rates for single-phase and three-phase pole-mounted transformers respectively for each year from 2021 to 2026.

Table 2-5: Single-Phase Pole Mounted Transformers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Pole-Mounted Transformers (#)	140	160	180	200	200	200

Table 2-6: Three-Phase Pole Mounted Transformers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Pole-Mounted Transformers (#)	20	20	20	20	20	20

2.5.2 Rationale for Recommendations

The recommended replacement plan is based on a total of 1886 single-phase pole-mounted transformers expected to require attention in the next ten years and a realization that the previously combined recommendation level was for approximately 80 transformers per year. Ramping this program up as recommended will result in a replacement of 1080 units between 2021 and 2026. For the first three years of ramping up the program, this trend will level off to approximately 200 per year.

For three-phase pole-mounted transformers, a total of 194 units are expected to require attention in the next ten years. This recommendation of twenty units per year is expected to be consistent over the next ten years.

Pole-mounted transformers are either replaced through the proactive replacement program or when the pole line is rebuilt. Those that are not part of planned rebuilds are usually detected through regular visual inspections and replaced proactively.

The results of this report point to an increase in investment level; however, balancing the extrapolation factors would suggest renewal levels be ramped up somewhat but still be based on actual field observations.

2.6 Pad-mount Transformers

Elexicon has about 13,600 pad-mounted transformers of which about 1,587 are three-phase units. A three-phase transformer is reported as a single unit.

Age information is available for 94% of the population. There is known to be a total of 2,664 units that are expected to fail by 2030. Extrapolating this over the unknown units would bring the total pad-mounted transformers in the ten-year plan to 2,832.

2.6.1 Recommended Replacement Plan

The recommendation is based on replacing all Very Poor units (76) in year 1, and the Poor units (469) by end of year 3. The remaining 2,112 transformers expected to fail should be targeted in years 4 to 10 at a rate of 300 per year. Table 2-7 presents the recommended replacement rates for each year for 2021 to 2026.

Table 2-7: Pad-Mounted Transformers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Pad-Mounted Transformers	200	240	280	300	300	300

2.6.2 Rationale for Recommendations

Renewal of a single pad-mounted transformer typically takes place as underground cables are rehabilitated or replaced. The driver for transformer replacement is generally deterioration of the enclosure which can create a public safety hazard or, deterioration of the pad.

The recommended action plan is establishing a large increase over previous plans based on a large number of units approaching the TUL of 40 years.

2.7 Vault Transformers

There are 154 installations designated as vault transformers. All of these assets are in the legacy Veridian area. If there are transformers in vaults in the legacy Whitby area, they do not carry the “vault” identifier and are included in other data sets. Vault transformers are assessed entirely based on visual inspection records.

2.7.1 Recommended Replacement Plan

There are no vault transformers recommended for replacement in the planning window. Table 2-8 presents the recommended replacement plans for each year for 2021 to 2026, provided for consistency purposes.

Table 2-8: Vault Transformers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Vault Transformers (#)	0	0	0	0	0	0

2.7.2 Rationale for Recommendations

Vault transformers are generally protected inside a building or other structure and, therefore, do not exhibit the same modes of degradation as pad-mounted transformers. Age information is not currently available for vault transformers and this would give an indication of the future expected performance of the asset. Presently, there are no indications that assets require attention with the exception of data gathering.

2.8 Distribution Switchgear

Elexicon owns 439 pad-mounted distribution switchgear, which includes air-insulated and SF6-type units. Age information is available for 72% of the population. There is known to be a total of 80 units that are expected to fail by 2030. Extrapolating this over the unknown units would bring the total distribution switchgears in the ten-year plan to 111.

2.8.1 Recommended Replacement Plan

For the purposes of renewal planning, it is reasonable to extrapolate the units with no valid HI across the sampled dataset. Switchgears in Very Poor condition are most likely to have been replaced. The missing information for switchgear in most cases is age, which is not a specific driver for renewal as the condition is more heavily affected by the operating environment of the asset. The remaining units can be assumed to be randomly distributed.

The recommendation for replacements based on replacing those units that are recorded to be in Poor or Very Poor condition in year 1, and those units which have historically been identified in the inspection and maintenance processes. See Table 2-9 for replacement quantities for each year from 2021 to 2026.

Table 2-9: Distribution Switchgears recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Distribution Switchgear (#)	12	12	12	12	12	12

2.8.2 Rationale for Recommendations

The recommended replacement levels for switchgear do not appear to be supported by ACA results. This is because switchgears are critical assets to system operations and are replaced promptly when defects are discovered. Therefore, replacement recommendations are driven by historical replacement levels.

The typical replacement levels for the legacy Whitby area are at a declining pace, of around 8 units per year at the current time, expected to decline to 5 or 6 once the backlog of older designed units is replaced, and previous replacement levels in the Veridian area are approximately 14 units per year, also declining with the inclusion of SF6 units.

2.9 Overhead Switches – Three-Phase

Three Phase overhead switches include three-phase, gang-operated, pole-mounted, and load interrupter switches. Elexicon owns 3,387 gang-operated switches, all of which are in Very Good to Fair condition except for approximately 640 switches which did not all for a valid health index to be calculated. Age and condition data were available for 2,695 (80%) of the units.

Separate HI formulations were created for the Whitby and Veridian sub-populations due to the lack of soft-copy IR scanning results from the legacy Veridian area. The results of these HI scores did not reveal any Poor or Very Poor condition assets, given the fact that switches are regularly inspected and problems reported resulting in the switches being proactively replaced.

2.9.1 Recommended Replacement Plan

The recommended overhead switch replacements for the years 2021 to 2026 are summarized in Table 2-10. The recommendation is a nominal quantity which is more likely driven by pole replacements or the occasional device upgrade.

Table 2-10: Overhead Switches – Three-Phase recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Overhead Switches-Three Phase (#)	2	2	2	2	2	2

2.9.2 Rationale for Recommendations

Gang-operated overhead switches of the traditional air-insulated types are typically maintained in-situ and parts are regularly replaced while the switch is still mounted on the pole. Switch replacements are more likely to occur due to pole line rebuild projects than switch conditions.

New single-piece or tanked devices, such as SCADA switches or gas-insulated load interrupters, are more likely to be replaced as they reach the end of life, but most of these devices have been installed in recent years and are not yet close to the end of life.

2.10 Single-Phase Switches, Blades, and Cut-outs

Elexicon owns approximately 14,300 overhead switching devices including fused switches (K or E Type), solid-blade disconnects, Trip Savers, in-line disconnect switches, in-line fused switches, fuse riser switches, fused cut-outs, power fuses, and switchgear fuses. A very insignificant portion of overhead switching devices resulted in being high-risk to the system based on the condition parameter results of service age, visual inspections, and IR scan results.

2.10.1 Recommended Replacement Plan

There is no specific replacement plan identified for single-phase switches. Overhead switches are assumed to be replaced at the same rate as the pole which is about 1.6% per year. Table 2-11 presents the recommended replacement rates for each year for 2021 to 2026.

Table 2-11: Single Phase Overhead Switches recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Single Phase Switches (#)	250	250	250	250	250	250

2.10.2 Rationale for Recommendations

Generally, minor devices in poor condition will be detected in visual inspections and IR scans and replaced promptly or they are renewed as part of a line rebuild project.

3 Station Assets

Elexicon tracks data for 61 substations: 59 municipal substations ("MS") – 11 of which were formerly owned by Whitby Hydro compared to 48 formerly owned by Veridian Connections – and two large substations on customer premises (named Shandex and Mason Windows) owned by Elexicon. The former Whitby Hydro substations include 11 numbered substations (MS 5 to MS 15). Each of the former Veridian Connections substations is named according to its locations. These substations typically step the power down from 44 kV to a range of 27.6 kV to 4.16 kV for MS and 600 V for customer premises.

The results of the ACA analysis were used to identify high-risk assets (Very Poor and Poor) for intervention within the 5-year replacement plan. Initial review of the HI results indicated five Very Poor and fifteen Poor station assets within the system. However, this analysis was also looked at holistically to determine assets that may be in Fair condition within the same substation to which work should be scheduled. In doing so, an additional three Station Transformers and one Station Circuit Breaker has been identified for further assessment during the planning of Station refurbishments/ replacements.

It is recommended that the locations of the identified high-risk assets be taken into consideration when planning substation renewal projects as it is apparent that both Station Transformers and Station Circuit Breakers requiring attention within the same substation. The following substations contain multiple Station assets identified as high-risk:

- Edgehill MS: one station transformer, two station circuit breakers;
- Catherine MS: one station transformer, one station circuit breaker;
- Squires Beach MS: one station transformer, two station circuit breakers;
- Harder MS: one station transformer, one station circuit breaker; and
- Uxbridge East MS: one station transformer, one station circuit breaker.

3.1 Station Transformers

Elexicon maintains 96 station transformers which include a spare unit and two units at customer premises (Shandex and Mason Windows) owned by Elexicon. Of the Elexicon owned units, 29 are legacy Whitby and 66 are legacy Veridian units. Station transformers are the single most critical asset class owned by an LDC, and therefore also the most tested and tracked utility asset and reliable indicators of the impending need for maintenance or replacement include dissolved gas analysis and power factor testing. Each transformer can be valued in the range of a million dollars and can affect tens of thousands of customers.

3.1.1 Recommended Replacement Plan

Table 3-1 lists the recommended number of station transformers for replacement over the years 2021 to 2026. High-risk station transformers were identified based on their overall HI which yielded seven assets in Poor condition and an additional three assets in Fair condition located at substations where related Circuit Breakers are in Poor or Very Poor condition for further assessment. Maintenance and rehabilitation options exist beyond the replacement of the asset.

Table 3-1: Station Transformers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Station Transformers	2	2	2	2	2	2

Transformers identified that require attention are shown in Table 3-2. Transformers on this list do not necessarily require replacement. In some cases, re-testing may be sufficient.

Table 3-2: List of Station Transformer requiring attention

Station Transformer	Age -- Condition Notes
Applecroft	30 years -- DGA/OQ
Edgehill	59 years -- PF/OQ
First	45 years -- PF/OQ
Harder	48 years -- DGA/OQ
Jones	56 years -- OQ
Squires Beach	33 years -- OQ
Spare 10	40 years -- DGA

Additional “Fair” station transformers were identified for intervention due to related circuit breakers at the station with Poor to Very Poor condition:

- Catherine – 68 years;
- Town Centre (MS#8) T1 – 48 years; and
- Uxbridge East T1 – 56 years.

3.1.2 Rationale for Recommendations

Station transformers are critical assets for a distribution utility both in terms of asset value and impact on reliability. Each station transformer should be assessed on an individual level and a specific plan for maintenance, rehabilitation, or replacement should be developed.

Station transformers should be replaced before the risk of failure increases. In cases where the condition is slipping, additional monitoring and testing including, in some cases, online monitoring can be put in place to reduce risk. Also, stations with back-up configurations, either internally or externally are at lower risk should equipment fail.

3.2 Station Circuit Breakers

Station circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. This section refers only to stations with circuit breakers and does not include stations with fuses and hydraulic reclosers; a total of 175 station circuit breakers were recorded.

Breaker degradation occurs 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. Therefore, high-risk station circuit breakers were assessed based on Service Age, Testing results, Visual Inspections, and Functional Obsolescence (if applicable). This assessment yielded seven assets in Poor condition and five assets in Very Poor condition as well as one asset in Fair condition identified for further assessment due to a related Station Circuit Breaker within the same substation being in Poor condition.

3.2.1 Recommended Replacement Plan

Table 3-3 lists the recommended number of station circuit breakers for replacement over the years 2021 to 2026. Both Station Transformers and Station Circuit Breakers have been reported to be at high-risk at Edgehill MS and Catherine MS and would seem to be the most urgently needing attention. It may be that maintenance and rehabilitation options exist beyond the simple replacement of the asset.

Table 3-3: Circuit Breakers recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Circuit Breakers	3	3	3	3	3	3

Circuit breakers identified that require attention are shown in Table 3-4.

Table 3-4: List of Circuit Breakers requiring attention

Circuit Breaker ID	Health Index
Uxbridge East -- UXBE-F3	Very Poor
Harder -- HARD-F1	Very Poor
MONARCH MONA MS4 -- MONA-F3	Very Poor
MONARCH MONA MS4 -- MONA-F4	Very Poor
MONARCH MONA MS4 -- MONA-F4	Very Poor
RIVERSIDE MS -- RIVE-F1	Poor
SQUIRES BEACH -- SQUI-F3	Poor
SQUIRES BEACH -- SQUI-TB	Poor
TOWN CENTRE M.S.#8 -- TOWN-F1	Poor
Edgehill MS -- EDGE-F3	Poor
Edgehill MS -- EDGE-T1	Poor
CATHERINE -- F21	Poor

An additional circuit breaker identified for intervention due to its Fair condition and the planned intervention above to conduct work at the station is:

- Riverside MS – RIVE-F2.

3.2.2 Rationale for Recommendations

Circuit breakers are critical assets for a distribution utility both in terms of asset value and impact on reliability. Each breaker should be assessed on an individual level and a specific plan for maintenance, rehabilitation, or replacement should be developed. It is not practical to extrapolate results for breakers.

Circuit breakers should be replaced before the risk of failure increases. In cases where the condition is slipping, additional monitoring and testing including in some case online monitoring can be put in place to reduce risk. Stations with backup configurations, either internally or externally are at lower risk should equipment fail.

3.3 Station Batteries

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. Both the electrodes and electrolyte 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. Discharge testing provides detail on individual cell charges, total voltage, and discharge rates as the battery supplies energy over time. Elexicon has recorded data for 35 sets of substation batteries, including one spare battery at MS11. Elexicon's practice is to replace battery banks at 50% of the manufacturer's recommended lifespan (referred to as "effective life expectancy" in the ACA) to ensure equipment reliability.

3.3.1 Recommended Replacement Plan

Table 3-5 summarizes the total number of substation batteries recommended for replacement for each year from 2021 to 2026. The recommended approach is in line with the previous Asset Replacement 2017 report and will maintain the current Health Index.

For 2021, the systems at Bell Substation and Riverside Substation should receive priority attention.

Table 3-5: Station Batteries recommended for replacement (2021 to 2026)

Year	2021	2022	2023	2024	2025	2026
Station Batteries	7	7	7	7	7	7

3.3.2 Rationale for Recommendations

All the substation batteries will be replaced by 2025. The recommended replacement rates are consistent with a levelized approach to renewal.

3.4 Station Protective Relays

Protective relays are an asset used in substation operations to trip a circuit breaker when a fault is detected. Elexicon presented detailed demographics, testing, and visual inspection data for 34 sets of protective relays all located within the Whitby legacy area. Following the assessment of the risk posed by these Protective Relays, none were identified for requiring attention within the next ten years. Protective relays in the Veridian legacy are regularly inspected; however, data is captured by exception rather than in condition code format.

3.4.1 Recommended Replacement Plan

There is no specific replacement plan identified for station protective relays.

3.4.2 Rationale for Recommendations

Substation relays are replaced promptly if they are found to be in poor condition; however, these units are typically housed in structures that protect them from physical deterioration and meaning replacement due to degradation is rare. Historical electro-mechanical relays required regular calibration and maintenance and would often require replacement, but newer microprocessor relays have no moving parts and are reliable. A protective relay is more likely to be replaced when a station breaker line-up is replaced or when enhanced functionality or communications is required.

3.5 Station Fences and Buildings

Station buildings and fences are typically subjected to quarterly inspection and are maintained as issues arise. In some cases, these assets 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, gates are repaired, and buildings are patched up as needed to remain functional.

Following the assessment of these assets, all Station buildings were found to be in Very Good condition and only one Station fence at Monarch SS was identified for repair.

3.5.1 Recommended Replacement Plan

There is no specific replacement plan identified for station buildings and fences. One fence at Monarch SS was identified as in need of repair.

3.5.2 Rationale for Recommendations

Station buildings and fences are rarely replaced; however, there may be merit in establishing an overall condition score for substation facilities that consider all physical aspects of the substation site.

4 Conclusions

As Figure 4-1 and Figure 4-2 indicate, most asset classes analyzed are at low risk to the system, with a significant portion of asset populations not requiring any intervention within the next ten years. This can indicate Elexicon has taken steps in the past to manage its asset health and performance for the benefit of its customers. As with every system, however, some areas require Elexicon's attention in the coming years where asset populations contain material portions of equipment in or approaching high-risk conditions. These populations of high-risk assets have been identified and suitable six-year plans developed to guide planning engineers in the development of paced and prioritized asset renewal programs.

A few asset classes are healthy, meaning no unit in the asset class was evaluated to be in Poor or Very Poor condition. This applies to the following asset classes:

- Vault transformers; and
- Station relays.

However, these assets require continuous inspections to monitor and note any health degradation observed. Though not commonly observed, asset materials are prone to experiencing degrading conditions and can quickly change from a Good condition grade to a Poor condition within a year. Hence, although this plan does not identify an immediate need to replace any units of the asset classes, it is advised to Elexicon to be diligent in observing changing trends and planning accordingly. Furthermore, some asset classes such as station buildings and fences would not require a complete renewal though may require minor improvements to maintain the integrity of the assets.

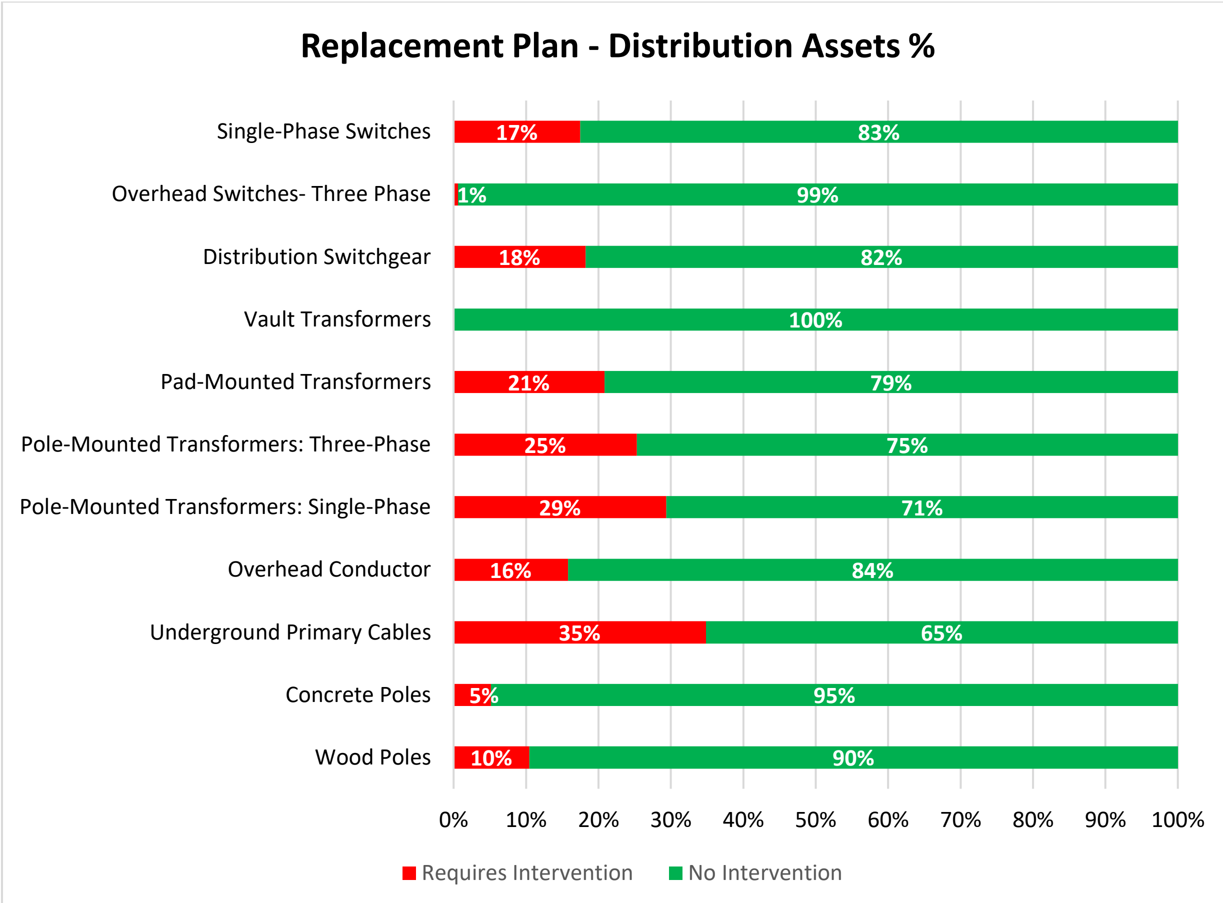

Figure 4-1: Distribution Assets requiring attention within next ten years

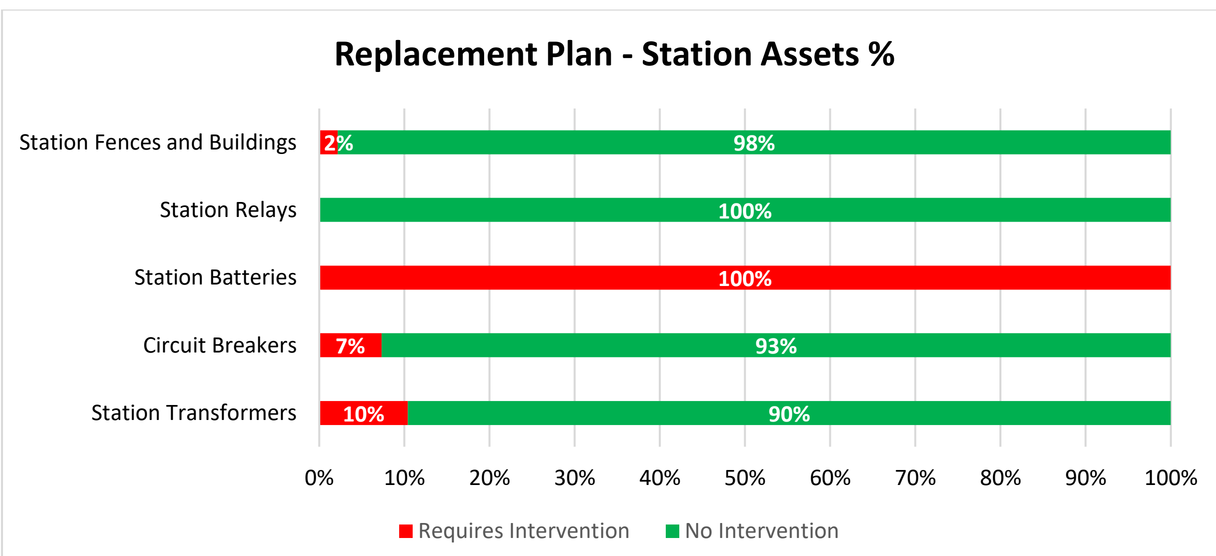

Figure 4-2: Station Assets requiring attention within next ten years

APPENDIX H: Load Forecast

METSCO

MAKING IT POSSIBLE

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Elexicon Load Forecast Model Development and 2020 Results

Nov. 9, 2020

<u>Prepared For:</u>

Elexicon Energy Inc.

<u>Prepared By:</u>

METSCO Energy Solutions Inc.

Disclaimer

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Elexicon Load Forecast Model Development and 2020 Results

METSCO Report # 19-228 IFR

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Version History

Version	Date	Description
IFR	May 15th, 2020	Issued for review with 2020 to 2030 forecast
R0	Nov. 9th, 2020	Revised customer count forecast and added clarification to weather normalization methodology

Executive Summary

METSCO Energy Solutions ("METSCO") created a load forecast model for Elexicon Energy ("Elexicon"). The load forecast model incorporates two methodologies: an engineering and an econometric approach to predict load growth across Elexicon's service area using distinct, but ultimately complementary methods:

- The engineering or "bottom-up" approach looks at each major municipality in the Elexicon service area and utilizes historical loading data, customer counts, historical ratios between households and customers, and forecasted service area households. Forecasts for specific regions are created and apportioned across the municipal substations supplying those regions by analyzing service area loading patterns.

- The econometric or "top-down" approach utilizes macroeconomic variables such as gross domestic product, price of energy, and housing starts to see how it impacts Elexicon's aggregate load across its service territory. Combinations of variables are evaluated to determine those which hold the strongest relation to load. This helps create a multivariate regression equation to predict changes in load in conjunction with forecasted changes in the econometric variables themselves.

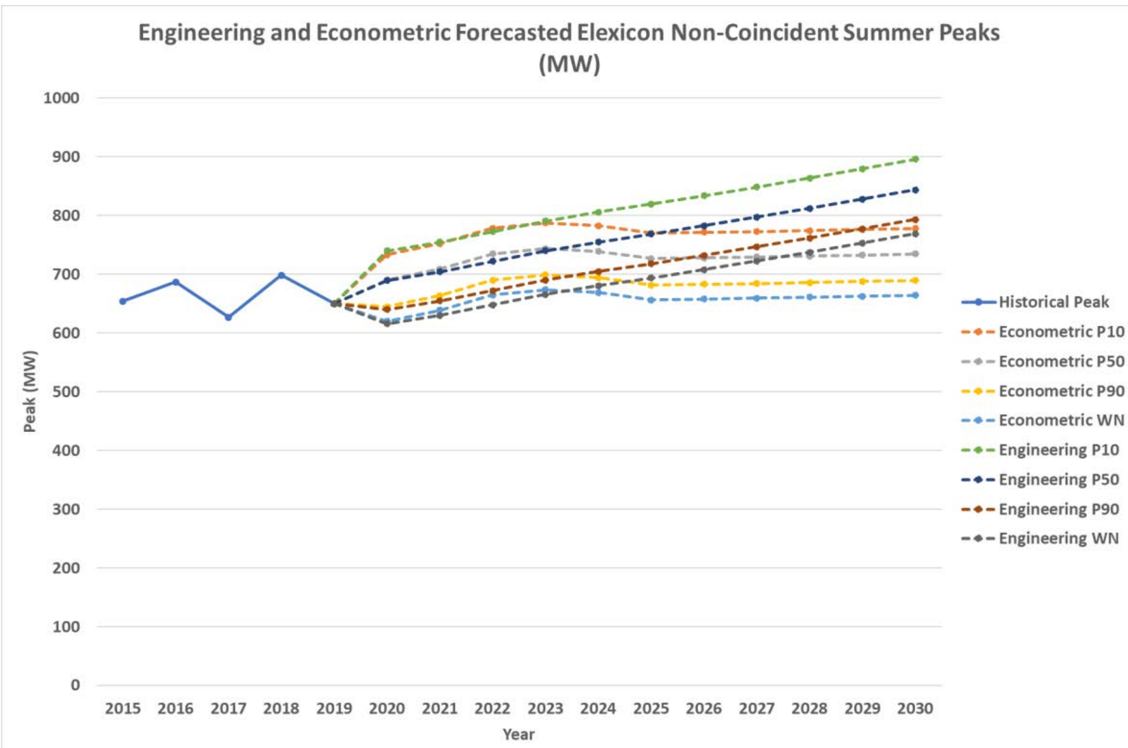
The overall load forecasting methodology consists of six steps:

1. Conduct data cleansing of historical peak load information to exclude outlier data.
2. Control for the short-term effects of weather on the historical peak readings using weather normalization techniques.
3. Analyze relationships between load and the explanatory variables utilized in the top-down and bottom-up methodologies.
4. Independently produce forecasts of weather-normalized peaks using top-down and bottom-up approaches.
5. Reincorporate weather effects to the forecasted peaks of both models using a Monte-Carlo simulation built on historical weather distributions.
6. Use the 10th, 50th and 90th percentile values of these forecasts to derive the three probabilistic scenario forecasts (P10, P50, and P90) for the ten-year period.

While the above approach applies to the majority of Elexicon's service territory, METSCO customized it in select cases to account for the non-contiguous and geographically distributed nature of Elexicon's service territory. In the regions of Port Hope and Gravenhurst, weather was not found to have a strong relationship to load. As a result, we performed the Monte-Carlo simulation on the historical peak load for these regions and divided by the customer count to forecast the total megawatts per customer. This approach captures the year-over-year variability of demand over time. The P10, P50, and P90 values of the simulated megawatts per customer are then multiplied by the customer forecasts to derive load projections. The weather-independent Monte-Carlo simulation for the variability of peak demand per customer only applies to these specific regions rather than systematically; therefore, it does not apply to the econometric approach.

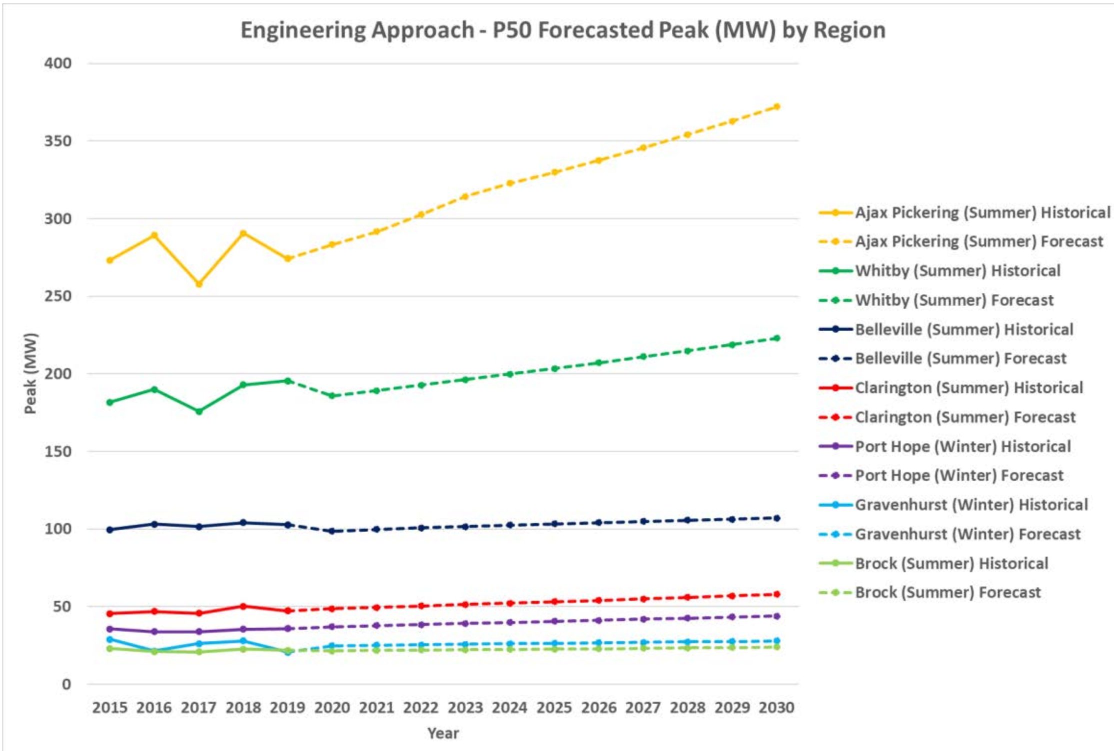
In conducting our analysis, we relied on historical daily loading data for the region, stations, station transformers, and feeders from the years 2009 to 2019. Weather data from 2009 to 2019 are taken from the nearest weather station to calculate weather indices. The weather parameters used are the daily maximum temperature, minimum temperature, maximum wind speed, and maximum relative humidity. Historical and forecasted econometric indicators utilized include the Cooling Degree Days ("CDD"), housing starts for all service areas for Elexicon, and a time trend.

We combine the regional coincident peaks from the engineering forecast to create the non-coincident system-level summer peak forecast for Elexicon. In the figure below, we compare the system-level econometric and engineering forecasts for summer peak load at the P10, P50, and P90 values.



While the two approaches rely on different inputs and analysis, they predict load growth following a similar trend for the first four years and diverge thereafter. The engineering model provides a higher estimate due to the assumption that load will continue to grow year over year. The forecasted peaks for the econometric model start to decrease after 2023 due to the effect of the time trend that was derived through the econometric analysis. The time trend suggests that load will decrease as time passes – potentially due to factors such as energy efficiency improvements or changes in the mix of economic activities. Overall, the final forecasts predict that substantial load growth will occur in the first four years of the forecast period. This can be attributed to major development in the Ajax-Pickering region of Elexicon's service area.

The following graph exhibits the P50 peak forecasts for all regions obtained using the engineering approach. The regional peaks are non-coincident with one another. In fact, while most regions are summer peaking, Gravenhurst and Port Hope experience peak load during the winter.



The engineering approach predicts that much of Elexicon's future growth will be produced from the Ajax-Pickering area, representing 59.9% (39.43 MW) of the total peak load growth from 2020 to 2024. When we evaluate the forecasts for all regions, Whitby demonstrates the next highest growth rate, representing 21.2% (13.96 MW) of the total peak load growth from 2020 to 2024. In total, 81.1% of the forecasted load growth for Elexicon is expected to occur within the municipalities of Ajax, Pickering, and Whitby.

METSCO will perform analysis on the forecasted values and actual results on a biannual basis to refine the two methodologies and investigate potential approaches to further integrate the econometric and engineering results. To facilitate these planned continuous improvement steps, METSCO is providing a set of recommendations for Elexicon to consider at the end of this report.

Contents

1. Introduction

The distribution system of Elexicon Energy Inc. ("Elexicon") receives its power supply from Hydro One Networks Transmission Inc, at either the 44 or 27.6 kV voltages. Elexicon then steps down this incoming supply to 27.6 kV, 13.8 kV, 8.32 kV, or 4.16 kV distribution voltages to supply power to their industrial, commercial, and residential customers at the appropriate utilization voltages using step-down distribution transformers.

The main objective of any utility's power system is to supply the electrical load to its customers safely, reliably (during both normal and abnormal conditions), and economically. Accordingly, the starting point for planning future development of the power system is the forecast of future changes in customer demand across the system. To supply customers over time as customer demand (load) increases, power system equipment within distribution stations, overhead and underground subsystems must be adequately rated to withstand the growing capacity demands.

At the most fundamental level load growth increases as the populations of cities and towns increase, bringing with them increased economic activity of various types. An important feature of power systems that makes load growth forecasting so impactful is that they are generally expected to be built to withstand the highest peak loading levels which may only occur for several hours each year. Accordingly, making accurate prediction of the scale, pace and location of future load increases can result in significant economic efficiencies in the form of deferred or optimized investments in transformer station or local area feeder or stepdown equipment capacity.

In Elexicon's case, load growth expectations vary significantly across the service area. While areas like Pickering (and specifically the community of Seaton), are expected to undergo significant growth, load in areas like Gravenhurst is not expected to change materially. While these general expectations help planners formulate a basic outlook of the future system capacity needs, utilities increasingly require greater granularity and objectivity of analysis to ensure that the scale and timing of their system capacity investments deliver optimal customer value.

Any power system planning methodology must have a good foundation, which starts with acquiring data on customer loads as well as deriving key load characteristics such as coincidence, intermittency, and seasonality. While the sum of the electrical customers' load in an area is the total connected load of that area, not all customers operate their equipment at the same time and some equipment operates at less than full loading. Accordingly, the resultant demand of the power equipment is less than the sum of the connected load. Application of factors to load demand such as demand factor, diversity factor, load factor, and coincident factor help system designers optimize the technical specifications of feeders, transformers, and switchgears for immediate load requirements and predicted future loads.

Elexicon relies on load forecasts to predict future system peaks, identify the anticipated capacity constraints, and ultimately address the resultant investment needs. Elexicon retained METSCO Energy Solutions Inc. ("METSCO") to develop a load forecast model using two distinct but complementary approaches – econometric and engineering – to compare the results, perform a variance analysis of actual results and forecasted results on a biannual basis, and review future improvements to both approaches annually.

METSCO's econometric "top-down" approach utilizes various macroeconomic variables and past peak load data to run an exhaustive trial of multivariate regression runs to find the best possible combinations of variables that predict future load changes. Having selected the most significant explanatory macroeconomic variables, we established a forecasting equation based on regression run results. To derive the forecasted load values for the econometric model, we populated our equations with independent forecasts of future values for the explanatory variables, which we obtained from independent third parties.

METSCO's engineering "bottom-up" approach utilizes historical municipally based household forecasts, internal Elexicon residential customer counts, and peak load data as inputs to model the relationship between housing developments, customer additions and load. The underlying assumption in the engineering model is that peak load is driven by customer growth due to residential development. Forecasted peak loads are then produced using a forecasted customer count driven by adjusted municipal household forecasts of each region. The household forecasts are adjusted based upon the historical accuracy of the actual households and the forecasted households within the region. This historical accuracy is trended linearly into the future. The customer forecast is then computed through the historical average ratio of total residential customers to total households in the area. From this juncture, regional forecasts are proportionally allocated to the station, station transformer, and station feeder level.

While the two forecasting approaches rely on the same historical load and weather data inputs and ultimately yield forecasts in a consistent format, another important distinction between the two concerns the scale of application. While the "top-down" econometric model examines the relationships between load and its predictors at the aggregate, utility-wide level, the engineering, "bottom up" model defines these relationships using a different type of predictors by starting at the more granular, regional level. For the purposes of the "bottom up" load forecasting work, we divided Elexicon's service area into the following regions:

- Ajax-Pickering;
- Whitby;
- Brock - consisting of Sunderland, Cannington, and Beaverton within the Township of Brock, as well as Scugog (Port Perry) and Uxbridge;
- Gravenhurst;
- Port Hope;
- Clarington - consisting of Bowmanville, Newcastle, and Orono; and
- Belleville.

The remainder of the report describes the overall load forecasting methodology, load forecast results, and conclusions and recommendations. Chapter 2 encompasses the overall load forecasting methodology and the steps taken. Our approach to data cleansing and weather normalization is expanded upon. The methodologies and approaches to the engineering and econometric model are also outlined in further detail. Finally, we describe the reintroduction of weather or variability through Monte Carlo to both load forecast models. Chapter 3 presents the results produced by the engineering and econometric models. The engineering model results are provided for each region alongside a station level forecast. The finalized econometric forecast results are shown for the entire system level. Lastly, a comparison between the system level forecast for the engineering and econometric model is also provided. Chapter 4 summarizes the conclusions and recommendations discovered from the load forecasting exercise. Chapter 5 lists the references and Appendix A provides the data sources data used.

Going forward, METSCO will perform a variance analysis on model results compared actuals on a biannual basis, with iterative improvements to the load forecast approach made on an annual basis.

2. Load Forecasting Methodology

Prior to conducting weather normalization, METSCO performed extensive data cleansing on Elexicon's historical load datasets. Regional system peaks are aggregated alongside any primary metering points/feeders to the regional system peak. Events and data points that are expected to distort normal relationship between load and its drivers, such as weekends, holidays, load transfers, and zero loads, are removed from the data set. In cases where loading is more variable or atypical such as Port Hope and Gravenhurst, weekends and holidays are not removed.

Prior to performing analysis on the econometric and engineering models on the cleansed dataset, METSCO adjusted the historical system peaks by the short-term effects of weather fluctuations through a procedure commonly known as weather normalization. In order to weather normalize the system peaks, weather data from the nearest weather station is extracted to create weather indices that we then regress to system peaks. If the statistical relationship between weather and the peaks is robust, the annual slope is taken, and the loads are normalized using the annual slope and the difference between the biweekly weighted weather indices and daily weighted weather indices. Each annual weather normalized dataset for each season is then combined to form the ten-year weather normalized datasets for summer and winter. After the cleansed and weather normalized historical peaks are produced, our workflow separates into the dedicated econometric and engineering model activities.

The econometric model iterates through thousands of macro-economic variable combinations by means of a statistical algorithm to establish the strongest plausible combination of macro-economic variables that have predictive power as to the magnitude of weather-normalized historical system peaks. Heuristic filtering is used to remove any combinations of variables where regression signs are not intuitive or where forecasting input data would be difficult to obtain (e.g. future greenhouse gas emission levels). In addition, correlation tests are utilized to determine whether and how the changes in some explanatory variables are related to changes in other explanatory variables, which would misstate the combined impact of these variables on predicted changes in load. We identify the strongest multivariate regression using summary statistics produced by analysis. Summary statistics used include p-values and R^2 values where we use industry standards to identify the strongest candidates. Finally, we produce weather-normalized peak forecasts with the use of the multivariate regression and independent forecasts of changes in the selected explanatory econometric variables.

Within the engineering model, the relationship between residential customer counts and households is derived independently for each given region. Household forecasts are obtained from the various municipalities and are provided in Appendix A for reference. The accuracy of each household forecast is back calculated based on historical accuracy through the ratio of the actual final household count and the forecasted household count. The household forecasts utilized to produce the accuracy factors are provided in Appendix A.3. We produce a linear trend for the historical accuracy into the future to adjust the latest municipal household forecasts moving forward. We utilize this accuracy factor alongside the customer-to-household relationship to produce customer forecasts from household forecasts. The weather-normalized historical peak data is divided by the historical customer counts to acquire the weather-normalized peak load per customer. The average value of the historical megawatts per customer is taken and we multiply the forecasted customer counts to this average value to acquire the forecasted weather-normalized peak loads.

Once the weather-normalized peaks are forecasted, we reintroduce the effects of weather to create the P10, P50, and P90 system peaks. To model the effects of weather, we take the top 10% of peaks for each season over the past ten years and calculate the mean and standard deviation. We then model the variance from the mean of the peaks of each given year. We apply Monte Carlo to the first distribution using the mean and standard deviation and acquire one simulated peak. Monte Carlo is then applied to this peak to simulate for the other peaks of the given year considering the historical variance. We perform 1000 simulations and take the 10th, 50th, and 90th percentile values (respectively as the P10, P50, and P90 values). The percentile values are finally multiplied with the ten-year historical regression slope to weather and added to the weather-normalized peaks. The final peaks produced include the weather-normalized peaks that represent system peaks at average weather, P10 peaks that represent the peak value threshold that 10% of annual peaks will exceed, P50 peaks that represent the peak value threshold that 50% of annual peaks will exceed, and P90 peaks that represent the peak value threshold that 90% of annual peaks will exceed.

2.1 Data Cleansing

Prior to weather normalization, a historical ten-year dataset of daily regional peaks is extracted. We perform data cleansing of the ten-year historical daily peaks to remove specific events to produce a cleansed ten-year peak dataset. Figure 1 illustrates the data cleansing process.

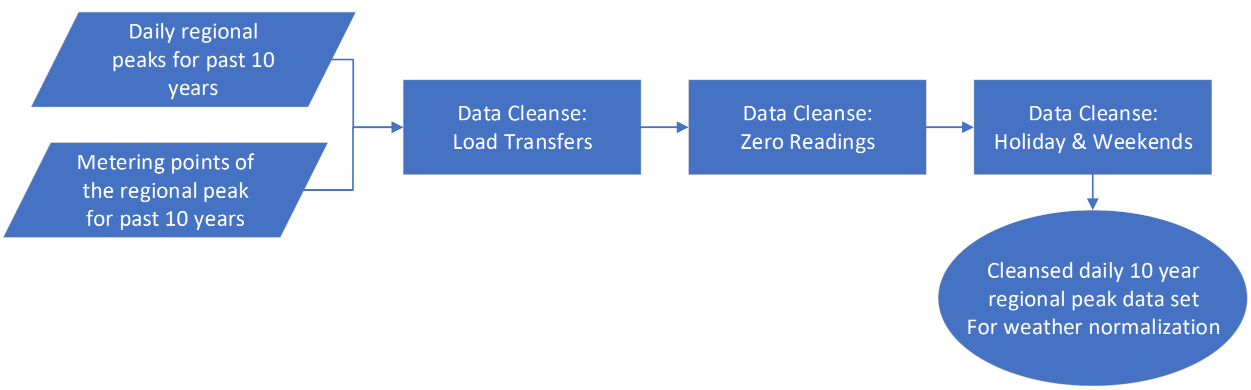


Figure 1: Data Cleansing Process

Events identified and removed include:

- Holidays;
- Weekends;
- Zero readings; and
- Possible load transfers

In these cases, when a holiday, weekend, or zero reading is identified within the dataset, it is removed. However, in cases of areas having seasonal customers and different loading patterns such as Gravenhurst and Port Hope, weekends and holidays were not removed. In addition, if any of the metered points contributing to the regional system peak were zero, the day was identified as a load transfer. Furthermore, if a load transfer occurred within a three-day period and the day previously or after also was a load transfer, the days are labelled as load transfer days. As such, load transfer days are also removed from the dataset. Figure 2 represents the identification of various events through our data cleansing exercise.

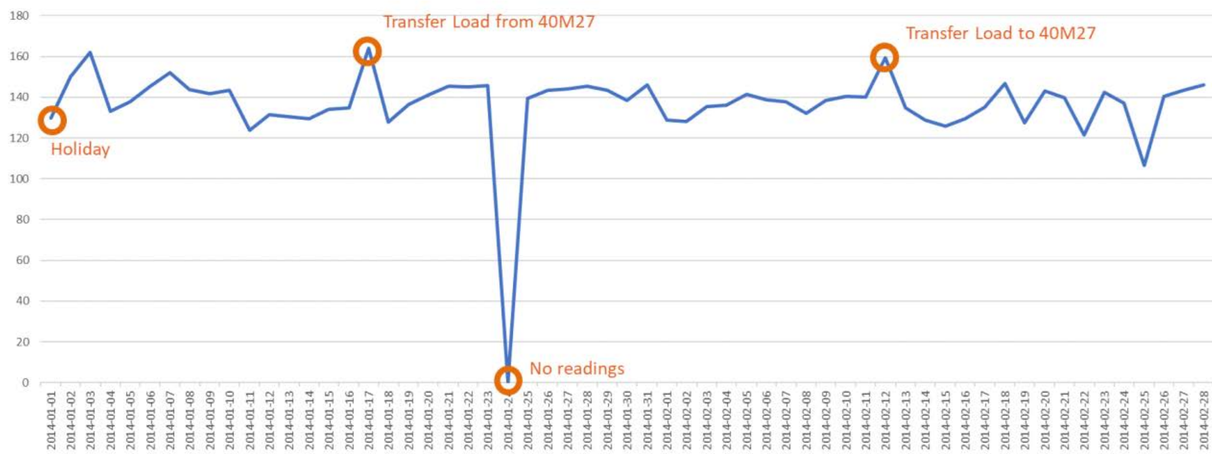


Figure 2: Events identified in Data Cleansing

2.2 Weather Normalization

Due to the annual variability of weather patterns and the resulting effect on load, we normalize historical daily loading data to the observed weather that day. Figure 3 illustrates the process, which is performed to determine the annual slope of the weather normalization trendline that is used to produce the annual weather normalized peaks of the season.

