Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Kathleen Burke
Director, Applications Delivery
T 416-770-0592
Kathleen.Burke@HydroOne.com

BY EMAIL AND RESS

November 30, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2018-0270 and EB-2018-0242 – Hydro One Networks Inc. 2023-2027 Distribution System Plan for the areas formerly served by Orillia Power Distribution Corporation and Peterborough Distribution Inc.

Hydro One Networks Inc. is submitting 2023-2027 Distribution System Plan (DSP) for the areas formerly served by Orillia Power Distribution Corporation (OPDC) and Peterborough Distribution Inc. (PDI) as part of the conditions of approval for the Mergers, Acquisitions, Amalgamations and Divestitures (MAAD) applications for OPDC (EB-2018-0270) and PDI (EB-2018-0242).

Electronic copies of this Distribution System Plan have been submitted using the Board's Regulatory Electronic Submission System under EB-2018-0270 and EB-2018-0242.

Sincerely,

Kathleen Burke




2023-2027
Distribution System Plan

for the Areas Formerly Served by
Orillia Power Distribution Corporation and
Peterborough Distribution Inc.

DSP CONTENTS

DSP SECTION 1 - DISTRIBUTION SYSTEM PLAN OVERVIEW

1.1 INTRODUCTION

Hydro One Networks Inc. (Hydro One) has prepared a five-year Distribution System Plan (DSP) for the 2023 to 2027 period for the Hydro One service areas formerly served by Orillia Power Distribution Corporation (OPDC) and Peterborough Distribution Inc. (PDI). Hydro One is filing this DSP as part of its conditions of approval for the Mergers, Acquisitions, Amalgamations and Divestitures (MAAD) applications for OPDC (EB-2018-0270) and PDI (EB-2018-0242). In its Decisions and Orders for these applications (the "MAADs decisions"), the Ontario Energy Board (OEB) directed Hydro One to provide DSPs within 18 months of operational integration, which occurred on June 1, 2021. Pursuant to the conditions of approval, Hydro One is filing this DSP prior to the December 1, 2022 deadline. This is the first DSP for these service areas, as OPDC and PDI did not file a consolidated DSP since the onset of the OEB's requirement to do so.[1]

This DSP is based on guidance from the OEB's Chapter 5 Filing Requirements for Electricity Distribution Applications: Consolidated Distribution System Plan Filing Requirements issued on April 18, 2022 (the "Filing Requirements"). It provides a consolidated view of the capital expenditure plan for the subject distribution assets and the asset management and investment planning process that underpinned the development of this plan. Information regarding Hydro One Distribution's General Plant assets is provided in Hydro One's Joint Rate Application, EB-2021-0110, Exhibit B4 - General Plant System Plan.

Table 1 below maps each section of Hydro One's DSP to the Filing Requirements.

[1] OPDC MADD Application: EB-2018-0270, Decision and Order, April 30, 2020, p. 37-38.
PDI MADD Application: EB-2018-0242, Decision and Order, April 30, 2020, p. 37-39.

1 **Table 1 - Mapping of the DSP Sections to the Filing Requirements**

DSP Section	Filing Requirements
Section 1 – Distribution System Plan Overview	5.2
1.1 Introduction	5.2.1
1.2 Background on the MAADs Proceedings	5.2.1
1.3 Distribution System Plan Overview	5.2.1
Attachment 1: Filing Requirements Checklist	
Section 2 – Coordinated Planning with Third Parties	5.2.2
2.1 Introduction	5.2.2
2.2 Customer Engagement Activities	5.2.2
2.3 Regional Planning Consultations	5.2.2
2.4 Telecommunications Entities	5.2.2
2.5 Renewable Energy Generation (REG)	5.2.2
Attachment 1: Planning Status Letter – Orillia	5.2.2
Attachment 2: Planning Status Letter – Peterborough	5.2.2
Attachment 3: Regional Infrastructure Plan – South Georgian Bay/Muskoka	5.2.2
Attachment 4: Regional Infrastructure Plan – Peterborough to Kingston	5.2.2
Section 3 – Performance Measurement for Continuous Improvement	5.2.3
3.1 Performance Measurement for Continuous Improvement	5.2.3
3.2 Customer Focus	5.2.3
3.3 Operational Effectiveness	5.2.3
3.4 Public Policy Responsiveness	5.2.3
3.5 Financial Ratios	5.2.3
Attachment 1: OEB Appendix 2-G	5.2.3
Section 4 – Asset Management Process	5.3
4.1 Planning Process	5.3.1
4.2 Overview of System and Service Areas	5.3.2
4.3 Overview of Assets Managed and Asset Lifecycle Optimization Policies and Practices	5.3.2, 5.3.3
4.4 System Capability Assessment for Renewable Energy Generation	5.3.4
4.5 CDM Activities to Address System Needs	5.3.5
Section 5 – Capital Expenditure Plan	5.4
5.1 Capital Expenditure Summary	5.4.1
5.2 Historical Capital Expenditure Trends	5.4.1
5.3 Forecast Capital Expenditure Trends	5.4.1, 5.4.2

DSP Section	Filing Requirements
5.4 Impact of Capital Investments on Operations and Maintenance Expenditures	5.4.1
5.5 Material Investment Summary Documents	5.4.2
D-SA-01 Joint Use and Relocations	5.4.2.1
D-SA-02 New Load Connections, Upgrades, Cancellations	5.4.2.1
D-SA-03 Connecting Distributed Energy Resources	5.4.2.1
D-SA-04 Metering Sustainment	5.4.2.1
D-SR-01 Distribution Stations Demand Capital Program	5.4.2.1
D-SR-04 Distribution Station Refurbishment	5.4.2.1
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response Program	5.4.2.1
D-SR-07 Pole Sustainment Program	5.4.2.1
D-SR-08 Distribution Lines Minor Component Replacement Program	5.4.2.1
D-SR-10 Distribution Lines Sustainment Initiatives	5.4.2.1
D-SR-11 Life Cycle Optimization and Operational Efficiency Projects	5.4.2.1
D-SS-03 Demand Investments	5.4.2.1
D-SS-06 Power Quality and Stray Voltage	5.4.2.1
Attachment 1: OEB Appendices 2-AA and 2-AB	5.4.1

A Filing Requirements checklist is provided in Attachment 1 to this section.

1.2 BACKGROUND ON THE MAADS PROCEEDINGS

On April 30, 2020, Hydro One Inc. (HOI), Hydro One's parent company, received approval from the OEB to purchase all of the issued and outstanding shares of OPDC and to purchase the distribution system of the amalgamated corporation of PDI and Peterborough Utilities Services Inc., and to subsequently transfer the assets and liabilities of the electricity businesses to Hydro One.

Customers of the former service areas are currently in a ten-year deferred rebasing period approved by the OEB and set to expire on August 31, 2030 for the areas formerly served by OPDC and July 31, 2030 for the areas formerly service by PDI. During years one to five of the deferred rebasing period, all base distribution delivery rates for the acquired customers of OPDC and PDI are frozen. In addition, there is a 1% reduction in base distribution delivery rates for residential, general service and large use customers. For years six to ten of the deferred rebasing period, rates will be set using the price cap index adjustment mechanism and an earnings sharing mechanism will provide a guaranteed fixed refund amount to these acquired ratepayers based on a 50:50 sharing of forecast earnings at the time of the MAAD applications.

The MAADs decisions also specified that no Incremental Capital Module (ICM) is available during the ten-year deferred rebasing period for the areas formerly served by OPDC and PDI. The OEB confirmed that Z-factor adjustments will be available for rates of the acquired utilities based on the OEB's criteria for electricity distributors.

The following subsections provide additional information for the Hydro One areas formerly served by OPDC and PDI (herein referred to as "Orillia" and "Peterborough", respectively).

1.2.1 Orillia

On September 16, 2009, OPDC filed a Cost of Service (COS) rate application (EB-2009-0273) which resulted in approved rates effective May 1, 2010. Subsequently, OPDC filed annual updates for rates effective May 1 for each year from 2011 through 2020. However, due to the MAAD applications before the OEB (EB-2016-0276 and EB-2018-0270), OPDC did not request a price cap adjustment for rates between 2017 and 2020. As such, the current base distribution delivery rates are those approved in EB-2015-0024.

On April 30 and July 9, 2020, the OEB issued Decisions and a Rate Order granting approval for HOI to purchase all issued and outstanding shares of OPDC and for HOI to then transfer the assets and liabilities of the electricity distribution business from OPDC to Hydro One.

On September 1, 2020, HOI purchased the outstanding shares of OPDC and OPDC transferred its distribution system to Hydro One. As such, the ten-year deferred rebasing period, as approved by the OEB during the OPDC MAAD proceeding (EB-2018-0270), began on this date.

On February 17, 2021 the OEB transferred OPDC's rate order to Hydro One, cancelled OPDC's distribution licence (ED-2002-0530) and amended Hydro One's distribution licence (ED-2003-0043). On June 1, 2021, the integration of OPDC into Hydro One's distribution system was completed.

Hydro One filed its 2022 IRM (incentive rate mechanism) Application for Orillia and Peterborough on August 27, 2021 with the OEB (EB-2021-0050). The OEB approved the changes to the rates, including the effective date of January 1, 2022, in its Decision and Rate Order on December 16, 2021. Hydro One's 2023 IRM Application for Orillia and Peterborough was submitted on August 3, 2022 and is currently before the OEB (EB-2022-0040).

1.2.2 Peterborough

On February 14, 2013, PDI filed a COS rate application (EB-2012-0160) which resulted in approved rates effective May 1, 2013. Subsequently, PDI filed annual updates for rates effective May 1 for each year from 2014 through 2019, except for 2017 (due to the MAAD application, EB-2018-0242, before the OEB). As PDI did not request a price cap adjustment for its 2019 rates, the current base distribution delivery rates were approved in EB-2017-0266.

On April 30 and July 9, 2020, the OEB issued Decisions and a Rate Order granting leave to amalgamate PDI and Peterborough Utilities Services Inc. (PUSI) and to transfer the electricity distribution system and rate orders of the amalgamated corporation to 1937680 Ontario Inc. (a subsidiary of HOI).

On August 1, 2020, 1937680 Ontario Inc. purchased the distribution system of the amalgamated corporation. The electricity distribution licence (ED-2002-0504) and rate order for the amalgamated corporation were transferred to 1937680 Ontario Inc. The ten-year deferred rebasing period, as approved by the OEB during the PDI MAAD proceeding (EB-2018-0242), began on this date.

On June 1, 2021 the integration of 1937680 Ontario Inc. into Hydro One's distribution system was completed. The rate order of 1937680 Ontario Inc. dated July 9, 2020 was transferred to Hydro One. Hydro One's electricity distribution licence (ED-2003-0043) was amended to include the service areas listed in Schedule 1 of the 1937680 Ontario Inc.'s electricity distribution licence (ED-2002-0504). 1937680 Ontario Inc.'s electricity distribution licence was subsequently cancelled.

As noted above, Hydro One filed its 2022 IRM Application for Orillia and Peterborough on August 27, 2021 with the OEB (EB-2021-0050). The OEB approved the changes to the rates, including the effective date of January 1, 2022, in its Decision and Rate Order on December 16, 2021. Hydro One's 2023 IRM Application for Orillia and Peterborough was submitted on August 3, 2022 and is currently before the OEB (EB-2022-0040).

1.3 DISTRIBUTION SYSTEM PLAN OVERVIEW

1.3.1 INTRODUCTION

Hydro One has prepared a five-year DSP for the 2023 to 2027 period for Orillia and Peterborough. The DSP presents a portfolio of capital investments that have been prioritized based on an outcomes-driven and customer-focused investment planning framework, in alignment with the principles and expectations articulated by the OEB in its Renewed Regulatory Framework (RRF). The capital investments outlined in this DSP have been selected to meet pressing distribution asset and system needs and customer service imperatives.

1.3.2 SERVICE AREA

Hydro One's distribution system is diverse in its design, operation, and needs. Similarly, Orillia and Peterborough have unique characteristics and needs, which Hydro One's capital plan has been designed to meet.

Orillia serves 14,625 customers utilizing 241 distribution circuit kilometers in the City of Orillia. Orillia is an urban service area, with both radial and looped distribution feeder sections. It is a partially embedded distributor, with supply connections from Hydro One's

Transmission and Distribution systems. The distribution service territory for the former Orillia Power Distribution Company is shown in Figure 1.

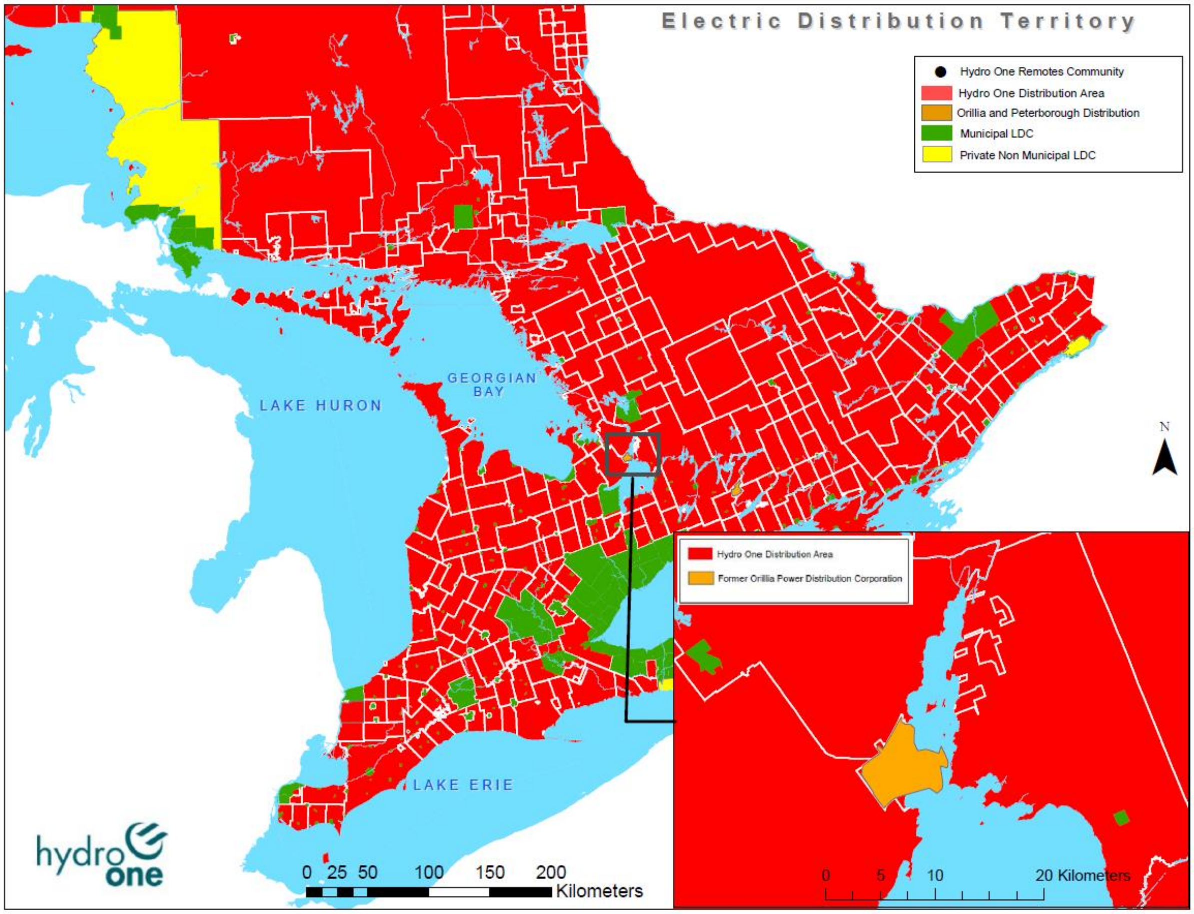


Figure 1: Map of Hydro One's Orillia Service Territory

Peterborough serves 37,547 customers utilizing 545 distribution circuit kilometers in the City of Peterborough, the Town of Norwood, and the Village of Lakefield. Peterborough is an urban service area, with both radial and looped distribution feeder sections. It is a partially embedded distributor, with supply connections from Hydro One Networks' Transmission and Distribution systems. The distribution service territory for the former Peterborough Distribution Inc. is shown in Figure 2.

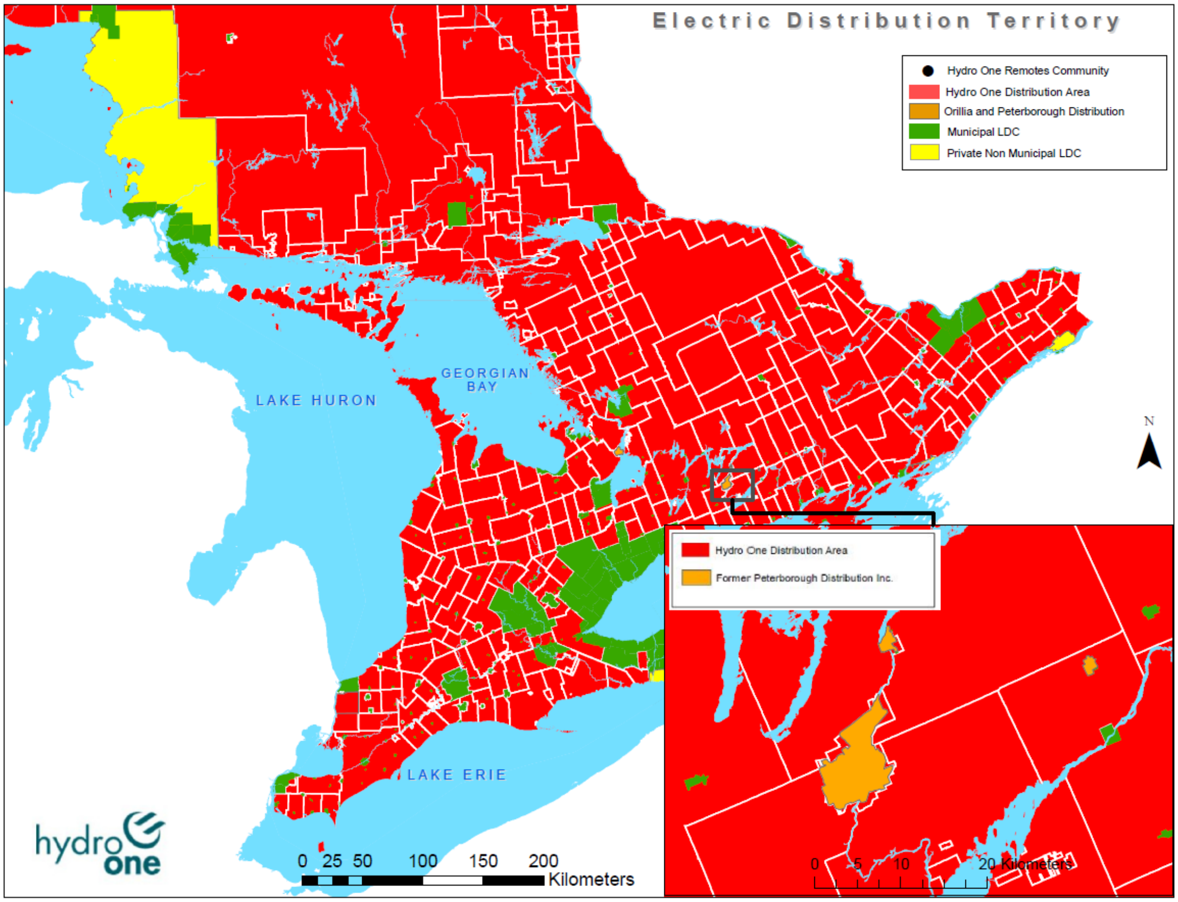


Figure 2: Map of Hydro One Peterborough's Service Territory

1.3.3 SUMMARY OF THE DSP CAPITAL PLAN

From 2023 to 2027, Hydro One plans to invest $13.85M in Orillia and $28.49M in Peterborough. These investments are shaped by a range of inputs and considerations, including customer preferences, regional planning, asset condition, and system capacity needs.[2] A summary of the forecast capital expenditures by OEB Category is provided below in Table 2.

[2] Refer to Section 4.1 – Planning Process for details.

Table 2 - Forecast Capital Expenditures for 2023-2027

Area / OEB Category	Forecast					2023-2027 Total
	2023	2024	2025	2026	2027	
Orillia						
System Access	1.16	1.10	1.11	1.16	1.22	5.74
System Renewal	0.63	1.04	3.76	0.89	0.65	6.97
System Service	0.22	0.23	0.23	0.23	0.24	1.14
General Plant*	0.00	0.00	0.00	0.00	0.00	0.00
Total Orillia	**2.01**	**2.37**	**5.10**	**2.28**	**2.10**	**13.85**
Peterborough						
System Access	2.34	2.41	2.44	2.42	2.52	12.13
System Renewal	1.37	4.16	2.70	2.56	4.31	15.09
System Service	0.25	0.25	0.25	0.26	0.26	1.27
General Plant*	0.00	0.00	0.00	0.00	0.00	0.00
Total Peterborough	**3.96**	**6.81**	**5.39**	**5.23**	**7.09**	**28.49**

** Information regarding Hydro One Distribution's General Plant assets is provided in Hydro One's Joint Rate Application, EB-2021-0110, Exhibit B4 - General Plant System Plan.*

Over the five-year period, most capital investments fall within the OEB categories for System Renewal or System Access. These investments address asset needs and regulatory obligations, while also aligning with research on customer needs and preferences. For both Orillia and Peterborough, customers cited good reliability as a main reason for being satisfied with their existing distribution supply.[3] By addressing poor condition assets, Hydro One will mitigate the risk of outages caused by equipment failure to maintain reliability for customers.

1.3.3.1 SUMMARY OF THE DSP CAPITAL PLAN - Orillia

The capital expenditure forecast for Orillia is displayed in Figure 3.

[3] Refer to Section 2.2 - Customer Engagement Activities for details.

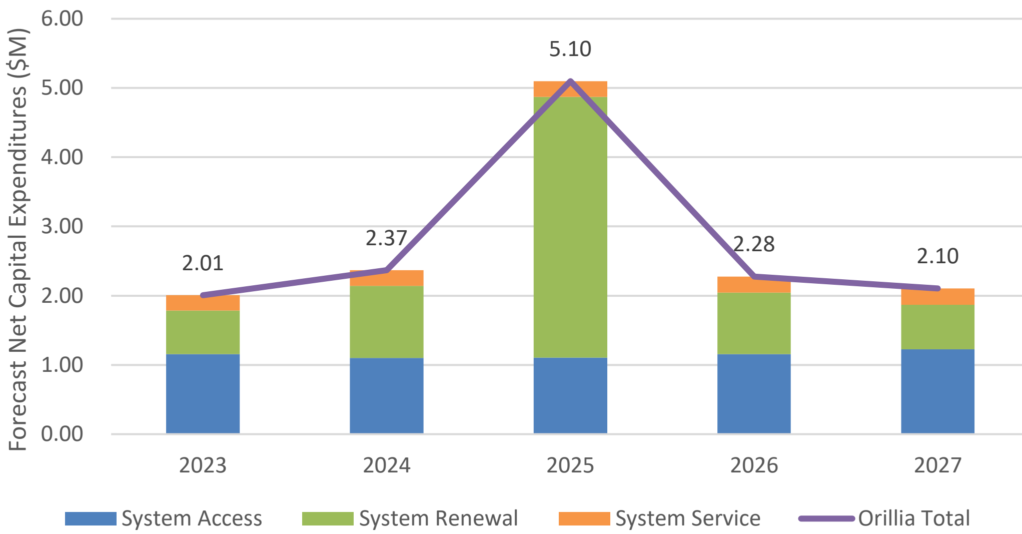


Figure 3: Forecast net capital expenditures for Orillia from 2023-2027

Hydro One is forecasting $13.85M in capital expenditures for Orillia between 2023-2027, resulting in an average annual forecast of $2.77M. Majority of the forecasted capital expenditures relate to System Renewal investments ($6.97M or 50% of the total forecast) and System Access investments ($5.74M or 41% of the total forecast).[4]

- **System Renewal**: $4.76M of the capital expenditure forecast relates to investments in Life Cycle Optimization (Section 5.5, D-SR-11). These investments will address condition and environmental issues at stations and reconfigure the system for increased growth and operability. The remaining System Renewal forecast ($2.21M) relates to sustainment investments that address assets in poor condition and storm response activities. These investments help maintain the safe and effective operation of the distribution system.
- **System Access**: investments are primarily comprised of New Load Connections, Upgrades and Cancellations ($5.21M; Section 5.5, D-SA-02), which are required to comply with statutory, regulatory, and license obligations.

[4] Additional details on the capital expenditure forecast for Orillia can be found in Section 5.3 - Forecast Capital Expenditure Trends and Section 5.5 - Material Investments Summary Documents.

- **System Service:** capital expenditures of $1.14M are forecasted between 2023-2027. These investments address near term system needs that arise because of localized growth on the distribution system.

1.3.3.2 SUMMARY OF THE DSP CAPITAL PLAN - Peterborough

The capital expenditure forecast for Peterborough is displayed in Figure 4.

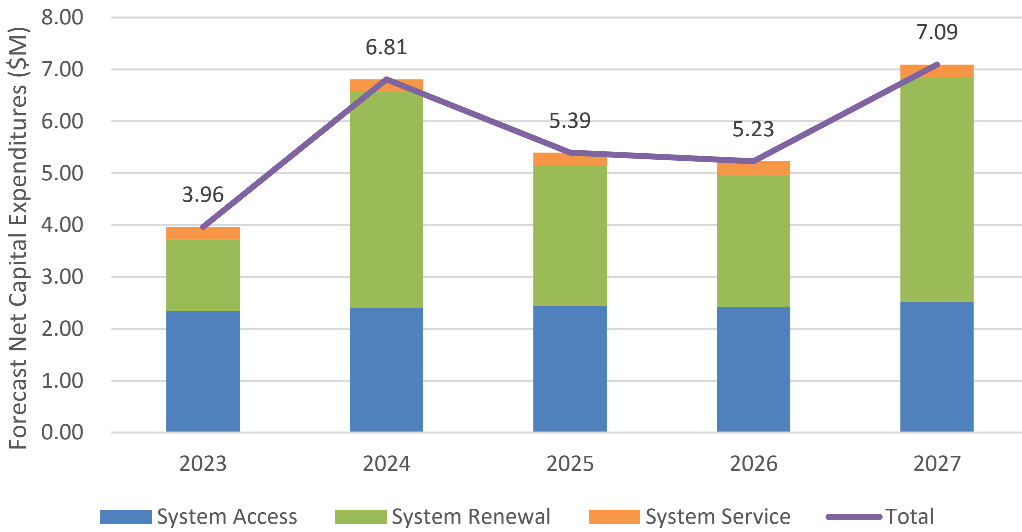


Figure 4: Forecast net capital expenditures for Peterborough from 2023-2027

Hydro One is forecasting $28.49M in capital expenditures for Peterborough between 2023-2027, resulting in an average annual forecast of $5.70M. Majority of the forecasted capital expenditures relate to System Renewal investments ($15.09M or 53% of the total forecast) and System Access investments ($12.13M or 43% of the total forecast).[5]

- **System Renewal:** $8.94M of the capital expenditure forecast relates to Station Refurbishment investments (Section 5.5, D-SR-04). These investments address poor condition stations and reduce the risk of interruptions caused by equipment failure. The remaining System Renewal forecast ($6.15M) relates to sustainment investments that address assets in poor condition and storm response activities.

[5] Additional details on the capital expenditure forecast for Peterborough can be found in Section 5.3 - Forecast Capital Expenditure Trends and Section 5.5 - Material Investments Summary Documents.

These investments help maintain the safe and effective operation of the distribution system.

- **System Access:** investments in Peterborough primarily relate to New Load Connections, Upgrades and Cancellations ($9.30M; Section 5.5, D-SA-02) and Metering Sustainment ($2.72M; Section 5.5, D-SA-04), which funds the replacement of failed meters to maintain accurate billing for customers.
- **System Service:** capital expenditures of $1.27M are forecasted between 2023-2027. These investments address near term system needs that arise because of localized growth on the distribution system.

FILING REQUIREMENTS CHECKLIST

This exhibit has been filed separately in MS Excel format.

DSP SECTION 2 - COORDINATED PLANNING WITH THIRD PARTIES

2.1 INTRODUCTION

The following section discusses Hydro One's infrastructure planning coordination with customers, Hydro One Transmission, other distributors, the Independent Electricity System Operator (IESO) and other third parties. It is organized into the following subsections:

- 2.2 Customer Engagement Activities;
- 2.3 Regional Planning Consultations;
- 2.4 Telecommunication Entities; and
- 2.5 Renewable Energy Generation (REG).

2.2 CUSTOMER ENGAGEMENT ACTIVITIES

Hydro One regularly engages with and obtains feedback from its customers through a variety of channels and methods to gain a solid understanding of what different customer segments expect from their electricity provider and where the company can make improvements to its services for customers. As applicable, this feedback is considered during, and helped inform, the investment planning process.

Hydro One engaged electricity customers in the areas formerly served by Orillia Power Distribution Corporation and Peterborough Distribution Inc. (herein referred to as "Orillia" and "Peterborough", respectively) to better understand their needs and preferences. This research was conducted in July 2020 and revealed that customers in both territories expressed very high customer satisfaction levels with their electricity providers. As the main reasons for satisfaction, customers stated good reliability, good customer service, and reasonable rates. Conversely, poor reliability, billing issues, poor customer service, and high rates were reasons for dissatisfaction. Few customers made specific service improvement suggestions, but those who did brought up lower rates, billing assistance, improved reliability, and infrastructure improvements. These findings are in line with customer needs and preferences in Hydro One's broader service territory.

Each customer segment has unique needs, and Hydro One engages with different customer segments in different ways. Larger customers (i.e. Large Distribution Accounts (LDA)) often require customized solutions and consultations. Hydro One engages with these customers through its Large Customer Account Management Group (Section 2.2.1 below). To ensure Hydro One maintains a regular view of its customers' needs and preferences, Hydro One performs the following activities on an ongoing basis to monitor changing customer service trends:

- Customer Satisfaction Research (Section 2.2.2 below)
- Call Centre Trends (Section 2.2.3 below)
- External Relations (Section 2.2.4 below)
- Hydro One's Ombudsman Office (Section 2.2.5 below)

2.2.1 LARGE CUSTOMER ACCOUNT MANAGEMENT

The Large Customer Account Management Group provides large distribution-connected customers with a single point of contact at Hydro One for all types of interactions. This group communicates with customers on matters that include customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. This approach facilitates a consistent and more comprehensive reporting of customer needs and preferences for use by planners, operators and customer service teams – feedback that is considered when making investment decisions.

To manage its performance and customer satisfaction, Hydro One consolidated the service delivery model for its large customers. An Account Executive is assigned to each of these large customers to track customer information and interactions and to identify opportunities to advocate for them across the organization.

Account Executives from Hydro One's Large Customer Account Management Group meet with their customers on a regular basis to ensure that the needs and preferences of customers are identified and discussed, and action plans are developed to address them. If an action plan results in new or modified connection facilities and/or asset needs, then the Account Executive will directly communicate with the affected customer(s) to ensure a common understanding of the related connection process and contractual requirements, such as connection cost estimates and capital cost recovery agreements. Hydro One's Account Executives also proactively engage with LDA customers to review and coordinate planned outage activities to minimize impacts on customers and to optimize opportunities for both Hydro One and customers to plan and execute work on their respective facilities.

2.2.2 CUSTOMER SATISFACTION RESEARCH

Since 1999, Hydro One has been collecting feedback from all customer segments through a comprehensive customer satisfaction research program. This research is conducted by independent expert customer research firms and incudes both perceptional and transactional satisfaction research.

Hydro One conducts transactional surveys on an ongoing basis to monitor customer needs and preferences, monitor trends, address transactional concerns in a timely fashion, and influence those practices in the future. These surveys contact a sub-set of Hydro One customers after they have had an interaction with the company to determine how well its customer service met their expectations. These surveys measure operational effectiveness for the call centre, the myAccount portal, service upgrades, new connections, and forestry work.

Hydro One also measures customers' perception of the company as a whole, whether they have interacted with Hydro One recently or not. These surveys monitor how well the company meets customers' expectations and delivers on critical success factors. These perception surveys are conducted monthly for residential and small business customers. All other customers, including Commercial and Industrial (C&I) and LDA customers are surveyed on an annual basis.

The trending of results over time assists Hydro One in identifying areas to improve customer satisfaction. Hydro One uses this data to inform and improve business practices and stay informed about the trends that matter most to its distribution customers. Customer Satisfaction scores serve as important performance measures and are includes in various scorecards (as described in Section 3.2 of this DSP).

2.2.3 CALL CENTER TRENDS

Residential and small business customers work with the Customer Contact Centre (CCC) when they have a question about their service or bill. Whether the customer contacts Hydro One by phone, e-mail, chat, or mail, these interactions are monitored closely, and any concerning trends are escalated and analyzed to assure Hydro One's performance is continuously improving and distribution system outcomes are aligned with customer needs and preferences.

Customer calls are actively monitored for quality control purposes to ensure Hydro One customers receive quality service and the timely and accurate information they need. Feedback is also received through the Customer Relationship Centre, which addresses escalated calls that require more detailed investigation and resolution.

C&I customers who are demand or interval metered are serviced by a dedicated team within the Business Contact Center. This dedicated team is the customer's "one-stop-shop" for questions regarding technical support or their bill. These representatives have the training to address billing questions or concerns and are readily able to navigate through the company's lines of business to get the technical information or contacts as required.

2.2.4 EXTERNAL RELATIONS

Hydro One's External Relations department maintains relationships with representatives of the Ontario government, Members of Provincial Parliament, municipality representatives and elected officials, and key stakeholder groups that represent large customer segments for Hydro One, such as the Ontario Federation of Agriculture and the Federation of Ontario Cottagers' Associations. Through these interactions, Hydro One is able to stay current with the issues these key stakeholders and their constituents or members may have, and External Relations is able to coordinate assistance on behalf of the company.

External Relations also coordinates Hydro One's presence at several stakeholder and community events to interact directly with customers and community leaders, providing information about Hydro One’s services and programs and listening to their views and concerns. Public consultation for major infrastructure investments and operational programs across Ontario is also a large part of the department’s work.

2.2.5 HYDRO ONE’S OMBUDSMAN OFFICE

When customers do not feel that a response or decision made by Hydro One was appropriate or fair, they can reach out to the Hydro One Ombudsman. The Ombudsman addresses these specific customer issues, but also performs systemic investigations. These investigations can highlight where changes are needed to better meet customers’ needs and preferences. Customer Service works with the Ombudsman’s office on a regular basis to understand any underlying trends of concern which may have arisen, which can then assist Customer Service to better align how it works with its residential and commercial customers.

2.3 REGIONAL PLANNING CONSULTATIONS

2.3.1 ROLES AND RESPONSIBILITIES OF HYDRO ONE DISTRIBUTION

As a province-wide distributor, Hydro One Distribution actively participates in regional planning activities. Hydro One Distribution’s assets are located in 20 of the 21 regions that have been identified for the purpose of regional planning. These regions correspond to the same 20 regions where Hydro One Transmission is the lead transmitter. Orillia is part of the Group 2 - South Georgian Bay/Muskoka region, while Peterborough is part of the Group 2 – Peterborough to Kingston region.

By participating in the regional planning process, Hydro One Distribution is actively engaged in various phases of the process. Hydro One Distribution’s role is to provide the lead transmitter with the information and data required to complete the Regional Infrastructure Planning (RIP) process, including information based on its embedded distributors’ data. Hydro One Distribution assesses the impact of regional supply plans to its distribution systems and where appropriate, develops and reviews potential distribution options to address the identified regional needs. Hydro One Distribution is also expected to support regional planning by identifying to the lead transmitter, any activity/elements on a sub-regional level that may impact a review cycle in a region to the transmitter.

In its role as a distributor, Hydro One Distribution may be requested to provide the following input.

- Provide short-term and long-term load forecasts to the lead transmitter and the IESO. Hydro One Distribution provides “gross” and “net” peak demand forecast for the short-term (five years) and medium-term (ten years), as well as the unbundled information used to show how they arrived at the “net” peak demand forecast.
- Provide background on the distribution system including information on past system performance.
- Identify local supply needs or constraints.
- Participate in community engagement sessions such as Local Advisory Committees or with local municipalities and other stakeholders.
- Participate in local planning led by the lead transmitter to address local supply needs.
- Identity and evaluate potential distribution-based solutions to meet regional or local infrastructure needs.
- Attend regularly scheduled Integrated Regional Resource Plan and RIP Working Group meetings at the regional and sub-regional level as required.
- Provide input and comments to proposed wires and non-wires solutions to address identified system needs.
- Review and provide comments on draft planning reports/documents prepared by the IESO and the lead transmitter.

To meet the requirements of its distribution rate application, Hydro One Distribution requested Hydro One Transmission to provide a letter confirming the status of regional planning for the regions that contain Orillia and Peterborough. This letter also ensures the alignment between Hydro One Distribution, as a local distribution company (LDC) and Hydro One Transmission, as a lead transmitter in regards of the identified needs in each region as well as the resulting cost allocation – if applicable – to Hydro One Distribution. Copies of the Regional Planning status letters are provided as Attachment 1 and Attachment 2 for the South Georgian Bay/Muskoka region and the Peterborough to Kingston region, respectively.

2.3.2 SUMMARY OF HYDRO ONE DISTRIBUTION NEEDS AND ASSOCIATED INVESTMENTS

By nature, regional planning is primarily focused on the capacity and infrastructure needs of a broader area, and therefore does not specifically identify investments to address needs that are embedded within the distribution system. However, by way of participating in the regional planning process, Hydro One Distribution benefits as an LDC, as it is an opportunity to confirm forecasts and trends on the distribution system. The following subsections describe the results of the RIPs for South Georgian Bay/Muskoka and Peterborough to Kingston, to the extent that they impact Orillia and Peterborough, respectively.

2.3.2.1 SOUTH GEORGIAN BAY/MUSKOKA

The South Georgian Bay/Muskoka Region is comprised of two sub-regions: Barrie/Innisfil and Parry Sound/Muskoka. The participants include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Utilities
- Hydro One Networks Inc. (Distribution), including Orillia
- InnPower Corporation
- Orangeville Hydro Ltd.
- Elexicon Energy Inc.
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

The 2017 RIP for South Georgian Bay/Muskoka is provided as Attachment 3. Orillia is not affected by any planned work in the Barrie/Innisfil and Parry Sound/Muskoka sub-regions and as such, no capital contributions from Hydro One Distribution to Hydro One Transmission are anticipated for Orillia at this time.

2.3.2.2 PETERBOROUGH TO KINGSTON

The Peterborough to Kingston Region includes the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, Frontenac County on the East, and Lake Ontario on the South. The participants include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution), including Peterborough
- Kingston Hydro
- Elexicon Energy Inc.
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

The 2022 RIP for Peterborough to Kingston is provided as Attachment 4. Peterborough is not affected by any planned work in the Peterborough to Kingston sub-regions and as such, no capital contributions from Hydro One Distribution to Hydro One Transmission are anticipated for Peterborough at this time.

2.4 TELECOMMUNICATIONS ENTITIES

Hydro One currently has joint use agreements in effect with five telecommunication entities in Orillia and six telecommunication entities in Peterborough, covering approximately 13,000 pole attachments. Hydro One regularly engages with these partners to coordinate work and enable expansions. In addition to these local relationships, Hydro One maintains a list of approximately 140 telecommunication entities with agreements for telecommunication attachments across the province of Ontario.

Given the vast service territory and to allow for appropriate business planning, Hydro One requires information on the upcoming permit applications (in terms of volume, timing, and targeted locations) from telecommunication entities. This enables Hydro One to consider the impact of planned system upgrades, enhancements, or maintenance work on the joint use effort in advance of project proposal submission. Accordingly, Hydro One has requested licensees to provide forecasts of all upcoming work. Hydro One makes best efforts to identify planned work and/or other potential third-party attachment conflicts that may overlap with joint-use make-ready work as permit applications are submitted by joint use partners.

Hydro One supports innovation and continuous improvement to enable and accelerate joint use/broadband projects in collaboration with its Joint Use Partners. In September 2022, Hydro One rolled out a new work execution model for joint use/broadband work, to facilitate the acceleration of broadband connectivity to unserved and underserved homes and businesses in joint service territories. This new model, informed by feedback from telecommunication entities, will help reduce barriers to joint use partners in support of the timely deployment of broadband across the province of Ontario.[1]

2.5 RENEWABLE ENERGY GENERATION (REG)

Orillia and Peterborough REG investments are related to enabling specific applications to connect REG to the distribution system in Orillia and Peterborough. The investments represent regulatory obligations for renewable enabling improvements and the renewable energy expansion cost cap.

In the past, the Feed-In Tariff (FIT) program was the dominant source of opportunity for REG. Consultation with the IESO during the FIT program allowed Hydro One and IESO to validate the volume of expected REG in Hydro One territory. No FIT contracts were issued after 2017, and consultation with the IESO is no longer necessary to validate REG investments. REG investments today are largely a result of applications to the net-metering program.

Hydro One has not made any REG investments in the DSP for the sole purpose of creating future REG capacity. Because the major impacts of distributed energy resources (DER) interconnections are extremely localized, it is very difficult to predict where a REG investment will be prudent. Hydro One participates in the IESO Regional Planning Process and therefore has an opportunity to coordinate any plans that might result in additional

[1] Hydro One Letter: New Joint Use/Broadband Choice-Based Operating Model is Live, September 6, 2022. (https://www.hydroone.com/JUMP/Documents/Hydro_One_Joint_Use_Broadband_Go-Live_Announcement.pdf)

REG capacity. Hydro One coordinates REG investments with other LDCs when a DER requests a connection to a feeder which is shared between Hydro One and the other LDC. Letters from Hydro One's Regional Planning Group to Hydro One's Distribution Asset Management are provided as Attachments 1 and 2 to this section of the DSP. These attachments summarize Hydro One's participation in the IESO regional planning activities for the South Georgian Bay/Muskoka region and the Peterborough to Kingston region, respectively.

Hydro One Network Inc.
483 Bay Street
14th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

July 07, 2022

Peter Faltaous
Director- Distribution Asset Management
Hydro One Network Inc.
483 Bay Street, 15th Floor
Toronto, Ontario M5G 2P5

Via email: peter.faltaous@HydroOne.com

Dear Mr. Faltaous:

Subject: Regional Planning Status – Orillia Power Distribution Corporation service area.

This letter is in response to your request for a Planning Status letter. For the purposes of regional planning the province has been divided into 21 regions. These 21 regions are assigned to one of the three groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 regions[1] and the list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. is the lead transmitter in 20 regions and Orillia Power Distribution Corporation service area belongs to the Southern Georgian Bay/Muskoka Region in Group 2.

This letter confirms that the first cycle of regional planning process was completed in 2017. The second cycle regional planning process for the Southern Georgian Bay/Muskoka Region is currently under development; the Needs Assessment (NA)[2] Report was completed in April 2020 followed by the Integrated Regional Resource Planning (IRRP) reports for Barrie/Innisfil[3] and Parry Sound/Muskoka[4] which were completed in May 2022. The final phase of the regional planning process, the Regional Infrastructure Plan (RIP), is scheduled to be completed by the end of Q4 2022.

1 Hydro One Regional Planning
2 Southern Georgian Bay/Muskoka Needs Assessment (NA)
3 Southern Georgian Bay/Muskoka Integrated Regional Resource Planning (IRRP) - Barrie/Innisfil
4 Southern Georgian Bay/Muskoka Integrated Regional Resource Planning (IRRP) - Parry Sound/Muskoka

The planning status for this region is described below.

Southern Georgian Bay/Muskoka

The Southern Georgian Bay/Muskoka Region Working Group (WG) included representatives from Hydro One Networks Inc , the Independent Electricity System Operator (IESO) and directly affected LDCs. The region was divided into two sub-regions: a) Barrie/Innisfil and b) Parry Sound/Muskoka. Below are the needs identified for each sub-region:

a) Barrie/Innisfil

The Barrie/Innisfil sub-region 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. This sub-region is electricity supplied by the following three local distribution companies (LDC), namely: Hydro One Networks Inc. (Distribution), Alectra Utilities and Innpower Corporation. The recent study done by the Technical Working Group (TWG), identified near to medium plan for this sub-region as follows:

- Installation of a new transformer substation in/near Innisfil as the Barrie TS is to reach its summer 10-day LTR and supply capacity constraint at 44kV feeder level.
- Adjustment of the CT ratio of transformer breakers at Everett TS
- Like-for-like replacement of a section(s) of the E8V/E9V circuit

The TWG also initiated below potential long-term needs in this sub-region as follow:

- Monitoring growth for Alliston and Midhurst stations to determine when further reinforcements will be needed.
- Monitoring the demand growth in the area served by the M6E/M7E circuits including Midhurst and to consider incremental cost-effective CDM

Single line of this sub-region is added to Appendix C.

b) Parry Sound/Muskoka

The Parry Sound/Muskoka sub-region encompasses the Districts of Muskoka and Parry Sounds and the northern part of Simcoe County. The Electrical supply to this sub-region is provided through the autotransformers at Essa TS (near Barrie) and Minden TS and the 230 kV transmission lines and step-down transformers shown on the single line in Appendix C.
The electricity within the sub-region is supplied by the following six LDCs: Hydro One Networks Inc , Alectra Utilities, Elexicon Energy, Lakeland Power, EPCOR Electricity Distribution Ontario Inc. and Newmarket-Tay Power Distribution Ltd.

The recent study done by the TWG, identified near to medium plan for this sub-region as follows:

- Upgrading the Waubaushene station capacity as this TS demand forecast is over its summer 10-day LTR
- Replacement of a section(s) of the M6E/M7E section
- Replacement of a section(s) of the D1M/D2M section

The TWG also initiated below potential long-term needs in this sub-region as follow:

- Monitoring growth, and upgrading the M6E/M7E supply capacity since losing either M6E or M7E will cause the remaining circuit will exceed its Long Term Emergency (LTE) rating
- Monitoring growth, and upgrading Minden TS station capacity since this TS demand forecast will exceed its summer 10-day LTR

No planned work in the Barrie/Innisfil and Parry Sound/Muskoka sub-regions affects Orillia Power Distribution Corporation service area. Furthermore, at this time it is expected that no capital contribution is required by Hydro One Networks Inc Transmission from Orillia Power Distribution Corporation service area for the projects recommended through the regional planning in the Southern Georgian Bay/Muskoka region.

Hydro One Networks Inc would like to acknowledge and thank you for your work and effort in support of the Regional Planning process. We look forward to continuing to work with you in the future. If you have any further questions, please feel free to contact me.

Sincerely,

Original Signed By Ajay Garg

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

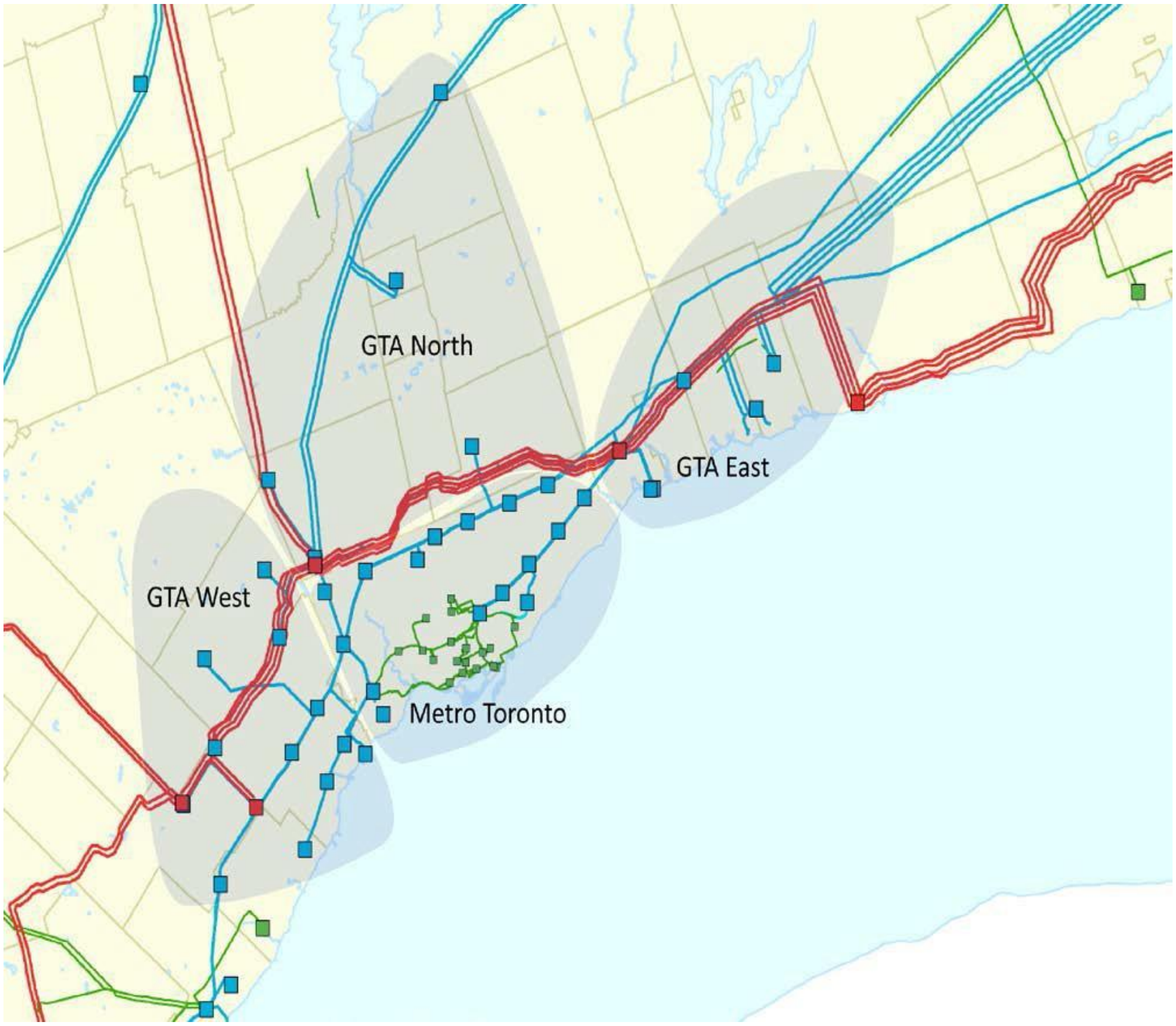
Cc:
Mark VAN TOL, Senior Network Management Engineer, Distribution Investment Planning

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee*
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge- Guelph (“KWCG”)		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

*This region is not within Hydro One’s territory.

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power) • Brantford Power Inc. • Burlington Hydro Inc. • Alectra Utilities Corporation • Hydro One Networks Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Veridian Connections Inc
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. • Hydro One Networks Inc. • Centre Wellington Hydro Ltd. • Kitchener-Wilmot Hydro Inc. • Guelph Hydro Electric System - Rockwood Division • Milton Hydro Distribution Inc. • Guelph Hydro Electric Systems Inc. • Waterloo North Hydro Inc. • Halton Hills Hydro Inc. • Wellington North Power Inc.