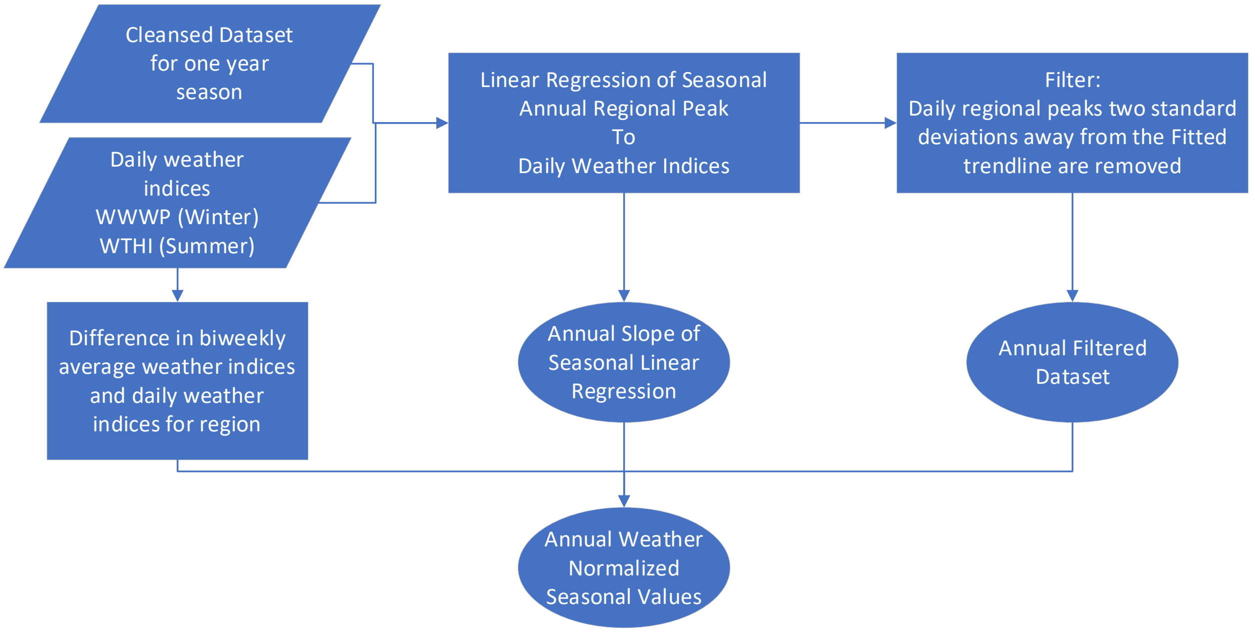


Figure 3: Weather Normalization Process

To perform weather normalization, we selected three weather stations:

1. Oshawa Municipal Airport for all Durham municipalities and Port Hope;
2. Muskoka Airport for Gravenhurst; and
3. CFB Trenton for Belleville.

The specific weather variables we use in the weather normalization process are:

- Maximum temperature;
- Minimum temperature;
- Maximum wind speed; and
- Maximum relative humidity.

We utilize maximum temperature and maximum relative humidity to create the temperature humidity index ("THI") for summer. The weather indices, "WTHI" and "WWWP" utilized in the weather normalization process are found in PJM's 2016 load forecast whitepaper [1]. Temperature Humidity Index is used to account for the combination of effects from temperature and humidity. It can be described as the measure of heat stress that an individual will experience. In addition, we utilize the minimum temperature and maximum wind speed to create the winter weather parameter ("WWP"). The winter weather parameter accounts for the combined effects of temperature and the effects of wind speed. Two separate indices are created for the respective seasons due to the difference in weather variables that effect peak loads.

Equation 1: Winter Weather Parameter (WWP)

Let w be windspeed and let t_D be dewpoint temperature (farenheit). We define the winter weather parameter ("WWP") as

$$I_{WWP} = \ t_D - 0.5(w - 10)$$

if $w > 10$ mph and otherwise

$$I_{wwp} = t_D$$

Equation 2: Temperature Humidity Index (THI)

Let h_R be the relative humidity (so a value of 1 represents 100% humidity). We define the temperature humidity index ("THI") as

$$I_{THI} = \ t_D - 0.55(1 - h_R)(t_D - 58)$$

if $t_d \geq 58$ and otherwise

$$I_{THI} = t_D$$

After determining the daily values of WWP and THI, a two-day weighted factor is calculated. The present-day value is given a numerical weighting of 4 and the previous day value is given a numerical weighting of 1. We define the two-day weighted winter weather parameter ("WWWP") below.

Equation 3: Two Day Weighted Winter Weather Parameter (WWWP)

$$I_{WWWP} = \frac{4I_{WWP}(0) + I_{WWP}(-1)}{5}$$

where $I_{WWP}(0)$ represents the current day WWP and $I_{WWP}(-1)$ represents the previous day

In a similar manner we define the two-day weighted temperature humidity index (WTHI) as:

Equation 4: Two Day Weighted Temperature Humidity Index (WTHI)

$$I_{WTHI} = \frac{4I_{THI}(0) + I_{THI}(-1)}{5}$$

where $I_{THI}(0)$ represents the current day THI and $I_{THI}(-1)$ represents the previous day

With the cleansed dataset, we perform a linear regression of the system peaks to the weather indices produced. Any outliers two standard deviations away from the original trendline are assumed to be erroneous; this assumption is confirmed by manually checking the data. We remove these outliers such that any erroneous readings events are removed from the final dataset.

To weather normalize the historical peaks, we utilize the formula found in Equation 5. We first subtract the biweekly historical average and the daily value of weather indices. This difference is then multiplied by the annual regression slope (the annual regression slope prior to the removal of outliers). The product of the difference and annual regression slope is then added to the historical daily peak to create weather normalized system peaks for the season. Depending on the slope and the difference in biweekly historical average and daily weather indices values, the difference can either be positive or negative.

Equation 5: Weather Normalized Peak Load Calculation

$$L_{WNP} = L_D + m_{reg}(I_b - I_a)$$

where L_{WNP} represents the weather normalized peak load, m_{reg} represents the annual-year seasonal regression slope, I_b is the biweekly weighted weather indices, and $I_a$is the actual weighted weather indices.

This step allows us to remove or add the effects of weather on the daily peak loads as needed. It is prudent to control for the short-term effect of weather on loads if we want to examine long-term relationships between load growth and economic factors that cause it (e.g., changes in customer numbers or an area's GDP). Conversely, to ensure that the forecasted load data using adjusted long-term relationships reflects reality, it is important to re-introduce the expected effects of short-term weather variability onto load to produce the probabilistic peak load forecasts.

Having produced historical weather-normalized peak load data and ensured that we can add the peak back into the forecast, our annual data set is created. Each year's weather-normalized values for each season are combined into one ten-year weather normalized dataset for each season. Both models explore the relationships between peak load and the explanatory factors that apply in each case, without the effect of distortions caused by short-term weather changes.

The ten-year weather normalized summer dataset for Ajax-Pickering is illustrated in Figure 4. The maximum value of the weather-normalized peak associated with each season and year is declared as the weather normalized value peak value of that time.

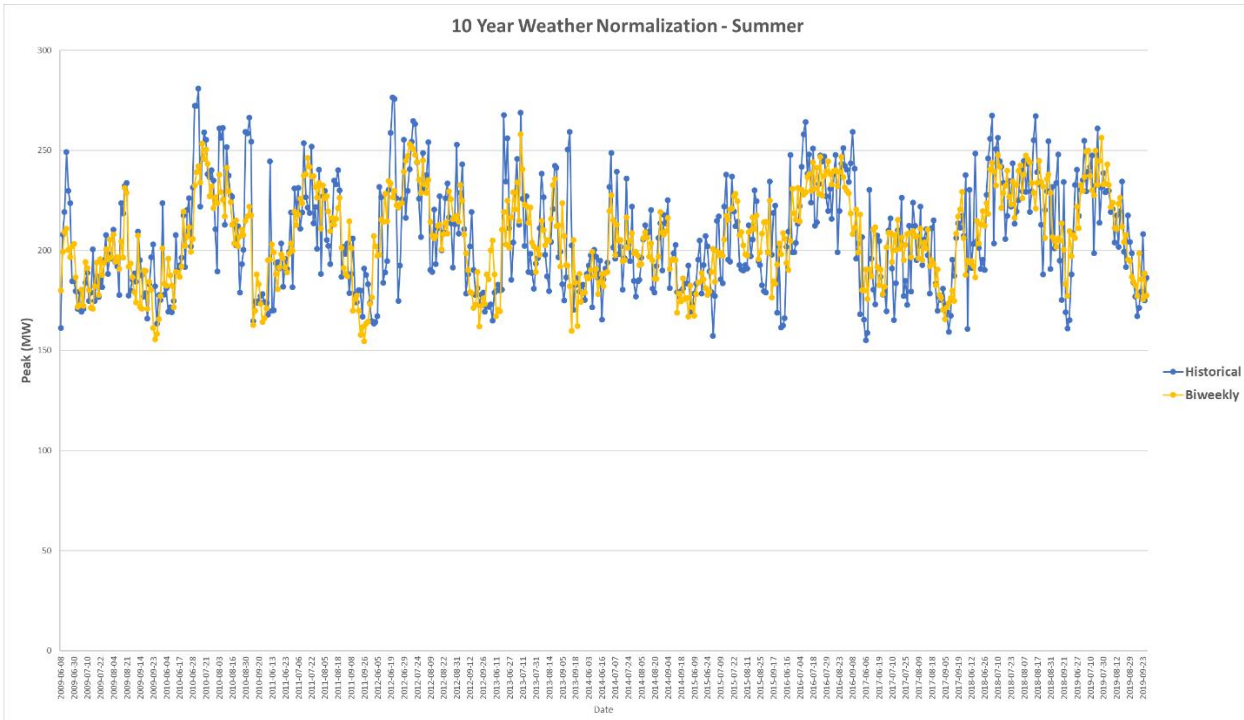


Figure 4: Ajax-Pickering Historical Weather-Normalized Loads

2.3 Engineering Model Approach

Figure 5 illustrates METSCO's engineering approach for load forecasting and Table 1 lists the key inputs.

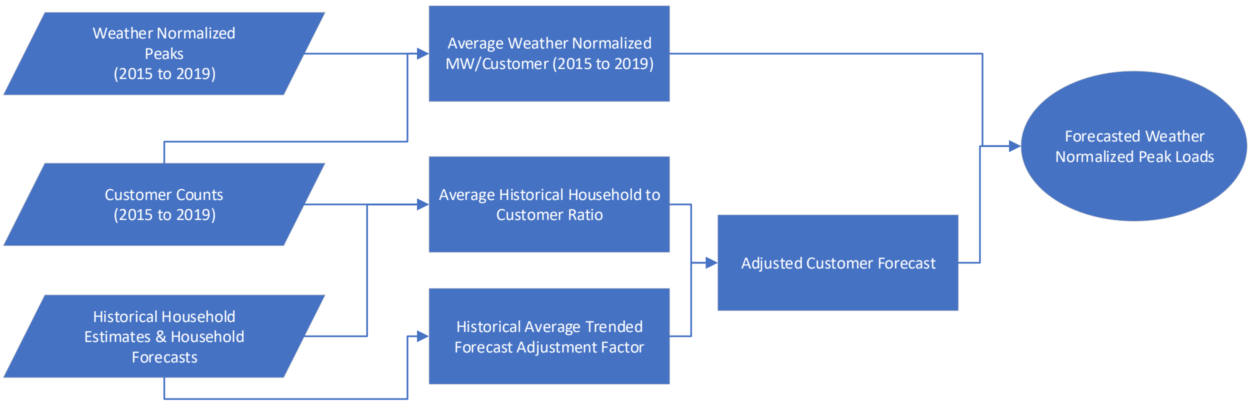


Figure 5: Engineering Model Process

Table 1: Engineering Model Inputs

Data Inputs	Data Time Frame
Municipal Development Forecasts (Households)	2015 to 2019
Historical Residential Customer Counts	2011 to 2019
Weather Normalized System Peaks	2014 to 2019
Station Peaks	2011 to 2019
Station Transformer Peaks	2011 to 2019
Feeder Peaks	2011 to 2019

The first step taken in the engineering model is to analyze the municipal development forecasts and create adjustment factors based on the historical accuracy. These municipal development forecasts are extracted from the household forecasts found in Appendix A.3. Understanding that not all development forecasts materialize, we create an adjustment factor in order to represent the historical accuracy of the development forecasts compared to the actual household completions. The adjustment factor (Equation 6) is linearly trended across the short-term forecast. The adjusted household forecasts are used as a base that will then be applied to the historical household-to-customer ratio. Certain regions have overestimated or underestimated in their respective households' forecasts, and we aim to represent their historical performance of forecasting through adjustment factors. Since the Region of Durham only forecasts household growth up to May 2024, we linearly extrapolate our adjusted household additions moving forward. We then take the average growth rate of the short-term forecast and applying the percentage year-over-year moving forward onto the extrapolated household additions. Long-term forecasts are, therefore, reflective of the short-term forecasted growth rates.

For the regions of Gravenhurst, Port Hope and Belleville, we utilize household forecasts noted in Appendix A.3 sourced from the official government websites and developed by external consultants. For these regions, we did not create an accuracy forecast as there were no historical forecasts or results to compare against. In cases where forecasted results are multi-year increments, such as Gravenhurst, Belleville, and Port Hope, we perform linear interpolation to produce household numbers annually. As Port Hope only produced forecasted households to 2029, linear extrapolation was then applied to produce 2030 numbers.

Equation 6: Municipal Forecast Adjustment Factor

$$A_{fctr} = \frac{\sum_{i=1}^{n}\left(\frac{\mathrm{H}_{act,i}}{\mathrm{H}_{fcst,i}}\right)}{n}$$

where A_{fctr} represents the average adjustment factor, H_{act} is the number of households connected, H_{fcst} is the number of households forecasted *n* is the number of forecasts in forecast period ,and *i* is the year.

The ratio of historical households and residential customer counts (Equation 7) is then calculated. We use each region's unique historical residential customer count and historical household total to create a ratio representing the historical relation of how much one customer is to each household. Finally, we average the historical conversion ratio across the years to convert the household forecasts into residential customer forecasts.

Equation 7: Customer-to-Household Ratio

$$R_{CH} = \frac{\sum_{i=1}^{n}\left(\frac{\mathrm{C}_{act,i}}{\mathrm{H}_{act,i}}\right)}{n}$$

where R_{CH} represents the average ratio of customers to households, H_{act} is the number of households connected, C_{act} is the number of residential customers, *n* is the number of historical years, and *i* is the year.

We divide the weather-normalized system peaks by the residential customer count to create the weather-normalized peak load per customer (Equation 8). This step is performed in order to establish how much each customer utilizes in demand of mega-watts during peak times at normal weather. We produce an average of the historical five-year megawatt demand of each customer to illustrate the historical average demand of a customer in the region. Since we have the historical average of an individual customers megawatt demand for peaks, we multiply this historical ratio by the total forecasted customers (Equation 9) to forecast the weather-normalized regional peaks (Equation 10).

Equation 8: Weather-Normalized MW/Customer

$$C_{WN} = \frac{P_{wn,i}}{\mathrm{CC}_{act,i}}$$

where C_{WN} represents the weather normalized megawatt per customer, $P_{wn,i}$ is the number of households connected, C_{act} is the number of residential customers, *n* is the number of historical years, and *i* is the year.

Equation 9: Customer Forecast with Adjustment Factor

$$C_{fcst} = A_{fctr}\mathrm{H}_{fcst}\, R_{CH}$$

where C_{fcst} represents the Customer Forecast, A_{fctr} is the municipal forecast adjustment factor, R_{CH} is the customer to household ratio, and $\mathrm{H}_{fcst,i}$ is the number of forecasted households.

Equation 10: Weather-Normalized Forecasted Regional Peaks

$$P_{wn,fcst} = C_{fcst}\, C_{WN}$$

where $P_{wn,fcst}$ represents the weather normalized forecasted regional peak, C_{fcst} represents the Customer Forecast, and $C_{WN}$is the weather normalized megawatt per customer.

We calculate the coincidence and allocation factors at the station, station transformer, and station feeder level to convert the regional forecast to the distribution level. Coincidence factors describe how each system component's demand is to the total of the system. The allocation factors create percentages of each system level components demand to the total demand of all system level components. Daily peaks are utilized to calculate the average coincidence factor and allocation factor for summer and winter.

With the historical allocation factor to the station level, we separate the new residential customer additions and apply historical factors to separate customer additions to be added on to the station level. By separating the customer additions, Elexicon can selectively place new customers and load growth on stations they envision the new connected growth to be located.

Equation 11 is used to convert system loading to the system components that contribute to the system loading. For example, for the coincidence factor of transformers to the station, the peak of the system would be the station and the sum of the individual peaks to the system would be all the transformer peaks on that station.

Equation 11: Historical Coincidence Factor

$$f_C = \frac{P_{sys}}{\sum_{i=1}^{n} P_{comp}}$$

where f_C represents the coincidence factor, P_{sys} represents the peak of the system, and P_{comp} is the peak of the individual components.

Equation 12: Historical Allocation Factor

$$f_A = \frac{P_{comp}}{S\sum_{i=1}^{n} P_{comp}}$$

where f_A represents the allocation factor, and P_{comp} represents the peak components of the system.

Equation 13 is used to find the percentage that each individual peak has to the total of the individual peaks of the same level. For example, there are two transformers connected to one station. Each transformer has a portion of the total load transferred from the station level to the transformer level. The historical coincidence and allocation factor are used in conjunction to convert the station peak to the two station transformer peaks.

Equation 13: Conversion of Regional Peak to Station Peaks

$$S_{fcst} = P_{fcst} f_{CReg} f_{ASt}$$

where S_{fcst} represents the individual station forecast, and P_{fcst} represents the regional peak forecast, f_{CReg} represents the coincidence factor from the region to the total station load, and f_{ASt} represents the allocation factor from total station load to individual station load.

Equation 14: Conversion of Station Peak to Transformer Peaks

$$T_{fcst} = S_{fcst} f_{CTx} f_{ATx}$$

where T_{fcst} represents the individual transformer forecast, f_{CTx} represents the individual transformer coincidence factor, S_{fcst} represents the individual station forecast ,and f_{ATx}

represents the allocation factor from stations to transformers. Note that former Veridian stations only had the transformer peaks for data and thus the coincidence factor is assumed to be one as the station peaks were produced by adding the transformer peaks.

Equation 15: Conversion of Transformer Peak to Feeder Peaks

$$F_{fcst} = T_{fcst} f_{CFdr} f_{AFdr}$$

where F_{fcst} represents the feeder forecast, T_{fcst} represents the individual transformer forecast, f_{CFdr} represents the individual feeder coincidence factor, and f_{AFdr} represents the allocation factor from transformer to feeders.

Through these equations, we can capture the weather-normalized regional, station, transformer, and feeder peaks. We will describe the process of adding weather back onto the forecast in Section 2.5. Equation 13, Equation 14, and Equation 15 are also used for the P10, P50, and P90 peaks to convert the peaks into P10, P50 and P90 stations, transformers, and feeder peaks.

2.4 Econometric Approach

In addition to the engineering approach described in the previous section, METSCO developed an econometric model to forecast weather-normalized non-coincident peak load values for summer months. The choice to run a time series analysis at a monthly frequency was due to the fact that, other than weather, econometric data was most frequently available in monthly increments. In the case where we have annual data, and not monthly, for a given variable we convert annual data to monthly data in two different ways and try all possibilities. The first approach to convert annual data to monthly data is to hold the annual data constant across all months. The second approach is to use linear interpolation between the current year's annual value and the next year's annual value to assign unique values to each month. The analysis described below was run on the regional level; however, we were not able to find consistent models across regions with meaningful explanatory variables. We therefore ran the econometric modelling on the system level, where there were meaningful explanatory variables to predict peak load.

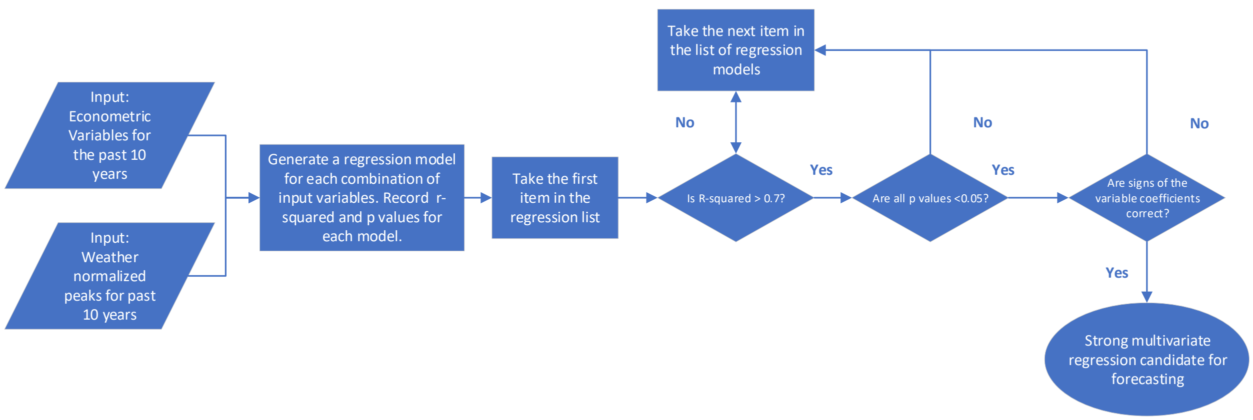


Figure 6: Econometric Model Process

METSCO's econometric model approach uses macro-economic and weather variable forecasts to predict future load. To determine which possible input variables to use in our final analysis, we take a list of candidate variables, fit a multivariate predictive model to each possible subset of variables, and record summary statistics for each model. A multivariate model approximates a linear relationship between each of the variables and the target variable, which in this case is weather normalized monthly peak load. For a given combination of variables we use the R^2 statistic to gauge the closeness of this fit and therefore the accuracy of the prediction of changes in these variables on changes in weather-normalized monthly peak load, and we use p-values to gauge which variables are significant in making the prediction. Table 2 summarizes a list of the variables used in the process and Appendix A.4 provides the sources to each economic variable utilized.

Table 2: Econometric Model Input Variables

Variable Name	Frequency	Granularity	Description
Population	Annual	Regional	Population refers to the total number of residents who permanently reside within a given region
Business Counts	Annual	Regional	Business Counts refers to the total number of active businesses operating within a given region
Customer Count	Annual	Regional	The total number of customers as defined by Elexicon
Housing Starts	Annual	Regional	Housing starts are defined as the total number of new completed houses
Gross Domestic Product	Annual	Ontario	Gross domestic product (GDP) is the total monetary value of goods and services produced within a year
Price of Energy	Annual	Ontario	Price of Energy is presented as an index and is defined as the cost of various forms of energy such as electricity, natural gas, fuel oil and other fuels, gasoline, and fuel, parts, and accessories for recreational vehicles
Time Trend	Annual	N/A	A variable that increases linearly with the passage of time. This variable will dampen or heighten the value of the predicted load, depending on if the sign of the coefficient is positive or negative respectively as the time to forecasted load increases
Industrial Production Index	Annual	Canada	The industrial production index measures the output of business integrated in the industrial sector of economy such as manufacturing, mining, and utilities
Unemployment Rate	Annual	Ontario	Unemployment Rate is the percentage of unemployed workers in the total labour force. A worker is considered unemployed if they do not have work despite being willing and able to do so.
Commercial Production	Annual	Ontario	Commercial Production is based on the Ontario Economic Accounts published by the Government of Ontario’s Ministry of Finance. It is defined as the sum of monetary production of various commercial sectors
Cooling Degree Days	Annual	Oshawa Municipal Airport	A cooling degree day is the number of degrees that a day’s average is above 18°C. The cooling degrees days monthly data point is the sum of these degree days for the month

Variable Name	Frequency	Granularity	Description
Max Temperature - Peak Days	Annual	Oshawa Municipal Airport	The maximum temperature of a peak day is defined as the maximum temperature of the peak load day
Weighted Temperature Humidity Index	Annual	Oshawa Municipal Airport	A weighted sum of maximum relative humidity and maximum temperature in a day

METSCO also performed a standard data transformation to the datasets above to lag the variables by one year and include these lag variables as possibilities in the modelling. A one-year lag on a variable indicates that the value of the variable each year will be a predictor of the value of the load the next year. This was done to account for any delay in the effect of a given independent variable on the prediction of load.

We set industry standard thresholds on both R^2 values and p-values and only consider those combinations of variables that meet these thresholds. Using advanced statistical algorithms METSCO's econometric procedure tested all combinations of two, three, and four variables, totalling 195,661 combinations. Models with five or more variables lead to statistical overfitting and would therefore have low accuracy when predicting future peak load.

The output of the multivariate regression fitting described above, for a given choice of input variables, is a set of coefficients, one for each variable, that describe the linear relationship between each variable and the load. Typically, the magnitude of these coefficients does not convey useful insight. However, the sign of these variables, whether they are positive or negative, gives very important information about the direction of the linear relationship. For example, a positive coefficient would suggest that as the input variable increases so does the load, and a negative coefficient would suggest the opposite general trend. We use subject matter expertise to rule out possible combinations of variables for which these directional indicators are incorrect.

The output of this process is a multivariate model with an R^2 value of 0.78. The variables selected for the model are listed below along with their p-values. Note that a p-value below 0.05 indicates a very strong statistical significance. AppendixA.4 provides the sources to each economic variable utilized in the forecast. We chose the model with the most significant variables, based on p-values and subject matter expertise, and with maximum R^2. The multivariate model gives the equation shown below and a summary of the variables.

Equation 16: Multivariate Equation used in the Econometric Model

$$y = 505.4 + 0.7580x_1 + 0.01891x_2 - 3.159x_3$$

where x_1, x_2, x_3 are the values of cooling degree days, housing starts with one-year lag and the time trend variable, respectively, and y is the predicted peak load. The coefficients represent the change in the predicted peak load as the input variables change, which exhibit positive correlations for cooling degree days and housing starts and a negative correlation for the time trend variable.

Table 3: Summary of variables used in Equation 16

Variable	Description	p-Value	Sign of Coefficient
Cooling Degree Days	A cooling degree day is the number of degrees that a day's average is above 18°C. The cooling degrees days monthly data point is the sum of these degree days for the month	3.4 x 10-9	Positive
Housing Starts – 1 Year Lag	Housing starts are defined as the total number of new completed houses	0.03	Positive
Time Trend	A variable that increases linearly with the passage of time. This variable will dampen or heighten the value of the predicted load, depending on if the sign of the coefficient is positive or negative respectively, as the time to forecasted load increases	0.03	Negative

In order to forecast the variables identified, we made assumptions based upon the historical data. Cooling Degree Days are forecasted using the historical monthly average of the past ten years. We calculate the average CDD from Oshawa Municipal Airport and then utilized the variable as a constant average into the future. The housing starts forecast was extracted from the different municipal household forecasts for the Elexicon service territory. The semi-annual household projections from the Region of Durham were forecasted up to the year 2023. We use linear interpolation to create the annual numbers from 2018 to 2023 of Port Hope, Gravenhurst and Belleville. The individual housing numbers were added together to create the system-level housing starts. As the forecast did not extend past 2030, the growth rate year over year of the system level housing starts was calculated across the 2018 to 2023 period. Finally, the average growth rate was calculated and applied to the system-level housing start forecast into the future.

2.5 Measuring the Variability of Weather

To understand the effects of weather, we take the ten-year filtered dataset and plot the historical peaks associated to the set of the daily weighted weather indices. If the R^2 value of the linear regression is strong, we conclude that there is a strong relationship between load and weather. R^2 is the coefficient of determination, or proportion of the variance in the dependent variable that is predictable from the independent variable. Higher R^2 values represent small differences between the observed data and fitted data (the trendline in this case). For example, in Figure 7, Ajax-Pickering region's ten-year historical summer peaks are linearly regressed using WTHI as the independent variable. As demonstrated from the slope, weather has a significant effect on summer loads in Ajax-Pickering. The R^2 value signifies that there is a strong relationship between WTHI and summer peaks.

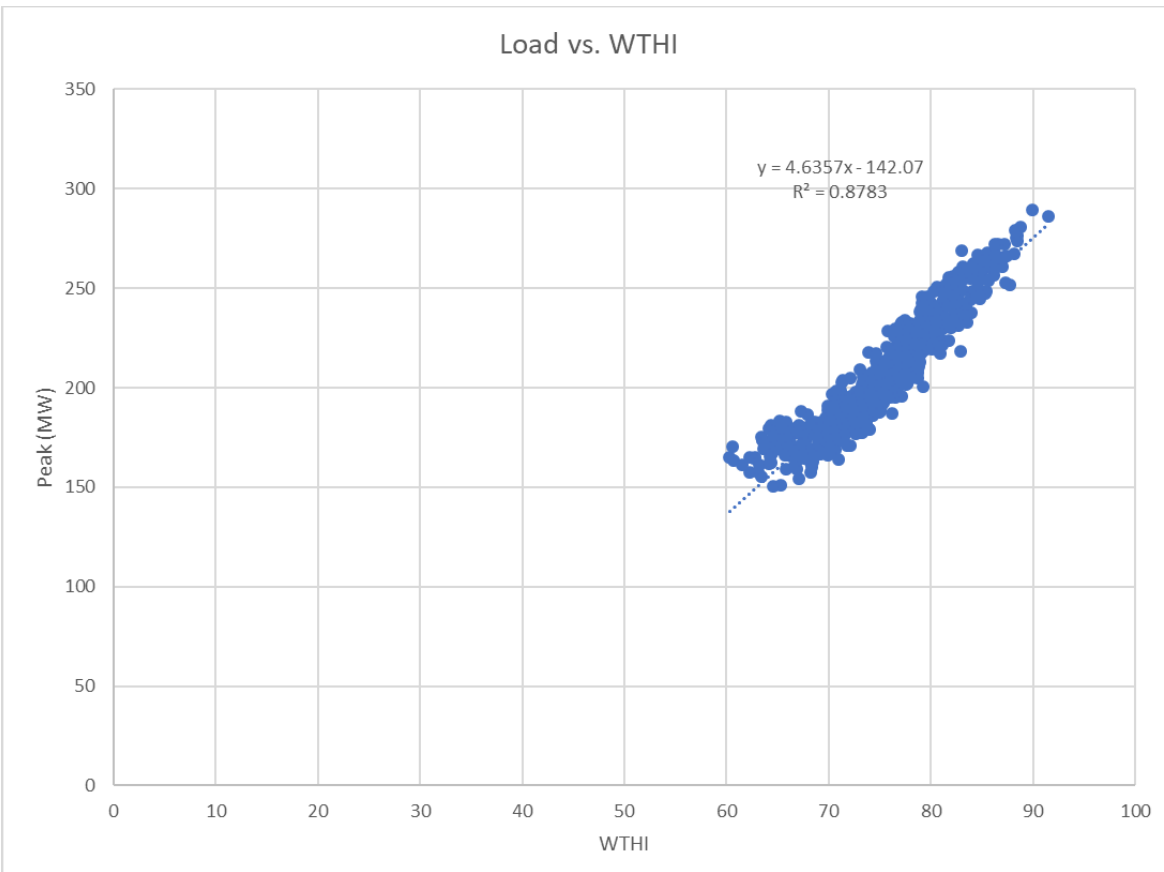


Figure 7: Ajax Pickering Summer Peak Loads (MW) vs WTHI

Ajax-Pickering's historical daily ten-year winter peaks are plotted against WWWP in Figure 8. The regression slope is less steep in the winter than in the summer. The R^2 value suggests there is a moderately strong relationship between WWWP and winter peaks.

It is evident that the summer peaks hold a stronger relationship to WTHI than winter peaks to WWWP based on the higher R^2 value and steeper slope. A higher R^2 represents smaller differences between the observed and fitted data (trendline). A steeper slope suggests that for each weather indices, the peak will increase that much more depending on the direction and magnitude of the slope.

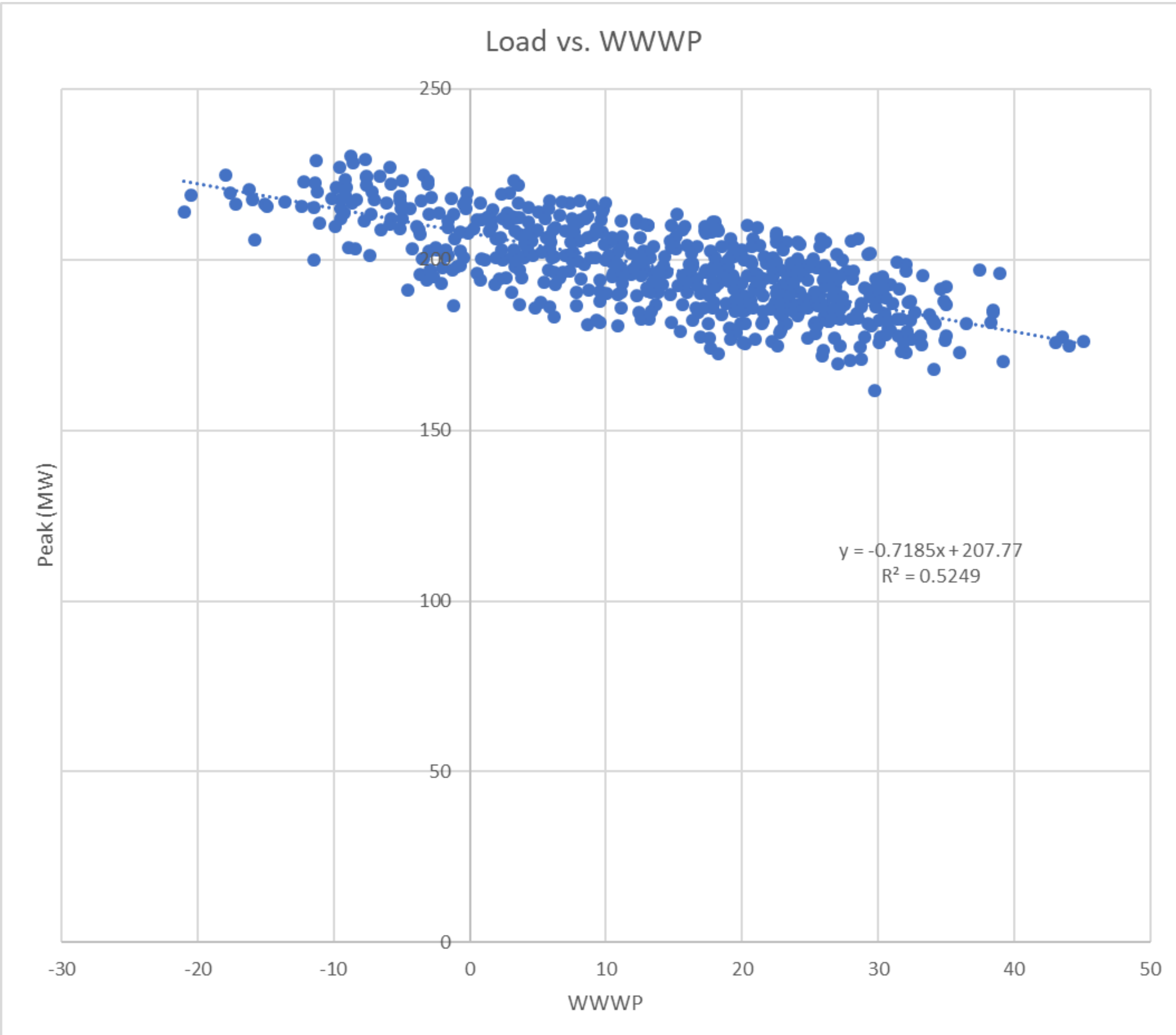


Figure 8: Ajax Pickering Winter Peak Loads (MW) vs WWWP

Table 4 summarizes the results of the linear regression of peaks to weather indices on all service areas. Port Hope and Gravenhurst held very poor relationships with the weather indices as demonstrated by the low R^2 and slope values. As a result, we do not weather normalize system peaks in Gravenhurst and Port Hope. The ten-year slope values found in Table 4 will be utilized to re-introduce weather.

Table 4: Summary of Seasonal Regression Results

Region	Summer Slope	Summer R^2	Winter Slope	Winter R^2
Ajax-Pickering	4.6357	0.8783	-0.7185	0.5249
Whitby	3.6044	0.8918	-0.4086	0.4153
Brock	0.3134	0.8260	-0.1066	0.4998
Belleville	1.2647	0.8569	-0.3084	0.5567
Clarington	0.8010	0.8121	-0.1516	0.5216
Port Hope	0.1450	0.1551	-0.0844	0.1413
Gravenhurst	0.0892	0.1924	-0.0686	0.2369

2.6 Monte Carlo Simulation

Monte Carlo simulation is used to understand the impact of risk and uncertainty in forecasting models. In our load forecasting models, we primarily associate the impact of risk and uncertainty to weather and its variability (see Section 2.5.1). In the regions of Gravenhurst of Port Hope, where the peak load is not strongly correlated with weather, we instead correlate uncertainty with the seasonality of customers in these regions as the main source of variability (see Section 2.5.2).

2.6.1 Adding the Effects of Weather

Both the engineering and econometric approaches forecast weather-normalized peaks by modelling new growth using past historical weather normalized peaks. The effects of weather need to be added back to account for the variable effects of weather onto load. We introduce weather to apply probabilistic scenarios based on past historical data. For example, one summer may have higher WTHI then another summer where it is cooler. Adding the effects of weather provides us with four forecasts that illustrate and capture the variability of peak which are the weather normalized, P10, P50 and P90 peaks historically. Figure 9 illustrates the first stage of the Monte Carlo simulation process for weather variability, wherein the P10, P50, and P90 values of the weather parameters are determined. (Figure 11 illustrates the second stage of the Monte Carlo simulation to predict the P10, P50, and P90 load forecasts based on the weather parameters.)

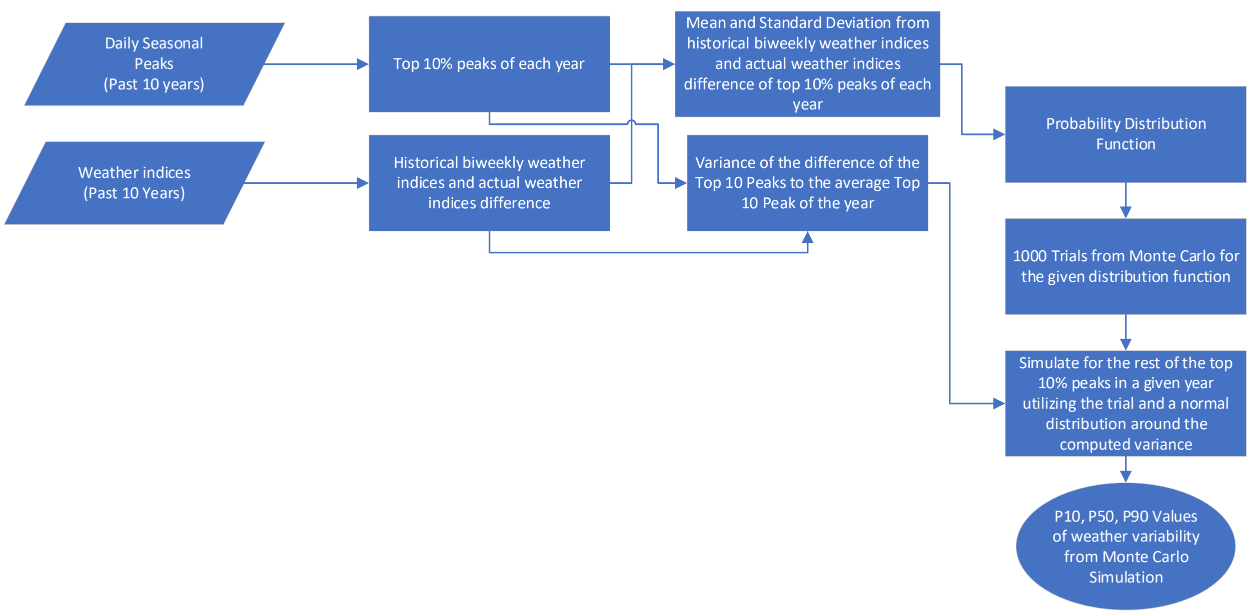


Figure 9: Monte Carlo Process Stage 1

To add the effects of weather onto the weather-normalized forecasts, we take a sample of the top 10% daily loads of each historical year for the past ten years to simulate the historical peak loading as well as the variability of colder and hotter seasons (e.g., some years can feature a colder summer than average). The difference between the biweekly average and actual daily value is calculated for each day (and denoted as ω). The mean and the standard deviation of ω are calculated in order to create a normal distribution.

We apply randomness to the probability distribution functions from the standard deviation and mean of ω for each region in order to simulate for the uncertainties in weather. In the weather normalization step, we multiplied ω by the annual regression slopes to remove and normalize the effects of weather onto the daily peaks. We utilize the same variable ω in order to reintroduce the effects of weather historically for the past ten years to our forecasts. The simulation is composed of two normal distributions:

1. The first distribution predicts variability of weather between years. It is defined by the historical difference between ω for all extreme weather days over 10 years. It is used to predict one extreme weather day in the top 10% annually for the Monte Carlo simulation.
2. The second distribution predicts variability of weather within a year. It is defined by the historical variance of ω during any given year. It is used to predict the remaining extreme weather days in the top 10% for that trial (i.e., year) of the Monte Carlo simulation.

The Monte Carlo simulation is run for 1000 trials (where each trial is a simulated load within the top 10% for that year). Each trial is then utilized with the historical variance around a normal distribution function to simulate other peaks in the given year. Figure 10 shows an example histogram of the difference between the daily simulate WTHI and biweekly average.

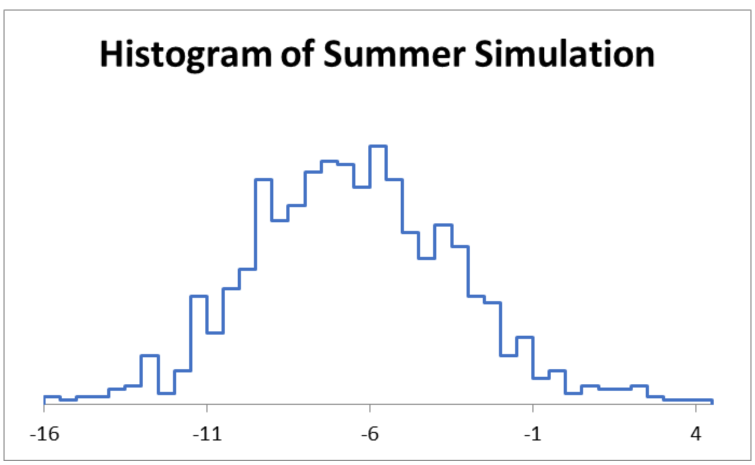


Figure 10: MC Simulation Histogram for Summer

An assumption is made that the lowest difference (summer) and highest difference (winter) are where the peaks occur. We take the minimum (summer) or maximum (winter) of these simulated ω values. For example, the minimum or highest negative summer value is multiplied by the summer slope and subtracted by the weather-normalized peak. This adds the value to the weather-normalized peak to create the P10, P50, and P90 forecasts. The highest winter value is multiplied by the negative slope and then subtracted; thus, incorporating the value to the weather-normalized peak for winter. The minimum and maximum values are taken to represent the highest weather effects of a given simulated year to create the peaks. The 90th, 50th and 10th percentile values of these results are then taken to produce the P10, P50, and P90 forecasts, respectively.

Figure 11 maps out the second and final stage of the Monte Carlo process to simulate the variability of weather and its effect on peak load.

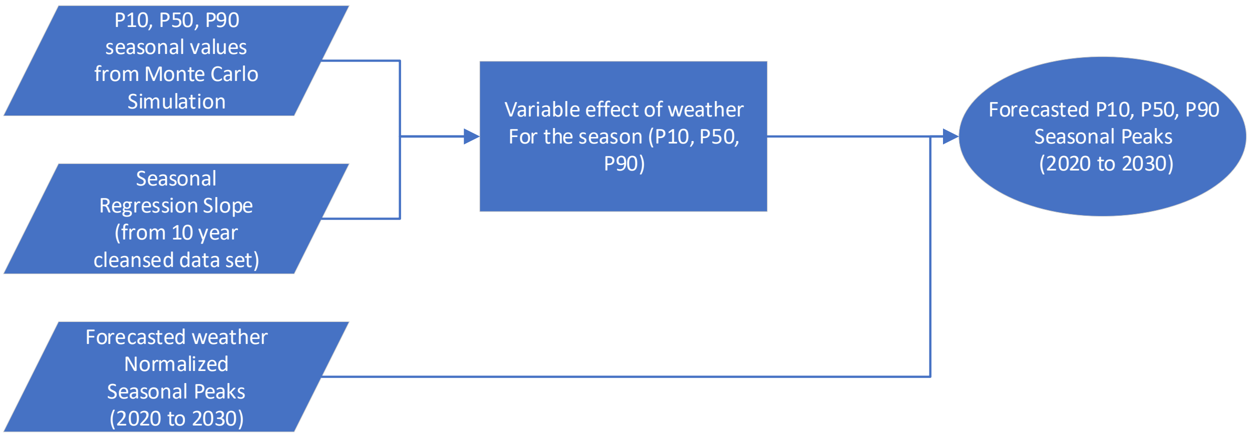


Figure 11: Monte Carlo Process Stage 2

With the regression slope from the ten-year weather historical peak dataset, we multiply the slope by the P10, P50, and P90 values from the new Monte Carlo results of ω. The weather-normalized loads are added with the product of the ten-year regression slope and Monte Carlo simulated P10, P50, P90 values to produce the P10, P50, P90 forecasted peak loads.

Equation 17: Forecasted P10, P50, P90 Peaks

$$FP_i = WNFP - m_{ten}(\ P_i\ )$$

where FP represents Forecasted Peak, $WNFP$ represents the Weather Normalized Forecasted Peak, m_{ten} represents the Regression Slope from 10-year data set, P represents the percentile of the simulated value from the Monte Carlo Simulation, and i represents the number of the percentile taken (in this case, 10, 50, 90).

For the engineering model, Equation 13, Equation 14, and Equation 15 and the forecasted P10, P50 and P90 peaks are used to create the P10, P50 and P90 station, transformer, and feeder peaks.

For the econometric model, the total weather effects of P10, P50, and P90 found in the Monte Carlo Simulation and analysis were added to the weather normalized system level forecast. As the econometric forecast was created on the system level, we added all the weather effects of each region to create weather's effect on the system. This effect was then added to the weather normalized forecast to create the P10, P50 and P90 forecasted econometric system level peaks.

2.6.2 Monte Carlo Simulation for Port Hope and Gravenhurst

The regression results produced for Port Hope and Gravenhurst (Table 4) demonstrate that weather does not hold a strong relation to load for these two regions. In addition, both regions historically have peaked in the winter. Furthermore, analysis of historical metering indicates that Port Hope and Gravenhurst peaks vary significantly year over year. As weather did not hold a strong relationship to load in the two regions, we decided to target the variability in peak megawatts per customer between years as the primary source of uncertainty. Figure 12 illustrates the process to simulate uncertainty in peak load for these regions.

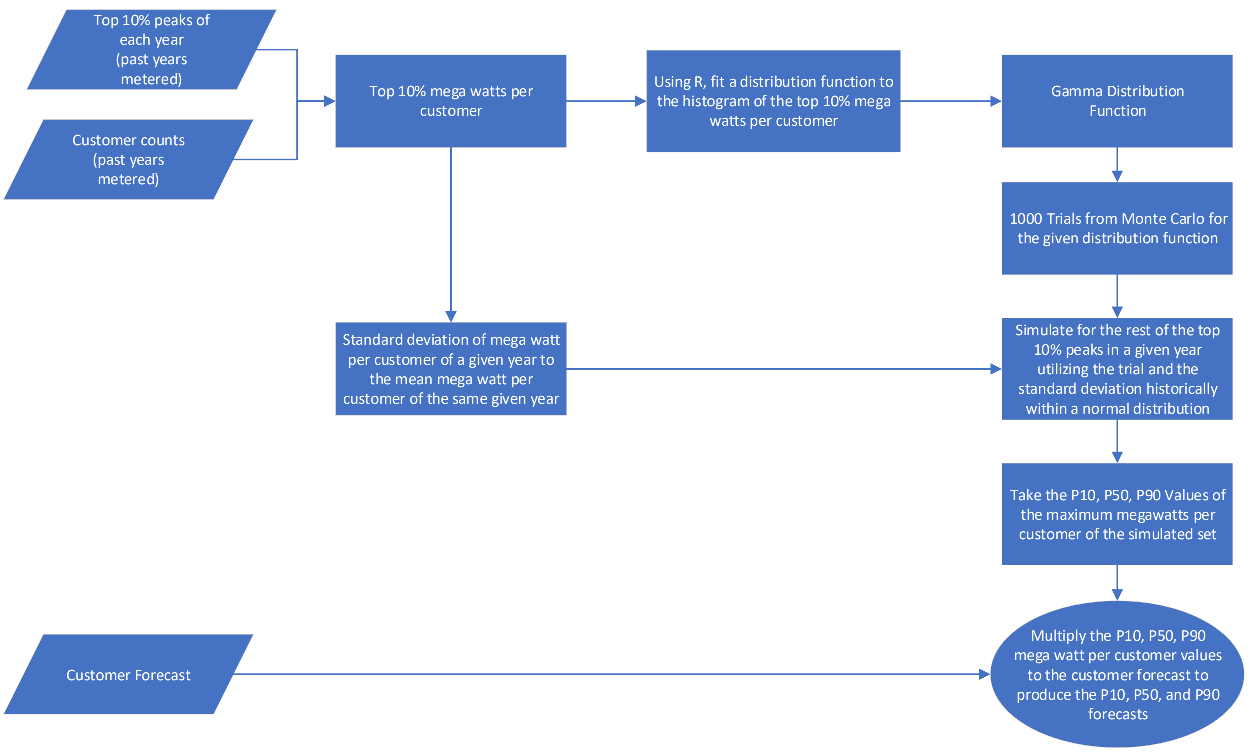


Figure 12: Monte Carlo Process for Gravenhurst and Port Hope

We took the top 10% daily loads of each year historically and divided them by the customer count of the peak's month. This exercise produces a historical dataset of the peak megawatts per customer for the region. The historical datasets were found not to follow a normal distribution, as the largest peak megawatt per customer results were located on the far-right tail of the plotted histogram. Thus, we utilized R, a statistical computing software, to fit a probability distribution to the two sets. A gamma distribution was found to be the most applicable in both regions.

In order to simulate for the variability of seasons, we calculate the mean of each given year's peak megawatts per customer values. The historical megawatts per customer for each year was then divided by the mean of its associated year to give us the percentage difference. The standard deviation of this relationship was taken. This step is taken to simulate for the variability of other peak megawatts per customer values in the same year. An assumption is made that peaks within a year will fall within a typical standard deviation from the mean of the year.

1. Monte Carlo was performed on the gamma distribution of the region for 1000 trials. Each trial represents a given year. Figure 13 shows an example histogram of the results depicting the modelled variability of peak megawatts per customer.
2. The standard deviation to megawatts per customer and the mean megawatts per customer historically was identified. The first trial from our gamma distribution is taken alongside the standard deviation within a normal distribution. This produces the other peaks within the given year.
3. The maximum result of each year is taken as a set. We extract the P10, P50, and P90 values from the set and multiply it to the customer forecast to produce the P10, P50 and P90 forecasted peaks.

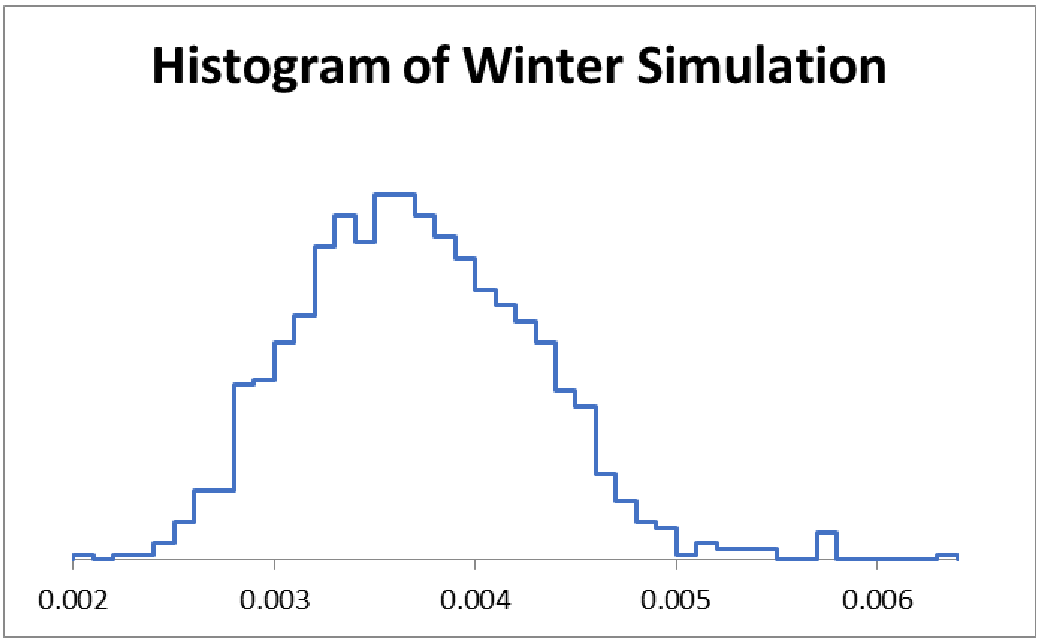


Figure 13: MC Simulation - Winter Histogram - Gamma Distribution for Gravenhurst

Equation 18: Forecasted P10, P50, P90 Peaks for Port Hope and Gravenhurst

$$FP_i = CF * P_i$$

where FP represents Forecasted Peak, CF represents the Customer Forecast, P represents the percentile of the simulated value from the Monte Carlo Simulation, and i represents the number of the percentile taken (in this case, 10, 50, 90). Similarly, for the engineering model, we use this forecasted peak and Equation 13, Equation 14, Equation 15 to model the P10, P50 and P90 peaks on the stations, transformers and feeder level.

As noted in Section 2.6.1, weather was added together to create the weather effect of the whole system for the econometric model. However, we were not able to run any Monte Carlo simulation for the variability of peak load per customer for Port Hope and Gravenhurst with the econometric model. This difference is noted when we compare the engineering and econometric model results with one another at the system level.

3. Model Results

For each region of the service area, METSCO's engineering model results are provided for the stations in the area. The P10, P50, and P90 peak load values are forecasted with the associated seasonal coincident peak for the service area. The highest annual recorded peak of the region is plotted for the historical years from 2015 to 2019. The forecasted P10, P50, P90, and weather-normalized peaks are plotted from 2020 to 2030. The station forecast assumes even distribution of load growth, but planners can utilize the engineering model to assign the forecast customer additions to specific stations. The station forecasts are based on the P10 results of the associated seasonal peak to the service area. Finally, the forecasted regional coincident peaks are added together to create the non-coincident peak of the whole Elexicon service territory.

Econometric model results are shown at the Elexicon system level. The historical coincident summer peaks are provided for the years 2015 to 2019. For the areas of Gravenhurst and Port Hope, the historical coincident winter peaks are provided for the years 2015 to 2019. For Ajax-Pickering, Belleville, Whitby, Brock and Clarington, the forecasted P10, P50, P90, and weather-normalized coincident summer peaks are provided for years 2020 to 2030. Forecasted P10, P50, and P90 coincident winter peaks are provided for years 2020 to 2030 for Gravenhurst and Port Hope.

3.1 Regional and Station-Level Forecast (Engineering)

3.1.1 Ajax-Pickering

The Ajax-Pickering region is a distinct part of Elexicon's service area since switching and other changes in the power system are dynamic between the two municipalities. Both areas are expected to experience higher development than elsewhere in Durham, with Pickering expecting the most growth. This high growth is a result of the high development in Seaton and other concentrated areas of load growth in the city centre , South Pickering and Duffin Heights. A high portion of forecasted load growth in the Elexicon service area will be from the Ajax-Pickering territory.

The projected growth in the Ajax-Pickering region is noted in two biannual forecasts from the Region of Durham, specifically for the Town of Ajax and the City of Pickering. In addition, the City of Pickering produces its own twenty-year report anticipating the major growth coming into the region.

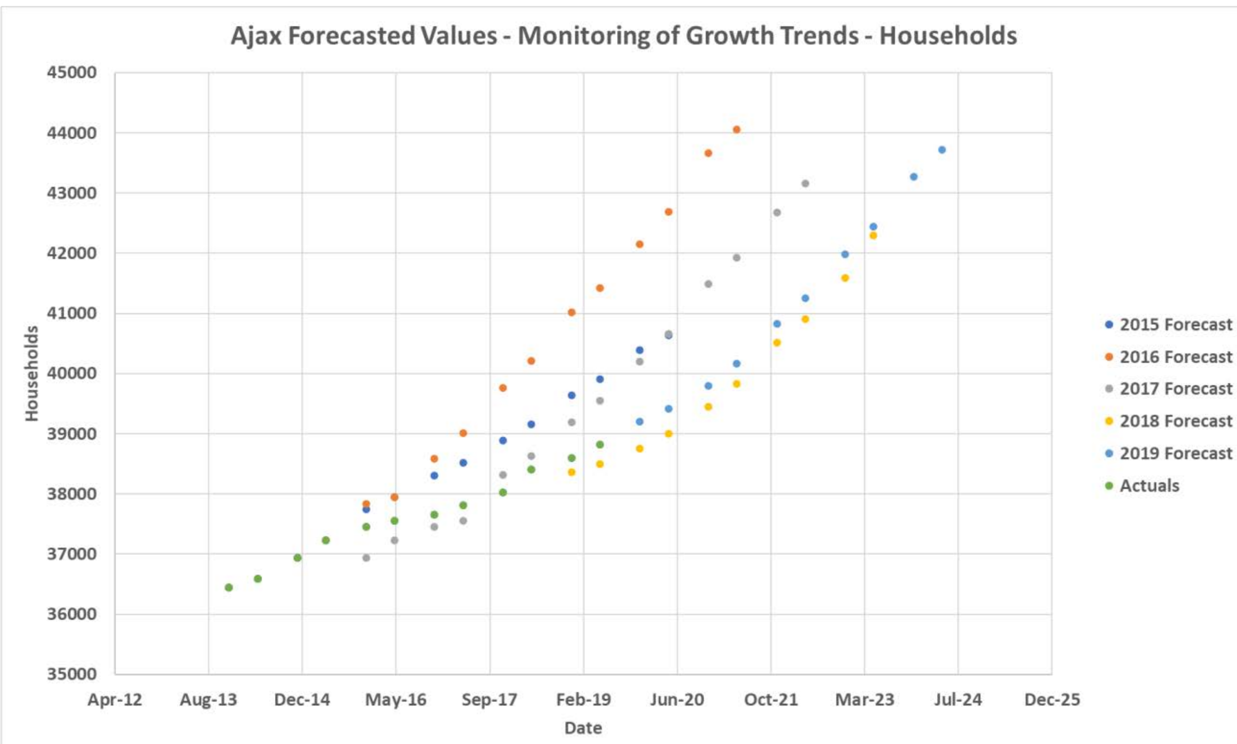


Figure 14: Ajax Historical and Forecasted Household Growth

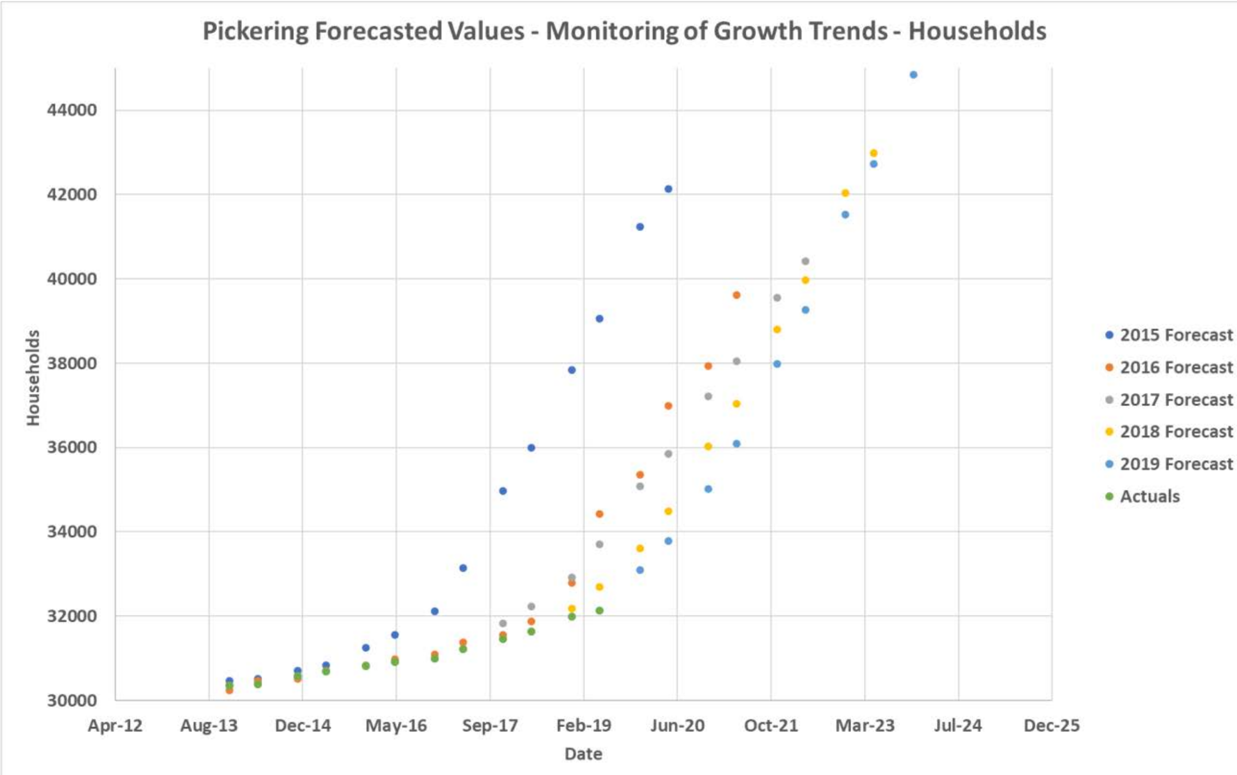


Figure 15: Pickering Historical and Forecasted Household Growth

When comparing previous municipal household forecasts against historical actuals, it is evident that the City of Pickering has overestimated the volume of household completions in 2015. The years 2016 to 2019 track more closely to the actual values. Due to the significant outlier in accuracy (year 2015), we remove the overprediction year and only use the results for the accuracy of forecasts from 2016 to 2018. In addition, the City of Pickering has predicted major growth consistently for the past five forecasts which highlights the municipalities expectations of household growth in the area. Much of the household growth in the area is driven by the new Seaton neighbourhood development.

Ajax has also historically overestimated for household completions for the years from 2015 to 2017. However, the 2018 forecast for Ajax predicted a lower household total as compared to the actual value. We apply the trend to the historical average accuracy to both Ajax and Pickering's household forecasts, as shown in Figure 16.

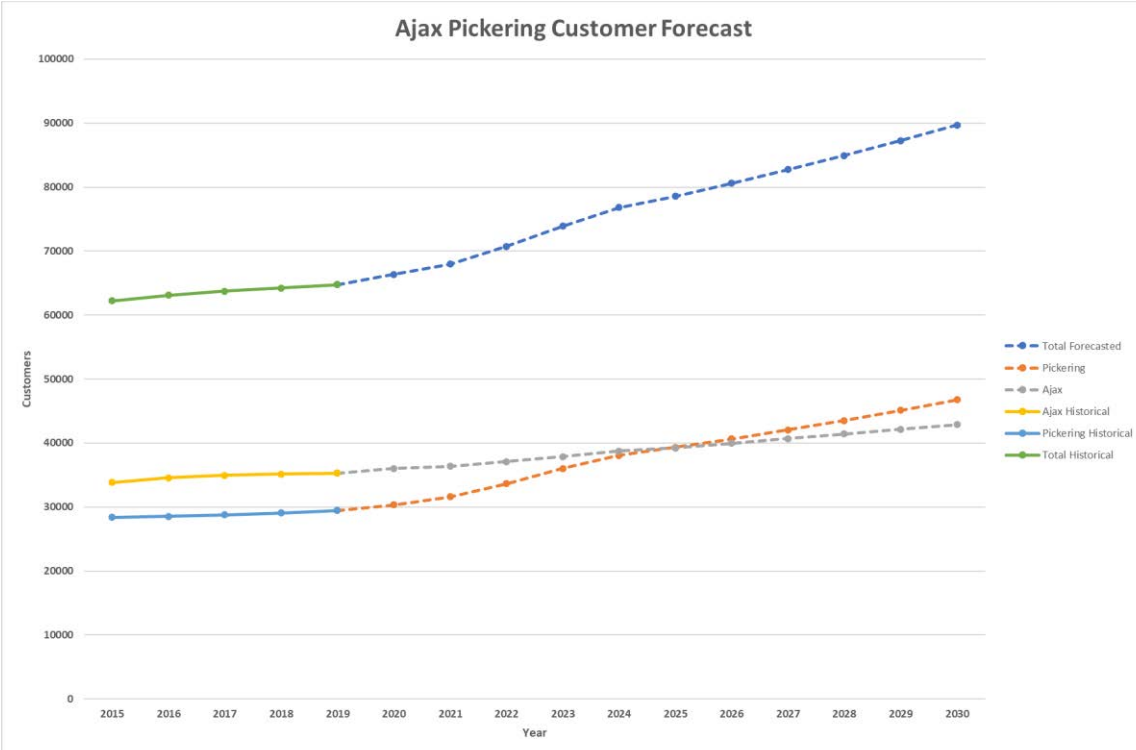


Figure 16: Ajax Pickering Customer Forecast

The adjusted household additions from 2024 to 2030 are linearly extrapolated. The average percentage of household growth for the forecasted four years is applied onto the household additions moving forward to 2030 for Ajax. The annual average unit growth rate from the twenty-year City of Pickering report [2] is applied to the forecasted household additions from 2024 to 2030. Applying the adjustment factor to the household forecast and the customer-to-household ratio produces the customer forecast for Ajax-Pickering in Figure 16. Historical customer additions suggest that both regions have consistently increased in growth year over year without any major jump in growth. However, the customer forecast shows that both regions will have a much higher increase in customer additions than historically. This is representative of the major housing developments in Ajax and Pickering. Pickering will experience significant growth in the next four years due to the new Seaton development. Ajax is forecasted to have consistent customer growth in the next four years that is higher than the past five years of customer additions.

Table 5: Ajax-Pickering Forecasted Total Customers – Summer

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ajax Customers (Summer)	36,192	36,722	37,470	38,318	38,989	39,614	40,326	41,048	41,780	42,522	43,274
Pickering Customers (Summer)	30,932	32,605	34,867	37,104	38,703	39,988	41,349	42,792	44,321	45,942	47,661
Total (Summer)	67,123	69,327	72,337	75,422	77,692	79,601	81,675	83,840	86,102	88,465	90,935

The resultant load forecast is shown in Figure 17**.** Major developments within the area (i.e., Seaton) will bring new customers to Elexicon and will drive the load growth in the Ajax-Pickering region. In total, 39.43 MW of load growth is forecasted for the Ajax Pickering region from 2020 to 2024.

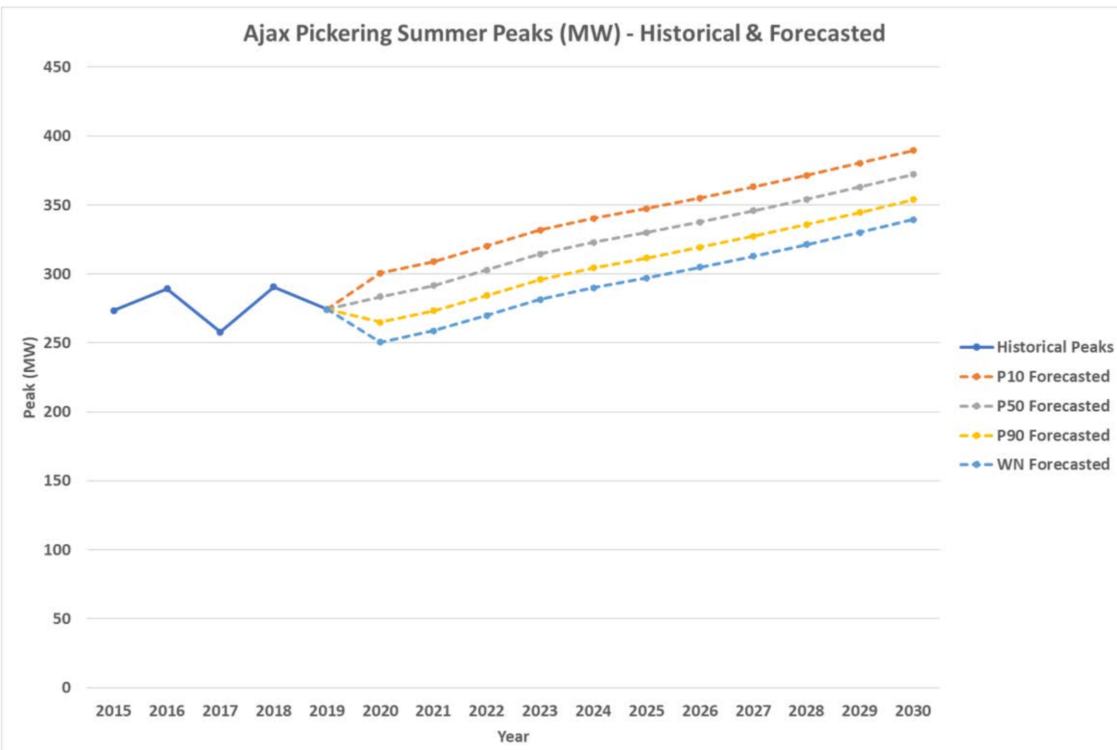


Figure 17: Ajax Pickering Forecasted Summer Peaks (MW)

Table 6: Ajax-Pickering Forecasted Summer Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	300.72	308.94	320.17	331.68	340.15	347.28	355.02	363.09	371.53	380.35	389.57
P50	283.35	291.57	302.80	314.31	322.78	329.91	337.64	345.72	354.16	362.98	372.20
P90	264.95	273.18	284.41	295.92	304.39	311.51	319.25	327.33	335.77	344.59	353.81
WN	250.47	258.69	269.92	281.43	289.90	297.03	304.76	312.84	321.28	330.10	339.32

Assuming evenly distributed growth on stations in the Ajax-Pickering region, Table 7 is a generalized forecast from the region to the station level. Assumptions from the past average historical coincidence factors and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the substation level. Planners can assign customer additions based on percentages and create scenarios from the forecast for specific locations.

Table 7: Ajax Pickering - Evenly Distributed P10 Forecasted Summer Station Peaks

Station	S2020	S2021	S2022	S2023	S2024	S2025	S2026	S2027	S2028	S2029	S2030
DOWT	11.94	12.44	13.12	13.82	14.33	14.76	15.22	15.71	16.21	16.74	17.29
PICB	26.18	26.61	27.19	27.80	28.25	28.63	29.04	29.48	29.93	30.41	30.91
MONA	16.90	17.38	18.03	18.69	19.18	19.60	20.04	20.51	21.00	21.51	22.04
NOTI	15.35	15.83	16.49	17.17	17.67	18.08	18.54	19.01	19.50	20.02	20.55
WESH	19.99	20.45	21.07	21.72	22.20	22.60	23.03	23.49	23.97	24.46	24.99
APPL	19.07	19.53	20.16	20.82	21.30	21.70	22.14	22.60	23.08	23.58	24.11
BAYR	11.24	11.74	12.43	13.13	13.65	14.08	14.54	15.03	15.54	16.07	16.62
FAIR	16.38	16.86	17.51	18.18	18.68	19.09	19.54	20.01	20.50	21.01	21.54
SAND	21.16	21.61	22.23	22.87	23.34	23.74	24.17	24.62	25.10	25.59	26.11
TOWN	15.25	15.74	16.40	17.07	17.57	17.99	18.44	18.91	19.40	19.92	20.46
SQUIRE	17.03	17.51	18.16	18.82	19.31	19.72	20.17	20.64	21.12	21.63	22.16

3.1.2 Whitby

The Whitby area is expecting consistent growth of households moving forward. Areas of high household development include Brooklin, West Whitby, and Port Whitby. The forecasted households and actual households are shown in Figure 18.

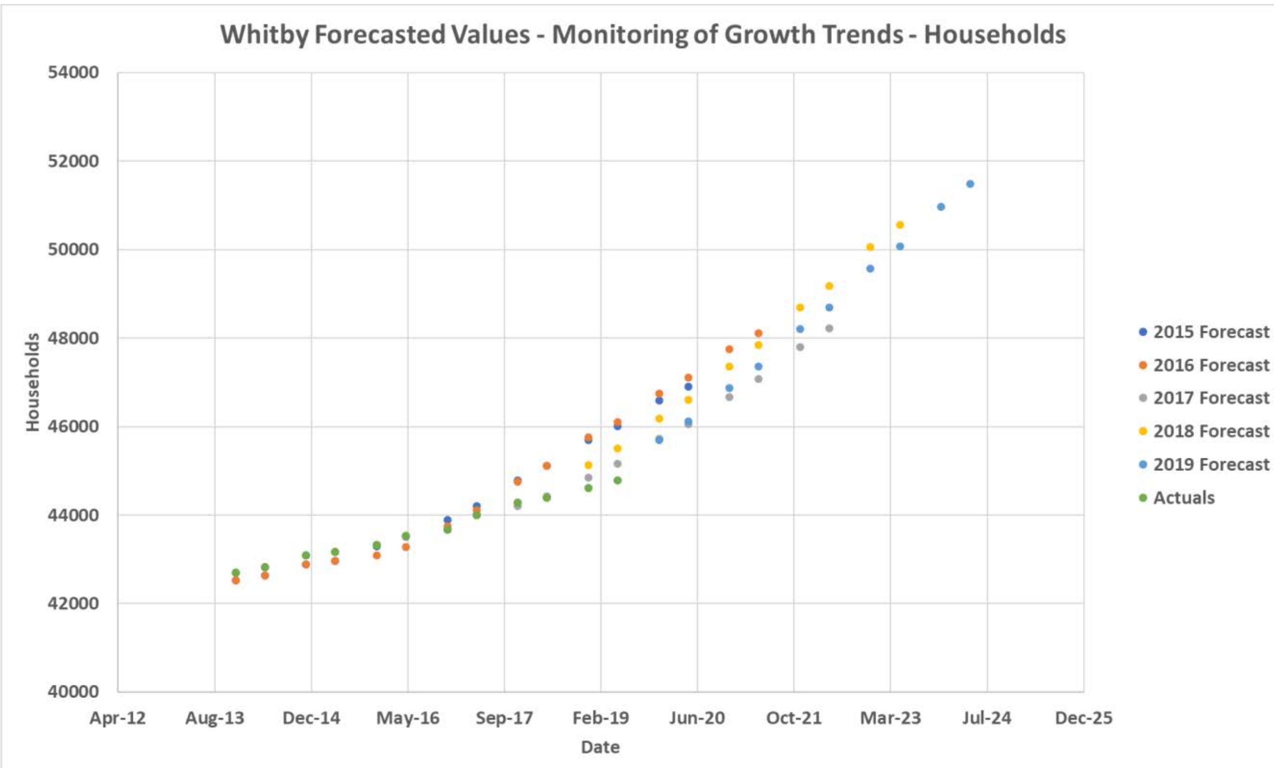


Figure 18: Whitby Forecasted and Historical Households

As seen in the forecasted values over the past five years, there is an expected consistent slope and growth of households. The shape of the forecasted values is quite similar upon visual inspection over the past five years. Upon further inspection, it can be noted that the Town of Whitby has historically overpredicted residential growth. We use the data presented in the municipal household forecasts to adjust for a historical accuracy going forward by creating an adjustment factor. The purpose of this analysis is to evaluate how the Town of Whitby's forecasts have performed when they were initially forecasted and the actual households of the forecasted year.

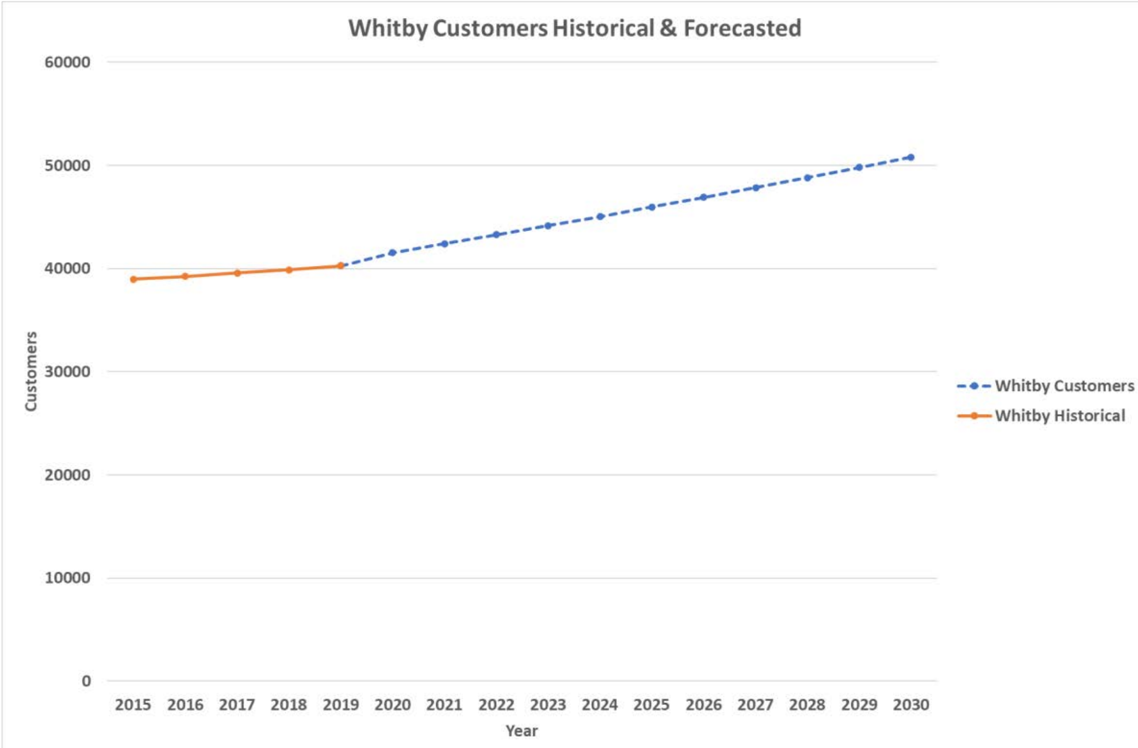


Figure 19: Whitby Customer Forecast

The adjusted household additions from Whitby are linearly extrapolated from 2024 to 2030. The average growth rate of the Whitby forecast is then applied onto the household additions moving forward. The forecasted households are converted to the customer additions from 2024 to 2030. After applying the adjustment factor on the municipal household forecast and the historical customer to household ratio to the new household forecast, the results in Figure 19 are produced. The new customer forecast expects consistent growth in the next four year. It is evident that forecasted customer additions for the first four years are higher than the historical customer additions over the past five years. The increased customer growth is representative of the increase in housing developments within Whitby.

Table 8: Whitby Forecasted Total Customers - Summer

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Whitby Customers (Summer)	41,226	42,040	42,913	43,792	44,680	45,586	46,510	47,452	48,413	49,392	50,391

The finalized load forecast results are shown in Figure 20. In total, 13.97 MW of load growth is forecasted in the Whitby region from 2020 to 2024. Most of the growth is driven from developments in the areas of West Whitby, Port Whitby, and Brooklin.

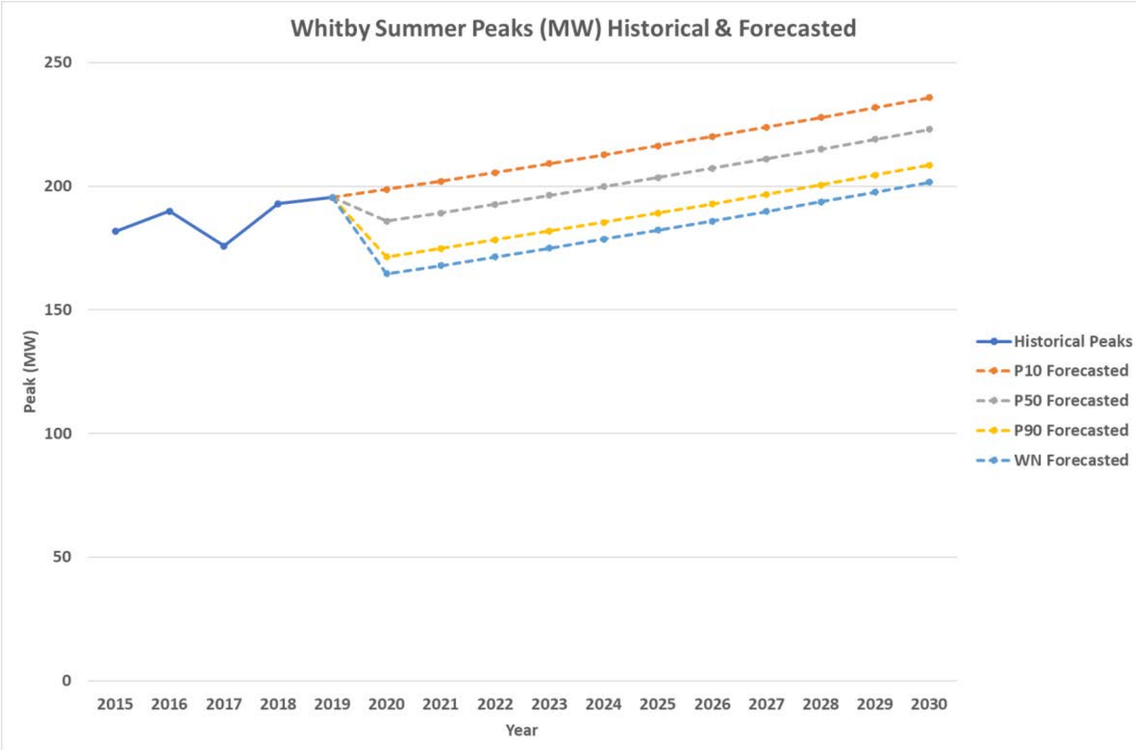


Figure 20: Whitby Forecasted Summer Peaks (MW)

Table 9: Whitby Forecasted Summer Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	198.72	202.01	205.54	209.09	212.69	216.35	220.08	223.89	227.78	231.74	235.77
P50	185.90	189.19	192.72	196.27	199.86	203.53	207.26	211.07	214.95	218.91	222.95
P90	171.46	174.75	178.28	181.83	185.43	189.09	192.82	196.63	200.52	204.48	208.51
WN	164.55	167.84	171.37	174.93	178.52	182.18	185.91	189.72	193.61	197.57	201.60

Assuming evenly distributed growth in Whitby, Table 10 presents a generalized forecast from the region to the station level. Assumptions from the past average historical coincidence factors, and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the substation level. Planners can assign customer percentages based on knowledge.

Table 10: Whitby - Evenly Distributed P10 Forecasted Summer Station Peaks

Station	S2020	S2021	S2022	S2023	S2024	S2025	S2026	S2027	S2028	S2029	S2030
MS5	12.09	12.30	12.53	12.76	12.99	13.22	13.46	13.71	13.95	14.21	14.47
MS6	16.01	16.21	16.42	16.64	16.85	17.08	17.30	17.53	17.77	18.01	18.26
MS7	15.05	15.25	15.47	15.68	15.91	16.13	16.36	16.60	16.84	17.08	17.33
MS8	11.82	12.03	12.26	12.49	12.72	12.96	13.20	13.44	13.69	13.94	14.20
MS9	10.52	10.74	10.97	11.20	11.44	11.68	11.92	12.17	12.42	12.68	12.94
MS10 T1	13.19	13.39	13.62	13.84	14.07	14.30	14.54	14.78	15.02	15.27	15.53
MS10 T2	13.36	13.57	13.79	14.01	14.24	14.47	14.70	14.94	15.19	15.44	15.69
MS11	22.00	22.18	22.37	22.57	22.76	22.97	23.17	23.39	23.61	23.83	24.06
MS12	7.20	7.43	7.67	7.91	8.16	8.41	8.66	8.92	9.19	9.45	9.73
MS13	7.03	7.26	7.50	7.75	7.99	8.24	8.50	8.76	9.02	9.29	9.56
MS14	11.07	11.28	11.51	11.74	11.98	12.22	12.46	12.71	12.96	13.21	13.48
MS15	12.34	12.55	12.78	13.00	13.23	13.47	13.71	13.95	14.20	14.45	14.71

3.1.3 Belleville

Belleville does not produce a biannual forecast like the Durham municipalities under Elexicon. Instead, Belleville enlists an external consultant who forecasts municipal households in five-year increments. We assume linear interpolation between the forecasted years in order to produce the annual household numbers between the five-year forecasts, as shown in Figure 21. Due to the non-existence of past forecasts, there is no adjustment factor that can be applied to the forecast. The new household additions are converted to customer additions based on the historical household to customer ratio

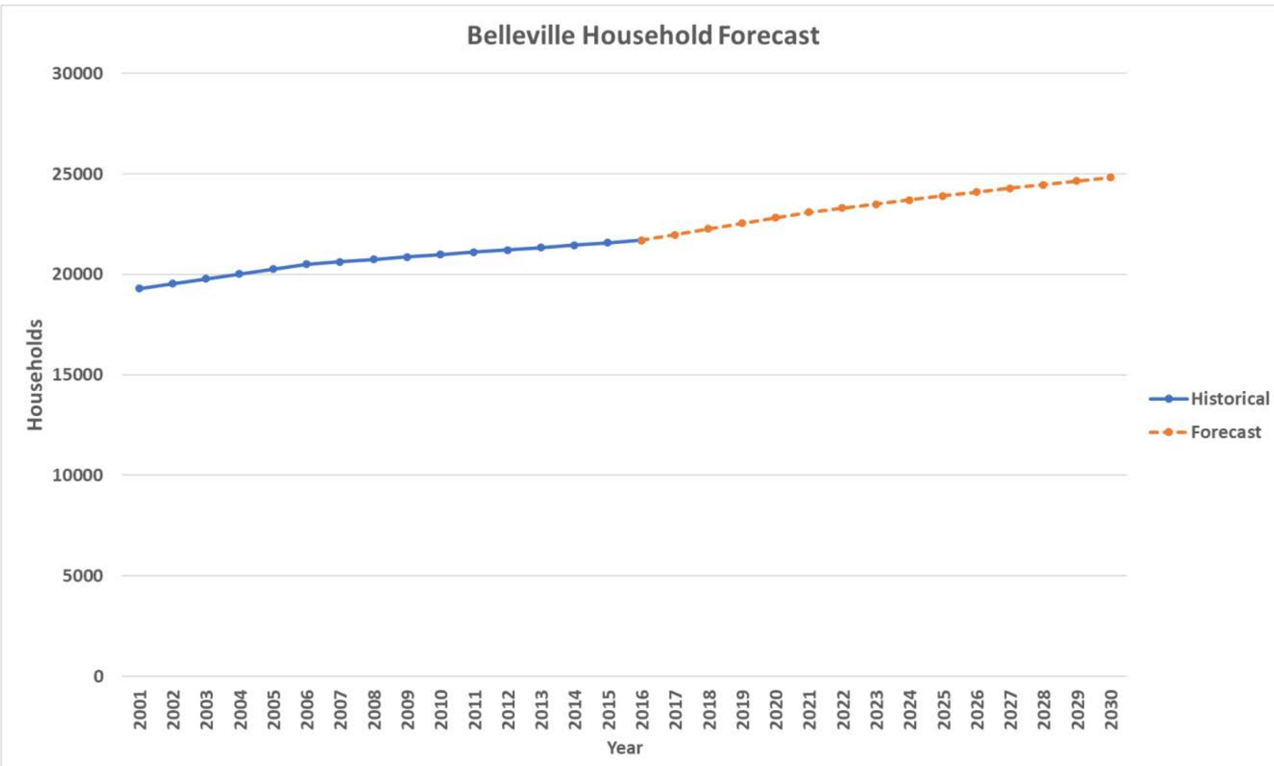


Figure 21: Belleville Forecasted & Historical Households

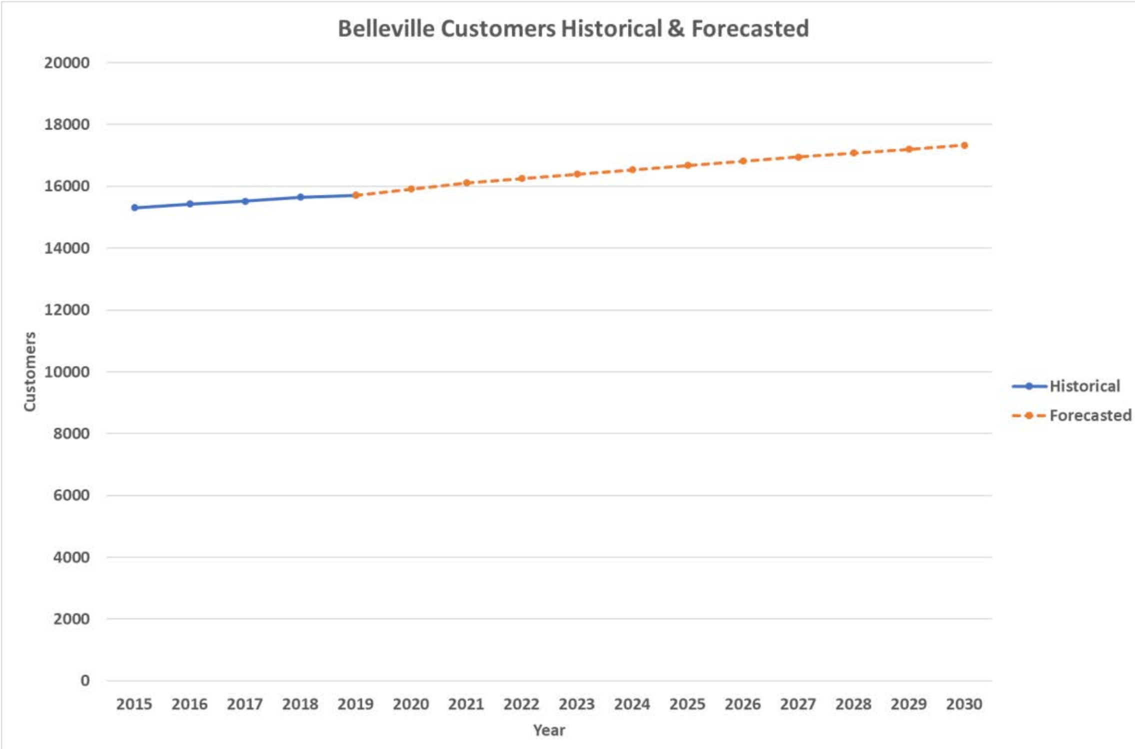


Figure 22: Belleville Customer Forecast

After converting the household forecast into a customer forecast with the historical customer to household ratio, we produce the customer forecast in Figure 22. The newly produced customer forecast is similar in shape to the historical customer additions and historical customer counts annually. Belleville's forecast of consistent household growth is reflected upon the customer forecast moving forward. No major housing developments, which would bring a larger than normal increase in residential customers, is expected as shown in the customer forecast.