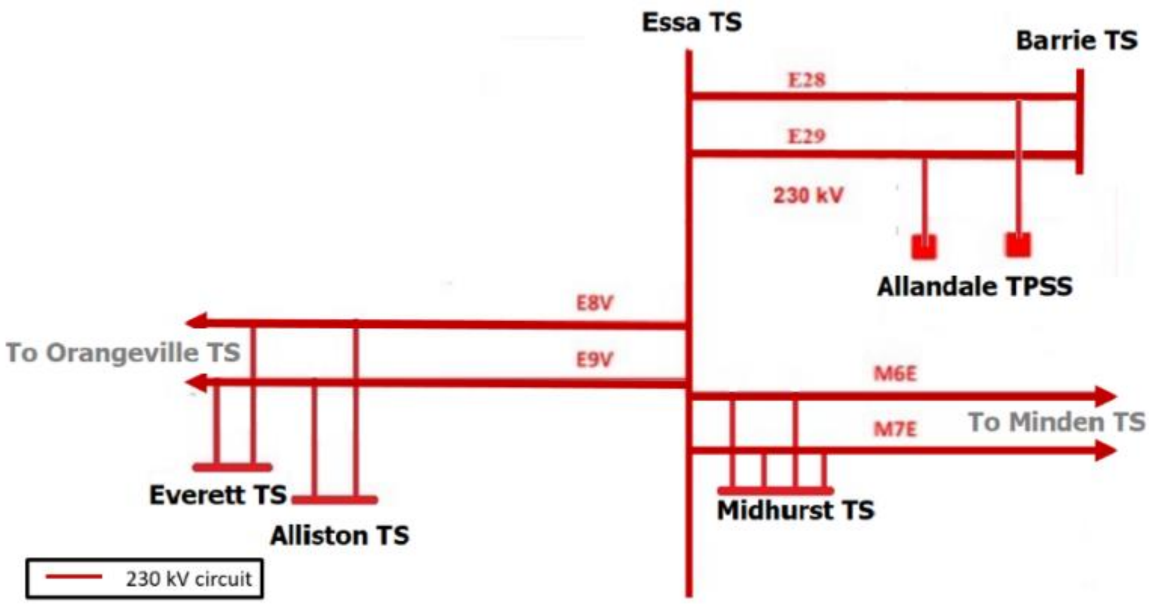
6. Metro Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Fort Frances Power Corporation • Hydro One Networks Inc. • Sioux Lookout Hydro Inc. • Synergy North
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior* *Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region.	• Algoma Power Inc. • Chapleau PUC • Sault Ste. Marie PUC • Hydro One Networks Inc.
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Elexicon Energy Inc.
11. London Area	• Entegrus Power Lines Inc. [Middlesex] • Erth Power Inc. • Hydro One Networks Inc. • London Hydro Inc. • Tillsonburg Hydro Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Elexicon Energy Inc.

13. South Georgian Bay/Muskoka	• Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Parry Sound Water Corp. • Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Tay Power • Veridian Connections Inc. • Veridian-Gravehurst Hydro Electric Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• North Bay Hydro • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation
18. North of Moosonee** **Hydro One Transmission is not the lead transmitter in this region.	• N/A (Distribution in this region is provided by FNEI)

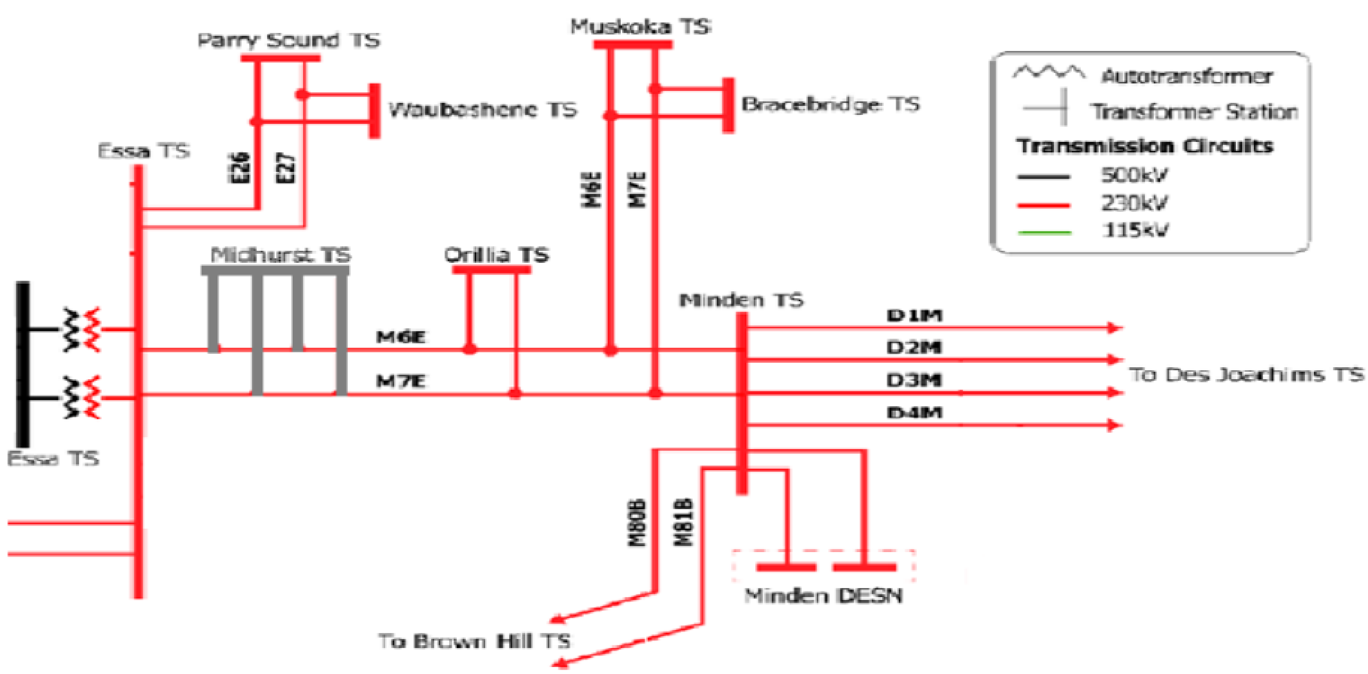
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Appendix C: Sub-Region SLDs

Barrie/Innisfil



Parry Sound/Muskoka



Hydro One Network Inc.
483 Bay Street
14th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

July 07, 2022

Peter Faltaous
Director- Distribution Asset Management
Hydro One Network Inc.
483 Bay Street, 15th Floor
Toronto, Ontario M5G 2P5

Via email: peter.faltaous@HydroOne.com

Dear Mr. Faltaous:

Subject: Regional Planning Status – former Peterborough Distribution Inc. service area

This letter is in response to your request for a Planning Status letter. For the purposes of regional planning, the province has been divided into 21 regions. These 21 regions are assigned to one of the three groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 regions[1] and the list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. is the lead transmitter in 20 regions and the former Peterborough Distribution Inc. service area (now part of Hydro One Networks Inc. Distribution) belongs to the Peterborough to Kingston region in Group 2.

This letter confirms that the second cycle of regional planning process was completed in 2022. The second cycle Needs Assessment (NA)[2] report was completed in February 2020 followed by the Scoping Assessment (SA)[3] in May 2020. The Integrated Regional Resource Planning (IRRP)[4] and the Regional Infrastructure Plan (RIP)[5] for this region were completed in November 2021 and May 2022 respectively.

1 Hydro One Regional Planning
2 Peterborough to Kingston Needs Assessment (NA)
3 Peterborough to Kingstone Scoping Assessment (SA)
4 Peterborough to Kingston Integrated Regional Resource Planning (IRRP)
5 Peterborough to Kingston Regional Infrastructure Plan (RIP)

The Peterborough to Kingston Technical Working Group (TWG) includes representatives from Hydro One Networks Inc. (Transmission), Eastern Ontario Power Inc., Elexicon Energy Inc., Hydro One Networks Inc. (Distribution), Independent Electricity System Operator ("IESO"), Kingston Hydro, and Lakefront Utilities Inc. The Peterborough to Kingston region is comprised of the area bordered approximately by Clarington on the West, North Frontenac County on the North, Frontenac County on the East and Lake Ontario on the South. Single line diagram of this region representing the transmission stations is added to Appendix C.

The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon for this region are provided below:

- Upgrading existing copper conductor on secondary side of auto transformers at Cataraqui TS
- Replacing T1/T2 transformers at Gardiner TS DESN1 with similar type and size equipment as per current standard
- Transferring load from Gardiner TS DESN1 to Gardiner TS DESN2
- Developing plan to build new 230kV 75/125 MVA DESN station in the Frontenac TS area as needed
- Transferring load from 44kV bus at Otonabee TS to Dobbin TS to overcome Otonabee TS station capacity limits
- Replacing T3/T4 transformers at Port Hope TS with similar type and size equipment as per current standard
- Building a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site
- Replacing T1/T2 transformers at Picton TS with similar type and size equipment as per current standard
- Replacing T1/T2/T5 auto-transformers at Dobbin TS with two new 150/250 MVA unit and refurbish the station switchyard

For potential long-term needs in this region, the TWG will monitor changes in growth, progress in electrification, and any significant changes in forecast growth and plans accordingly.

No planned work in the Peterborough to Kingston region affects the former Peterborough Distribution Inc service area. Furthermore, no capital contribution is required by Hydro One Networks Inc. Transmission from Hydro One Networks Inc. Distribution for the former Peterborough Distribution Inc service area for the projects recommended through the regional planning process in the Peterborough to Kingston region.

Hydro One Networks would like to acknowledge and thank you for your work and effort in support of the Regional Planning process. We look forward to continuing to work with you in the future. If you have any further questions, please feel free to contact me.

Sincerely,

Original Signed By Ajay Garg

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

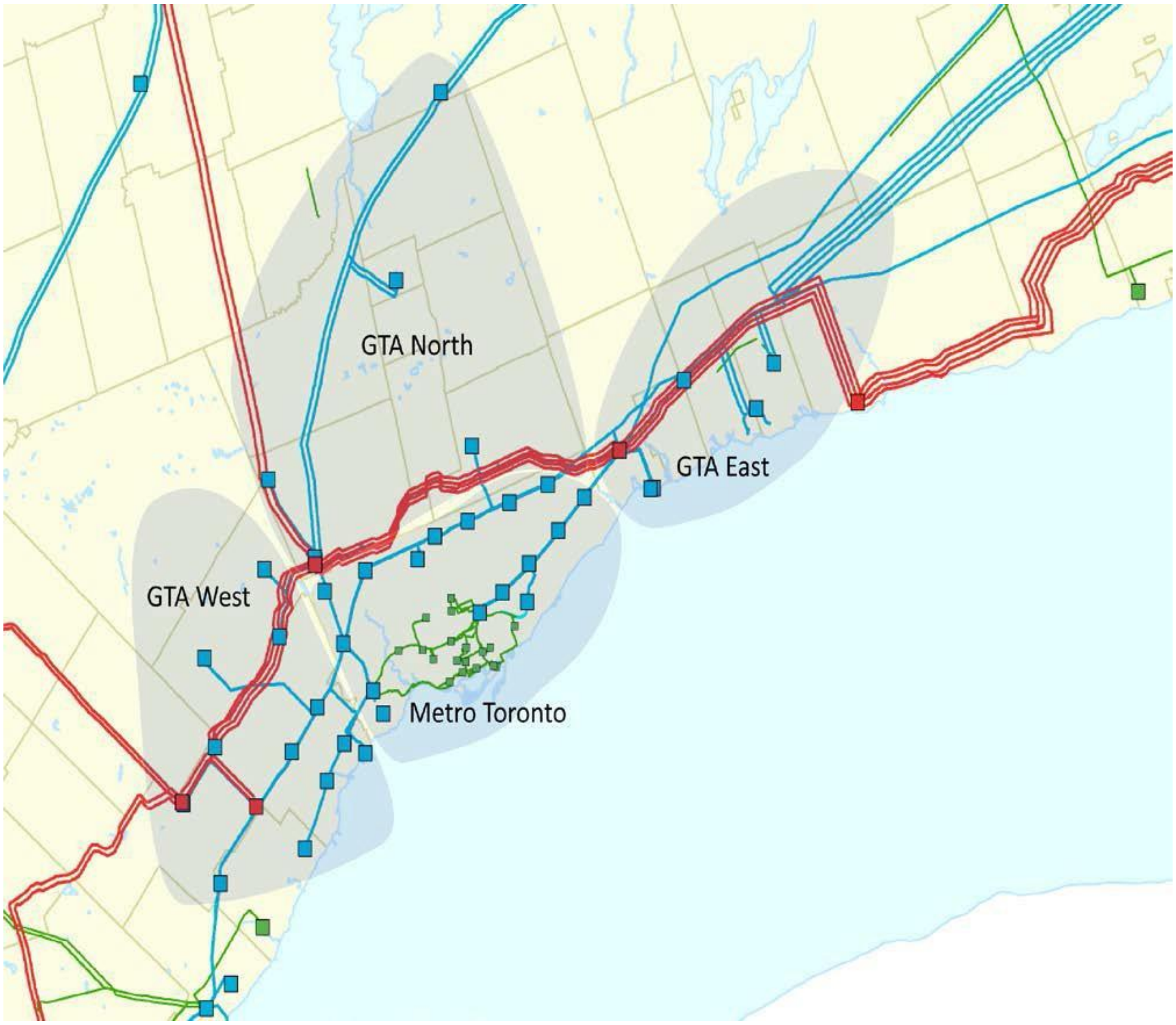
Cc:
Mark VAN TOL, Senior Network Management Engineer, Distribution Investment Planning

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
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Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee*
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Kitchener- Waterloo- Cambridge-Guelph ("KWCG")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

*This region is not within Hydro One's territory.

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
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	• Halton Hills Hydro Inc. • Wellington North Power Inc.
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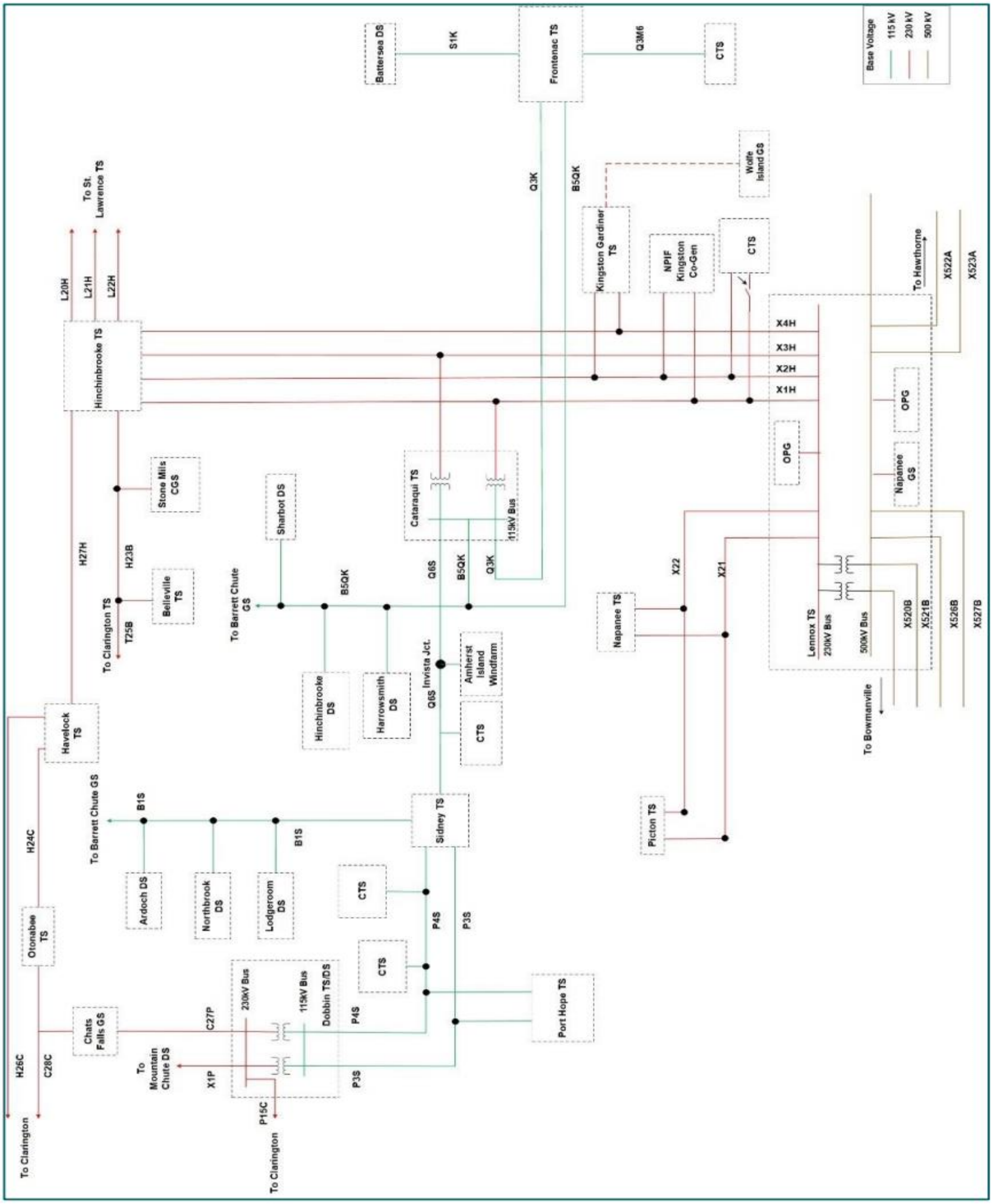
Appendix C: Peterborough to Kingstone SLD



South Georgian Bay/Muskoka

REGIONAL INFRASTRUCTURE PLAN

August 18th, 2017

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator
Alectra Utilities Corporation (formerly PowerStream Inc.)
Hydro One Networks Inc. (Distribution)
InnPower Corporation
Orangeville Hydro Ltd.
Veridian Connections Inc.

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 also any additional needs identified based on new and/or updated information provided by the RIP Study Team.

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE STUDY TEAM 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 SOUTH GEORGIAN BAY/MUSKOKA REGION.

The participants of the RIP Study Team included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Alectra Utilities (formerly PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Veridian Connections Inc.

This RIP is the final phase of the OEB's mandated regional planning process for the South Georgian Bay/Muskoka Region. It follows the completion of Integrated Regional Resource Plans ("IRRP") for Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions on December 16, 2016.

This RIP provides a consolidated summary of the needs and recommended plans for the South Georgian Bay/Muskoka Region which includes the Barrie/Innisfil and Muskoka/Parry Sound Sub-Regions. The major transmission and distribution infrastructure investments planned for the South Georgian Bay/Muskoka Region over the near and mid-term, as identified in the various phases of the regional planning process are given in the Table below.

No.	Project	I/S Date	Cost ($ Million)
1	Replacement of 115-44kV transformers (T1 and T2) at Barrie TS, uprating 115kV circuits to 230kV, adding additional feeders to Barrie DESN	2020/2021	$84
2	Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	2020/2021	$17
3	Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	2021	$5-7
4	Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	2020	$7
5	Replacement of 230/44 kV transformers at Parry Sound TS*	2021	$20
6	Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS	2024/2025	$33

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

A load transfer from Barrie TS to Midhurst TS that is planned for 2019 will address the near-term capacity need at Barrie TS and will defer the capacity need of the upgraded Barrie TS to 2031.

A cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

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 can also be started earlier.

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 SOUTH GEORGIAN BAY/MUSKOKA 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, Alectra Utilities (formerly PowerStream Inc.) (“Alectra”), Veridian Connections Inc. (“Veridian”), Innisfil Hydro Distribution Systems Ltd (“InnPower”), Orangeville Hydro Ltd (“Orangeville 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 South Georgian Bay/Muskoka region consists of the area roughly bordered by the Municipality of West Nipissing to the northwest, Algonquin Provincial Park to the northeast, Peterborough County and Hastings County to the southeast, Lake Scugog, York and Peel Regions to the south, Wellington County to the southwest and the Municipality of Grey Highlands to the west. Figure 1-1, on the following page, shows the boundaries of the South Georgian Bay/Muskoka Region.

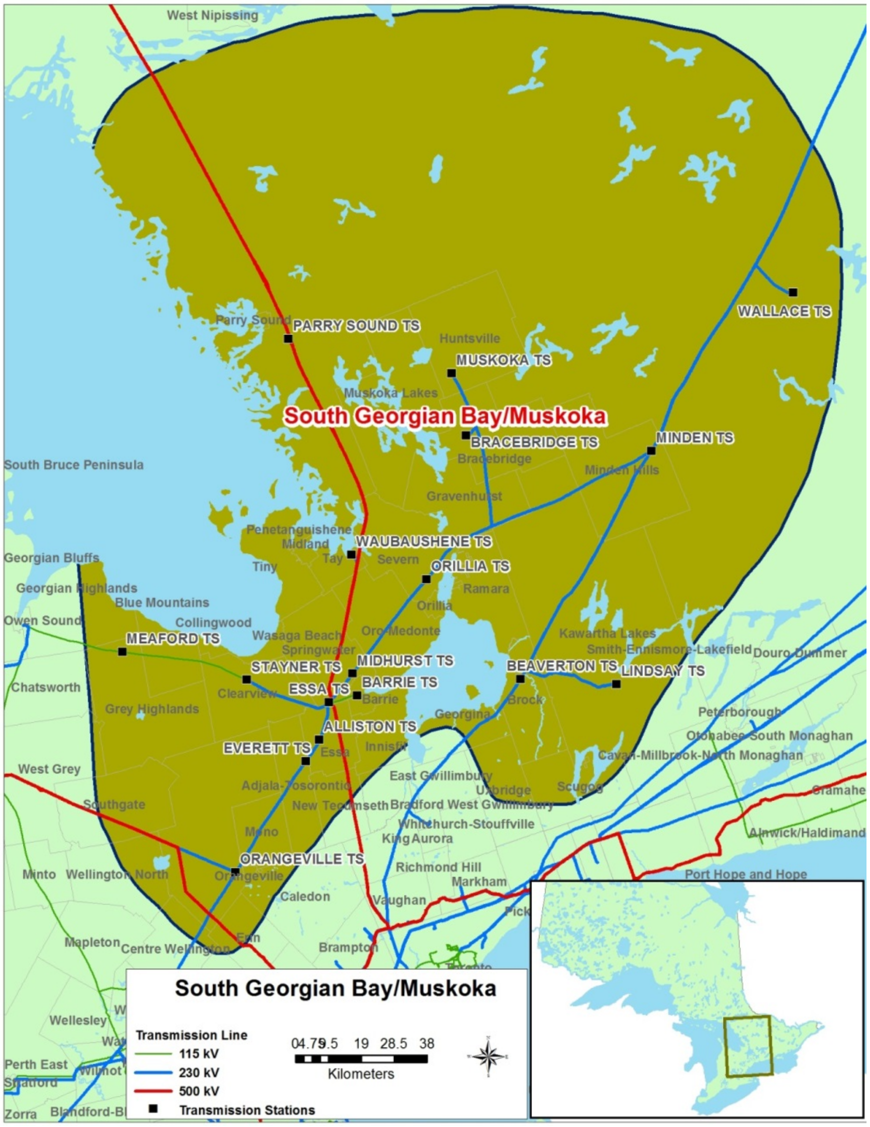

Figure 1-1 South Georgian Bay/Muskoka Region

1.1 Scope and Objectives

This RIP report examines the needs in the South Georgian Bay/Muskoka Region. Its objectives are to:

- Identify new 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;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and/or distribution facilities 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 Region's 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 Barrie-Innisfil and Parry Sound/Muskoka sub-region IRRPs.

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 can also be started earlier.

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 performed 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[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 or comprehensive planning is required an assessment is undertaken for any necessary investments directly by the LDCs (or customers) 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.

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 require regional coordination, the Study Team can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, 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 is identified in the NA phase, it is possible that different approaches 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

[1] Also referred to as Needs Screening.

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 timeline 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.

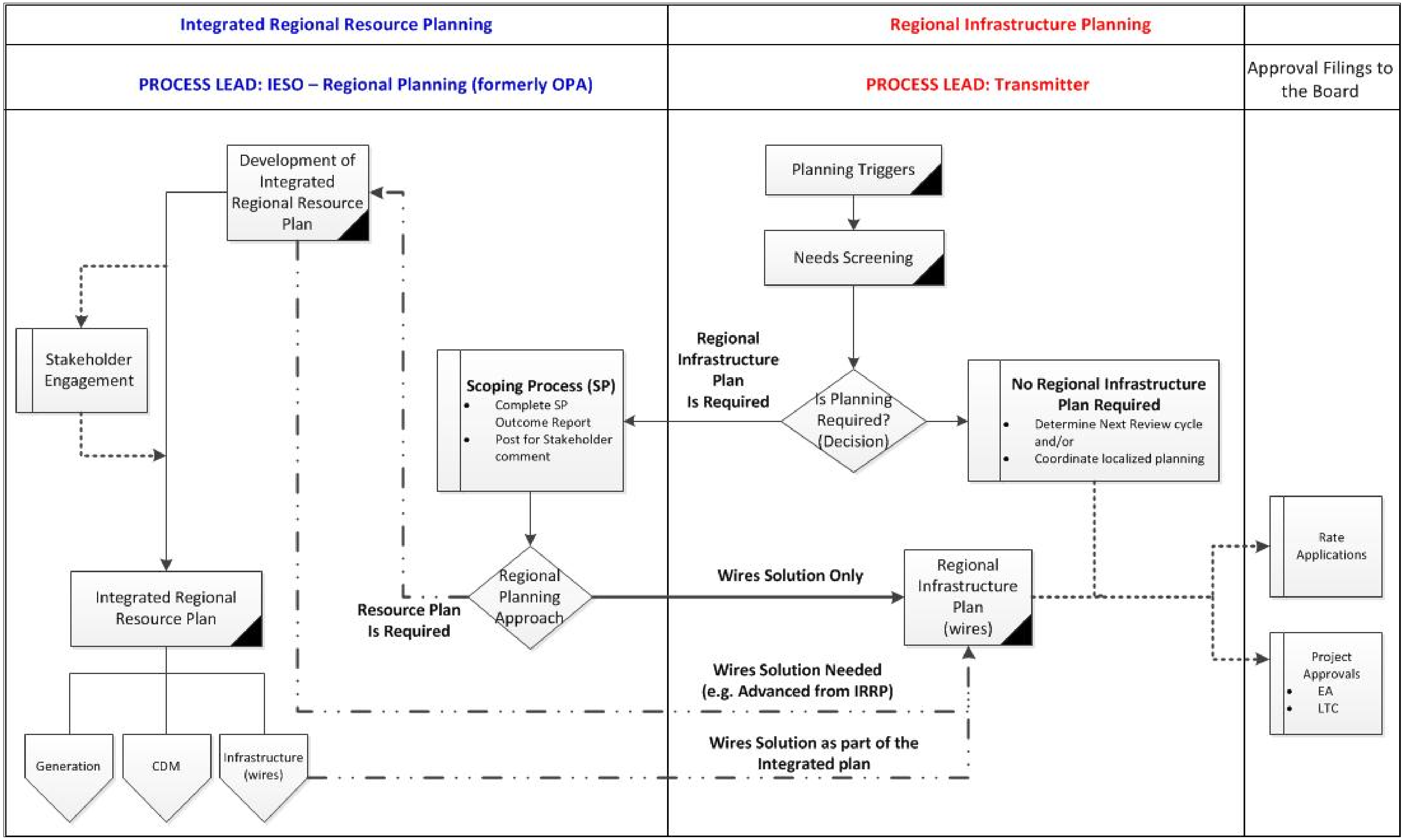

Figure 2-1 Regional Planning Process Flowchart

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 Study Team to reconfirm or update the information as required:
   - Net peak demmand forecastt at the transformer statiion level. Thhis includes the effect oof any diistributed genneration ("DGG") or CDM pprograms;
   - EExisting area network and ccapabilities inncluding any bbulk system ppower flow asssumptions;
   - Other data andd assumptionss as applicablle such as assset conditionss, load transfefer capabilities, and prreviously commmitted transmmission and ddistribution syystem 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.

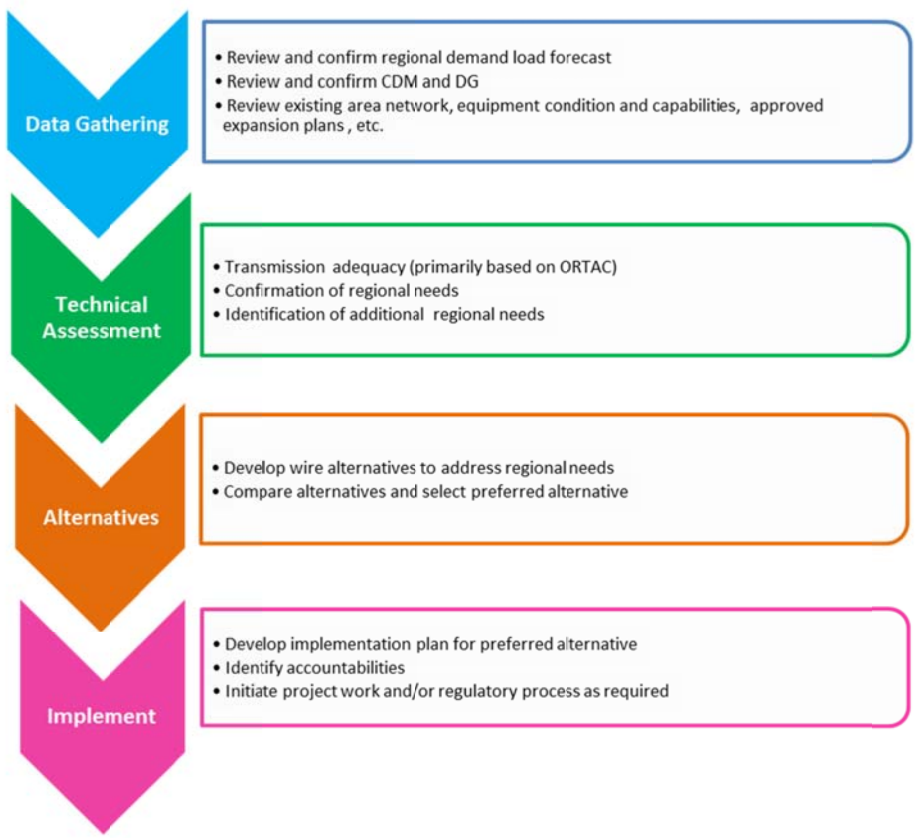

Figure 2-2 RIP Methoddology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M 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. THE 2015 WINTER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1,350 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

There are sixteen Hydro One-owned 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 March 2013 South Georgian Bay/Muskoka Region NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region. An IRRP was undertaken for each sub-region. A map of the South Georgian Bay/Muskoka Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Barrie/Innisfil Sub-Region

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

3.2 Parry Sound/Muskoka Sub-Region

This sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, and Minden TS, and transmission circuits M6E/M7E and E26/E27.

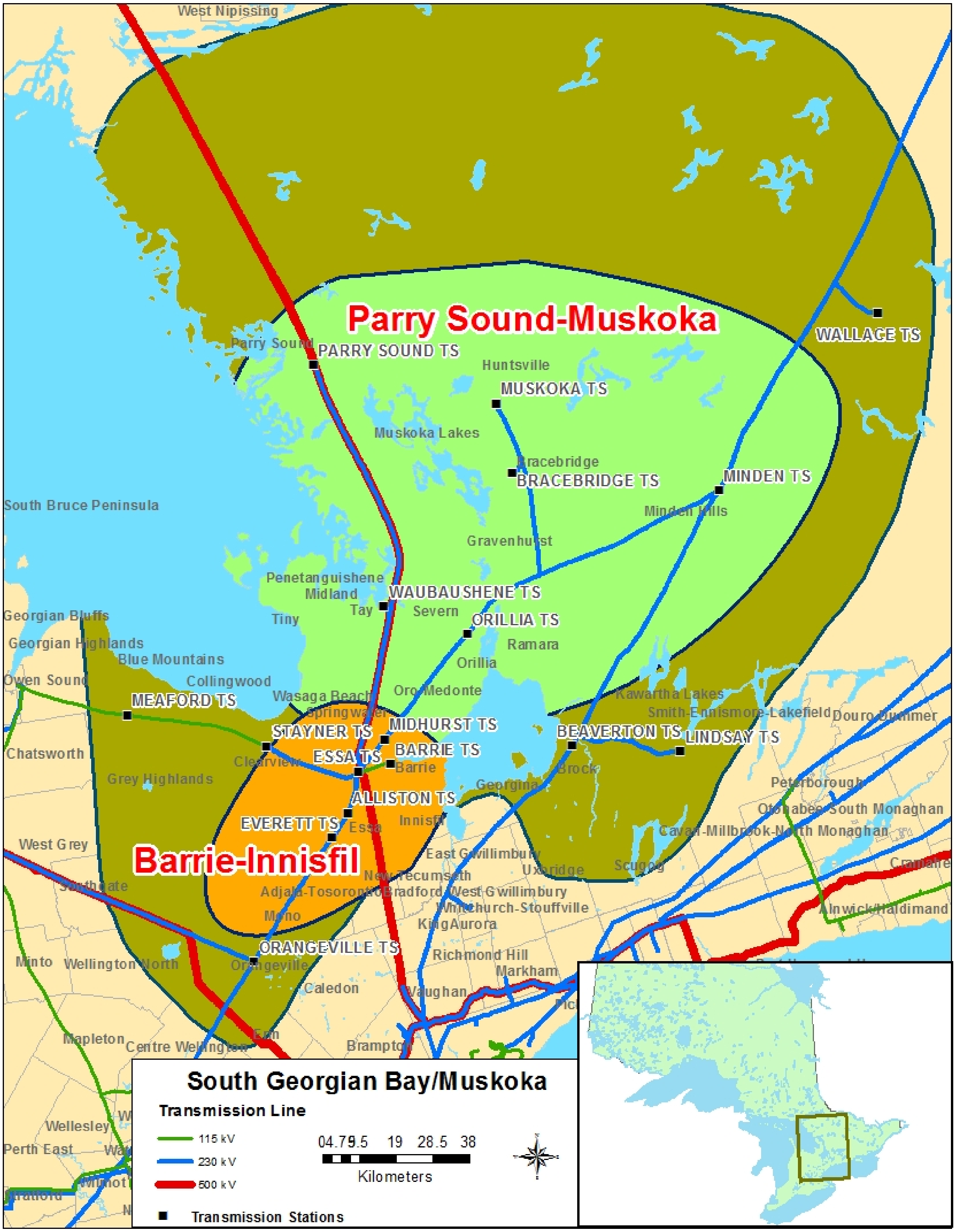

Figure 3-1 South Georgian Bay/Muskoka – Supply Areas

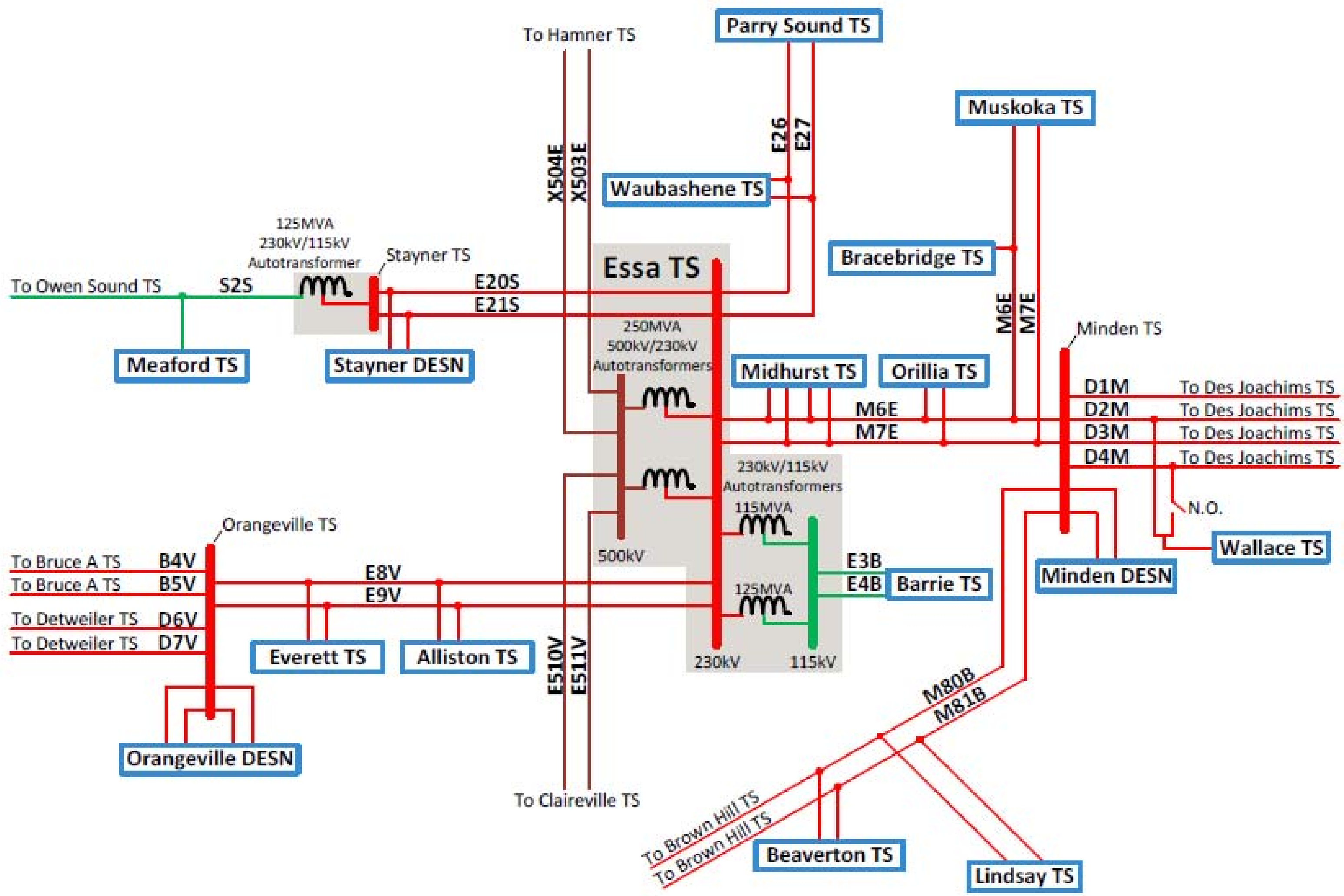

Figure 3-2 South Georgian Bay/Muskoka Region Single Line Diagram (Current)

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 HAVE BEEN INITIATED, AIMED AT IMPROVING THE SUPPLY TO THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

A brief listing of the development projects along with their in-service dates over the last 10 years is given below:

- Everett TS (2007) – Construction of new 50/85 MVA 230/44 kV Everett transformer station to alleviate load from Alliston TS, which was loaded beyond its capacity, and provide additional capacity for the load growth in the South Georgian Bay area.

- South Georgian Bay Transmission Reinforcement (2009) – Replacement of 27 km of 115 kV single circuit (S2E) between Essa TS and Stayner TS with a 230 kV double circuit (E20S/E21S) to improve supply reliability and prevent excessive post-contingency voltage decline. Replacement of two 50/83 MVA 115/44 kV step-down transformers at Stayner TS with two 75/125 MVA 230/44 kV transformers to provide additional capacity for the load growth in the South Georgian Bay area.

- Essa TS Shunt Capacitor Bank (2010) – Installation of one (1) 230 kV 245 MVAr shunt capacitor bank to address the need for added voltage support to increase the transfer capability of power from north to south and accommodate committed generation facilities north and west of Sudbury.

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44 kV 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (2 banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and improve the power quality for customers.

- Meaford TS Transformer Replacement (2015) – Like-for-like replacement of 25/42 MVA 115/44 kV transformers that were over 60 years old and nearing end-of-life.

The following development projects are expected to be placed in-service within the next 5-10 years:

- Barrie TS (2020/2021) – Hydro One is working with IESO, Alectra Utilities, InnPower, and Hydro One Distribution to replace the aging infrastructure while also addressing the growth related needs. The plan entails uprating 115kV lines E3B/E4B to 230kV, upgrading existing DESN transformer from 115/44 kV, 55/92 MVA to 230/44 kV, 75/125 MVA, increasing the number of feeders at Barrie TS, and removing the two 230/115 KV auto-transformers and 115 kV switchyard at Essa TS.

- Minden TS (2020-2021) – A recent station assessment has identified that power transformers T1 and T2, protection and control equipment, and select 44kV switchyard assets are degrading in condition and require replacement. Work involves replacing existing T1 & T2 three-phase power transformers with standard size three-phase power transformers, and upgrading and replacing the 44kV switchyard components.

- Orangeville (2024-2025) End-of-life transformers T1 and T2 (non-standard) will be replaced with two standard three-phase transformers sized 215.5-28 kV, 50/66.7/83.3 MVA units and T3 and T4 will be replaced with standard 215.5-44 kV, 75/100/125 MVA units. To standardize the configuration, the T1/T2 switchyard will be reconfigured as a single 230-28 kV switchyard and the two existing 44 kV feeders, M45 and M46, will be relocated and supplied from the T3/T4 DESN. Associated end-of-life protection, control and telecom assets and station service equipment is also planned for replacement.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the South Georgian Bay/Muskoka Region is expected to increase at an annual rate of approximately 1.17 % between 2016 and 2034. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The winter and summer, gross and net non-coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

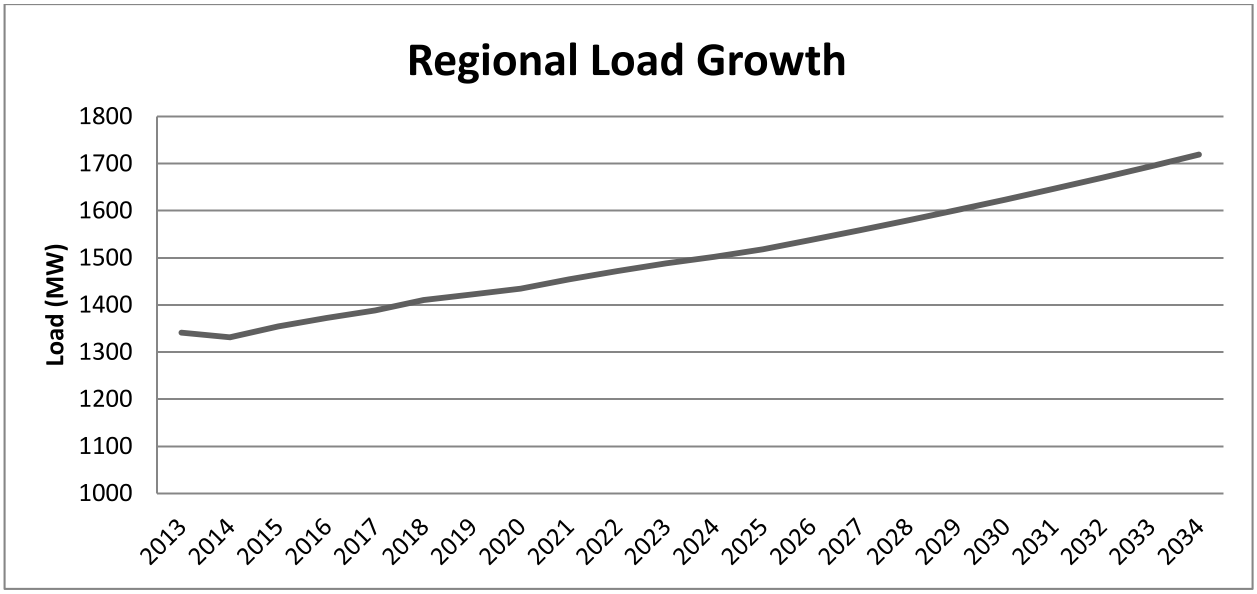

Figure 5-1 South Georgian Bay/Muskoka Region Winter Coincident Net Load Forecast

Prior to the RIP's kick-off, the Study Team was asked to confirm the load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for South Georgian Bay/Muskoka Region did not have a significant revision compared to the IRRP's load forecast.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2014 – 2034.
- The Region is winter peaking, however five out of sixteen stations in the Region are summer peaking (Alliston TS, Barrie TS, Everett TS, Midhurst TS and Orangeville TS T1/T2 DESN). Therefore, this assessment is based on both winter and summer peak loads, as appropriate.
- "Barrie Area Transmission Upgrade project" to be completed by the end of 2020.
- 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.[2] Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR") or the winter 10-Day LTR depending on what season the station peaks.

- Barrie TS is forecasted to experience the highest average yearly growth rate of any TS in the study area over the 20 year planning period for all growth scenarios.

[2] These power factor assumptions differ from those in the IRRP, which assumes a 90% lagging power factor for all stations. This results in differences in need dates for station capacity when comparing the IRRP and the RIP.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY/MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, six regional assessments have been conducted for the South Georgian Bay/Muskoka Region. The findings of these studies are an input to the RIP:

1. South Georgian Bay/Muskoka Region Needs Assessment Report – March 3, 2015 [2]
2. South Georgian Bay/Muskoka Region Scoping Assessment Report – June 22, 2015 [3]
3. Local Planning Report – Orangeville TS End of life (“EOL”) Replacement – May 27, 2016 [4]
4. Barrie/Innisfil Sub-Region IRRP – Dec. 16, 2016 [5]
5. Parry Sound/Muskoka Sub-Region IRRP – Dec. 16, 2016 [6]

The NA, IRRP, 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 South Georgian Bay/Muskoka Region assuming Essa/Barrie and E3B/E4B upgrade to be completed by 2020/2021, Minden DESN transformer replacement and 44kV upgrade to be completed by November 2020/2021, and Orangeville transformer replacement and station reconfiguration to be completed by October 2024/2025.

Sections 6.1-6.3 present the results of this review and Table 6-1 lists the Region’s near, mid and long-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near, Mid and Long-Term Needs in the South Georgian Bay/Muskoka Region

Type	Section	Needs	Timing
Station Capacity	7.1	Barrie TS (existing 115/44kV configuration)	Today
	7.2	Barrie TS (future 230/44kV configuration)	2031[3]
	7.7	Everett TS	2027
	7.3	Parry Sound TS	Today
	7.7	Waubaushene TS	2027[4]
Transmission line capacity	7.1	E3B/E4B forecasted to exceed their Load Meeting Capability (LMC)	2019
Load Restoration	7.4	Load Restoration for loss of double-circuit M6E/M7E	Today
Load Security	7.7	Load Security for M6E/M7E – load growth may exceed its 600 MW LMC	Early 2030s
Outage Duration and Frequency	7.5	44kV Parry Sound/Muskoka Sub-Region experience below average performance w.r.t frequency and duration of outages	Today
Distribution Feeder Capacity	7.6	The one Barrie TS feeder that is designated to InnPower will exceed its normal operating rating	2020
End of Life	7.8	Minden TS (two transformers and associated ancillary equipment)	2020/2021
	7.9	Orangeville TS (All four transformers)	2024/2025
	7.3	Parry Sound TS (one transformer, T2)[5]	2021

6.1 115kV and 230kV Transmission Facilities

The South Georgian Bay/Muskoka Region is comprised of mostly 230kV circuits, M6E/M7E, E8V/E9V E26/E27, E20S/E21S, D1M/D2M/D3M/D4M, M80B/M81B, and one pair of 115kV circuits E3B/E34B, supplying the Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions and other areas outside the two sub-regions. Refer to Figure 3-2 for existing facilities in the Region.

[3] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[4] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

[5] Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition.

Bulk system planning is being conducted by the IESO and is also informed by government policy such as the Long-Term Energy Plan (LTEP). The next LTEP is expected to be issued in 2017. Any outcomes impacting planning decisions will be later updated in this regional planning report.

6.2 Barrie/Innisfil Sub-Region's Step-Down Transformer Station Facilities

There are four step-down transformer stations in the Barrie/Innisfil Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Barrie/Innisfil Sub-Region

Station	DESN	Voltage Transformation
Alliston TS	T2/T3/T4	230/44kV
Barrie TS	T1/T2	115/44kV
Everett TS	T1/T2	230/44kV
Midhurst TS	T1/T2	230/44kV

Based on the LTR of these transformer stations, additional transformation capacity is required at Barrie TS (115/44kV) since the station exceeded its LTR in 2015. This will be addressed by the proposed replacement and upgrade of Barrie TS and circuits E3B/E4B (see details in Section 7.1). In 2031, the upgraded Barrie TS is forecasted to reach its capacity.[6] Since this is a long-term capacity need, it will be monitored and investigated further in the next cycle of the Regional Planning Process. The upgrade of Barrie TS will also address the InnPower distribution feeder capacity need that arises in 2020 – see Section 7.6 for more information.

Everett TS is expected to reach its LTR in approximately ten years. The station's LTR of 86 MW is presently limited by the tap ratio setting of the low voltage current transformers (CT). As the capacity need date approaches, the tap ratio will be increased and the capacity of the station will increase to the LTR of the transformers. The solution to address this capacity need is further described in Section 7.7.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

[6] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

Table 6-3 Transformation Capacities in the Barrie Innisfil Sub-Region

Station	LTR (MW)	2016 Summer Peak (MW)	Relief Required By
Alliston TS (T2)	100	118	-
Alliston TS (T3/T4)	101		-
Barrie TS (T1/T2)	109	102	Immediately
Barrie TS (uprated)	161.5[7]	102	The uprated Barrie TS will exceed its capacity by 2031
Everett TS (T1/T2)	86	70	2027
Midhurst TS (T1/T2)	163	105	-
Midhurst TS (T3/T4)	150	106	-

6.3 Parry Sound/Muskoka Sub-Region's Step-Down Transformer Station Facilities

There are five step-down transformer stations in the Parry Sound/Muskoka Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Parry Sound Muskoka Sub-Region

Station	DESN	Voltage Transformation
Bracebridge TS	T1	230/44kV
Muskoka TS	T1/T2	230/44kV
Orillia TS	T1/T2	230/44kV
Parry Sound TS	T1/T2	230/44kV
Waubaushene TS	T5/T6	230/44kV

Under peak conditions in winters between 2013 and 2016, Parry Sound TS transformers supplied up to 6 MW over their LTR. Although the 2017 winter station peak only reached 44 MW (8 below LTR), the immediate addition of 44 kV capacity is required to provide relief to Parry Sound TS. Two alternatives to address this need are discussed further in Section 7.3.

Waubaushene TS is expected to exceed its LTR of 105 MW by 2027[8]. Plans to mitigate loading problems in Waubaushene TS are discussed in Section 7.7 as long-term needs.

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[7] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[8] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Muskoka TS, Orillia TS and Bracebridge TS are 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 Parry Sound/Muskoka Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Bracebridge TS (T1)	84	11	-
Muskoka TS (T1/T2)	198	145	-
Orillia TS (T1/T2)	177	115	-
Parry Sound TS (T1/T2)	52	44	Immediately
Waubaushene TS (T5/T6)	104[9]	81	2027

The winter and summer non-coincident load forecasts for all stations in the Region are given in Appendix C and Appendix D, respectively.

6.4 Areas outside of Sub-region

The table below lists the seven transformer stations that are outside of the Sub-regions

Table 6-6 Transformation Capacities in the Areas outside of Sub-Region

Station	DESN	Voltage Transformation
Beaverton TS	T3/T4	230/44kV
Lindsay TS	T1/T2	230/44kV
Meaford TS	T1/T2	115/44kV
Minden TS	T1/T2	230/44kV
Orangeville TS	T1/T2	230/44/27.6kV
Orangeville TS	T3/T4	230/44kV
Stayner TS	T3/T4	230/44kV
Wallace TS	T3/T4	230/44kV

[9] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP..