Table 11: Belleville Forecasted Total Customers - Summer

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Belleville Customers (Summer)	15831	16029	16194	16336	16477	16619	16761	16894	17022	17149	17277

The resultant load forecast results are shown in Figure 23. In total, 3.77 MW of load growth is forecasted in Belleville from 2020 to 2024.

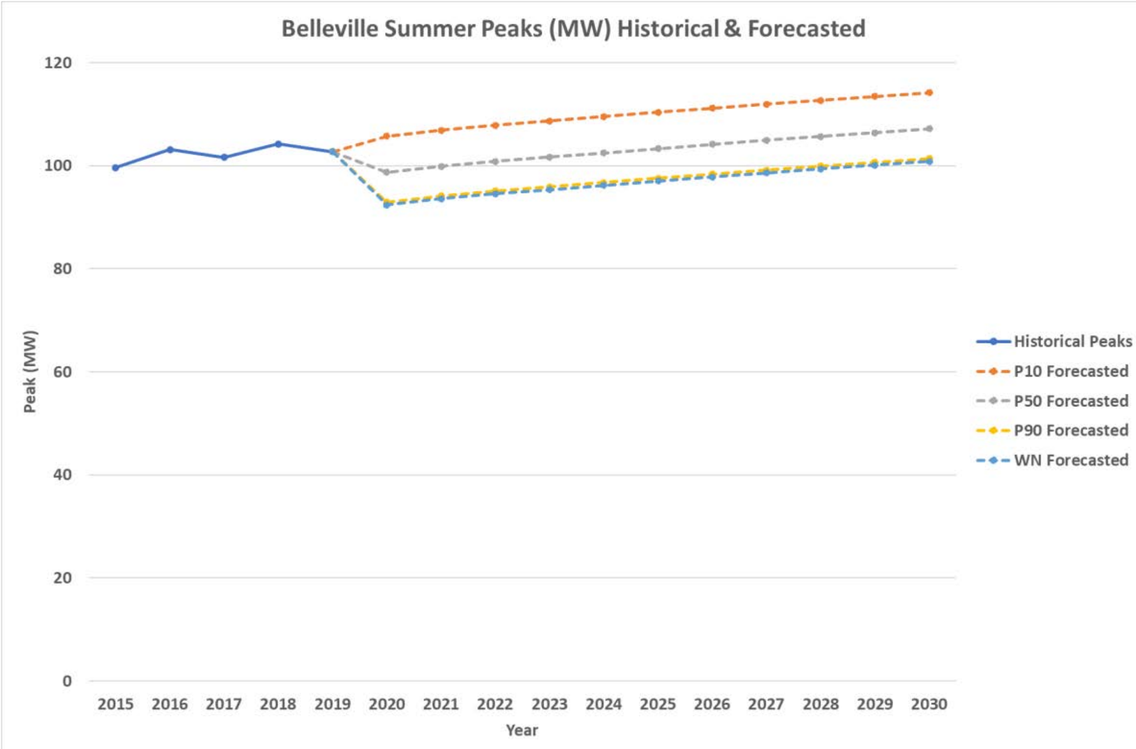


Figure 23: Belleville Forecasted Summer Peaks (MW)

Table 12: Belleville Forecasted Summer Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	105.76	106.91	107.88	108.71	109.53	110.36	111.19	111.96	112.71	113.45	114.20
P50	98.73	99.89	100.85	101.68	102.50	103.33	104.16	104.94	105.68	106.43	107.17
P90	92.97	94.12	95.09	95.92	96.74	97.57	98.40	99.18	99.92	100.66	101.41
WN	92.42	93.58	94.54	95.37	96.20	97.02	97.85	98.63	99.37	100.12	100.86

Assuming evenly distributed growth in Belleville, Table 13 presents a generalized forecast from the region to the station level. Assumptions from the past average historical coincidence factors, and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the substation level. Planners can assign a percentage of the total customer additions based on knowledge.

Table 13: Belleville - Evenly Distributed P10 Forecasted Summer Station Peaks

Station	S2020	S2021	S2022	S2023	S2024	S2025	S2026	S2027	S2028	S2029	S2030
EDGE	10.99	11.06	11.12	11.17	11.23	11.28	11.33	11.38	11.42	11.47	11.52
SIDN	11.02	11.09	11.15	11.20	11.25	11.30	11.35	11.40	11.45	11.49	11.54
REID	10.85	10.92	10.98	11.03	11.09	11.14	11.19	11.24	11.28	11.33	11.38
BELL	14.19	14.25	14.31	14.35	14.40	14.45	14.50	14.54	14.59	14.63	14.68
CHUR	2.61	2.70	2.77	2.83	2.89	2.95	3.01	3.06	3.12	3.17	3.22
HERC	4.03	4.11	4.18	4.24	4.30	4.36	4.41	4.47	4.52	4.57	4.63
CASC	4.02	4.10	4.17	4.23	4.29	4.34	4.40	4.46	4.51	4.56	4.62
JONE	3.92	4.01	4.07	4.13	4.19	4.25	4.31	4.36	4.42	4.47	4.52
RIVR	2.09	2.17	2.24	2.30	2.37	2.43	2.49	2.54	2.60	2.65	2.71

3.1.4 Clarington

Elexicon's service area for the Clarington region includes the municipalities of Bowmanville, Newcastle, and Orono. The Region of Durham produces a biannual household forecast for Clarington which is used as an input for the load forecast model.

As can be seen in the municipal forecast in Figure 24, it is expected that the number of households in Clarington will grow consistently for the next four years. Judging from past forecasts to actuals, Clarington as a region has consistently forecasted values that follow similar household growth. Across the four forecasts from 2015 to 2018, we notice that Clarington has over-predicted total households within the region. We linearly extrapolate the adjusted household forecast from 2024 to 2030. The average growth rate from the historical Clarington forecast is then applied onto the household additions moving into the future.

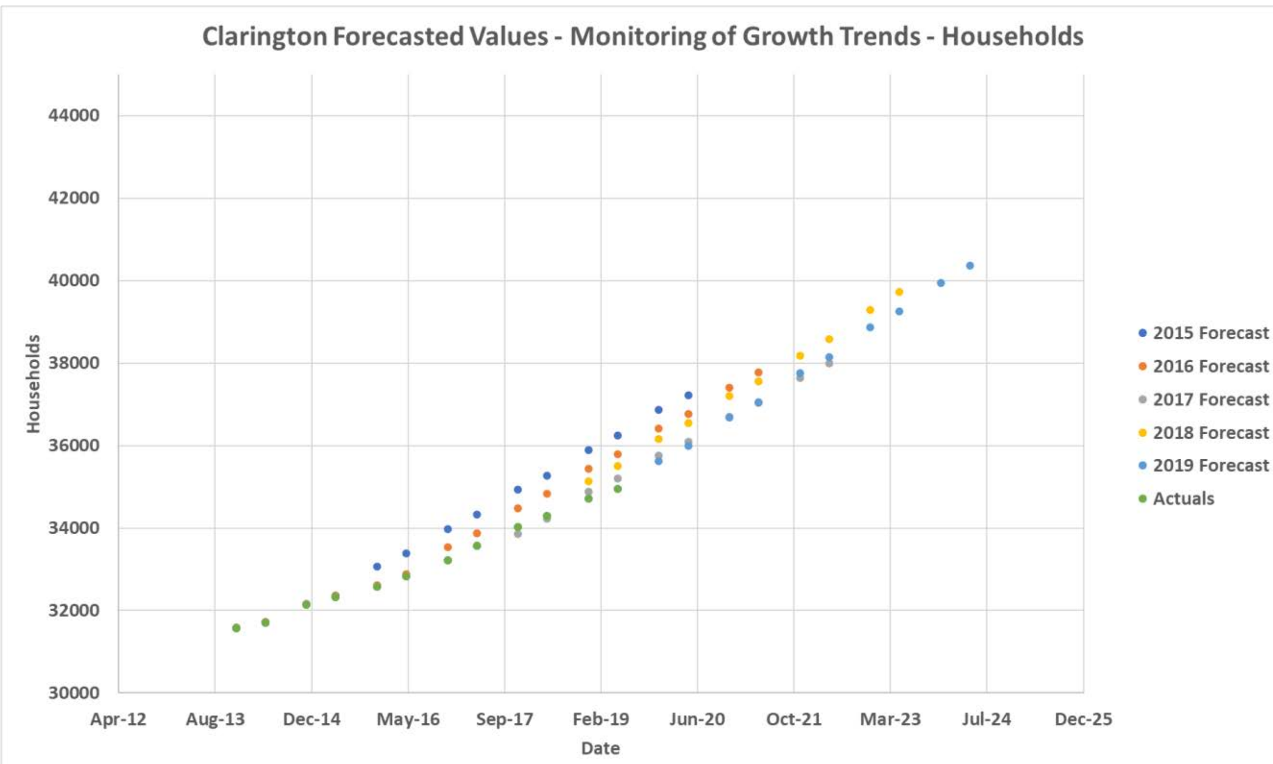


Figure 24: Clarington Forecasted and Historical Households

After applying the historical adjustment factor to the present household forecast and using the historical customer to household ratio, the customer forecast for Clarington in Figure 25 is produced. The new forecasted customer growth follows closely to the historical customer additions and total customer counts. The customer forecast suggests that the housing developments in Clarington will not produce any major increase in customer additions.

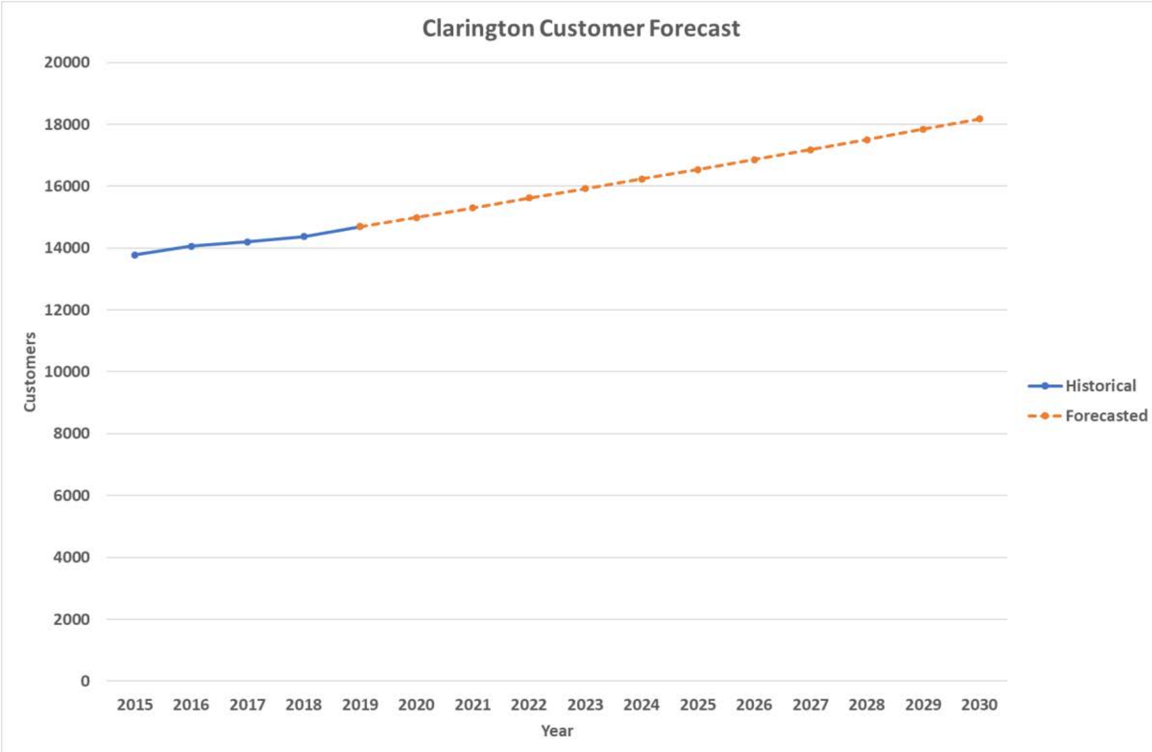


Figure 25: Clarington Customer Forecast

Table 14: Clarington Forecasted Total Customers - Summer

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Clarington Customers (Summer)	14,981	15,295	15,614	15,925	16,229	16,539	16,855	17,177	17504	17838	18179

The finalized load forecast results are shown in Figure 26 where 3.64 MW of load growth is forecasted in Clarington from 2020 to 2024.

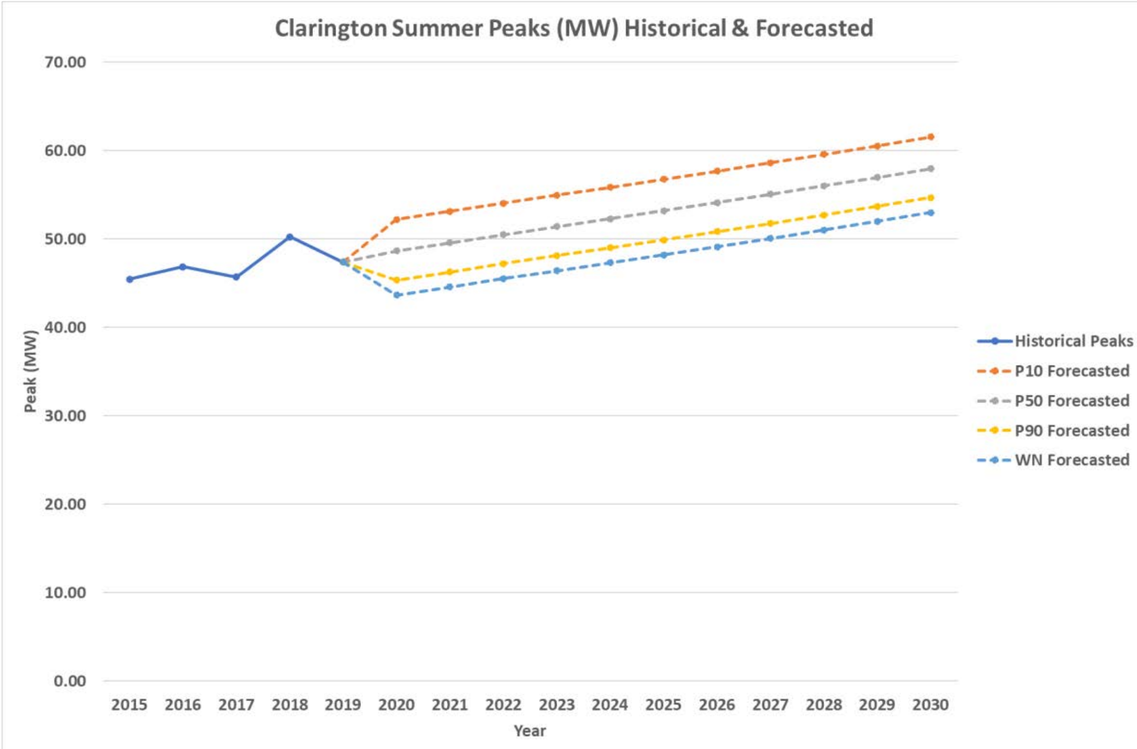


Figure 26: Clarington Forecasted Summer Peaks

Table 15: Clarington Forecasted Summer Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	52.22	53.14	54.07	54.98	55.86	56.77	57.69	58.63	59.58	60.56	61.55
P50	48.66	49.58	50.51	51.42	52.30	53.21	54.13	55.07	56.02	56.99	57.99
P90	45.38	46.29	47.22	48.13	49.02	49.92	50.84	51.78	52.74	53.71	54.70
WN	43.68	44.60	45.53	46.43	47.32	48.23	49.15	50.08	51.04	52.01	53.01

Assuming evenly distributed growth on stations in Clarington, Table 16 presents the generalized forecast from the region to the station level and not of where specific growth will be located. Assumptions from the past average historical coincidence factors, and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the substation level. Planners can assign customer additions based on percentages and create scenarios from the forecast for specific locations.

Table 16: Clarington - Evenly Distributed P10 Forecasted Summer Station Peaks

Station	S2020	S2021	S2022	S2023	S2024	S2025	S2026	S2027	S2028	S2029	S2030
TORO	8.38	8.56	8.75	8.93	9.11	9.29	9.48	9.66	9.86	10.05	10.25
WILM	2.42	2.63	2.83	3.03	3.23	3.42	3.63	3.83	4.04	4.25	4.46
SPRY	15.87	16.03	16.19	16.35	16.50	16.66	16.83	16.99	17.17	17.34	17.52
BRAD	10.64	10.81	10.99	11.17	11.34	11.51	11.69	11.87	12.06	12.25	12.44
LIBN	13.52	13.68	13.85	14.02	14.18	14.35	14.52	14.69	14.87	15.05	15.23

3.1.5 Brock (Brock, Uxbridge, Scugog)

The Brock region of Elexicon's service areas includes the Townships of Brock, Uxbridge, and Scugog. The three municipal household forecasts of Brock, Uxbridge, and Scugog are inputs to the engineering load forecast model. The following three figures represent the 2015 to 2019 household forecasts for the three regions. Brock as a region has historically underpredicted household forecasts. The results for the years 2015, 2016, and 2018 suggest an underprediction as they fall below the historical household estimates. For Scugog, all forecasts except for 2016 have overpredicted the annual household growth. Lastly, Uxbridge has consistently overpredicted household growth every year.

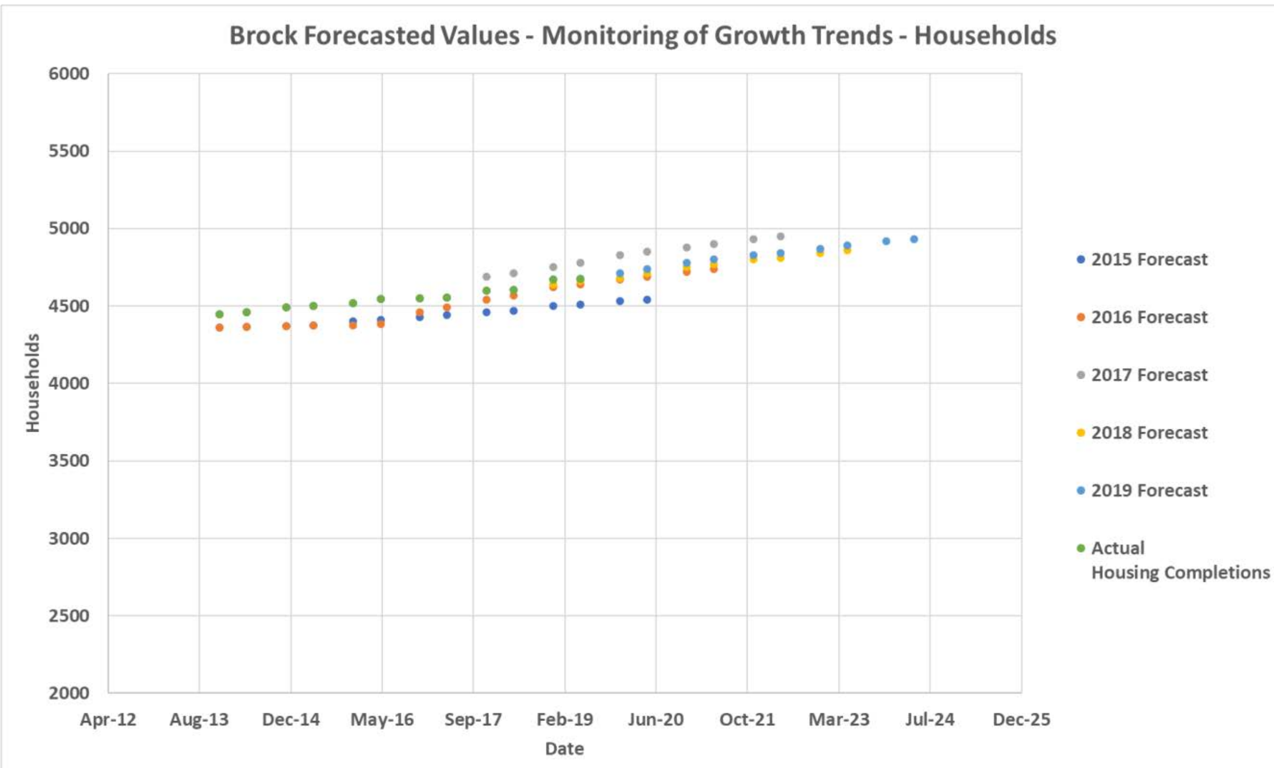


Figure 27: Brock Historical and Future Household Forecasts – Township of Brock

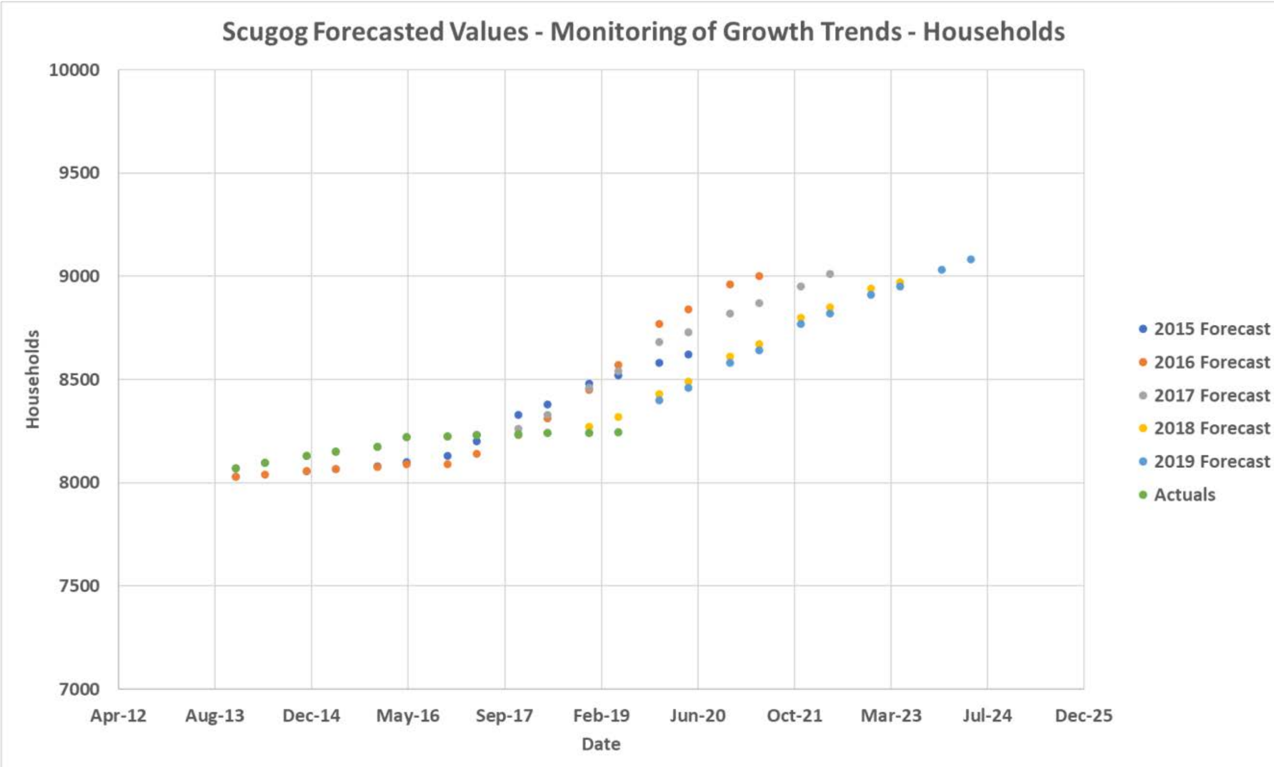


Figure 28: Brock Historical and Future Household Forecasts – Township of Scugog

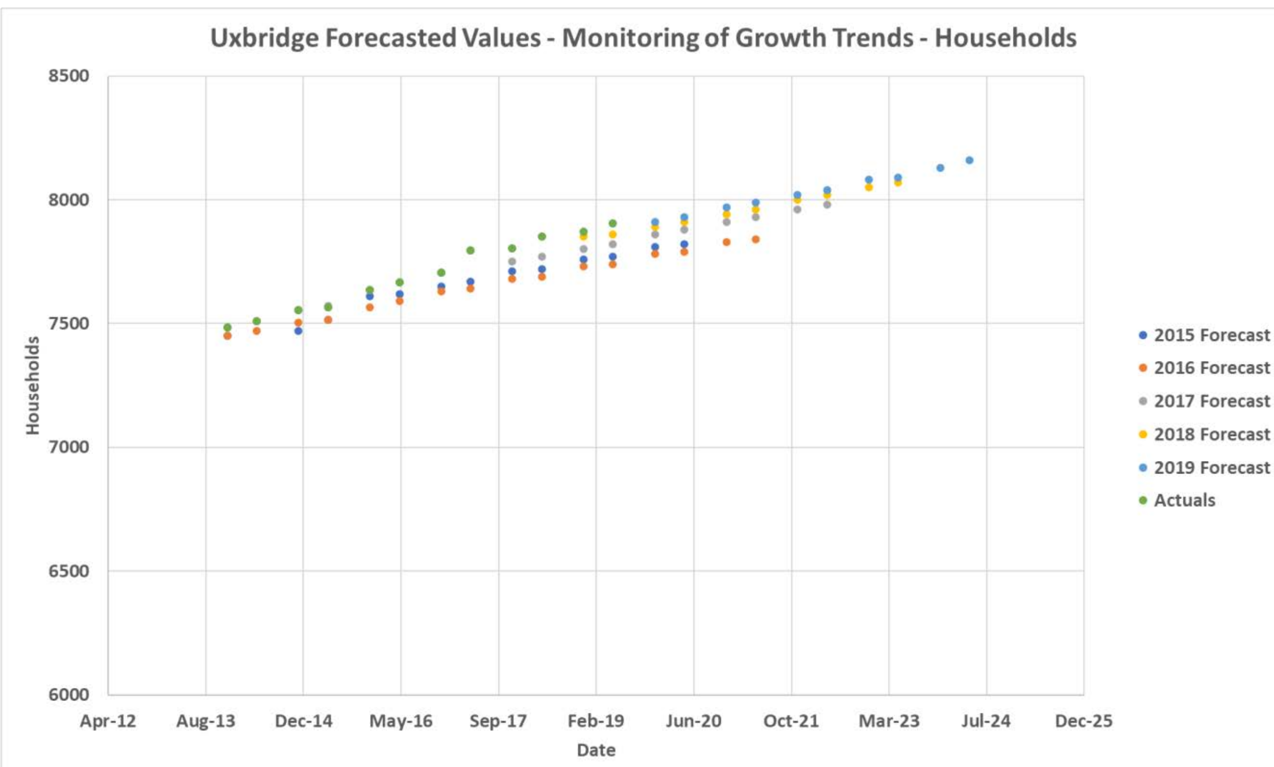


Figure 29: Brock Historical and Future Household Forecasts – Township of Uxbridge

We apply the adjustment factor and customer to household ratio to the household forecast to produce the customer forecast in Figure 30. Historical customer counts suggest that Scugog and Uxbridge have had minimal customer growth and even declines in customers whereas Brock has had larger customer growth.

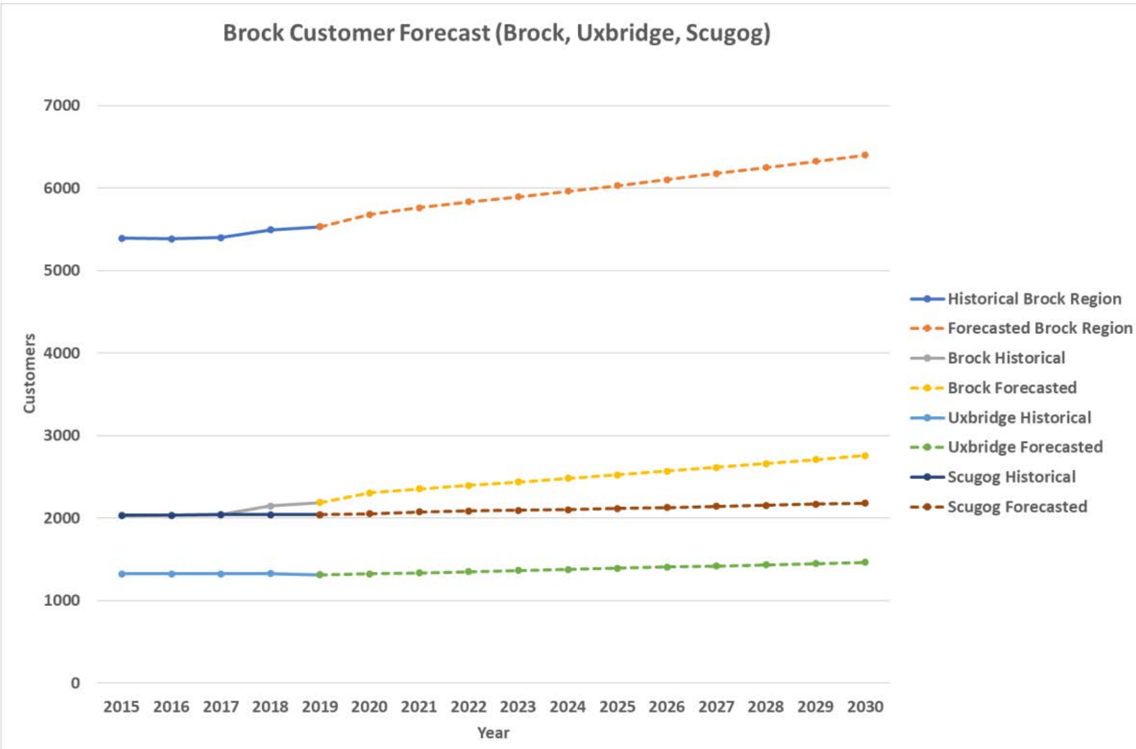


Figure 30: Brock Customer Forecast

Table 17: Brock Forecasted Total Customers - Summer

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Brock Customers (Summer)	2,305	2,352	2,394	2,437	2,480	2,524	2,569	2,615	2,661	2,709	2,757
Scugog Customers (Summer)	2,052	2,073	2,087	2,092	2,102	2,116	2,129	2,141	2,155	2,168	2,181
Uxbridge Customers (Summer)	1,323	1,337	1,351	1,364	1,377	1,391	1,405	1,419	1,433	1,447	1,462
Total (Summer)	5,680	5,762	5,832	5,893	5,960	6,031	6,102	6,175	6,249	6,324	6,400

The finalized load forecast results are shown in Figure 31. In total, 0.95 MW of load growth is forecasted in Brock from 2020 to 2024.

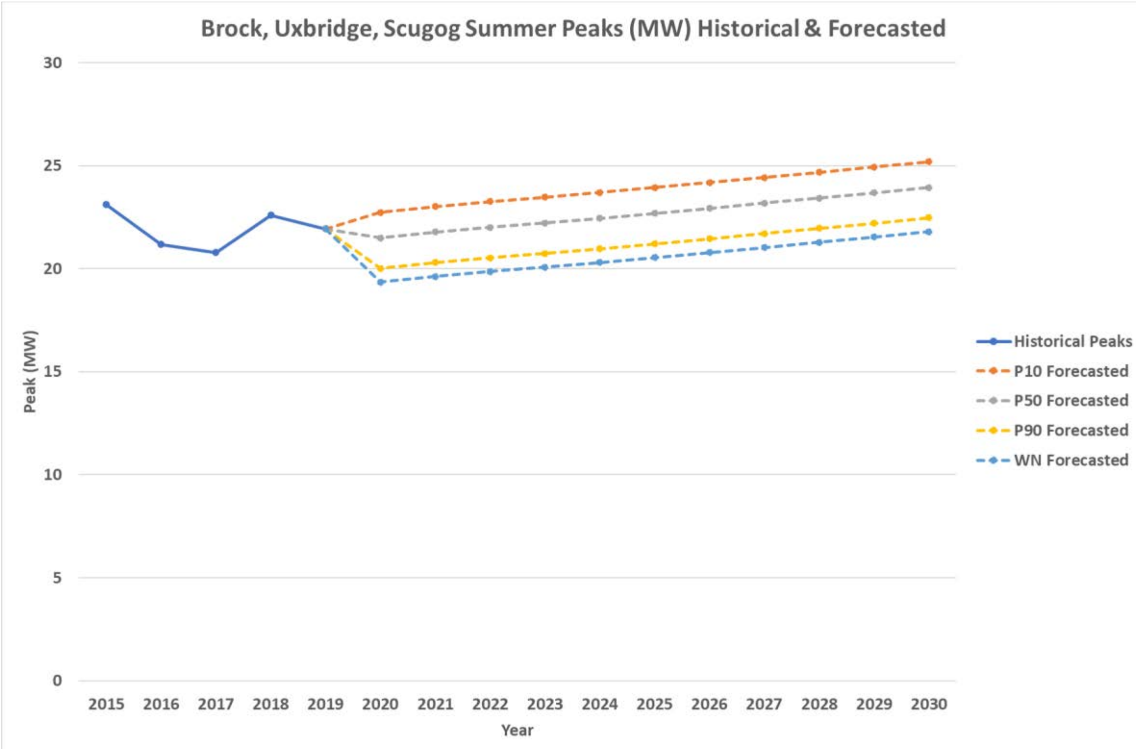


Figure 31: Brock Forecasted Summer Peaks (MW)

Table 18: Brock Forecasted Summer Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	22.74	23.02	23.25	23.46	23.69	23.93	24.17	24.42	24.67	24.93	25.19
P50	21.49	21.77	22.01	22.22	22.45	22.69	22.93	23.18	23.43	23.68	23.94
P90	20.02	20.30	20.53	20.74	20.97	21.21	21.45	21.70	21.95	22.21	22.47
WN	19.34	19.62	19.86	20.07	20.30	20.54	20.78	21.03	21.28	21.54	21.79

Assuming evenly distributed growth in Brock, Table 19 presents a generalized forecast from the region to the station Level. Assumptions from the past average historical coincidence factors, and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the station level. Planners can assign customer percentages based on the expected location of the growth.

Table 19: Brock - Evenly Distributed P10 Forecasted Summer Station Peaks

Station	S2020	S2021	S2022	S2023	S2024	S2025	S2026	S2027	S2028	S2029	S2030
CRAN	3.65	3.67	3.70	3.72	3.74	3.77	3.79	3.82	3.84	3.87	3.89
BIGE	4.00	4.03	4.05	4.07	4.09	4.12	4.14	4.16	4.19	4.21	4.24
MABL	3.56	3.59	3.62	3.64	3.66	3.68	3.71	3.73	3.76	3.79	3.81
BEAW	1.91	1.95	1.97	2.00	2.02	2.05	2.08	2.10	2.13	2.16	2.19
MAIN	1.02	1.05	1.08	1.10	1.13	1.16	1.19	1.22	1.25	1.28	1.31
UXBE	1.02	1.05	1.08	1.10	1.13	1.16	1.19	1.22	1.25	1.28	1.31
UXBW	2.88	2.91	2.94	2.96	2.98	3.01	3.04	3.06	3.09	3.12	3.14
LAID	2.70	2.73	2.75	2.78	2.80	2.83	2.85	2.88	2.91	2.94	2.96
SUND	1.57	1.60	1.63	1.65	1.68	1.70	1.73	1.76	1.79	1.82	1.85

3.1.6 Port Hope

Unlike the other Elexicon regions, the analysis of Port Hope's historical load did not yield a strong relationship with the weather indices as demonstrated from the weather normalization results in Table 4. METSCO decided to capture the variability in the megawatts per customer usage historically instead and apply Monte Carlo moving forward. The historical peak megawatts per customer was calculated by taking all the historical peaks and dividing by the historical customer count associated to that month. Monte Carlo was performed on the historical megawatts per customer to create a P10, P50, P90 forecast. In addition, Port Hope's historical peaks have occurred in the winter.

Unlike other municipalities served by Elexicon, Port Hope does not produce a municipal household forecast on an annual or biannual basis. As discovered during our research, Port Hope enlists an external consultant to forecast household totals and the report is provided on their website. The household totals for Port Hope are not forecasted annually, but rather for the years 2019 and 2029. Due to the forecast period of Port Hope, we distribute the household additions evenly across the ten years as an assumption through linear interpolation.

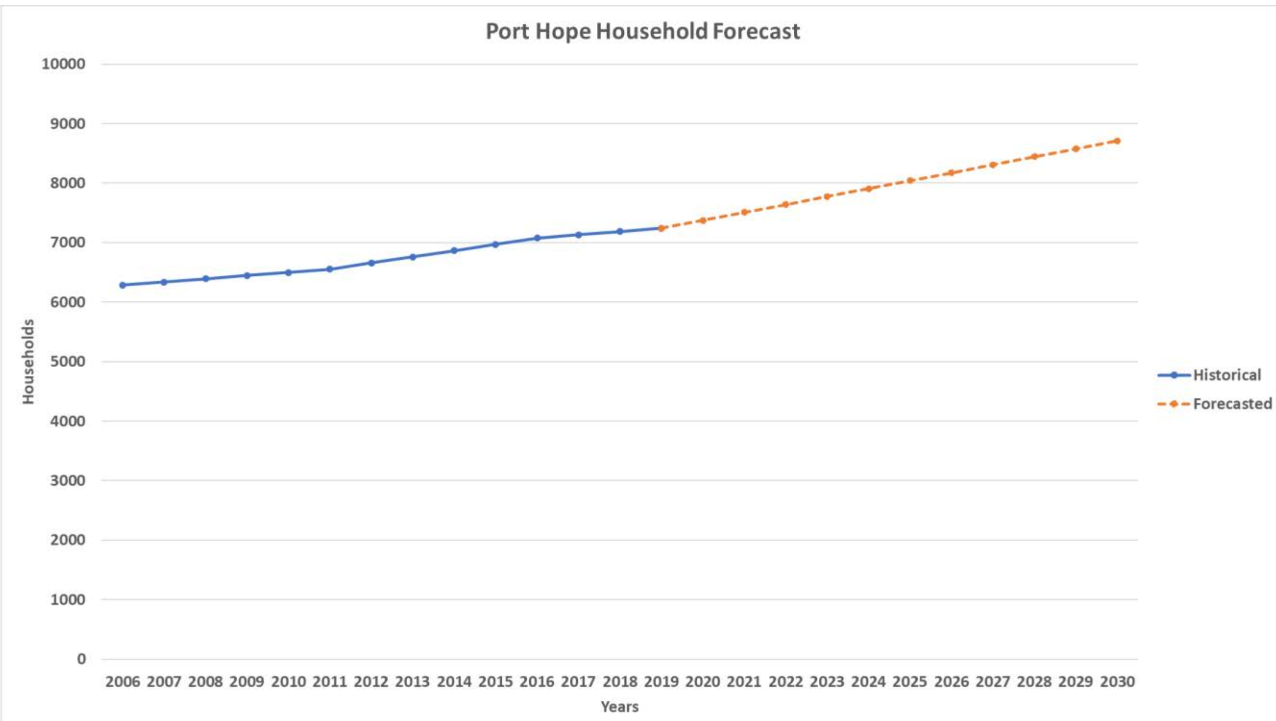


Figure 32: Port Hope Forecasted and Historical Households

We apply the historical customer-to-household ratio to the household forecast to produce a customer forecast shown in Figure 33. We find that the forecasted customer additions are much larger than the past five years of customer additions as shown in the slope. The customer forecast suggests that there will be increased customer growth in the area.

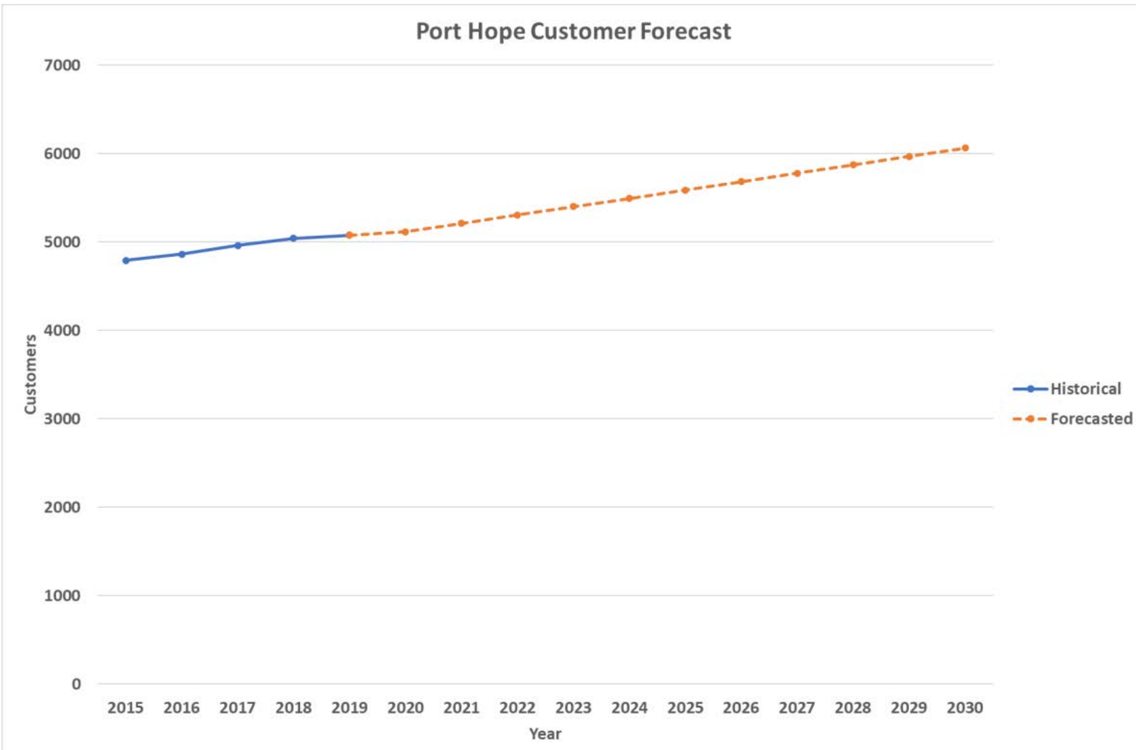


Figure 33: Port Hope Customer Forecast

Table 20: Port Hope Forecasted Total Customers - Winter

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Port Hope Customers (Winter)	5,116	5,211	5,306	5,400	5,495	5,590	5,685	5,780	5,875	5,970	6,064

The load forecast results are shown in Figure 34. Between 2.53 MW and 3.00 MW of load growth is forecasted in Port Hope from 2020 to 2024. Unlike other municipalities under Elexicon, we apply the Monte Carlo simulation to the variability in megawatts per customer for Port Hope.

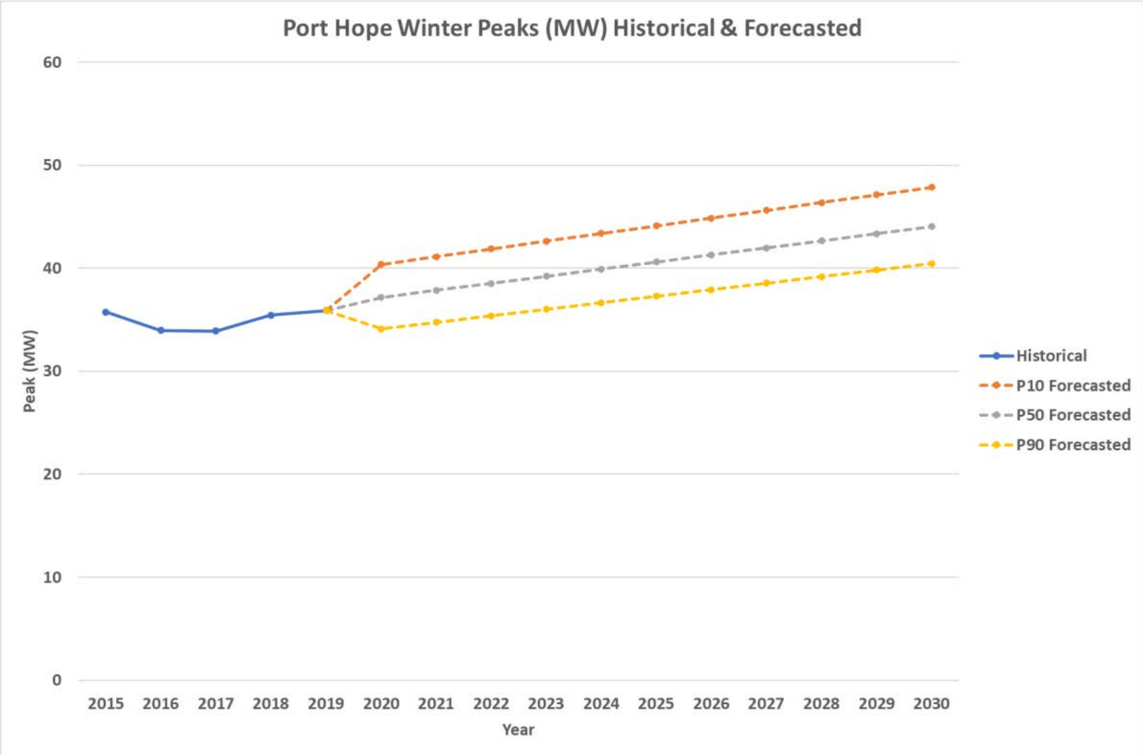


Figure 34: Port Hope Forecasted Winter Peaks (MW)

Table 21: Port Hope Forecasted Winter Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	40.37	41.12	41.87	42.62	43.37	44.12	44.86	45.61	46.36	47.11	47.86
P50	37.15	37.84	38.53	39.22	39.91	40.60	41.29	41.98	42.66	43.35	44.04
P90	34.11	34.75	35.38	36.01	36.64	37.28	37.91	38.54	39.17	39.81	40.44

Assuming an evenly distributed growth in Port Hope, Table 22 represents the generalized forecast from the region to the station level. Assumptions from the past average historical coincidence factors, and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the station level. Planners can assign customer percentages based on the expected location of the growth.

Table 22: Port Hope - Evenly Distributed P10 Forecasted Winter Station Peaks

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SHUT	3.08	3.15	3.21	3.27	3.33	3.40	3.46	3.52	3.58	3.65	3.71
JAM	6.44	6.50	6.56	6.62	6.69	6.75	6.81	6.87	6.94	7.00	7.06
HOWA	1.46	1.52	1.59	1.65	1.71	1.77	1.84	1.90	1.96	2.02	2.09
PEAC	2.77	2.83	2.89	2.95	3.02	3.08	3.14	3.20	3.26	3.33	3.39
CAVN	2.98	3.04	3.10	3.17	3.23	3.29	3.35	3.42	3.48	3.54	3.60
CAVS	3.48	3.55	3.61	3.67	3.73	3.79	3.86	3.92	3.98	4.04	4.11

3.1.7 Gravenhurst

The Gravenhurst region within Elexicon's service area is quite unique compared to other regions. For instance, there are many seasonal customers using recreational properties for only parts of the year. Due to this distinction, Elexicon designates certain customers as seasonal within the customer counts for Gravenhurst, which is not the case for other regions. Gravenhurst's peak occurs in the winter thanks in large part to electric heating. When we attempted to use the same weather normalization strategy from other areas, we found that there was not a strong relationship of peak loads to weather indices. When discussing with Elexicon SMEs, they confirmed that Gravenhurst was quite unpredictable and has been in history.

Hydro One Networks Inc. ("HONI") bills Elexicon for the difference in load from the metering channels coming into and egressing out of the Gravenhurst Area. This difference is reported as Gravenhurst's peak and is used as the peak in our forecasts.

Unlike other regions within Elexicon's service area, Gravenhurst does not produce a municipal forecast on an annual or biannual basis but has enlisted external consultants to produce a household forecast up to 2030. The household forecast produced are forecasted values in five-year increments. As such, an assumption was made that the growth was linearly interpolated in the gap years. Due to the unavailability of past forecasts to compare to, an adjustment factor for the household forecast was not created.

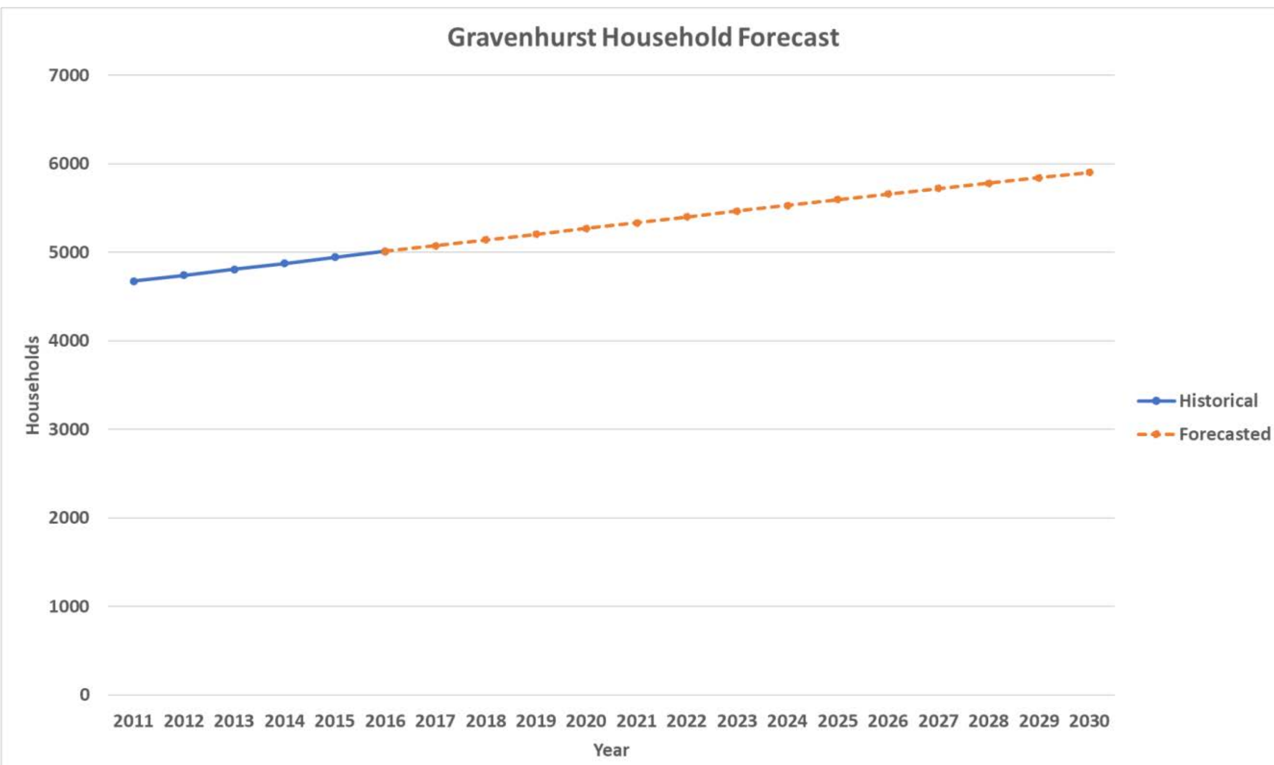


Figure 35: Gravenhurst Forecasted & Historical Households

We apply the historical customer-to-household ratio to the household forecast to produce the customer forecast shown in Figure 36. Using the customer-to-household ratio, we find that the forecasted customer additions are similar to the historical customer additions over the past five years. Gravenhurst expects consistent residential customer growth for the future. Housing developments in the area are not large enough such that a significant or large amount of customer additions will be expected.

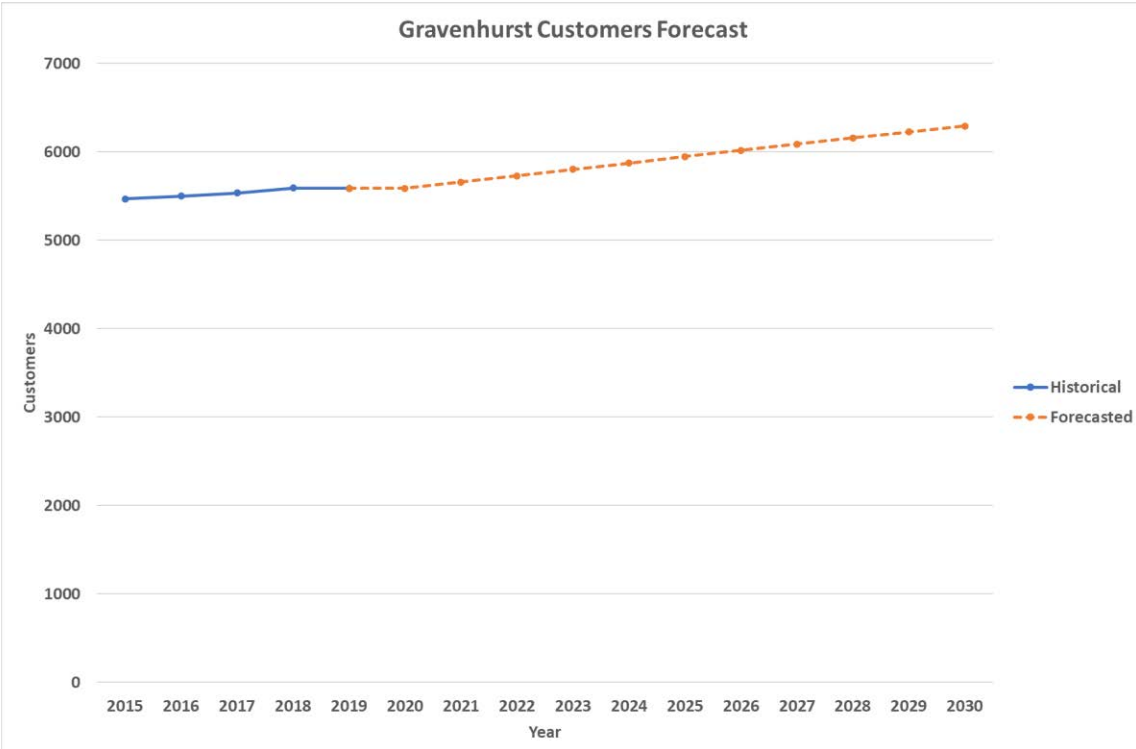


Figure 36: Gravenhurst Customer Forecast

Table 23: Gravenhurst Forecasted Total Customers - Winter

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gravenhurst Customers (Winter)	5588	5660	5732	5804	5875	5947	6019	6091	6158	6226	6293

Due to the weak relationship between peak load in Gravenhurt and the stablished weather indices, we performed a Monte Carlo simulation on the historical megawatts per customer. In doing so, the top 10% peaks were taken for each season and the megawatts per customer were found to fit into a gamma distribution. In order to simulate for the variability in seasons, the percentage change to each data's histroical year mean was calculated. The first trial was then taken as the mean to a normal distribution with the percentage change as the standard deviation. This allows the forecast to reflect the variability in historical peaks as seen in Figure 37.

The finalized load forecast results are shown in Figure 37**.** In total, 1.03 MW to 1.57 MW of load growth is forecasted in Gravenhurst from 2020 to 2024. As shown in the historical coincident winter peaks, Gravenhurst's peaks have varied quite considerably year over year. This variability is captured through applying Monte Carlo to the historical megawatts per Customer and produces P10, P50, and P90 bands that encompass the irregular peak behavior of Gravenhurst. The peaks that Gravenhurst experiences as shown historically are sporadic and can occur at random times unlike the other Elexicon regions.

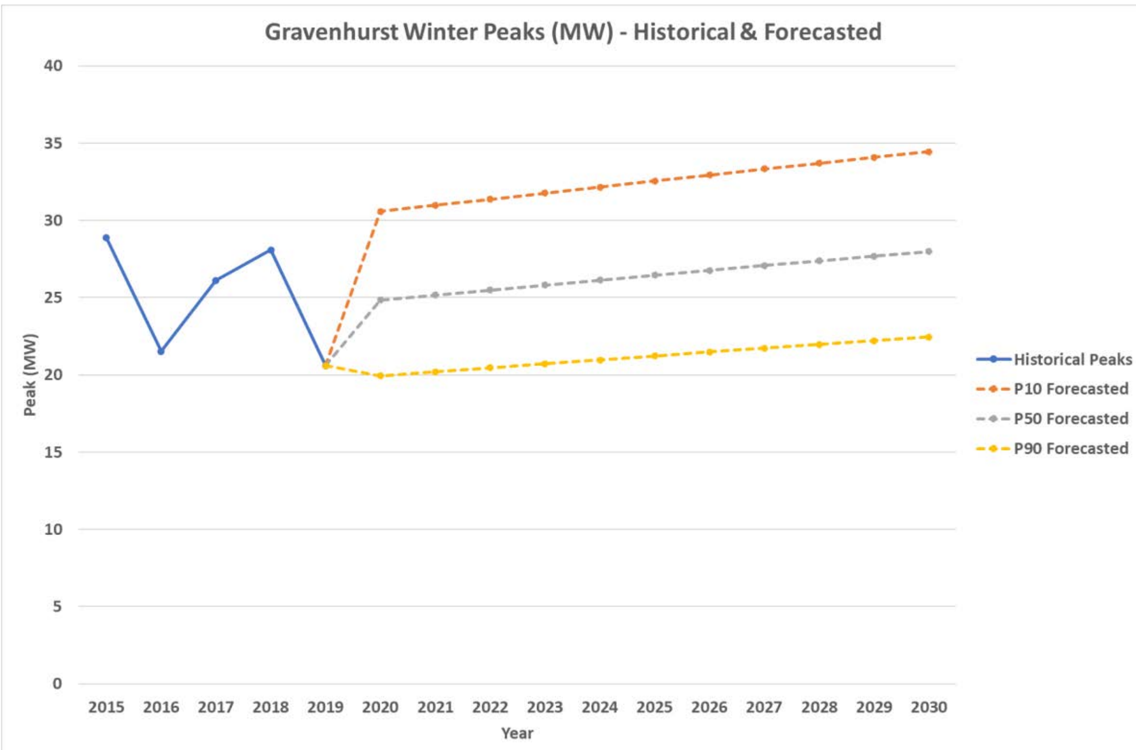


Figure 37: Gravenhurst Forecasted Winter Peaks (MW)

Table 24: Gravenhurst Forecasted Winter Peaks (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	30.59	30.98	31.37	31.77	32.16	32.55	32.95	33.34	33.71	34.08	34.44
P50	24.85	25.17	25.49	25.81	26.13	26.45	26.77	27.09	27.39	27.69	27.99
P90	19.94	20.20	20.46	20.71	20.97	21.23	21.48	21.74	21.98	22.22	22.46

Assuming evenly distributed growth in Gravenhurst, Table 25 presents the generalized forecast from the region to the station level. Assumptions from the past average historical coincidence factors and average allocation factors are held. This is meant to provide a generalized picture of the forecast on the station level. Planners can assign customer percentages based on the location of expected growth

Table 25: Gravenhurst - Evenly Distributed P10 Forecasted Winter Station Peaks

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BAY	3.72	3.77	3.82	3.86	3.91	3.95	4.00	4.05	4.09	4.13	4.18
JAMS	3.98	4.03	4.07	4.12	4.17	4.21	4.26	4.30	4.35	4.39	4.43
FIRS	3.03	3.07	3.12	3.17	3.21	3.26	3.30	3.35	3.39	3.44	3.48

3.2 Annual Customer Forecast from the Engineering Model

A summary of the annual year-end residential customer additions by service area are provided in Table 26. These customer additions are utilized in forecasting the load growth expected in Elexicon's service territory in the Engineering Model. The forecasts are built from regional and municipality projections of household development, adjusted for historical accuracy. Where the referenced projections lack granularity, we interpolate the forecast; where the projections end before 2030, we extrapolate the forecast.

Table 26: Total Forecasted Residential Customer Additions – Year-End

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ajax-Pickering	1,468	2,730	3,209	2,997	1,750	2,023	2,110	2,204	2,303	2,407	2,516
Whitby	745	863	880	879	896	913	931	950	968	987	1,007
Belleville	198	198	142	142	142	142	142	127	127	127	127
Clarington	316	312	325	301	307	312	318	324	330	337	343
Brock	87	79	63	61	70	71	72	73	75	75	77
Port Hope	95	95	95	95	95	95	95	95	95	95	95
Gravenhurst	72	72	72	72	72	72	72	67	67	67	67
Total	**2,981**	**4,349**	**4,785**	**4,546**	**3,331**	**3,628**	**3,740**	**3,841**	**3,967**	**4,096**	**4,233**

3.3 System-Level Forecast (Econometric)

The econometric model analyzes and models the behaviour of the total non-coincident peak load to econometric variables. In this case, the finalized list of variables (defined in Section 2.4) used include:

- Housing Starts;
- Cooling Degree Days (CDD); and
- Time Trend.

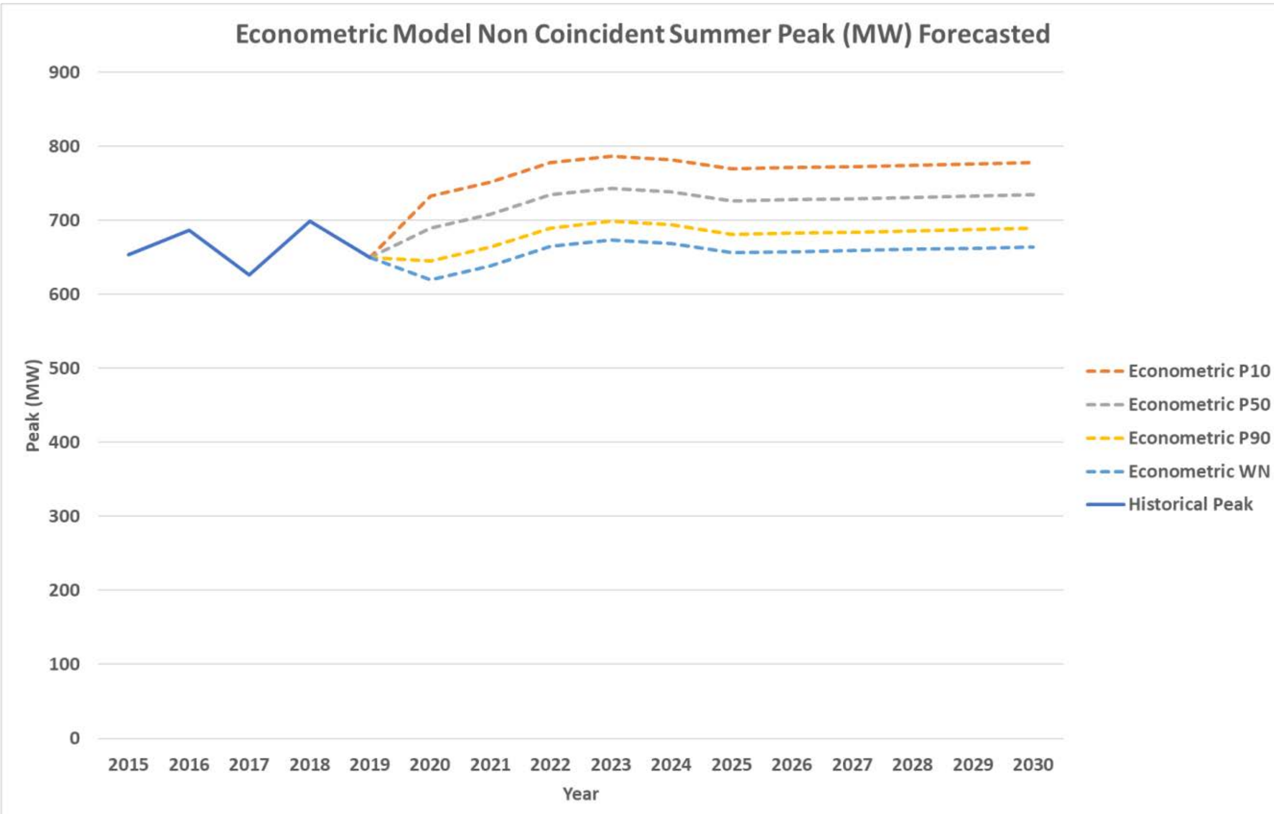


Figure 38: Econometric Elexicon Energy Non-Coincident Summer Peaks (MW) Forecasted

Table 27: Econometric Elexicon Energy Non-Coincident Summer Peaks (MW) Forecasted

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
P10	733.07	751.96	778.08	786.92	782.28	769.79	771.13	772.59	774.17	775.87	777.69
P50	689.62	708.51	734.63	743.46	738.82	726.33	727.68	729.14	730.72	732.42	734.24
P90	644.66	663.55	689.67	698.51	693.87	681.38	682.73	684.19	685.76	687.46	689.29
WN	619.58	638.47	664.59	673.43	668.79	656.30	657.65	659.11	660.68	662.38	664.21

3.4 Comparison of Results

To compare the engineering model to the econometric model, all weather normalized, P10, P50, and P90 regional summer peaks from the engineering model were added together to create the non-coincident total Elexicon summer peak.

As shown in Figure 39, both the engineering and econometric forecasts predict similar growth for the first four years. As the forecast moves into the future, the engineering model continues to assume load growth will be cumulatively added. The econometric model's underlying time trend is apparent as load starts to decrease after 2023.

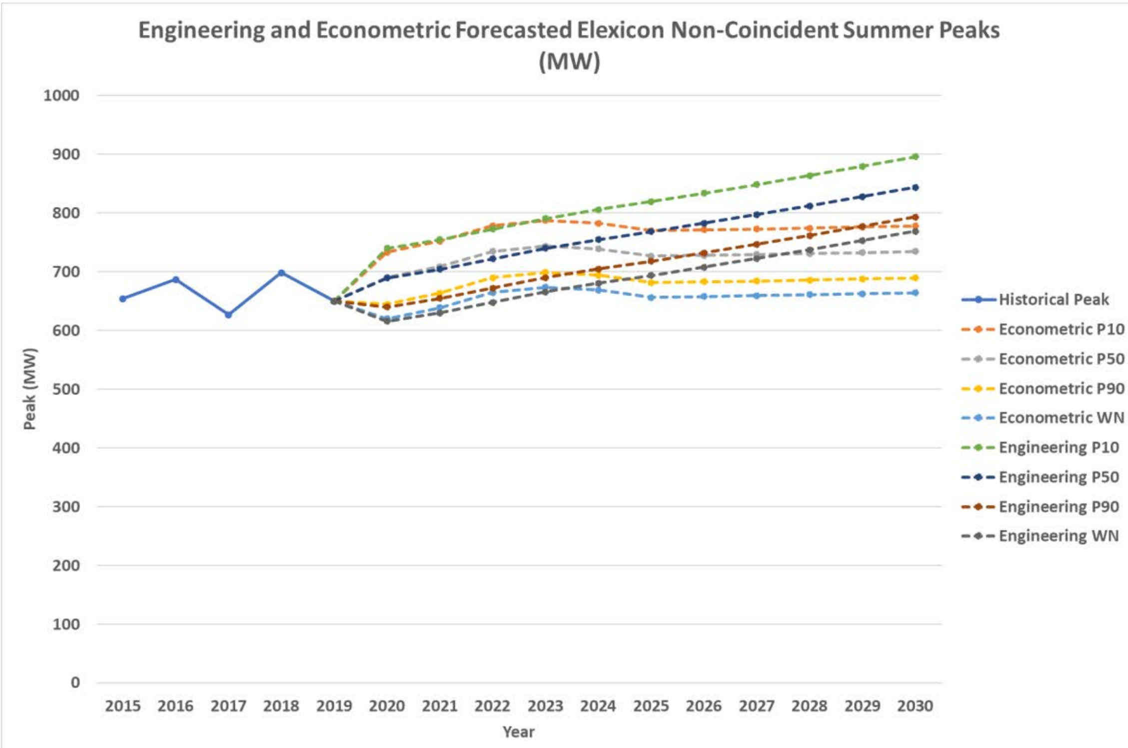


Figure 39: Comparison of Engineering and Econometric Non-Coincident Summer Peaks (MW) Forecasted

The key result from the two forecasts is that both models forecast considerable load growth in the next four years. It is evident that new housing developments in the Elexicon service area will be a major driver in load growth throughout the region. The major driver of load growth will be found in the Ajax-Pickering area as shown in the engineering model and comparisons of household numbers into the future for all regions.

Upon evaluating the results of the forecast, the time trend that exists in the econometric model may capture the historical benefits of load conservation. This load conservation reduces the peak load of the econometric forecast due to its negative coefficient. The engineering model assumes a constant peak load per customer where reductions are not captured into the future.

Another aspect that could explain the divergence of the two forecasts is that the engineering model extrapolates and interpolates the historical trend of total households into the future depending on the service area. For example, the Durham municipal forecasts cover up to May 2024. An accuracy factor is also applied to the first four years of the forecast from 2020 to 2023 for the Durham municipalities. The adjusted household additions are linearly extrapolated into the future until 2030 and an average growth rate for households is then applied to the household additions. Future household additions for Durham service areas are produced using the short-term forecast, which may not represent the long-term outlook of housing. The municipalities of Belleville, Port Hope, and Gravenhurst have long-term forecasts, but linear interpolation is applied to fill the household counts between years. An accuracy factor could not be applied as there were no historical forecasts for these service areas. Additionally, as Port Hope's household forecast ended in 2029, a 2030 household forecast was produced through linear extrapolation.

Finally, the econometric model does not capture the variability of year-over-year peak loads in Gravenhurst and Port Hope that the engineering model captures. Monte Carlo simulated P10, P50, and P90 effects were added to the econometric forecast for Ajax-Pickering, Whitby, Belleville, Brock and Clarington like the engineering model. However, the Port Hope and Gravenhurst sections of the econometric forecast do not have variability of peak load usage per customer that the engineering model has. To create the non-coincident econometric forecast, we added the normalized peaks of Port Hope and Gravenhurst. No P10, P50 or P90 values were added for Port Hope and Gravenhurst on the econometric model. The difference between the two models could potentially be decreased if variability for Gravenhurst and Port Hope are added onto the econometric side.

The two models will incorporate the new economic and household data in the future. The engineering model will be updated to include the potential of conservation impacts which will decrease the peak load per customer into the future. This could potentially decrease the divergence between the two forecasting models moving forward from 2024.

Table 28: Engineering and Econometric Elexicon Energy Non-Coincident Summer Peaks (MW) Forecasted

Peak (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WN Econometric	619.58	638.47	664.59	673.43	668.79	656.30	657.65	659.11	660.68	662.38	664.21
WN Engineering	615.31	629.91	647.53	665.27	680.02	693.51	707.69	722.26	737.26	752.74	768.70
P90 Econometric	644.66	663.55	689.67	698.51	693.87	681.38	682.73	684.19	685.76	687.46	689.29
P90 Engineering	639.63	654.22	671.84	689.58	704.33	717.81	732.00	746.58	761.58	777.05	793.02
P50 Econometric	689.62	708.51	734.63	743.46	738.82	726.33	727.68	729.14	730.72	732.42	734.24
P50 Engineering	689.31	704.01	721.73	739.57	754.39	768.01	782.29	796.97	812.05	827.61	843.69
P10 Econometric	733.07	751.96	778.08	786.92	782.28	769.79	771.13	772.59	774.17	775.87	777.69
P10 Engineering	739.71	754.53	772.38	790.35	805.31	819.04	833.46	848.25	863.47	879.17	895.36

4. Conclusions and Recommendations

Conclusions:

As described in Section 3.4, both models had different aspects which may have contributed to the divergence in forecast after 2023. The engineering and econometric approaches forecast similar load growth for the first four years at the system level for their respective forecasts. However, the existence of a time trend in the econometric model creates a decrease from 2024 and onwards. This trend captured by the econometric model could represent the load conservation efforts by customers. The engineering model does not incorporate any form of load conservation moving into the future. In addition, the engineering model takes the average growth rate for the short-term forecast for the Durham municipalities to project households into the future. The incremented forecasts of Port Hope, Belleville and Gravenhurst are linearly interpolated to create annual household totals. Lastly, the econometric model does not capture the variability of peak load usage of the areas of Gravenhurst and Port Hope. The weather normalized peaks for those regions are used and added with the weather-normalized, P10, P50, and P90 peaks of the other regions to create the system-level non-coincident peak of Elexicon. The engineering model adjusts for the variability in Port Hope and Gravenhurst to produce variable forecasts. These three key differences are the potential causes to the divergence of the forecasts moving forward.

It would be worthwhile in the future to examine how the two approaches could be further combined into one forecast that utilizes the strengths of both approaches. The engineering approach is flexible in being able to forecast load growth for specific regions and substations within the service area, while the econometric approach can forecast broader econometric variables on the system level.

The engineering model was created on the assumption that households drive load growth and utilizes the historical ratio of total households to total residential customers in order to create the load forecast. The household forecasts were also adjusted for historical accuracy based on how accurate past forecasts have been to actual household numbers.

The econometric model used an exhaustive approach in order to identify econometric variables that held strong relations to system peaks. Housing starts was identified as a strong indicator and utilized in conjunction with cooling degree days.

Model Use Potential:

Using the regional load forecast from the engineering model, planners can assign the customer growth to station-level forecasts. This is done using historical allocation and coincidence factors calculated from region to total station loads to individual stations, station transformers, and station feeders. Planner may place these customer additions to stations to reflect where they believe load growth will occur. The distributed growth of load would most likely be applicable in smaller regions but in areas such as Whitby, Ajax, and Pickering, certain development areas have been designated. Municipal Substations within the proximity of these developments should have these customers assigned. In addition, if a new large user or bigger customer intends on establishing themselves in a specific region, planners can add new large point loads to the specific substation they believe the load would be connected to.

Recommendations and Improvements for Stakeholder Collaboration:

Continued and further engagement with municipal and regional stakeholders would be very beneficial for the forecast. Acquiring more granular data from the municipalities would help with analysis and forecasting. Valuable data and information include:

- Local and more granular econometric data (e.g., business counts, population, etc.);
- Development plans and household forecasts;
- Stakeholder meetings with each municipality; and
- Surveys or templates for municipal stakeholders to provide development information. For example, a timeline for upcoming plans, growth patterns, new large users, economic plans would be valuable.

Elexicon Data Improvements:

- Address discrepancies with the Whitby System Capacity reports as there was blank data for certain years and repeated data. Whitby loading data from Kinetiq, Elexicon's metering portal, was utilized as there were no gaps.
- Use current loading data to address any different loadings on feeders and stations. After discussion with Elexicon SMEs, there is miscommunication at times with how loading has been changed on feeders. This was evident when the data was graphed specifically for the historical allocation and loading on stations, transformers, and feeders.
- Record load transfers or look to automate a report of load transfers. Discussions with Elexicon's SME noted that load transfers were not necessarily reported. This would be beneficial from the planning side as well as noting discrepancies in the actual peak loadings on certain system components.

METSCO model improvements:

- METSCO can research into creating a mixed use forecast on the engineering model. Business counts can potentially be used to attribute load portions of the total peak load to industrial and commercial customers. The current engineering model uses the relation of historical residential customer counts and households and assumes residential customer load is the primary driver. Incorporating a business count or larger user analysis can improve the forecast. However, this requires an even more granular level of data and time to acquire the demand of large users, businesses, and different customers. It would be interesting if metering data could be pulled for the average demand of residentials and large businesses to acquire a more granular level of data for utility customers.
- METSCO will evaluate the actual peaks and forecasted peaks to produce a variance analysis. Opportunities of improvement and learning can be found in this evaluation year over year.

- METSCO will continue research into other methods and experiment with new changes to current models, including varying the weather parameters used. Investigations into combining the engineering and econometric model will be performed.
- METSCO can research into incorporating the effect of distributed energy resources and new electric vehicle infrastructure to peak loads.
- Add uncertainties related to other variables and incorporate Monte Carlo to these variables such as household additions, and MW per customer. These improvements can provide a more complete probabilistic model with P10, P50 and P90.
- Incorporate the probability in relation to the total amount of times load can exceed certain capacity limits. This would require more granular level data around minute intervals.

Future possibilities for both METSCO and Elexicon:

- Investigate the possibility of integrating load growth based on forecast models and development models into a geographical heat map.
- Acquire more granular customer counts at the station, transformer, and feeder level.
- Implement an engineering model that allows planners to assign customer additions to the feeder level instead of the station level. This is difficult due, in part, to loading changes as the control room may switch customers on specific feeders which changes typical loading. This would require consultations with Elexicon SMEs on what normal loading or normal customer counts on each feeder is.

How METSCO and Elexicon can work together to improve the process:

- Identify normal loading levels of different system components to ensure that the regional forecast can be more accurately portrayed at the distribution level.
- Discuss where specific developments will occur from the regional forecast to the specific substation. Customer additions can then be assigned to the closest substation of these specific developments.
- Explore improvements that Elexicon can potentially see for both models.
- Improve data capturing, acquire more granular data from Elexicon and associated city stakeholders and consider other valuable data that could improve models.
- Review the development and implementation of electric vehicle infrastructure and distributed energy resources within the Elexicon service area and discuss its impact on system peaks and the load forecast. Consider new upcoming projects, initiatives, as well as civilian and municipal opinions on the subject matter. An earlier meeting between METSCO and Elexicon suggested that EV charging could shift the peak if more consumers adopt EVs.

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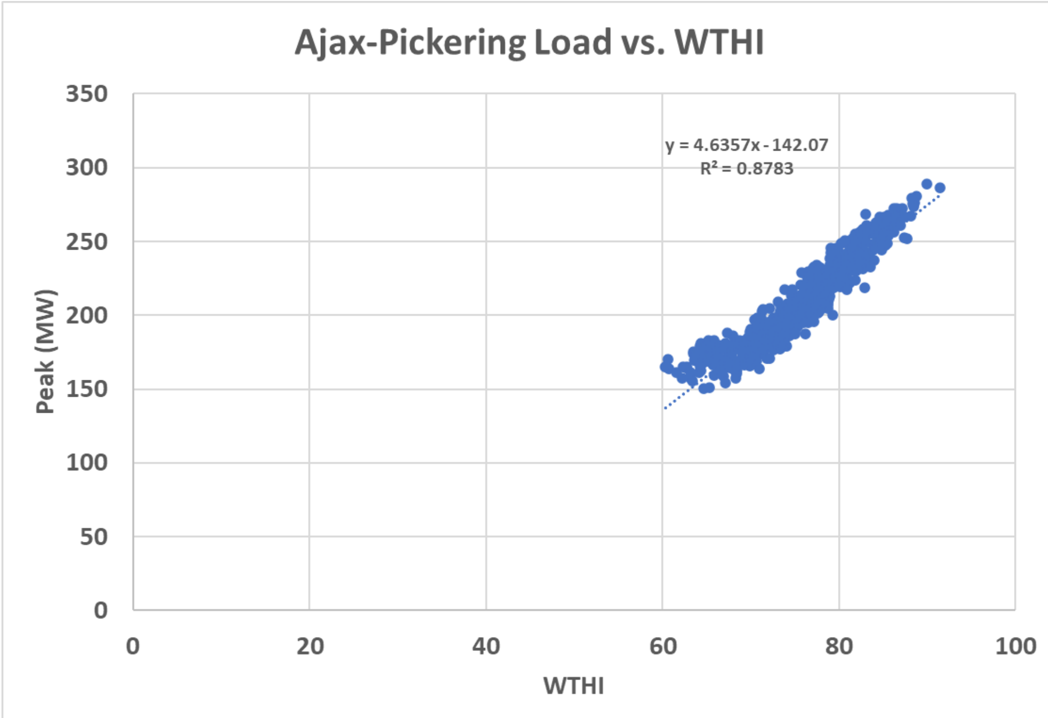
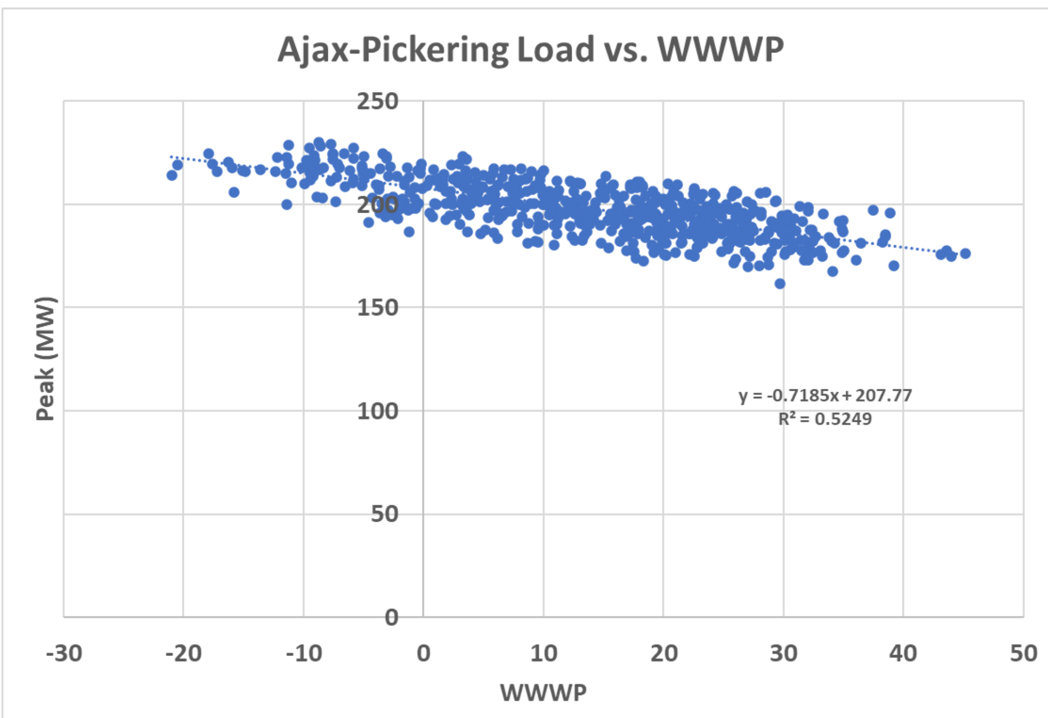
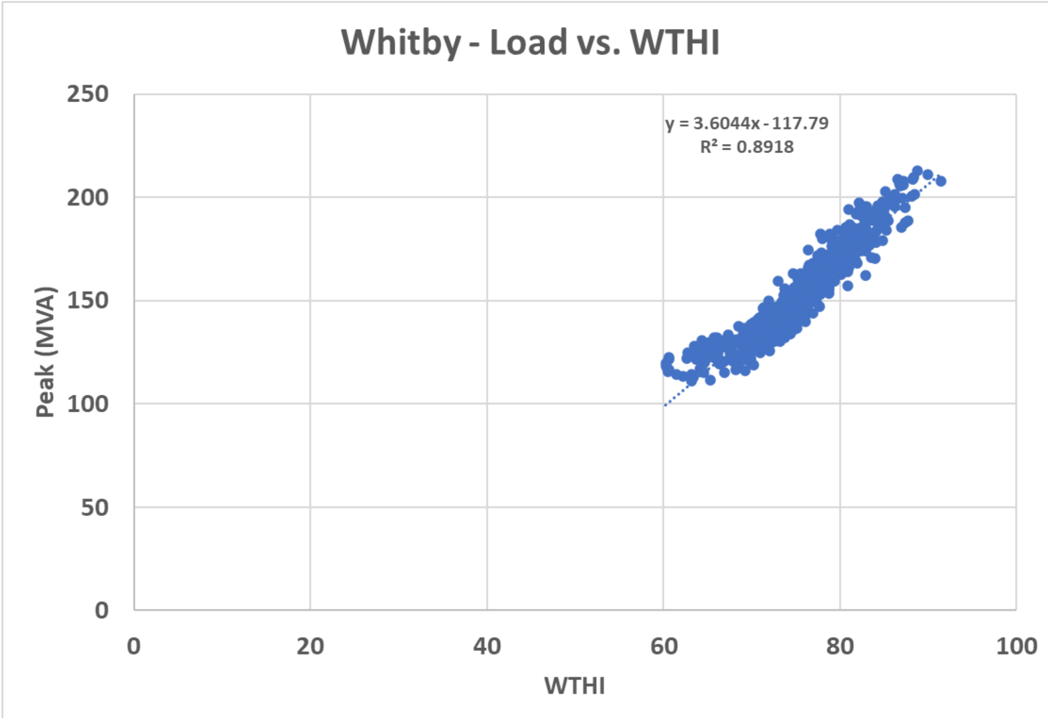
Appendix A Source Data

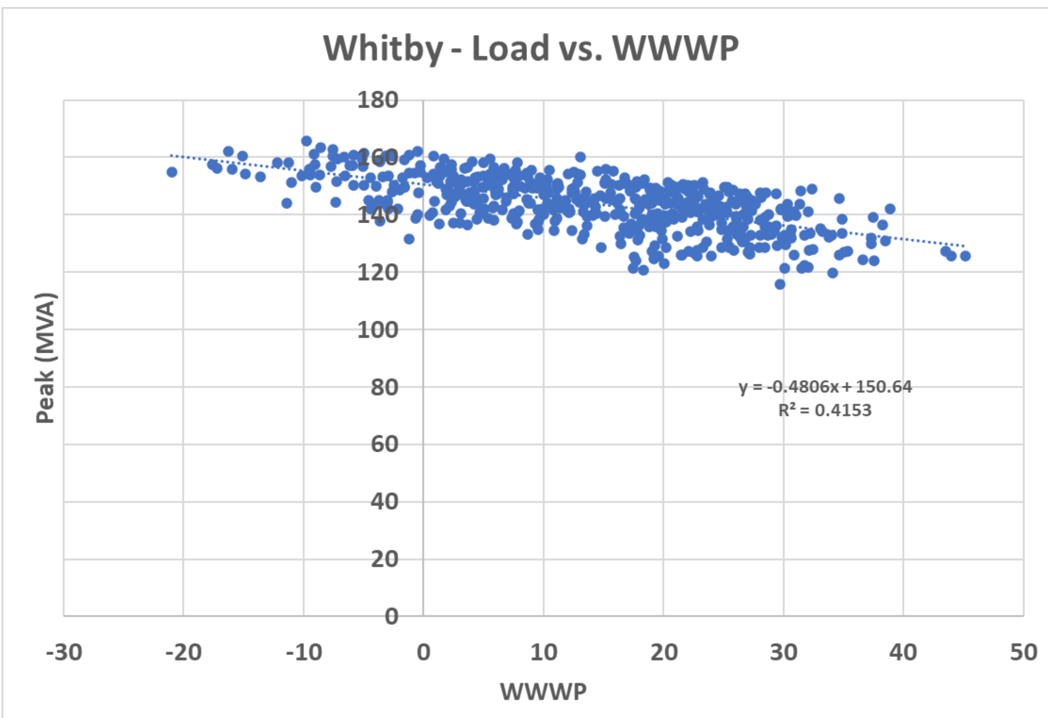
A.1 Weather Normalization Inputs and Results

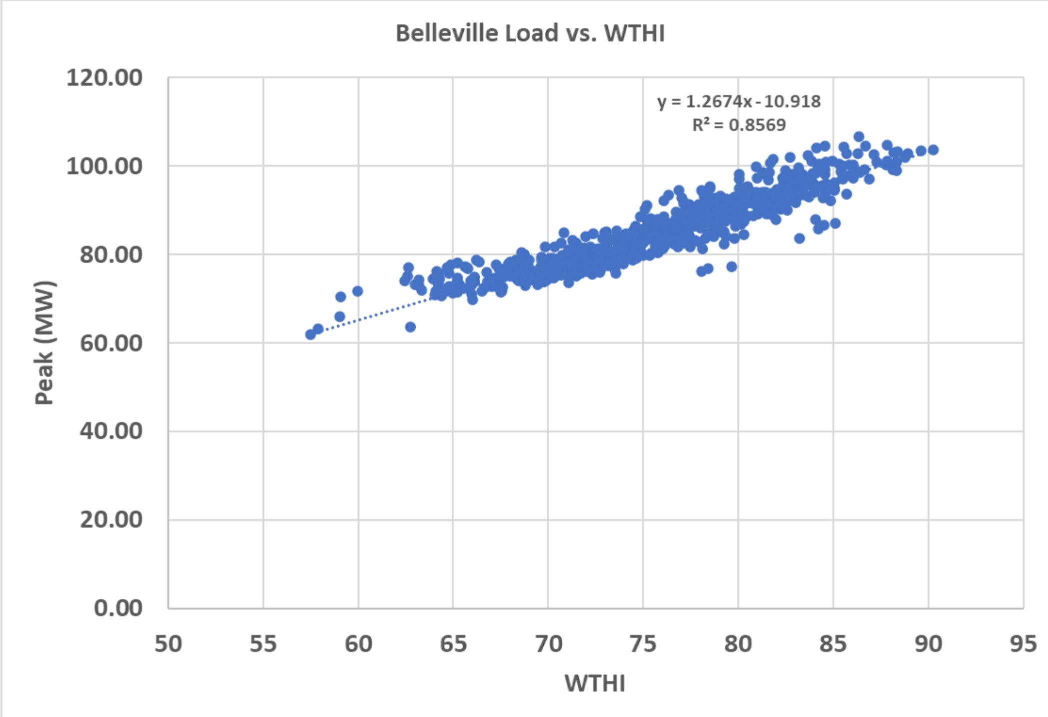
Variable	Range	Unit	Granularity	Source
Peak Load Data	2009 to 2019	MW	All Elexicon Regions	Elexicon Metering Portal 'Kinetiq'
Maximum Temperature	2009 to 2019	Celsius	Closest Assigned Airport between Oshawa Municipal Airport, CFB Trenton, and Muskoka Airport	[3]
Minimum Temperature	2009 to 2019	Celsius	Closest Assigned Airport between Oshawa Municipal Airport, CFB Trenton, and Muskoka Airport	[3]
Maximum Relative Humidity	2009 to 2019	% based (1.00 represents 100%)	Closest Assigned Airport between Oshawa Municipal Airport, CFB Trenton, and Muskoka Airport	[3]
Maximum Wind Speed	2009 to 2019	Km/h	Closest Assigned Airport between Oshawa Municipal Airport, CFB Trenton, and Muskoka Airport	[3]
Weighted Temperature Humidity Index	2009 to 2019	Indices calculated from Maximum Temperature and Maximum relative humidity	All Elexicon Regions	Calculated with [3]
Weighted Winter Weather Parameter	2009 to 2019	Indices calculated from Minimum Temperature and Maximum Wind Speed	All Elexicon Regions	Calculated with [3]