Table 6-7 Transformation Capacities in the Areas outside of Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Beaverton TS	213	72.2	-
Lindsay TS	183	76.6	-
Meaford TS	58	31.7	-
Minden TS	58	50.6	-
Orangeville TS (T1/T2) 27.6 kV	110	32	-
Orangeville TS (T1/T2) 44 kV	56	21	-
Orangeville TS (T3/T4)	118	71	-
Stayner TS	203	124.5	-
Wallace TS	54	33.3	-

Based on peak load conditions, all the transformers are within their respective LTRs.

End-of-Life Equipment Replacements

Recent station assessments have identified near-term end-of-life needs at Orangeville TS and Minden TS, and a recent condition assessment of Parry Sound TS has revealed that one of the existing power transformers at the station is in a very poor condition and must be replaced in the near-term.

- The Minden TS facility was originally built in 1950. Its assets are degrading in condition and require replacement in 2020-2021. Existing 230/44 kV T1 and T2 three-phase power transformers and associated ancillary equipment will be upgraded with the smallest available standard size 230/44 kV three-phase power transformers. As a result, the rating of transformers will increase from 25/33/42 to 50/66.7/83.3 MVA. See Section 7.8 for more information.

- Switchyards at Orangeville TS were placed in-service in 1960s and several of the assets are at the end of their useful lives including all four transformers (T1, T2, T3, and T4). In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard which introduces challenges with maintenance, spare parts and future replacement strategies. The existing switchyard supplied by T1/T2 consists of 28kV feeders, plus additional two 44kV feeders.

  After reviewing different alternatives, the preferred solution is to replace T1/T2 with standard three-phase 215.5-28kV transformers, while T3 and T4 will be replaced with standard 215.5-44kV units. The existing 44kV feeders in the T1/T2 DESN will be relocated to the T3/T4 DESN. Due to this modification, the T3/T4 rating will change from 50/67/83 to 75/100/125 MVA, while the T1/T2 rating will change from 75/100/125 to 50/66.7/83.3 MVA. See Section 7.9 for more information.

- Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition which has triggered a station assessment which will be undertaken by Hydro One's Station Sustainment team in 2017. The team will assess all of the Parry Sound TS equipment to determine when the various components need to be replaced in order to avoid end-of-life failures. See Section 7.3 for more information.

It is worth noting that there are potential bulk power system elements that are also at the end of their useful lives. These include 230 kV transmission lines D1M/D2M, E8V/E9V, and M6E/M7E. IESO will lead the bulk power system studies for these lines in coordination with Hydro One.

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE NEEDS, WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE SOUTH GEORGIAN BAY/MUSKOKA REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRPS FOR THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS.

The near-term needs 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 Barrie/Innisfil Sub-Region

Description

The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

Over the next 10 years, the load in this Sub-Region is forecasted to increase at a rate of approximately 2.5% annually.

Based on the net forecasts (DG and CDM incorporated) in the Sub-Region, adequate transformation capacity is available at Midhurst TS and Alliston TS to maintain reliable supply to meet the demand over the near and mid-term period.

Barrie TS is a summer-peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand. Circuits E3B/E4B that supply radially to Barrie only are also approaching their LMC, which they are expected to exceed by 2019.

Everett TS has a long term need which is discussed in Section 7.7.

Recommended Plan and Current Status

During the regional planning process, the Study Team considered multiple alternatives to address the transformation capacity and end-of-life needs in this Sub-Region.

The 44 kV switchyard at Barrie TS was placed in-service in 1962 and the assets are in degraded condition and are in need of replacement. Previous assessments have suggested the replacement of aged and degraded infrastructure, including both transformer banks, low voltage switchgear, capacitor banks and associated ancillary equipment. Loading on the Barrie TS T1/T2 yard has steadily increased since 2013 and has reached a point where it is encroaching on the LTR rating of the transformer banks, and limiting further connections downstream from the station.

Since Barrie TS currently exceeds its supply capacity, the like-for-like option would not result in any increase in capacity. Instead it was proposed to remove T1/T2 (230/115kV) at Essa TS and replace T1/T2 (55/95MVA, 115/44kV) at Barrie TS with one pair of transformers T1/T2 (75/125MVA, 230/44kV) at Barrie TS, along with uprating circuits E3B/E4B from 115kV to 230 kV. This would increase the Barrie DESN capacity by 50MW, and increase the LMC of E3B/E4B as well.

The Study Team recommended to rebuild and uprate Barrie TS as the best solution to meet the transformation capacity need in the Sub-Region. Hydro One is currently developing this plan, called the 'Barrie Area Transmission Upgrade project'. Class Environmental Assessment (EA) is in progress for this project. Since circuits E3B and E4B are 9km in length, an OEB Section 92 approval is required for this project. It will be initiated once the engineering estimate is completed for this project by early 2018.

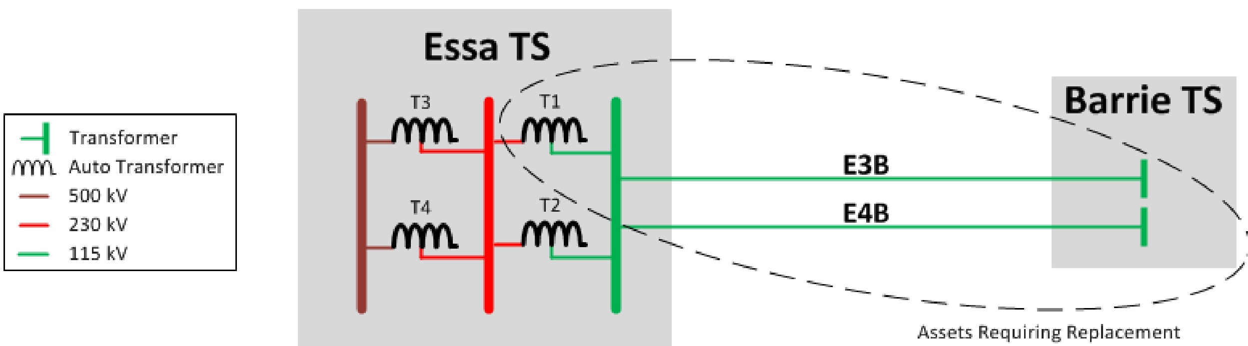

Figure 7-1 Current Arrangement of Essa TS, Barrie TS, and Circuits E3B/E4B

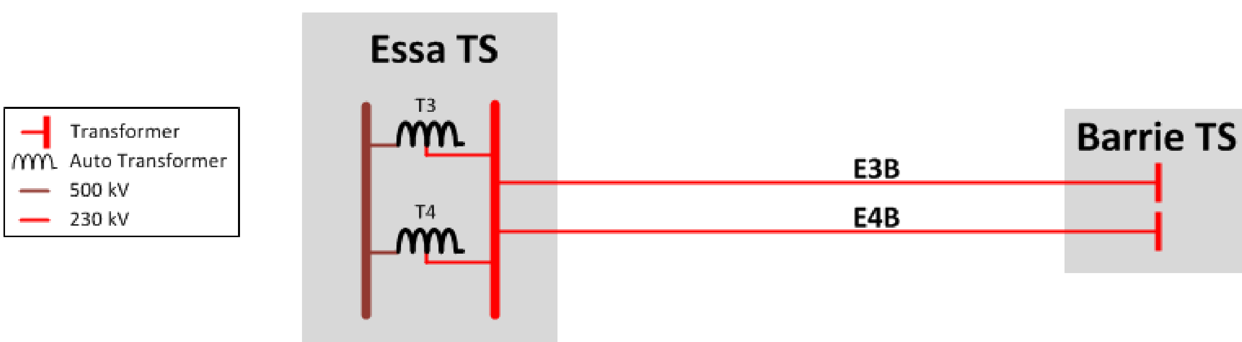

Figure 7-2 New Configuration of Essa/Barrie Supply to Barrie DESN

The total cost of this project is estimated to be $84M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection arrangements as defined above, and feeder egress to the distribution risers outside of the station.

7.2 Transformation Capacity Need at Uprated Barrie TS

Description

Over the 20 year planning period, Barrie TS will experience the biggest growth out of all the transformer stations, which is influenced by the recent continued development of data centers in the City Of Barrie, and greenfield residential development in the annexed lands in south Barrie, in addition to the proposed industrial and commercial development at Innisfil Heights near Highway 400. With the forecast data collected, it is determined that the uprated Barrie TS will exceed its LTR by 2031.

Proposed Alternatives and Recommended Plan

One of the alternatives to accommodate load growth in Barrie/Innisfil Sub-Region, is to build a new 230 kV station via the idle Hydro One right-of-way, a corridor currently being utilized by the existing 13M3 feeder, which could provide an additional 150MW capacity.

The additional feeders that are being built by Alectra will facilitate the transfer of up to 27 MW of load from Barrie TS to Midhurst TS by 2019 and will defer a capacity need at the upgraded Barrie TS to 2031. This need will be monitored and investigated further in the next cycle of the Regional Planning Process. Long-term options beyond 2026 are discussed in Section 7.7.

7.3 Increase Transformation Capacity in Parry Sound/Muskoka Sub-Region

Description

The load forecast reflects an annual growth of 0.82 % in Parry Sound/Muskoka area throughout the study period.

Based on historical demand data and the station's net demand forecast, Parry Sound TS T1/T2 has already exceeded its respective normal supply capacity and will continue to do so over the study period. Parry Sound TS is a winter peaking station with a winter LTR of 52 MW. It had exceeded its LTR by as much as 6 MW in the winters of 2013 to 2016, however the 2017 winter peak was 8 MW below the LTR.

Waubaushene TS is expected to be loaded beyond its winter LTR (104.5 MW) by 2026-27. Recommended plans for addressing this need are discussed in Section 7.7. Although the summer peak is not expected to exceed the summer LTR over the study period based on the net demand forecast, historical summer peak demand (2015/2016) at Waubaushene TS was approaching the summer LTR. The

Study Team will continue to monitor the summer and winter demand closely and explore opportunities to manage the peak demand growth at Waubaushene TS.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for both Parry Sound TS and Waubaushene TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

There are two options that have been proposed to address the capacity need at Parry Sound TS: a) Distribution load transfer and b) upsize transformers at Parry Sound TS.

Option a) To accommodate the load growth at Parry Sound TS, 6 MW of Parry Sound's load can be transferred over to Muskoka TS. For this load transfer to take place, Hydro One Distribution will need to seek approval to construct a new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS, which would cost approximately $7M and would be in service by 2020. This option will address the near term supply needs at Parry Sound TS.

Option b) Hydro One has identified that Parry Sound TS (T1/T2) transformer T2 is in poor condition and must be replaced in the near-term. The second transformer is also identified to be reaching the end of its useful life over the next 5-10 years. As a result, Hydro One is planning to replace T2 which is a non-standard 25/42 MVA, 230/44 kV transformer with a 50/83 MVA unit which is currently the smallest standard size transformer at this voltage level. In addition, Hydro One will also consider advancing the replacement of the companion transformer, T1, since it will be much more efficient and economical to replace both transformers at the same time. The additional cost to replace T1 is approximately $8M. This would address the near- and long-term capacity need at Parry Sound TS; eliminate the need to spend $7M on the 44 kV sub-transmission line; and provide better reliability for customers. The advancement cost of replacing T1 is approximately $2M. The new transformers at Parry Sound TS would be expected in service by 2021.

Since the peak demand growth is relatively slow in this area, conservation and local demand management and distributed generation can be used in the meantime to defer capacity-related upgrades at these stations. Results from the Parry Sound/Muskoka Local Achievable Potential ("LAP") study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Going forward, the Study Team will need to assess the cost-benefit of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformer, T1, at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2021.

With the future increased station capacity at Parry Sound TS, the long-term capacity need at Waubaushene TS could be addressed via permanent load transfers since transfer capability already exists between the two stations.

7.4 Parry Sound/Muskoka Load Restoration Assessment

Description

The Parry Sound/Muskoka load restoration need was identified in the Parry Sound/Muskoka Sub-Region IRRP report, which indicated that for the loss of two transmission elements (M7E/M6E transmission lines) the load interrupted with current circuit configuration during peak periods will exceed load restoration criteria.

M6E/M7E transmission lines currently supply 465 MW of peak demand. In the event of a double circuit outage, all customers on this double circuit will be interrupted for more than 30 minutes. As per ORTAC criteria, this constitutes a violation unless 215 MW of peak load can be restored within 30 minutes for a M76/M7E outage during a peak demand period.

Proposed Alternatives and Recommended Plan

In collaboration with the Study Team, a recommendation for the load restoration was identified in the Region. One of the alternatives considered was resupplying load from the 44 kV system. However, this will only supply about 20-30 MW.

The Study Team is recommending that an investment in motorized disconnect switches (MDS) should be made, which can be used to isolate sections of the transmission lines within 30 minutes. These switches would be installed at the Orillia TS junction. Another alternate solution was installing breakers on the line instead of motorized switches, since breakers can immediately isolate a section faulted line.

Breakers would be useful if the loading on the double circuit was more than 600 MW, however given the uncertainty of future load growth and the cost of breakers which are 3-4 times more expensive than motorized switches, the Study Team recommended to proceed with the installation of two 230 kV motorized switches at Orillia TS. The switches will be in service by 2021 at a cost of $5-7M.

In the event of a double M6E/M7E outage, with the motorized disconnect switches installed, at least 50% of the load on this double circuit supply can be restored within 30 minutes, meeting the ORTAC 30 minute load restoration criteria.

IESO has issued a hand-off letter to Hydro One to initiate the development work for the installation of motorized disconnect switches at Orillia TS. The development work is currently underway, in the budgetary estimating phase.

7.5 Outage Duration And Frequency in Parry Sound/Muskoka Sub-Region

Description

Load in the Parry Sound/Muskoka Sub-Region is supplied via:

- Local generation resources;
- 230 kV transmission system;
- 44 kV sub-transmission and low-voltage distribution system.

Customers supplied by Muskoka TS and Parry Sound TS in this sub-region experience more frequent and prolonged outages, almost double the provincial performance, which can impede economic development. Most of the incidents occur on the 44kV sub-transmission system due to longer feeder length as compared to the average length of feeders in the rest of the province. Longer lines increase exposure to tree contact and require additional time for repair crews to identify and isolate faulted sections.

Recommended Plan and Current Status

Hydro One Distribution currently has a number of on-going maintenance and outage mitigation initiatives. These are listed below:

- Vegetation Management Program
- Line Patrols
- Mid-cycle Hazard Tree Program
- Distribution Management System and Grid Modernization

In addition, Hydro One Distribution will assess other options as well and provide an update to the communities and LACs on plans to improve the 44 kV system by the end of 2017.

Another option to mitigate outages on the 44 kV is to build new distribution lines from Bracebridge TS, and transfer some load over to Bracebridge TS, since currently the industrial load demand at that station has been decreasing over the last several years.

Cost-Benefit/Responsibility will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the 44 kV sub-transmission system, which will be completed by the end of 2017.

7.6 Distribution Feeder Capacity to Supply InnPower

Description

Currently six feeders in Barrie TS are used to supply Alectra, and one feeder supplies InnPower. From the forecast provided, the Study Team concluded in the IRRP that InnPower will exceed its load capacity of

25 MW, which its existing feeder can supply, by 2020. An additional feeder will be required for InnPower starting 2020.

Recommended Plan and Current Status

The uprated Barrie TS will include eight feeders, as opposed to the current seven feeders that exist today. This additional feeder can be used in addition to the existing InnPower dedicated feeder to supply InnPower load.

7.7 Long Term Regional Plan

As discussed in Section 5, the electricity demand in South Georgian Bay/Muskoka Region is forecasted to grow at 1.46% annually over the next 10 years, and at a slightly lower average rate of 1.17% from 2016-2034. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1% annually from year 2024 to 2034 in the Parry Sound/Muskoka Sub-Region, while 1.9% in the Barrie/Innisfil Sub-Region. 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.

<u>Parry Sound/Muskoka</u>

Currently the Muskoka-Orillia 230kV subsystem supplies up to 454 MW. Based on electricity demand growth, Muskoka-Orillia is not expected to exceed its LMC of 600 MW until early 2030.

The following options will be revisited in the next regional planning cycle:

- Upgrade the transmission lines in the area, thus increasing M6E/M7E LMC.
- Connect a 20 MW generation on the Muskoka-Orillia 230 kV system
- Results from the Parry Sound/Muskoka LAP study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Electricity demand forecast is expected to exceed Waubaushene TS system's capability by 2026-27. To manage this long term growth, 4MW load can be transferred from Waubaushene TS to Orillia TS. More transfer capability between Waubaushene TS and Midhurst TS will be available upon completion of 'Barrie Area Transmission Upgrade' project. With the potential increase of the capacity at Parry Sound TS, there will be capability to transfer additional load from Waubaushene TS to Parry Sound TS.

<u>Barrie/Innisfil</u>

Barrie/Innisfil sub region is the area supplied by Midhurst TS, Barrie TS, Alliston TS, and Everett TS. The planning load forecast projects that load will exceed the aggregate capacity of these transformers by

2033. Due to the uncertainty of long term forecasts, IESO will monitor the area and an annual update to the Study Team on demand, conservation and DG trends.

Everett TS is forecasted to exceed its LTR (86.4 MW) by 2026. This LTR is currently limited by the CT ratio. Hydro One is now able to update CT ratio whenever desired which would increase the LTR. The new LTR may defer the capacity need at Everett TS beyond the study period.

In the Barrie area, load is expected to exceed the area's LMC (Midhurst TS and Barrie TS capacity) by 2031. Alectra Utilities and InnPower will undertake a LAP study to address the long term needs for Barrie TS service area to determine the conservation and demand management potential in the area beyond the conservation values already accounted for in the planning forecast.

Metrolinx is planning to electrify the Barrie GO train lines and has approached Hydro One, requesting 40-50MW of capacity. The new 230kV circuits from Essa TS to Barrie TS would provide adequate capacity and tapping positions for Metrolinx's substation, however the supply capacity at Essa TS may present some limitations. Therefore the Metrolinx project is being closely monitored by the IESO and Study Team.

7.8 Minden TS End of Life Assets

Description

The Minden T1/T2 yard is a unique DESN which transforms voltages from 230 kV to 44 kV and facilitates load delivery to the Minden area via four (4) feeders supplying the Hydro One distribution system. This station was built in the 1950s and is primarily composed of older equipment. The T1 and T2 transformers are each rated at 25/42 MVA and are non-standard as per the current standards. Non-standard and obsolete equipment introduces complexities in repairing failures and difficulties in finding and installing spare equipment. The transformers are currently beyond their expected service life and their condition is deteriorating and leak risk is increasing. Furthermore, due to the station's unique configuration, an outage on the high voltage bus or a transformer will cause load loss, which does not occur in a standard DESN layout.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life situation at Minden TS:

- Maintain Status Quo ("do nothing"): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, 25/42 MVA transformers and associated equipment which is not justifiable based on the load forecast and would cost more than the smallest standard 230/44 kV transformers which are 50/83 MVA.

- Replace transformers with standard 50/83 MVA units and reconfigure switchyard: This alternative will include replacing the existing transformers with 50/83 MVA units and reconfiguring part of the switchyard to meet standard DESN layout and improve supply reliability to customers.

The preferred alternative is for Hydro One to replace the existing transformers with standard 50/83 MVA units and reconfigure the switchyard to allow it to operate the way a standard DESN should. The new equipment is expected to have a service life of over 50 years and will be able to supply the forecasted load growth in the Minden area. This option allows for easy installation of spare equipment in case failures occur and the improved reliability will improve the customer satisfaction in the area. This refurbishment project is currently planned to be completed in 2020-2021 at a cost of $17 million.

7.9 Orangeville TS End of Life Assets

Description

Orangeville TS is a transmission station that provides 230 kV switching as well as transformation of 230 kV to 44 kV and 27.6 kV. Orangeville TS serves as the supply for Hydro One Distribution and Orangeville Hydro customers in and around the town of Orangeville via two DESN switchyards, T1/T2 (27.6 and 44 kV) and T3/T4 (44 kV). The 27.6 kV and 44 kV switchyards were placed in-service in 1969 and many assets are in a degraded condition and in need of replacement. Previous assessments have identified that all four transformers T1, T2, T3, and T4 and associated equipment are candidates for replacement. In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard, which introduces challenges with maintenance, sparing and future replacement strategies.

In recent discussions, Orangeville Hydro expressed its intent to further increase its use of the 27.6 kV feeders supplied from Orangeville TS. Consequently, Orangeville Hydro intends to reduce the number of customers and stations connected to the 44 kV feeders M3 and M5.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life issue at Orangeville TS:

- Maintain Status Quo (“do nothing”): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, transformers and associated equipment which is not justifiable based on the cost of custom equipment, Orangeville Hydro’s supply voltage plans, and Hydro One’s effort to standardize non-standard station configurations.
- Replace transformers with standard units and reconfigure 27.6 kV and 44 kV switchyards: This alternative aims to replace the existing T1/T2 transformers with standard units, standardize the configuration of the T1/T2 switchyard by converting it to a typical 230/27.6 kV DESN, replace

the aging T3/T4 230/44 kV transformers to maintain overall 44 kV capacity, and relocate 44 kV feeders to the new T3/T4 DESN.

The preferred alternative is for Hydro One to replace the existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Hydro One will also replace the existing T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate the additional capacity required by the relocation of the two 44 kV feeders. This alternative will address the need to replace end-of-life transformers T1/T2/T3/T4 and associated equipment as well as associated end-of-life protection, control and telecom assets. It will allow Hydro One to standardize the DESN layout, simplify equipment maintenance and installation in case of a failure, and reliably supply the forecasted demand for the area. This refurbishment project is currently planned to be completed in 2024-2025 at a cost of $33 million.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA 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 115kV Barrie TS	Today
II	Additional transformation capacity for the uprated 230kV Barrie TS	Long-term[10]
III	Additional transformation capacity for Parry Sound TS	Today
IV	Transmission Line Capacity for E3B/E4B	2019
V	Load restoration for loss of M6E/M7E	Today
VI	Mitigate frequency and duration of outages on the 44kV Parry Sound/Muskoka sub-region	Today
VII	Additional feeder position for InnPower supplied from Barrie TS	2020
VIII	Additional capacity required for Barrie/Innisfil Sub-Region and Barrie sub-area	Long-term
IX	Additional transformation capacity for Waubaushene TS	Long-term[11]
X	Additional transformation capacity for Everett TS	Long-term
XI	LMC and Load Security for M6E/M7E	Long-term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

[10] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[11] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacity banks have a 90% power factor and stations with low-voltage capacity banks have a 95% power factor. Since Waubaushene TS has low voltage capacity banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Table 8-2 Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

Project	Lead Responsibility	I/S Date	Cost	Need Mitigated
Replacement of 115/44 kV transformers (T1 and T2) at Barrie TS, uprating 115 kV circuits E3B/E4B to 230 kV, adding additional feeder to Barrie DESN	Hydro One	2020	$84M	I, IV, VII
Replacement of 230/44 kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	Hydro One	2020-2021	$17M	End-of-Life
Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	Hydro One	2021	$5-7M	V
Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	Hydro One	2020	$7M	III
Replacement of 230/44 kV transformers at Parry Sound TS*	Hydro One	2021	$20M	End-of-Life, III
Replacement of Orangeville TS transformers and associated low voltage equipment, and reconfiguration of low voltage switchyards	Hydro One	2024-2025	$33M	End-of-Life

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

For the Need III, Parry Sound/Muskoka Local Achievable Potential ("LAP") study will be initiated shortly to help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage the electricity demand growth in the area. Furthermore, the Study Team will need to assess the cost-benefits of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformers at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2020s.

For Need VI, cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

Barrie/Innisfil Sub-Region and Barrie sub-area needs (Need VIII) has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended for the time being, while the IESO and the Study Team will continue to monitor load growth in the area and determine the conservation and demand management potential in the area.

As described in Section 7.7, no investment is required at this time to address the long-term needs II, IX, X, and XI. Further developments in the Region will be monitored and the need will be reviewed again as part of the next 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

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APPENDICES

Appendix A: Stations in the South Georgian Bay-Muskoka Region

Station (DESN)	Voltage Level	Supply Circuits
Everett TS (T1/T2)	230/44kV	E8V/E9V
Alliston TS (T2/T3/T4)	230/44kV	E8V/E9V
Midhurst TS (T1/T2)	230/44kV	M6E/M7E
Barrie TS (T1/T2)	120/44kV	E3B/E4B
Essa TS (T1/T2)	230/120kV	Essa TS 230kV supply
Parry Sound TS (T1/T2)	230/44kV	E26/E27
Waubaushene TS (T5/T6)	230/44kV	E26/E27
Muskoka TS (T1/T2)	230/44kV	M6E/M7E
Bracebridge TS (T1)	230/44kV	M6E
Orillia TS (T1/T2)	230/44kV	M6E/M7E
Beaverton TS T3/T4	230/44kV	M80B/M81B
Lindsay TS T1/T2	230/44kV	M80B/M81B
Minden TS T1/T2	230/44kV	Minden TS 230kV supply
Orangeville TS T3/T4	230/44kV	Orangeville TS 230kV supply
Orangeville TS T1/T2	230/44/28kV	Orangeville TS 230kV supply
Stayner TS T3/T4	230/44kV	Stayner TS
Wallace TS T3/T4	230/44kV	D2M/D4M
Meaford TS T1/T2	115/44kV	S2S

Appendix B: Transmission Lines in the South Georgian Bay Muskoka Region

Location	Circuit Designation	Voltage Level
Essa TS to Parry Sound/Waubaushene TS	E26/E27	230kV
Essa TS to Midhurst/Orillia/Muskoka TS	M6E/M7E	230kV
Essa TS to Alliston/Everett/Orangeville TS	E8V/E9V	230kV
Essa TS to Barrie TS	E3B/E4B	115kV
Essa TS to Stayner TS	E20S/E21S	230kV
Stayner TS to Meaford TS	S2S	115kV
Minden TS to DesJoachims TS	D1M/D2M/D3M/D4M	230kV
Minden TS to Lindsay/Beaverton TS	M80B/M81B	230kV

Appendix C: Non-Coincident Winter Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Non Coincidental Gross		28.7	29.1	29.5	29.7	30.2	30.7	31.2	31.5	31.8	32.1	32.4	32.7	33.1	33.4	33.7	34.1	34.4	34.8	35.1	35.5	35.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.6	0.8	1.3	1.7	1.8	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.8	4.0	4.0	4.1	4.1
S: 100	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 115	Non Coincidental Net	28.6	28.5	28.7	28.9	29.1	29.4	29.4	29.5	29.7	29.7	29.8	29.9	30.1	30.2	30.3	30.4	30.5	30.6	30.8	31.1	31.4	31.7
Alliston TS (T3/T4)	Non Coincidental Gross		60.1	68.5	71.4	74.4	77.4	80.3	82.9	85.6	88.3	90.9	91.9	93.8	95.7	97.7	99.7	101.6	103.5	105.4	106.5	108.4	110.2
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.3	4.5	5.0	5.7	6.5	7.1	7.7	8.3	9.1	9.8	10.6	11.4	12.1	12.2	12.4	12.6
S: 112	DG (MW)		0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077
W: 128	Non Coincidental Net	60.8	59.6	67.5	70.0	72.7	75.2	76.9	78.3	80.5	82.5	84.4	84.7	86.1	87.3	88.5	89.8	91.0	92.1	93.2	94.2	95.9	97.5
Barrie TS	Non Coincidental Gross		96.3	99.1	102.6	107.1	113.5	120.6	128.6	136.7	144.8	153.0	157.6	162.3	167.2	172.2	177.4	182.7	188.2	193.8	199.6	205.6	211.8
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.3	3.1	4.9	6.9	8.0	9.4	10.9	12.2	13.3	14.5	16.0	17.4	19.0	20.7	22.2	22.9	23.6	24.3
S: 115	DG (MW)		0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
W: 128	Non Coincidental Net	94.0	95.6	97.7	100.6	104.8	110.4	115.6	121.6	128.6	135.4	142.1	145.4	149.0	152.7	156.2	159.9	163.7	167.5	171.5	176.7	182.0	187.5
Beaverton TS	Non Coincidental Gross		96.6	97.6	98.6	98.9	100.1	101.3	102.6	103.3	103.9	104.5	105.34	106.18	107.03	107.88	108.75	109.62	110.49	111.38	112.27	113.17	114.07
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.1	2.7	4.1	5.5	6.1	6.7	7.4	8.1	8.7	9.3	10.0	10.7	11.4	12.1	12.8	12.9	13.0	13.1
S: 204	DG (MW)		1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655
W: 224	Non Coincidental Net	92.7	94.2	94.6	95.1	95.1	95.7	95.5	95.4	95.6	95.5	95.4	95.6	95.8	96.1	96.2	96.4	96.6	96.7	96.9	97.7	98.5	99.3
Bracebridge TS	Non Coincidental Gross		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 93	Non Coincidental Net	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Non Coincidental Gross			61.2	62.4	64.4	65.6	67.5	69.2	70.9	73.4	75.1	77.4	79.7	82.1	84.5	87.1	89.7	92.4	95.1	98.0	100.9	104.0
LTR (MVA)	CDM (MW)			0.8	1.2	1.4	1.8	2.8	3.7	4.2	4.7	5.3	6.0	6.5	7.1	7.9	8.6	9.3	10.1	10.9	11.2	11.6	11.9
S: 96	DG (MW)			0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
W: 96	Non Coincidental Net	54.7	0.0	60.4	61.2	63.0	63.8	64.7	65.4	66.7	68.6	69.7	71.4	73.1	74.9	76.6	78.5	80.3	82.2	84.2	86.7	89.3	92.0
Lindsay TS	Non Coincidental Gross		91.6	93.3	94.3	94.6	95.9	97.5	98.9	99.9	100.9	101.8	102.8	103.8	104.9	105.9	107.0	108.1	109.1	110.2	111.3	112.5	113.6
LTR (MVA)	CDM (MW)		0.7	1.3	1.8	2.0	2.6	4.0	5.3	5.9	6.5	7.2	7.9	8.5	9.1	9.9	10.5	11.2	12.0	12.6	12.8	12.9	13.0
S: 169	DG (MW)		1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634
W: 193	Non Coincidental Net	89.2	89.3	90.4	90.9	90.9	91.6	91.9	91.9	92.4	92.7	92.9	93.2	93.7	94.2	94.4	94.8	95.2	95.5	96.0	96.9	97.9	98.9
Meaford TS	Non Coincidental Gross		29.9	30.4	30.9	31.1	31.7	32.2	32.8	33.2	33.6	34.0	34.4	34.8	35.2	35.7	36.1	36.5	37.0	37.4	37.9	38.3	38.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.7	0.9	1.3	1.8	1.9	2.2	2.4	2.7	2.8	3.1	3.3	3.6	3.8	4.1	4.3	4.3	4.4	4.4
S: 54	DG (MW)		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
W: 61	Non Coincidental Net	29.7	29.7	30.0	30.3	30.4	30.8	30.9	31.0	31.2	31.4	31.6	31.8	32.0	32.2	32.3	32.5	32.7	32.9	33.1	33.5	33.9	34.3
Midhurst TS (T1/T2)	Non Coincidental Gross			108.0	110.7	113.0	115.8	119.2	131.0	133.4	136.3	139.2	141.5	144.3	147.2	149.7	154.6	157.5	160.5	163.4	166.3	169.2	172.1
LTR (MVA)	CDM (MW)			0.5	1.2	1.6	2.4	3.1	3.6	4.5	5.5	6.4	7.4	8.6	9.8	10.9	12.1	13.2	14.7	16.0	16.2	16.3	16.5
S: 172	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 194	Non Coincidental Net	101.6	105.5	107.5	109.5	111.4	113.4	116.0	127.3	128.9	130.8	132.8	134.0	135.8	137.4	138.7	142.5	144.3	145.8	147.4	150.1	152.9	155.6
Midhurst TS (T3/T4)	Non Coincidental Gross			65.5	67.7	69.9	72.6	75.4	88.6	90.8	93.5	96.3	98.5	101.2	104.0	106.2	106.9	109.6	112.3	115.0	117.7	120.4	123.1
LTR (MVA)	CDM (MW)			0.3	0.7	1.0	1.6	2.3	2.6	3.2	4.0	4.7	5.6	6.5	7.6	8.7	9.5	10.4	11.7	12.8	13.1	13.2	13.5
S: 166	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 192	Non Coincidental Net	75.0	63.3	65.2	67.0	68.9	71.0	73.1	86.0	87.6	89.5	91.6	92.8	94.7	96.4	97.5	97.5	99.3	100.6	102.2	104.6	107.2	109.7
Minden TS	Non Coincidental Gross			58.8	59.5	59.8	60.3	61.2	62.0	62.5	62.9	63.3	63.7	64.1	64.5	64.9	65.4	65.8	66.2	66.6	67.0	67.4	67.8
LTR (MVA)	CDM (MW)			0.2	0.4	0.5	0.7	0.9	1.0	1.2	1.4	1.5	1.6	1.8	2.0	2.1	2.3	2.5	2.7	2.8	2.8	2.8	2.8
S: 59	DG (MW)			1.630	1.630	1.630	1.630	1.630	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770
W: 64	Non Coincidental Net	55.0	56.3	57.0	57.5	57.6	58.0	58.7	59.2	59.5	59.8	60.0	60.3	60.5	60.8	61.0	61.3	61.6	61.7	62.0	62.4	62.8	63.2

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Non Coincidental Gross			160.6	163.0	164.7	166.9	169.8	172.7	175.0	177.2	179.4	181.6	183.9	186.2	188.7	191.2	193.7	196.0	198.5	201.0	203.5	205.9
LTR (MVA)	CDM (MW)			0.5	1.1	1.5	2.2	2.9	3.4	4.1	4.8	5.3	5.9	6.6	7.1	7.7	8.2	8.8	9.5	10.0	10.0	10.0	9.9
S: 154	DG (MW)			3.360	3.360	3.360	3.360	5.060	5.110	5.110	5.110	5.110	5.110	5.110	5.110	5.110	4.600	4.600	2.080	2.080	2.080	2.080	1.970
W: 175	Non Coincidental Net	165.0	167.4	156.7	158.5	159.9	161.3	161.9	164.2	165.8	167.3	169.0	170.6	172.2	174.0	175.9	178.4	180.3	184.4	186.4	188.9	191.4	194.1
Orangeville TS (T1/T2 - 27.6kV)	Non Coincidental Gross		51.4	51.9	53.1	54.2	55.4	56.6	57.8	59.0	60.0	61.0	62.1	63.2	64.4	65.5	66.7	67.9	69.1	70.4	71.6	72.9	74.2
	CDM (MW)		0.4	0.7	1.0	1.2	1.5	2.3	3.1	3.5	3.9	4.3	4.8	5.2	5.6	6.1	6.6	7.1	7.6	8.1	8.2	8.4	8.5
LTR (MVA)	DG (MW)		3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154
S: 104 W:122	Non Coincidental Net	49.3	47.9	48.1	48.9	49.9	50.7	51.1	51.5	52.4	53.0	53.5	54.2	54.9	55.6	56.3	57.0	57.7	58.4	59.1	60.3	61.4	62.6
Orangeville TS (T1/T2 - 44kV)	Non Coincidental Gross		23.4	23.9	24.3	24.6	25.1	25.6	26.1	26.6	27.0	27.4	27.8	28.2	28.7	29.1	29.5	30.0	30.4	30.9	31.3	31.8	32.3
	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.0	1.4	1.6	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.6	3.6	3.7
LTR (MVA)	DG (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 53 W: 63	Non Coincidental Net	24.0	23.2	23.6	23.8	24.1	24.4	24.6	24.7	25.0	25.3	25.5	25.7	25.9	26.2	26.4	26.6	26.8	27.1	27.3	27.7	28.1	28.6
Orangeville TS (T3/T4)	Non Coincidental Gross		86.2	87.7	89.3	90.3	92.2	94.1	96.1	97.6	99.1	100.5	101.9	103.3	104.8	106.2	107.7	109.2	110.8	112.3	113.9	115.5	117.1
LTR (MVA)	CDM (MW)		0.6	1.2	1.7	1.9	2.5	3.8	5.2	5.7	6.4	7.1	7.9	8.4	9.1	9.9	10.6	11.4	12.2	12.9	13.1	13.3	13.4
S: 106	DG (MW)		2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058
W: 124	Non Coincidental Net	82.6	83.5	84.5	85.5	86.3	87.6	88.2	88.9	89.8	90.6	91.3	92.0	92.8	93.6	94.3	95.1	95.8	96.6	97.4	98.8	100.2	101.6
Orillia TS	Non Coincidental Gross			127.0	128.9	131.1	133.5	136.0	138.3	139.8	141.6	143.2	144.8	146.4	148.2	149.9	151.7	153.4	155.2	156.9	158.6	160.4	162.1
LTR (MVA)	CDM (MW)			0.6	1.2	1.6	2.3	3.0	3.4	4.1	4.8	5.3	6.0	6.7	7.4	8.2	8.8	9.5	10.4	11.1	11.2	11.2	11.1
S: 165	DG (MW)			3.690	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	0.540	0.540	0.540	0.540	0.540
W: 186	Non Coincidental Net	122.4	118.3	122.7	123.5	125.3	127.0	128.8	130.6	131.5	132.6	133.6	134.6	135.5	136.5	137.5	138.7	139.7	144.2	145.2	146.9	148.7	150.5
Parry Sound TS	Non Coincidental Gross			61.2	62.1	62.7	63.4	64.5	65.5	66.3	67.1	67.9	68.6	69.4	70.2	71.1	71.9	72.8	73.6	74.5	75.3	76.2	77.1
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.2	1.5	1.7	1.9	2.1	2.3	2.6	2.7	2.9	3.1	3.3	3.6	3.8	3.8	3.8	3.8
S: 52	DG (MW)			0.410	0.410	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	0.650	0.650	0.650	0.650	0.650
W: 57	Non Coincidental Net	57.5	60.5	60.6	61.2	61.6	62.0	62.8	63.7	64.2	64.7	65.3	65.9	66.4	67.1	67.7	68.4	69.1	70.0	70.7	71.5	72.4	73.3
Stayner TS	Non Coincidental Gross		139.4	140.6	141.9	142.2	143.8	145.6	147.3	148.3	149.3	150.2	151.1	152.0	152.9	153.8	154.8	155.7	156.6	157.6	158.5	159.5	160.4
LTR (MVA)	CDM (MW)		1.0	1.9	2.7	3.1	3.9	6.0	8.0	8.7	9.6	10.7	11.7	12.4	13.2	14.3	15.2	16.2	17.2	18.1	18.2	18.3	18.4
S: 191	DG (MW)		18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864
W: 214	Non Coincidental Net	138.3	119.5	119.9	120.3	120.3	121.0	120.8	120.5	120.7	120.8	120.7	120.6	120.7	120.8	120.7	120.7	120.6	120.6	120.6	121.5	122.3	123.1
Wallace TS	Non Coincidental Gross		40.0	40.6	41.1	41.2	41.8	42.4	42.9	43.3	43.6	43.9	44.2	44.5	44.8	45.1	45.5	45.8	46.1	46.4	46.7	47.1	47.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.8	0.9	1.1	1.7	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.8	5.1	5.3	5.4	5.4	5.4
S: 55	DG (MW)		3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871
W: 60	Non Coincidental Net	39.3	35.8	36.2	36.4	36.4	36.8	36.8	36.7	36.9	36.9	36.9	36.9	37.0	37.1	37.1	37.1	37.1	37.2	37.2	37.5	37.8	38.1
Waubaushene TS	Non Coincidental Gross			99.2	99.2	100.2	101.1	102.5	103.8	104.6	105.6	106.6	107.5	108.5	109.3	110.3	111.3	112.2	113.2	114.2	115.0	115.9	116.8
LTR (MVA)	CDM (MW)			0.2	0.5	0.8	1.1	1.5	1.9	2.3	2.9	3.4	3.9	4.5	5.0	5.5	5.9	6.3	6.8	7.2	7.2	7.2	7.2
S: 100	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 110	Non Coincidental Net	94.1	95.9	99.0	98.7	99.5	100.0	101.0	101.9	102.3	102.8	103.2	103.6	104.0	104.3	104.8	105.4	105.9	106.5	107.0	107.8	108.7	109.6

Appendix D: Non-Coincident Summer Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Gross			38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
LTR (MVA)	CDM (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 100	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 115	Net	28.6	33.2	38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
Alliston TS (T3/T4)	Gross			56.8	59.0	61.3	66.0	71.0	73.5	76.1	78.3	80.6	82.4	84.3	86.1	88.1	90.0	91.8	93.7	95.5	97.4	99.2	101.0
LTR (MVA)	CDM (MW)			0.4	1.2	1.4	2.1	2.7	3.3	3.9	4.5	5.1	5.7	6.5	7.0	7.8	8.5	9.1	10.0	10.7	10.8	10.8	10.8
S: 112	DG (MW)			0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222
W: 128	Net	60.8	50.3	56.1	57.7	59.6	63.7	68.0	70.0	72.0	73.6	75.3	76.5	77.6	78.9	80.0	81.3	82.4	83.5	84.6	86.4	88.2	90.0
Barrie TS	Gross			107.4	112.5	116.1	124.4	132.1	140.3	147.7	155.7	163.2	169.6	176.9	184.0	191.1	196.7	203.1	210.4	214.4	219.4	225.4	230.3
LTR (MVA)	CDM (MW)			0.5	1.2	1.9	3.2	4.5	5.4	6.6	7.8	8.9	10.6	12.1	14.1	16.5	18.1	19.9	22.2	24.2	24.5	24.6	24.8
S: 115	DG (MW)			0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041
W: 128	Net	94.0	96.8	106.9	111.2	114.2	121.1	127.5	134.9	141.1	147.8	154.2	158.9	164.8	169.9	174.6	178.6	183.1	188.2	190.1	194.8	200.7	205.5
Beaverton TS	Gross		57.2	57.6	58.2	58.1	58.8	59.5	60.3	60.7	61.1	61.4	61.7	62.0	62.3	62.6	63.0	63.3	63.6	63.9	64.2	64.5	64.9
LTR (MVA)	CDM (MW)		0.4	0.8	1.1	1.2	1.6	2.4	3.3	3.6	3.9	4.4	4.8	5.1	5.4	5.8	6.2	6.6	7.0	7.3	7.4	7.4	7.4
S: 204	DG (MW)		12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411
W: 224	Net	92.7	44.4	44.4	44.7	44.4	44.8	44.7	44.6	44.7	44.7	44.6	44.5	44.5	44.5	44.4	44.3	44.3	44.2	44.2	44.4	44.7	45.0
Bracebridge TS	Gross			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W: 93	Net	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Gross		67.1	69.8	71.2	73.7	75.1	77.5	79.7	81.8	85.0	87.2	89.4	91.6	93.9	96.3	98.7	101.1	103.7	106.2	108.9	111.6	114.4
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.2	4.3	4.8	5.5	6.2	6.9	7.5	8.1	9.0	9.7	10.5	11.4	12.2	12.5	12.8	13.1
S: 96	DG (MW)		0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211
W: 96	Net	54.7	66.4	68.7	69.6	71.9	72.8	74.1	75.2	76.8	79.3	80.8	82.3	83.9	85.6	87.1	88.7	90.4	92.1	93.8	96.2	98.6	101.1
Lindsay TS	Gross		74.3	75.4	76.2	76.1	77.1	78.5	79.7	80.5	81.2	82.0	82.7	83.5	84.2	85.0	85.8	86.5	87.3	88.1	88.9	89.7	90.5
LTR (MVA)	CDM (MW)		0.6	1.0	1.4	1.6	2.1	3.2	4.3	4.7	5.2	5.8	6.4	6.8	7.3	7.9	8.4	9.0	9.6	10.1	10.2	10.3	10.4
S: 169	DG (MW)		9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799
W: 193	Net	89.2	63.9	64.6	65.0	64.7	65.2	65.5	65.6	66.0	66.2	66.4	66.6	66.9	67.1	67.3	67.5	67.7	67.9	68.2	68.9	69.6	70.3
Meaford TS	Gross		25.5	25.9	26.2	26.4	26.8	27.3	27.8	28.2	28.5	28.9	29.2	29.5	29.8	30.1	30.4	30.7	31.0	31.3	31.6	31.9	32.2
LTR (MVA)	CDM (MW)		0.2	0.3	0.5	0.6	0.7	1.1	1.5	1.7	1.8	2.1	2.3	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
S: 54	DG (MW)		0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
W: 61	Net	29.7	25.3	25.5	25.7	25.8	26.1	26.2	26.3	26.5	26.6	26.8	26.9	27.1	27.2	27.3	27.4	27.5	27.6	27.7	28.0	28.3	28.5
Midhurst TS (T1/T2)	Gross			109.8	112.5	114.8	118.4	121.4	124.2	126.8	130.3	132.8	135.4	138.9	141.5	144.0	147.7	150.2	153.8	156.4	159.9	162.5	166.0
LTR (MVA)	CDM (MW)			0.7	1.6	2.2	3.3	4.4	5.1	6.1	7.3	8.3	9.5	10.9	12.1	13.4	14.7	15.8	17.5	18.7	19.0	19.1	19.4
S: 172	DG (MW)			2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786
W: 194	Net	101.6	99.9	106.3	108.1	109.8	112.3	114.2	116.4	117.9	120.2	121.7	123.1	125.3	126.6	127.9	130.2	131.7	133.5	134.9	138.1	140.5	143.8
Midhurst TS (T3/T4)	Gross			72.0	75.0	78.0	80.0	83.0	86.0	89.0	91.0	94.0	97.0	100.0	103.0	105.0	108.0	111.0	115.0	118.0	121.0	124.0	127.0
LTR (MVA)	CDM (MW)			0.2	0.6	0.9	1.6	2.3	2.6	3.3	4.4	5.4	6.6	7.8	9.3	10.8	12.1	13.5	15.5	17.2	17.5	17.6	17.9
S: 166	DG (MW)			0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
W: 192	Net	75.0	65.0	71.7	74.3	77.1	78.4	80.7	83.4	85.6	86.6	88.6	90.4	92.2	93.6	94.2	95.8	97.4	99.5	100.8	103.5	106.3	109.0
Minden TS	Gross			25.4	25.6	25.8	26.0	26.4	26.8	27.0	27.2	27.4	27.5	27.7	27.9	28.1	28.3	28.5	28.7	28.9	29.0	29.2	29.4
LTR (MVA)	CDM (MW)			0.2	0.3	0.4	0.6	0.7	0.8	1.1	1.3	1.5	1.7	1.9	2.2	2.4	2.6	2.9	3.2	3.4	3.4	3.4	3.4
S: 59	DG (MW)			1.660	1.660	2.210	2.330	2.940	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.050
W: 64	Net	55.0	24.3	23.6	23.6	23.2	23.1	22.7	22.9	22.8	22.8	22.9	22.7	22.7	22.7	22.6	22.6	22.6	22.5	22.5	22.6	22.7	23.0

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Gross			93.5	94.7	95.4	96.3	98.0	99.5	100.6	101.5	102.5	103.5	104.3	105.4	106.5	107.5	108.7	109.6	110.6	111.5	112.5	113.6
LTR (MVA)	CDM (MW)			0.7	1.4	1.9	2.8	3.6	4.3	5.1	6.0	6.7	7.4	8.2	8.9	9.6	10.2	11.0	12.0	12.6	12.6	12.6	12.4
S: 154	DG (MW)			7.970	8.070	8.290	8.620	13.400	13.450	13.450	13.450	13.450	13.450	13.450	13.450	13.450	12.940	12.940	10.420	10.410	10.410	8.150	5.810
W: 175	Net	165.0	97.2	84.9	85.2	85.2	84.9	81.0	81.8	82.0	82.1	82.4	82.7	82.6	83.1	83.5	84.3	84.8	87.2	87.6	88.5	91.8	95.4
Orangeville TS	Gross		53.1	56.1	57.4	58.4	59.5	60.8	62.1	63.2	64.2	65.2	66.2	67.2	68.2	69.2	70.2	71.3	72.4	73.4	74.5	75.7	76.8
(T1/T2 - 27.6kV)	CDM (MW)		0.4	0.8	1.1	1.3	1.6	2.5	3.4	3.7	4.1	4.6	5.1	5.5	5.9	6.4	6.9	7.4	7.9	8.4	8.6	8.7	8.8
LTR (MVA)	DG (MW)		1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519
S: 104 W: 122	Net	49.3	51.2	53.8	54.8	55.6	56.4	56.8	57.2	58.0	58.5	59.1	59.6	60.2	60.8	61.2	61.8	62.4	62.9	63.5	64.5	65.5	66.5
Orangeville TS	Gross		24.2	24.5	25.0	25.1	25.6	26.2	26.8	27.2	27.6	28.0	28.4	28.8	29.2	29.6	30.0	30.4	30.9	31.3	31.7	32.2	32.6
(T1/T2 - 44kV)	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.1	1.4	1.6	1.8	2.0	2.2	2.4	2.5	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
LTR (MVA)	DG (MW)		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
S: 53 W: 63	Net	24.0	24.0	24.2	24.5	24.6	24.9	25.1	25.3	25.6	25.8	26.0	26.2	26.4	26.7	26.8	27.1	27.3	27.5	27.7	28.1	28.5	28.9
Orangeville TS (T3/T4)	Gross		67.4	68.4	69.6	70.2	71.5	73.1	74.6	75.8	77.0	78.1	79.2	80.3	81.4	82.6	83.7	84.9	86.1	87.3	88.5	89.7	91.0
	CDM (MW)		0.5	0.9	1.3	1.5	2.0	3.0	4.0	4.4	5.0	5.5	6.1	6.6	7.1	7.7	8.2	8.8	9.4	10.0	10.2	10.3	10.4
LTR (MVA)	DG (MW)		1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071
S 106 W: 124	Net	82.6	65.8	66.4	67.2	67.6	68.5	69.0	69.5	70.3	71.0	71.5	72.0	72.7	73.3	73.8	74.4	75.0	75.6	76.2	77.3	78.4	79.5
Orillia TS	Gross			99.8	101.2	103.2	105.2	107.2	109.0	110.3	111.6	112.9	114.2	115.4	116.8	118.1	119.6	120.9	122.2	123.7	125.0	126.4	127.7
LTR (MVA)	CDM (MW)			0.6	1.3	1.7	2.5	3.3	3.8	4.7	5.5	6.2	7.0	7.9	8.8	9.7	10.5	11.3	12.5	13.4	13.4	13.4	13.3
S: 165	DG (MW)			10.620	11.240	11.350	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	7.770	7.710	7.650	7.510	1.410
W: 186	Net	122.4	84.9	88.5	88.6	90.1	91.2	92.4	93.7	94.2	94.7	95.3	95.7	96.1	96.6	96.9	97.6	98.1	101.9	102.6	104.0	105.5	113.0
Parry Sound TS	Gross			31.3	31.8	32.1	32.5	33.0	33.6	34.0	34.4	34.8	35.1	35.6	36.0	36.4	36.9	37.3	37.8	38.2	38.7	39.1	39.6
LTR (MVA)	CDM (MW)			0.2	0.5	0.6	0.9	1.1	1.3	1.7	2.0	2.2	2.5	2.8	3.0	3.3	3.6	3.9	4.3	4.5	4.6	4.6	4.5
S: 52	DG (MW)			0.460	0.490	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	0.730	0.730	0.730	0.730	0.730
W: 57	Net	57.5	30.9	30.6	30.9	30.4	30.5	30.7	31.1	31.2	31.3	31.5	31.5	31.7	31.8	31.9	32.2	32.3	32.8	32.9	33.4	33.8	34.3
Stayner TS	Gross		104.6	105.2	106.1	105.9	106.9	108.3	109.7	110.5	111.2	111.9	112.6	113.2	113.9	114.6	115.3	116.0	116.7	117.4	118.1	118.8	119.5
LTR (MVA)	CDM (MW)		0.8	1.4	2.0	2.3	2.9	4.4	5.9	6.5	7.2	7.9	8.7	9.3	9.9	10.7	11.3	12.1	12.8	13.5	13.5	13.6	13.7
S: 191	DG (MW)		8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735
W: 214	Net	138.3	95.1	95.1	95.3	94.9	95.2	95.1	95.0	95.3	95.3	95.2	95.1	95.3	95.3	95.2	95.2	95.2	95.1	95.2	95.8	96.4	97.1
Wallace TS	Gross		36.0	36.4	36.8	36.9	37.3	37.8	38.4	38.7	39.0	39.3	39.6	39.9	40.1	40.4	40.7	41.0	41.3	41.6	41.8	42.1	42.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.7	0.8	1.0	1.5	2.1	2.3	2.5	2.8	3.1	3.3	3.5	3.8	4.0	4.3	4.5	4.8	4.8	4.8	4.9
S: 55	DG (MW)		3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880
W: 60	Net	39.3	31.9	32.0	32.2	32.2	32.4	32.4	32.4	32.5	32.6	32.6	32.6	32.7	32.8	32.8	32.8	32.8	32.9	32.9	33.2	33.4	33.7
Waubaushene TS	Gross			75.1	75.5	76.1	76.9	77.7	78.5	79.2	80.8	81.5	82.1	82.7	83.4	84.0	84.7	85.4	86.1	87.8	88.3	88.9	89.5
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.3	1.5	2.1	2.8	3.4	4.2	5.0	5.7	6.3	7.0	7.6	8.3	8.9	8.9	9.0	9.0
S: 100	DG (MW)			9.360	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.300	4.570	2.240
W: 110	Net	94.1	71.6	65.5	65.6	66.0	66.5	67.0	67.6	67.7	68.6	68.7	68.5	68.3	68.3	68.3	68.3	68.4	68.4	69.5	70.1	75.4	78.3

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

Peterborough to Kingston

REGIONAL INFRASTRUCTURE PLAN

May 27, 2022

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Eastern Ontario Power Inc.
Elexicon Energy Inc. (Elexicon)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Kingston Hydro
Lakefront Utilities Inc.

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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 needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group ("TWG").

The preferred solution(s) that have been identified in this report may be re-evaluated 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 TWG.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP TECHNICAL 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 WITHIN THE PETERBOROUGH TO KINGSTON REGION.

The participants of the RIP Technical Working Group (TWG) included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Eastern Ontario Power Inc.
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Kingston Hydro
- Lakefront Utilities Inc.

This RIP is the final phase of the second cycle of the Peterborough to Kingston regional planning process. It follows the completion of the Peterborough to Kingston Integrated Regional Resource Plan ("IRRP") in November 2021 and the Peterborough to Kingston Needs Assessment ("NA") in February 2020.

The Peterborough to Kingston RIP provides a consolidated summary of the needs and recommended plans for the region based on available information. It discusses the needs identified in the previous and current regional planning cycle, , any new needs identified as part of this RIP phase, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway from the previous planning cycle, including:

- Load transfer from Gardiner TS DESN 1 to Gardiner TS DESN 2 to provide transformation capacity relief at Gardiner TS DESN 1 (completed in 2019)

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

Table 1-1: Recommended Plans in Peterborough to Kingston over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate[1] ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[2]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

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[1] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

[2] The new standard units are expected to have a higher LTR of about 160 MW

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 PETERBOROUGH TO KINGSTON REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) on behalf of the Technical Working Group (TWG) that consists of Hydro One Inc. (Transmission), Eastern Ontario Power Inc., Elexicon Energy Inc. (“Elexicon”), Hydro One Inc. (Distribution), Independent Electricity System Operator (“IESO”), Kingston Hydro, and Lakefront Utilities Inc., in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Peterborough to Kingston region is comprised of the area bordered approximately by Clarington on the West, North Frontenac county on the North, Frontenac County on the East and Lake Ontario on the South. The boundaries of the Region are shown in Figure 1-1 below.

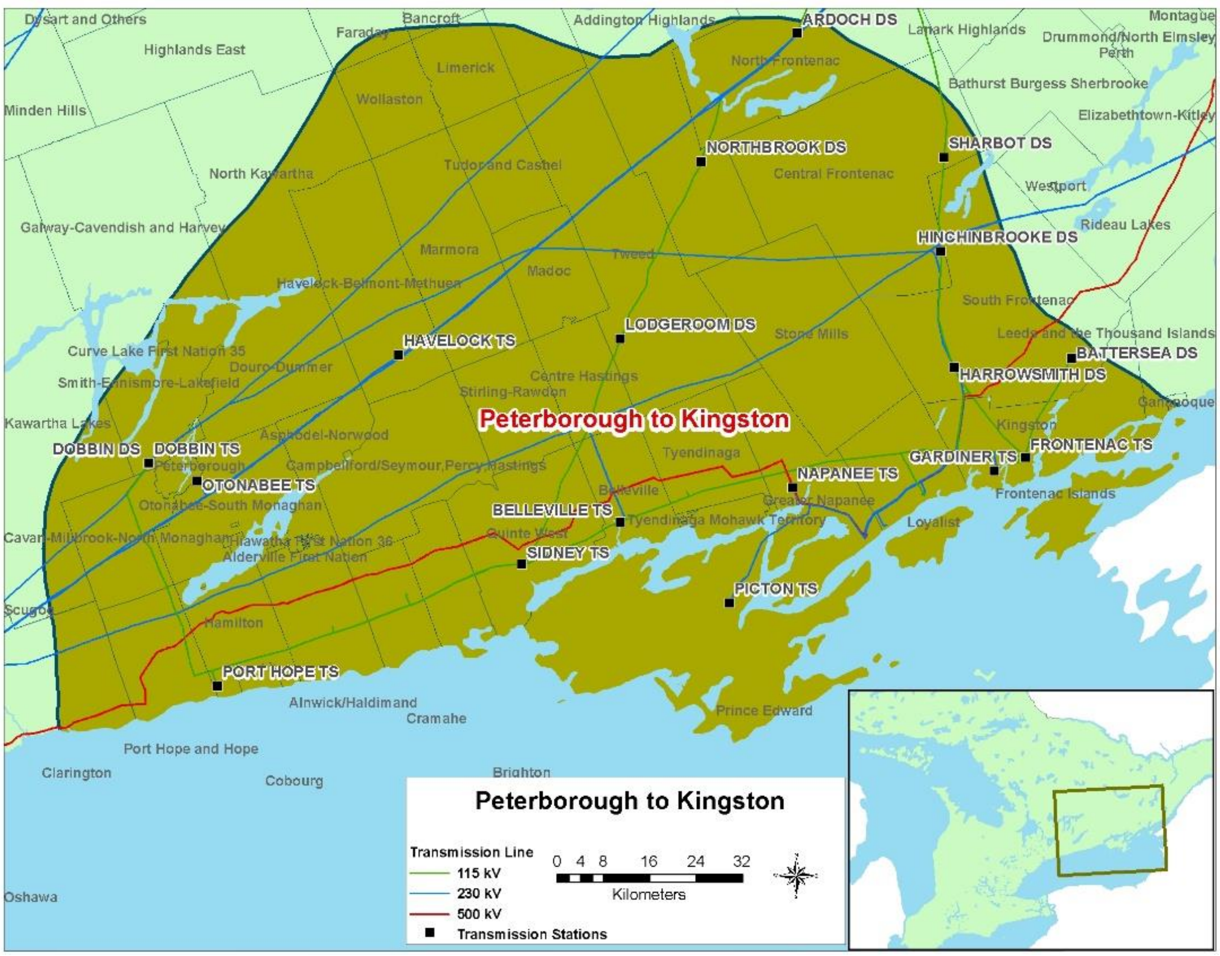

Figure 1-1: Peterborough to Kingston Region

1.1. Objectives and Scope

This RIP report examines the needs in the Peterborough to Kingston 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, asset renewal for major high voltage transmission equipment , 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 needs and relevant plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and wires plans to address them
- Consideration of long-term needs identified in the Peterborough to Kingston IRRP or identified by the TWG.

1.1. 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[3] ("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 TWG 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 and where further regional coordination is required. 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

[3] Also referred to as Needs Screening

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.

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, LP, and IRRP phases of regional planning;
- 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.

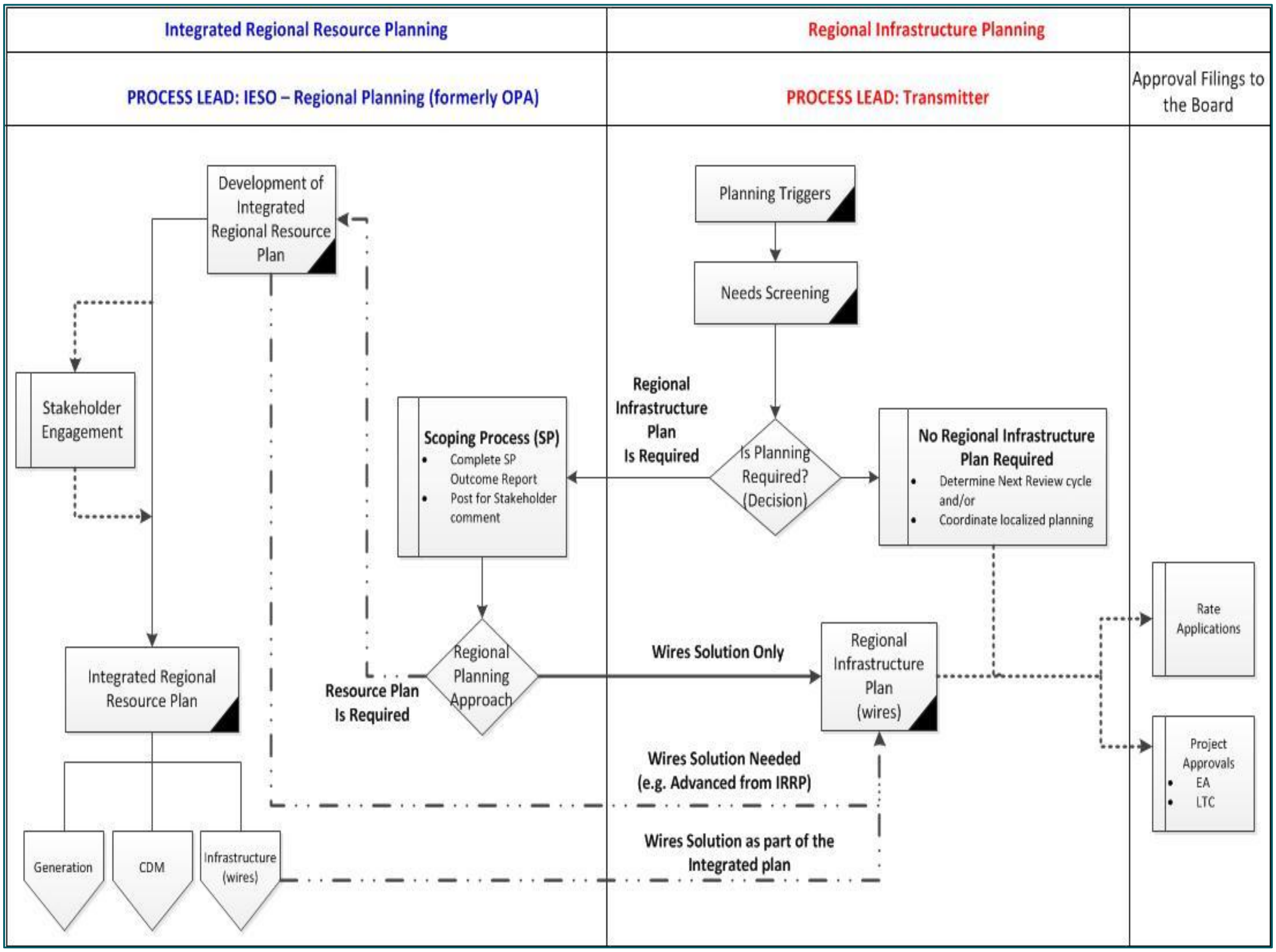

Figure 1: Regional Planning Process Flowchart

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 RIP process is the review of planning assessment data collected in the previous phases of the regional planning process. Hydro One collects this information and reviews it with the TWG 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. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, 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 any changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to a specific issue(s) only. Additional needs may be identified in this phase.

3. Alternative Development: The third step is the development of wires options to address the needs and determine 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.

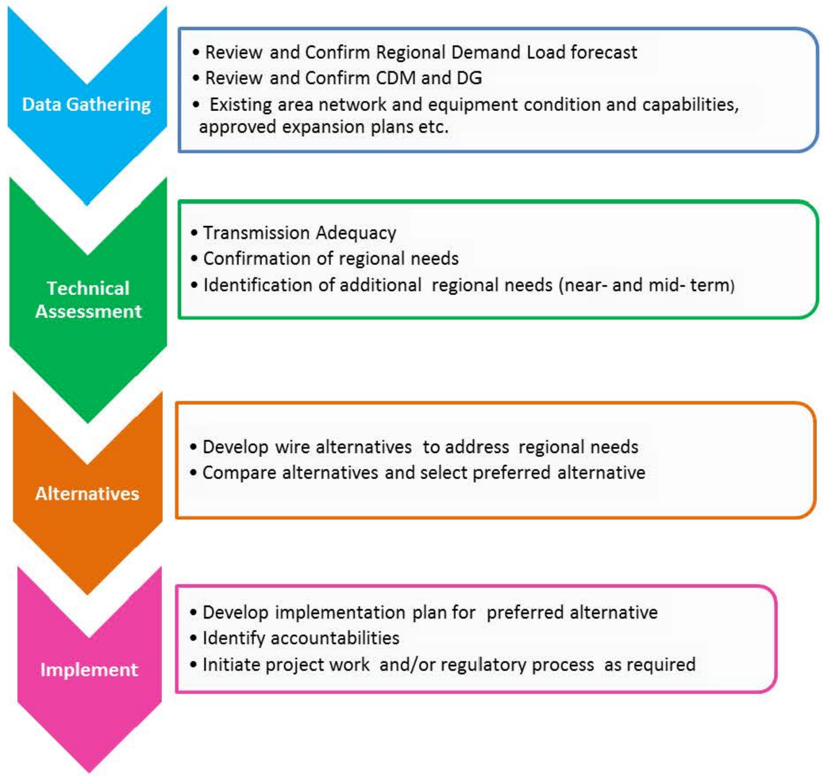

Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE PETERBOROUGH TO KINGSTON REGION IS COMPRISED OF THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY THE MUNICIPALITY OF CLARINGTON ON THE WEST, NORTH FRONTENAC COUNTY ON THE NORTH, FRONTENAC COUNTY ON THE EAST, AND LAKE ONTARIO ON THE SOUTH. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TEN STEP-DOWN TRANSFORMER STATIONS AND EIGHT HIGH VOLTAGE DISTRIBUTION STATIONS.

Electrical supply to the region is provided through 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS, and a 230kV and 115kV transmission network supplying the various step-down TS's and HVDS's in the region. The main generation facility in the region is the 2000 MW Lennox Generation Station connected to Lennox TS.

The Local Distribution Customers (LDC) in the Peterborough to Kingston Region are Hydro One Distribution, Eastern Ontario Power, Elexicon, Kingston Hydro, and Lakefront Utilities. The high-voltage system in this Region also provides supply to five other direct transmission connected load customers.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. 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
- There are 7 existing Transmission connected generating stations in the Region as follows:
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Lennox GS is a 2000 MW natural gas-fired station connected to 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

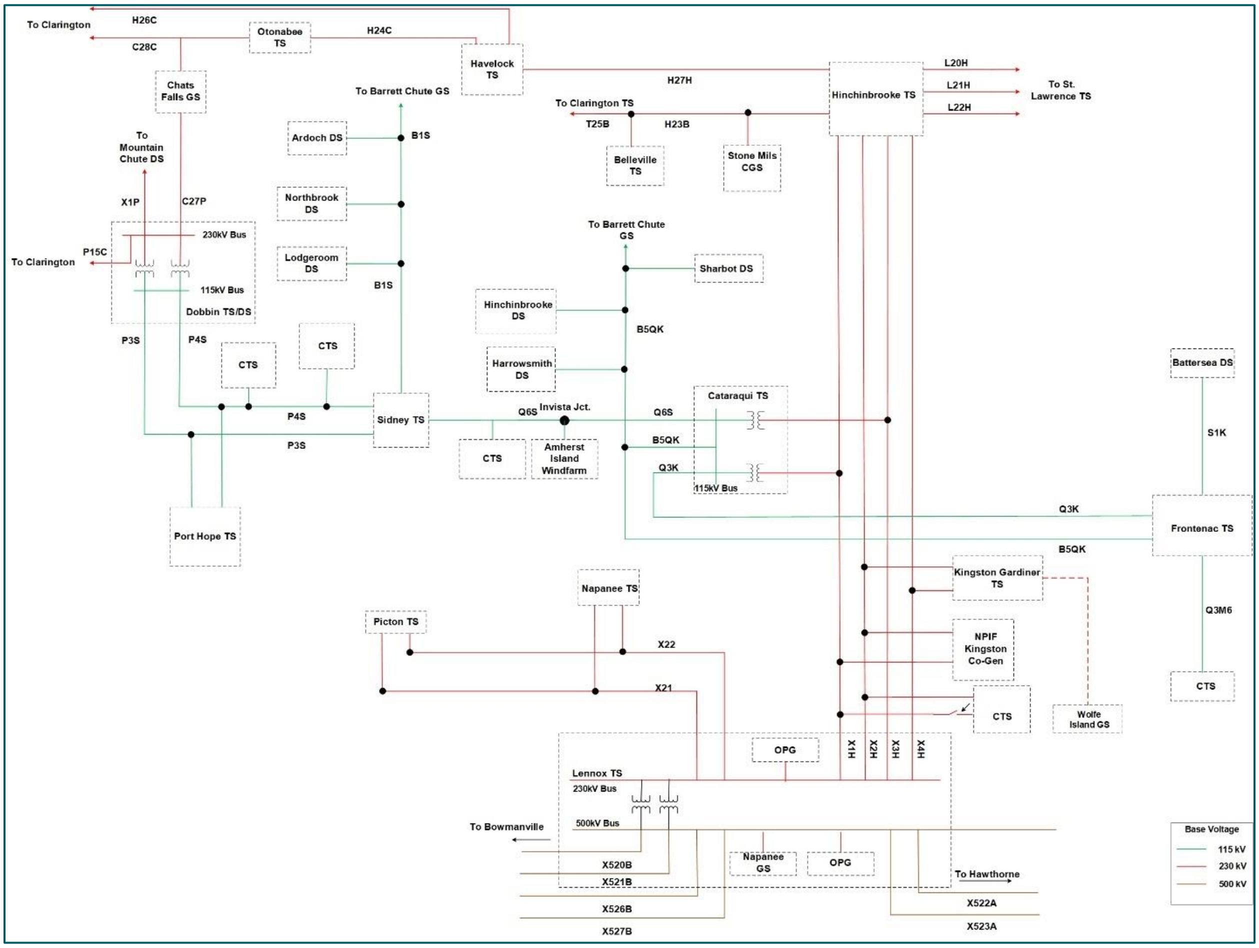

Figure 3-1: Single Line Diagram of Peterborough to Kingston's Transmission Network

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 PETERBOROUGH TO KINGSTON REGION.

A summary and description of the major projects completed over the last 10 years is provided below:

- Connect Napanee GS (2017) – A 910 MW gas turbine (Napanee GS) was connected to the 500 kV bus in the Lennox TS switchyard

- Transformation capacity relief at Gardiner TS DESN 1 (2019) – Gardiner TS DESN 1 load exceeded its normal supply capacity. Hydro One Distribution transferred load from Gardiner TS DESN 1 to Gardiner TS DESN 2.

The following projects are currently underway:

- Lennox TS 230kV & 500kV Breaker Replacement (2026/27)
- Belleville TS T1/T2 Transformer Replacement (2022)

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Peterborough to Kingston Region is anticipated to grow about .8% annually from 2021 to 2031.

Figure 5-1 shows the Peterborough to Kingston Region's extreme weather coincident peak net load forecast ("load forecast") for summer and winter. The load forecast for the individual stations in the Peterborough to Kingston Region is given in Appendix D.

As per the new regional planning process requirement, the load forecast used in the RIP is same as the IRRP phase unless there is a material change or if a LDC(s) member of the TWG requests to update their load forecast.

In the case of the Peterborough to Kingston Region, the TWG decided to use the load forecast in the recently completed Peterborough to Kingston Region IRRP (Nov. 2021) for the purposes of the RIP load forecast. Note that the TWG reviewed the extreme summer non-coincident peak net load forecast from the IRRP against the actual historical peak load observed in 2020 for the stations that have been identified to have a capacity need, namely Belleville TS, Frontenac TS, Gardiner TS DESN 1, and Otonabee TS (discussed in Section 6.4). Although, the actual 2020 peak load for these stations is slightly lower than what was forecasted in the IRRP, the TWG decided to proceed with the IRRP 2020 forecasted load since it does not materially change the planning outcome. The need dates will continue to be monitored throughout the regional planning process.

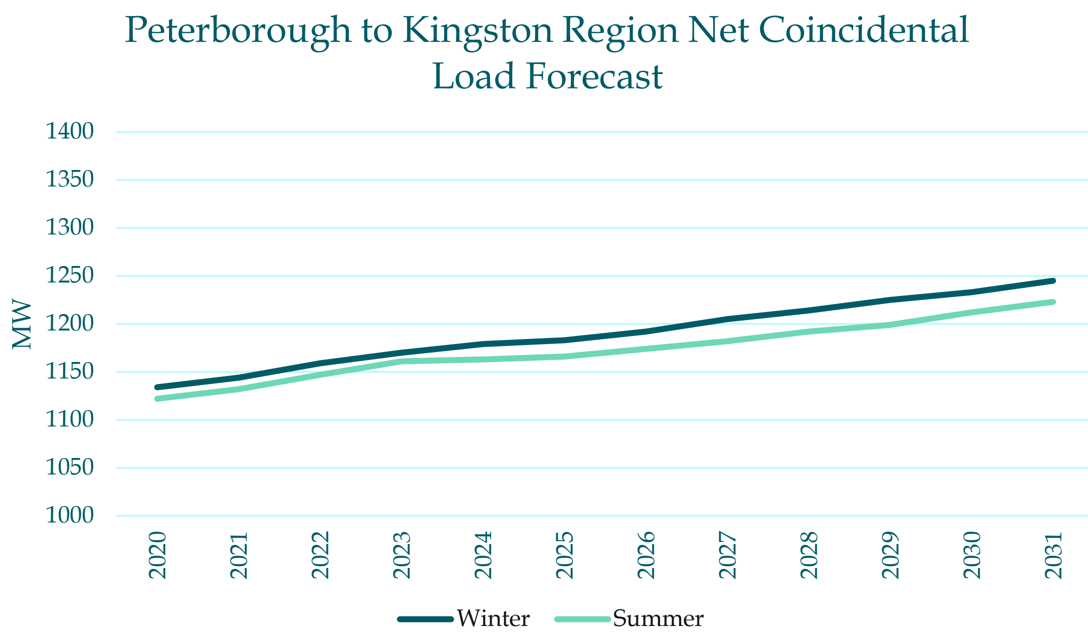

Figure 5-1: Peterborough to Kingston Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP adequacy assessment is 2020-2031.
- All planned facilities for which work has been initiated and are listed in Section 4 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 all stations 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 using peak loads in the area.
- Output of generating stations in the area is based on 98% dependable generation availability for transmission connected run of river hydro-electric stations as per Ontario Resource Transmission Assessment Criteria (ORTAC) criteria.
- Adequacy assessment is conducted as per ORTAC and using the load forecast described in section 5.1.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE PETERBOROUGH TO KINGSTON REGION OVER THE PLANNING PERIOD (2021-2031).

Within the current regional planning cycle, three regional planning reports have been completed for the Peterborough to Kingston Region. The findings of these reports are inputs to this Regional Infrastructure Plan. These reports are:

- 2020 Peterborough to Kingston Region Needs Assessment ("NA") Report;
- 2020 Peterborough to Kingston Region Scoping Assessment ("SA") Report; and,
- 2021 Peterborough to Kingston Region Integrated Regional Resource Plan ("IRRP")

This section provides a review of the adequacy of the transmission lines and stations in the Peterborough to Kingston Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D and assumes all projects currently underway (described in section 4) are in-service. Sections 6.1 to 6.5 present the results of this review. Asset renewal needs for major HV transmission equipment were identified in previous phases of this regional planning cycle and are also addressed in Section 7 of this RIP report.

6.1 230/115 kV Autotransformers

Bulk power supply to the Peterborough to Kingston Region is provided by Hydro One's 500kV/230kV and 230 kV/115kV autotransformers. The number and location of these autotransformers are as follows:

a) Two 500/230 kV autotransformers at Lennox TS
b) Two 230/115 kV autotransformers at Cataraqui TS
c) Three 230/115 kV autotransformers at Dobbin TS

The 500/230 kV autotransformers at Lennox TS are part of the bulk system and outside the scope of this RIP.

Based on the RIP load forecast, the load growth at Frontenac TS and other 115kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to increase over the long-term.

The 230/115 kV autotransformers at Dobbin TS are expected to be adequate over the study period.

6.2 230 kV Transmission Lines

All 230 kV transmission circuits, with the exception of circuits X21 and X22 in the Peterborough to Kingston Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of the Ontario’s transmission system and to the load centers in the Greater Ottawa regions. These circuits are as follows:

- 230kV circuits: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X2H, X3H and X4H.

These 230kV transmission lines can be divided into the main corridors as summarized below:

a) Clarington TS to Otonabee TS, Havelock TS, Chats Falls SS 230kV circuits T22C, T31H, T32H
    - Supplies Otonabee TS, Havelock TS
b) Clarington TS to Hinchinbrooke SS 230kV circuits T25B and H23B
    - Supplies Belleville TS
c) Lennox TS to Hinchinbrooke SS 230 kV circuits, X1H, X2H, X3H, X4H
    - Supplies Gardiner TS and a Customer CTS
d) Cherrywood TS to Dobbin TS, Chat Falls SS 230kV circuits P15C and C27P

From the circuits listed above, P15C is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits X1P or C27P. This supply capacity need is being assessed as part of the bulk system planning.

6.3 115 kV Transmission Lines

The Peterborough to Kingston Region consists of several 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into the main corridors as summarized below:

a) Dobbin TS to Sidney TS 115kV transmission circuits P3S/P4S
    - Supplies Port Hope TS, Sidney TS, and two Customer CTS

b) Sidney TS to Cataraqui TS 115kV transmission circuit Q6S
    - Supplies Sidney TS and a Customer CTS

c) Cataraqui TS to Frontenac TS 115kV transmission circuits Q3K/B5QK
    - Supplies Sharbot DS, Hinchinbrooke DS, Harrowsmith DS, and Frontenac TS

d) Barrett Chute GS to Sidney TS 115kV transmission circuit B1S
    - Supplies Ardoch DS, Northbrook DS, Lodgeroom DS

From the circuits listed above, Q6S is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits 230kV circuits X1P, C27P, or P15C.

This supply capacity need is being assessed as part of the bulk system. The remaining 115 kV circuits are within their thermal limits and within the voltage range as per ORTAC for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

There is a total of ten step-down transformer stations and eight high voltage distribution stations that supply the Peterborough to Kingston load as shown in Table 6-1 below:

Table 6-1: Step-Down Transformer Stations and High Voltage Distribution Stations

Dobbin TS	Port Hope TS	Sidney TS	Picton TS
Otonabee TS	Havelock TS	Belleville TS	Napanee TS
Gardiner TS	Frontenac TS	Dobbin DS	Ardoch DS
Northbrook DS	Lodgeroom DS	Hinchinbrooke DS	Harrowsmith DS
Sharbot DS	Battersea DS		

A station capacity assessment was performed over the study period for the above stations in the Region using either the summer or winter station peak load forecasts as appropriate. The results are as follows:

6.4.1 Belleville TS T1/T2 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Belleville TS was forecasted to be 170 MW[4]. The Summer 10-Day LTR of Belleville TS is about 161 MW.

Based on the RIP load forecast, Belleville TS is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term. In addition to normal load growth in the area, Elexicon has recently received approximately 30 MW of new load connection inquiries to be connected at Belleville TS.

6.4.2 Frontenac TS T3/T4 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is 101 MW[5]. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the RIP load forecast, Frontenac TS is expected to reach its Summer 10-Day LTR by 2029.

[4] The 2020 extreme summer weather non-coincident peak net load at Belleville TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual, weather corrected 2020 summer peak load at Belleville TS was 157 MW, but still forecasted to exceed the 161MW LTR in 2022.

[5] The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Frontenac TS was 104 MW.

6.4.2 Gardiner TS DESN 1 (T1/T2) Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 was forecasted to be 146 MW[6]. The Summer 10-Day LTR of Gardiner TS DESN 1 and DESN 2 is about 125 MW and 85 MW, respectively.

Based on the RIP load forecast, the loading on Gardiner TS DESN 1 is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.3 Otonabee TS (T1/T2) 44kV Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV is 97 MW.

Based on the 2020 net loading and load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.4 Other TSs and HVDSs in the Region

Based on the RIP load forecast, all the other TSs and HVDSs in the Region are expected to be within their normal supply capacity during the study period. Therefore, any capacity needs for these TSs and HVDSs will be reviewed in the next regional planning cycle.

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

Station	Summer 10-Day LTR Capacity (MW)	2020 Summer Peak Net Forecast (MW)	Need Date
Belleville TS T1/T2	161	170	Today
Frontenac TS T3/T4	111	101	2029
Gardiner TS DESN 1 (T1/T2)	125	146	Today
Otonabee TS 44kV Bus	97	103	Today

[6] The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Gardner TS DESN 1 was 130 MW.

6.5 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.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

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.

6.6 Other Needs

6.6.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Peterborough to Kingston Region. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

These needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement work planned over the study period in the region is summarized in Table 6-3.

Table 6-3: Peterborough to Kingston Region – Planned Asset Replacement Work

No.	Station	Description	in-service Timing
1	Picton TS	T1/T2 Replacement	2025
2	Port Hope TS	T3/T4 Replacement	2026
3	Lennox TS	230kV & 500kV Breaker Replacement. Part of Bulk system	2026/27
4	Dobbin TS	Auto Transformers T1/T2/T5 Replacement	2029
5	Gardiner TS DESN 1	T1/T2 Replacement	2028*

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

7. REGIONAL PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE PETERBOROUGH TO KINGSTON REGION AND PRESENTS WIRES ALTERNATIVES AND PREFERRED WIRES SOLUTIONS FOR ADDRESSING THESE NEEDS. TABLE 7-1 LISTS NEEDS PREVIOUSLY IDENTIFIED IN THE NA AND IRRP FOR THE PETERBOROUGH TO KINGSTON REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THIS RIP REPORT.

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

Table 7-4: Identified Near and Mid-Term Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-service Timing
Supply Capacity	7.1	Peterborough to Quinte West	Today
	7.2	Cataraqui TS Autotransformers	2023
Station Capacity	7.3	Belleville TS	Today
	7.4	Frontenac TS	2029
Station Capacity	7.5	Gardiner TS DESN 1 (T1/T2)	Today
Station Capacity	7.6	Otonabee TS 44kV Bus	Today

Table 7-5: Major Asset Renewal Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-Service Timing
Asset Renewal for Major HV Transmission Equipment	7.7	Picton TS T1/T2 transformers	2025
	7.8	Port Hope TS T3/T4 transformers	2025
	7.9	Gardiner TS T1/T2 (DESN 1) transformers	2028*
	7.10	Dobbin Auto Transformers T1/T2/T5	2029

*Hydro One is exploring if and how Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

Maintaining status quo is not an option for any of the end of life autotransformers or station transformers due to risk of equipment failure and would result in increased maintenance cost and prolonged customer outages and interruptions. These transformers will be replaced with standard units.

No other lines or HV station equipment in the Peterborough to Kingston region than listed above, have been identified for major replacement/refurbishment at this time.

7.1 Supply Capacity – Peterborough to Quinte West

7.1.1 Description

The Peterborough to Quinte West sub region mainly consists of Port Hope TS and Sidney TS. The area is supplied from Dobbin TS to the North West, Cataraqui TS from the East, and Barrett Chute SS to the North East. During low water conditions and contingency situations, the thermal capacity on circuits P15C and Q6S can be exceeded.

7.1.2 Alternatives and Recommendation

IESO is currently undertaking a bulk study of the area and the recommendations from the study is expected to resolve the thermal loading limits of P15C and Q6S.

7.2 Supply Capacity – Cataraqui TS Autotransformers

7.2.1 Description

Cataraqui TS supplies the 115kV stations in the Eastern sub region of the region through two 230/115kV auto transformers. It is forecasted that in 2023 the coincidental loading of the stations in the sub region will reach the supply capacity of the Cataraqui TS auto transformers.

7.2.2 Alternatives and Recommendation

The current limitation of the Cataraqui TS auto transformers are due to a short span of copper conductors connected the secondary side of the auto transformers within the station. Upgrading the conductors will allow the long term emergency to increase by 35 MW and resolve this need in the near term.

7.3 Station Capacity – Belleville TS

7.3.1 Description

Belleville TS consists of one DESN supplied by 230kV circuits, H23B and T25B. The station has a summer 10-Day LTR of 161 MW. The station is also limited by voltage drop limitations when transmission circuit H23B is lost along with the companion transformer by configuration and the maximum loading can be as low as 130 MW, depending on the load composition at the station.

Based on the 2020 net load forecast, the station will exceed its capacity in 2022. In addition, Elexicon has also recently received approximately 30 MW of load connection inquiries to be connected at Belleville TS, but not including in the current load forecast. Hence, there is an immediate need for additional transformation capacity at Belleville TS today.

While the Belleville TS T1/T2 transformer replacement is currently underway, with an expected in-service date of 2022, this refurbishment is not expected to result in any significant improvement to the station’s capacity and does not solve the voltage limitation issue.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the Belleville TS station capacity need:

1. **Alternative 1 – Install a new DESN with two 75/125 MVA transformers with two 32 MVAR Capacitor banks and assess transmission line capacity**: Installing a second DESN at Belleville TS with two 32 MVAR capacitor banks will help mitigate the voltage drop at the Belleville TS LV bus and will resolve the station capacity need over the long-term (20 years) based on the current load forecast. Belleville TS switchyard also has space for a second DESN. The estimated cost for this option is approximately $35-40 M. However, it should be noted that preliminary studies indicate that there will be voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency, which will restrict the full utilization of the additional station capacity in the long term as the total load at Belleville TS DESN1 and the new Belleville TS DESN2 is expected to be limited to 210 MW total, but should be sufficient capacity to meet the forecasted demand in the next 20 years. To fully utilize the capacity of the second DESN and increase the capacity beyond 210 MW, new supply lines into Belleville will be required to alleviate the voltage drop limits at Belleville TS. A possible reinforcement option is to extend X21/X22 from Napanee TS to Belleville TS along an existing Q6S Right of Way. There may also be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts when looking beyond 20 years.

2. **Alternative 2 – Install an additional third 75/125 MVA transformer at Belleville TS and assess transmission line capacity**: Installing a third transformer at Belleville TS would resolve the need over the study period, however it is not a long term solution as compared to alternative 1 as it does not provide reliability of a full DESN, will significantly increase short circuit level at the 44kV bus, and does not alleviate the current voltage limitation. The estimated cost for this option is also similar to alternative 1 at approximately $30-35 M.

3. **Alternative 3 – Load transfers:** Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers was not recommended by the TWG.

Considering the above alternatives, the TWG recommends Alternative 1. To address today’s station capacity need at Belleville TS, as well as the growing electricity demand in the region, Hydro One (Transmission and Distribution) and Elexicon have started development of a new DESN transformer station at Belleville, with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS in the near and mid term.

The TWG will continue to monitor the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle in order to re-assess whether/when a transmission line reinforcement to Belleville is required in the long term. In case of a H25B contingency where voltage violations are exceeded, operational measures will be taken to resolve the issue. Furthermore, IESO will undertake any necessary bulk system studies regarding the transmission reinforcement to Belleville TS.

7.4 Station Capacity – Frontenac TS

7.4.1 Description

Frontenac TS consists of one DESN supplied by 115kV circuits, Q3K and B5QK. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the 2020 net load forecast, Frontenac TS is expected to exceed its Summer 10-Day LTR by 2029 but can be as early as 2022 for a high growth scenario. As there is limited load transfer capability between Frontenac TS and Gardiner TS DESN1 and excess load in Eastern Kingston area may not be able to supply from Gardiner TS DESN1, there is a need for additional transformation capacity at Frontenac TS in the mid-term.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the Frontenac TS station capacity need:

1. **Alternative 1 – Upgrade Frontenac T3/T4 transformers**: The transformers at Frontenac TS are already the largest size for a 115/44kV DESN and therefore upgrading these transformers is not feasible.

2. **Alternative 2 – Install a new DESN with 50/83MVA transformers at Frontenac TS**: As the 115kV circuits supplying Frontenac TS have little thermal capacity, adding a second DESN at Frontenac TS will require significant upgrades to the existing 115kV transmission circuits. In addition, the cost of converting 115 kV transmission line to 230 kV is large and has been a deterrent due to low load growth in the area.

3. **Alternative 3 – Extend 230kV circuits X2H and X4H 13 km to the East of St. Lawrence River and install a new 75/125 MVA DESN**
   This option was assessed and reject due to the high cost and many environmental and real estate issues with the line extension.

4. **Alternative 4 –Build a new 230kV 75/125 MVA DESN near Gardiner TS**
   Load transfer capability exists between Frontenac TS and Gardiner TS DESN 1 via 44kV feeder ties but is limited and for operation measures and is not be suitable for permanent new loads forecasted in Eastern Kingston. Building a new 230 kV DESN near the current X2H/X4H corridor can alleviate this constraint by supplying new load in the area as well as providing an extra station where load can be transferred from Frontenac TS to the new DESN, as needed.

Considering the above alternatives, the TWG recommends Alternative 4. Hydro One transmission will work with Kingston Hydro and Hydro One Distribution to undertake development work for a new station in the area in the near term, which may be built by the Transmitter or the LDC.

The development of additional energy efficiency, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station

7.5 Station Capacity – Gardiner TS DESN 1 (T1/T2)

7.5.1 Description

Gardiner TS DESN 1 is supplied by 230 kV circuits X2H and X4H. The Summer 10-Day LTR of Gardiner TS DESN1 is 125 MW.

Based on the 2020 net load forecast, Gardiner TS has exceeded its Summer 10-Day LTR. Hence, there is a need for additional transformation capacity at Gardiner TS DESN1 in the near term.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the Gardiner TS DESN1 station capacity need:

1. **Alternative 1 – Expedite Gardiner TS DESN1 refurbishment**:
   As the current transformers 10 Day LTR is 125 MW, replacing it with new standard 75/125 MVA transformers will increase the LTR to about 160 MW. This will provide enough capacity to meet the load growth at DESN 1 until 2033.

2. **Alternative 2 – Load Transfer from Gardiner TS DESN1 to Gardiner TS DESN2**:
   Gardiner TS DESN2 was built within the last 15 years and has a 10 day LTR of 85 MW. DESN2 has available capacity at the station to supply additional loading. Hydro One distribution has confirmed that an permanent additional 11 MW load transfer from Gardiner TS DESN1 to Gardiner TS DESN2 is possible by reconfiguring its distribution system.

Considering the above alternatives the TWG recommends to proceed with both Alternatives 1 and 2. As the cost of the distribution load transfer is low and the load transfer work is much faster than the Gardiner TS DESN1 refurbishment, Hydro One Distribution can proceed with the work to alleviate the immediate loading constraint on Gardiner TS DESN1 with an expected completion date end of 2022, while Hydro One Transmission will explore opportunity to accelerate the Gardiner TS DESN1 refurbishment. The combination of these two options will address the current capacity limit at Gardiner TS DESN1. Hydro One Transmission will provide an update to the Technical Working Group for Gardiner TS DESN1 refurbishment in Q3 2022.

7.6 Station Capacity – Otonabee TS 44kV bus (T1/T2)

7.6.1 Description

The 2020 non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV winding is 97 MW.

Based on the 2020 net load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today. Hence, there is a need for additional transformation capacity at Otonabee TS 44 kV bus in the near term.

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the Otonabee TS 44kV station capacity need:

1. **Alternative 1 – Transfer load from Otonabee TS 44kV to Dobbin TS**:
   Dobbin TS is nearby station that have over 50MW of remaining capacity and is not expected to reach its LTR of 160 MW in the long term. The secondary voltage is also 44kV, which allows load transfer between the two stations. Although there is an existing plan to transfer 4 MW of load from Otonabee TS 44kV bus to Dobbin TS, that is not enough to alleviate the capacity limits at Otonabee TS 44kV bus. Hydro One Distribution has confirmed that an additional 8 MW of load can be transfer from

Otonabee TS 44kV to Dobbin TS. This will provide enough capacity to meet the load growth forecast at Otonabee TS 44 kV bus until 2030.

2. **Alternative 2 – Transfer load from Otonabee TS 44kV to Otonabee 27.5kV**: As the voltage levels are different between the 2 low voltage winding of the bus, transferring the load between the different voltages is extremely difficult, costly, and time consuming as it requires all the downstream DS's to be converted to 27.6kV, and in many cases due to distance is not feasible.

The TWG recommends that Hydro One Distribution proceed with the above work in Alternative 1 to ensure continued supply reliability to customers at Otonabee TS 44 kV. Otonabee TS 44kV bus will be monitored after the load transfer and plans should be made if more load transfer from Otonabee TS 44kV bus to Dobbin TS is needed in the long term.

7.6 Asset Renewal Need – Picton TS T1/T2 Transformer Replacement

7.6.1 Description

Picton TS is a 230/44kV transformer station serving Hydro One Distribution. The station comprises two 50/83MVA transformers, T1/T2. The station's 2020 actual peak load was 59 MW and it has a Summer 10-Day LTR of approximately 78MW.

Transformers T1 and T2 are currently about 60 years old and are planned for similar standard units based on their asset condition assessment and taking "right sizing" into consideration. The tentative in-service date is expected in 2025.

The TWG recommends that Hydro One proceed with the above work to ensure continued supply reliability to customers.

7.6.2 Alternatives and Recommendation

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 Picton TS T1/T2. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.7 Asset Renewal Need – Port Hope TS T3/T4 Transformer

7.7.1 Description

Port Hope TS is located in the city of Port Hope, Ontario and supplies Hydro One Distribution and Elexicon loads. Port Hope TS T3/T4 are 50/83 MVA transformers with a 10 day LTR of 104 MW. T3/T4 currently supplies about 70 MW of load and the long term forecast is well within the current LTR.

The T3/T4 transformers were built in 1959 and have been identified as has reached the end of service life and requiring replacement. The scope of this project is to replace T3/T4 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 right sizing approach to downsizing and/or upsizing these transformers based on needs. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is not decreasing. Upsizing is also not an option as the long term forecast does not justify upgrade. Accordingly, it is recommended to replace these transformers with similar size.

7.7.2 Alternatives and Recommendation

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 Port Hope TS T3/T4. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Asset Renewal Need – Gardiner TS T1/T2 (DESN 1) Transformer

7.8.1 Description

Gardiner TS is located in the city of Kingston, Ontario and supplies Hydro One Distribution and Kingston Hydro loads. Gardiner TS DESN1 T1/T2 are 75/125 MVA transformers with a 10 day LTR of 125 MW. The current loading on T1/T2 have exceeded its 10 day LTR.

The T1/T2 transformers were built in mid 1970s and has reached the end of service life requiring replacement in the previous planning cycle. Following recent inspections of the transformers, the conditions of the transformers were found to be acceptable and the plan to replace the transformers were deferred to 2028.

The Study Team has assessed downsizing and/or upsizing need for these transformers. As the 10 day LTR of the current transformers are substandard, the Working Group concluded that replacing the current transformers which new standard 75/125 MVA units will increase the supply capacity to about 160 MW and alleviate the current overloading at DESN1. Reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option as the current units are already the largest size for a 230/44kV step-down transformers.

7.8.2 Alternatives and Recommendation

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:
Expedite this end of life asset replacement as the current transformers are already overloaded. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.9 Asset Renewal Need – Dobbin TS T1/T2/T5 Auto Transformers

7.9.1 Description

Dobbin TS is located near the city of Peterborough, Ontario and supplies Peterborough to Quinte loads. Dobbin TS consists of three 230/115 kV auto transformers. T1 is rated at 150/250 MVA and T5 is rated at 115 MVA. T2 is rated at 36/78 MVA and currently out of service.

During the previous planning cycle, T2 and T5 were planned to be replaced with one 150/250 MVA unit. However, as T1 has also reached the end of service life, it would be more efficient and cost effective to replace all three transformers with two 150/250 MVA units.

7.9.2 Alternatives and Recommendation

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 three existing autotransformers with two units:
Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Dobbin 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 REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE PETERBOROUGH TO KINGSTON REGION.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 8-1 below. As the industry is currently witnessing supply chain issues and delays in procurement of equipments, it can impact the near term planning horizon if left unresolved.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-1.

Table 8-1: Recommended Plans in Peterborough to Kingston Region over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate(7) ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[8]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

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[7] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

[8] The new standard units are expected to have a higher LTR of about 160 MW

9. REFERENCES

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[5]. 2nd Cycle Peterborough to Kingston Needs Assessment Report (2020)
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APPENDIX A: STATIONS IN THE PETERBOROUGH TO KINGSTON REGION

Station	Voltage (kV)	Supply Circuits
Ardoch DS (T1)	115	B1S
Battersea DS (T1/T2)	115	S1K
Belleville TS (T1/T2)	230	T25B, H23B
Dobbin DS (T1/T2)	115	P3S, P4S
Dobbin TS (T3/T4)	115	Q20H, Q20A
Frontenac TS (T3/T4)	115	B5QK, Q3K
Gardiner TS (T1/T2)	230	X4H, X2H
Gardiner TS (T3/T4)	230	X2H, X4H
Harrowsmith DS (T1/T2)	115	B5QK
Hinchinbrooke DS (T1)	115	B5QK
Lodgeroom DS (T1/T2)	115	B1S
Napanee TS (T1)	230	X21, X22
Northbrook DS (T1)	115	B1S
Otonabee TS (T1/T2)	230	T22C, T31H
Otonabee TS (T1/T2)	230	T22C, T31H
Picton TS (T1/T2)	230	X21, X22
Port Hope TS (T1/T2)	115	P3S, P4S
Port Hope TS (T3/T4)	115	P3S, P4S
Sharbot DS (T1)	115	B5QK
Sidney TS (T1/T2)	115	Q12AT, Q6S

APPENDIX B: TRANSMISSION LINES IN THE PETERBOROUGH TO KINGSTON REGION

Location	Circuit Designations	Voltage (kV)
Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
Picton TS – Lennox TS	X21, X22	230
Belleville TS – Hinchinbrooke SS	H23B	230
Hinchinbrooke SS – Havelock TS	H27H	230
Dobbin TS – Chenaux TS	X1P	230
Dobbin TS – Chat Falls GS	C27P	230
Clarington TS – Havelock TS	T32H	230
Chat Falls GS – Havelock TS	C25H	230
Clarington TS – Chat Falls GS	T22C	230
Cherrywood TS – Dobbin TS	P15C	230
Clarington TS – Belleville TS	T25B	230
Dobbin TS – Sidney TS	P3S, P4S	115
Cataraqui TS – Sidney TS	Q6S	115
Barrett Chute TS – Sidney TS	B1S	115
Cataraqui TS – Frontenac TS	Q3K	115
Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

APPENDIX C: DISTRIBUTORS IN THE PETERBOROUGH TO KINGSTON REGION

Distributor Name	Station Name	Connection Type
Eastern Ontario Power Inc.	Frontenac TS	Dx
Elexicon Energy Inc. – Veridian Connections Inc.	Belleville TS	Tx
	Port Hope TS	Dx
Hydro One Distribution	Ardoch DS	Tx
	Battersea DS	Tx
	Belleville TS	Tx
	Dobbin DS	Tx
	Dobbin TS	Tx
	Frontenac TS	Tx
	Gardiner TS	Tx
	Harrowsmith DS	Tx
	Hinchinbrooke DS	Tx
	Lodgeroom DS	Tx
	Napanee TS	Tx
	Northbrook DS	Tx
	Otonabee TS	Tx
	Otonabee TS	Tx
	Picton TS	Tx
	Port Hope TS	Tx
	Sharbot DS	Tx
	Sidney TS	Tx
	Dobbin DS	Dx
	Dobbin TS	Dx
	Otonabee TS	Dx
Kingston Hydro Corporation	Frontenac TS	Tx
	Frontenac TS	Dx
	Gardiner TS	Dx
Lakefront Utilities Inc.	Port Hope TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1: Net Summer Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	9	9	9	9	9	9
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	111	111	117	122	123	123	125	126	127	129	131	132
Frontenac TS	97	96	100	102	104	104	105	107	108	109	111	112
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Gardiner TS (T3/T4)	25	28	28	28	28	28	28	28	28	28	28	28
Harrowsmith DS	16	16	16	16	16	16	16	16	16	16	17	17
Havelock TS	74	74	74	75	74	74	75	75	76	76	76	77
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6
Lodgeroom DS	9	9	9	9	9	9	9	9	9	9	9	9
Napanee TS	61	62	62	63	63	64	64	65	66	66	67	68
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6
Otonabee TS	123	124	119	119	115	115	116	118	119	120	122	124
Picton TS	43	43	44	44	44	45	45	45	46	46	47	47
Port Hope TS	121	121	122	122	122	122	123	123	124	124	125	126
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	79	79	79	79	79	79	79	80	80	81	81	82
CTS	14	14	14	14	14	14	14	14	14	14	14	14
Total	1122	1132	1147	1161	1163	1166	1174	1182	1192	1199	1212	1223

Table D-2: Net Winter Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	3	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	11	11
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	87	87	93	98	99	100	101	102	104	105	106	107
Frontenac TS	101	101	104	106	109	109	111	112	113	115	116	118
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Gardiner TS (T3/T4)	29	32	32	32	32	32	32	33	33	33	33	33
Harrowsmith DS	19	19	19	19	19	19	19	19	19	19	19	19
Havelock TS	69	69	69	69	70	70	70	71	71	72	72	73
Hinchinbrooke DS	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	11	11	11	11	11
Napanee TS	70	70	71	71	72	72	73	74	75	75	76	77
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7
Otonabee TS	145	146	146	142	138	139	140	142	143	146	147	149
Picton TS	48	49	49	50	50	50	51	51	52	52	53	53
Port Hope TS	127	128	128	129	130	130	130	131	132	132	133	134
Sharbot DS	4	4	4	4	4	5	5	5	5	5	5	5
Sidney TS	69	69	68	68	68	68	69	70	70	71	71	72
CTS	26	26	26	26	26	26	26	26	26	26	26	26
Total	1134	1144	1159	1170	1179	1183	1192	1205	1214	1225	1233	1245

Table D-3: Net Summer Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Frontenac TS	101	101	108	107	107	107	108	109	110	111	112	114
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Otonabee TS 44 kV	102	102	98	98	95	95	96	97	98	99	100	102

Table D-4: Net Winter Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Frontenac TS	111	113	117	117	117	118	119	120	121	122	123	125
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Otonabee TS 44 kV	115	116	116	113	109	110	111	113	114	115	116	118

Table D-5: Net Summer Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	187	187	187	188	189	190	191	192
Frontenac TS	101	102	109	110	111	113	117	121	125	129	133	137
Gardiner TS (T1/T2)	146	148	151	153	155	156	158	159	161	163	165	168

Table D-6: Net Winter Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	114	119	120	121	124	128	132	136	140	144	148
Gardiner TS (T1/T2)	132	134	136	138	141	142	144	146	148	150	152	155

Table D-7: Net Winter Non-Coincidental Load Forecast Growth Scenario 2 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	116	124	126	130	136	145	155	165	174	183	193
Gardiner TS (T1/T2)	132	135	138	142	145	148	151	154	157	160	163	167

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

DSP SECTION 3 -PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

3.1 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

The OEB's Renewed Regulatory Framework (RRF) is an outcomes-based approach to regulation, with four key outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. Performance in these areas is reported and tracked through the OEB's mandated Electricity Distributor Scorecard.