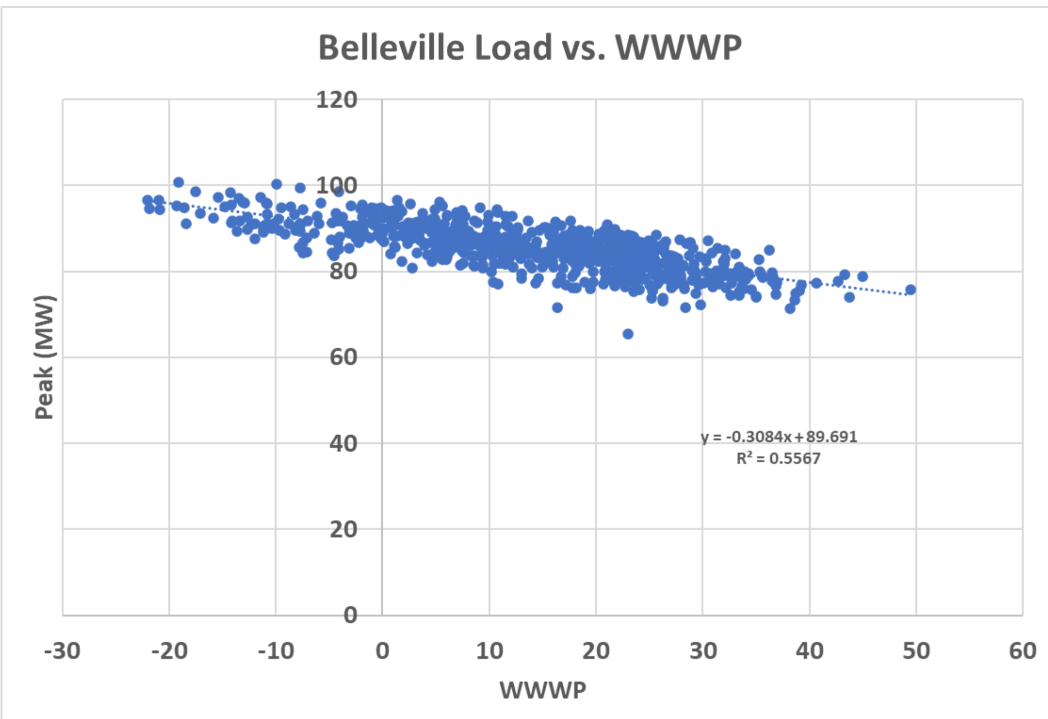

Ajax-Pickering Load vs. WTHI
y = 4.6357x - 142.07
R² = 0.8783
Peak (MW)
WTHI
350
300
250
200
150
100
50
0
0
20
40
60
80
100

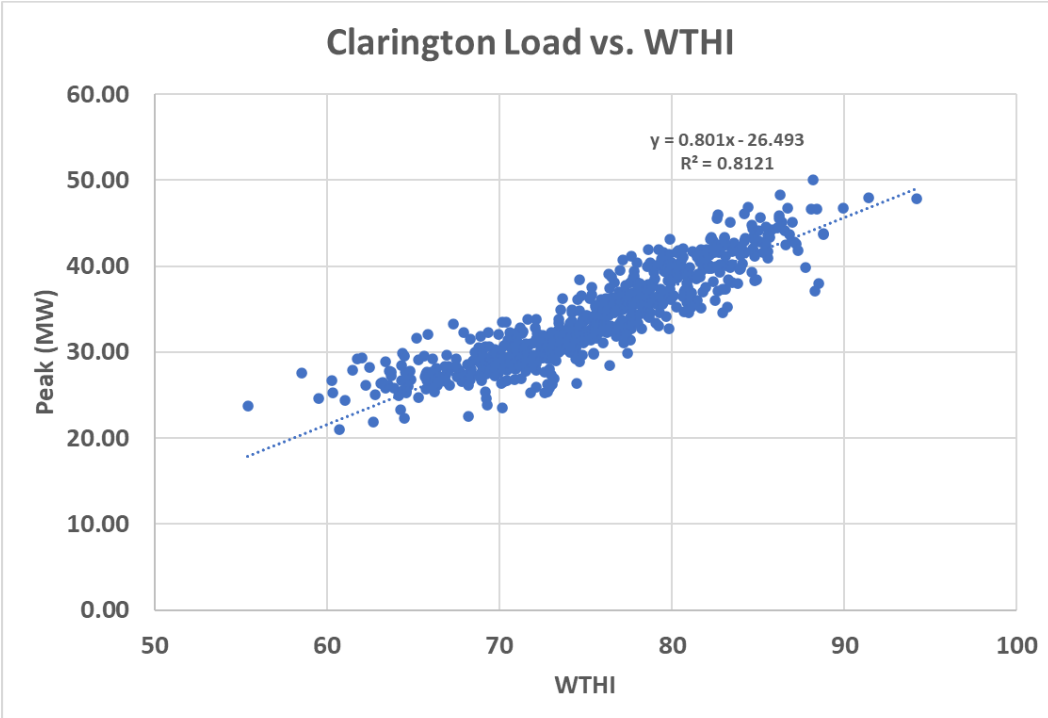

Ajax-Pickering Load vs. WWWP
y = -0.7185x + 207.77
R² = 0.5249
Peak (MW)
WWWP
250
200
150
100
50
0
-30
-20
-10
0
10
20
30
40
50

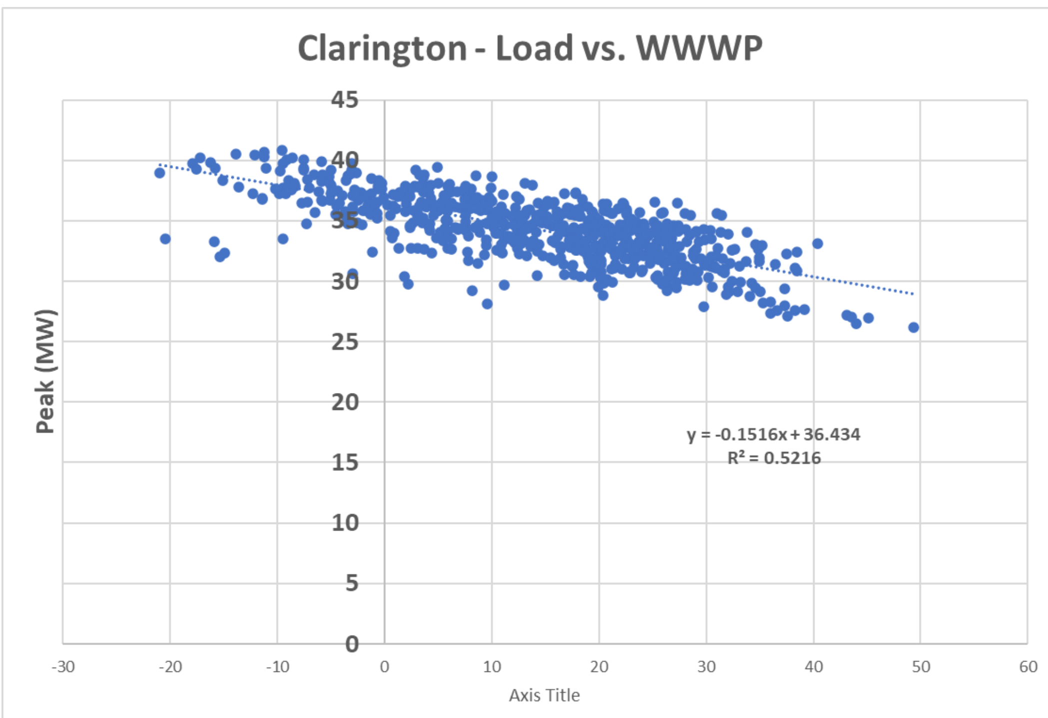

Whitby - Load vs. WTHI
y = 3.6044x - 117.79
R² = 0.8918
Peak (MVA)
250
200
150
100
50
0
0
20
40
60
80
100
WTHI

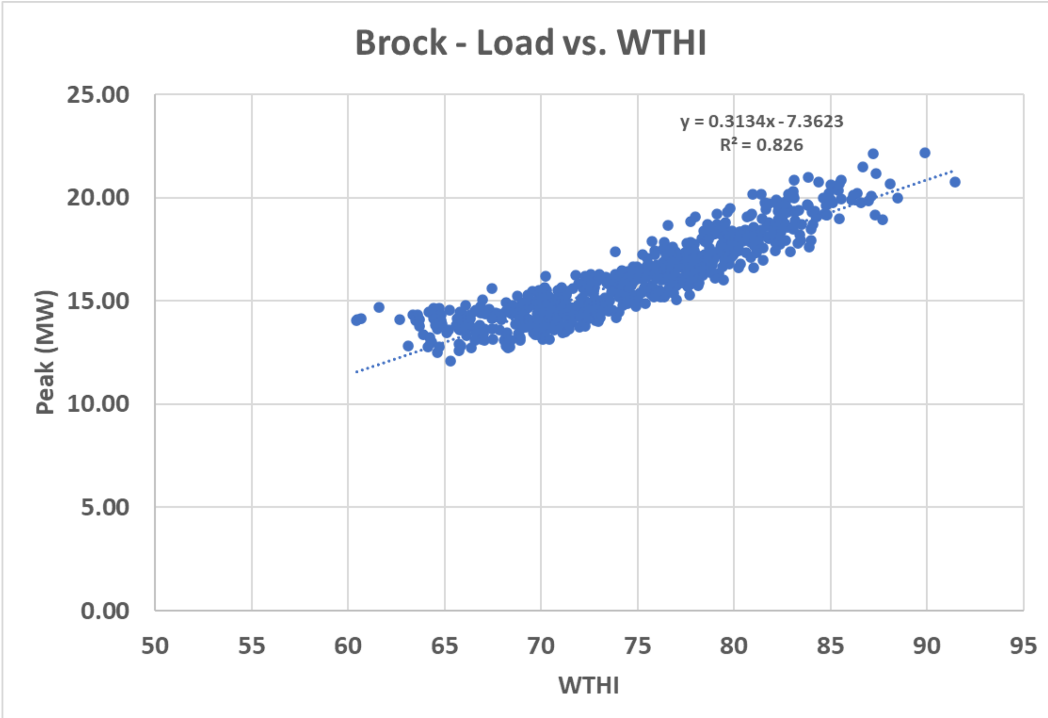

Whitby - Load vs. WWWP
y = -0.4806x + 150.64
R² = 0.4153
Peak (MVA)
180
160
140
120
100
80
60
40
20
0
-30
-20
-10
0
10
20
30
40
50
WWWP

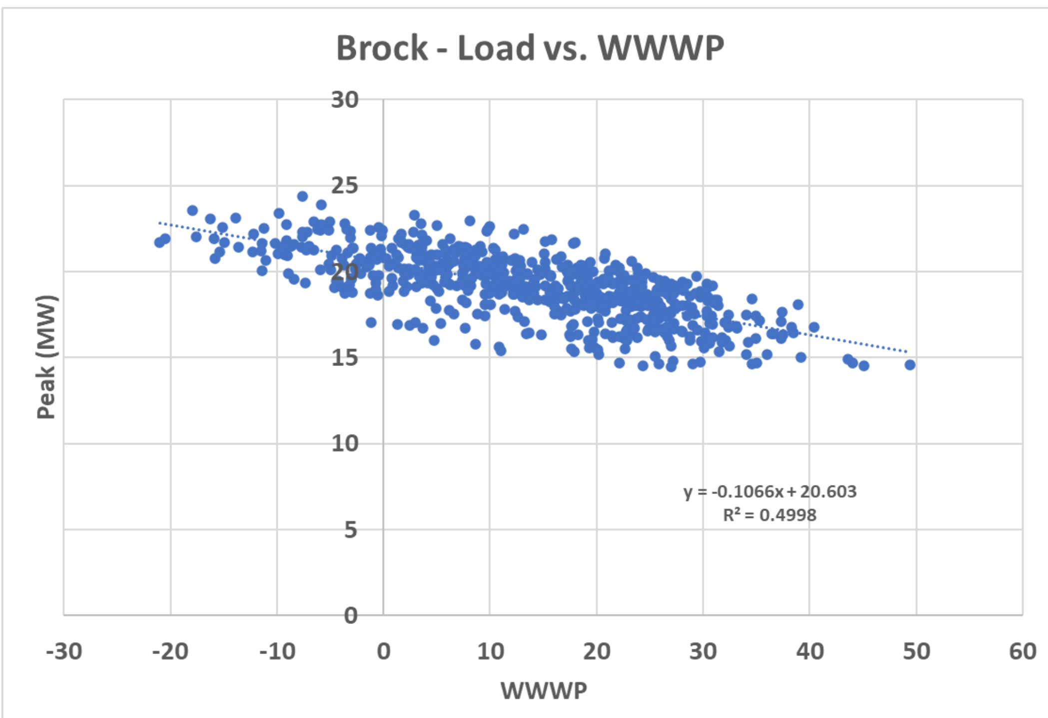

Belleville Load vs. WTHI
y = 1.2674x - 10.918
R² = 0.8569
Peak (MW)
120.00
100.00
80.00
60.00
40.00
20.00
0.00
50
55
60
65
70
75
80
85
90
95
WTHI

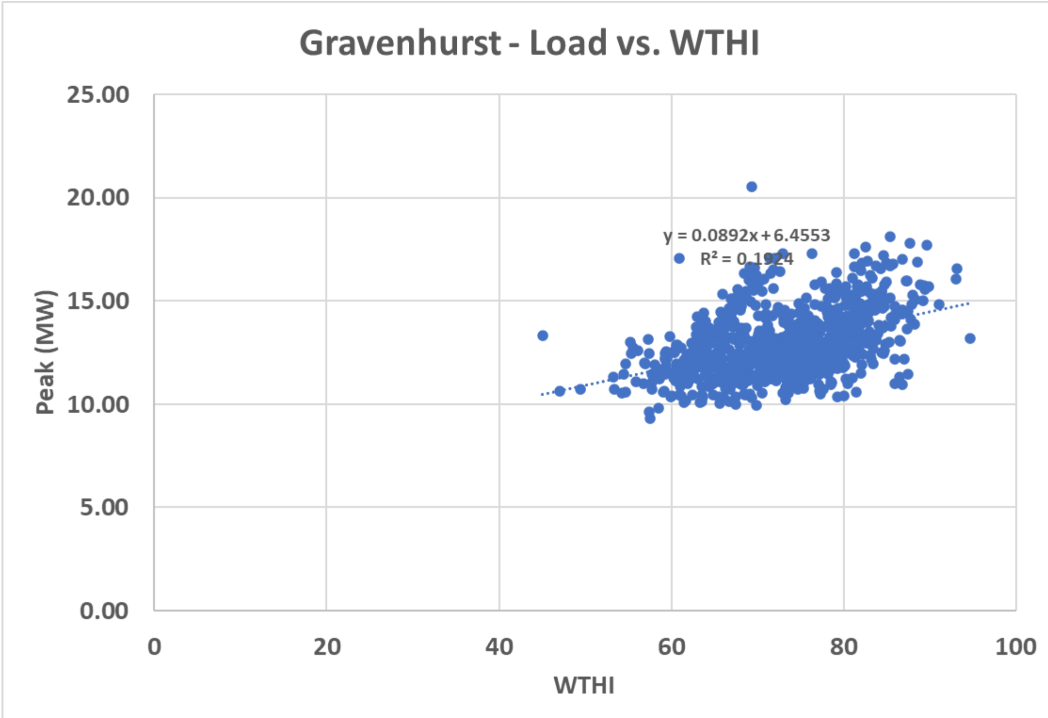

Belleville Load vs. WWWP
y = -0.3084x + 89.691
R² = 0.5567
Peak (MW)
120
100
80
60
40
20
0
-30
-20
-10
0
10
20
30
40
50
60
WWWP

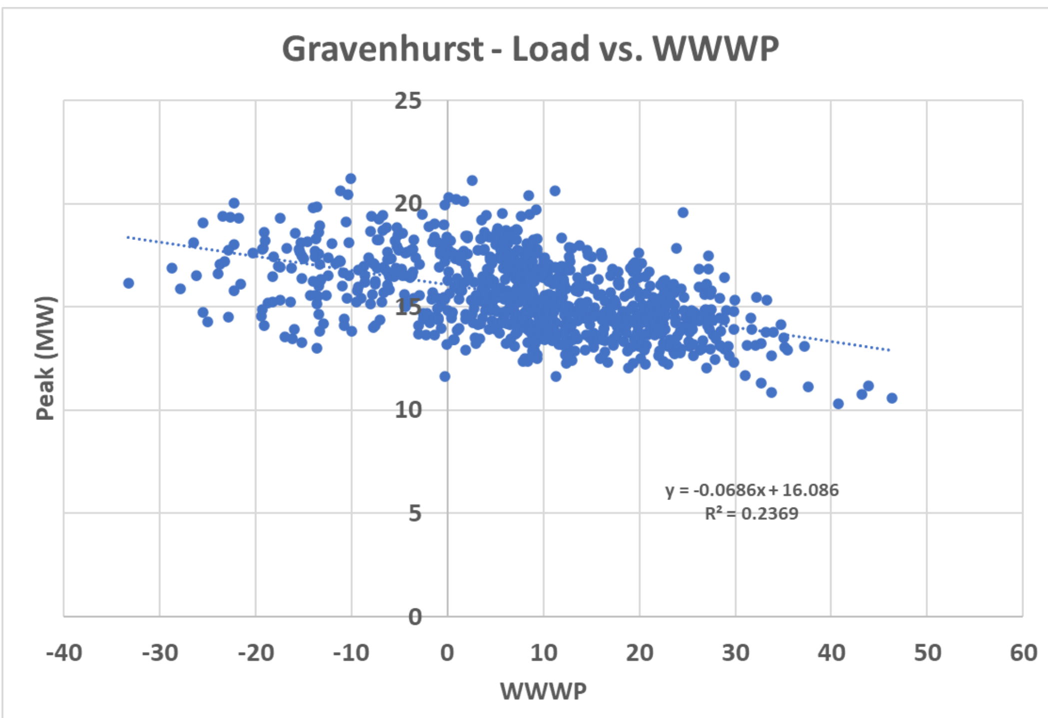

Clarington Load vs. WTHI
y = 0.801x - 26.493
R² = 0.8121
Peak (MW)
WTHI
60.00
50.00
40.00
30.00
20.00
10.00
0.00
50
60
70
80
90
100

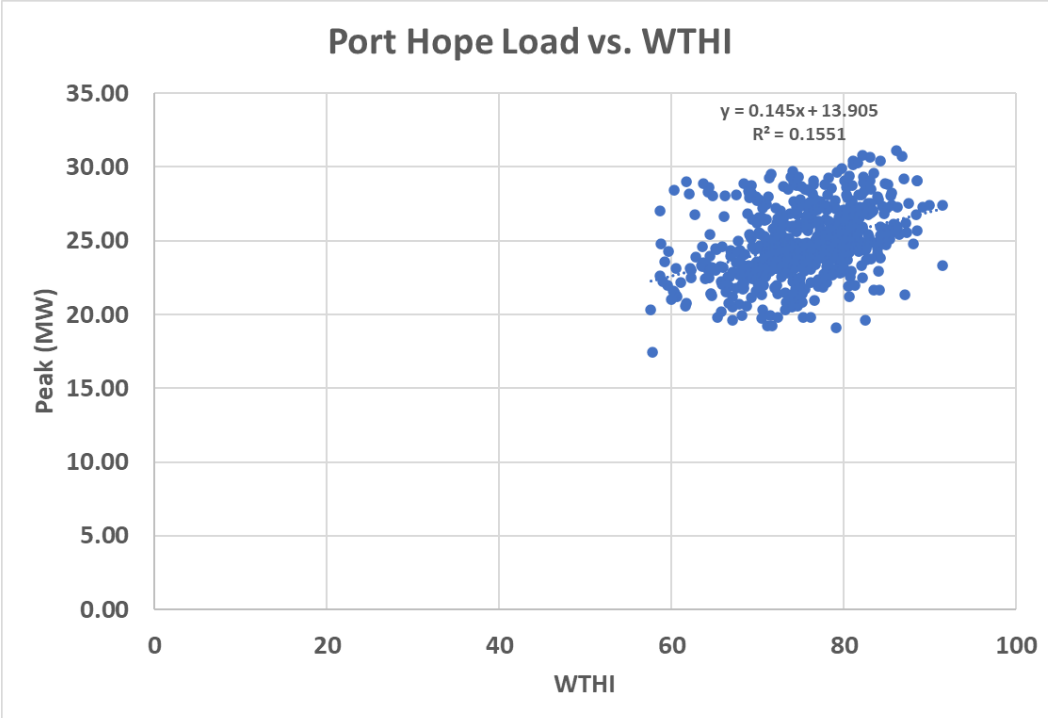

Clarington - Load vs. WWWP
y = -0.1516x + 36.434
R² = 0.5216
Peak (MW)
Axis Title
45
40
35
30
25
20
15
10
5
0
-30
-20
-10
0
10
20
30
40
50
60

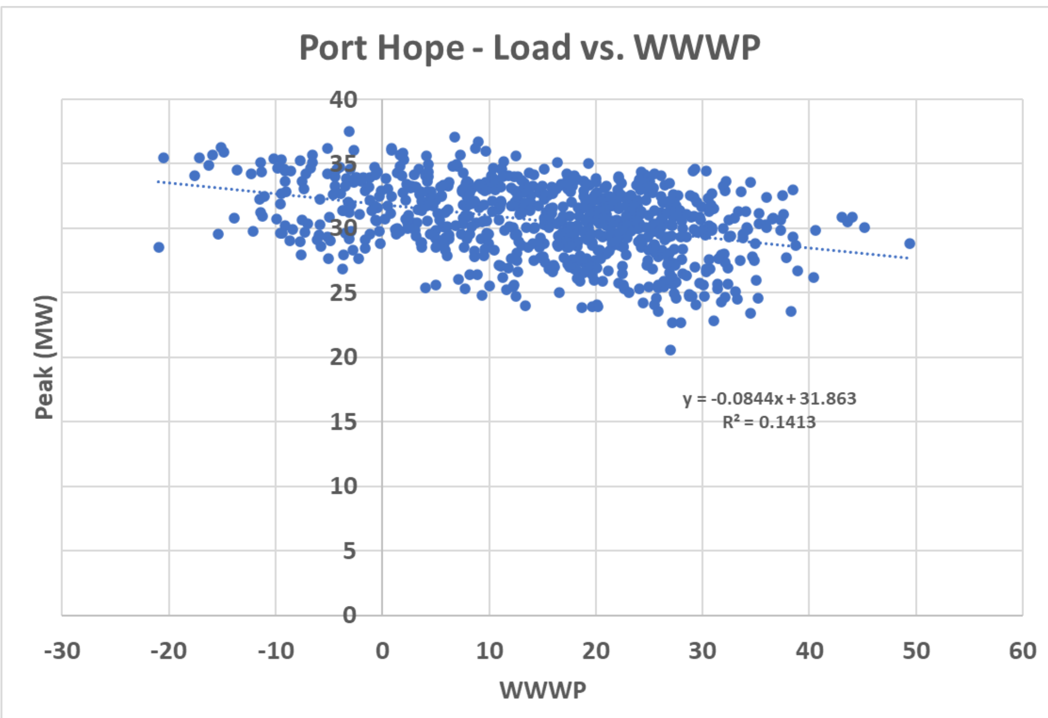

Brock - Load vs. WTHI
y = 0.3134x - 7.3623
R² = 0.826
Peak (MW)
25.00
20.00
15.00
10.00
5.00
0.00
50
55
60
65
70
75
80
85
90
95
WTHI


Brock - Load vs. WWWP
y = -0.1066x + 20.603
R² = 0.4998
Peak (MW)
30
25
20
15
10
5
0
-30
-20
-10
0
10
20
30
40
50
60
WWWP


Gravenhurst - Load vs. WTHI
y = 0.0892x + 6.4553
R² = 0.1924
Peak (MW)
25.00
20.00
15.00
10.00
5.00
0.00
0
20
40
60
80
100
WTHI


Gravenhurst - Load vs. WWWP
y = -0.0686x + 16.086
R² = 0.2369
Peak (MW)
25
20
15
10
5
0
-40
-30
-20
-10
0
10
20
30
40
50
60
WWWP


Port Hope Load vs. WTHI
y = 0.145x + 13.905
R² = 0.1551
Peak (MW)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0
20
40
60
80
100
WTHI


Port Hope - Load vs. WWWP
y = -0.0844x + 31.863
R² = 0.1413
Peak (MW)
40
35
30
25
20
15
10
5
0
-30
-20
-10
0
10
20
30
40
50
60
WWWP

A.2 Historical Residential Customer Counts for Elexicon

Variable	Range	Unit	Granularity	Source
Former Veridian Residential Customer Counts	2014 to 2019	Customers	Ajax, Pickering, Uxbridge, Scugog, Brock, Belleville, Gravenhurst, Port Hope, Clarington	Internal Elexicon Residential Customer Count information
Former Whitby Residential Customer Counts	2014 to 2018	Customers	Whitby	[4] [5] [6] [7] [8]

Pickering - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	28382	28530	28810	29083	29484	29445
Feb	28328	28547	28827	29126	29485	29482
Mar	28349	28561	28845	29150	29661	29518
Apr	28361	28578	28864	29178	29707	29678
May	28395	28609	28876	29255	29741	29795
Jun	28413	28643	28890	29299	29836	29889
Jul	28373	28666	28909	29317	29866	29936
Aug	28400	28690	28930	29339	29903	29978
Sep	28432	28715	28953	29342	29912	30137
Oct	28467	28735	28975	29358	29914	30178
Nov	28491	28755	29010	29405	29939	30213
Dec	28510	28779	29050	29471	29957	30249

Ajax - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	33849	34571	34953	35145	35282	35769
Feb	33860	34604	34989	35158	35321	35791
Mar	33892	34655	35003	35156	35342	35837
Apr	33943	34688	35009	35161	35357	35855
May	33973	34728	35028	35169	35416	35886
Jun	34035	34757	35038	35178	35460	35926
Jul	34103	34806	35043	35183	35483	35947
Aug	34188	34818	35056	35184	35522	35960
Sep	34297	34854	35061	35199	35536	35970
Oct	34417	34895	35066	35216	35553	35995
Nov	34491	34919	35106	35246	35560	36013
Dec	34531	34940	35133	35262	35561	36018

Whitby - Residential Customer Counts						
Month	2013	2014	2015	2016	2017	2018
Year end Annual	38987	39279	39613	39922	40315	40828

Clarington - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	13641	13760	13900	14174	14269	14555
Feb	13644	13769	13924	14168	14270	14561
Mar	13660	13773	13946	14167	14290	14578
Apr	13664	13776	13991	14168	14292	14595
May	13670	13780	14021	14184	14299	14622
Jun	13676	13780	14043	14203	14332	14672
Jul	13686	13782	14063	14205	14370	14693
Aug	13697	13782	14092	14219	14387	14735
Sep	13716	13793	14109	14230	14412	14751
Oct	13727	13838	14133	14242	14431	14770
Nov	13747	13856	14159	14254	14488	14791
Dec	13753	13867	14165	14269	14498	14797

Uxbridge - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	1322	1324	1324	1327	1326	1307
Feb	1322	1325	1325	1327	1326	1307
Mar	1322	1325	1325	1327	1326	1307
Apr	1322	1325	1325	1326	1326	1307
May	1322	1325	1325	1326	1326	1308
Jun	1321	1325	1324	1326	1327	1311
Jul	1321	1325	1324	1325	1326	1311
Aug	1321	1325	1324	1326	1326	1311
Sep	1322	1325	1324	1326	1326	1312
Oct	1322	1324	1324	1326	1327	1315
Nov	1322	1325	1327	1326	1315	1315
Dec	1323	1325	1327	1326	1316	1315

Port Hope - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	4792	4864	4963	5043	5078	5096
Feb	4802	4877	4965	5053	5078	5095
Mar	4806	4879	4971	5053	5087	5095
Apr	4806	4880	4976	5051	5090	5094
May	4805	4887	4986	5050	5092	5094
Jun	4818	4896	4992	5050	5094	5094
Jul	4816	4902	4999	5060	5094	5100
Aug	4824	4911	5005	5061	5094	5107
Sep	4829	4936	5013	5064	5103	5106
Oct	4850	4946	5020	5066	5102	5106
Nov	4861	4950	5027	5074	5103	5108
Dec	4863	4954	5037	5073	5103	5108

Brock - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	2030	2031	2029	2034	2124	2187
Feb	2030	2031	2029	2034	2135	2187
Mar	2030	2031	2029	2033	2143	2190
Apr	2031	2030	2029	2032	2143	2190
May	2031	2030	2032	2032	2123	2190
Jun	2031	2030	2032	2037	2144	2190
Jul	2031	2029	2033	2044	2146	2189
Aug	2032	2030	2033	2046	2198	2244
Sep	2033	2029	2033	2052	2199	2243
Oct	2032	2030	2033	2093	2197	2243
Nov	2032	2030	2034	2106	2198	2245
Dec	2031	2029	2034	2112	2198	2274

Belleville - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	15216	15269	15312	15436	15527	15657
Feb	15216	15273	15311	15454	15535	15659
Mar	15224	15272	15312	15458	15576	15661
Apr	15222	15272	15321	15460	15587	15673
May	15226	15273	15366	15483	15589	15669
Jun	15226	15278	15373	15487	15555	15672
Jul	15233	15280	15377	15491	15573	15672
Aug	15235	15284	15386	15498	15622	15680
Sep	15240	15289	15399	15503	15629	15685
Oct	15246	15291	15406	15514	15641	15688
Nov	15257	15299	15417	15515	15645	15715
Dec	15265	15305	15429	15522	15654	15715

Scugog - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	2035	2036	2033	2039	2042	2038
Feb	2034	2036	2035	2039	2042	2038
Mar	2036	2035	2037	2038	2041	2039
Apr	2036	2035	2036	2038	2042	2039
May	2036	2035	2036	2038	2042	2039
Jun	2036	2035	2036	2038	2042	2039
Jul	2036	2035	2035	2039	2042	2040
Aug	2036	2036	2036	2039	2042	2040
Sep	2035	2035	2035	2040	2035	2040
Oct	2035	2032	2036	2040	2037	2040
Nov	2033	2034	2038	2041	2037	2040
Dec	2035	2033	2038	2042	2037	2040

Gravenhurst - Residential Customer Counts						
Month	2014	2015	2016	2017	2018	2019
Jan	5448	5471	5500	5537	5594	5588
Feb	5447	5472	5502	5543	5594	5588
Mar	5447	5475	5502	5543	5599	5589
Apr	5450	5475	5502	5547	5599	5588
May	5444	5476	5505	5550	5600	5586
Jun	5450	5479	5507	5557	5595	5584
Jul	5454	5483	5511	5558	5593	5583
Aug	5454	5484	5519	5570	5594	5583
Sep	5462	5488	5522	5574	5600	5578
Oct	5461	5489	5521	5576	5597	5583
Nov	5464	5492	5530	5588	5599	5579
Dec	5466	5497	5533	5588	5604	5582

A.3 Municipal Household Estimates & Forecasts

Variable	Range	Unit	Granularity	Source
2019 Durham Household Estimates & Forecasts	Historical: 2014 to 2019 Forecast: 2019 to 2024	Household Units	Ajax, Brock, Clarington, Pickering, Scugog, Uxbridge, Whitby	[9] [10] [11] [12] [13]
2018 Durham Household Estimates & Forecasts	Historical: 2013 to 2018 Forecast: 2018 to 2023	Household Units	Ajax, Brock, Clarington, Pickering, Scugog, Uxbridge, Whitby	[9] [10] [11] [12] [13]
2017 Durham Household Estimates & Forecasts	Historical: 2012 to 2017 Forecast: 2017 to 2022	Household Units	Ajax, Brock, Clarington, Pickering, Scugog, Uxbridge, Whitby	[9] [10] [11] [12] [13]
2016 Durham Household Estimates & Forecasts	Historical: 2011 to 2016 Forecast: 2016 to 2021	Household Units	Ajax, Brock, Clarington, Pickering, Scugog, Uxbridge, Whitby	[9] [10] [11] [12] [13]
2015 Durham Household Estimates & Forecasts	Historical: 2010 to 2015 Forecast: 2015 to 2020	Household Units	Ajax, Brock, Clarington, Pickering, Scugog, Uxbridge, Whitby	[9] [10] [11] [12] [13]
Belleville Household Estimates & Forecasts	Historical: 2001 ,2006, 2011, 2016 Forecast: 2021, 2026, 2031	Household Units	Belleville	[14]
Port Hope Household Estimates & Forecasts	Historical: 2006, 2011, 2016 Forecast: 2019, 2029	Household Units	Port Hope	[15]
Gravenhurst Household Estimates & Forecasts	Historical: 2011 Forecast: 2016, 2026, 2036	Household Units	Gravenhurst	[16] [17]

2019 Durham Household Estimates & Forecasts

Historical Estimate							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2014 (Dec)	36,940	4,490	32,135	30,570	8,130	7,555	43,095
2015 (May)	37,225	4,500	32,335	30,685	8,150	7,565	43,175
2015 (Dec)	37,450	4,520	32,580	30,815	8,175	7,635	43,325
2016 (May)	37,550	4,545	32,840	30,920	8,220	7,665	43,530
2016 (Dec)	37,655	4,550	33,225	30,985	8,225	7,705	43,670
2017 (May)	37,815	4,555	33,570	31,220	8,230	7,795	44,005
2017 (Dec)	38,030	4,600	34,020	31,465	8,235	7,805	44,275
2018 (May)	38,400	4,605	34,290	31,630	8,240	7,850	44,395
2018 (Dec)	38,595	4,670	34,710	31,990	8,240	7,870	44,615
2019 (May)	38,825	4,675	34,955	32,130	8,245	7,905	44,780
Forecast							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2019 (Dec)	39,200	4,710	35,620	33,090	8,400	7,910	45,690
2020 (May)	39,410	4,740	36,000	33,780	8,460	7,930	46,120
2020 (Dec)	39,790	4,780	36,680	35,020	8,580	7,970	46,870
2021 (May)	40,160	4,800	37,060	36,090	8,640	7,990	47,350
2021 (Dec)	40,830	4,830	37,750	37,990	8,770	8,020	48,200
2022 (May)	41,250	4,840	38,150	39,260	8,820	8,040	48,690
2022 (Dec)	41,980	4,870	38,870	41,530	8,910	8,080	49,570
2023 (May)	42,440	4,890	39,260	42,720	8,950	8,090	50,070
2023 (Dec)	43,270	4,920	39,950	44,840	9,030	8,130	50,960
2024 (May)	43,720	4,930	40,370	45,880	9,080	8,160	51,480

2018 Durham Household Estimates & Forecasts

Historical Estimate							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2013 (Dec)	36,440	4,445	31,565	30,350	8,070	7,485	42,690
2014 (May)	36,585	4,460	31,700	30,390	8,095	7,510	42,815
2014 (Dec)	36,940	4,490	32,135	30,570	8,130	7,555	43,095
2015 (May)	37,225	4,500	32,335	30,685	8,150	7,565	43,175
2015 (Dec)	37,450	4,520	32,580	30,815	8,175	7,635	43,325
2016 (May)	37,550	4,545	32,840	30,920	8,220	7,665	43,530
2016 (Dec)	37,655	4,550	33,225	30,985	8,225	7,705	43,670
2017 (May)	37,815	4,555	33,570	31,220	8,230	7,795	44,005
2017 (Dec)	38,030	4,600	34,020	31,465	8,235	7,805	44,275
2018 (May)	38,400	4,605	34,290	31,630	8,240	7,850	44,395
Forecast							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2018 (Dec)	38,360	4,640	35,140	32,180	8,270	7,850	45,130
2019 (May)	38,500	4,660	35,510	32,690	8,320	7,860	45,510
2019 (Dec)	38,750	4,680	36,160	33,610	8,430	7,890	46,180
2020 (May)	39,000	4,710	36,540	34,480	8,490	7,910	46,610
2020 (Dec)	39,450	4,750	37,210	36,030	8,610	7,940	47,360
2021 (May)	39,830	4,770	37,560	37,030	8,670	7,960	47,840
2021 (Dec)	40,510	4,800	38,180	38,800	8,800	8,000	48,690
2022 (May)	40,900	4,810	38,580	39,970	8,850	8,020	49,180
2022 (Dec)	41,590	4,840	39,280	42,040	8,940	8,050	50,060
2023 (May)	42,290	4,860	39,720	42,980	8,970	8,070	50,560

2017 Durham Household Estimates & Forecasts

Historical Estimate							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2012 (Dec)	35,920	4,400	30,995	30,030	8,040	7,440	42,210
2013 (May)	36,135	4,425	31,160	30,145	8,050	7,460	42,435
2013 (Dec)	36,440	4,445	31,565	30,350	8,070	7,485	42,690
2014 (May)	36,590	4,460	31,700	30,390	8,095	7,510	42,815
2014 (Dec)	36,940	4,490	32,135	30,570	8,130	7,555	43,095
2015 (May)	37,225	4,500	32,335	30,690	8,150	7,570	43,175
2015 (Dec)	37,450	4,520	32,580	30,815	8,175	7,635	43,325
2016 (May)	37,550	4,545	32,840	30,920	8,220	7,665	43,530
2016 (Dec)	37,655	4,550	33,225	30,985	8,225	7,705	43,670
2017 (May)	37,815	4,555	33,570	31,220	8,230	7,795	44,005
Forecast							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2017 (Dec)	38,320	4,690	33,850	31,820	8,260	7,750	44,200
2018 (May)	38,630	4,710	34,220	32,220	8,330	7,770	44,430
2018 (Dec)	39,190	4,750	34,880	32,920	8,460	7,800	44,840
2019 (May)	39,550	4,780	35,200	33,700	8,540	7,820	45,160
2019 (Dec)	40,200	4,830	35,760	35,080	8,680	7,860	45,720
2020 (May)	40,660	4,850	36,100	35,850	8,730	7,880	46,060
2020 (Dec)	41,490	4,880	36,700	37,210	8,820	7,910	46,670
2021 (May)	41,920	4,900	37,040	38,050	8,870	7,930	47,070
2021 (Dec)	42,680	4,930	37,640	39,550	8,950	7,960	47,800
2022 (May)	43,160	4,950	38,000	40,420	9,010	7,980	48,220

2016 Durham Household Estimates & Forecasts

Historical Estimate							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2011 (Dec)	35,295	4,340	30,305	29,420	8,005	7,375	41,455
2012 (May)	35,530	4,345	30,490	29,665	8,005	7,390	41,765
2012 (Dec)	36,065	4,350	31,010	30,110	8,015	7,420	42,090
2013 (May)	36,310	4,355	31,175	30,235	8,020	7,430	42,295
2013 (Dec)	36,660	4,360	31,585	30,465	8,030	7,450	42,525
2014 (May)	36,835	4,365	31,725	30,505	8,040	7,470	42,640
2014 (Dec)	37,245	4,370	32,165	30,710	8,055	7,505	42,890
2015 (May)	37,570	4,375	32,365	30,840	8,065	7,515	42,960
2015 (Dec)	37,835	4,375	32,620	30,980	8,075	7,565	43,095
2016 (May)	37,950	4,385	32,880	31,095	8,090	7,590	43,280
Forecast							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2016 (Dec)	38,590	4,460	33,540	31,370	8,090	7,630	43,750
2017 (May)	39,010	4,490	33,880	31,550	8,140	7,640	44,110
2017 (Dec)	39,760	4,540	34,480	31,880	8,230	7,680	44,750
2018 (May)	40,210	4,570	34,830	32,790	8,310	7,690	45,110
2018 (Dec)	41,020	4,620	35,440	34,430	8,450	7,730	45,750
2019 (May)	41,420	4,640	35,790	35,350	8,570	7,740	46,110
2019 (Dec)	42,150	4,670	36,420	36,990	8,770	7,780	46,750
2020 (May)	42,690	4,690	36,770	37,930	8,840	7,790	47,110
2020 (Dec)	43,660	4,720	37,410	39,610	8,960	7,830	47,750
2021 (May)	44,060	4,740	37,770	40,680	9,000	7,840	48,110

2015 Durham Household Estimates & Forecasts

Historical Estimate							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2010 (Dec)	34 675	4 335	29 695	29,310	7,995	7,335	40,805
2011 (May)	35,040	4,335	29,880	29,330	8,000	7,345	41,020
2011 (Dec)	35,295	4,340	30,305	29,420	8,005	7,375	41,455
2012 (May)	35,530	4,345	30,490	29,665	8,005	7,390	41,765
2012 (Dec)	36,065	4,350	31,010	30,110	8,015	7,420	42,090
2013 (May)	36,310	4,355	31,175	30,235	8,020	7,430	42,295
2013 (Dec)	36,660	4,360	31,585	30,465	8,030	7,450	42,525
2014 (May)	36,835	4,365	31,725	30,505	8,040	7,505	42,890
2014 (Dec)	37,245	4,370	32,165	30,710	8,055	7,470	42,890
2015 (May)	37,570	4,375	32,365	30,840	8,065	7,515	42,960
Forecast							
Year	Ajax	Brock	Clarington	Pickering	Scugog	Uxbridge	Whitby
2015 (Dec)	37,740	4,400	33,070	31,250	8,080	7,610	43,290
2016 (May)	37,950	4,410	33,390	31,560	8,100	7,620	43,510
2016 (Dec)	38,310	4,430	33,980	32,110	8,130	7,650	43,890
2017 (May)	38,520	4,440	34,320	33,140	8,200	7,670	44,210
2017 (Dec)	38,890	4,460	34,930	34,970	8,330	7,710	44,790
2018 (May)	39,160	4,470	35,270	36,000	8,380	7,720	45,110
2018 (Dec)	39,640	4,500	35,890	37,830	8,480	7,760	45,690
2019 (May)	39,910	4,510	36,240	39,050	8,520	7,770	46,010
2019 (Dec)	40,390	4,530	36,860	41,240	8,580	7,810	46,590
2020 (May)	40,640	4,540	37,220	42,140	8,620	7,820	46,910

Belleville Household Estimates & Forecasts

Year		Total Households
Historical	2001	19,300
	2006	20,500
	2011	21,100
	2016	21,700
Forecast	2021	23,100
	2026	24,100
	2031	25,000

Port Hope Household Estimates & Forecasts

Year		Total Households
Historical	Mid 2006	6,285
	Mid 2011	6,552
	Mid 2016	7,075
Forecast	Mid 2019	7,240
	Mid 2029	8,575

Gravenhurst Household Estimates & Forecasts

Year		Total Households
Historical	2011	4,675
Forecast	2016	5,010
	2026	5,660
	2036	6,270

A.4 Econometric Model Source Data

Variables tested in Multivariate Regression Model

Variable	Range	Unit	Granularity	Source
Average Economic Family Income	1993-2017	Dollars CAD	Ontario	[18]
Average Precipitation (Winter & Summer)	2009-2019	Millimetres	Oshawa Municipal Airport	[3]
Average Rent of Two Bedroom Apartment	1993-2018	Dollars CAD	Belleville	[19]
Average Rent of Two Bedroom Apartment	2008-2018	Dollars CAD	Brock	[19]
Average Rent of Two Bedroom Apartment	1998-2018	Dollars CAD	Gravenhurst	[19]
Average Rent of Two Bedroom Apartment	1993,1994 1997-1999 2005-2018	Dollars CAD	Port Hope	[19]
Average Rent of Two Bedroom Apartment	2008-2018	Dollars CAD	Scugog	[19]
Average Rent of Two Bedroom Apartment	2010-2018	Count	Whitby	[20]

Average Rent of Two Bedroom Apartment	2011-2018	Count	Pickering	[20]
Average Rent of Two Bedroom Apartment	2011-2018	Count	Ajax	[20]
Average Rent of Two Bedroom Apartment	2011-2018	Count	Uxbridge	[20]
Average Rent of Two Bedroom Apartment	2009-2018	Count	Clarington (Bowmanville, Newcastle, Orono)	[20]
Average Temperature (Winter & Summer)	2009-2019	Degrees Celsius	Oshawa Municipal Airport	[3]
Average Value of Building Permits	2011-2018	Dollars CAD	Ontario	[21]
Business Counts	2015-2018	Count	Ajax	[22]
Business Counts	2015-2018	Count	Brock	[22]

Business Counts	2015-2018	Count	Clarington	[22]
Business Counts	2015-2018	Count	Pickering	[22]
Business Counts	2015-2018	Count	Scugog	[22]
Business Counts	2015-2018	Count	Uxbridge	[22]
Business Counts	2015-2018	Count	Whitby	[22]
Business Counts	2015-2018	Count	Gravenhurst	[23]
Business Counts	2015-2018	Count	Port Hope	[24]
Business Counts	2015-2018	Count	Belleville	[24]

Cooling Degree Days	2009-2019	Days	Oshawa Municipal Airport	[3]
Corporate Greenhouse Gas Emissions Inventory	2007-2016	tonnes CO2e	Durham Region	[25]
Electricity Generation	2008-2019	MWh	Ontario	[26]
Employment	1996-2000	Count	Belleville	[27]
Greenhouse Gas Emissions	2013-2018	Kilotonnes	Ontario	[28]
Heating Degree Days	2009-2019	Days	Oshawa Municipal Airport	[3]
Housing completions	2008-2019	Count	Brock	[29]
Housing completions	1993-2009	Count	Gravenhurst	[29]

Housing completions	1993-2009	Count	Port Hope	[29]
Housing completions	2008-2019	Count	Scugog	[29]
Housing completions	1993-2009	Count	Belleville	[30]
Housing Completions	2010-2019	Count	Whitby	[31]
Housing Completions	2002-2019	Count	Ajax	[32]
Housing Completions	2002-2019	Count	Pickering	[33]
Housing Completions	2002-2019	Count	Clarington	[34]
Housing Completions	2002-2019	Count	Port Hope	[35]

Housing Completions	2002-2019	Count	Uxbridge	[36]
Housing starts	2008-2019	Count	Brock	[29]
Housing starts	2008-2019	Count	Gravenhurst	[29]
Housing starts	1993-2009	Count	Port Hope	[29]
Housing starts	1993-2009	Count	Scugog	[29]
Housing starts	1993-2009	Count	Belleville	[30]
Housing Starts	2014-2018	Count	Durham Region	[37]
Housing Starts	2009-2018	Count	Clarington	[38]

Housing Starts	2016-2018	Count	Bowmanville	[38]
Housing Starts	2016-2018	Count	Newcastle	[38]
Housing Starts	2016-2018	Count	Orono	[38]
Housing Starts	2009-2019	Count	Whitby	[20]
Housing Starts	2009-2018	Count	Ajax	[20]
Housing Starts	2009-2018	Count	Pickering	[20]
Housing Starts	N/A	Count	Uxbridge	[20]
Housing under construction	2008-2019	Count	Brock	[29]

Housing under construction	1993-2019	Count	Gravenhurst	[29]
Housing under construction	1993-2019	Count	Port Hope	[29]
Housing under construction	2008-2019	Count	Scugog	[29]
Housing under construction	1993-2019	Count	Belleville	[30]
Industrial Production Index	2008-2019	Index	Canada	[39]
Number of Households	2011,2016	Count	Whitby	[20]
Number of Households	2010-2019	Count	Belleville	[14]
Number of Households	2010-2019	Count	Port Hope	[15]

Number of Households	2010-2019	Count	Gravenhurst	[16] [17]
ON GHG Emissions - Agriculture	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - Buildings	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - Electricity	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - Indsutry	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - TOTAL	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - Transport	1993-2016	Megatonnes CO2e	Ontario	[40]
ON GHG Emissions - Waste	1993-2016	Megatonnes CO2e	Ontario	[40]

Ontario GDP	1997-2018	Dollars CAD (MM)	Ontario	[41]
Population	2006-2018	Count	Durham Region (excluding Oshawa)	[42]
Population	1993-2005	Count	Durham Region	[43]
Population	2006-2018	Count	Belleville	[44]
Population	2006-2018	Count	Port Hope	[44]
Population	1996-2000	Count	Belleville	[44]
Population	1993-2019	Count	Ontario	[45]
Population	2001,2006, 2011,2016	Count	Gravenhurst	[46]

Population	1993-2012	Count	Gravenhurst	[47]
Population	2009-2018	Count	Whitby	[48]
Population	2009-2018	Count	Ajax	[48]
Population	2009-2018	Count	Pickering	[48]
Population	2011,2016	Count	Belleville	[49] [50]
Population	2009-2018	Count	Brock (Beaverton, Cannington, Sunderland)	[48]
Population	2011,2016	Count	Beaverton	[49] [50]
Population	2011,2016	Count	Cannington	[49] [50]

Population	2011,2016	Count	Sunderland	[49] [50]
Population	2009-2018	Count	Cannington (Bowmanville, Newcastle, Orono)	[48]
Population	2011,2016	Count	Bowmanville	[49] [50]
Population	2011,2016	Count	Newcastle	[49] [50]
Population	2011,2016	Count	Orono	[49] [50]
Population	2009-2018	Count	Scugog/Port Perry	[48]
Population	2009-2018	Count	Uxbridge	[48]
Price of Energy	1993-2018	CPI (relative to 2002)	Ontario	[51]

Renewable Energy Generation	2008-2019	MWh	Ontario	[52]

Forecasted Variables Utilized

Variable	Range	Unit	Granularity	Source
Cooling Degree Days	2020-2030	Day	Ontario	Historical Cooling Degree Day Monthly Average from [3]
Housing Starts	2020-2030	Household Units	Elexicon	[9] [10] [11] [12] [13] [14] [15] [16] [17]

APPENDIX I: Project Prioritization Process

BUDGET PRIORITIZATION PROCESS & FRAMEWORK

Summary Report

August, 2020

Prepared For:

Elexicon Energy Inc.,

55 Taunton Road East

Ajax, ON L1T 3V3

Prepared By:

METSCO Energy Solutions Inc.