Since this is the first DSP prepared for the service areas formerly served by Orillia Power Distribution Corporate (OPDC) (herein referred to as "Orillia") and Peterborough Distribution Inc. (PDI) (herein referred to as "Peterborough"), there are no historical DSP performance objectives to reference. For the 2017-2020 period, OPDC and PDI submitted Electricity Distributor Scorecards. As integration occurred on June 1, 2021, Orillia and Peterborough were included in Hydro One's 2021 Electricity Distributor Scorecard, with Hydro One Distribution, Norfolk, Haldimand and Woodstock, on a consolidated basis.

The following sections discuss actual scorecard results from 2017-2021 for Orillia and Peterborough. To enable comparisons between historical performance and performance post-integration, Hydro One has made efforts to provide data that is specifically applicable to Orillia or Peterborough, wherever feasible. However, many of the performance measures for 2021 onwards can only be provided on a consolidated basis for Hydro One, which is consistent with the data submitted to the OEB through the OEB's Reporting and Record-keeping Requirements (RRR). For Hydro One's consolidated scorecard targets for 2022-2027, please refer to Hydro One's Joint Rate Application, EB-2021-0110, Exhibit B3, Section 3.5 – DSP – Performance Measurement and Outcomes.

The 2017-2020 Electricity Distributor Scorecards for Orillia and Peterborough, as filed by OPDC and PDI through the OEB's RRR, are provided in Figure 1 and Figure 2, below. Hydro One's consolidated 2021 Electricity Distributor Scorecard is provided in Figure 3.

				OPDC			
Performance Outcomes	**Performance Categories**	**Measures**		**2017**	**2018**	**2019**	**2020**
Customer Focus	**Service Quality**	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%
		Scheduled Appointments Met on Time		100.00%	99.78%	100.00%	100.00%
		Telephone Calls Answered on Time		97.43%	96.95%	98.83%	98.64%
	Customer Satisfaction	First Contact Resolution		99.88%	99.90%	99.89%	99.97%
		Billing Accuracy		99.98%	99.99%	99.99%	99.99%
		Customer Satisfaction Index		A	A	A	A
Operational Effectiveness	**Safety**	Level of Public awareness		84.00%	84.00%	84.00%	84.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0
			Rate per 10, 100, 1000km of line	0.000	0.000	0.000	0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		3.63	1.43	0.82	1.13
		Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		0.92	1.50	0.54	0.82
	Asset Management	Distribution System Plan Implementation Progress		In progress	In progress	Pending	Pending
	Cost Control	Efficiency Assessment		3	3	3	3
		Total Cost per Customer		$646	$666	$676	$725
		Total Cost per km of Line		$36,942	$38,646	$39,810	$43,062
Public Policy Responsiveness	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed on Time					
		New Micro-embedded Generation Facilities Connected on Time		100.00%	100.00%		
Financial Performance	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.70	0.72	0.61	0.37
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.05	0.97	1.14	0.00
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.85%	9.85%	9.85%
			Achieved	11.03%	7.55%	6.02%	2.77%

Figure 1: Electricity Distributor Scorecard for Orillia, as reported by OPDC[1]

[1] 2020 Scorecard – Orillia Power Distribution Corporation, October 22, 2021. (Scorecard - Orillia Power Distribution Corporation.pdf (oeb.ca))

Performance Outcomes	Performance Categories	Measures		PDI 2017	PDI 2018	PDI 2019	PDI 2020
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time		97.52%	99.19%	97.44%	98.31%
		Scheduled Appointments Met on Time		99.90%	99.91%	100.00%	99.82%
		Telephone Calls Answered on Time		90.42%	87.47%	75.60%	84.02%
	Customer Satisfaction	First Contact Resolution		0	0	0	6
		Billing Accuracy		99.51%	99.91%	99.89%	99.87%
		Customer Satisfaction Index		A	A	A	A
Operational Effectiveness	Safety	Level of Public awareness		85.00%	85.00%	85.00%	82.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C
		Serious Electrical Incident Index	Number of General Public Incidents	0	2	1	1
			Rate per 10, 100, 1000km of line	0.000	0.350	0.175	0.175
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		1.60	2.18	1.42	1.08
		Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		2.26	1.92	1.60	1.45
	Asset Management	Distribution System Plan Implementation Progress		85%	87%	71%	71%
	Cost Control	Efficiency Assessment		4	3	3	3
		Total Cost per Customer		$570	$592	$587	$579
		Total Cost per km of Line		$37,309	$38,383	$38,133	$37,650
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time					
		New Micro-embedded Generation Facilities Connected on Time		95.24%	100.00%		100.00%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.63	1.39	1.59	0.21
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.32	1.12	1.01	0.00
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.98%	8.98%	8.98%	8.98%
			Achieved	5.05%	7.31%	6.28%	2.81%

Figure 2: Electricity Scorecard for Peterborough, as reported by PDI[2]

[2] 2020 Scorecard – Peterborough Distribution Inc., October 22, 2021. (Scorecard - Peterborough Distribution Incorporated.pdf (oeb.ca))

Performance Outcomes	Performance Categories	Measures		2021[3]	Target: Industry	Target: Distributor
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time		99.98%	90.00%	
		Scheduled Appointments Met on Time		100.00%	90.00%	
		Telephone Calls Answered on Time		70.41%	65.00%	
	Customer Satisfaction	First Contact Resolution		77%		
		Billing Accuracy		99.17%	98.00%	
		Customer Satisfaction Index		82.4%		
Operational Effectiveness	Safety	Level of Public awareness		78.00%		
		Level of Compliance with Ontario Regulation 22/04		C		C
		Serious Electrical Incident Index	Number of General Public Incidents	15		11
			Rate per 10, 100, 1000km of line	0.121[4]		0.092
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		6.50		7.22
		Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		2.36		2.47
	Asset Management	Distribution System Plan Implementation Progress		100.9%		
	Cost Control	Efficiency Assessment		4		
		Total Cost per Customer		$1,033		
		Total Cost per km of Line		$11,940		
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%		
		New Micro-embedded Generation Facilities Connected on Time		98.72%	90.00%	
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.64		
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.72		
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.00%		
			Achieved	10.99%		

Figure 3: 2021 Consolidated Electricity Scorecard for Hydro One[5]

[3] Starting in 2021, many of the Scorecard metrics (with the exception of the Safety Components B and C) are inclusive of the service territories formerly served by OPDC and PDI.
[4] The Serious Electrical Incident Index Rate measure was incorrectly presented as 0.120.
[5] 2021 Scorecard – Hydro One Networks Inc, August 31, 2022. (Scorecard - Hydro One Networks Inc..pdf (oeb.ca))

The following subsections discuss the individual components of Hydro One's Consolidated Electricity Scorecard (the Scorecard).

3.2 CUSTOMER FOCUS

3.2.1 SERVICE QUALITY

Table 1 provides the three Service Quality measures included in the Scorecard.

Table 1 - Customer Focus – Service Quality Measures

Measure	Description
New Residential/Small Business Services Connected on Time	This measure assesses Hydro One's ability to process new connection requests for residential and small business low-voltage customers (those with service less than 750 V), within five business days (or as agreed to by the customer and Hydro One). The OEB's Distribution System Code (DSC) requires that this be met at least 90 percent of the time on a yearly basis.[6]
Scheduled Appointments Met on Time	This measure applies to appointments where customer presence is required and to those where customers do not need to be present. When a customer requests an appointment, the appointment must be scheduled within five business days (or as otherwise agreed to by the customer and the distributor). If customer presence is required, the distributor must commit to, and arrive within a four-hour window for the appointment. If customer presence is not required, the distributor must arrive on the scheduled date. The DSC requires that this be met at least 90 percent of the time on a yearly basis.[7]
Telephone Calls Answered on Time	The OEB's DSC requires call centre staff to answer calls within 30 seconds, 65% of the time, whenever the customer reaches an agent—either directly or by means of a transfer. In the two years since the insourcing of the call centre, Hydro One has exceeded this target.[8]

From 2017-2020, the Orillia and Peterborough measures submitted by OPDC and PDI consistently exceeded the minimum requirements.

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[6] Distribution System Code, Section 7.2, October 1, 2022. (Distribution System Code (DSC) - October 1, 2022 (oeb.ca))
[7] Distribution System Code, Sections 7.3 and 7.4, October 1, 2022. (Distribution System Code (DSC) - October 1, 2022 (oeb.ca))
[8] Distribution System Code, Section 7.6, October 1, 2022. (Distribution System Code (DSC) - October 1, 2022 (oeb.ca))

In 2021, on a consolidated basis, Hydro One Distribution exceeded the minimum requirements set for each measure, as follows:

- 99.98% of new residential/ small business services were connected on time versus the requirement of 90%;
- 100% of scheduled appointments were met on time versus the requirement of 90%; and
- 70.41% of telephone calls were answered on time versus the requirement of 65%.

3.2.1 CUSTOMER SATISFACTION

For the Customer Satisfaction performance category, the Scorecard includes one measure with an industry defined target (Billing Accuracy) and two measures which can vary by distributor (First Contact Resolution and Customer Satisfaction). Table 2 provides the description of each measure, including Hydro One's approach to measuring First Contact Resolution and Customer Satisfaction.

Table 2 - Customer Focus – Customer Satisfaction Measures

Measure	Description
First Contact Resolution	First Contact Resolution (FCR) reports the success of the distributor in resolving a customer's issue during the first contact, as reported by the customer. Hydro One measures FCR based on transactional surveys that are performed within five days of our interaction with the customer.
Billing Accuracy	Billing Accuracy is the measure for the number of bills issued that are derived based on actual meter readings and do not require any subsequent adjustments as a percentage of the total number of bills issued in a given bill period. The DSC requires that this be met at least 98 percent of the time on a yearly basis.[9]
Customer Satisfaction Index	Hydro One measures Customer Satisfaction using an equally weighted composite index consisting of the following seven components: (1) Outage Handling; (2) Call Centre Customer Satisfaction; (3) Forestry Services; (4) Lines New Connections and Upgrades; (5) My Account; (6) Large Distribution Accounts (LDAs); and (7) Distributed Generation Customers (estimated as per cent of new connections met on-time).

[9] Distribution System Code, Sections 7.11, October 1, 2022. (Distribution System Code (DSC) - October 1, 2022 (oeb.ca))

In terms of Billing Accuracy, the Orillia and Peterborough measures submitted by OPDC and PDI in 2017-2020 consistently exceeded the minimum requirement. In 2021, Hydro One also exceeded the minimum requirement of 98% by achieving 99.17% billing accuracy.

For the other two measures, the pre-integration values submitted by OPDC and PDI cannot be effectively compared to the post-integration results for 2021, for the following reasons:

- the measurement approaches vary by distributor, and
- Hydro One's 2021 values are provided on a consolidated basis and are therefore based on Hydro One's entire distribution service territory.

For 2021, on a consolidated basis, Hydro One resolved 77% of issues during first contact and achieved a Customer Satisfaction Index of 82.4%.

3.3 OPERATIONAL EFFECTIVENESS

3.3.1 SAFETY

For the Safety performance category, the Scorecard includes measures that vary by distributor. Table 3 provides Hydro One's description and measurement approach for each Safety measure.

Table 3 - Operational Effectiveness – Safety Measures

Measure	Description
Level of Public Awareness	Hydro One measures public awareness of electrical safety every two years. To gauge overall electrical safety awareness amongst the general public, six core questions are asked to randomly-selected Ontario residents. These questions include: likelihood to call before you dig, impact of touching a power line, proximity to overhead power line, danger of tampering with electrical equipment, proximity to downed power lines, and actions taken in vehicle in contact with wires.
Level of Compliance with Ontario Regulation 22/04	Ontario Regulation 22/04 was introduced in early 2004 following recommendations from the ESA to enhance electrical safety for the people of Ontario. The regulation sets the basis for the requirements for the safe operation of the distribution system in Ontario. This measure is based on ESA's assessment of Hydro One's performance based on 3 major factors: 1. Hydro One's performance on the Annual External Audit and Self Declaration of Compliance to Regulation 22/04, 2. Hydro One's performance on its Due Diligence Inspections and; 3. Hydro One's performance on Public Safety Concerns.
Serious Electrical Incident Index	The Serious Electrical Incident Index was designed to track and help improve public electrical safety on the distribution network over time. A distributor, its contractors and operators are required to report to the ESA, within 48 hours, any serious electrical incident involving members of the general public. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or has the potential to cause, critical injury or death in any part of the distribution system operating at greater than 750 Volts (except as caused by lightning strikes).

Since these metrics vary by distributor, Hydro One cannot comment on the pre-integration measures submitted by OPDC and PDI.

The 2021 Hydro One Safety measures exclude Orillia and Peterborough for the following reasons:

- The Level of Public Awareness measure is based on a survey conducted every two years. The 78% reported for 2021 was the result of the 2020 survey, which was prior to integration. Orillia and Peterborough will be included in the 2022 survey.

- The Level of Compliance with Ontario Regulation 22/04 and Serious Electrical Incident Index are measures that lag by approximately one year.[10] Hydro One Distribution's 2021 results do not include Orillia and Peterborough due to the one-year lag as well as the integration date. However, Table 4 provides the 2021 results for OPDC, PDI and Hydro One Distribution, showing that all three utilities complied with Ontario Regulation 22/04. Since Hydro One Distribution is significantly larger than OPDC and PDI, the Serious Electrical Incident Index results are not comparable. For Hydro One Distribution's 2022 results, Orillia and Peterborough will be included from the post-integration period.

Table 4 - 2021 Safety Measures

Measure		**PDI**	**OPDC**	**Hydro One Distribution**
Level of Compliance with Ontario Regulation 22/04		C	C	C
Serious Electrical Incident Index	Number of General Public Incidents	0	0	15
	Rate per 10, 100, 1000km of line	0	0	0.121

[10] Compliance Investigations: April 01, 2020 to March 31, 2021, Serious Electrical Incidents: January 01, 2020 to December 31, 2020

3.3.2 SYSTEM RELIABILITY

The System Reliability performance category measures can vary by distributor. Hydro One's approaches for measuring System Reliability are provided in Table 5.

Table 5 - Operational Effectiveness – System Reliability Measures

Measure	Description
Average Number of Hours that Power to a Customer Is Interrupted	*Average number of hours that power to a customer is interrupted* normally is measured in SAIDI (System Average Interruption Duration Index): It is defined as the system average interruption duration (in hours) for customer served per year. $\mathrm{SAIDI} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Customers Served}}$ In Hydro One's reporting for OEB Electricity Distribution Scorecard, all planned and unplanned interruptions of one minute or more (excluding Loss of Supply (LOS) and excluding Force Majeure Events (FM)) are used to calculate this measure.
Average Number of Times that Power to a Customer Is Interrupted	*Average number of times that power to a customer is interrupted* normally is measured in SAIFI (System Average Interruption Frequency Index): It is defined as the system average interruption frequency for customer served per year. $\mathrm{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$ In Hydro One's reporting for OEB Electricity Distribution Scorecard, all planned and unplanned interruptions of one minute or more (excluding Loss of Supply and excluding Force Majeure Events) are used to calculate this measure.

Hydro One's consolidated 2021 performance included a reported SAIDI of 6.50 hours per customer and a SAIFI of 2.36 interruptions per customer. These measures reflect Hydro One's entire service territory, which includes approximately 1.4 million residential, commercial, industrial and local distribution company (LDC) customers, and spans across a mostly rural service area of over 961,000 sq km.

The pre-integration values submitted by OPDC and PDI cannot be effectively compared to Hydro One's consolidated results presented in the 2021 Scorecard.

To provide an indicative comparison of performance pre- and post-integration, Hydro One has provided the following for the 12-month period between June 1, 2021 and May 31, 2022:

- the reliability performance of Hydro One's Couchiching Operating Centre, which includes Orillia's service territory; and
- the reliability performance of Hydro One's Ashburnham Operating Centre, which includes Peterborough's service territory.

On this basis, the 12-month post-integration specific SAIDI and SAIFI for the Couchiching and Ashburnham Operating Centres, excluding loss of supply (LOS) and major (Force Majeure) events, are presented in Table 6.[11]

Table 6 - Specific Reliability Performance for Orillia and Peterborough for the 12-Month Post-Integration (June 1, 2021 to May, 31, 2022)

Specific Reliability Performance*	Couchiching (Orillia)	Ashburnham (Peterborough)
SAIDI (hours per customer)	0.83	2.34
SAIFI (interruptions per customer)	0.87	1.81

**Excludes loss of supply events and major (Force Majeure) events.*

[11] Prior to acquisition, OPDC and PDI were considered embedded LDC's supplied by Hydro One distribution feeders, and as a result, outages originating on those feeders would be classified as 'LOS' for OPDC and PDI. Post-integration, those same outages will no longer be classified as 'LOS', as OPDC and PDI are now part of Hydro One's distribution system. As a result of this outage classification change, fewer 'LOS' SAIDI may be excluded resulting in artificially higher SAIDI and SAIFI results in future years. Note that interruptions originating from the transmission system will continue to be classified as 'LOS' post-integration.

Comparisons of the 12-month post-integration performance provided above in Table 6 to the historical measures submitted by OPDC and PDI in 2017-2020 are provided below in Figure 4 for Orillia and Figure 5 for Peterborough.

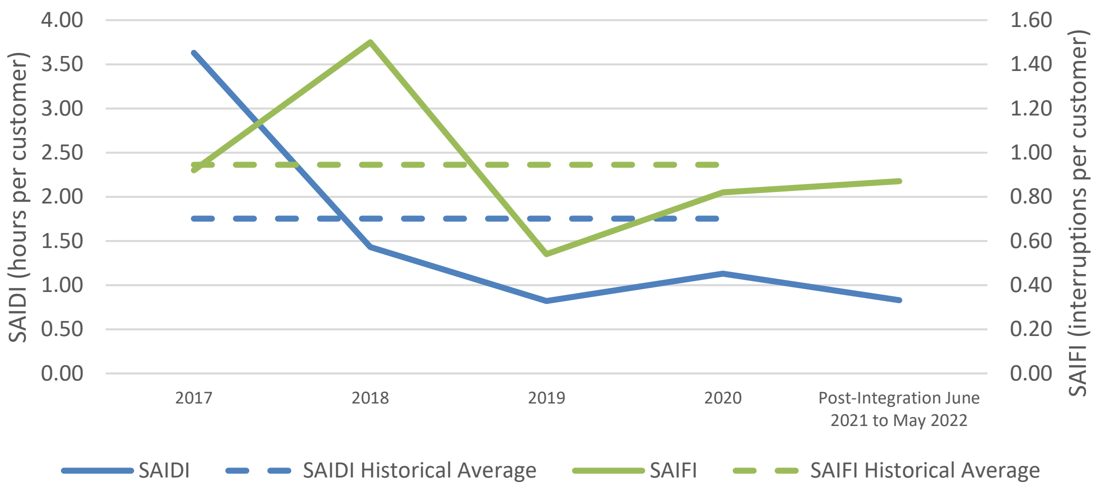

Figure 4: High-level Comparison of Historical Reliability Performance as Reported by OPDC to Hydro One's Couchiching Operating Centre Reliability Performance for the 12-Month Period Post-Integration (Representative of Orillia)

As shown in Figure 4, Hydro One recorded positive reliability performance for Couchiching Operating Centre in the 12-month period post-integration. Both the SAIDI performance of 0.83 hours per customer and SAIFI performance of 0.87 interruptions per customer are lower than OPDC's 2017-2020 historical average SAIDI and SAIFI results of 1.75 hours per customer and 0.94 interruptions per customer, respectively, and in line with OPDC's 2019 and 2020 performance.

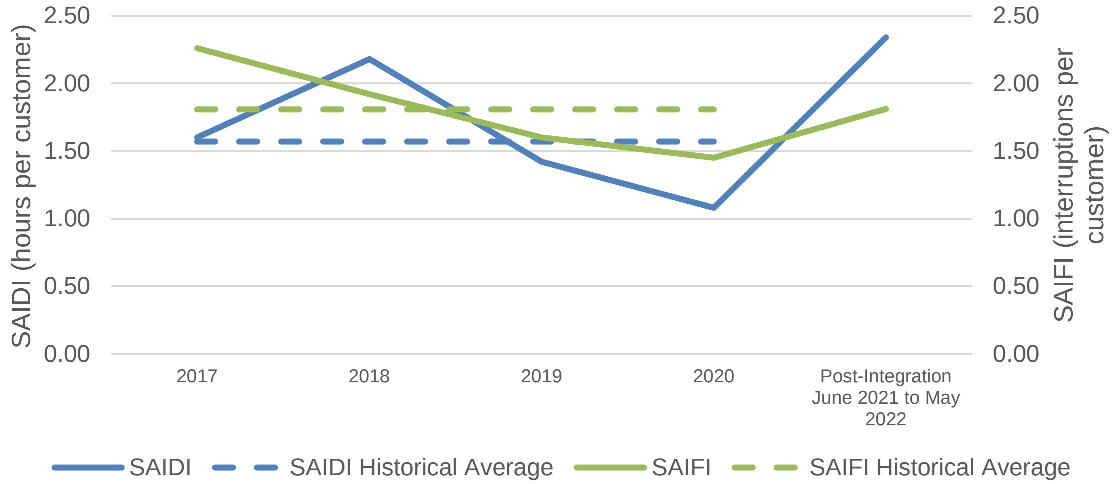

Figure 5: High-level Comparison of Historical Reliability Performance as Reported by PDI to Hydro One's Ashburnham Operating Centre Reliability Performance for the 12-Month Period Post-Integration (Representative of Peterborough)

As shown in Figure 5, Hydro One's 12-month period post-integration SAIDI performance of 2.34 hours per customer in Ashburnham Operating Centre is higher than PDI's 2017-2020 historical average SAIDI performance of 1.57 hours per customer for Peterborough. This is primarily due to an increase in interruption hours attributed to defective equipment and tree contact caused outages. In terms of SAIFI performance, Hydro One's 12-month period post-integration SAIFI of 1.81 interruptions per customer is in line with PDI's 2017-2020 historical average of 1.81 interruptions per customer.

3.3.3 ASSET MANAGEMENT

For the Asset Management performance category, the Scorecard measure varies by distributor. Table 7 provides Hydro One's description and measurement approach for the DSP Implementation Progress measure.

Table 7 - Operational Effectiveness – Asset Management Measures

Measure	Description
DSP Implementation Progress	Established by the OEB in 2013, the DSP implementation progress is a distributor-defined performance metric. Hydro One Distribution Business's DSP outlines the Business's forecasted capital expenditures over the next five years, required to maintain and expand electricity system to serve current and future customers. Progress is measured as the ratio of actual total in-service capital expenditures made in a calendar year to the total amount of planned in-service capital expenditures for the same year.

Since these metrics vary by distributor, Hydro One cannot comment on the pre-integration measures submitted by OPDC and PDI, nor can they be effectively compared to Hydro One's consolidated 2021 result of 100.9% which includes Orillia and Peterborough.

3.3.4 COST CONTROL

The measures for the Cost Control performance category are provided in Table 8.

Table 8 - Operational Effectiveness – Cost Control Measures

Measure	Description
Efficiency Assessment	Cost control metrics are evaluated on behalf of the OEB by an independent party, the Pacific Economics Group LLC (PEG). The PEG study segments electrical distributors into five groups based on actual costs vs. the prediction of costs from PEG's econometric model. Group 1 distributors are considered most efficient, with actual costs 25% or more below predicted costs. Group 5 distributors are considered least efficient, according to the PEG methodology, with actual costs 25% or more above predicted costs.
Total Cost per Customer	The total cost per customer is defined as the total Capital and Operations Maintenance & Administration (OM&A) costs, divided by the total number of customers served. This includes certain adjustments prescribed by the PEG methodology.
Total Cost per KM of Line	The total cost per kilometre of line is defined as the total Capital and OM&A costs, divided by the total number of kilometres of line operated to serve customers, along with certain PEG prescribed adjustments.

Since Hydro One reports the measures presented in Table 8 on a consolidated basis and Hydro One's entire service territory is vastly different than the specific territories of Orillia and Peterborough, the pre-integration values submitted by OPDC and PDI cannot be effectively compared to the post-integration results presented in the 2021 Scorecard.

In 2021, on a consolidated basis, Hydro One was determined to be a Group 4 distributor, with total cost per customer and total cost per km of line of $1,033 and $11,940, respectively. These measures reflect Hydro One's entire service territory, which spans across a mostly rural service area of over 961,000 sq km.

3.4 PUBLIC POLICY RESPONSIVENESS

3.4.1 CONNECTION OF RENEWABLE GENERATION

Descriptions of the Cost Control performance category measures are provided in Table 9.

Table 9 - Public Policy Responsiveness – Connection of Renewable Generation Measures

Measure	Description
Renewable Generation Connection Impact Assessments Completed on Time	A Connection Impact Assessment (CIA) is used to assess the impact of a new connection on the distribution system and is applicable to renewable energy generation facilities that have a name-plate rated capacity of greater than 10 kW. The CIA completed on time is being measured by completing the assessment within 60 days of the receipt of the application as per section 6.2.12 of the DSC.
New Micro-Embedded Generation Facilities Connected on Time	This metric measures Hydro One's success in connecting micro-embedded generation facilities (name-plate rated capacity of 10kW or less) 90% of the time within a five business-day window, or at such later date as agreed to by a micro-embedded generator and the distributor, of the generator informing the distributor that it has satisfied all applicable service conditions and received all necessary approvals, as per sections 6.2.7 and 6.2.7A of the DSC.

From 2017-2020, OPDC and PDI did not report on the completion of any CIAs. For 2021, Hydro One, on a consolidated basis, met the requirements for this measure 100% of the time.

For the New Micro-Embedded Generation Facilities Connected on Time measure, OPDC and PDI consistently exceeded the minimum requirement of 90% from 2017-2020. Likewise, Hydro One exceeded the minimum requirement in 2021, with 98.72% of new micro-embedded generation facilities connected on time.

3.5 FINANCIAL PERFORMANCE

3.5.1 FINANCIAL RATIOS

Descriptions of the Financial Ratios performance category measures are provided in Table 10.

Table 10 - Financial Performance – Financial Ratios Measures

Measure	Description
Liquidity: Current Ratio (Current Assets/Current Liabilities)	Liquidity is measures as the ratio of the current assets to current liabilities. Current assets is defined as cash or other assets to be converted to cash within the year. Current liabilities is defined as short term debts or financial obligations that become due within the year.
Leverage: Total Debt (Includes Long-Term and Short-Term Debt) to Equity Ratio	The debt-to-equity ratio is a measure of the Business's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors. The OEB-deemed capital structure is 60% debt to 40% equity structure (a ratio of 1.5)
Profitability: Regulatory Return on Equity	Regulatory return on equity is calculated using several regulatory adjustments established in section 2.1.5.6 of the annul RRR filing.

The historical RRR financial results submitted by OPDC and PDI on a standalone basis cannot be compared to Hydro One Distribution's 2021 Scorecard results, which in some cases include Orillia and Peterborough, post-integration, as described below.

For the 2021 Scorecard, the basis for these financial ratios is Hydro One's Distribution Business Financial Statements for the year ended December 31, 2021, as filed under the RRR submission. The following provides additional details on the financial ratios for 2021.

- Liquidity: Current Ratio (Current Assets/Current Liabilities) – as at December 31, 2021, the Current Ratio for Hydro One Distribution including the Acquired Utilities, Peterborough and Orillia, is reported as 0.64. The result indicates that for every dollar of debt due within the year, the Business had $0.64 in cash or cash equivalents on-hand to cover the obligations.

- Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio - the Total Debt-to-Equity Ratio is a measure of the Business's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors. The OEB-deemed capital structure is 1.5. As at December 31, 2021, the Business's Total Debt-to-Equity Ratio was 1.72. The Total Debt-to-Equity Ratio fully includes results from Peterborough and partially includes financial results from Orillia due to the difference in how each utility was integrated.
- Profitability: Regulatory Return on Equity – Deemed (included in rates) - Hydro One Distribution's deemed regulatory return on equity (ROE) for 2021 is 9.00%, as approved by the OEB.
- Profitability: Regulatory Return on Equity – Achieved - for the year 2021, Hydro One achieved a regulatory ROE of 10.99%. The ROE excludes the Acquired Utilities, Peterborough and Orillia. The 2021 Achieved ROE was 1.99% higher than the Deemed ROE of 9.00%. Achieved ROE was higher than deemed in 2021 primarily due to higher actual loads than anticipated which resulted in increased revenues, and lower removal costs. After application of the OEB approved earnings sharing mechanism, Hydro One will share $24.5 million with ratepayers which reduced the 2021 Achieved ROE from 10.99% to 10.47%. Since Orillia and Peterborough have been integrated into Hydro One Distribution, separate financial statements are no longer prepared, and the ROE is no longer reported.

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OEB APPENDIX 2-G

SERVICE RELIABILITY AND QUALITY INDICATORS

This exhibit has been filed separately in MS Excel format.

DSP SECTION 4 - ASSET MANAGEMENT PROCESS

4.1 PLANNING PROCESS

Hydro One's integrated system planning process is comprised of a three-phase, risk-based process to identify, prioritize, and optimize investments. The resulting multi-year investment plan prudently addresses system and asset needs in alignment with the OEB's Renewed Regulatory Framework (RRF), Hydro One's strategic priorities and the customer service imperatives that are at the core of its business mandate. As presented in Figure 1 and summarized below, the three phases of the system planning framework are: (i) Strategy and Context, (ii) Asset Management, and (iii) Investment Planning.

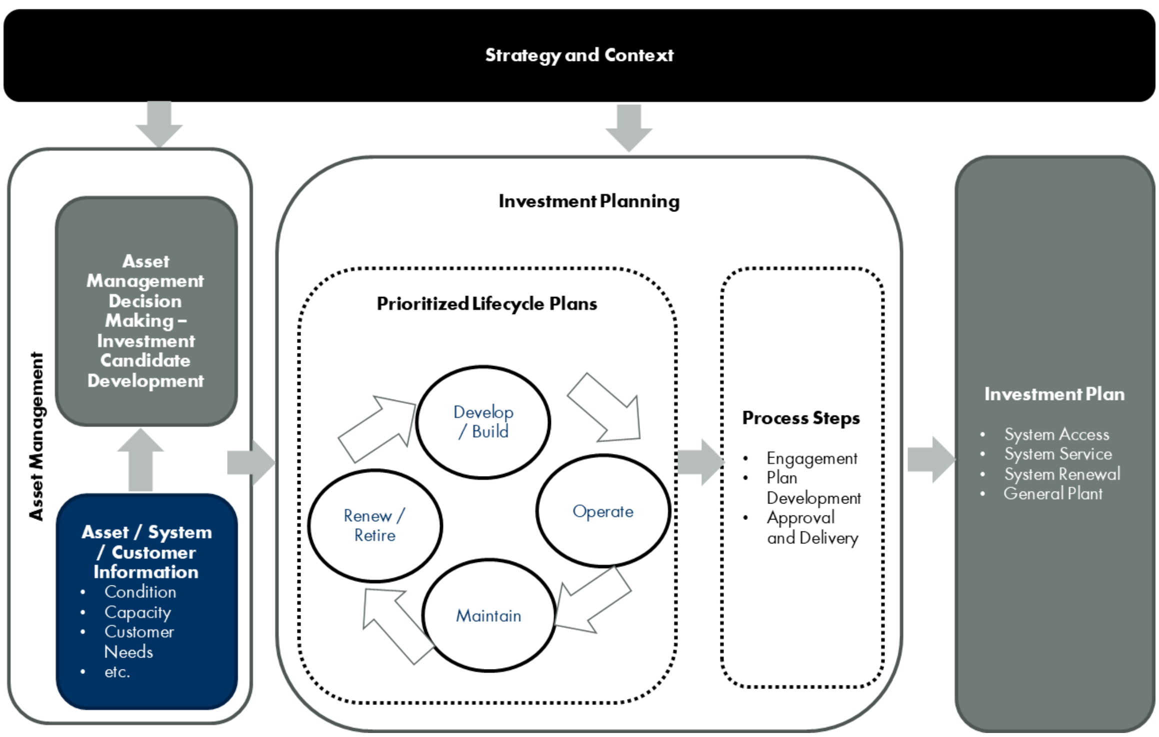

Figure 1: System Planning Process Diagram

4.1.1 STRATEGY AND CONTEXT

Hydro One identifies long-term system needs within the context of asset condition, customer priorities, and system needs and is informed by the Company's Strategic Priorities and the Company's alignment with the OEB's RRF. These factors establish the focus of the investment plan by identifying areas that are valued by the Company's diverse stakeholders, customers and regulators. Hydro One’s Strategic Priorities are presented in Figure 2 below.

Figure 2: Hydro One’s Strategic Priorities and Objectives

In managing assets that are critical to customers and Ontario's economy, Hydro One is committed to meeting the RRF outcomes and has integrated them into its investment planning process. The outcomes of the DSP align with the principles of the RRF with the aim to achieve the following outcomes:

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

As demonstrated through various Investment Summary Documents (ISDs) (provided as attachments to Section 5.5), each investment is developed with explicit consideration for how it will achieve outcomes in alignment with the RRF.

Hydro One's planning context is also influenced by customer needs, preferences and priorities. Hydro One regularly engages with and obtains feedback from its customers through a variety of channels and methods. This allows Hydro One to gain a solid understanding of what different customer segments expect from their electricity provider and where the company can make improvements to its services for customers. As applicable, feedback from these forms of customer engagement is taken into account during the investment planning process.

- ***Large Customer Accounts Management*** **–** The Large Customer Account Management Group provides large distribution-connected customers with a single point of contact at Hydro One. This group communicates with customers on matters including customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. This facilitates a consistent and comprehensive reporting of customer needs and preferences for use by planners, operators and customer service teams.
- ***Customer Satisfaction Research*** – Hydro One regularly collects feedback from all customer segments through a customer satisfaction research program. Hydro One conducts surveys on an ongoing basis to monitor customer needs and preferences, monitor trends, address transactional concerns in a timely fashion, and influence those practices in the future. These surveys monitor how well the company meets customers' expectations and delivers on critical success factors.
- ***Call Centre Trends*** – For residential and small business customers, Hydro One monitors call centre trends and escalates any concerning trends to assure Hydro One's performance is continuously improving and distribution system outcomes are aligned with customer needs and preferences.
- ***External Relations*** – Hydro One's External Relations department maintains relationships with representatives of provincial government, municipality representatives, and key stakeholder groups that represent large customer

segments for Hydro One, such as the Ontario Federation of Agriculture and the Federation of Ontario Cottagers' Associations. This enables Hydro One to stay current with the issues these key stakeholders and their constituents or members may have, and to coordinate assistance on behalf of the Company.

4.1.2 ASSET MANAGEMENT

Hydro One employs a lifecycle management approach which considers and balances asset performance, costs, and associated risks during the asset's service life. By monitoring the current state of its distribution assets and identifying current and future needs, Hydro One develops a set of candidate investments, which are then evaluated and prioritized via the investment planning process.

The investments proposed in this DSP are underpinned by a thorough understanding of the current state of the distribution system, including the evaluation of actual and anticipated asset, customer, and overall system needs, as described below.

4.1.2.1 ASSET NEED ASSESSMENT

Hydro One planners perform an asset needs assessment to identify the drivers in the development of candidate investments and collect the data necessary to assess risks and facilitate the subsequent risk scoring and calibration process. A systematic assessment of asset-specific investment needs is an essential prerequisite of, and critical input into, the investment planning process. The output of the asset needs assessment is a portfolio of investment candidates that reflects asset-related needs and risks, particularly on the basis of asset condition. The investment candidates are further scored and prioritized through the investment planning process to achieve the desired balance of risk and benefits.

The asset needs assessment processes are structured to determine individual asset needs, based on specific asset condition data and other fleet characteristics. This process drives effective planning decisions by ensuring a consistent view of asset information. As part of the preliminary needs assessment, asset condition and other factors are assessed against current and future requirements to identify investment candidates.

Asset condition is the key factor that helps identify asset risks that require further screening and confirmation:

- **Condition** – The degradation of asset condition over time increases the probability of failure, which presents a risk to the system. Asset condition is defined using different criteria for different assets. While methods to evaluate condition vary, the condition of all assets of a given type is evaluated consistently based upon objective criteria. Assets of a given type that are in poor condition are candidates for refurbishment or replacement.

Hydro One considers additional factors including load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to help ensure that capital expenditures target an appropriate mix of assets.

On-site assessments with field personnel are conducted to validate and confirm asset condition, based on site-specific considerations. For high-value assets such as transformers, subject matter experts perform a thorough assessment of asset condition and consider and advise on issues such as equipment obsolescence, manufacturer support, and “repair vs. replace” evaluations. Detailed asset assessment and field review, inspection, and validation are tools that ensure the identified needs actually reflect the condition of the assets in the field.

Many system renewal investments in the System Plans are informed by the asset needs assessment process, largely driven by asset condition. Material planned investments to address asset needs include:

- Section 5.5, D-SR-04 – Distribution Station Refurbishments – to address poor condition station transformers
- Section 5.5, D-SR-07 – Distribution Pole Replacements – to address poor condition wood poles

4.1.2.2 CUSTOMER NEEDS

As noted above in Section 4.1.1, Hydro One regularly engages with customers through various mechanisms. Understanding the needs of customers is critical to Hydro One's business, and investment planning processes. Hydro One's ongoing process mechanisms help the Company quickly and proactively identify customer needs. The needs of new customers are most often identified through direct customer connection requests, needs assessments and customer consultations conducted as part of the Regional Planning process. The needs of existing customers are identified by continuous monitoring of the power system and engagement with large distribution accounts.

Planned System Access investments are largely informed by specific customer needs and requests, including:

- Section 5.5, D-SA-02 – New Load Connections and Upgrades
- Section 5.5, D-SA-03 – Connecting Distributed Energy Resources

4.1.2.3 SYSTEM NEEDS

System needs relate to work that is necessary to maintain and operate the distribution system to adequately and reliably deliver electricity to customers, driven by the requirement to meet current and forecast requirements resulting from the connection of new load customers, generation facilities and other distributed energy resources. These investments consider the thermal and short circuit capacity of system elements, regional planning requirements, restoration of service following disruptions, and reliability studies focused on maintaining- and where appropriate, improving- long-term power quality and reliability.

System needs include:

- provision of adequate capacity to deliver electricity reliably;
- address local area reliability performance, including pockets of distribution customers who may experience poor reliability; and

- local distribution upgrades and enhancements to relieve system capacity constraints and meet forecast load growth, consistent with the requirements of the Distribution System Code (DSC).

System needs assessments result in the identification of system service investments, including:

- Section 5.5, D-SS-03 – Demand Investments
- Section 5.5, D-SS-06 – Power Quality and Stray Voltage

4.1.3 INVESTMENT PLANNING PROCESS

The information and data collected through the asset management process establishes the basis for evaluating and prioritizing investments and establishing the DSP. Through the investment planning process, non-mandatory project candidates are assessed in terms of their total risk mitigation. Through the investment planning process, Hydro One evaluates and prioritizes non-mandatory candidate investments to arrive at the final DSP.

4.1.3.1 INVESTMENT CANDIDATE LIFECYCLE RISK ASSESSMENT

For each non-mandatory project candidate, Hydro One assesses the amount of risk that is expected to be mitigated across three risk taxonomies as applicable - safety, reliability, and environmental.

Each risk taxonomy features clear definitions and a consistent approach to permit a proper assessment of the risk mitigated for each candidate investment. The assessment considers both the probability and consequence of an event materializing, relying on condition information and experience to the extent possible and taking into account the total risk mitigated by each candidate investment through the comparison of the risk profile pre and post investment.

Hydro One also utilizes a "flagging" process to supplement the three risk taxonomies. Flags are used to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. For example, these flags enable the consideration of compliance driven investments, as well as investments that address specific customer priorities.

4.1.3.2 CALIBRATION

Once candidate investments have been risk assessed and flagged, candidate investments are further reviewed among internal investment owners, so as to ensure that the risk assessment and scoring process has been applied consistently.

4.1.3.3 PRIORITIZATION AND OPTIMIZATION

Hydro One tailored its prioritization framework with the specific objectives of efficiency, cost effectiveness, reliability and quality of service. With these specific objectives, a more targeted approach to system investment has been adopted, to balance ongoing service requirements, with targeted renewal and expansion to address high-risk assets.

Through a hybrid approach, the results of the risk assessments are translated into risk scores for non-mandatory project investments, based on total risk mitigation, which are used to generate an initial prioritization. Risk scores for these investments are normalized by estimated investment cost and used to rank these investments. Any risks that are deemed unacceptable are reduced to an acceptable level through the inclusion of the necessary investments into the plan. Once a prioritized list is determined, challenge sessions are held among a broad set of stakeholders to (i) review the integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g. strategic, productivity investments), (iii) assess and debate investments, and (iv) confirm trade-off decisions. As part of these trade-off decisions, investments are promoted or demoted based on the following levers:

- **Risk:** augmenting the prioritization by considering the risk level remaining, any unfunded investments that mitigate significant risk, as well as total/absolute risk exposure to verify that all critical risks are being addressed.
- **Flags**: considering investments that need to be funded due to non-risk merits.

This tailored approach to prioritization has allowed Hydro One to develop a balanced plan that meets the objectives of efficiency, cost effectiveness, reliability and quality of service.

4.1.3.4 ENTERPRISE ENGAGEMENT

Enterprise engagement ensures that the investment plan is properly reviewed and updated by the executing lines of business. This process incorporates operational and execution considerations, including resourcing, material availability, and updated cost estimates, schedules, and scope. This feedback is then incorporated into the investment plan scenarios developed for the planning cycle.

4.1.3.5 INVESTMENT PLAN APPROVAL AND DELIVERY

During this stage of the process, the final investment plan will be reviewed and approved by Hydro One's Board of Directors as part of the 2023-2029 Business Planning Process. As the plan is released to work execution teams for delivery, Hydro One closely monitors the ongoing implementation of the investment plan on a monthly basis. As unforeseen asset, system and customer needs emerge, Hydro One adapts and re-evaluates its investment plan as part of a rigorous re- direction and re-prioritization process.

4.2 OVERVIEW OF SYSTEM AND SERVICE AREAS

4.2.1 SYSTEM AND SERVICE AREA - ORILLIA

The Hydro One area formerly served by Orillia Power Distribution Corporation (OPDC) (herein referred to as “Orillia”) serves 14,625 residential and commercial customers by utilizing 241 distribution circuit kilometers in the City of Orillia. In addition to end-use customers, Orillia also has successfully integrated approximately 23.8 MW of distributed energy resources (DER) into the distribution system and continues to support new customer requests within the current regulatory framework.

The key statistics for distribution assets owned and operated by Hydro One are summarized in Table 1 below.

Table 1 - Orillia Distribution System Assets – Key Statistics

System Assets	Total
Number of Customers	14,625
Distribution Poles (Total Number)	4,265
Length of Overhead Distribution Lines (Total Circuit km)	167
Length of Underground Distribution Cables (Total Circuit km)	74
Distribution Stations	9
Distribution Line Transformers	1,650

The distribution service area for Orillia is shown in Figure 3.

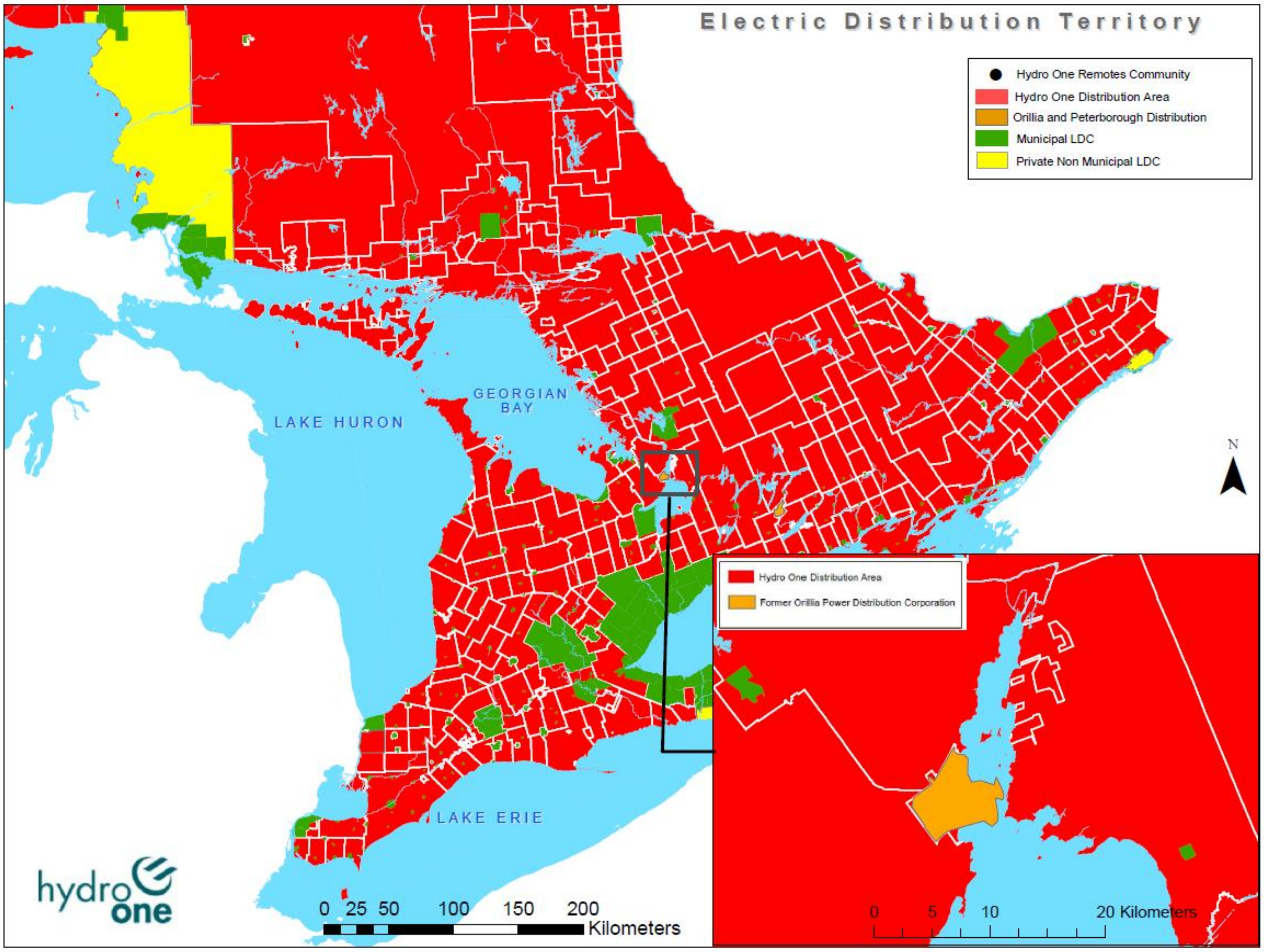

Figure 3: Map of Hydro One's Orillia Service Territory

Orillia is an urban service area, with both radial and looped distribution feeder sections. It is a partially embedded distributor, with the following supply connections to the Hydro One Networks' Transmission and Distribution systems:

Table 2 - Orillia Connection Points by Station and Feeder

Station	Feeder
Orillia TS	M8
Orillia TS	M5
Orillia TS	M4
Orillia TS	M1

Orillia is not a host distributor to any local distribution companies (LDCs).

Orillia does not have any transmission or high voltage assets. In addition, Hydro One confirms that Orillia does not have any transmission or high voltage assets previously deemed as distribution assets by the OEB.

4.2.2 SYSTEM AND SERVICE AREA - PETERBOROUGH

The Hydro One area formerly served by Peterborough Distribution Inc. (PDI) (herein referred to as "Peterborough") serves about 37,547 mostly residential and commercial electricity customers by utilizing approximately 545 distribution circuit kilometers in the City of Peterborough, the Town of Norwood, and the Village of Lakefield. In addition to end-use customers, Peterborough also has successfully integrated approximately 39.2 MW of DER into the distribution system and continues to support new customer requests within current regulatory frameworks.

The key statistics for distribution assets owned and operated by Hydro One are summarized in Table 3 below.

Table 3 - Peterborough Distribution System Assets – Key Statistics

System Assets	Total
Number of Customers (including acquired utilities)	37,547
Distribution Poles (Total Number)	8,639
Length of Overhead Distribution Lines (Total Circuit km)	367
Length of Underground Distribution Cables (Total Circuit km)	178
Distribution Stations (including Recloser/Breaker Stations)	20
Distribution Line Transformers	3,979

The distribution service area for Peterborough is shown in Figure 4.

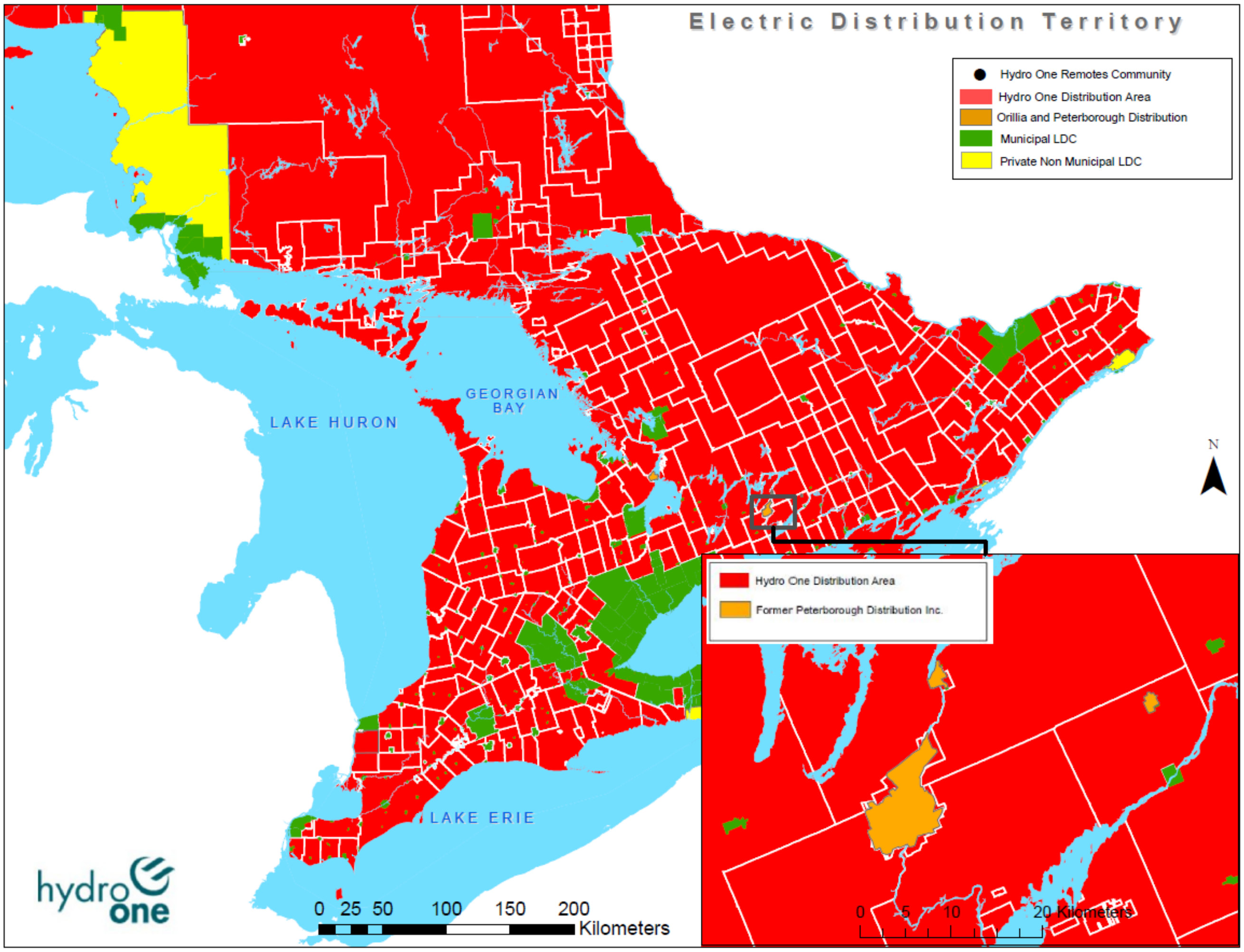

Figure 4: Map of Hydro One Peterborough's Service Territory

Peterborough is an urban service area, with both radial and looped distribution feeder sections. It is a partially embedded distributor, with the following supply connections to the Hydro One Networks' Transmission and Distribution systems:

Table 4 - Peterborough Connection Points by Station and Feeder

Station	Feeder
Dobbin TS	M3
Dobbin TS	M4
Dobbin TS	M6
Dobbin TS	M7
Dobbin TS	M8
Otonabee TS	M8
Otonabee TS	M9
Otonabee TS	M10
Otonabee TS	M11
Otonabee TS	M12
Otonabee TS	M25
Otonabee TS	M26
Otonabee TS	M27
Otonabee TS	M28
Dobbin DS	F1
Dobbin DS	F2
Burnham DS	F1
Burnham DS	F2
Norwood DS	F1
Norwood DS	F2
Norwood DS	F3

Peterborough is not a host distributor to any LDCs.

Peterborough does not have any transmission or high voltage assets. In addition, Hydro One confirms that Peterborough does not have any transmission or high voltage assets previously deemed as distribution assets by the OEB.

4.3 OVERVIEW OF ASSETS MANAGED AND ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

This section provides asset information and the asset lifecycle strategy for the major asset types that comprise the distribution systems for Orillia and Peterborough.

This section presents information related to the major distribution station and line components that comprise Hydro One's distribution system in Orillia and Peterborough. Information relating to these distribution components includes a description and purpose of the component; demographic and condition information; and lifecycle strategy, including approaches to maintenance and replacement.

Hydro One operates and maintains power system assets associated with 9 distribution stations in Orillia and 20 distribution stations (including recloser/breaker stations) in Peterborough, which are critical to the reliable transformation and delivery of power received from the transmission system to distribution customers. Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm and residential customers. Distribution station components presented in this section include station transformers (4.3.1), station reclosers and breakers (4.3.2), station switches and fuses (4.3.3) and other station assets (4.3.4).

Hydro One operates and maintains power system assets associated with 241 circuit kilometres of distribution lines in Orillia and 545 circuit kilometres of distribution lines in Peterborough, which are critical to the reliable delivery of power to distribution customers. Distribution line components presented in this section include poles (4.3.5), and line transformers (4.3.6).

Finally, this section also includes information regarding wholesale revenue and retail meters (4.3.7).

Asset Condition

Condition-based renewal is the cornerstone of Hydro One's asset management and investment planning process as discussed above in Section 4.1. Condition degradation leads to elevated risk of failure. If left unmitigated, such risk can materialize in failures of critical distribution system assets and result in adverse impacts on system operations or performance. Where the potential failure of poor condition assets may lead to significant reliability, safety and/or environmental impacts, Hydro One plans to mitigate the risk on a planned basis.

Condition assessments account for a range of considerations, including diagnostic testing results and visual inspections that gauge the deterioration of relevant components. Where condition assessment is not feasible given the nature of a particular asset (e.g. electronic components of meters), assessments are based on factors such as years in service, known performance issues, availability of spares and vendor support, and/or obsolescence.

While expected service life (ESL) is a useful population-level indicator of asset demographics, it is not a driver for replacement. Similarly, as a lagging indicator of asset condition, reliability performance cannot replace condition as the primary basis for renewal investments. The condition of the assets across Distribution lines and stations determines the replacement. Leaving poor condition assets unaddressed will lead to elevated risks for reliability (e.g. failed components resulting in unplanned customer outages), safety (e.g. failure of overhead buses in metalclad buildings), and the environment (e.g. transformer oil leaks). In addition, unplanned equipment outages may impact Hydro One's ability to proceed with planned outages, potentially resulting in the cancellation or rescheduling of required maintenance work. This can delay preventative and corrective maintenance work and increase the risk of equipment failure that further compounds the aforementioned risks.

Asset Demographics

Hydro One operates and maintains power system assets associated with 9 distribution stations in Orillia and 20 distribution stations (including recloser/breaker stations) in Peterborough, and 241 circuit kilometres of distribution lines in Orillia and 545 circuit kilometres of distribution lines in Peterborough. ESL enables a view of asset demographics based on the average number of years that an asset is expected to operate under normal system conditions and is determined with reference to manufacturer guidelines and historical asset retirement data. The longer an asset has been in service, the more cumulative wear and tear accrues from its ongoing utilization and environmental exposure, and thus these assets tend to exhibit greater condition deterioration compared to younger assets.

ESL does not drive replacement decisions. However, it can provide useful information at the fleet level for gauging overall asset demographics. ESL sheds light on the directional magnitude of possible replacement needs (but never to underpin the actual replacements) over the longer term.

In limited cases where the nature of the particular assets (e.g. electronic metering devices) means that actual condition cannot be tested, ESL is an important input for the appropriate lifecycle management strategy in alignment with industry practices.

Details regarding condition and age for other Distribution Stations and Distribution Lines assets are provided in the sections that follow.

Asset Lifecycle

Hydro One's approach to lifecycle management maximizes benefits to Hydro One and its customers during the asset's service life, while balancing asset performance, condition, and risks to Hydro One's business objectives.

Hydro One manages distribution assets through planned and demand maintenance programs and capital investments. Hydro One's inspection practices and frequencies for distribution assets are established to ensure their safe and reliable operations and to satisfy the Minimum Inspection Requirements under the DSC.

Through inspections, the condition of distribution assets is monitored. Deficiencies that are identified are prioritized and addressed through corrective maintenance or capital replacement investments. The frequencies and prioritization for removing station assets from service for maintenance are based on input such as asset condition data (obtained through inspections and diagnostic testing), maintenance records, manufacturer recommendations, replacement plans, bundling opportunities, and funding constraints. For identified capital replacement candidates, asset risk drives the replacement prioritization.

4.3.1 STATION TRANSFORMERS

4.3.1.1 ASSET DESCRIPTION / PURPOSE

Station transformers in Peterborough and Orillia convert 44 kV supply voltages to lower distribution voltages; 4.16 kV or 27.6 kV in Peterborough, and 4.16 kV or 13.8 kV in Orillia. An example of a 7.5/10 MVA, 44-13.8 kV station transformer is provided below in Figure 5.

Figure 5: 7.5/10 MVA, 44-13.8 kV Station Transformer at Orillia James DS

4.3.1.2 ASSET DEMOGRAPHICS

In Orillia, Hydro One owns and operates 11 distribution station transformers, as categorized in Table 5 below by primary and secondary voltage level.

Table 5 - Orillia Transformer Count by Voltage Level

Primary Voltage Level	Secondary Voltage Level	Number of Transformers
44 kV	13.8 kV	7
44 kV	4.16 kV	4

The current average age of Hydro One's distribution station transformer fleet in Orillia is 28 years (Figure 6). Currently, 9% of the fleet are beyond their ESL of 50 years, and an additional 27% (if no capital replacements are undertaken) will reach or exceed their ESL by 2027, which would bring the total to 36%.

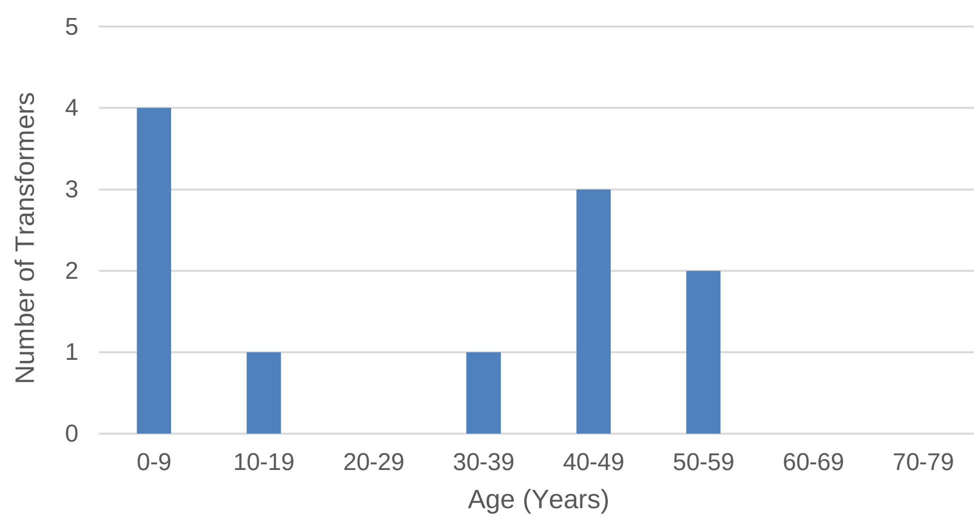

Figure 6: Demographics of the Orillia Distribution Station Transformers

In Peterborough, Hydro One owns and operates 23 distribution station transformers, as categorized in Table 6 below by primary and secondary voltage level.

Table 6 - Peterborough Transformer Count by Voltage Level

Primary Voltage Level	Secondary Voltage Level	Number of Transformers
44 kV	4.16 kV	22
44 kV	27.6 kV	1

The current average age of Hydro One's distribution station transformer fleet in Peterborough is 57 years (Figure 7). Currently, 78% of the fleet are beyond their ESL of 50 years, and an additional 13% (if no capital replacements are undertaken) will reach or exceed their ESL by 2027, which would bring the total to 91%.

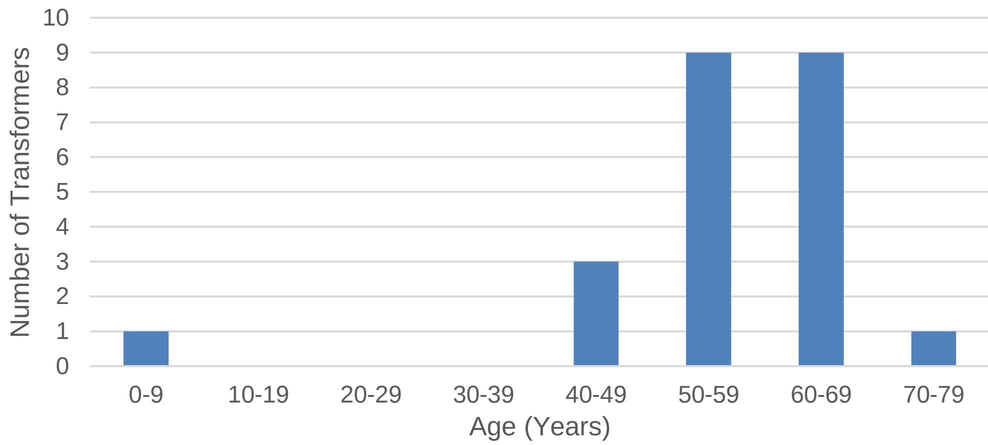

Figure 7: Demographics of the Peterborough Distribution Station Transformers

4.3.1.3 ASSET CONDITION

In Orillia there are currently no distribution station transformers in the poor condition category (Figure 8).

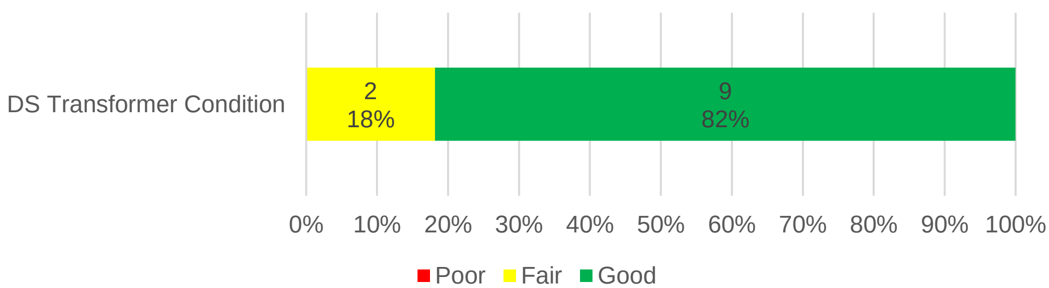

Figure 8: Orillia Distribution Station Transformer Condition

In Peterborough approximately 52% (12) of Hydro One's distribution station transformers fall into the poor condition category (Figure 9). These units are at a higher risk of failure compared to the overall transformer population and are considered for replacement or corrective repair in order to address significant deterioration or deficiencies before failures occur and impact service to distribution customers.

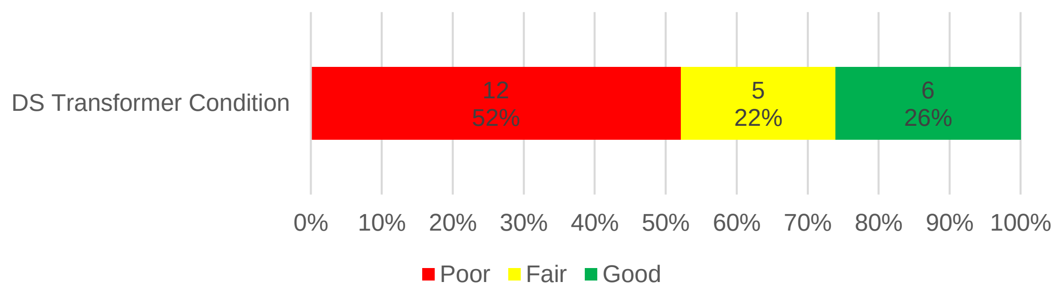

Figure 9: Peterborough Distribution Station Transformer Condition

Many factors lead to the degradation of a transformer's internal components over time, including: transformer loading, switching, lightning surges, moisture contamination, and paper insulation degradation. The internal components degrade over time and the resulting asset condition is one of the leading predictive indicators of transformer failure.

Hydro One assesses a distribution transformer's condition based on transformer oil test results (obtained via industry standard diagnostic testing), visual inspections, thermographic inspections, internal inspections and diagnostic testing. Annual oil sample test results are obtained for all transformer main tanks. Visual inspections identify aspects of transformer condition such as oil leaks. Thermographic inspections identify transformer components that are overheating. Internal inspections and diagnostic testing can identify the source of the poor transformer condition that was identified through oil sampling.

Testing and inspection results indicating poor condition identify transformers that are expected to fail. Corrective repair or planned replacement of these transformers before they fail is crucial to avoid reactive measures upon failure and associated lengthy customer interruptions.

4.3.1.4 LIFECYCLE STRATEGY

Hydro One aims to mitigate the risk of distribution station failures through predictive testing, condition based corrective maintenance or planned replacement of transformers to avoid asset failure and lengthy customer interruptions.

Transformers identified as in fair condition are typically addressed through corrective maintenance activities, and monitoring of the transformer condition to help prevent further degradation.

Transformers identified as in poor condition are considered for replacement or corrective maintenance. The factors that inform whether a poor-condition transformer is proposed for replacement or corrective maintenance include the age of the unit and the extent of corrective maintenance required.

Inspection and Maintenance Practices

<u>Preventive Maintenance</u>

To effectively maintain its distribution transformer population, Hydro One utilizes several types of maintenance activities (each with associated tasks and frequency of completion). Transformer deficiencies observed through the following testing and inspection methods can lead to either corrective maintenance activities or transformer replacement depending on the findings and condition:

- *Station Visual Inspection* – Station transformers and regulators are visually inspected on a six-month cycle for rural stations and monthly for urban stations.
- *Thermographic Inspection* – Each station undergoes a thermographic inspection of all power equipment every two years to identify hot spots in station electrical components.
- *General Oil Test* – Annually, an oil sample is taken from the transformer main tank and sent to a third-party lab for analysis to obtain industry-standard diagnostic test results including Dissolved Gas Analysis, Moisture Content and Furan Analysis.
- *Transformer Diagnostic Test* – Following an unsatisfactory oil sample result, the main tank of the transformer may receive diagnostic testing and internal inspection. This maintenance activity includes but is not limited to inspection of current

carrying parts, insulation resistance tests, turns ratio and phase angle tests, core loss test, winding resistance test, repair of minor or moderate oil leaks, and oil level check and top-up.

Corrective Maintenance

Based on the findings of cyclical inspections, transformer maintenance is prioritized based on observed condition and includes the following three categories:

- Transformer condition based maintenance following high risk oil sample results for transformer main tanks;
- Maintenance on leaking transformers to mitigate the leaks; and
- Maintenance on transformers with unsatisfactory polychlorinated biphenyl (PCB) content to reduce PCB content in oil filled compartments to meet Environment Canada requirements.[1]

Replacement and Refurbishment

Fair condition transformers are candidates for corrective repair or monitoring. Fair condition transformers experience elevated dissolved gas analysis results, moisture content in oil, insulation paper degradation and oil leaks, just as poor condition transformers but not as severe.

Once it is known that a transformer is in poor condition, the transformer is considered for repair or replacement. Younger transformers in poor condition are typically candidates for corrective repair. Performing corrective repairs on younger transformers normally allows them to reach their 50-year ESL.

Poor condition transformers approaching or beyond their 50-year ESL tend to be candidates for replacement as opposed to corrective repair. This is because correctively repairing an older transformer may only slightly extend its service life, which would not be economical as more components are expected to fail and need to be further addressed.

[1] PCBs were used as an additive to transformer oil up until the late 1970’s.

The repair versus replacement decision is driven by factors such as condition, age, and the cost of corrective work.

For identified transformer replacement candidates, the risk scoring approach described above in Section 4.1.3.3 drives the replacement prioritization. Transformers in poor condition that have a lower priority may be considered for repair as opposed to replacement, if possible and economical. Factors that feed into the prioritization include transformer condition, downstream customer counts, and environmental impact (e.g. major oil leaks that are costly to repair).

Poor condition transformers that have been prioritized for capital intervention are addressed through the following alternatives:

- Planned transformer replacements,
- Station rebuilds,
- Station replacements with non-fenced pad-mount solutions (load permitting), or
- Voltage conversion projects involving the elimination of the station and the transformer.

The effective long-term management of poor condition transformers as observed in Peterborough requires sustained capital investment to replace transformers on a planned basis and address poor condition transformers before their elevated failure risk materializes. A sustained program targeting a high number of poor condition transformers in Peterborough is required to maintain the number of transformer failures at a manageable level.

4.3.2 BREAKERS AND RECLOSERS

4.3.2.1 ASSET DESCRIPTION / PURPOSEASSET DESCRIPTION / PURPOSE

<u>Breakers</u>

Hydro One currently manages 29 and 84 distribution station circuit breakers in Orillia and Peterborough, respectively (see example depicted in Figure 10 below). Breakers are used to remove assets from service under fault conditions. However, they cannot rapidly open and reclose to clear system faults.

Figure 10: Metalclad Breaker at Peterborough Erskine DS

<u>Reclosers</u>

Hydro One currently manages 7 and 5 three-phase equivalent distribution station reclosers in Orillia and Peterborough, respectively. Reclosers are used to remove assets from service under fault conditions. Reclosers can rapidly open and reclose to clear system faults, restoring service to customers when faults are temporary or transient in nature.

4.3.2.2 ASSET DEMOGRAPHICS

<u>Breakers</u>

Hydro One has 1 type of breaker on its distribution system in Orillia and 3 types of breakers on its distribution system in Peterborough. The number of devices for each type is shown in Table 7.

Table 7 - Peterborough and Orillia DS Breakers by Type

Type	Orillia Number of Breakers	Peterborough Number of Breakers
Metalclad	29	73
Oil	0	10
Air Blast	0	1

Most of the metalclad breakers in Orillia and Peterborough are obsolete and replacement parts may not be available. These breakers are no longer supported by the manufacturer. As such, if one breaker in a bank of metalclad breakers fails and is not repairable, the entire bank of metalclad breakers may need to be replaced. In addition, some of the metalclad breakers were designed to be installed in small buildings, which do not meet Hydro One's current clearance requirements. Hydro One mitigates this risk with safe work practices, removing the breaker from service before the execution of work.

<u>Reclosers</u>

There are two types of reclosers within Peterborough distribution stations. They are either oil interrupter hydraulic controlled reclosers, or vacuum interrupter electronic controlled reclosers. All reclosers in Orillia distribution stations are vacuum interrupter electronic controlled reclosers. The number of devices for each type is shown in Table 8.

Table 8 - Orillia and Peterborough DS Reclosers by Type

Type	Orillia Number of Feeders	Peterborough Number of Feeders
Oil interrupter and hydraulic controlled	0	3
Vacuum interrupter and electronic controlled	7	2

Oil reclosers use oil to act as an arc extinguishing agent during interruption and to insulate recloser contacts from each other after the arc has been extinguished. Hydro One no longer purchases oil interrupter reclosers because they require more frequent maintenance compared to vacuum interrupter reclosers.

Vacuum reclosers have interrupters that use magnetic fields to aid in extinguishing the arc. The arc is moved around the surfaces of the recloser contacts, which minimizes contact erosion and formation of hot spots. Vacuum interrupter technology requires less maintenance and has higher reliability over other arc quenching media such as oil.

All reclosers Hydro One purchases today are vacuum interrupter reclosers and are either hydraulic or electronic controlled, depending on system needs. Hydraulic reclosers use hydraulic control to sense overcurrent and provide timed tripping, reclosing functions and lockout. Electronic reclosers are controlled by a programmable digital protective relay, also known as an IED, and provide additional functionality such as remote operation.

4.3.2.3 ASSET CONDITION

Breakers

The condition of station breakers is primarily driven by deficiencies that can affect their ability to open when required to clear system faults or impact their ability to close when required to restore power. Breakers have many electromechanical components which must be regularly inspected and maintained to ensure the correct operation of the breaker. Breaker operating mechanisms can become damaged if they are not kept lubricated. Breaker contactors will wear based on the number of operations and the amount of fault current interrupted. Coils and contactors must be regularly inspected and lubricated to monitor wear and ensure they are functioning properly. The wear of other breaker components such as motor commutators and brushes, relays, auxiliary switches must be inspected and monitored.

Hydro One currently does not have condition data for the Peterborough and Orillia breaker population. This data will be obtained as breakers are removed from service and undergo preventive maintenance as outlined in Section 4.3.2.4.

Reclosers

The condition of reclosers is primarily driven by the condition of the recloser contacts which provide for arc extinction. Contact wear is driven by the number of operations as well as the interrupter type. Recloser contacts in oil interrupters wear nearly four times as quickly as contacts in vacuum interrupters. Defects such as hot spots identified through thermographic inspections, damaged bushings, damaged connectors, rusted tanks or oil leaks identified through visual inspections also factor into recloser condition.

The small recloser populations in the Peterborough and Orillia service areas are in good condition.

4.3.2.4 LIFECYCLE STRATEGY

Inspection and Maintenance Practices

Breakers

Hydro One's strategy for the station breaker population is to continue to maintain the fleet (through preventative maintenance every six years) and continue to keep them in-service until they are replaced or removed through a capital project. The breakers are maintained on a time-cycle in order to inspect, lubricate, test operate or replace the electrical and mechanical components as needed to ensure reliable operation.

To monitor their condition and perform maintenance, breakers must be removed from service and inspected. When these breakers are removed from service for maintenance, they undergo:

- *Diagnostic Test* – The breaker is function tested, manually operated, and undergoes cleaning and lubrication of operating mechanisms; and
- *Selective Intrusive (SI) Inspection* – Inspection of all internal components, insulation condition, contacts and rack-in mechanisms where applicable.

Reclosers

Consistent with the recommendations of recloser manufacturers, a primary factor that drives Hydro One's maintenance of these assets is the number of operations that they undergo (in addition to identified visual defects and failure to operate when required).

Distribution stations are inspected in the spring and fall, at which time the station reclosers are visually inspected for any visible defects. The recloser counter operations are checked and recorded to ensure they have not exceeded the manufacturer recommended number of operations since they were last inspected. Stations also receive infrared thermography scan every two years to identify any overheating power equipment (including reclosers), which may indicate a high probability of failure. Reclosers found to be overheating are removed for assessment and are replaced with a spare from inventory.

When the Type W oil interrupter hydraulic controlled reclosers in Peterborough require maintenance, they will be replaced with refurbished recloser models of the same type that are stored in inventory. They are maintained (i.e. removed for refurbishment) based on visual inspection results and when the manufacturer recommended counter operations have been reached.

Vacuum interrupter electronic controlled reclosers in Peterborough and Orillia are visually inspected for deficiencies and controller batteries are replaced on a time cycle. These reclosers are installed under capital projects when remote tripping capability or short circuit interruption capability above 6 kilo-amps is required.

Reclosers are also replaced with higher rated reclosers when fault levels in the system have exceeded the interruption capabilities of the recloser.

Replacement and Refurbishment

Refurbishment – Breakers

When breakers are removed from service for inspection and maintenance, any defects identified will be addressed prior to returning the breakers to service. If station breakers fail to operate, they will be repaired if replacement parts can be obtained.

Refurbishment – Reclosers

Oil interrupter hydraulic reclosers in Peterborough stations receive maintenance based on their condition, performance and when counter readings have exceeded the manufacturer recommended number of operations. Hydraulic reclosers are physically removed from the station and sent to a maintenance shop. At this time, recloser contacts, oil and other components are replaced based on their condition. The removed hydraulic reclosers are replaced like-for-like with already overhauled reclosers.

Vacuum interrupter electronic controlled reclosers are inspected for visual defects. Electronic recloser controllers have back-up batteries which require regular battery replacement. These batteries are scheduled for replacement every five years as recommended by manufacturers.

Replacement – Breakers and Reclosers

During planned station refurbishment or transformer replacement projects, breakers which are obsolete or non-arc resistant will be considered for replacement with vacuum interrupter electronically controlled reclosers. Hydraulic reclosers – while less expensive – are not suitable replacement candidates because they normally cannot interrupt the higher short circuit levels present at these stations. Reclosers offer improved reliability compared to breakers because reclosers can often clear faults by rapid open and close sequences prior to locking out.

Station refurbishment investments are primarily driven by high risk transformers in need of replacement. Hydro One does not have a proactive strategy to replace breakers, other than those bundled with transformer replacements under station refurbishment investments.

4.3.3 SWITCHES AND FUSES

4.3.3.1 ASSET DESCRIPTION / PURPOSE

Station switches enable the isolation of equipment such as transformers or breakers for the purpose of carrying out maintenance work. Station fuses provide a means to protect transformers in stations when a fault occurs. An example of a switch and fuse combination is provided below in Figure 11.

Figure 11: Orillia Jarvis DS Switch and Fuse Combination

4.3.3.2 ASSET DEMOGRAPHICS

In Orillia, Hydro One currently manages 36 three-phase switches and 33 three-phase fuses installed at distribution stations. The number of switches and fuses are shown in Table 9 by primary voltage level:

Table 9 - Orillia DS Switches and Fuses by Voltage

Primary Voltage Level	Number of Switches	Number of Fuses
44 kV	12	11
< 27.6 kV	24	22

In Peterborough, Hydro One currently manages 101 three-phase switches and 17 three-phase fuses installed at distribution stations. The number of switches and fuses are shown in Table 10 by primary voltage level:

Table 10 - Peterborough DS Switches and Fuses by Voltage

Primary Voltage Level	Number of Switches	Number of Fuses
44 kV	25	13
< 27.6 kV	76	4

4.3.3.3 ASSET CONDITION

The condition of switch and fuse assets is determined during regular station maintenance program activities. A visual inspection of switch and fuse assets is completed twice a year to note any defects. Defects are also observed during planned station outages for transformer or breaker maintenance work. During these outages, switches are manually test operated and fuses undergo an airflow test.

Some of the main failure modes of switches include seized bearings, misalignment of the blade and jaw and failure of porcelain insulators. These failure modes can render the switches inoperable and can leave the switches stuck in an open or closed position. This can lead to unplanned interruptions or prolonged interruptions to repair the switches and enable the system to be returned to normal operation. Currently, no defects have been observed for switches based on visual inspections in the Orillia and Peterborough service territories.

The most common defects observed for fuses include peeling of the outer coating, failed airflow testing, water ingress, broken fuse holders or broken support insulators. Eight defects have been identified for fuses in Orillia based on visual inspections, and no defects have been identified for fuses in Peterborough.

4.3.3.4 LIFECYCLE STRATEGY

Inspection and Maintenance Practices

Hydro One visually inspects switches during routine station inspections, and manually test operates them during planned station outages for transformer or breaker maintenance work. Normally defects are discovered when the switch must be operated. Deficiencies that have been identified are normally addressed during planned station outages for transformer or breaker maintenance. Station switches that have been found to be defective and cannot be repaired are planned for replacement.

Hydro One visually inspects fuses during routine station inspections and performs an airflow test on them during planned station outages for transformer or breaker maintenance work. Fuses that have been found to be defective through visual inspection or airflow test are replaced during planned station outages for transformer or breaker maintenance.

Replacement

Station switches that have been found to be defective and cannot be repaired are planned for replacement. Normally these defects are discovered when the switch must be operated.

Station fuses that are found to be defective upon inspection or through testing are replaced with new fuses. Transformer or recloser replacements may also trigger the need to replace fuses with those of different continuous current rating and interrupting speed in order to allow for proper protection coordination.

4.3.4 OTHER STATION ASSETS

4.3.4.1 ASSET DESCRIPTION / PURPOSE

In addition to the above-noted station assets, Hydro One distribution station assets in Peterborough and Orillia also encompass buildings, fences and gates, grounding systems, station service transformers, instrument transformers, insulators and bus. Stations equipped with breakers or vacuum electronic reclosers also have protection relays or intelligent electronic devices (IEDs).

- *Buildings* can house distribution station electrical components. In Orillia and Peterborough, typically LV metalclad breakers, relays and station service equipment are contained in buildings. In Peterborough, the power transformers, HV switches and fuses may also be contained in buildings.
- *Fences* separate live station equipment from the public to maintain public safety, while gates are used as an entry point for Hydro One maintenance vehicles, construction vehicles and staff. Most station fences are chain link, though some are wooden.
- *Grounding Systems* are used in stations to safely dissipate fault currents into the ground in the event of equipment failure, to protect Hydro One employees and the public.
- *Station Service Transformers* are used to transform distribution system voltages to 120 V to supply station equipment such as IEDs and receptacles.
- Instrument transformers such as potential transformers and current transformers are used to measure voltage and current for metering or for equipment operation.
- *Insulators* provide electrical insulation between live equipment and grounded station structures. They are also used to mount the power equipment to the station structures.
- *Bus* work in stations is used to electrically connect the power equipment within the station.
- *Protection Relays* in stations are used to trip feeder breakers in the event of a system fault.
- IEDs are used to control electronic vacuum reclosers, directing the reclosers when to open and close during system faults.

4.3.4.2 ASSET DEMOGRAPHICS

The approximate count of these other station components are shown in Table 11 below:

Table 11 - Other Orillia and Peterborough Distribution Station Components

Station Component	Orillia DS units	Peterborough DS units
Buildings	1	10
Fences	9	12
Station Grounding Systems	9	20
Station Service Transformers and Instrument Transformers	52	84
Insulators	unknown	unknown
Bus Work	9	20
Protection Relays	21	64
IEDs	16	14

4.3.4.3 ASSET CONDITION

No defects have been observed for these other station components in the Orillia and Peterborough service areas based on visual and thermography inspections.

4.3.4.4 LIFECYCLE STRATEGY

Inspection and Maintenance Practices

These additional station assets are generally inspected for defects during routine station visual inspections. The live electrical components will also undergo a thermography inspection. If any defects are identified, they are addressed as corrective maintenance work where practical.

Replacement and Refurbishment

Following routine inspections of these station components, any components that are defective and cannot be repaired will be planned for replacement through planned and demand component replacement programs or bundled with station refurbishment projects.

4.3.5 POLES

4.3.5.1 ASSET DESCRIPTION / PURPOSE

The structural integrity of a distribution line is largely dependent on the poles that support the line. These poles keep the electrical equipment a safe distance from the ground and other objects. Hydro One owns, maintains and operates 4,265 poles in Orillia, of which 98% are wood poles and 8,639 poles in Peterborough, of which 96% are wood poles. The remaining, non-wood poles are steel, composite, or concrete. In addition, Hydro One maintains and operates overhead lines that are supported by 66 poles in Orillia and 417 poles in Peterborough owned by joint use partners.

Wood is currently the most cost-effective material for the majority of pole applications. In some situations, a composite pole may need to be used, however these poles are more expensive than wood for all sizes on the distribution system.[2] Based on the Company's overhead distribution standards, Hydro One's distribution engineering technicians select the appropriate size and class of pole and framing components based on the span lengths, conductor sizing, equipment sizing, and loading angles.

Wood deteriorates over time as it is exposed to the environment. Ground line rot is the most common natural aging failure mode for wood poles. Mechanical damage (from cars, snowplows, etc.) as well as animal damage including woodpecker and insects will also shorten the life of a pole.

To mitigate natural deterioration over time, poles are initially treated with Chromated Copper Arsenate (CCA) in advance of installation. This chemical fixes within the pole to prevent rot from developing over time. Figure 12 shows a cross section of a treated pole. The green colored section is the CCA-treated soft wood shell of the pole. The central lighter colored section is the untreated heartwood.

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[2] Pursuant to Hydro One's Overhead Distribution Standards, composite poles are utilized in areas prone to woodpecker or insect damage and low lying areas that may be prone to water damage.

Figure 12: Treated Wood Pole Cross Section

4.3.5.2 ASSET DEMOGRAPHICS

Figure 13 shows the current demographics of the Hydro One pole population within the Orillia area. The average age of poles is 33.7 years. There are currently 409 poles (10%) that are 60 years of age or older.

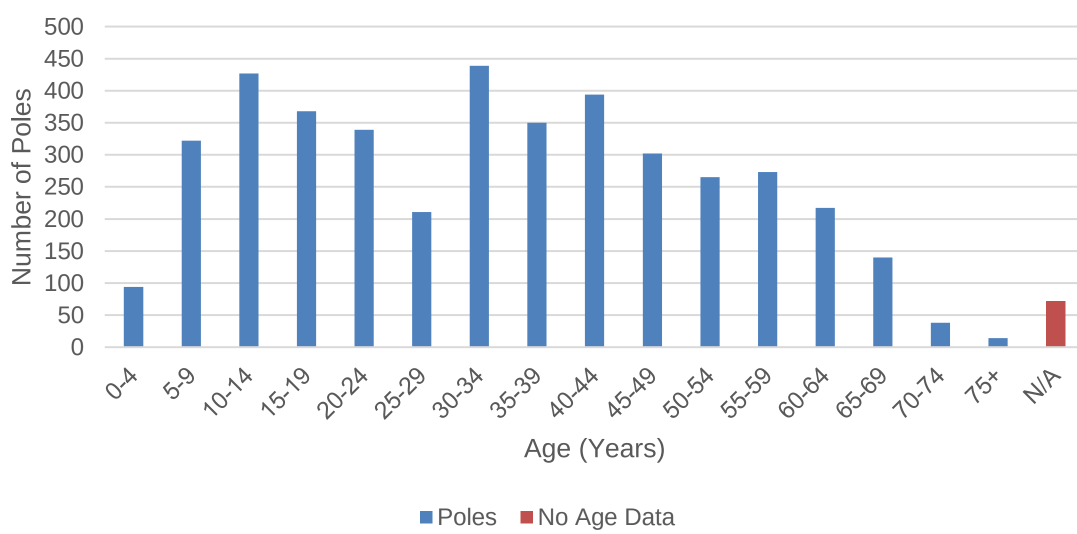

Figure 13: Demographics of Hydro One Owned Distribution Poles in Orillia

Figure 14 shows the current demographics of the Hydro One pole population within the Peterborough area. The average age of poles is 34.3 years. There are currently 843 poles (10%) that are 60 years of age or older.

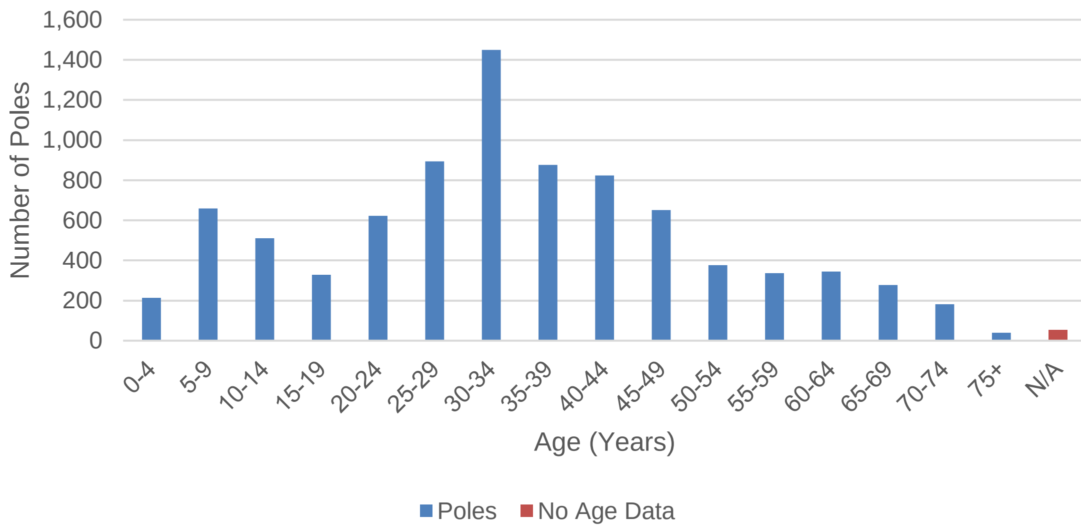

Figure 14: Demographics of Hydro One Owned Distribution Poles in Peterborough

4.3.5.3 ASSET CONDITION

Pole condition is assessed as part of regular inspections (performed as part of vegetation management inspections) and the wood pole test and treat programs. Poles that have failed a test or have severe visual damage are considered to be in poor condition and require either refurbishment or replacement. Figure 15, Figure 16, and Figure 17 are examples of pole defects that require remedial action.

Figure 15: Woodpecker Damage

Figure 16: Ground Line Surface Rot

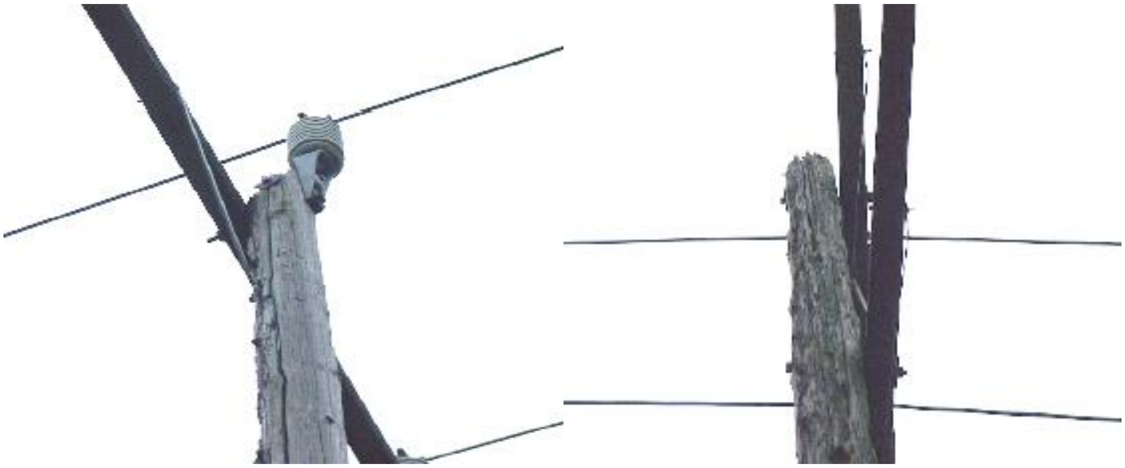

Figure 17: Pole Top Damage

Figure 18 and Figure 19 show the breakdown of the condition ratings of Hydro One distribution poles in Orillia and Peterborough, respectively, as determined based on observed defects or testing results. There are 112 poles in Orillia and 307 poles in Peterborough that are in poor condition and require replacement or refurbishment. The remainder of the poles are in good or fair condition. Poles in these two categories are not proactively planned for replacement or refurbishment.

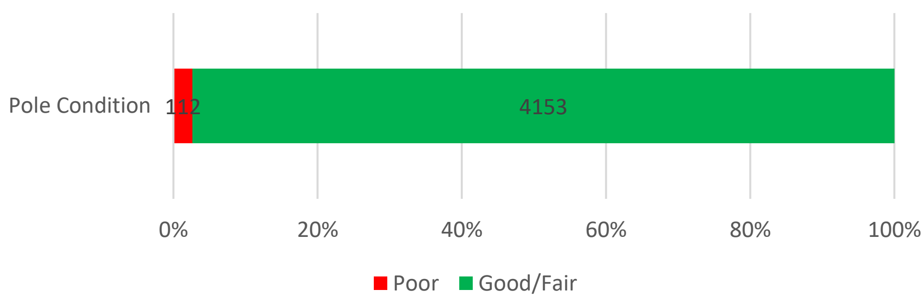

Figure 18: Orillia Pole Condition

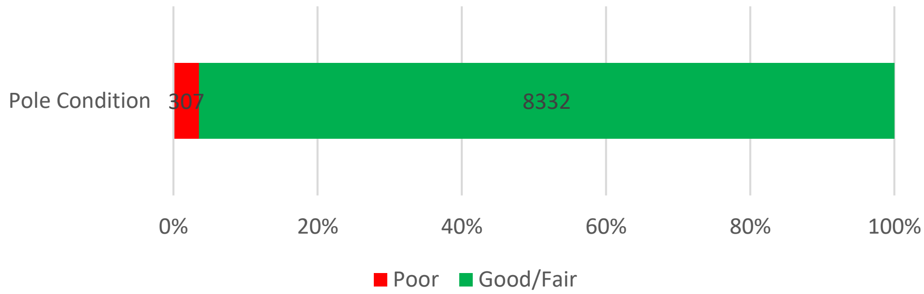

Figure 19: Peterborough Pole Condition

4.3.5.4 LIFECYLE STRATEGY

Inspection and Maintenance Practices

Poles are required to be inspected every six years for rural areas and three years for urban areas as specified in the DSC, Appendix C. In 2019, the inspection program was combined with the forestry planning process. These inspections are primarily intended to identify visual deficiencies on the pole, including woodpecker holes, mechanical surface damage, surface rot, severe leaning, or even broken poles. Other defects identified on the lines are also recorded during the inspections, including damaged cross arms, insulator defects, and missing guys.

Hydro One collects additional condition data as part of its pole test and treat program. This program will test and treat 360 poles per year in Orillia and 750 poles per year in Peterborough on an approximate 10-year cycle. A pole test consists of hammering the pole to identify any hollow sections, drilling the pole in three locations to measure the remaining shell thickness, measuring the depth of any significant surface damage, and measuring any circumference reductions over time. These quantitative measurements are used to calculate a percent remaining strength. The data collected from this activity will supplement pole condition data and help identify additional poles that require replacement or poles that can be mechanically refurbished.

Replacement and Refurbishment

Refurbishment

Hydro One Distribution has two refurbishment programs: (i) chemical refurbishment that is completed as part of the pole test and treat program and (ii) mechanical refurbishment completed under the mechanical refurbishment program.

As part of the test and treat program, a copper borate rod is inserted into the holes that were drilled to test the pole. These rods defuse over time into the wood to rejuvenate the initial treatment at the ground line. Sufficient levels of chemical preservative at the ground line prevents rot and fungal growth and helps to extend the overall life of the pole.

If a pole had deteriorated at the ground line only, it may be a good candidate for mechanical refurbishment. Mechanical refurbishment involves installing one or two steel structure braces to support the pole (see example depicted in Figure 20). This activity will extend the life of the existing pole for potentially 20 years or more and delay the replacement of the pole until the steel structure has deteriorated or the pole becomes damaged in another area that the steel can no longer support. Installing this steel structure support requires less labour and is less expensive than replacing the pole. In order for a pole to be eligible for mechanical refurbishment, it requires suitable soil conditions, no joint use attachments, and adequate shell thickness measurements to ensure there is sufficient structural strength above the ground line. When the pole's poor condition is isolated to the ground line area and the characteristics of the pole and ground line allow for it, mechanical refurbishment is a cost-effective means of addressing risk associated with poles in poor condition.

Figure 20: Mechanically Refurbished Pole

Replacement

Hydro One's primary program for replacing poles in poor condition is the wood pole sustainment program. Poles which have failed a condition assessment are considered for planned replacement under this program. Poles that do not undergo planned replacement and fail structurally during the plan period would be replaced as part of the trouble program. Hydro One also replaces poles through other planned investments based on system needs, including voltage conversions, sustainment projects, addressing system growth, and joint use and relocations, which all contribute to the renewal of Hydro One's pole fleet. However, these other investments do not target poor condition poles.

4.3.6 LINE TRANSFORMERS

4.3.6.1 ASSET DESCRIPTION / PURPOSE

Distribution Line Transformers are used to convert electricity from primary distribution voltage levels (e.g., 4.16 kV, 13.8 kV) to secondary voltage levels (e.g., 600 V or 240 V/120 V) so the power can be utilized by residential and small business customers.

Depending on the proximity of adjacent customers, each single-phase pole top or pad mounted transformer may supply one or several customers at 240 V/120 V. A three-phase pole top or pad mounted transformer generally supplies a single customer at 600 V/347V or 208 V/120 V.

Figure 21: Picture of a Pole-Top Line Transformer

4.3.6.2 ASSET DEMOGRAPHICS

Hydro One maintains a total fleet of approximately 1,650 and 4,000 transformers in overhead (pole mounted) or underground (pad mounted) configurations in Orillia and Peterborough, respectively. Table 12 provides a breakdown of the approximate number of transformers by type. Figure 22 and Figure 23 provide the age profile of overhead transformers for Orillia and Peterborough, respectively. Figure 24 provides the age profile of underground transformers for Peterborough. Hydro One does not currently have age information for the underground Orillia line transformers.

Table 12 - Line Transformer Type

Line Transformer Type	Orillia	Peterborough
Overhead: Pole Mounted Transformers	961	2,465
Underground: Pad Mounted Transformers	689	1,514

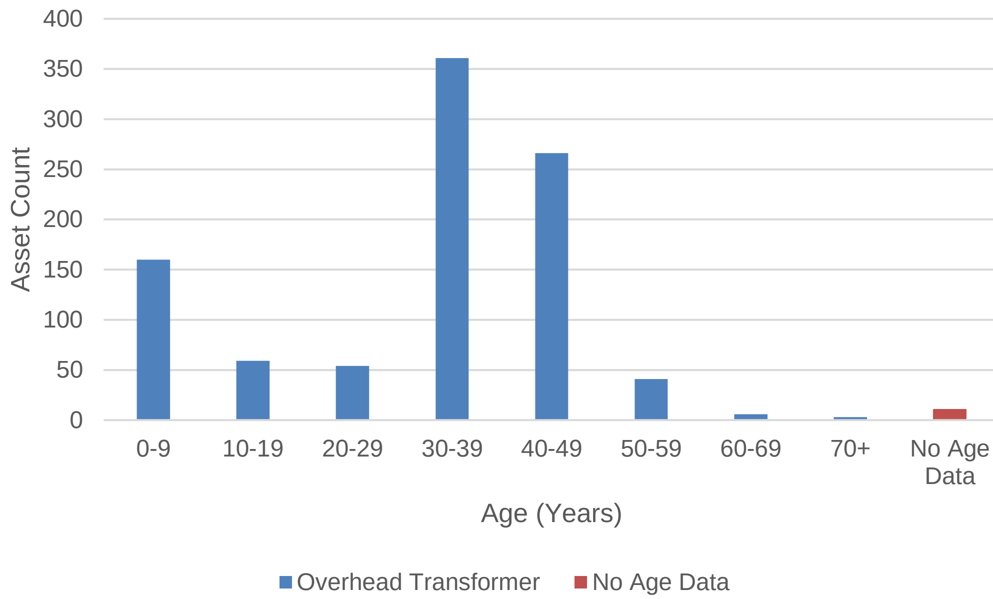

Figure 22: Orillia Overhead Transformer Demographics

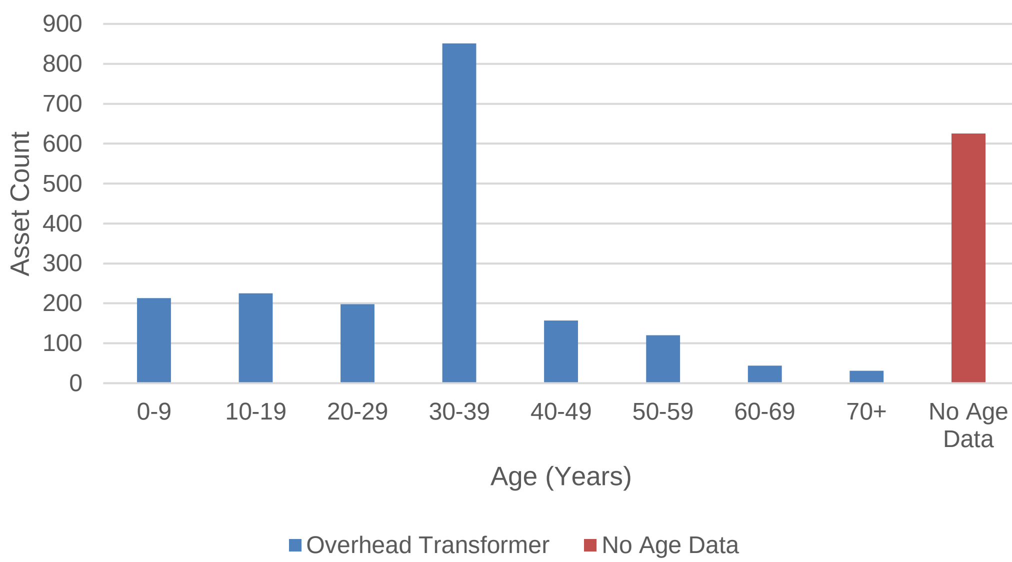

Figure 23: Peterborough Overhead Transformer Demographics

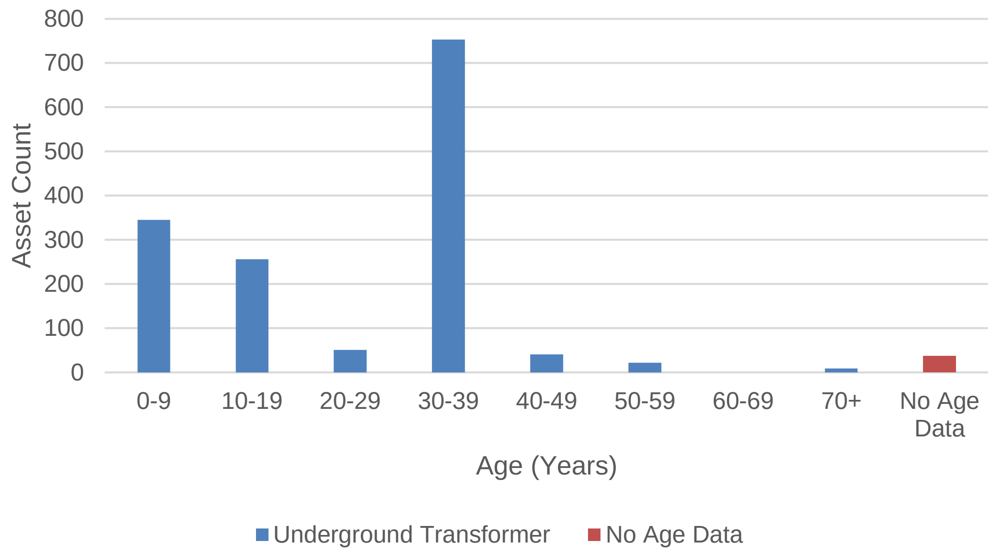

Figure 24: Peterborough Underground Transformer Demographics

4.3.6.3 ASSET CONDITION

The primary consideration in assessing line transformer condition is internal degradation due to the electrical stresses placed upon it, including both the normal loading of the transformer, as well as abnormal electrical events (e.g. electrical faults or lightning strikes on the feeder supplying the transformer).