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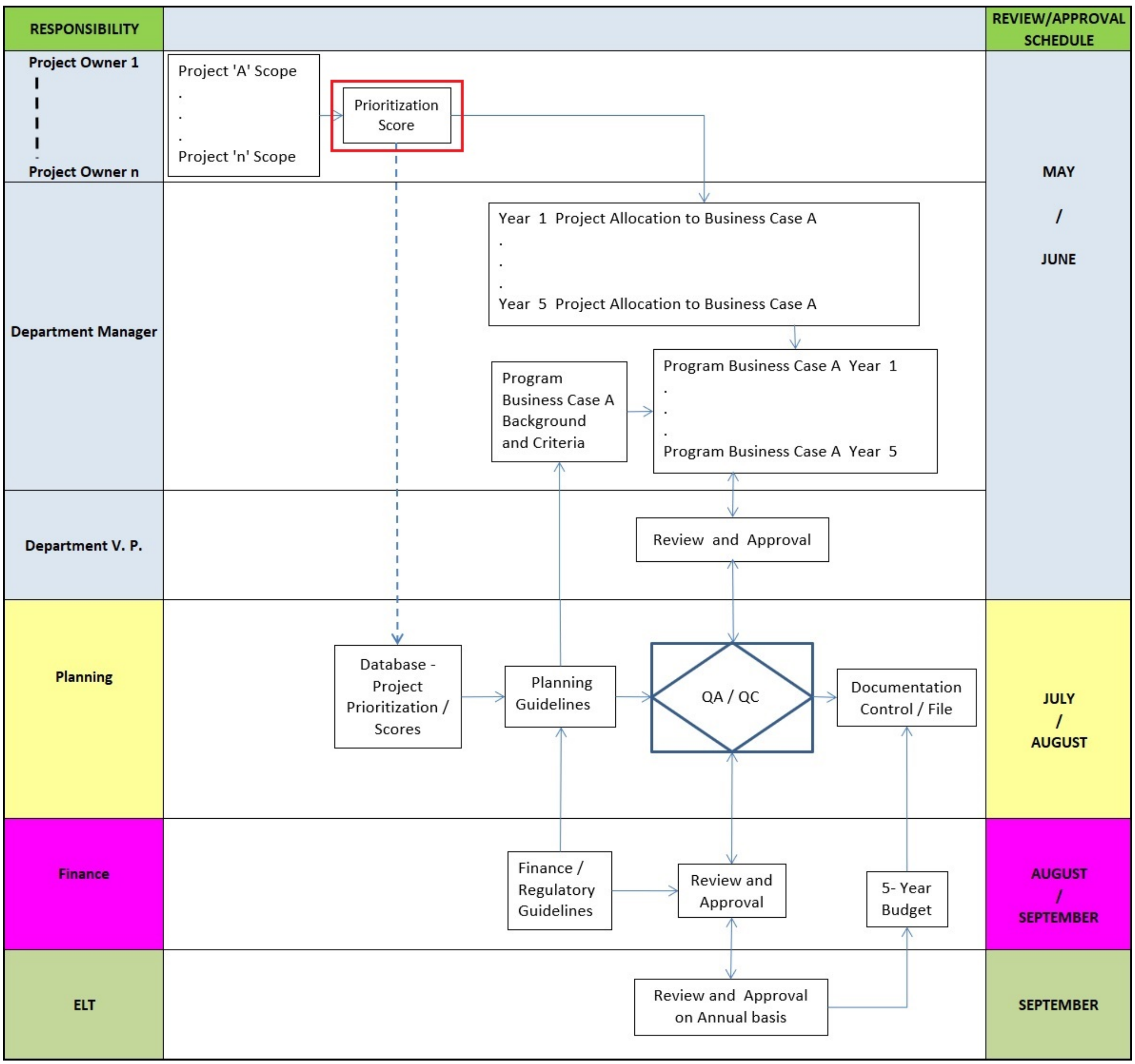
Disclaimer

Table of Contents

Overview & Context

The budget prioritization process and its role within Elexicon's overall capital planning process is depicted in Figure 1 below. The capital planning process begins with the creation of project scope documents, which outline key information such as drivers, costs, benefits, alternatives, and priority. The priority is established through the Prioritization Score, as highlighted in Figure 1, which is an output of the budget prioritization process. The budget prioritization process is a multi-phase, multi-criteria approach which is used to objectively and consistently rank budget items using quantitative and qualitative methods. It allows Elexicon to assess the risk associated with projects, ensure alignment with organizational goals, and optimize capital expenditures. It is a requirement of the Ontario Energy Board's Chapter 5 Filing Requirements for Distribution System Plans. Budget prioritization is conducted annually and adjusted throughout the year as Elexicon's investment needs evolve.

Figure 1: Capital Planning Process



Additional details about the prioritization process are provided in the following section. After scope documents have been created, projects are organized into programs, which are summarized through business case documents by department managers. Business cases are program-level documents which outline key information such as the basis for action, program alternatives, merged operations planning and insights, and the scope documents for the projects within the program. The department manager considers guidelines created by the Planning and Finance departments when creating business cases. These business cases are key documents as they are submitted to the OEB along with the Distribution System Plan ("DSP") as they provide a justification of capital expenditures.

After business cases have been created, they are submitted to the Department Vice President ("VP") who is responsible for reviewing and approving them. After this step is complete, a tentative budget is documented and a Quality Assurance ("QA") process is completed by the Planning department. The Planning department also reviews prioritization scores, adjusts planning guidelines accordingly, and ensures that the budget aligns with planning guidelines. Once the Planning department has completed a QA check, the budget is reviewed and approved by the Finance department, which ensures that the budget aligns with Finance/Regulatory guidelines. The final step of the capital planning process involves Elexicon's executive team, also known as the Elexicon Leadership Team ("ELT"), which is comprised of the individuals listed in Table 1. The ELT completes a final review and approval for the budget and the Planning and Finance departments update the documented budget accordingly.

Table 1: Elexicon Leadership Team Members

Lesley Gallinger	Chief Executive Officer
Falguni Shah	Vice President, Technology and Innovation
Kevin Whitehead	Vice President, Asset Management
Kristine Chandler	General Counsel and Corporate Secretary
Lucy Lombardi	Chief Financial Officer, Vice President, Regulatory Affairs
Moranne McDonnell	Vice President, Distribution Operations
Norm Fraser	Consultant
Rob Scarffe	Vice President, Customer Experience
Stacia Boss	Vice President, Human Resources and Corporate Services

Prioritization Process

The budget prioritization process consists of three steps: filtering out mandatory projects, risk assessment, and project ranking – this section outlines each of these steps.

Filtering

A portion of Elexicon's capital expenditures is mandatory to comply with Conditions of Service and other obligations of Elexicon as a licensed distributor in the Province of Ontario, including customer service requests, plant relocations as a result of third-party infrastructure development requirements, and metering. These mandatory expenditures are classified into the OEB-defined System Access investment category which includes investments that allow Elexicon to fulfill its obligation to provide access to electrical service to customers in its service area via the distribution system. These mandatory capital expenditures are automatically promoted to the appropriate years' investment plan rather than receiving a Priority Score.

Risk Assessment

Risk Assessment is the process of calculating prioritization scores for non-mandatory investments in order to prioritize them. The prioritization score is calculated using the following equation:

$$Prioritization\ Score = \sum Criterion\ Weight * Risk\ Score$$

where the risk score is calculated as follows:

$$Risk\ Score = Impact\ Score * Probability\ Score$$

The equations above are combined to yield the final prioritization score formula:

$$Prioritization\ Score = \sum Criterion\ Weight * Impact\ Score * Probability\ Score$$

The first element of this formula, the Criterion Weight, is an input from Elexicon's AM objectives. Elexicon's AM objectives are a set of goals that reflect Elexicon's corporate values, drive key strategic decisions, and influence investment planning. Given that Elexicon is a recently merged utility, its AM objectives were developed using the AM objectives of the two legacy utilities as a starting point. The legacy objectives were modified to reflect system and non-system objectives and to align with industry standards. Elexicon's AM Objectives are summarized in Table 2 below. Each objective has an associated weight which indicates its relative importance in comparison to other objectives and is calculated based on an Analytic Hierarchy Process ("AHP"). The ELT participates in this process as each member completes pairwise comparisons between all AM objectives[1]. The participants assign a value between 1 and 9 to represent the relative importance of one objective in comparison to another[2]. A mathematical model is used to determine the weight of each objective based on the inputs provided by all participants[3]. This approach allows Elexicon to align the priorities of all business units with its corporate goals and objectives. The proposed methodology

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[1] K. D. Goepel, "Implementing the analytic hierarchy process as a standard method for multi-criteria decision making in corporate enterprises," *Proc. Int. Symp. Analytic Hierarchy Process*, Kuala Lumpur, Malaysia, 2013.
[2] K.D. Goepel, "Comparison of Judgment Scales of the Analytical Hierarchy Process - A New Approach," 20 May 2018. [Online]. Available: https://bpmsg.com/wordpress/wp-content/uploads/2018/05/2018-05-10-AHP-Judgm-Scales-blog.pdf
[3] K. D. Goepel, "New AHP Excel template with multiple inputs," [Online]. Available: https://bpmsg.com/new-ahp-excel-template-with-multiple-inputs/.

has been successfully used as a decision-making tool throughout several industries[4]. The Criterion Weight in the prioritization score equation above is equal to the AM objective weight listed in Table 2 below.

Table 2: Elexicon's AM Objectives and Weights

AM Objective	Description	Weight
Service Continuity	Risk of sustained interruptions to material segments of customer load (system projects) or those associated with non-electrical equipment that facilitates core utility operations (general plant projects).	8.4%
Customer Convenience/Confidence	Risk of underinvestment in utility plant and general plant (e.g., customer care and metering) that causes material inconvenience to the customers' interaction with the utility and its assets.	5.8%
Customer Preferences	Risk of material customer dissatisfaction resulting from a failure to consider customer preferences when planning investments.	3.7%
Worker/Public Safety	Risk of safety incidents sustained by Elexicon's staff, contractor, or general public living, working, or in transit in the vicinity of the utility's equipment.	32.0%
Asset Performance and Health	Risk of asset deterioration through normal wear and tear up to the point where replacement is the most economical intervention option.	5.1%
Workforce Health and Productivity	Risk of restrictions to safe and efficient operation of staff or core utility functions due to spatial constraints or access restrictions caused by major facilities systems outages.	17.7%
Operational Efficiency	Risk of lost opportunities for efficiency improvements through investment in labour-saving capital equipment.	5.4%
Environmental Impact	Risk of unplanned and uncontrolled release of a hazardous substance required in normal operation of Elexicon's equipment into the natural environment.	11.4%
Regulatory Compliance	Risk of non-compliance with regulatory and legislative requirements to ensure that its system meets relevant standards.	10.5%

The second element of the prioritization score formula, the Impact Score, is identified using the tables provided in Appendix A: Scoring Frameworks for All Criteria. Each criterion or AM objective has a unique predefined scoring paradigm which quantifies the impacts of non-completion – for example, Table 4 outlines the scoring framework for the Service Continuity criteria. In some cases, including the Service Continuity criterion, system projects and general plant projects are assessed using different impacts as they vary in nature. In this manner, the potential bias between system and non-system investments is eliminated since all categories apply to both types of investments.

The third element of the prioritization score formula, the Probability Score, is consistent across all AM objectives and is identified using Table 13. It reflects the probability of occurrence of the impact used to identify the Impact Score. The project planner/owner of the business unit is responsible to develop the scope

[4] D. Maletič, F. Lasrado, M. Maletič, and B. Gomišček, "Analytic Hierarchy Process Application in Different Organisational Settings," IntechOpen, 31-Aug-2016. [Online]. Available: https://www.intechopen.com/books/applications-and-theory-of-analytic-hierarchy-process-decision-making-for-strategic-decisions/analytic-hierarchy-process-application-in-different-organisational-settings.

and to select, from the tables provided in the appendix, the criteria which accurately identifies the risks mitigated by that project, as outlined in Figure 1. Elexicon's internal QA/QC process provides additional checks to confirm the accuracy of the scoring ensures that the overall approach is consistent between projects. Once identified, the impact and probability scores can be used in conjunction with the criterion weight to calculate the priority score for a single criterion. The final prioritization score is the sum product of the Criterion Weight, Impact Score, and Probability score across all criteria – a sample calculation is provided in Table 3below.

Table 3: Sample Prioritization Score Calculation

Criteria	Weight	Impact Score	Probability Score	Calculation	Final Score
Service Continuity	8.4%	25	1	=0.084*25*1	2.1
Customer Convenience/Confidence	5.8%	3	4	=0.058*3*4	0.696
Customer Preferences	3.7%	0	4	=0.037*0*4	0
Worker/Public Safety	32.0%	9	3	=0.32*9*3	8.64
Asset Performance and Health	5.1%	3	2	=0.051*3*2	0.306
Workforce Health and Productivity	17.7%	0	1	=0.177*0*1	0
Operational Efficiency	5.4%	25	3	=0.054*25*3	4.05
Environmental Impact	11.4%	1	4	=0.114*1*4	0.456
Regulatory Compliance	10.5%	9	1	=0.105*9*1	0.946
Final Prioritization Score					17.2

Project Ranking

Once priority scores have been calculated for all projects within an investment category, they can be prioritized accordingly. This process allows Elexicon to understand which projects have the greatest risk associated with non-completion and those that will provide the most benefit to its distribution system, operations, and customers.

Conclusions & Recommendations

The budget prioritization process should be applied annually once the overall budget envelopes have been set. The results of the budget prioritization process should be referenced whenever budget adjustments need to be made throughout the year (e.g., due to unforeseen investment needs). An investment's priority score indicates how closely it aligns with Elexicon's asset management objectives. The results should also be used to inform the budget setting process for future years.

The long-term approach for Elexicon with respect to its AM objectives is to develop a Strategic Asset Management Plan ("SAMP"). The SAMP describes the relationship between an organization's corporate goals and AM objectives, while also providing a roadmap to develop the organization's AM capabilities. The SAMP is a living document that will be updated annually; thus, the validity of the set of AM objectives is confirmed annually.

Although it is recommended to update the SAMP annually, it is not necessary to repeat the AHP exercise annually to recalculate the weights. The weights should be recalculated whenever there is a shift in strategy at the company. Without this triggering event, it is recommended to reassess the weights every five years, at a minimum.

Appendix A: Scoring Frameworks for All Criteria

Table 4: Scoring Framework for Service Continuity Impacts

Electrical Service Continuity - risk of sustained interruptions to material segments of customer load.	Utility Systems Service Continuity - risk of material interruptions or service restrictions associated with non-electrical equipment that facilitates core utility operations	Score
Relevant to all types of Electrical Assets.	*Relevant for all types of General Plant investments*	
no impact on reliability of distribution.	No impact on assets' operating performance	0
potential sustained interruption of < 0.5 MW of distribution load (< 100 residential customers)	IT/OT system interruption or safe facility access / operability restriction resulting in loss of < 50 hours of productive time annually	1
potential sustained interruption of 0.5-1.5 MW of distribution load (100-300 residential customers)	IT/OT system interruption or safe facility access / operability restriction resulting in loss of 50-150 hours of productive time annually	3
potential sustained interruption of 1.5-4.5 MW of distribution load (300-900 residential customers)	IT/OT system interruption or safe facility access / operability restriction resulting in loss of 150-450 hours of productive time annually	9
potential sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers)	IT/OT system interruption or safe facility access / operability restriction resulting in loss of 450-1250 hours of productive time annually	25
potential sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers)	IT/OT system interruption or safe facility access / operability restriction resulting in loss of > 1250 hours of productive time annually	50

Table 5: Scoring Framework for Safety & Security Impacts

Safety & Security - Risk of safety and/or physical/cyber security incidents sustained by Elexicon's staff, contractor or general public.		Score
Relevant to Electrical Plant as well as most Fleet and Facilities investments, and IT/OT work involving Control Centre work.	*Relevant to Electrical Plant as well as most Fleet and Facilities investments, and IT/OT work involving Control Centre work.*	
no impact on safety.	no impact on safety.	0
risk of near miss events. However, such issues can also be prevented with regular PPE and Job Plan.	risk of near miss events. However, such issues can also be prevented with regular mitigation measures.	1
risk of minor injury/ illness requiring first aid. Impairment is reversible and can be prevented with added PPE and Job Plan.	risk of minor injury/ illness requiring first aid or minor physical/cyber security incident. Impairment is reversible and can be prevented with extra mitigation measures.	3
risk of moderate injury/illness requiring first aid. Impairment is reversible and can be prevented with additional safety measures.	risk of moderate injury/illness requiring first aid or moderate physical/cyber security incident. Impairment is reversible and can be prevented with additional mitigation measures.	9
risk of serious injury/illness requiring medical attention. LTI or temporary impairment will result in continued as-is state and additional safety measure is required to mitigate the risk.	risk of serious injury/illness requiring medical attention or serious physical/cyber security incident. LTI or temporary impairment will result in continued as-is state and additional mitigation measures are required.	25
risk of permanent disabling injury or fatality to both the public and employees. Additional safety measures are required to mitigate the risk.	risk of permanent disabling injury or fatality to both the public and employees. Additional safety measures are required to mitigate the risk.	50

Table 6: Scoring Framework for Asset Performance, Health, and Lifecycle Optimization Impacts

Asset Performance, Health & Lifecycle Optimization - risk of asset deterioration through normal wear and tear up to the point where replacement is the most economical intervention option.		Score
Relevant to all types of electrical assets, including growth-driven projects where non-investment would cause existing assets to be overloaded.	*Relevant to all types of non-system assets.*	
no impact on asset performance or health.	no impact on asset performance or health.	0
minor deterioration to assets with no current deficiencies or impact on service levels.	minor deterioration to assets with no current deficiencies or impact on service levels.	1
minor deterioration to assets where majority of assets are in good or better condition	minor deterioration to assets where majority of assets are in good or better condition	3
moderate deterioration (i.e. condition is Fair) of assets, but still functioning properly.	moderate deterioration of assets or reaching the end of normal manufacturer support.	9
significant deterioration of assets or equipment that are still functioning properly.	Equipment operating within extended manufacturer support.	25
asset deficiency impacting reliable operation of electrical equipment at a station level.	Critical General Plant assets operating beyond the extended manufacturer support for >5% of total service life to date.	50

Table 7: Scoring Framework for Environmental Impacts

Environmental Impact - Risk of unplanned and uncontrolled release of a hazardous substance required in normal operation of Elexicon's equipment into the natural environment.	Environmental Impact - Risk of unplanned and uncontrolled release of a hazardous substance required in normal operation of Elexicon's equipment into the natural environment.	Score
Relevant to most types of Electrical Plant as well as Fleet and Facilities Investments	*Relevant to most types of Electrical Plant as well as Fleet and Facilities Investments*	
no impact on environmental concerns	no impact on environmental concerns	0
possibility of a non-reportable event or minor improvement in electrical efficiency.	possibility of a non-reportable event or minor improvement in electrical efficiency.	1
possibility of reportable event that is mitigated with current EMS or moderate improvement in electrical efficiency.	possibility of reportable event that are mitigated with current EMS or moderate improvement in electrical efficiency.	3
possibility of reportable event that is not mitigated with current EMS, major improvement in electrical efficiency, or minor reduction in GHG emissions.	possibility of reportable event that are not mitigated with current EMS, major improvement in electrical efficiency, or minor reduction in GHG emissions.	9
possibility of environmental damage or moderate reduction in GHG emissions.	possibility of environmental damage or moderate reduction in GHG emissions.	25
non-compliance with environmental regulations or major reduction in GHG emissions.	non-compliance with environmental regulations or major reduction in GHG emissions.	50

Table 8: Scoring Framework for Workforce Health and Productivity Impacts

Healthy & Productive Workforce - project replaces substandard equipment or otherwise improves the operations and maintenance practices on the system	Healthy & Productive Workforce - risk of restrictions to safe and efficient operation of staff or core utility functions due to spatial constraints or access restrictions caused by major facility/system outages.	Score
Pertains to any asset change on the system that improves the utility's maintenance or operations practice such as switching of correcting substandard equipment.	*Relevant primarily for Fleet and Facilities investments and certain IT/OT investments (e.g., enabling remote connectivity).*	
No impact on correcting substandard conditions or improving the operations and maintenance practice on the system	No impact on staff's working conditions or operations logistics	0
Minor correction of substandard conditions improving the operations and maintenance practices on the system	Minor (but manageable) deviation from corporate standards on staff's working areas or optimal logistical support arrangements (e.g. equipment storage)	1
< 5% of the new assets will improve the operations and maintenance practices on the system	< 5% of local operating centre staff or supporting operations footprint cannot be accommodated in a manner prescribed by corporate standards	3
5-15% of the new assets will improve the operations and maintenance practices on the system	5-15% of local operating centre staff or supporting operations footprint cannot be accommodated in a manner prescribed by corporate standards	9
15-50% of the new assets will improve the operations and maintenance practices on the system	15-50% of local operating centre staff or supporting operations footprint cannot be accommodated in a manner prescribed by corporate standards	25
> 50% of the new assets will improve the operations and maintenance practices on the system	> 50% of local operating centre staff or supporting operations footprint cannot be accommodated in a manner prescribed by corporate standards	50

Table 9: Scoring Framework for Operational Efficiency Impacts

Operational Efficiency - risk of lost opportunities for efficiency improvements through investment in labour-saving capital equipment.		Score
Relevant for all types of investments.	*Relevant for all types of investments.*	
No impact on OM&A costs over the five-year period	No impact on OM&A costs over the five-year period	0
OM&A cost reduction/avoidance of < $10k	OM&A cost reduction/avoidance of < $10k	1
OM&A cost reduction/avoidance of $10k-$30k	OM&A cost reduction/avoidance of $10k-$30k	3
OM&A cost reduction/avoidance of $30k-$90k	OM&A cost reduction/avoidance of $30k-$90k	9
OM&A cost reduction/avoidance of $90k-$250k	OM&A cost reduction/avoidance of $90k-$250k	25
OM&A cost reduction/avoidance > $250k	OM&A cost reduction/avoidance > $250k	50

Table 10: Scoring Framework for Customer Convenience and Confidence Impacts

Customer Convenience and Confidence - risk of underinvestment in utility plant that causes material inconvenience to the customers' interaction with the utility and its assets.		Score
Most readily relevant to IT/OT investments in the area of Customer Care / Meter-to-Cash Value Chain, but also larger Electrical Plant where outages can cause prolonged traffic disruptions.	*Most readily relevant to IT/OT investments in the area of Customer Care / Meter-to-Cash Value Chain, but also larger Electrical Plant where outages can cause prolonged traffic disruptions.*	
No impact on the manner customers interact with the utility or their expectations and preferences as to the scope and nature of investments or services	No impact on the manner customers interact with the utility or their expectations and preferences as to the scope and nature of investments or services	0
Asset / system malfunction results in a reduction of speed / efficiency / convenience of normal interaction between customers and the utility for < 1 business day per year	Asset / system malfunction results in a reduction of speed / efficiency / convenience of normal interaction between customers and the utility for < 1 business day per year	1
Asset / system malfunction results in a reduction of speed / efficiency / convenience of normal interaction between customers and the utility for < 5 business days per year	Asset / system malfunction results in a reduction of speed / efficiency / convenience of normal interaction between customers and the utility for < 5 business days per year	3
Asset / system malfunction leads to a measurable impact on customers' day-to-day activities for < 30 business days in a year (e.g. disrupting traffic, or access to account info)	Asset / system malfunction leads to a measurable impact on customers' day-to-day activities for < 30 business days in a year (e.g. disrupting traffic, or access to account info)	9
Asset / system malfunction leads to a measurable impact on customers' day-to-day activities for < 90 business days in a year (e.g. disrupting traffic, or access to account info)	Asset / system malfunction leads to a measurable impact on customers' day-to-day activities for < 90 business days in a year (e.g. disrupting traffic, or access to account info)	25
Asset / system malfunction leads to missing one or more annual Distributor Scorecard ESQR targets related to customer service (e.g. billing accuracy, appointments scheduling).	Asset / system malfunction leads to missing one or more annual Distributor Scorecard ESQR targets related to customer service (e.g. billing accuracy, appointments scheduling).	50

Table 11: Scoring Framework for Regulatory Compliance Impacts

Regulatory Compliance - ensure the asset management strategies are compliant with regulations and legal obligations are met		Scores
Relevant to all investments	*Relevant to all investments*	
No impact on regulatory compliance.	No impact on regulatory compliance.	0
Minor improvements where regulations and standards are currently being met.	Minor improvements where regulations and standards are currently being met.	1
Addresses an issue that with become non-conformant with best practices if no action is taken.	Addresses an issue that with become non-conformant with best practices if no action is taken.	3
Addresses a currently non-conformant issue with respect to best practices	Addresses a currently non-conformant issue with respect to best practices	9
Addresses an issue that with become non-compliant with regulations if no action is taken.	Addresses an issue that with become non-compliant with regulations if no action is taken.	25
Addresses a currently non-compliant issue to meet regulations or external standards for asset operations	Addresses a currently non-compliant issue to meet regulations or external standards for asset operations	50

Table 12: Scoring Framework for Customer Preference Impacts

Customer Preference – directly from the customer engagement results based on the customers support for the proposed or accelerated approach		Scores
Applies to all investments tested with customers	*Applies to all investments tested with customers*	
highly negative customer impact; <25% of customers support the proposed or accelerated approach.	highly negative customer impact; <25% of customers support the proposed or accelerated approach.	-25
negative customer impact; 25%-45% of customers support the proposed or accelerated approach.	negative customer impact; 25%-45% of customers support the proposed or accelerated approach.	-9
neutral customer impact; 45%-55% of customers support the proposed OR primary driver is outside the top 5 customer priorities	neutral customer impact; 45%-55% of customers support the proposed OR primary driver is outside the top 5 customer priorities	0
positive customer impact; 55%-75% of customers support the proposed or accelerated approach OR primary driver is a top 5 customer priority	positive customer impact; 55%-75% of customers support the proposed or accelerated approach OR primary driver is a top 5 customer priority	9
highly positive customer impact; >75% of customers support the proposed or accelerated approach OR primary driver is a top 2 customer priority	highly positive customer impact; >75% of customers support the proposed or accelerated approach OR primary driver is a top 2 customer priority	25

Table 13: Scoring Framework for Probability Score

Frequency of Occurrence	Score
is very unlikely (i.e., it can be assumed occurrence may not be experienced).	1
is unlikely to occur during the 5-year planning period.	2
is likely (i.e., expected to occur once during the 5-year planning period).	3
is very likely (i.e., expected to occur more than once during the 5-year planning period).	4
is almost certain (i.e., is expected to occur frequently during the 5-year planning period).	5

APPENDIX J: Reliability Report

Distribution System Reliability Analysis

Final Report

May 25, 2020

Elexicon Energy Inc.

55 Tauton Road East

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TABLE OF CONTENTS

Introduction

Elexicon Energy Inc.'s ("Elexicon") distribution system is comprised of many components and processes which provide power to its customers. It consists of several complex and interconnected devices and assets which work collectively to achieve this goal. These components and their related processes are frequently monitored and refined in order to ensure that they are operating optimally and providing the required service. However, the distribution system can malfunction for a variety of reasons and Elexicon's customers may experience service interruptions as a result. These outages are problematic as they negatively affect customer experience, reliability performance, and Elexicon's ability to achieve its corporate objectives.

This report analyzes various aspects of Elexicon's distribution system reliability performance in order to understand the nature and impact of service interruptions. Specifically, this report analyzes Elexicon's historical reliability performance, outages by cause code, Major Event Days ("MED"), and Worst Performing Feeders ("WPF"). These analyses allow Elexicon to identify factors which pose a risk to system reliability and take action to mitigate these risks. The outcomes of this report also play a role in the planning processes involved in Elexicon's Distribution System Plan ("DSP").

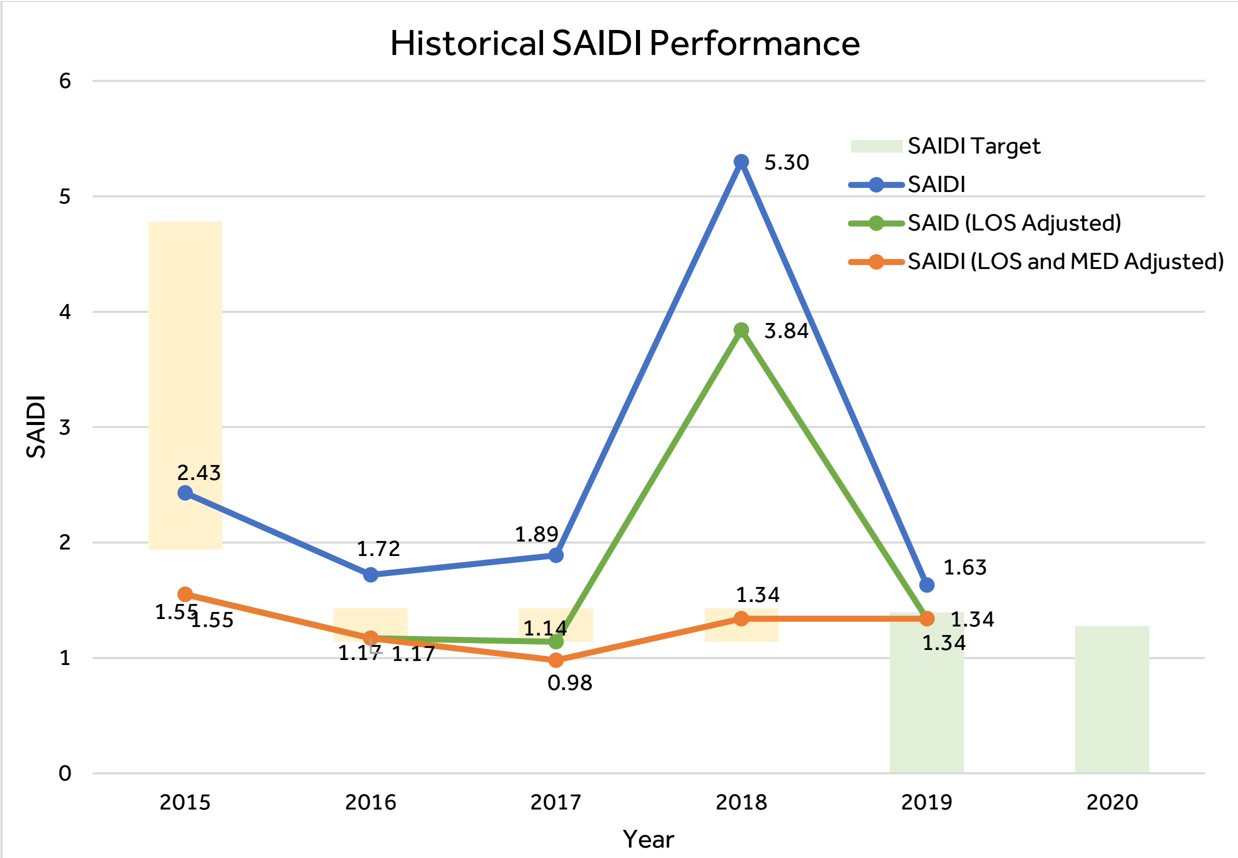
Historical Performance

Table 1 below shows Elexicon's historical performance for the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI") reliability measures and includes adjustments for Loss of Supply ("LOS") events and MEDs. Targets for these measures are set by taking the five-year average of Elexicon's performance over the historical period, which is 2015 to 2019 for the upcoming DSP. Therefore, it is expected that approximately half of the historical data will exceed the current target and the other half will fail to meet it. Given the fact that Elexicon began operating in 2019, historical targets from 2015-2018 are unavailable. Instead, a target range is highlighted in Figure 1 and Figure 2 below. These ranges represent the maximum/minimum target values and are based on the target values of the predecessor utilities.

Table 1: Historical Reliability Performance

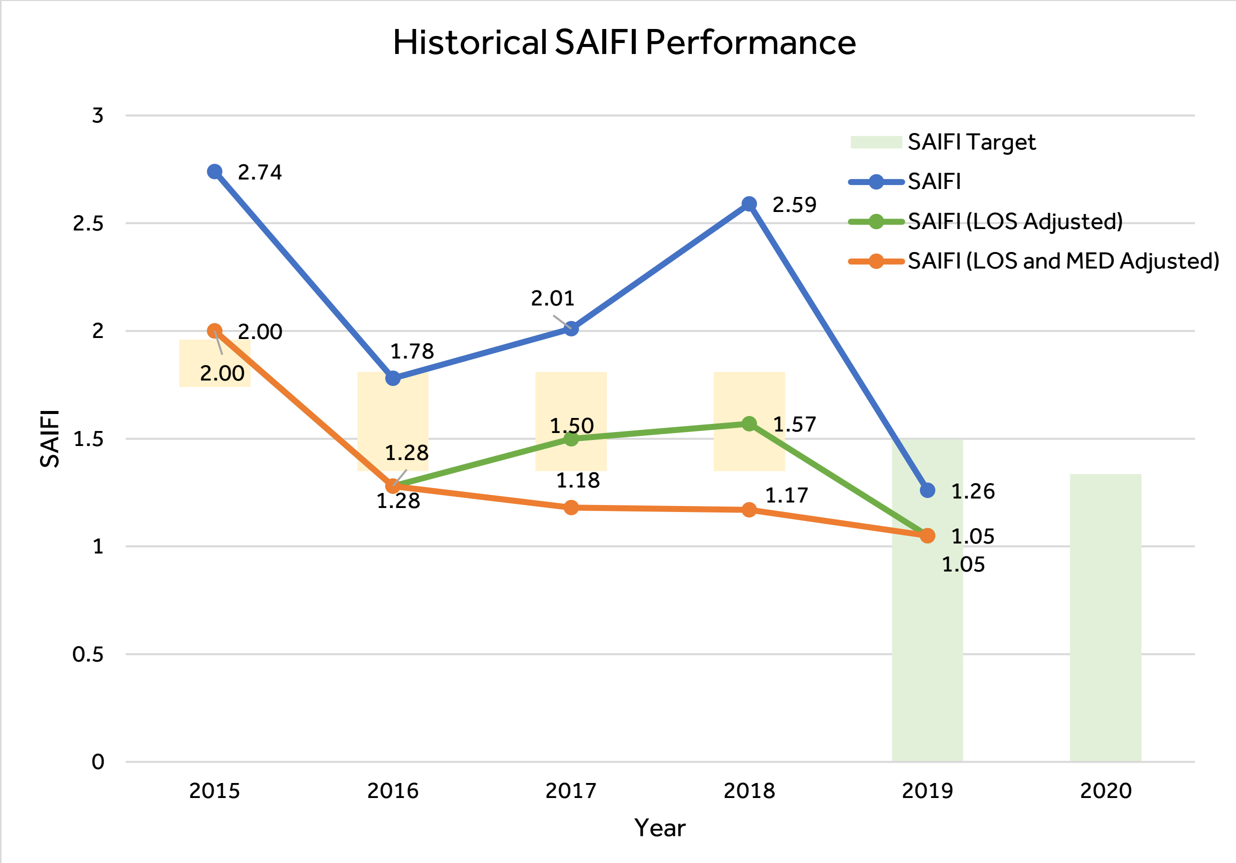
Metric	2015	2016	2017	2018	2019	Target
Total Outages						
SAIDI	2.43	1.72	1.89	5.30	1.63	2.59
SAIFI	2.74	1.78	2.01	2.59	1.26	2.08
Loss of Supply Adjusted						
SAIDI	1.55	1.17	1.14	3.84	1.34	1.81
SAIFI	2.00	1.28	1.5	1.57	1.05	1.48
Loss of Supply and Major Event Adjusted						
SAIDI	1.55	1.17	0.98	1.34	1.34	1.28
SAIFI	2.00	1.28	1.18	1.17	1.05	1.33

Figure 1: Historical SAIDI Performance



Elexicon's historical performance for SAIDI indicates that the system's reliability is consistent as there is no notable upward or downward trend over the historical period (for LOS and MED adjusted values). Elexicon's historical performance for SAIDI falls within the acceptable range for all years during the historical period after adjusting for LOS and MED events. A notable aspect of the historical period is the result in 2018. During this year, SAIDI was extremely high at 5.3 prior to LOS and MED adjustments. This occurred due to a high volume of MEDs which were primarily caused by Adverse Weather and LOS and are discussed in more detail in the MEDs analysis below. The current target value for SAIDI is 1.28 and is based on the historical performance from 2015 to 2019.

Figure 2: Historical SAIFI Performance



Elexicon's SAIFI performance trend indicates that the system's reliability is improving as it trends downwards over the historical period. Elexicon's historical performance for SAIFI is relatively high prior to LOS and MED adjustments in 2015 and 2018. As mentioned above, Elexicon experienced a high volume of MEDs in 2018 which were caused by Adverse Weather and LOS events. Elexicon's 2018 performance falls within the acceptable range after adjusting for MEDs and LOS events. In 2015, Elexicon also experienced a higher than average volume of MEDs, nearly all of which were driven by LOS related outages. After adjusting for LOS and MEDs in 2015, Elexicon marginally fails to meet the target by 0.04 or 2%. Additional information about these MEDs can be found in the MEDs analysis section. The current target value for SAIFI is 1.34 is based on the historical performance from 2015 to 2019.

Cause Code Analysis

Table 2 below shows the volume of outages which occurred during the historical period. MED related outages and momentary interruptions are excluded to better understand the typical volume of sustained interruptions experienced by Elexicon customers. In addition, MEDs are discussed in greater detail in the MEDs analysis section. Elexicon experiences 1,081 sustained interruptions per year on average. The number of outages experienced by Elexicon's customers varies over the course of the historical period, ranging from 1,006 to 1,187. Table 2 also shows the disaggregation of outages by cause code. There is a slight increase in the number of outages in 2018, primarily due to an increase in the number of LOS events.

Over the historical period, the most significant contributors to Customer Hours Interrupted ("CHI") were Loss of Supply (29.9%) and Defective Equipment (25.9%). LOS events can be difficult to minimize, but the number of outages due to Defective Equipment may indicate the need for increased asset replacement efforts. Other contributors which are less significant but still impactful include Foreign Interference (11.1%), Tree Contacts (10.3%), and Adverse Weather (9.9%). The remaining cause codes collectively account for 12.8% of CHI. A breakdown of sustained interruptions by cause code in terms of the number of outages, Customers Interrupted ("CI"), and CHI can be found in Figure 4, Figure 5, and Figure 6 respectively. These sustained interruptions are further analyzed and discussed in terms of cause codes below.

Table 2: Outage Volume by Cause Code

Outage Data (excluding MEDs and momentary interruptions)						
Number of Interruptions by Cause Code						
Cause Code	2015	2016	2017	2018	2019	%
0 - Unknown/Other	123	107	95	96	119	10.0%
1 - Scheduled Outage	169	286	256	263	186	21.5%
2 - Loss of Supply	51	40	49	40	29	3.9%
3 - Tree Contacts	92	72	82	81	54	7.1%
4 - Lightning	8	3	10	1	1	0.4%
5 - Defective Equipment	380	301	331	403	379	33.2%
6 - Adverse Weather	35	35	36	68	26	3.7%
7 - Adverse Environment	2	8	2	3	6	0.4%
8 - Human Element	18	11	17	14	5	1.2%
9 - Foreign Interference	224	176	192	218	201	18.7%
Total	**1,102**	**1,039**	**1,070**	**1,187**	**1,006**	**100%**
Number of Customers Interrupted by Cause Code						
Cause Code	2015	2016	2017	2018	2019	%
0 - Unknown/Other	79,031	37,170	33,349	43,888	32,129	14.9%
1 - Scheduled Outage	3,358	4,558	7,990	7,557	7,582	2.0%
2 - Loss of Supply	100,762	80,732	84,022	122,709	37,442	28.1%
3 - Tree Contacts	26,483	26,834	21,173	14,571	11,101	6.6%
4 - Lightning	3,516	2,395	7,163	508	1	0.9%
5 - Defective Equipment	126,416	63,803	56,788	53,910	69,447	24.4%
6 - Adverse Weather	13,078	30,123	31,916	32,080	13,789	8.0%
7 - Adverse Environment	2	6,689	179	650	2,501	0.7%
8 - Human Element	16,819	10,354	13,984	11,616	2,247	3.6%
9 - Foreign Interference	52,620	24,965	20,753	27,622	37,176	10.8%
Total	**422,085**	**287,623**	**277,317**	**315,111**	**213,415**	**100%**
Number of Customers Hours Interrupted						
Cause Code	2015	2016	2017	2018	2019	%
0 - Unknown/Other	19,603	11,418	16,456	20,026	12,316	5.4%
1 - Scheduled Outage	10,140	9,026	19,660	16,767	17,481	4.9%
2 - Loss of Supply	79,045	87,574	122,638	107,242	49,447	29.9%
3 - Tree Contacts	35,427	32,122	29,896	25,548	30,762	10.3%
4 - Lightning	8,473	2,002	649	-	2	0.7%
5 - Defective Equipment	117,788	80,419	43,966	83,282	60,551	25.9%
6 - Adverse Weather	29,929	25,278	22,849	43,332	26,494	9.9%
7 - Adverse Environment	6	5,146	761	611	1,058	0.5%
8 - Human Element	1,431	3,445	2,819	8,947	2,604	1.3%
9 - Foreign Interference	26,472	21,330	23,278	22,286	72,781	11.1%
Total	**328,315**	**277,759**	**282,972**	**328,041**	**273,498**	**100%**

Figure 3: Distribution of Number of Outages by Cause Code

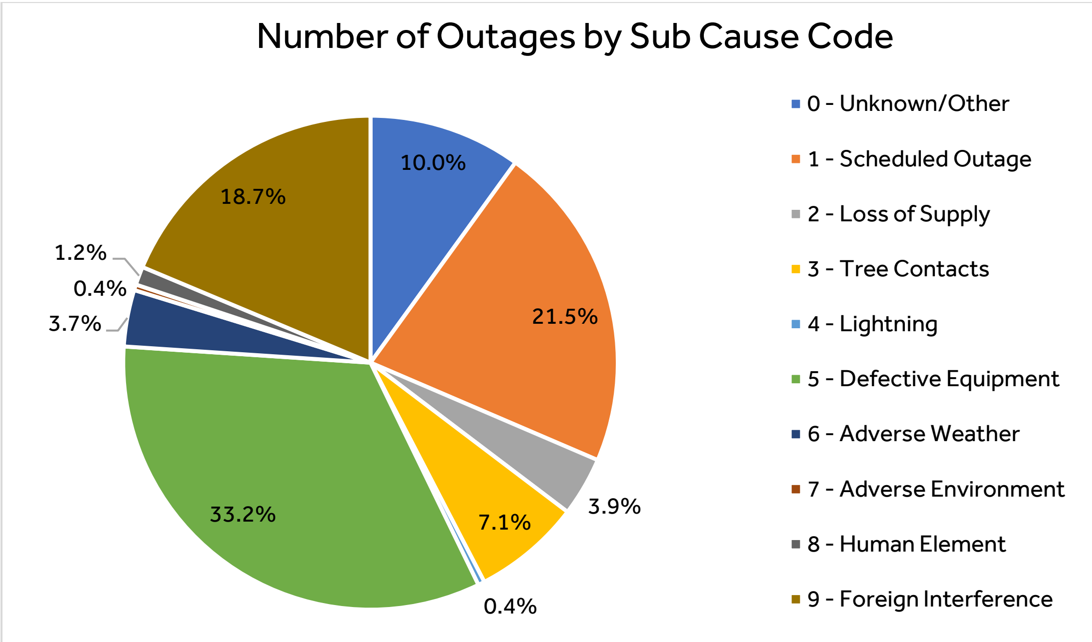


Figure 4: Distribution of Customers Interrupted by Sub Cause Code

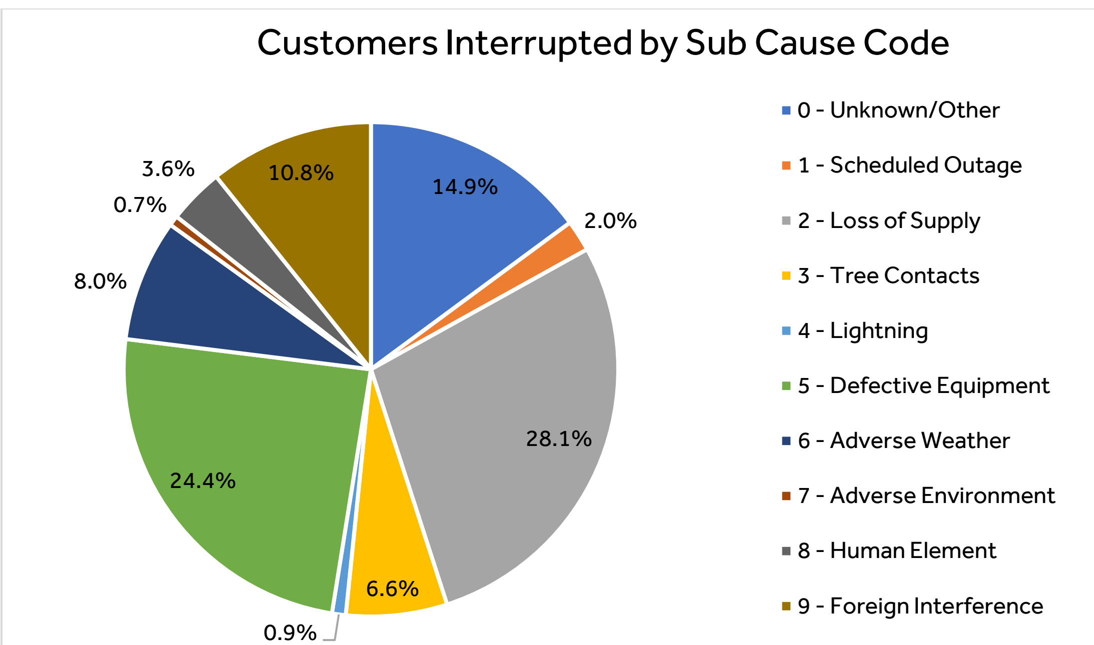
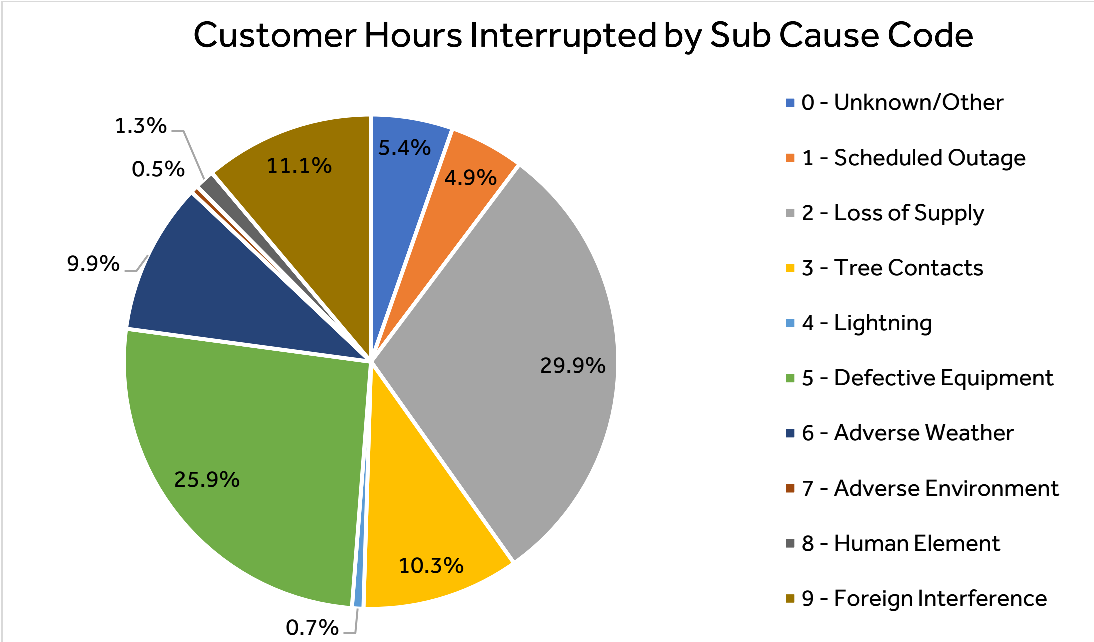


Figure 5: Distribution of Customer Hours Interrupted by Sub Cause Code



0 - Unknown/Other

Unknown/Other cause code outages are defined by the OEB as customer interruptions with no apparent cause that contributed to the outage. The number of outages due to the Unknown/Other cause code ranged from 95 to 123 and averaged to 108 outages per year. The number of CHI varies notably during the historical period as it ranges from 11,418 to 20,026. This cause code accounts for 10.0% of outages, 14.9% of CI, and 5.4% of CHI over the historical period. Given that the reason for unknown outages is not clear, specific measures that can reduce the volume and impact of these outages are difficult to identify.

1 – Scheduled Outage

Scheduled Outage cause code outages are defined by the OEB as customer interruptions due to disconnection at a selected time for the purpose of construction and preventative maintenance. Over the historical period, the number of Scheduled Outages ranged from 169 to 286 and averaged to 232 outages per year. The number of customer hours interrupted varies notably as it ranged from 9,026 to 19,660. This cause code accounts for 21.5% of outages, 2.0% of CI, and 4.9% of CHI. The number of outages does not correlate to the number of CI or CHI. This is expected as Elexicon schedules these outages in a manner which minimizes the outage duration experienced by its customers. Given that Scheduled Outages are reflective of planned work on the system as opposed to issues with the system, specific measures that can reduce the volume and impact of these outages are difficult to identify.

2 – Loss of Supply

Loss of Supply cause code outages are defined by the OEB as customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system (which is defined according to ownership demarcation). Over the historical period, the number of LOS outages ranged from 29 to 51 and averaged to 42 outages per year. There was a significant drop in LOS outages in 2019, as the typical outage volume dropped from an average of 45 (from 2015 to 2018) to 29. The number of CHI ranged from 49,447 to 122,638 over the historical period, making this cause code one of the more significant contributors. This cause code accounts for 3.9% of outages, 28.1% of CI, and 29.9% of CHI over the historical period.

Table 3 below shows the CHI by sub cause code for LOS outages, which typically align to specific transmission stations. Wilson TS has been a significant contributor to LOS outages as it accounts for 25.6% of CHI over the historical period. Other sub cause codes with a notable impact include Cherrywood TS (9.8%), Shepard TS (6.6%), and Planned Outages (6.0%). Given the fact that LOS outages occur due to problems in parts of the bulk distribution system that are not owned by Elexicon, it is difficult to reduce the volume and impact of these types of outages. However, Elexicon is involved in consultations with Hydro One Networks Inc. ("HONI") in order to mitigate these outages (see DSP section 5.2.2 for more details).

Table 3: Customer Hours Interrupted due to Loss of Supply by Sub Cause Code

Loss of Supply							
Sub Cause Code		2015	2016	2017	2018	2019	%
2.001	Loss of Supply;- Malvern T.S.	2,257	-	11,584	-	464	3.2%
2.002	Loss of Supply;- Sheppard T.S.	-	12,967	16,480	-	-	6.6%
2.003	Loss of Supply;- Cherrywood T.S.	-	-	-	43,499	-	9.8%
2.004	Loss of Supply;- Whitby T.S.	-	-	-	2,601	-	0.6%
2.005	Loss of Supply;- Armitage T.S.	3,132	6,748	8,819	44	-	4.2%
2.006	Loss of Supply;- Wilson T.S.	10,706	36,183	35,300	17,830	13,934	25.6%
2.007	Loss of Supply;- Belleville T.S.	408	2,076	-	482	-	0.7%
2.008	Loss of Supply;- Beaverton T.S.	6,649	2,323	4,978	434	4,968	4.3%
2.009	Loss of Supply;- Other.	40,395	14,567	15,527	11,348	7,406	20.0%
2.01	Loss of Supply;- Planned (Any Hydro One owned TS / DS)	4,235	3,078	4,021	3,010	12,386	6.0%
N/A	Other/Unidentified	11,262	9,631	25,829	27,995	10,281	19.1%
Total		**79,045**	**87,574**	**122,638**	**107,242**	**49,447**	**100%**

3 – Tree Contacts

Tree Contacts cause code outages are defined by the OEB as customer interruptions caused by faults resulting from tree contact with energized circuits. Over the historical period, the number of outages ranged from 54 to 92 and averaged to 76 outages per year. The number of CHI due to Tree Contacts outages ranges from 25,548 to 35,427. This cause code accounts for 7.1% of outages, 6.6% of CI, and 10.3% of CHI over the historical period.

Table 4 below shows the CHI by sub cause code for Tree Contacts outages, which reflect different modes of tree contact. Tree contacts resulting from storm conditions are the most significant contributor at 42.3% of CHI and falling trees also have a considerable impact at 25.5%. Other types of tree contacts that have a notable impact include broken branches (11.8%) and tree contacts in normal weather conditions (11.2%). These outages are not completely avoidable as they are often caused by harsh weather conditions, but they can be minimized through maintenance activities such as tree trimming/removal.

Table 4: Customer Hours Interrupted due to Tree Contacts by Sub Cause Code

Tree Contacts							
Sub Cause Code		2015	2016	2017	2018	2019	%
3.001	Tree Contact;Normal Weather	6,011	4,008	1,407	5,740	100	11.2%
3.001.1	Falling tree	3,053	3,713	8,207	11,207	13,029	25.5%
3.001.2	Branch Broken	1,094	6,257	7,898	1,948	921	11.8%
3.001.3	Untrimmed Tree	55	83	22	496	76	0.5%
3.002	Tree Contact; Storm Condition	21,780	17,003	6,236	3,394	16,636	42.3%
3.003	Tree Contact; Customer Owned Tree; Storm	-	-	1	513	-	0.3%
3.004	Other Vegetation	-	-	-	-	-	0.0%
N/A	Other/Unidentified	3,434	1,057	6,124	2,250	-	8.4%
Total		**35,427**	**32,122**	**29,896**	**25,548**	**30,762**	**100%**

4 – Lightning

Lightning cause code outages are defined by the OEB as customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flashovers. The number of outages due to this cause code ranged from 1 to 10 and averaged to 5 outages per year. The CHI varied significantly as they ranged from 0 to 8,473. This is because Elexicon has seen a significant reduction in lightning related outages in recent years as the CHI decreased from 8,473 in 2015 to 2 in 2018 and 2019 collectively. These outages are relatively insignificant as they account for 0.4% of outages, 0.9% of CI, and 0.7% of CHI over the historical period. Measures can be implemented to reduce the risk of lightning related outages, but this work is not considered high priority given the volume and impact of these outages.

5 – Defective Equipment

Defective Equipment cause code outages are defined by the OEB as customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance. The number of outages due to this cause code ranged from 301 to 403 and averaged to 359 outages per year. The CHI due to Defective Equipment outages varied notably as they ranged from 43,966 to 117,788. Defective Equipment outages represent a significant area of improvement as they accounted for 33.2% of all outages, 24.4% of CI, and 25.9% of CHI.

Table 5 shows the CHI by sub cause code for Defective Equipment related outages. Outages caused by defective insulators are most significant contributor to as they account for 20.6% of CHI over the historical period. Another contributor which is just as significant is underground primary cable failure as it accounts for 20.4% of Defective Equipment outages. There is also a significant portion of outages for which the root cause could not be identified (e.g., "5.13 Equipment Failure – Other" and "Other/Unidentified") which amounts to 12.1% of CHI. Based on these results, Elexicon should prioritize asset replacement/maintenance activities on insulators and underground primary cables.

Table 5: Customer Hours Interrupted due to Defective Equipment by Sub Cause Code

Defective Equipment							
Sub Cause Code		2015	2016	2017	2018	2019	%
5.01	Defective Switches	8,393	4,258	1,238	1,967	1,410	4.5%
5.02	Defective Insulators	40,590	7,910	7,112	14,890	9,061	20.6%
5.03	Elbow and Insert	266	907	859	2,120	208	1.1%
5.04	Lightning Arrestor	215	1,841	1,033	1,129	7,288	3.0%
5.05	Dist. Trans. O/H	1,227	1,640	212	818	686	1.2%
5.06	Dist. Trans. U/G	534	1,050	1,501	3,674	615	1.9%
5.07	Overhead Primary Connections, Sleeves, Taps	282	5,204	1,472	9,928	5,490	5.8%
5.08	Substation Equipment	8,256	458	1,444	13,607	4,983	7.5%
5.09	Overhead Secondary service connections	157	101	307	520	447	0.4%
5.1	Equipment Failure;Service Connection at Meterbase	8	4	4	23	39	0.0%
5.11	Underground Primary cable failure	11,588	22,159	9,778	16,265	18,995	20.4%
5.12	Underground Secondary cable failure	424	95	196	308	277	0.3%
5.13	Equipment Failure - other	14,676	6,052	13,190	2,150	10,586	12.1%
5.14	Switchgear	-	-	-	10,127	467	2.7%
5.15	Automation/SCADA/Communication	2	1	1	-	-	0.0%
N/A	Other/Unidentified	31,168	28,740	5,619	5,758	-	18.5%
Total		**117,788**	**80,419**	**43,966**	**83,282**	**60,551**	**100%**

6 – Adverse Weather

Adverse Weather cause code outages are defined by the OEB as customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events). The number of Adverse Weather outages ranged from 26 to 68 and averaged to 40 outages per year over the historical period. There was a notable spike in Adverse Weather related outages in 2018 as the typical volume was 35 from 2015 to 2017 and nearly doubled in 2018 at 68. The CHI range from 22,849 to 43,332, though the latter is the aforementioned outlier year 2018. The typical volume of CHI is approximately 26,000. This is a relatively significant area of improvement as it accounts for 3.7% of outages, 8.0% of CI, and 9.9% of CHI.

Table 6 shows the CHI by sub cause code for Adverse Weather related outages. Wind related outages are the most common as they result in thousands of CHI every year and account for 36.3% of CHI over the historical period. Ice storms are another significant sub cause of Adverse Weather outages as they account for 25.5% of CHI. However, ice storm related outages have only been prevalent in recent years as they contributed no CHI from 2015 to 2017. Rain related outages are another relatively significant contributor as they account for 13.8% of CHI. Adverse Weather events are difficult to predict and prepare for, but the distribution system's reliability can be improved through practices such as tree trimming/removal and storm hardening.

Table 6: Customer Hours Interrupted due to Adverse Weather by Sub Cause Code

Adverse Weather							
Sub Cause Code		2015	2016	2017	2018	2019	%
6.001	Adverse Weather; rain	1,648	17,464	99	1,171	-	13.8%
6.002	Adverse Weather; ice strom	-	-	-	21,985	15,681	25.5%
6.003	Adverse Weather; wet snow	2	43	235	-	-	0.2%
6.004	Adverse Weather; extreme ambient temperatures	-	-	-	-	-	0.0%
6.005	Adverse Weather;Wind	14,340	7,123	16,957	4,391	10,813	36.3%
6.006	Adverse Weather; freezing fog or frost	-	-	-	-	-	0.0%
N/A	Other/Unidentified	13,939	648	5,558	15,785	-	24.3%
Total		**29,929**	**25,278**	**22,849**	**43,332**	**26,494**	**100%**

7 – Adverse Environment

Adverse Environment related outages are defined by the OEB as customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing. The number of Adverse Environment outages ranged from 2 to 8 outages and averaged to 4 outages per year. The CHI due to these outages varied significantly as they ranged from 6 to 5,146. These outages are relatively insignificant as they account for 0.4% of outages, 0.7% of CI, and 0.5% of CHI. Measures can be implemented to reduce the risk of Adverse Environment outages, but this work is not considered high priority given the volume and impact of these outages.

8 – Human Element

Human Element outages are defined by the OEB as customer interruptions due to the interface of distributor staff with the distribution system. The number of Human Element outages ranged from 5 to 18 and averaged to 13 outages per year. The CHI due to these outages varied notably as they ranged from 1,431 to 8,947. These outages are relatively insignificant as they account for 1.2% of outages, 3.6% of CI, and 1.3% of CHI. Human Element outages can be minimized through improved training and standard work practices, but remedial actions for these types of outages are not highly prioritized given their volume and impact.

9 – Foreign Interference

Foreign Interference outages are defined by the OEB as customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects. The number of Foreign Interference outages ranged from 176 to 224 and averaged to 202 outages per year. The CHI ranged from 21,330 to 72,781, but it should be noted that the latter is an outlier (2019) as the typical CHI is approximately 23,500 per year. Foreign Interference outages are relatively significant as they account for 18.7% of outages, 10.8% of CI, and 11.1% of CHI.

Table 7 shows the CHI by sub cause code for Foreign Interference Outages. The majority of Foreign Interference outages can be attributed to vehicle accidents as this sub cause code account for 64.5% of CHI. Vehicle accidents are also the reason for the sharp increase in CHI in 2019. Squirrels are another notable contributor to Foreign Interference outages as they account for 12.0% of CHI. All other sub cause codes collectively account for 23.5% of CHI – a large subset of this comes from other/unidentified outages (11.9%). As defined by the OEB, these Foreign Interference outages are typically out of the control of the distributor, but the volume of these types of outages can be reduced through proactive measures such as the installation of guard fences and security systems.

Table 7: Customer Hours Interrupted due to Foreign Interference by Sub Cause Code

Foreign Interference							
Sub Cause Code		2015	2016	2017	2018	2019	%
9.001	Foreign Interference;Vehicle Accident	14,202	10,899	10,962	9,982	61,164	64.5%
9.002	Foreign Interference;Construction Accident	1,060	15	5	274	652	1.2%
9.003	Foreign Interference;Contractor Contact	593	2,172	2,354	99	422	3.4%
9.004	Foreign Interference;Squirrel	3,443	2,873	3,234	5,090	5,260	12.0%
9.005	Foreign Interference;Raccoon	138	419	234	763	961	1.5%
9.006	Foreign Interference;Bird	321	530	26	474	3,113	2.7%
9.007	Foreign Interference;Other Animal	436	1,001	44	-	82	0.9%
9.008	Human Felled tree	-	-	-	1,012	225	0.7%
9.009	Vandal Foreign object	-	-	37	607	3	0.4%
9.01	Dig in	163	51	23	52	900	0.7%
9.011	Foreign interference; Third party attachment	2	-	-	-	-	0.0%
N/A	Other/Unidentified	6,115	3,369	6,360	3,932	-	11.9%
Total		**26,472**	**21,330**	**23,278**	**22,286**	**72,781**	**100%**

Description of MEDs

Elexicon uses the IEEE 1366 Beta 2.5 methodology to classify MEDs. This method involves setting a daily threshold (T_{MED}) for SAIDI, which classifies the day as a MED if exceeded. Table 8 presents the number of outages (as identified by Elexicon's internal outage tracking system), CI, and CHI due to MEDs per year. Table 9 presents a summary of specific MEDs which occurred over the historical period. In 2016 and 2019, Elexicon customers experience no outages due to MEDs. In all other years except 2018, Elexicon experienced MED related outages resulting in 25,000 to 62,000 CHI. In 2018, Elexicon experienced a significant increase in MEDs as the CHI amount to 572,611. A description of each MED including the causes and affected areas can be found below.

Table 8: MEDs Outage Data

	2015	2016	2017	2018	2019	2020
Number of Outages	6	0	13	217	0	5
Customers Interrupted	20,027	0	51,136	155,690	0	18,071
Customer Hours Interrupted	61,188	0	25,428	572,611	0	45,141

Table 9: Summary of Major Event Days during the Historical Period

#	Date	Cause Code	Customers Interrupted	Customer Hours Interrupted
1	2015-05-31	2	20,027	61,188
2	2017-12-28	6	51,136	25,428
3	2018-04-04	2/6	28,061	35,743
4	2018-04-16	6	9,265	40,653
5	2018-05-04	6	59,145	295,192
6	2018-05-05	6	4,571	77,998
7	2018-09-21	6	54,648	123,025
8	2020-01-25	2	18,071	45,141

2015

There was one MED recorded in 2015. This MED resulted from a LOS event which was triggered by Hydro One in order to perform repairs. As a result of this event, 20,027 customers in Belleville were affected and they experienced a total of 61,188 CHI.

2017

There was one MED recorded in 2017. This MED resulted from Adverse Weather conditions and only affected the Whitby service area. It resulted in 13 distinct outages and affected 4 feeders (14F1, 14F2, 14F3, and 40M8). This MED interrupted service to total of 51,136 customers which ultimately resulted in 25,428 CHI. This was the least significant MED during the historical period.

2018

Over the historical period, Elexicon typically experienced one or zero MEDs per year, but there was a significant increase in 2018 as there were five recorded MEDs. The first reported MED during this year occurred on April 4th and was primarily caused by Adverse Weather. A severe wind storm resulted in several instances of falling trees causing damage to power lines which resulted in outages. The wind storm also directly impacted the distribution system as there were cases of feeders auto reclosing or locking out and damage to other assets such as switches and underground cables. This MED affected 28,061 customers on 27 feeders and resulted in a total of 35,743 CHI in the following areas:

- Ajax
- Bowmanville
- Cannington
- Gravenhurst
- Newcastle
- Orono
- Pickering

The second MED occurred on April 16th and was primarily caused by Adverse Weather. An ice storm caused damage to distribution infrastructure such as overhead lines, underground cables, and poles. This also resulted in certain feeders being switched off in order to complete repairs. This MED affected 9,265 customers on 18 feeders and resulted in a total of 40,653 CHI in the following areas:

- Ajax
- Belleville
- Cannington
- Pickering
- Sunderland

The third MED occurred on May 4th and was the most significant MED over the historical period as it resulted in nearly 300,000 CHI. This MED was caused by a combination of Adverse Weather and LOS. A severe wind storm resulted in damage to distribution assets such as overhead lines and underground cables directly and due to falling trees. This MED affected 59,145 customers on 35 feeders in the following areas:

- Ajax
- Beaverton
- Belleville
- Gravenhurst
- Orono
- Pickering
- Uxbridge
- Whitby

The fourth MED occurred on May 5th and was primarily caused by Adverse Weather. A severe wind storm resulted in direct damage to distribution assets such as poles and switches. In addition, there were cases of falling trees which damaged overhead lines and poles. This MED affected 4,571 customers on 24 feeders and resulted in a total of 77,998 CHI in the following areas:

- Ajax
- Bowmanvillle
- Gravenhurst
- Newcastle
- Orono
- Pickering
- Port Perry

The final MED occurred on September 21st and was one of the more significant events as it resulted in 123,025 CHI. The primary cause was Adverse Weather – specifically, a severe wind storm. This MED was similar to other MEDs caused by wind storms in terms of the damage experienced by the distribution system. Falling trees caused damage to assets such as poles, overhead lines, and transformers which resulted in service interruptions. Additionally, several feeders auto-reclosed or locked out and switching operations had to be performed to facilitate repairs. This MED affected 54,648 customers on 29 feeders in the following areas:

- Ajax
- Belleville
- Cannington
- Gravenhurst
- Newcastle
- Port Hope

2020

One MED occurred in 2020 on January 25th and was caused by a LOS event. This LOS event was triggered by an outage at Belleville TS initiated by Hydro One. This MED interrupted service for 18,046 customers on 5 feeders and resulted in a total of 45,141 CHI in the following areas:

- Ajax
- Belleville
- Pickering
- Whitby

Worst Performing Feeders Analysis

The WPF analysis identifies the worst performing feeders in Elexicon's distribution system. It is based on the number of outages experienced, the number of CI, and the number of CHI. These criteria are assessed separately for sustained and momentary interruptions – however, only the number of outages and CI are considered for the latter given their nature. First, the ten worst performing feeders in terms of each of these five criteria are identified. A feeder is classified as a worst performing feeder if it ranks in the top ten across multiple criteria. The results of these assessments for sustained and momentary outages are presented below in Table 10 and Table 11, respectively. Additional details about the feeders such as the types of outages they experienced, their locations, and the areas they serve can be found below.

Table 10: Outage Statistics by Feeder for Sustained Interruptions

Sustained Interruptions								
Rank	Feeder	# of Outages	Rank	Feeder	CI	Rank	Feeder	CHI
1	JAMSF1	188	1	SHEPM4	112,394	1	ORILM6	94,236
2	WHITM48	169	2	ORILM6	75,552	2	JAMSF1	68,977
3	SHEPM4	134	3	WILSM11	50,373	3	SHEPM4	51,097
4	11F4	125	4	SHEPM2	49,898	4	WILSM11	50,790
5	BAYRF1	125	5	WILSM17	44,506	5	GRAVF1	49,970
6	MALVM35	112	6	MALVM35	39,253	6	WILSM14	46,126
7	PICBF6	85	7	BAYRF1	30,651	7	BAYRF1	36,020
8	GRAVF1	84	8	WHITM22	30,569	8	MALVM35	34,518
9	10F1	81	9	40M8	29,692	9	FAIRF1	31,517
10	NOTIF2	73	10	11F1	26,062	10	SHEPM2	29,629

Table 11: Outage Statistics by Feeder for Momentary Interruptions

Momentary Interruptions					
Rank	Feeder	# of Outages	Rank	Feeder	CI
1	12F2	41	1	40M27	135,554
2	7F4	40	2	ORILM6	105,086
3	JAMEF1	35	3	SHEPM4	93,833
4	BAYRF1	34	4	BAYRF1	87,348
5	10F1	31	5	12F2	78,214
6	10F6	31	6	WILSM11	77,716
7	7F2	31	7	MALVM35	68,378
8	SPRYF4	30	8	CHERM5	67,976
9	SHEPM4	29	9	40M25	65,699
10	FAIRF1	27	10	10F1	63,452

JAMSF1

The JAMSF1 feeder is supplied by the James substation located at 495 James St. W in Gravenhurst. This sub station is located south of Mounts Bay and west of downtown Gravenhurst. This feeder travels northwest along the coast of Mounts Bay where it provides service to commercial customers at 12.47kV. Although this feeder ranks outside the top ten in terms of CI, it experienced a significant impact from sustained interruptions as it ranked first in number of outages and second in CHI. This feeder experienced no momentary interruptions during the historical period.

As shown in Table 12, the majority of outages on this feeder occur due to Adverse Weather, Tree Contacts, Foreign Interference, and Scheduled Outages. This is largely due to the fact that the feeder travels through non-urban terrain with many trees which are prone to damaging distribution infrastructure. This risk is increased during harsh weather events which cause falling trees, broken branches, and other forms of disruption. This risk can be mitigated through maintenance activities such as tree trimming/removal and storm hardening.

Table 12: Outage Statistics for Feeder JAMSF1

Outage Statistics for JAMSF1											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	27	36	1	48	1	34	12	-	2	27	1
Sustained CI	2,613	4,383	1	9,232	1	1,430	733	-	138	2,574	>10
Sustained CHI	9,329	6,761	6	29,295	2	3,924	15,013	-	260	4,389	2
Momentary Outages	-	-	-	-	-	-	-	-	-	-	>10
Momentary CI	-	-	-	-	-	-	-	-	-	-	>10

SHEPM4

The SHEPM4 feeder is supplied by the HONI owned Sheppard TS DES2 which is located in the Metro Toronto region and distributes power to the western portion of Elexicon's service territory at 27.6kV. This feeder traverses residential, commercial, and non-urban areas. Table 13 below provides information about the sustained and momentary interruptions experienced by this feeder. This feeder experienced a significant number of sustained interruptions as it ranks third with respect to this metric, first in terms of CI, and third in terms of CHI. This feeder experienced a significant impact from sustained outages as it ranks high in terms of all three criteria.

In terms of sustained interruptions, the majority of CHI are caused by Loss of Supply, Defective Equipment, and Adverse Weather. Adverse Weather and Loss of Supply events can be difficult to control, but the impact of Defective Equipment related outages can be decreased by proactively replacing aging distribution infrastructure. In addition, it is important to consider that Defective Equipment related outages are often expedited by Adverse Weather events. The risk outages occurring can be reduced by implementing storm hardening measures.

The SHEPM4 feeder performance for momentary interruptions is poor as it ranks ninth in terms of the number of momentary interruptions and third in terms of the number of CI. Momentary interruptions on this feeder are caused by Defective Equipment, Tree Contacts, Adverse Weather, and Foreign Interference. As previously mentioned, Adverse Weather events are difficult to control and do not necessarily reflect the health of the feeder. However, the fact that Defective Equipment related outages are common and result in a large number of outages and CI may indicate that this feeder requires asset replacement and maintenance work in order to increase resilience to these types of outages. In addition, Foreign Interference and Tree Contacts related events can be reduced through activities such as the installation of security measures and tree trimming/removal.

Table 13: Outage Statistics for Feeder SHEPM4

Outage Statistics for SHEPM4											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	14	14	7	7	-	62	10	-	1	19	3
Sustained CI	26,575	110	25,284	3,808	-	36,056	16,207	-	3,285	1,069	1
Sustained CHI	8,318	192	17,293	1,221	-	14,021	6,102	-	164	3,785	3
Momentary Outages	12	-	-	4	-	7	2	-	-	4	9
Momentary CI	37,826	-	-	12,626	-	26,247	6,012	-	-	11,122	3

MALVM35

The MALVM35 feeder is supplied by the HONI owned Malvern TS which is located in the Metro Toronto Region and distributes power to the western portion of Elexicon's service territory at 27.6kV. This feeder traverses residential, commercial, and non-urban areas. In terms of the sustained interruptions experienced by the worst performing feeders, MALVM35 generally ranks low to mid-tier as it is sixth in terms of the number of outages, sixth in terms of the number of CI, and eighth in terms of CHI. As shown in Table 14, the sustained interruptions experienced by this feeder are primarily caused by LOS, Defective Equipment, and Tree Contacts. Given that LOS events are out of the distributor's control, remedial actions can only be implemented for the reduction of Defective Equipment and Tree Contacts related outages (e.g., proactive replacement of aging assets, tree trimming, etc.). Additional notable contributors to sustained interruptions include Human Element and Foreign Interference.

In terms of momentary interruptions, this feeder performs relatively well as, despite ranking seventh in terms of CI, it falls outside the top ten in terms of number of momentary interruptions. Defective Equipment outages are the largest contributor to momentary interruptions and can be reduced through replacement of aging distribution infrastructure. Other notable contributors include Tree Contacts, Adverse Weather, LOS, and Foreign Interference. These contributors are common across both sustained and momentary outages, which suggests that this feeder is prone to these types of outages due to the environment it travels through.

Table 14: Outage Statistics for Feeder MALVM35

Outage Statistics for MALVM35											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	23	6	6	15	-	36	7	2	4	13	6
Sustained CI	2,381	219	14,147	8,017	-	8,619	20	722	3,882	1,246	6
Sustained CHI	2,723	176	14,305	4,654	-	9,673	72	60	1,720	1,135	8
Momentary Outages	14	-	1	2	-	7	2	-	-	1	>10
Momentary CI	29,881	-	3,473	6,854	-	20,966	3,777	-	-	3,427	7

BAYRF1

The BAYRF1 feeder is supplied by the Bay Ridges substation located at 1338 Bayly Street in Pickering. This substation is located east of the intersection of Bayly Street and Liverpool Road, south of the 401. It supplies power at 13.8kV to residential and commercial customers in southern Pickering. In terms of sustained interruptions, this feeder generally ranks mid tier as it ranks fifth in terms of the number of outages, seventh in terms of CI, and seventh in terms of CHI. As shown in Table 15, the majority of sustained interruptions are caused Tree Contacts and Defective Equipment. This is primarily due to the fact that this feeder passes through several non-urban areas which increases the likelihood of these types of outages occurring. The likelihood of these outages can be reduced through maintenance efforts such as tree trimming/removal and the replacmenet of assets in poor condition. Other significant contributors include Scheduled Outages and Foreign Interference.

In terms of momentary interruptions, BAYRF1 ranks fourth in terms of the number of outages and the number of CI. Nearly all momentary interruptions are caused by Defective Equipment and Foreign Interference, which indicates that this feeder's reliability could be improved through asset replacement efforts and the implementation of additional security measures.

Table 15: Outage Statistics for Feeder BAYRF1

Outage Statistics for BAYRF1											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	10	14	-	6	-	72	-	-	3	20	5
Sustained CI	7,281	497	-	10,939	-	6,264	-	-	2,563	3,107	7
Sustained CHI	10,469	1,540	-	17,921	-	4,622	-	-	284	1,185	7
Momentary Outages	18	-	-	-	-	10	-	-	-	6	4
Momentary CI	45,323	-	-	-	-	25,824	-	-	-	16,201	4

GRAVF1

The GRAVF1 feeder is supplied by Gravenhurst substation located west of Jevin's Lake and north of the intersection of Highway 11 and Holmes Road in Gravenhurst. It travels northwest from Gravenhurst substation and supplies power to residential and commercial customers at 12.47kV. As shown in Table 16, this feeder experienced fewer sustained interruptions than most other worst performing feeders as it ranks eighth in terms of numbers of outages, outside the top ten in terms of CI, and fifth in terms of CHI. This feeder experienced no momentary interruptions during the historical period.

In terms of sustained interruptions, the majority are caused by LOS, Tree Contacts, and Adverse Weather related events. This is expected because Gravenhurst is largely a non-urban area dominated by natural features such as trees. While LOS and Adverse Weather events can be difficult to prevent, the likelihood of sustained interruptions can be decreased through weather resilience measures and maintenance activities such as tree trimming and removal.

Table 16: Outage Statistics for Feeder GRAVF1

Outage Statistics for GRAVF1											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	15	15	12	19	-	10	5	-	-	9	8
Sustained CI	380	1,205	5,711	2,376	-	1,631	660	-	-	369	>10
Sustained CHI	1,127	2,651	27,740	9,000	-	3,196	5,676	-	-	579	5
Momentary Outages	-	-	-	-	-	-	-	-	-	-	>10
Momentary CI	-	-	-	-	-	-	-	-	-	-	>10

ORILM6

The ORILM6 feeder is supplied by the HONI owned Orillia TS located in northern Orillia. This feeder supplies power at 44kV through a largely rural area to the Gravenhurst service territory where it is stepped down at Elexicon owned substations and distributed to residential and commercial customers. Although it ranks outside the top ten in terms of the number of sustained interruptions, it still experiences a significant impact from sustained interruptions as it ranks second in terms of CI and first in terms of CHI. It performs better in terms of momentary interruptions as it ranks outside the top ten in number of outages, but ranks second in terms of CI.

As shown in Table 17, nearly all sustained interruptions are caused by LOS and Foreign Interference. This is expected as it originates from an HONI owned transmission station and travels a large distance through rural areas to Gravenhurst, making it susceptible to Foreign Interference, especially animal related interference. LOS outages can be difficult to prevent, but the feeder's reliability can be improved by implementing measures to increase resilience to Foreign Interference. The majority of momentary interruptions are caused by LOS events, which are difficult to mitigate as they are related to parts of bulk distribution system not owned by Elexicon.

Table 17: Outage Statistics for Feeder ORILM6

Outage Statistics for ORILM6											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	-	-	16	1	-	-	-	-	-	2	>10
Sustained CI	-	-	65,537	1	-	-	-	-	-	10,014	2
Sustained CHI	-	-	82,713	1	-	-	-	-	-	11,523	1
Momentary Outages	8	-	11	-	-	-	-	-	-	-	>10
Momentary CI	46,203	-	58,883	-	-	-	-	-	-	-	2

WILSM11

The WILSM1 feeder is supplied by the HONI owned Wilson TS DES2 located in eastern Oshawa. This feeder supplies power at 44kV to Elexicon owned substations which step down and distribute power to residential and commercial customers in nearby areas such as Whitby and Bowmanville. In terms of sustained interruptions, WILSM11 generally ranks mid-tier as it falls outside the top ten for the number of outages, ranks third for CI, and ranks fourth for CHI. In terms of momentary interruptions, WILSM11 falls outside the top ten in terms of the number of outages and ranks sixth in terms of CI.

As shown in Table 18, nearly all sustained interruptions result from LOS, Tree Contacts, Adverse Weather, and Defective Equipment. Some of these factors are difficult to prevent, but the reliability performance of this feeder will benefit from maintenance activities such as tree trimming and proactive asset replacements. The majority of momentary interruptions are caused by LOS and Defective Equipment related events. LOS events can be difficult to control and predict, but the reliability performance for momentary interruptions can be improved through proactive asset replacements which reduce the probability of Defective Equipment related failures.

Table 18: Outage Statistics for Feeder WILSM11

Outage Statistics for WILSM11											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	-	1	7	3	-	3	1	-	-	-	>10
Sustained CI	-	1	33,240	2,381	-	7,884	6,867	-	-	-	3
Sustained CHI	-	8	22,598	10,581	-	8,033	9,569	-	-	-	4
Momentary Outages	12	-	5	-	-	1	-	-	-	-	>10
Momentary CI	54,752	-	19,704	-	-	3,260	-	-	-	-	6

SHEPM2

The WHITM46 feeder is supplied by the HONI owned Whitby TS DESN1 located in the northwestern Whitby area. It supplies power at 44kV to the Whitby substation which steps down and distributes power to residential and commercial customers in the Whitby service area. In terms of sustained interruptions, WHITM46 ranks outside the top 10 for the number of outages, fourth in terms of CI, and third in terms of CHI. Momentary interruptions are considered insignificant for this feeder as there it falls outside of the top ten in terms of the number of outages and CI.

As shown in Table 19, nearly all sustained interruptions are caused by Defective Equipment, LOS, and Tree Contacts. While LOS outages can be difficult to control, the reliability of this feeder can be improved through efforts which improve asset health (e.g., maintenance, replacements, and refurbishment).

Table 19: Outage Statistics for Feeder SHEPM2

Outage Statistics for SHEPM2											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	7	10	3	4	1	26	1	1	1	7	>10
Sustained CI	5,967	99	17,333	3,033	15	17,369	2,908	1	2,915	258	4
Sustained CHI	889	134	12,254	1,654	73	13,376	97	1	243	909	10
Momentary Outages	12	-	1	-	-	1	1	-	-	2	>10
Momentary CI	33,976	-	5,911	-	-	2,908	2,842	-	-	6,495	>10

12F2

The 12F2 feeder is supplied by the Whitby substation and provides power at 13.8kV to customers in the Whitby area. The reliability performance of 12F2 for sustained interruptions is better in comparison to other worst performing feeders as it ranks outside the top ten in terms of the number of outages, the number of customers affected, and the number of CHI. As shown in Table 21, the biggest contributors to sustained interruptions are Adverse Weather and Foreign Interference, which are avoidable to a degree and can be minimized with appropriate maintenance strategies.

In terms of momentary interruptions, this feeder ranks first for the number of outages experienced, and sixth for the number of CI. This feeder has the worst performance in terms of momentary interruptions as it experiences a higher volume than any other feeder. Although the majority of momentary interruptions occur for unknown reasons, the cause code analysis below still provides some useful insight. For example, a relatively large number of customers experienced momentary interruptions due to Adverse Weather which indicates an area of improvement for this feeder's reliability performance.

Table 20: Outage Statistics for Feeder 12F2

Outage Statistics for 12F2											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	4	14	-	-	-	3	4	-	1	8	>10
Sustained CI	40	83	-	-	-	31	5,663	-	13	2,049	>10
Sustained CHI	32	159	-	-	-	46	5,096	-	17	3,085	>10
Momentary Outages	40	-	-	-	-	-	1	-	-	-	1
Momentary CI	76,302	-	-	-	-	-	1,912	-	-	-	5

10F6

The 10F1 feeder is supplied by the Whitby substation and provides power at 13.8kV to customers in the Whitby area. This feeder ranks low-tier in terms of sustained interruptions as it ranks ninth for the number of outages and outside the top ten for the number of CI and CHI. In terms of momentary interruptions, this feeder ranks fifth in terms of the number of outages and tenth in terms of the number of CI.

As shown in Table 22, the majority of sustained interruptions are caused by Adverse Weather and Foreign Interference. These issues are similar to the issues experienced by other worst performing feeders and can be minimized through activities such as proactive asset replacement, increased security, and increased storm resilience. It is difficult to rectify momentary outages as the majority are attributed to the Unknown cause code.

Table 21: Outage Statistics for Feeder 10F1

Outage Statistics for 10F1											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	2	39	-	2	1	6	2	-	2	27	9
Sustained CI	82	437	-	38	1,215	1,404	4,008	-	41	3,121	>10
Sustained CHI	149	735	-	55	192	928	3,011	-	5	1,514	>10
Momentary Outages	30	-	-	-	-	-	-	-	-	1	5
Momentary CI	63,447	-	-	-	-	-	-	-	-	5	10

FAIRF1

The FAIRF1 feeder is supplied by the Fairport substation and provides power at 13.8kV to residential customers in Pickering. This feeder ranks low in terms of both sustained and momentary interruptions as it ranks outside the top ten in terms of the number of outages and CI and ranks ninth for CHI. In terms of momentary interruptions, this feeder ranks tenth in terms of the number of outages and outside the top ten in terms of CI.

As shown in Table 22, the majority of sustained interruptions are caused by Defective Equipment, Scheduled Outages, and Foreign Interference. Scheduled outages are difficult to reduce as they are often required to complete upgrades and repairs. However, Defective Equipment and Foreign Interference interruptions can be minimized through the replacement and refurbishment of aging assets and additional security measures such as fences. This would also benefit this feeder's performance in terms of momentary interruptions as Defective Equipment and Foreign Interference are significant contributors to momentary outages as well. However, there is some difficulty in completely rectifying momentary outages as the majority are attributed to the Unknown cause code.

Table 22: Outage Statistics for FAIRF1

Outage Statistics for FAIRF1											
Cause Code	0	1	2	3	4	5	6	7	8	9	Rank
Sustained Outages	3	3	-	1	-	25	1	-	-	10	>10
Sustained CI	3,106	1,974	-	1,770	-	9,950	15	-	-	1,868	>10
Sustained CHI	133	12,455	-	59	-	15,840	19	-	-	3,012	9
Momentary Outages	16	-	-	-	-	7	-	-	-	4	10
Momentary CI	29,143	-	-	-	-	12,385	-	-	-	7,248	>10