Due to the limited number of customers served by a line transformer, and given the cost of internal condition assessment relative to the replacement cost of the transformer, it is not cost effective to assess the condition of either overhead or underground distribution line transformers. As a result, asset condition is not available for these assets.

4.3.6.4 LIFECYCLE STRATEGY

Distribution line transformers are generally run to failure and not proactively replaced due to:

- the high cost of condition assessment relative to asset replacement; and
- the relatively small reliability impact of failure due to the limited number of customers served and the ability to quickly replace failed transformers.

However, transformers can be replaced before failure during the course of other work such as customer upgrades or voltage conversions.

Inspection and Maintenance Practices

Distribution line transformers are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. These inspections primarily consist of visual assessments by technicians as part of an integrated line and vegetation assessment activity.

Replacement and Refurbishment

As discussed, distribution line transformers are run to failure, with the following exceptions:

- transformers are replaced as a result of distribution feeder rebuilds, customer upgrades, or voltage conversions;
- transformers are replaced when they are damaged by external forces; and
- transformers are replaced when they pose an environmental hazard due to oil leakage.

4.3.7 METERS

4.3.7.1 ASSET DESCRIPTION / PURPOSE

Hydro One currently owns, operates and maintains two types of revenue meters: (i) wholesale revenue meters; and (ii) retail revenue meters.

Wholesale Revenue Metering

Wholesale Revenue Metering Installations (WRMIs) are employed to settle the purchase of energy, and where the point of supply is directly connected to the transmission system, the purchase of transmission services with the IESO. WRMIs can vary in size and complexity depending on the number of meter points in the installation. Major components of a WRMI include two revenue meters (main and alternate), a lockable and sealable meter cabinet, instrument transformers, and secondary cabling. The instrument transformers that provide a metering-related function at each meter point consist of current transformers and potential transformers that step down the current and voltage to a level that is consistent with the requirements of meter and control equipment.

For Orillia, Hydro One deregistered all WRMIs from the IESO market and now only retail metering installations exist in the former Orillia Power Distribution Corporation (OPDC) territory.

For Peterborough, Hydro One deregistered 10 WRMIs from the IESO market in the former Peterborough Distribution Incorporated (PDI) service territory. Four WRMIs were retained and remain in the IESO wholesale market serving Hydro One Peterborough.

Retail Revenue Metering

Retail revenue meters are used to measure energy consumption for retail customers. Advanced Metering Infrastructure (AMI) for retail revenue metering refers to all of the components (smart meters, repeaters, regional collectors, Head End System, and related software and firmware) that work together as a system to reliably obtain over-the-air meter readings for accurate and reliable Time-of-Use and Two-Tier customer billing in accordance with the OEB's Standard Supply Service Code. AMI can also provide a platform for improving customer service and reducing costs through enabling technology such as outage detection, the provision of customer usage information, tamper detection, and remote disconnect/reconnect capabilities.

In Orillia, Hydro One currently owns, operates, and maintains approximately 15,000 Sensus Flexnet retail revenue smart meters operating on a proprietary licenced 900 MHz point to multi-point network. Cellular point-to-point meters are also employed in select locations where the network has insufficient range.

In Peterborough, Hydro One currently owns, operates, and maintains approximately 38,000 retail revenue metering devices. The bulk of the retail meter population is served by a Honeywell Advanced Metering Infrastructure (AMI). Cellular point-to-point meters are also employed in select locations where the Honeywell mesh network has insufficient range.

4.3.7.2 ASSET DEMOGRAPHICS

Wholesale Revenue Meter Installations

As noted above, there are no active WRMI in Orillia.

For Peterborough, all four WRMIs were placed in service in 2003 and use similar devices. The major components are meters (main and alternate) and instrument transformers.

- Meters: All eight meters (four main and four alternate) are Schneider Electric ION 8650 meters and were installed in 2020. The 8650 model is further differentiated as "C" or "A" series. The C series is typically used as the main meter while the A series is used as the alternate meter. The A series provides additional advanced power quality analysis capability.
- Instrument Transformers: All four meter installations use Kuhlman MVCT-150 combination unit instrument transformers manufactured in 2003 with an in-service age of 19 years.

Retail Revenue Meters

Table 13 and Table 14 provide an overview of the number of retail metering devices by communication technology for Orillia and Peterborough, respectively.

Table 13 - Metering Devices by Technology

Meter Communication Technology	Number of Meters	Meters (%)	TGB*
Sensus Flexnet 900MHz	14,738	98.67%	1
Sensus Cellular P2P	142	0.95%	0
Mesh	3	0.02%	0
Other	53	0.35%	0
Total Devices	**14,936**	**100.00%**	**1**

**Tower Gateway Base-station: TGB required to enable Sensus communication and is listed here for completeness but is not owned or maintained by Hydro One.*

Table 14 - Metering Devices by Technology

Meter Communication Technology	Number of Meters	Meters (%)	Number of Gatekeepers	Number of Repeaters
Honeywell Advanced Metering Infrastructure (AMI).	37,710	99.3%	54	2
Honeywell Cellular P2P	236	0.6%	0	0
Other	44	0.1%	0	0
Total Devices	**37,990**	100.0%	**54**	**2**

4.3.7.3 ASSET CONDITION

The assessment of the condition of modern electronic meters is primarily age-based and measured against manufacturers' recommended service life, in contrast to other types of assets that are primarily assessed based on physical condition. This approach is due to a number of related factors including: (i) the sealed and complex electronic nature of the devices; (ii) the volume and geographic distribution of devices and (iii) the high cost of individual meter assessment (involving removal, shipping, laboratory testing and assessment, repair if feasible, resealing in accordance with regulatory requirements, and re-shipping). This age-based approach is supported by the analysis of empirical meter failure rates and trends, the identification and analysis of failure root causes, industry benchmarking, and related technical and other studies.

Wholesale Revenue Metering

As noted above, there are no active WRMIs in Orillia.

Peterborough utilizes four installations located inside Otonabee TS. For all eight meters (one main and one alternate in each installation), new ION 8650 wholesale meters were installed in 2020, with an expected service life of 20 years or greater. All four meter installations use Kuhlman MVCT-150 combination unit instrument transformers manufactured in 2003 with an in-service age of 19 years. The expected service life is 30 years or greater.

WRMIs are inspected annually, and inspection results to date indicate installations are expected to achieve normal service life.

Retail Revenue Metering

Meter age and meter failures are key indicators of the health of the retail revenue meter population.

For Orillia, the Sensus meters have a service life of approximately 15–20 years. The projected meter failure rate over the 2023-2027 period, based on historical meter performance and accounting for the age profile of the meter population, is 0.43% per annum or approximately 334 meter failures.[3] Figure 25 below provides the age distribution of meters by year for the meter population.

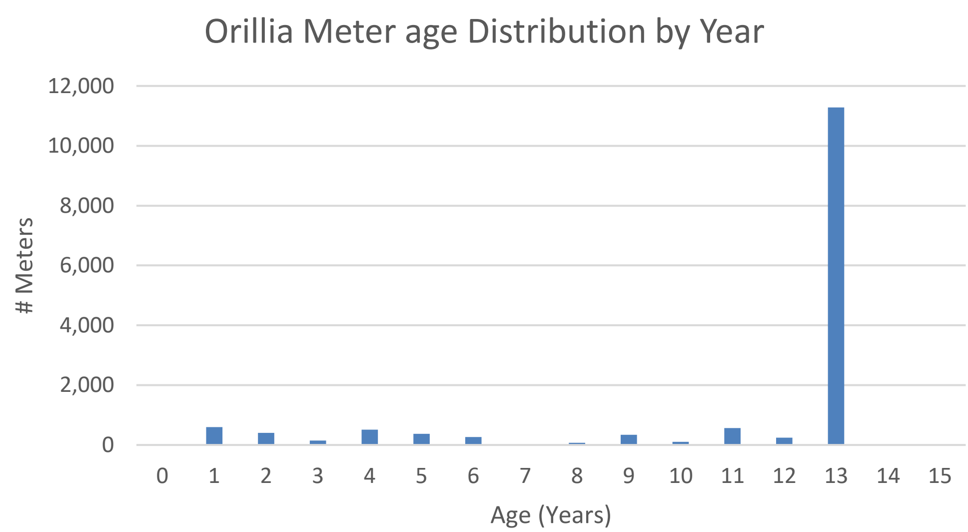

Figure 25: Meter Age Distribution by Year for Orillia

For Peterborough, the Honeywell retail meters have a service life of approximately 15-20 years. The projected meter failure rate over the 2023-2027 period, based on historical meter performance and accounting for the age profile of the meter population, is 3.6% per annum[4] or approximately 7,000 meter failures. Approximately three network devices are projected to fail annually during the forecast period based on historical failure rates.

[3] Meter failure projections are based on Sensus meter performance in the Hydro One service areas formerly served by Haldimand County Hydro Inc. and Norfolk Power Distribution Inc.
[4] Meter failure projections are based on Honeywell meter performance in the Hydro One service area formerly served by Woodstock Hydro Services Inc.

Figure 26 below provides the age distribution of meters by year for the meter population.

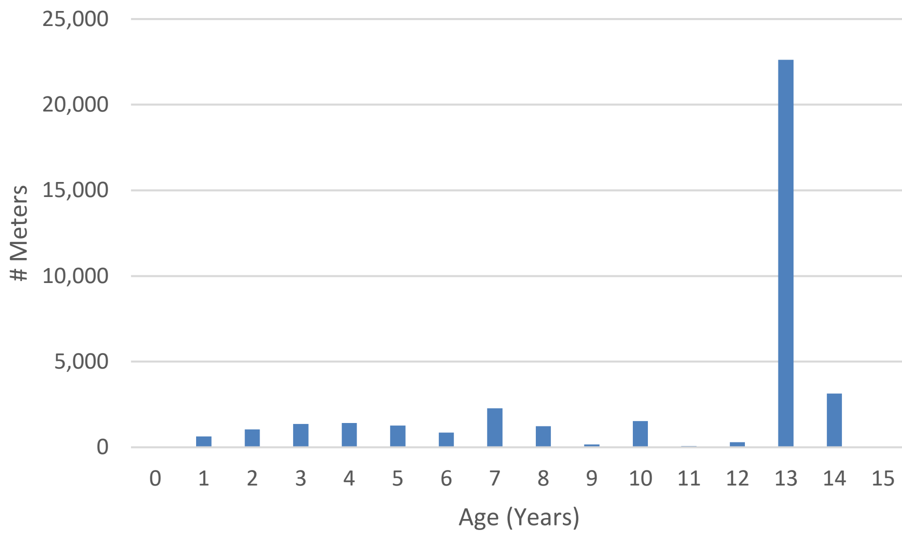

Figure 26: Meter Age Distribution by Year for Peterborough

4.3.7.4 LIFECYCLE STRATEGY

Wholesale Revenue Meters

Hydro One's WRMI replacement strategy is run to failure. This strategy has had minimal impact on customer load as WRMI failures in the majority of cases have not resulted in customer load interruption. Typically, one component of the WRMI fails (either a meter which has backup or one of the six instrument transformers), allowing the WRMI to continue to operate (although with reduced accuracy where the instrument transformer failed) while corrective maintenance or full installation replacement plans are executed. In the event of total WRMI failure, revenue metering data is managed by:

- installing temporary metering;
- executing the Emergency Instrument Transformer Restoration Plan pursuant to IESO Market Rules requiring the failed WRMI to be remediated within a 12 week period; and
- transferring the customer load to an alternate transformer/bus/feeder.

Inspection and Maintenance Practices for Wholesale Revenue Meters

WRMI capital corrective and preventative maintenance programs are employed to ensure compliance with applicable legal and regulatory requirements. The decision to perform corrective maintenance or replacement is dependent on IESO Market Rules, failure trends, age, and repair costs. The main inspection and maintenance practices are described below.

- Meter Accuracy Verification - The federal *Electricity and Gas Inspection Act* requires meters to be tested for accuracy on a pre-determined schedule (at typically the 10-year, 18-year, and 24-year marks). Based on test results, meters are either resealed and placed back into service or removed from service.
- Corrective Maintenance - Corrective maintenance is conducted in accordance with IESO Market Rules, Chapter 11 Performance of Metering Installation, Section 11.1.2.2.
- Preventive Maintenance - WRMI preventative maintenance is comprised of:
  - annually inspecting WRMIs for rust, corrosion, physical damage of components, loose and damaged connections, and indications of burning or discoloration indicating overheating;
  - confirming the current transformer ratio every six years; and
  - replacing seal expired meters.

Replacement and Refurbishment for Wholesale Revenue Meters

The approach to WRMI replacement varies based on WRMI component. Meters are replaced as a result of an expired seal that fails accuracy testing, a failed meter, or technological obsolescence (e.g., incompatibility with third party telecom upgrades). Instrument transformers are replaced if they are unable to be economically repaired or a condition assessment indicates imminent failure (e.g., corroding oil tank).

Based on Hydro One Networks' WRM failure history for similar instrument transformers, one instrument transformer is expected to fail in Peterborough over the rate filing period.[5]

[5] As noted above, there are no active WRMIs in Orillia.

Retail Revenue Meters

Hydro One, like other utilities and asset types, employs different maintenance strategies for retail revenue meters depending on the stage in the asset's lifecycle. There are two main stages for retail revenue meters.

1. **Normal Service Life** - Shortly after AMI installation and a period of stabilization, the AMI network enters a period of a consistent performance (i.e., normal service life). In the normal service life stage, a cost-effective, low customer impact, run to failure approach is employed where individual failed meters are replaced like for like with functioning meters. Meters are replaced rather than repaired because the cost of repair (involving removal, shipping, lab assessing and diagnostics, repairing if feasible, resealing, and re-shipping back to the field) is higher than replacement.

2. **End-of-Service Life** - In the end-of-service life stage, as meter digital components begin to deteriorate due to age and environmental conditions, and individual meter failures, individual meter replacement costs, and associated risks begin to increase, the need for mass meter replacements is assessed. This assessment is based on a combination of factors including manufacturer service life information, empirical failure trends and root causes, independent testing, and best industry practices from benchmarking and other sources. All of these inputs, discussed below, allow for the best correlation between age of device, risk of failure, and future costs.

   Given vendor attestations of meter service life, meter failure rates and trends, industry benchmarking and technological obsolescence considerations, Hydro One considers it prudent to plan AMI investments based on a recommended manufacturer service life of 15-20 years.

<u>Inspection and Maintenance Practices for Retail Revenue Meters</u>

The federal *Electricity and Gas Inspection Act* requires all meters to be verified through a sampling program at specified intervals to ensure a customer's electricity usage is metered accurately. Once a meter seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (through compliance testing) or be replaced.

Table 15 and Table 16 below for Orillia and Peterborough respectively provides the number of meters required to meet meter sample testing and reverification requirements in the forecast period based on Measurement Canada guidelines.

Table 15 - Orillia Meter Sampling and Reverification Program (2023-2027)

(number of meters)	2023	2024	2025	2026	2027
Reverification	75	66	6	34	34
Sampling	100	0	0	100	350
Total	175	66	6	134	384

Table 16 - Peterborough Meter Sampling and Reverification Program (2023-2027)

(number of meters)	2023	2024	2025	2026	2027
Reverification	44	31	32	58	27
Sampling	100	156	356	256	874
Total	144	187	388	314	901

<u>Replacement and Refurbishment for *Retail Revenue Meters*</u>

The AMI meter replacement approach (individual replacement vs. mass replacement) is dependent on the assets' lifecycle stage (normal service life and end-of-service life) as discussed above.

4.4 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION

This schedule summarizes the DERs connected to Orillia and Peterborough distribution system, and the capacity of the system to connect DER. It also provides information on historical and forecast renewable DER connections and capacity, as required by section 5.3.4 of the Filing Requirements. DERs refer to generation facilities including energy storage systems that connect to the distribution system and produce electricity to serve local areas. At the end of 2021, Orillia and Peterborough had connected a total number of

33 and 29 DER for a total capacity of 23.8 MW and 39.2 MW respectively to their distribution system. The total DERs connected to Orillia and Peterborough distribution system by fuel type are given in Figure 27 and Figure 28, respectively.

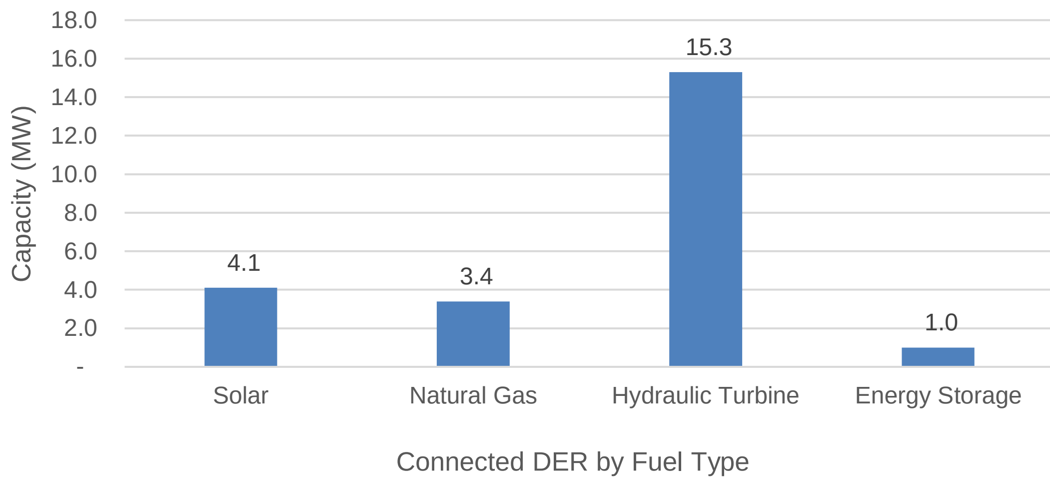

Figure 27: Total Orillia Connected DER Capacity (MW)

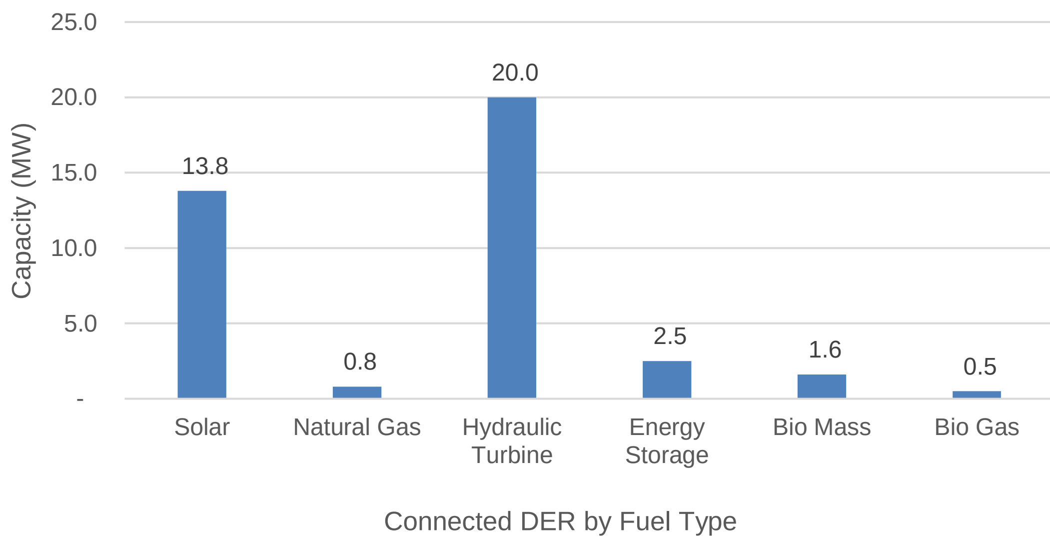

Figure 28: Total Peterborough Connected DER Capacity (MW)

4.4.1 CONNECTION FORECAST

DER activity in Ontario has shifted from retail generators participating in historical IESO procurement programs to behind-the-meter (BTM) Load Displacement Generators participating in the IESO's Industrial Conservation Initiative (ICI) program and Ontario Net Metering program. Previously, the dominant source of renewable DER applications had been the Feed-in Tariff (FIT) program which was terminated in 2017. The Net Metering program is still limited to renewable DER and remains active and regulated by Ontario Regulation 541/05 (O. Reg. 541/05). Hydro One continues to apply the DSC rules related to renewable projects by funding a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement (REI) investments.

The IESO ICI program allows large distribution connected load customers to reduce their Global Adjustment cost by reducing their peak during the five Ontario peaks. The majority of these projects are non-renewable and range in size from 500 kW to 20 MW depending on size of the load facility. The cost for connecting these non-renewable energy projects to Orillia and Peterborough distribution system is 100% recoverable from the DER customers. Currently, the only active renewable energy program in place in the province of Ontario is the Net Metering program, which is regulated by O. Reg. 541/05. Based on these two programs, the numbers of projects forecast for Orillia and Peterborough for 2023 to 2027 are shown in Table 17 and Table 18.

Table 17 - DER Forecast for 2023-2027 for Orillia

		Projects Forecast Number				
Year		**2023**	**2024**	**2025**	**2026**	**2027**
Non-Renewable Energy Projects	**> 10 kW**	0	1	0	1	0
	≤ 10 kW	0	0	0	0	0
Renewable Energy Projects	**> 10 kW**	1	1	1	1	1
	≤ 10 kW	2	2	2	2	2

Table 18 - DER Forecast for 2023-2027 Peterborough

		Projects Forecast Number				
Year		2023	2024	2025	2026	2027
Non-Renewable Energy Projects	> 10 kW	1	0	1	0	1
	≤ 10 kW	0	0	0	0	0
Renewable Energy Projects	> 10 kW	1	1	1	1	1
	≤ 10 kW	2	2	2	2	2

The IESO has recently launched an RFP for procurement of new generation which may result in additional DER connection requests. It is unknown if these requests will be renewable or non-renewable or if these requests will be inside Orillia / Peterborough territory.

4.4.2 STATION AND FEEDER CAPACITY

There is sufficient DER capacity available at feeders and stations serving Orillia and Peterborough customers. Hydro One provides information on station capacity in order to provide potential DER customers with assistance in determining a suitable location for their DER projects. The available capacity is published on Hydro One's website as the Hydro One List of Station Capacity (LSC) and is updated every month. Hydro One LSC includes Orillia and Peterborough feeders / stations as well. Additionally, Hydro One has made available a calculator tool to enable customers to easily determine the remaining DER capacity at their location of interest.

Orillia and Peterborough customers can find available DER capacity at any feeder / station using Hydro One capacity calculator. The available capacity at transmission stations serving Orillia and Peterborough is given in Table 19.

Table 19 - Available Thermal Capacity for Transmission Stations Serving Orillia and Peterborough

Name of TS	Territory	Total Capacity (MW)	Connected / Committed Generation (MW)	Remaining Capacity (MW)
Orillia TS	Orillia	100.4	54.0	46.4
Dobbin TS	Peterborough	90.1	47.1	43.0
Otonabee TS JQ Bus	Peterborough	39.3	3.4	35.9
Otonabee TS BY Bus	Peterborough	37.2	19.0	18.2

4.5 CDM ACTIVITIES TO ADDRESS SYSTEM NEEDS

Hydro One is developing processes to consider CDM activities following the completion of its 2023-2027 Joint Rate Application (EB-2021-0110), which preceded this filing requirement. The resulting processes will be applied to Orillia and Peterborough. This application does not include a request for CDM funding.

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DSP SECTION 5 - CAPITAL EXPENDITURE PLAN

5.1 CAPITAL EXPENDITURE SUMMARY

This section provides an overview of the DSP capital investment plans, along with an analysis of historical and forecast trends.

Table 1 presents a 10-year snapshot of the capital expenditures for the Hydro One service area formerly served by Orillia Power Distribution Corporation (OPDC) (herein referred to as “Orillia”). Likewise, Table 2 presents a 10-year snapshot of the capital expenditures for the Hydro One service area formerly served by Peterborough Distribution Inc. (PDI) (herein referred to as “Peterborough”).

Table 1 - Ten-year Capital Plan Snapshot for Orillia ($M)

Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
Capital Expenditures										
System Access	-	-	-	0.89	1.15	1.16	1.10	1.11	1.16	1.22
System Renewal	-	-	-	0.14	0.48	0.63	1.04	3.76	0.89	0.65
System Service	-	-	-	0.15	0.16	0.22	0.23	0.23	0.23	0.24
General Plant**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-integration***	2.38	4.10	2.34	1.01	-	-	-	-	-	-
Total Capital Expenditures	**2.38**	**4.10**	**2.34**	**2.18**	**1.79**	**2.01**	**2.37**	**5.10**	**2.28**	**2.10**
Operating and Maintenance (O&M) Costs******	**2.30**	**2.20**	**2.50**	**1.83**	**0.77**	**1.20**	**-**	**-**	**-**	**-**

**2022 Bridge forecast amounts are Hydro One’s planned expenditures.*
*** Information regarding Hydro One Distribution’s General Plant assets is provided in Hydro One’s Joint Rate Application, EB-2021-0110, Exhibit B4 - General Plant System Plan.*
**** Amounts relate to pre-integration costs (i.e. prior to June 1, 2021). Hydro One does not have the breakdown of these pre-integration costs by OEB Category.*
***** Pre-integration costs are based on O&M expenses reported in the RRR by OPDC. Post-integration costs are based on Hydro One’s Distribution Sustainment O&M Work Programs.*

Table 2 - Ten-year Capital Plan Snapshot for Peterborough ($M)

Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
Capital Expenditures										
System Access	-	-	-	1.46	2.10	2.34	2.41	2.44	2.42	2.52
System Renewal	-	-	-	0.13	2.78	1.37	4.16	2.70	2.56	4.31
System Service	-	-	-	1.36	0.70	0.25	0.25	0.25	0.26	0.26
General Plant**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-integration***	4.48	3.86	2.22	3.44	-	-	-	-	-	-
Total Capital Expenditures	**4.48**	**3.86**	**2.22**	**6.39**	**5.58**	**3.96**	**6.81**	**5.39**	**5.23**	**7.09**
Operating and Maintenance (O&M) Costs******	**3.49**	**3.18**	**3.95**	**2.64**	**1.45**	**2.01**	**-**	**-**	**-**	**-**

**2022 Bridge forecast amounts are Hydro One's planned expenditures. These exclude the costs associated with a significant storm event in May 2022. Hydro One submitted a Notice of Intent to file a Z-Factor Application for Peterborough storm damage on November 18, 2022 with the OEB.*
*** Information regarding Hydro One Distribution's General Plant assets is provided in Hydro One's Joint Rate Application, EB-2021-0110, Exhibit B4 - General Plant System Plan.*
**** Amounts relate to pre-integration costs (i.e. prior to June 1, 2021). Hydro One does not have the breakdown of these pre-integration costs by OEB Category.*
***** Pre-integration costs are based on O&M expenses reported in the RRR by PDI. Post- integration costs are based on Hydro One's Distribution Sustainment O&M Work Programs.*

The historical and forecast periods are discussed further in the following sections. In addition, OEB Appendix 2-AA and OEB Appendix 2-AB are provided in Attachment 1 to this section.

Hydro One confirms that there are no expenditures for non-distribution activities in the historical and forecast periods. Hydro One uses USGAAP as its basis of accounting and bases its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. Capitalized interest costs are calculated using the Company's weighted average effective cost of debt. These costs are included in the capital expenditures shown in the DSP.

5.2 HISTORICAL CAPITAL EXPENDITURE TRENDS

As noted above in Table 1 and Table 2, Hydro One does not have a breakdown of pre-integration capital expenditures by OEB category. As such, this section focuses on the post-integration capital expenditures for Orillia and Peterborough for the historical year of 2021 and the bridge year of 2022.

5.2.1 ORILLIA

For Orillia, a majority of the post-integration 2021 actual costs (i.e. June 1, 2021 through December 31, 2021) relate to System Access expenditures ($0.89M). For System Renewal and System Service, 2021 post-integration actuals were $0.14M and $0.15M, respectively.

In 2022, System Access also accounts for the largest portion of Hydro One's bridge year forecast for Orillia ($1.15M), with the bulk forecasted under new load connections, upgrades and cancellations ($1.03M). For System Renewal investments, $0.48M is forecasted for various activities, including lines sustainment initiatives ($0.21M), and pole replacements ($0.11M). Approximately $0.16M is forecasted for System Service, the bulk of which relates to demand investments to enable localized growth ($0.15M).

5.2.2 PETERBOROUGH

For Peterborough, majority of the post-integration 2021 actual costs (i.e. June 1, 2021 through December 31, 2021) relate to System Access ($1.46M), and System Service ($1.36M) expenditures.

In 2022, System Access expenditures are forecasted to be $2.10M, with $1.59M for new load connections, upgrades and cancellations, and $0.50M for metering sustainment. System Service expenditures are forecasted to be $0.70M, with $0.54M related to system upgrades driven by load growth investments.

For System Renewal in 2022, expenditures are forecasted to be $2.78M. This is primarily due to expenditures of $2.02M in distribution station refurbishment and $0.28M in lines sustainment initiatives.

5.3 FORECAST CAPITAL EXPENDITURE TRENDS

The total capital expenditures during the forecast period of 2023-2027 are $13.85M for Orillia and $28.49M for Peterborough. The bulk of expenditures in the forecast period relate to work for new load connections and addressing station condition and environmental risks. As a result of different system needs between the two acquired utilities, stations in Orillia will be addressed through Life Cycle Optimization and Operational Efficiency Projects (Section 5.5, D-SR-11), whereas stations in Peterborough will be addressed through Distribution Station Refurbishments (Section 5.5, D-SR-04). Where prudent, Hydro One will also address assets in poor condition through its Pole Sustainment Program (Section 5.5, D-SR-07) and Distribution Lines Sustainment Initiatives (Section 5.5, D-SR-10) to maintain the performance of the distribution system in these areas. Details of the expenditures for each service area are provided in the following subsections.

5.3.1 ORILLIA

The capital expenditure forecast for Orillia is shown in Figure 1.

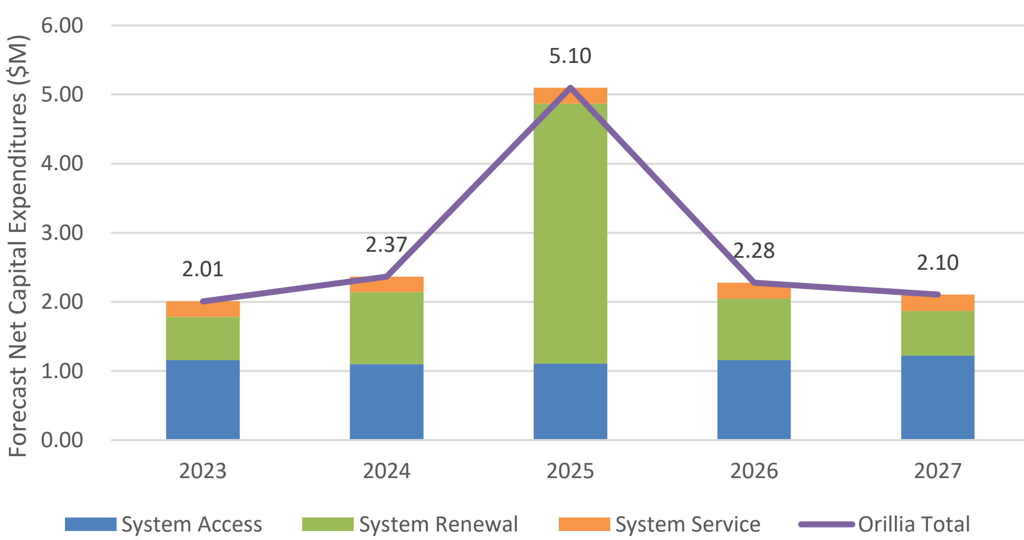

Figure 1: Forecast net capital expenditures for Orillia from 2023-2027

As displayed by Figure 1, majority of the forecasted $13.85M capital expenditures in 2023-2027 relate to System Renewal investments ($6.97M or 50% of the total forecast) and

System Access investments ($5.74M or 41% of the total forecast). The annual average forecast is $2.77M per year, which is higher than the 2022 bridge year forecast of $1.79M. This is mainly due to System Renewal project work planned in 2023-2027.

The System Renewal investments are primarily driven by forecast expenditures related to Life Cycle Optimization ($4.76M, Section 5.5, D-SR-11). As part of Life Cycle Optimization investments, James DS is planned to be rebuilt with increased capacity, which will enable the decommissioning of Central DS and Couchiching DS. The capacity increases at James DS will facilitate additional load growth within the downtown core of Orillia, address equipment condition at Central DS, and address environmental concerns at Couchiching DS. The bulk of the James DS project is planned to occur in 2025, accounting for the higher spend in System Renewal investments in 2025 displayed in Figure 1.

The remaining System Renewal forecast of $2.21M for Orillia includes funding for the following investments:

- Pole Sustainment Program ($1.14M; Section 5.5, D-SR-07) - funds the planned replacement and refurbishment of distribution poles in poor condition or in need of ground line retreatment. By proactively targeting poor condition poles, this investment helps maintain reliable operation of the distribution system and reduce the number of potential interruptions to customers.
- Distribution Lines Trouble Call and Storm Damage Response Program ($0.34M; Section 5.5, D-SR-05) - funds the emergency replacement of distribution lines assets that have either failed or pose an immediate safety hazard. This investment is required to restore systems to normal operation and to maintain reliability and safety.
- Distribution Lines Sustainment Initiatives ($0.30M; Section 5.5, D-SR-10) - funds the rebuilding of overhead lines in poor condition or in need of a relocation to improve reliability and accessibility.
- Distribution Stations Demand Capital Program ($0.22M; Section 5.5, D-SR-01) - funds the replacement of station assets that have failed or are subject to imminent failure.

- Distribution Lines Minor Component Replacement Program ($0.20M; Section 5.5, D-SR-08) - addresses condition, obsolescence or compliance concerns for minor assets not covered in other programs.

The System Access investments are primarily driven by New Load Connections, Upgrades and Cancellations ($5.21M, Section 5.5, D-SA-02). These are driven by customer service requests and includes the connection of new load customers, the upgrade of services for existing load customers, and cancelling existing services. This investment is required to comply with statutory, regulatory and licence obligations and the annual average forecast of $1.04M is approximately equal to the 2022 bridge year forecast of $1.03M.

The remaining $0.53M System Access forecast is related to investments in Joint Use and Relocations (Section 5.5, D-SA-01), Connecting Distributed Energy Resources (DERs) (Section 5.5, D-SA-03), and Metering Sustainment (Section 5.5, D-SA-04). These investments enable Hydro One to fulfill third party requests for joint use attachments and relocations of poles; modify and, as necessary, upgrade Hydro One's Distribution System to connect new DERs; and replace failed meters to maintain accurate billing for customers.

For System Service, the forecast capital expenditures are $1.14M between 2023-2027. The majority of this forecast ($1.08M) relates to Demand Investments (Section 5.5, D-SS-03), which address near term system needs that arise because of localized growth on the distribution system, such as equipment overload or power quality issues. The remaining forecast pertains to Power Quality and Stray Voltage investments (Section 5.5, D-SS-06).

5.3.2 PETERBOROUGH

The capital expenditure forecast for Peterborough is shown in Figure 2.

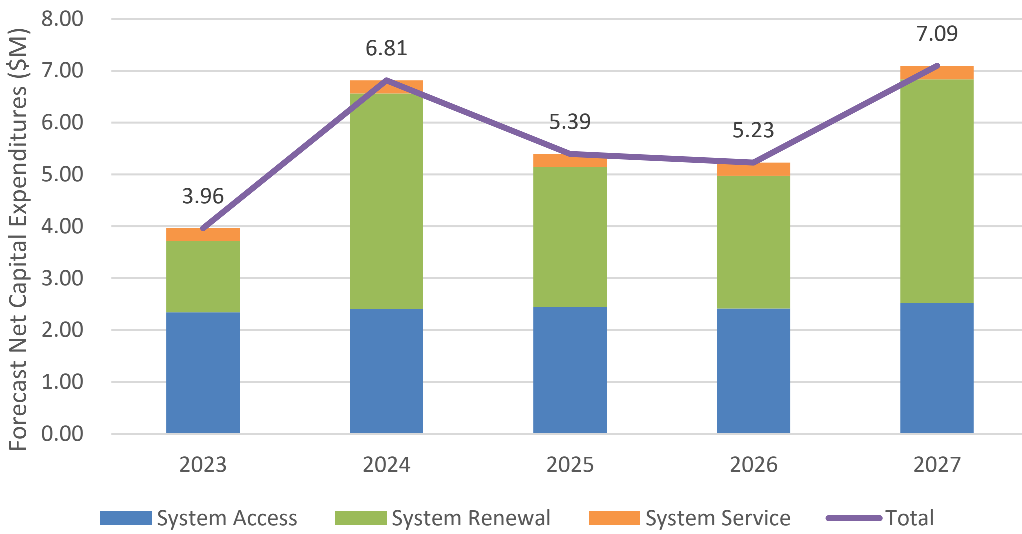

Figure 2: Forecast net capital expenditures for Peterborough from 2023-2027

As displayed in Figure 2, most of the forecasted capital expenditures from 2023-2027 relate to System Renewal investments ($15.09M or 53% of the total forecast) and System Access investments ($12.13M or 43% of the total forecast). The annual average forecast is $5.70M per year, which is aligned with the 2022 bridge year forecast of $5.58M.

A significant portion of Peterborough's System Renewal forecast is driven by Distribution Station Refurbishments ($8.94M, Section 5.5, D-SR-04), which will replace multiple station transformers in poor condition and address environmental concerns at two sites. These investments average to approximately $1.79M annually, which is slightly lower than the 2022 bridge year forecast of $2.02M. This difference and the fluctuation seen in year-over-year forecast capital expenditures for Peterborough are mainly due to the timing of project work (see Section 5.5, D-SR-04, Appendix A for additional details).

The remaining $6.15M System Renewal forecast for Peterborough consists of the following investments:

- Distribution Lines Trouble Call and Storm Damage Response Program ($1.71M; Section 5.5, D-SR-05) - funds the emergency replacement of distribution lines assets because they have either failed or pose an immediate safety hazard.
- Pole Sustainment Program ($1.64M; Section 5.5, D-SR-07) - funds the planned replacement and refurbishment of distribution poles in poor condition or in need of ground line retreatment.
- Distribution Lines Sustainment Initiatives ($1.56M; Section 5.5, D-SR-10) - funds the rebuilding of overhead lines in poor condition or in need of a relocation to improve reliability and accessibility.
- Distribution Lines Minor Component Replacement Program ($0.72M; Section 5.5, D-SR-08) - addresses condition, obsolescence or compliance concerns for minor assets not covered in other programs.
- Distribution Stations Demand Capital Program ($0.52M; Section 5.5, D-SR-01) - funds the replacement of station assets that have failed or are subject to imminent failure.

The System Access investments in Peterborough are primarily related to New Load Connections, Upgrades and Cancellations ($9.30M, Section 5.5, D-SA-02). These are driven by customer service requests and includes the connection of new load customers, the upgrade of services for existing load customers, and cancelling existing services. The annual average forecast of $1.86M is higher than the 2022 bridge year forecast of $1.59M and is required to comply with statutory, regulatory and licence obligations.

Of the remaining $2.83M System Access forecast, $2.72M is related to Metering Sustainment (Section 5.5, D-SA-04), which will replace failed meters to maintain accurate customer billing, and $0.11M is forecasted for Joint Use and Relocations (Section 5.5, D-SA-01) and Connecting DERs (Section 5.5, D-SA-03).

For System Service, the forecast capital expenditures are $1.27M between 2023-2027. The majority of Peterborough's forecast ($1.20M) relates to Demand Investments (Section 5.5, D-SS-03), which address near term system needs that arise because of localized growth on the distribution system, such as equipment overload or power quality issues.

The remaining forecast pertains to Power Quality and Stray Voltage investments (Section 5.5, D-SS-06).

5.4 IMPACT OF CAPITAL INVESTMENTS ON OPERATIONS AND MAINTENANCE EXPENDITURES

O&M expenditures are influenced by a variety of factors, including regulatory requirements, customer-driven requests, maintenance cycles and the number, age, and condition of various asset populations. While in some cases, capital expenditures may result in a corresponding increase or decrease in O&M expenditures, there are a number of areas where there is not a direct relationship between O&M and capital expenditures. This section provides an overview of where capital expenditures may influence O&M and identifies if O&M is expected to increase, decrease, or remain at historic levels as a result.

The forecast Distribution Sustainment O&M expenditure for 2023 is $1.20M for Orillia and $2.01M for Peterborough. Some of the capital expenditures proposed in this plan have allowed Hydro One to maintain or reduce sustainment O&M expenditures and without these investments sustaining O&M costs would increase.

Hydro One manages its Distribution Sustainment O&M by dividing the expenditures into the following four investment categories: 1) Stations, 2) Lines, 3) Meters, Telecom & Control and 4) Vegetation Management.

5.4.1 STATIONS

These O&M expenditures, forecasted to be $0.23M in Orillia and $0.29M in Peterborough for 2023, fund the work required to inspect, repair or maintain distribution stations or individual station components, as well as assess and carry out remedial work to reduce environmental contamination at distribution stations. The impacts from capital expenditures on Distribution Stations O&M are noted below for Orillia and Peterborough.

- For Orillia, Life Cycle Optimization and Operational Efficiencies (Section 5.5, D-SR-11) addresses poor condition stations by eliminating those stations through voltage conversion or load transfers. These investments are expected to decrease inspection and planned preventive maintenance costs since the investment results in the removal of stations, and cyclical inspections and planned preventive maintenance will no longer be required. Over the course of the 2023-2027 capital plan, these investments will result in a reduction of two stations in Orillia.

- For Peterborough, Distribution Station Refurbishment (Section 5.5, D-SR-04) addresses station transformers and equipment in poor condition on a planned basis. The proposed level of Distribution Station Refurbishments will not have an impact on inspections O&M as these are not condition based, but by addressing poor condition assets it is expected that station refurbishments will maintain preventive and corrective maintenance O&M forecasts.

5.4.2 LINES

Distribution Sustainment Lines O&M expenditures, forecast to be $0.75M for Orillia and $1.19M for Peterborough in 2023, fund the costs related to distribution lines assets, with approximately half of these expenditures related to Trouble Calls. Overall, planned capital investments will not have a material impact on Lines Sustainment O&M costs over the plan period.

5.4.3 METERS, TELECOM, PROTECTION AND CONTROL

These O&M expenditures, forecast to be $0.01M for Orillia and $0.11M for Peterborough in 2023, fund the work required to inspect, repair or maintain revenue meters, and protection and control equipment. Overall, planned capital investments will not have a material impact on Meters, Telecom and Control O&M costs over the plan period.

5.4.4 VEGETATION MANAGEMENT

These O&M expenditures, forecast to be $0.20M for Orillia and $0.41M for Peterborough in 2023, fund the work required to keep assets clear of vegetation such as adjacent trees and brush growth below lines. These expenditures are independent of distribution line equipment age or condition and are directly correlated with the number of kilometers of line section that need to be maintained. As a result, planned capital investments will not have any material impact on vegetation management O&M costs.

5.5 MATERIAL INVESTMENT SUMMARY DOCUMENTS

Investment Summary Documents (ISD) are attached to this exhibit. ISDs are provided for any proposed capital expenditure within the DSP that exceeds a materiality threshold of $0.01M in a single year for either Orillia or Peterborough.

The material DSP investments for Orillia and Peterborough are provided in Table 3 and Table 4, respectively. Their associated Investment Summary Documents (ISD) are provided in the following sections.[1]

[1] ISD numbering and assignments are aligned with the ISDs submitted as part of Hydro One's Joint Rate Application's DSP in EB-2021-0110, Exhibit B-03-01, DSP Section 3.11.

Table 3 - Material DSP Investments for Orillia ($M)

ISD	Investment Name	Forecasting Period				
		2023	**2024**	**2025**	**2026**	**2027**
System Access						
D-SA-01	Joint Use and Relocations	0.01	0.01	0.01	0.01	0.01
D-SA-02	New Load Connections, Upgrades, Cancellations	0.98	1.02	1.04	1.07	1.10
D-SA-03	Connecting Distributed Energy Resources	0.01	0.01	0.01	0.01	0.01
D-SA-04	Metering Sustainment	0.15	0.06	0.04	0.06	0.10
Total System Access		**1.16**	**1.10**	**1.11**	**1.16**	**1.22**
System Renewal						
D-SR-01	Distribution Stations Demand Capital Program	0.04	0.04	0.05	0.05	0.05
D-SR-04	Distribution Station Refurbishment	0.00	0.00	0.00	0.00	0.00
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	0.07	0.07	0.07	0.07	0.07
D-SR-07	Pole Sustainment Program	0.22	0.22	0.23	0.23	0.24
D-SR-08	Distribution Lines Minor Component Replacement Program	0.04	0.04	0.04	0.04	0.04
D-SR-10	Distribution Lines Sustainment Initiatives	0.06	0.06	0.06	0.06	0.06
D-SR-11	Life Cycle Optimization & Operational Efficiency Projects	0.20	0.61	3.32	0.44	0.19
Total System Renewal		**0.63**	**1.04**	**3.76**	**0.89**	**0.65**
System Service						
D-SS-03	Demand Investments	0.21	0.21	0.22	0.22	0.22
D-SS-06	Power Quality and Stray Voltage	0.01	0.01	0.01	0.01	0.01
Total System Service		**0.22**	**0.23**	**0.23**	**0.23**	**0.24**
Grand Total		**2.01**	**2.37**	**5.10**	**2.28**	**2.10**

1 **Table 4 - Material DSP Investments for Peterborough ($M)**

ISD	Investment Name	Forecasting Period				
		2023	2024	2025	2026	2027
System Access						
D-SA-01	Joint Use and Relocations	0.01	0.01	0.01	0.01	0.01
D-SA-02	New Load Connections, Upgrades, Cancellations	1.75	1.82	1.86	1.91	1.96
D-SA-03	Connecting Distributed Energy Resources	0.01	0.01	0.01	0.01	0.01
D-SA-04	Metering Sustainment	0.57	0.57	0.56	0.49	0.54
Total System Access		**2.34**	**2.41**	**2.44**	**2.42**	**2.52**
System Renewal						
D-SR-01	Distribution Stations Demand Capital Program	0.10	0.10	0.11	0.11	0.11
D-SR-04	Distribution Station Refurbishment	0.20	2.95	1.46	1.30	3.03
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	0.33	0.34	0.34	0.35	0.36
D-SR-07	Pole Sustainment Program	0.31	0.32	0.33	0.34	0.35
D-SR-08	Distribution Lines Minor Component Replacement Program	0.14	0.14	0.14	0.15	0.15
D-SR-10	Distribution Lines Sustainment Initiatives	0.30	0.31	0.31	0.32	0.32
D-SR-11	Life Cycle Optimization & Operational Efficiency Projects	0.00	0.00	0.00	0.00	0.00
Total System Renewal		**1.37**	**4.16**	**2.70**	**2.56**	**4.31**
System Service						
D-SS-03	Demand Investments	0.24	0.24	0.24	0.24	0.25
D-SS-06	Power Quality and Stray Voltage	0.01	0.01	0.01	0.01	0.01
Total System Service		**0.25**	**0.25**	**0.25**	**0.26**	**0.26**
Grand Total		**3.96**	**6.81**	**5.39**	**5.23**	**7.09**

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OEB APPENDICES 2-AA AND 2-AB CAPITAL PROJECTS TABLE AND CAPITAL EXPENDITURE SUMMARY FROM CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

This exhibit has been filed separately in MS Excel format.

D-SA-01	**JOINT USE AND RELOCATIONS**
Primary Trigger:	Mandated Obligations
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.01	0.01	0.01	0.01	0.01	0.06
Net Cost - Peterborough	0.01	0.01	0.01	0.01	0.01	0.06

Summary:

This investment involves the rearrangement, relocation, and/or the replacement of poles as required to accommodate joint use partners' attachments or due to siting conflicts with work by Road Authorities, railways, and private landowners. The primary trigger of this investment is compliance with regulatory and statutory obligations under Hydro One's Distribution Licence and the *Public Service Works on Highways Act*, respectively. The investment is expected to ensure ongoing compliance with these requirements and create mutual benefit to Hydro One and third-parties to support infrastructure development, generate external revenue, and realize cost sharing opportunities where applicable.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The investments in this ISD consist of two programs: Joint Use and Relocations. The purpose of these investments is to modify or upgrade distribution system facilities in Orillia and Peterborough, to accommodate the requirements of third-party joint use partners such as telecommunication and internet service providers who occupy Hydro One assets, or to relocate facilities at the request of Road Authorities and private landowners.

<u>Joint Use</u>

The main driver of the Joint Use program is to provide joint use partners with access to Hydro One's support structure network. Access to Hydro One assets is subject to Joint Use agreements between the joint use partners and Hydro One, consistent with the provisions included in Hydro One's distribution licence related to telecommunication attachments. These joint use capital expenditures reflect costs of "make ready" modifications to Hydro One's assets that are necessary to allow third parties to initially attach their equipment to Hydro One's support structures. Joint Use partners are responsible for all applicable costs related to their request.

<u>Relocations</u>

The main driver of the Relocation program is Hydro One's obligation to perform line relocation work at the request of:

- municipal and provincial Road Authorities as per the requirements of the *Public Service Work on Highways Act* (PSWHA) and associated Ministry of Transportation guidelines; and
- customers and third parties in accordance with Hydro One's Conditions of Service and what is allowed based on the distribution system code.

These capital expenditures are required to complete relocation work as requested by the party driving the work in order to facilitate the development of the property or the changing needs of the Road Authority, where known adverse impacts to Hydro One plant have been identified. The applicable costs would be charged to the party requesting the work as defined in the PSWHA or in Hydro One's Conditions of Service as appropriate.

The Joint Use and Relocations programs are driven by customer demand and thus must be accommodated within Hydro One's work program.

B. INVESTMENT DESCRIPTION

The necessary investments in Joint Use and Relocations vary year-over-year based on external third party and customer demand.

JOINT USE

Joint use investments modify or upgrade Hydro One distribution line equipment to enable use by third-party joint use partners. These partners may include telecommunication companies (communication circuits), municipalities (street lighting - safety), or generators connected to the distribution system.

The scope of the required modifications or upgrades may involve increasing pole class to accommodate changes in pole loading, and/or increasing pole height to obtain appropriate ground clearances for public safety. These activities may also carry the cost associated with premature retirement of in-service assets.

Over the 2023-2027 period, Hydro One expects to invest $0.05M in Orillia and Peterborough through the Joint Use program.

LINE RELOCATIONS

Line relocation investments alter the location of Hydro One distribution line equipment in response to road modifications initiated by Road Authorities or in response to property development initiated by individual customer requests.

Hydro One occupies road allowances at no cost. However, in return, Hydro One is required, on occasion, to install, relocate or reconstruct its facilities to accommodate specific Road Authority or property development requirements. Most commonly, this involves relocating lines to accommodate changes to roads, highways, and bridges. The cost of the plant relocation is either fully or partially recoverable, depending on the specific circumstances of each investment as defined by the PSWHA.

For relocations on other lands, including railway and public lands, Hydro One is required, on occasion, to rearrange, reconstruct or relocate its facilities in order to accommodate other developments that are known to have adverse impacts on the existing Hydro One plant. Hydro One recovers, from the third party requesting the work, all applicable costs based on existing permissions or rights-of-way agreements.

Over the 2023-2027 period, Hydro One expects to invest $0.08M in Orillia and Peterborough through the Relocations program.

C. OUTCOMES

C.1 OEB RRF OUTCOMES

Investments made under the Joint Use program align with the Renewed Regulatory Framework (RRF) Public Policy Responsiveness outcome, as they will result in Hydro One being able to continue servicing Joint Use requests pursuant to our Joint Use agreements and to maintain compliance with the company’s distribution licence. The principle of Hydro One’s Joint Use program is to work for the mutual benefit of Hydro One’s customers and the customers of the Joint Use partners. Further, the Joint Use program reduces duplicate pole infrastructure and allows for cost sharing between Hydro One and Joint Use partners.

The Relocations program also supports Public Policy Responsiveness outcomes, which address legislative requirements under the PSWHA.

The following table presents anticipated benefits as a result of the investment in accordance with the RRF:

Table 1 - Outcome Summary

Customer Focus	• Realize mutual benefits of Hydro One infrastructure for rate payers, while completing work to meet the interests and objectives of joint use partners, Municipal Road Authorities and other parties.
Public Policy Responsiveness	• Comply with Section 22.1 Hydro One's Electricity Distribution Licence for access to distribution poles by our joint use partners. • Comply with legal obligations regarding asset relocations under the PWHSA, Hydro One's Conditions of Service and the Distribution System Code.
Financial Performance	• Support the installation of new attachments by joint use partners that may result in increased External Revenue which will offset the rates revenue requirement. • Realize cost savings by cost sharing, where possible, on upgrades or renewal of the distribution system in response to Road Authority, joint use partners or customer requests.

D. EXPENDITURE PLAN

Planned expenditures for the 2023-2027 period are based on the historical spending available in the Joint Use and Relocations programs for Orillia and Peterborough, adjusted to reflect forecast work volumes provided by Joint Use partners. Year-over-year variations in expenditures are generally due to the expected volume and scope of Joint Use and Relocation requests.

The forecasted investments related to Joint Use over the planning period are anticipated to remain relatively stable during the investment period.[1]

Hydro One expects that demand for relocation requests will continue at historic levels since municipalities continue to expand at a relatively similar rate. Road Authorities require any existing infrastructure to be relocated to provide for these expansions. While year-over-year expenditures may vary due to the large, multi-year nature of many road

[1] Volumes and capital costs do not reflect potential volume changes that may arise from the new *Supporting Broadband and Infrastructure Expansion Act*.

expansion projects, Hydro One expects that aggregate expenditures over the 2023-2027 period will be consistent with historic levels.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.01	0.01	0.01	0.01	0.01	0.07
Less Removals	0.00	0.00	0.00	0.00	0.00	0.01
Capital and Minor Fixed Assets	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.01	0.01	0.01	0.01	0.01	0.07
Less Removals	0.00	0.00	0.00	0.00	0.00	0.01
Capital and Minor Fixed Assets	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**

E. ALTERNATIVES

This investment is non-discretionary. No alternatives are considered, because Hydro One would not be compliant with its distribution licence if it did not proceed to service these joint use requests. Similarly, Hydro One has statutory obligations under the PSWHA to perform requested relocations by Road Authorities.

F. EXECUTION RISK AND MITIGATION

Hydro One's forecast is based on historic and future volumes of joint use attachments identified by Joint Use partners. To the extent that volumes exceed the forecast due to new legislation or other factors, Hydro One will assess appropriate options to accommodate requests from Joint Use partners.

For the relocation portion of investment requests, Hydro One's forecast is based on historic and known future volumes. Hydro One works with third parties to identify future relocation requests with sufficient lead-time to plan and execute work without affecting other investments.

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D-SA-02	**NEW LOAD CONNECTIONS, UPGRADES, CANCELLATIONS**
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.98	1.02	1.04	1.07	1.10	5.21
Net Cost - Peterborough	1.75	1.82	1.86	1.91	1.96	9.30

Summary:

This investment involves the connection of new load customers to the distribution system, the upgrade of services for existing load customers, and cancelling existing services upon customer request as required to comply with statutory, regulatory and licence obligations. The primary trigger of the investment is customer service requests. The investment is expected to meet Hydro One's obligations to connect, upgrade, and cancel the services of requesting load customers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One is obligated to connect new customers to the distribution network, upgrade services where required to meet the needs of existing customers and cancel existing services upon customer request. The investments in the New Load Connections, Upgrades and Cancellations program in Orillia and Peterborough will allow Hydro One to meet the new and increased electrical needs of load customers, including a forecast of 2,873 new connections, 626 service upgrades and 356 service cancellations over the 2023-2027 period. These investments include the activities described below.

Pursuant to Hydro One's compliance responsibilities and commitments under the *Electricity Act, 1998,* Distribution System Code (DSC) and its distribution licence and conditions of service Hydro One is required to fulfill requests for connections or make an offer to connect all distribution customers in its service area on a non-discriminatory basis, upon written request for connection. A new connection normally requires the preparation of a service layout and installation of secondary service conductor and metering. A new connection may also require the installation or replacement of a service transformer, secondary bus or support structure, or modification or addition to the main distribution system. New connection work is divided into three major categories for forecasting: (1) non-subdivision new connections, (2) subdivisions, and (3) non-subdivision large expansions (single phase expansion projects greater than 1 km, or three phase expansion projects greater than 0.5 km).

Service Upgrades are upgrades of existing load connections in response to customer requests. A service upgrade normally requires the preparation of a service layout and replacement of secondary service conductors. A service upgrade may also require the replacement of the service transformer, secondary bus or metering, or modification of or addition to the main distribution system. Service upgrade work is divided into two major categories for forecasting: (1) service upgrades, and (2) large expansions (three phase expansion projects greater than 0.5 km).

For cancellations of existing service, Hydro One removes idle connection assets (such as transformers, wires and meters). Service cancellations happen in response to customer requests and for vacant premises.

Customer connections and upgrades are primarily driven by ongoing growth in residential, industrial and commercial load. Hydro One forecasts the following new connection, service upgrade and service cancellation volumes in Orillia and Peterborough for the 2023-2027 period:

Table 1 - New Connection, Service Upgrade and Service Cancellation Volumes

Description	2023	2024	2025	2026	2027
New Connections	569	572	575	577	580
Service Upgrades	124	124	125	126	127
Service Cancellations	70	70	72	72	72

The new connection, service upgrade and service cancellation volume forecasts are based on historic volumes.

B. INVESTMENT DESCRIPTION

Investments for New Load Connections, Upgrades and Cancellations are required to fund the design and construction activities associated with customer connections and removals in Orillia and Peterborough.

NEW CONNECTIONS

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to provide a connection service to new industrial, commercial and residential customers when requested. Work to provide a new connection may include, as required: performing distribution system impact assessments to ensure the system is sufficient to accommodate the connection without negative impacts on the new or existing customers and identifying necessary system modifications, providing high-level initial cost estimates to the customer, detailed design of the connection and expansion, obtaining easements and municipal consent to construct new facilities, performing economic evaluations, preparing offers to connect, and constructing and commissioning the necessary facilities. The division of costs between Hydro One and the customer is determined based on the company's connection policies, which are in accordance with the DSC requirements. A basic connection consisting of a service layout, overhead transformation, 30 meters of overhead conductor (for residential only), and standard retail metering, is provided free of charge to new customers that lie along the existing network, as per the DSC requirements. For customers that require expansion of the network to be connected, a discounted cash flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and system expansion.

SERVICE UPGRADES

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to respond to existing customers who require a larger service to accommodate additional load and/or modify their electrical service entrance. Work to provide a service upgrade may include, as required: performing distribution system impact assessments to ensure the system is sufficient to accommodate the connection without negative impacts on the existing customers and identifying necessary system modifications, providing high-level initial cost estimates to the customer, detailed design of the connection and expansion, obtaining easements and municipal consent to construct new facilities, performing economic evaluations, preparing offers to connect, and constructing and commissioning the necessary facilities. A service upgrade typically requires the replacement of secondary service wires and the preparation of a service design. It may also be necessary to upgrade transformer(s), replace meters or install additional transformers. For standard service upgrades, Hydro One will provide a service layout, pole-mounted transformer, and the meter installation, if required. Costs for service modifications beyond the standard service upgrade are recovered from the customer. Hydro One's customer capital contribution policies adhere to DSC requirements.

SERVICE CANCELLATIONS

Service cancellations involve customer requests for permanent disconnection from the distribution system, or connection assets that are unused for a prolonged period (vacant premises). Hydro One removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. As this work involves the removal of Hydro One owned equipment, these costs are accounted for under depreciation and are not capitalized. Service cancellations are included in this program's "Removals" costs in the cost table below.

C. OUTCOMES

This investment will meet Hydro One's license obligations to connect requesting load customers and accommodate the upgrade of existing load connections. It will also meet the need to cancel the services of requesting customers, including the removal of idle connection assets.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 2 - Outcome Summary

Customer Focus	• Fulfill customer requests for connections and upgrades within established time frames to ensure customer satisfaction.
Operational Effectiveness	• Ensure all new connections or upgrades meet latest standards. • Remove assets when services are cancelled to mitigate safety risks.
Public Policy Responsiveness	• Comply with Section 28 of the Electricity Act, 1998, and Section 7 of Hydro One's Distribution Licence to provide new connections or service upgrades when requested by customers.

D. EXPENDITURE PLAN

Planned costs for the program are based on unit costs and a forecast of future request volumes. The actual program costs will be comprised of the individual connections, upgrades, and service cancellations completed on an annual basis. The main factors impacting the program's cost are the number of requests received and the amount of main system and connection asset work required to accommodate the requests.

D.1 EXPENDITURE PLAN - ORILLIA

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	1.27	1.32	1.35	1.39	1.42	6.75
Less Removals	0.07	0.07	0.08	0.08	0.08	0.38
Capital and Minor Fixed Assets	**1.20**	**1.25**	**1.27**	**1.31**	**1.34**	**6.37**
Less Capital Contributions	0.22	0.23	0.23	0.24	0.24	1.16
Net Investment Cost	**0.98**	**1.02**	**1.04**	**1.07**	**1.10**	**5.21**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 4 below summarizes projected spending on the aggregate investment level.

Table 4 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	2.28	2.37	2.43	2.49	2.56	12.13
Less Removals	0.12	0.12	0.13	0.13	0.13	0.63
Capital and Minor Fixed Assets	**2.16**	**2.25**	**2.30**	**2.36**	**2.43**	**11.50**
Less Capital Contributions	0.42	0.43	0.44	0.45	0.47	2.21
Net Investment Cost	**1.75**	**1.82**	**1.86**	**1.91**	**1.96**	**9.30**

E. ALTERNATIVES

No alternatives are considered. Not proceeding with these investments would result in non-compliance with Hydro One's obligations under its distribution license requirements and the DSC.

F. EXECUTION RISK AND MITIGATION

Hydro One successfully connects several thousand load customers to its distribution system every year, and therefore does not anticipate any major risks to this program.

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D-SA-03	**CUSTOMER DEMAND DISTRIBUTED ENERGY RESOURCES**
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.01	0.01	0.01	0.01	0.01	0.05
Net Cost - Peterborough	0.01	0.01	0.01	0.01	0.01	0.05

Summary:

This investment involves funding for modifications to the distribution system required to connect new Distributed Energy Resource (DER) facilities. The funding will continue to enable the connection of renewable energy projects under various programs. The connection of DER is integral to meet the energy demands of the province, as well as to support reducing peak demand. The primary trigger of the investment is customer service requests. The investment is expected to meet Hydro One's distribution license obligations to connect DER that meet the requirements of the Distribution System Code.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The Distribution System Code (DSC) and Hydro One's distribution license obligate it to connect Distributed Energy Resources (DER) that meet the requirements of the DSC. The connection of DER to Hydro One's distribution system has added a significant amount of renewable energy in Ontario under different IESO programs and the Ontario Net Metering program.

DER activity in Ontario has shifted from retail generators participating in historical IESO procurement programs to behind-the-meter (BTM) load displacement generators participating in the IESO's Industrial Conservation Initiative (ICI) program and the Ontario Net Metering program. Previously, the dominant source of renewable DER applications had been the Feed-in Tariff (FIT) program which was terminated in 2017. The Net Metering program is still limited to renewable DERs and remains active and regulated by Ontario Regulation 541/05 (O. Reg. 541/05).

The IESO ICI program allows large distribution connected load customers to reduce their Global Adjustment cost by reducing their contributions to peak electricity use during the top five Ontario peak hours. Most of these projects are non-renewable and range in size from 500 kW to 20 MW depending on size of the load facility. Since 2018, the DER applications received by Hydro One have been primarily combined heat and power/co-generation, natural gas, diesel and battery energy storage systems (BESS). The cost for connecting these non-renewable energy projects to Hydro One distribution system is 100% recoverable from the DER customers. Currently, Hydro One is receiving a moderate number of DER applications under the IESO ICI program.

The only active renewable energy program in place in the province of Ontario is the Net Metering program, which is regulated by O. Reg. 541/05. The Net Metering program provides opportunities to all types of customers including residential, commercial and industrial to reduce their bills by offsetting their energy costs through renewable generation. Based on these two programs, the number of projects in Orillia and Peterborough forecast for 2023 to 2027 is shown in Table 1.

Table 1 - DER Forecast for 2023-2027

		Forecast Projects				
Year		2023	2024	2025	2026	2027
Non-Renewable Energy Projects	> 10 kW	1	1	1	1	1
	≤ 10 kW	0	0	0	0	0
Renewable Energy Projects	> 10 kW	2	2	2	2	2
	≤ 10 kW	4	4	4	4	4

This DER project forecast is based on current active DER programs. The IESO has recently launched an RFP for procurement of new generation which may result in additional DER connection requests. It is unknown if these requests will be renewable or non-renewable or if these requests will be inside Orillia / Peterborough territory.

B. INVESTMENT DESCRIPTION

The investments in this ISD modify and, as necessary, upgrade Hydro One's Distribution System to connect new DER in Orillia and Peterborough. These upgrades are necessary to prevent equipment damage and preserve power quality to existing load customers. DER customers make capital contributions to the connection work in accordance with Hydro One's connection policy and the cost allocation as required by the DSC. The required funding in excess of these contributions is provided by Hydro One. Hydro One continues to apply the DSC rules related to renewable energy projects by funding a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement (REI) investments. The costs for non-renewable energy projects are 100% recoverable from the DER customers.

The investments in this program are managed on a project basis. Each DER project involves estimating, design, labour, material and the costs associated with its physical connection to Hydro One distribution system. The typical scope of work required to enable the connection of DER to Hydro One's distribution system includes but is not limited to the following:

- the connection of the customer's tap line to Hydro One distribution system;
- building of new line expansions or upgrade of the existing line conductor;
- revenue metering upgrades;
- upgrades to the monitoring, protection, and control system;
- upgrades of in-line reclosers or station reclosers;
- the addition of new voltage regulators; and
- upgrades to the existing line voltage regulator controls.

C. OUTCOMES

This investment will facilitate the connection of DERs in Orillia and Peterborough without compromising system reliability by maintaining power quality, proper protection and loading capability of the distribution assets.

C.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcome Summary

Customer Focus	• Maintain customer satisfaction by connecting new DER within contractually established timeframe.
Operational Effectiveness	• Ensure that all upgrades are made to the latest Hydro One standards to maintain reliability of the distribution system.
Public Policy Responsiveness	• Comply with the requirements of DSC Section 6.2.4 and Hydro One's Electricity Distribution Licence to connect qualifying DER. • Enable the connection of renewable energy projects in the Province of Ontario under various programs.

D. EXPENDITURE PLAN

The investment forecasts provided in the following tables are based on forecast DER connections.

D.1 EXPENDITURE PLAN - ORILLIA

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.11	0.11	0.11	0.11	0.11	0.55
Less Removals	0.00	0.00	0.00	0.00	0.00	0.00
Capital and Minor Fixed Assets	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.55**
Less Capital Contributions	0.10	0.10	0.10	0.10	0.10	0.50
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.05**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 4 below summarizes projected spending on the aggregate investment level.

Table 4 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.11	0.11	0.11	0.11	0.11	0.55
Less Removals	0.00	0.00	0.00	0.00	0.00	0.00
Capital and Minor Fixed Assets	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.55**
Less Capital Contributions	0.10	0.10	0.10	0.10	0.10	0.50
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.05**

E. ALTERNATIVES

This is a demand-based program for connecting new DER to the distribution system. No alternatives are considered, as not proceeding with these investments would result in non-compliance with the requirements of Hydro One's distribution license and the DSC.

F. EXECUTION RISK AND MITIGATION

Hydro One connects a significant number of DER to its distribution system every year on demand. Subject to no policy changes, there are no expected major execution risks. However, there is potential for normal project risks that may affect the specific timing of individual projects, such as outage availability, volume of requests, weather, materials availability and other such variables.

These risks are mitigated by working with customers to set a schedule that aligns with outage availability. The DER projects are prioritized to meet the required service obligations. This prioritization and timing are completed through scheduling of work. Hydro One also maintains communication with the customer to ensure that all requirements are met so the parties can complete their connection by the agreed upon in-service date.

D-SA-04	**METERING SUSTAINMENT**
Primary Trigger:	Mandated Service Obligation
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost – Orillia	0.15	0.06	0.04	0.06	0.10	0.41
Net Cost - Peterborough	0.57	0.57	0.56	0.49	0.54	2.72

Orillia Summary:

Hydro One currently owns, operates, and maintains approximately 15,000 Sensus Flexnet smart meters operating on a proprietary licenced 900 MHz point to multi-point network in Orillia. Cellular point-to-point meters are also employed in select locations where the network has insufficient range. The primary trigger for the Metering Sustainment investment is regulatory compliance. This investment ensures sufficient meter inventory and resources for replacing failed retail meter installations in a timely manner for reliable customer billing in accordance with the OEB *Distribution System Code* and performing meter sample testing programs and replacing failing meter equipment in accordance with Measurement Canada's *Electricity Gas and Inspection and Weights and Measures Acts*. Sensus meters have an approximate service life of 15-20 years and the projected average meter failure rate over the 2023-2027 period is expected to be 0.43% per annum based on historical meter performance and the age profile of the Hydro One Sensus meter population.

Peterborough Summary:

Hydro One currently owns, operates, and maintains approximately 38,000 retail revenue metering devices and four wholesale meter installations in Peterborough. The bulk of the retail meter population is served by Honeywell Advanced Metering Infrastructure (AMI). Cellular point-to-point meters are also employed in select locations where the Honeywell mesh network has insufficient range. The primary trigger for Metering Sustainment investments is regulatory compliance. This investment ensures sufficient meter inventory and resources for replacing failed retail meter installations in a timely manner for reliable customer billing in accordance with the OEB *Distribution System Code*; performing meter sample testing programs and replacing failing meter equipment in accordance with Measurement Canada's *Electricity Gas and Inspection and Weights and Measures Acts*; and ensuring wholesale revenue meter installations are in compliance with *IESO Market Rules for the Ontario Electricity Market.* Honeywell retail meters have an approximate service life of 15-20 years and the projected average meter failure rate over the 2023-2027 period is forecast to be 3.6% per annum based on historical failure rates and the age profile of the Hydro One Honeywell meter population.

A. INVESTMENT NEED

This section of the ISD identifies the investment needs for Orillia and Peterborough and is organized as follows:

- Section A1 identifies common drivers for revenue metering investments;
- Section A2 identifies the specific drivers for Orillia revenue metering investments; and.
- Section A3 identifies specific drivers for Peterborough revenue metering investments.

A.1 INVESTMENT NEED - COMMON DRIVERS

The metering sustainment program funds investments ensuring the reliable measurement of electricity for customers in accordance with several regulatory requirements:

- Measurement Canada's *Electricity Gas and Inspection Act* (R.S.C., 1985, c. E-4) and related regulations setting out requirements that meters be resealed at specified intervals to ensure meter accuracy. Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended via compliance testing or be replaced. In addition, the Act sets out obligations for ensuring good repair of equipment.
- Measurement Canada's *Weights and Measures Act* (R.S.C., 1985, c. W-6) and related regulations setting out requirements for the approval and certification of meters, and related regulations requiring devices be maintained in proper operating condition.
- Ontario Energy Board's *Distribution System Code* (March 2020) setting out regulatory service standards requiring distributors to issue no more than two estimated bills every 12 months and to issue an accurate bill to customers at least 98% of the time;
- Ontario Energy Board's *Standard Supply Code for Electricity Distributors* (Oct. 13, 2020), setting out customer billing requirements; and
- IESO *Market Rules for the Ontario Electricity Market* (Feb. 26, 2021), Chapter 6, Wholesale Metering, setting out requirements for wholesale metering installations.

These requirements are achieved by replacing failed retail and wholesale meter installations in a timely manner to maintain reliable customer billing, performing mandated meter sampling and reverification programs, and performing the necessary upgrades and replacement of failed meters.

Given current failure rates and the up-to 20 year expected service life of the meters in Orillia and Peterborough, mass deployment of replacement meters is not proposed for the current 2023-2027 period.

Meter failures

Meter failures occur for several reasons (e.g., reaching the end of their service life, storm damage, vandalism, fire damage, manufacturer defects, etc.) and their replacement is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

Meter Sampling and Reverification

Hydro One must perform meter sampling and reverification programs in accordance with Measurement Canada regulatory requirements. Measurement Canada has jurisdiction over the administration and enforcement of the *Weights and Measures Act* and *Electricity Gas and Inspection Act*. These Acts govern Hydro One's ability to bill its customers for electricity usage, and require all meters be resealed at pre-determined intervals to ensure electricity use is metered accurately. Once a seal expires, the meter cannot be used for billing purposes and must either have its seal period extended (via compliance testing) or be replaced. For homogeneous meter batches, Measurement Canada allows a sampling protocol to verify meter accuracy. If the statistical accuracy from sample testing is within required levels, all the meters in the sample batch receive a seal extension. Certain meters need to be re-verified and tested individually because they do not fit within the sampling program and are required to be removed for testing and replaced with new meters. Table 1 below provides the meter inventory required for sampling and reverification purposes.

A.2 INVESTMENT NEED - ORILLIA

Hydro One owns, operates, and maintains a Sensus Flexnet Advanced Metering Infrastructure (AMI) system comprised of approximately 15,000 smart meters operating on the licenced 900 Mhz radio frequency spectrum in Orillia. Cellular point-to-point meters are also employed in select locations where the Sensus network has insufficient range.

The key drivers of the metering sustainment program investments are replacing failed meters and sample testing and reverification of meters in accordance with Measurement Canada guidelines.

Meter Failures

Sensus meters have a service life of approximately 15–20 years. The projected meter failure rate over the 2023-2027 period, based on historical meter performance and accounting for the age profile of the meter population, is 0.43% per annum[1] or approximately 334 meter failures.

Meter Sampling and Reverification

Error! Reference source not found. below provides the number of meters required to meet meter sample testing and reverification requirements in the 2023-2027 period based on Measurement Canada guidelines.

Table 1 - Orillia Meter Sampling & Reverification Program (2023-2027)

Meters	2023	2024	2025	2026	2027
Reverification	75	66	6	34	34
Sampling	100	0	0	100	350
Total	**175**	**66**	**6**	**134**	**384**

A.3 INVESTMENT NEED - PETERBOROUGH

Hydro One owns, operates, and maintains a Honeywell Advanced Metering Infrastructure (AMI) system comprised of approximately 38,000 smart meters and 55 network devices (Gatekeepers) in Peterborough. Cellular point-to-point meters are also employed in select

[1] Meter failure projections are based on Sensus meter performance in the former Haldimand and Norfolk Hydro service territories.

locations where the network has insufficient range. In addition, Hydro One owns, operates, and maintains four wholesale meter installations in Peterborough.

The key drivers of the metering sustainment program investments are replacing failed retail meters and network devices, and meter sample testing programs. In addition, wholesale revenue meter installations must be inspected and maintained, and failed wholesale meters and instrument transformers must be replaced as required.

Meter and Network Device Failures

Honeywell retail meters have a service life of approximately 15-20 years. The projected meter failure rate over the 2023-2027 period, based on historical meter performance and accounting for the age profile of the meter population, is 3.6% per annum[2] or approximately 7,000 meter failures. Approximately three network devices are projected to fail annually during the forecast period based on historical failure rates.

Meter Sampling and Reverification

Table 2 below provides the number of meters required to meet meter sample testing and reverification requirements in the 2023-2027 period based on Measurement Canada guidelines.

Table 2 - Peterborough Meter Sampling & Reverification Program (2023-2027)

Meters	2023	2024	2025	2026	2027
Reverification	44	31	32	58	27
Sampling	100	156	356	256	874
Total	**144**	**187**	**388**	**314**	**901**

[2] Meter failure projections are based on Honeywell meter performance in the former Woodstock Hydro service territory.

B. INVESTMENT DESCRIPTION

B.1 INVESTMENT DESCRIPTION - ORILLIA

The Metering Sustainment program funds the following needs over the 2023-2027 period:

- Replacing the approximately 334 Sensus meters that are projected to fail;
- Ensuring approximately 765 meters are available to address Measurement Canada sampling and reverification regulatory requirements (see Table 1); and
- Upgrading 2.5 element meter installations to 3.0 element to improve metering accuracy and meet Measurement Canada requirements.

B.2 INVESTMENT DESCRIPTION - PETERBOROUGH

The Metering Sustainment program funds the following needs over the 2023-2027 period:

- Replacing the approximately 7,000 Honeywell meters and 15 network devices that are projected to fail;
- Ensuring there are approximately 1,934 meters available to address Measurement Canada sampling and reverification requirements (see Table 2); and
- Replacing wholesale revenue metering instrument transformers based on historical instrument transformer failure rates.

C. OUTCOMES

Metering sustainment investments contribute to the following outcomes:

- Maintaining billing accuracy in accordance with the OEB's *Distribution System Code* by replacing failed meters in a timely manner and thus reducing estimated bills and bill corrections;
- Maintaining compliance with various requirements such as Measurement Canada's *Electricity Gas and Inspection Act* and regulations, and the IESO *Market Rules* to enable accurate and reliable billing;
- Ensuring a reliable source of billing settlement data that increases customer confidence and satisfaction that bills are accurate;

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - Outcome Summary

Customer Focus	• Maintaining billing reliability and accuracy. • Reducing the duration of customer interruptions by maintaining an adequate inventory of components for timely replacement of failures. • Maintaining timely customer access to energy usage information.
Operational Effectiveness	• Reducing the need for manual meter reading. • Maintaining meter network reliability to ensure a reliable source of billing settlement data. • Maintaining operational efficiencies gained through the installation of smart meters
Public Policy Responsiveness	• Compliance with OEB *Distribution System Code* (March, 2020) s. 5.1 and 7.11 requirements for metering services and billing accuracy. • Compliance with OEB *Standard Supply Service Code* (Oct. 2020) s.3.1 and 3.5 provisions for rates and consumer RPP pricing options. • Compliance with various provisions of the *Electricity and Gas Inspection Act*, R.C.S 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and ensuring meters are in good repair. • Compliance with various provisions of the *Weights and Measures Act*, R.S.C. 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and meter maintenance. • Compliance with IESO Market Rules for the Electricity Market (Feb. 2021), Chapter 6: Wholesale Metering.
Financial Performance	• Contributes to financial performance by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner.

D. EXPENDITURE PLAN

The costs for this program are projected based on historic labour costs, material unit costs, and future anticipated needs. These costs, in turn, are driven by the terms of procurement contracts and the types of devices requiring replacement or sampling. Controllable costs have been optimized through standardization of metering device purchasing specifications and vendor contracts to secure unit pricing for procurement of materials.

D.1 EXPENDITURE PLAN - ORILLIA

Table 4 below summarizes projected spending on the aggregate investment level.

Table 4 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.15	0.06	0.04	0.06	0.11	0.43
Less Removals	0.00	0.00	0.00	0.00	0.00	0.02
Capital and Minor Fixed Assets	**0.15**	**0.06**	**0.04**	**0.06**	**0.10**	**0.41**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.15**	**0.06**	**0.04**	**0.06**	**0.10**	**0.41**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 5 below summarizes projected spending on the aggregate investment level.

Table 5 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.59	0.59	0.58	0.51	0.56	2.83
Less Removals	0.02	0.02	0.02	0.02	0.02	0.11
Capital and Minor Fixed Assets	**0.57**	**0.57**	**0.56**	**0.49**	**0.54**	**2.72**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.57**	**0.57**	**0.56**	**0.49**	**0.54**	**2.72**

E. ALTERNATIVES

This investment is non-discretionary. No alternatives were considered, since failure to perform the work to repair and/or replace the meters and the associated network would not comply with regulatory requirements discussed in Section A.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated. Meter availability risk will be mitigated by optimizing inventory through an enhanced forecasting process (readjusting based on failures), and working closely with vendors.

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D-SR-01	**DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM**
Primary Trigger:	Asset Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness,

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.04	0.04	0.05	0.05	0.05	0.22
Net Cost - Peterborough	0.10	0.10	0.11	0.11	0.11	0.52

Summary:

This investment involves the replacement of failing and failed station components to maintain system reliability or restore power supply to customers in Orillia and Peterborough. This investment also addresses environmental concerns such as the replacement of station service transformers with high polychlorinated biphenyls (PCB) content to meet Environment Canada regulations.

The primary trigger of the investment is asset failure risk: replacing station assets that have failed or are subject to imminent failure.

The investment is expected to sustain system reliability and operation by replacing failed station equipment in a timely manner, minimizing customer outage duration. This investment is also expected to mitigate failures by removing transformers from service that are at risk of imminent failure before failures occur. The replacement of station equipment containing high PCB content will enable Environment Canada end-of-use deadlines to be met.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Asset failures or unplanned system deficiencies associated with various distribution station assets (transformers, breakers, reclosers, switches, insulators, station batteries and chargers, etc.) require immediate response by Hydro One personnel. If not rectified in a timely manner, such deficiencies and failures may result in significant service interruptions that require lengthy efforts to restore power, or present safety hazards to Hydro One employees or customers near the station or close to feeders protected by station equipment.

Service interruptions related to distribution stations can be addressed in some cases through switching and corrective repairs, while others must be addressed by replacement of failed station equipment through this investment program.

TRANSFORMERS

Hydro One monitors the condition of station transformers through routine inspections, annual oil sampling, and diagnostic testing, based on which a condition rating of “poor”, “fair”, or “good” is assigned. Hydro One manages its fleet of fair-condition transformers through corrective repairs and oil sampling. The fleet of poor-condition transformers is managed through a combination of corrective repairs, planned transformer replacements, and frequent oil sampling. Poor condition transformers have the highest likelihood of failure. When it is discovered that failure of a poor condition transformer is imminent, Hydro One will force the transformer out of service prior to the failure.

However, despite these efforts, transformer failures still occur and cannot be eliminated. There are also external factors that cause station transformers to fail such as lightning, system faults and animal contacts.

OTHER FAILED STATION COMPONENTS

Hydro One inspects rural stations every six months and urban stations monthly. These regular inspections may identify damaged or failed distribution station assets that pose a safety hazard to customers or Hydro One employees and must therefore be promptly replaced. Broken insulators that support switches or buses are one such example. If they are not replaced, they can lead to equipment falling down. Failed station batteries or chargers that are used to operate breakers are another example. If these are not replaced, feeder breakers may not open when required to interrupt system faults, posing a public safety hazard.

ENVIRONMENTAL NEEDS

In addition to replacing damaged or failed distribution station assets, there is a need to address unplanned environmental concerns in stations. Hydro One must sample all oil-filled assets and remove PCB content at or above 50 ppm by 2025. When station service transformers and instrument transformers are sampled and found to have high PCB content, they must be replaced. These assets are most efficiently addressed through an unplanned capital program rather than a planned program, as it is difficult to predict the number of station service transformers or instrument transformers that will be found to have PCB content at or above 50 ppm (as oil sampling is ongoing), and the quantities of such transformers are likely to be small.

B. INVESTMENT DESCRIPTION

This investment addresses the following distribution station asset needs in Orillia and Peterborough:

- Replacement of failing or failed equipment such as transformers, breakers, reclosers, switches, insulators, station batteries, and chargers to maintain distribution system reliability and operation.
- Replacement of high-PCB station service transformers and instrument transformers when they are identified.

Demand station work such as the replacement of failed or failing equipment are difficult to predict but must be addressed quickly, to mitigate customer interruptions and environmental risks.

C. OUTCOMES

Customers will benefit from this investment through sustained reliability and system operation resulting from the replacement of failed station equipment in a timely manner, which will minimize customer outage duration. Customers will also benefit from the replacement of failing station equipment before the failures occur, resulting in fewer customer interruptions and mitigating safety risk to customers and Hydro One employees.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Replacement of failed or high-risk equipment while minimizing customer interruption frequency and duration.
Operational Effectiveness	• Maintain distribution system reliability, operation and safety. Reduce safety risks associated with failed equipment.
Public Policy Responsiveness	• Comply with the Distribution System Code Appendix C – Minimum Inspection Requirements, to ensure that appropriate follow up and corrective action is taken regarding problems identified during inspections.

D. EXPENDITURE PLAN

The factors affecting the costs in this investment are as follows:

- The scope of the replacement required to address the failure;
- The type and number of failed assets requiring replacement (i.e., transformers, switches, breakers, reclosers, batteries, etc.);
- The type and number of station components requiring replacement on demand (i.e., station service transformers and instrument transformers with high PCB content, etc.);
- The ratings of the equipment requiring replacement.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.04	0.04	0.05	0.05	0.05	0.22
Less Removals	0.00	0.00	0.00	0.00	0.00	0.00
Capital and Minor Fixed Assets	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.22**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.22**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.10	0.10	0.11	0.11	0.11	0.52
Less Removals	0.00	0.00	0.00	0.00	0.00	0.00
Capital and Minor Fixed Assets	**0.10**	**0.10**	**0.11**	**0.11**	**0.11**	**0.52**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.10**	**0.10**	**0.11**	**0.11**	**0.11**	**0.52**

E. ALTERNATIVES

The replacement of failed or failing assets and assets with high PCB content are all non-discretionary. Failure to respond to these failed or poor condition assets would violate the Distribution System Code, Ministry of the Environment Conservation and Parks regulations, and Environment Canada regulations. It would also result in unacceptable reliability risks to customers. As a result, there are no alternatives.

The only feasible option is to replace failed or failing assets, and station service or instrument transformers with high PCB content.

F. EXECUTION RISK AND MITIGATION

The work in this investment is unplanned in nature. The primary risk for executing this unplanned work is the availability of spare power equipment to replace equipment that has failed. The lead time to acquire replacement equipment can delay project work. This risk is mitigated by maintaining a spares inventory and regularly monitoring spare inventory levels.

D-SR-04	**DISTRIBUTION STATION REFURBISHMENT**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	-	-	-	-	-	-
Net Cost - Peterborough	0.20	2.95	1.46	1.30	3.03	8.94

Summary:

This investment involves the planned replacement of station transformers that have been assessed to be in poor condition or are located on leased properties with environmental concerns. The primary triggers of the investment are the condition of the station transformer and/or property. The investment will also address other poor condition components within the station where appropriate in a bundled fashion. By proactively addressing poor condition transformers and equipment, this investment is expected to mitigate failures to maintain reliability of the distribution system.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One owns, maintains, and operates 29 distribution stations in Orillia and Peterborough. Assets in a distribution station include the transformer, reclosers and breakers, switches and fuses, station structure, fence, station grounding system, station service transformer, insulators, bus work, protection relays and intelligent electronic devices (IEDs).

The 29 distribution stations in Orillia and Peterborough consist of 34 distribution transformers. Transformer condition is assessed through oil sampling, thermography (infrared heat detection), and visual inspections. Many factors lead to the degradation of a transformer's internal components over time including transformer loading, switching, lightning surges, faults, moisture contamination, and paper insulation degradation. This deterioration and the resulting asset condition is one of the leading predictive indicators of transformer failure.

Hydro One has determined that in Peterborough many of the distribution station assets are in poor condition and will continue to deteriorate, leading to an increased likelihood of failures and associated increase in reliability and safety risk. As shown in Figure 1 below, approximately 52% (12) of Hydro One's distribution station transformers in Peterborough are in poor condition. These transformers are subject to an elevated risk of failure and are considered for replacement or corrective repair to address deficiencies before failures occur and impact service to distribution customers.

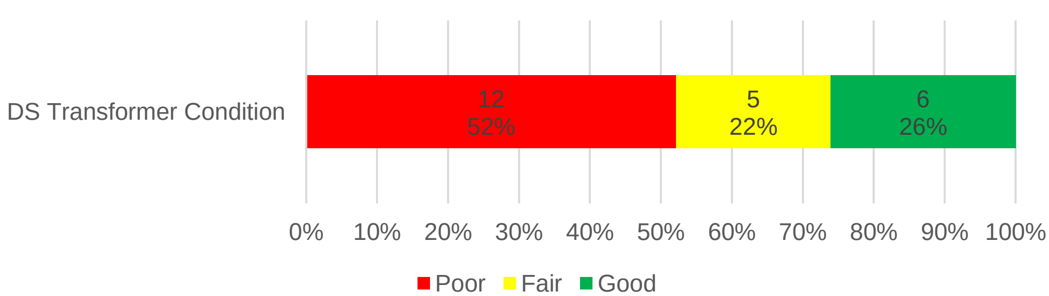

Figure 1: Peterborough Distribution Station Transformer Condition

In Orillia there are currently no distribution station transformers in poor condition as shown in Figure 2 below.

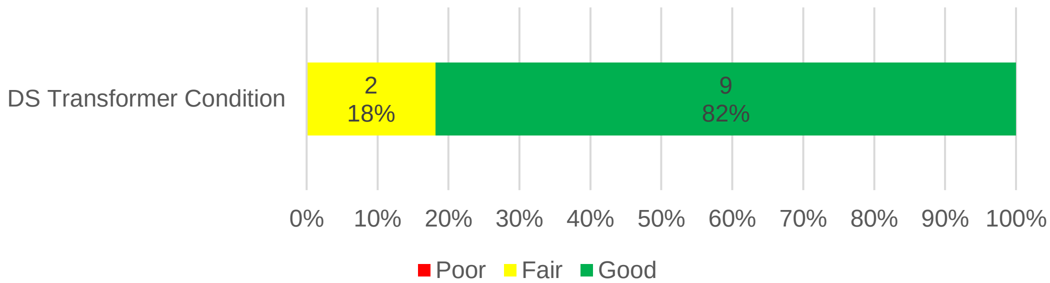

Figure 2: Orillia Distribution Station Transformer Condition

Station transformers are the most important asset component at a station. Poor-condition transformers need to be proactively addressed in a timely manner to limit the number of unplanned transformer failures. Without an adequate station refurbishment plan over the long term, there would be an expected increase in the number of failures resulting in unanticipated and potentially long duration outages for customers. Where a failure does not result in actual customer interruptions, a higher incidence would place pressure on the station demand capital program (D-SR-01).

This investment involves the relocation of a station on leased property in Peterborough that has environmental concerns and the planned replacement of station transformers that have been assessed to be in poor condition. If there are other station assets that are in poor condition and in need of replacement, they are also bundled with the transformer replacement. Equipment identified as obsolete is decommissioned (where no longer needed) or replaced with standard equipment along with the transformer replacement during refurbishment. Additionally, various station design elements will be taken into consideration such as higher capacity transformer units, additional station feeder positions and installing electronic reclosers to meet known future capacity requirements and installation of MUS structures to enable temporary bypass supply during station outages or a combination of these factors. Other factors considered include the potential need for soil remediation or mitigation of environmental risks.

In the event of a transformer failure at a distribution station, all customers supplied by that distribution station would either experience an interruption of service until power is restored through the repair/replacement of the failed equipment or where possible, customers will be temporarily transferred to another station. If planned refurbishment is not undertaken to address poor condition assets, unplanned failures will require Hydro One to transfer customer load to adjacent stations. This will load adjacent stations unimpacted by the failure, above normal operating levels, putting customers at risk of long outages in the event of subsequent station failures.

B. INVESTMENT DESCRIPTION

This investment involves the replacement of distribution stations in Peterborough to address station transformers and equipment identified as being in poor condition or distribution stations on leased properties with environmental concerns. This investment will relocate two stations located on leased properties to address environmental concerns, replacing 2 poor and 2 fair condition transformers in the process. In addition, this investment will refurbish 2 distribution stations in poor condition at their current locations, replacing 3 poor condition transformers in the process. Site locations, timing and costs for distribution stations included in this plan are shown in Appendix A.

When a station needs refurbishment, the overall station design and system needs are evaluated to determine the most cost-effective course of action. This includes an assessment of whether a pad-mounted distribution station (PDS) is a suitable solution. A PDS may be a low-cost option when compared to traditional refurbishments, due to the reduced cost of the power transformer, simplistic high/low voltage bus work, lack of station structure/fencing, and reduced engineering requirements. For a PDS to be a feasible alternative to a traditional refurbishment, specific criteria must be met. Examples of this criteria include limited existing (and forecast) loading due to PDS capacity limitations and adequate voltage support as the PDS design does not include the possibility of an Under Load Tap Changer (ULTC).

C. OUTCOMES

The station refurbishment program will result in the following outcomes:

- Maintain safe and reliable distribution system operation by addressing poor condition station transformers (bundled with other poor condition components where appropriate) through refurbishments.
- Relocate and rebuild stations that are on leased land with environmental concerns.
- Where appropriate, provide sufficient capacity to meet customer loading requirements for the foreseeable future.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Avoid customer interruptions by proactively addressing poor condition station transformers and equipment prior to failure.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by addressing poor condition station equipment in an integrated and cost-effective manner.
Financial Performance	• Realize cost savings by deploying cost-effective Padmount Distribution Stations where feasible. • Where appropriate, bundle other station components in poor condition as part of refurbishment work.

D. EXPENDITURE PLAN

The tables below summarize the projected spending on the aggregate investment level. The costs in this investment are forecast based on scope and historical costs of station refurbishment projects and padmount distribution stations.

The factors which could impact station refurbishment project costs within this investment include:

- Number of transformer banks;
- Size of transformer;
- Number of station feeders;
- Primary and secondary voltage level;
- Station design;
- Replacing or upgrading of station structure;
- Extent of civil work;
- Grounding system design;
- Procurement of real estate; and
- Environmental remediation required at the distribution and regulating station.

D.1 EXPENDITURE PLAN - ORILLIA

There are no forecast capital investments for this ISD in Orillia.

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.20	3.13	1.57	1.30	3.25	9.45
Less Removals	0.00	0.18	0.11	0.00	0.22	0.51
Capital and Minor Fixed Assets	**0.20**	**2.95**	**1.46**	**1.30**	**3.03**	**8.94**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.20**	**2.95**	**1.46**	**1.30**	**3.03**	**8.94**

E. ALTERNATIVES

Hydro One considered the following before selecting the recommended option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENTS

Wait for Distribution Station Equipment to Fail and Replace the Failed Components on a Reactive Basis.

This alternative is rejected for several reasons. Reactive management of stations would lead to degraded reliability for Hydro One's customers because of increases in station failures. The reactive replacements would be limited to addressing only the failed component and would not address other components in deteriorated condition that are also at risk of failure. Over time, the volume of failures would increase under this approach, requiring customer load to be transferred to adjacent stations. This would cause these stations to operate above normal operating levels, which may cause further power quality and reliability issues thus leading to a significant risk in system reliability and to potential outages.

ALTERNATIVE 2: PLANNED STATION REFURBISHMENTS *(RECOMMENDED)*

This alternative proactively addresses poor condition transformers and may include bundling of other poor condition components (such as station structure, MUS structures, fences, grounding systems, station service transformers, insulators and protection relays etc.) up to and including a full station refurbishment. Where required, this approach also allows the upgrading of the station to meet other needs such as load growth. Pad-mounted distribution stations are used to replace traditional stations where feasible as a lower cost alternative.

This alternative is recommended as it addresses needs identified at the station in the most cost-effective manner in order to maintain the reliability of supply.

F. EXECUTION RISK AND MITIGATION

The risks that can impact the completion of a station refurbishment project include the potential need to procure real estate to accommodate the station configuration, and potential environmental remediation of the site. These risks are mitigated by determining the requirements of the new station early in the project planning process, consulting with property owners and by requesting a land survey and environmental site survey before detailed design work has started.

APPENDIX A - DESCRIPTION OF INVESTMENTS

Project Name		Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
PDI MS#1 Station Replacement		Decommission 2 of 4 transformers at Alymer DS (MS#1) 44:4.16kV 4x3MVA station. Install 2x 3MVA Padmounted Distribution Stations (PDS) on new acquired locations and transfer load of two decommissioned transformers at MS#1 to the new PDSs.	0.00	0.00	0.00	0.70	1.60
PDI MS#8 Station Replacement		Decommission Peterborough Simcoe DS (MS#8) 44:4.16kV 2x3MVA station. Install two (2) 3MVA PDS to new acquired locations and transfer MS#8 supply to the PDS. Reconfigure 44kV line section outside the station to retain supply to two (2) existing 44kV customers.	0.00	0.41	1.46	0.49	0.00
PDI MS#18 Transformer Replacement		Refurbish 44:4.16kV 2x3MVA station to 2x3MVA PDS units.	0.00	0.00	0.00	0.11	1.43
PDI MS#29 Transformer Replacement		Refurbish 44:4.16kV 7.5MVA and 5MVA transformers to 4x3MVA PDS units.	0.20	2.54	0.00	0.00	0.00
Total			**0.20**	**2.95**	**1.46**	**1.30**	**3.03**

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D-SR-05	**DISTRIBUTION LINES TROUBLE CALL AND STORM DAMAGE RESPONSE PROGRAM**
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.07	0.07	0.07	0.07	0.07	0.34
Net Cost - Peterborough	0.33	0.34	0.34	0.35	0.36	1.71

Summary:

This investment involves the emergency replacement of distribution lines assets because they have either failed or have been determined to pose an immediate safety hazard. The primary trigger of the investment is demand-driven asset failure. The investment is required to restore systems to normal operation and to maintain reliability and safety.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is needed to respond to service interruptions or other system deficiencies on an urgent basis in compliance with the Distribution System Code.

Several situations may arise that cause service interruptions or other system deficiencies including severe weather or asset failures. Regular patrols and inspections may identify damaged or failed distribution assets that pose a safety hazard. Upon such occurrences or discoveries, Hydro One Distribution field crews must be dispatched to promptly assess and resolve any urgent deficiency. During storm conditions, poles that fail can sometimes trigger cascading failures, which result in the failure of a larger number of distribution system assets.

B. INVESTMENT DESCRIPTION

This demand program encompasses the capital costs for responding to trouble calls, storm damage, power interruptions, and other situations that pose reliability or safety risks and require immediate attention in Orillia and Peterborough.

The trouble call and storm damage response program includes the following activities:

- Emergency pole and equipment replacements.
- Emergency submarine and underground cable replacements.
- Storm damage response to resolve service interruptions caused by adverse weather conditions. This sub-program covers all costs for the response and replacement of failed assets (e.g., poles, conductors, transformers, reclosers, regulators and switches) caused by major storms.
- Post-trouble response to implement permanent solutions to any temporary repairs that were required during an emergency or a service interruption. Through this sub-program, Hydro One restores the affected part of the power system to original operations after the initial failure and emergency fix. Work is limited to correcting the area that is directly affected by the failure. Key work activities commonly include pole and transformer replacements.

- Damage claims, including payment for third-party damage that Hydro One Distribution cannot recover. Key work activities most commonly include pole replacement from motor vehicle accidents and conductor replacement from dig-ins or accidental contact.

C. OUTCOMES

The trouble call and storm damage program will result in:

- Ensuring Hydro One Distribution's ability to respond to trouble calls and service interruptions.
- Mitigating reliability and safety risks during and after emergency events.
- Complying with regulatory requirements with respect to timely incident response and restoration of supply.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Minimize customer interruption duration by carrying out demand work in a timely manner. • Address potential public safety hazards.
Operational Effectiveness	• Maintain the safe operation and performance of the distribution system by addressing immediate reliability and safety risks.
Public Policy Responsiveness	• Comply with Section 7 of the Distribution System Code to ensure timely response to storm damage, deficiencies and system outages

D. EXPENDITURE PLAN

The forecast expenditures for this demand program are calculated from the relative size of the distribution network and guided by the one year spend in the region.

The factors affecting the cost of the investment include:

- The amount of trouble call issues that arise in a given year.
- The scope of the work required to fix particular issues.
- The volume and severity of weather events across the province each year.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.08	0.08	0.08	0.08	0.09	0.41
Less Removals	0.01	0.01	0.01	0.01	0.01	0.05
Capital and Minor Fixed Assets	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.36**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.02
Net Investment Cost	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.34**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.38	0.39	0.40	0.41	0.42	2.01
Less Removals	0.05	0.05	0.05	0.05	0.05	0.24
Capital and Minor Fixed Assets	**0.34**	**0.35**	**0.35**	**0.36**	**0.37**	**1.77**
Less Capital Contributions	0.01	0.01	0.01	0.01	0.01	0.06
Net Investment Cost	**0.33**	**0.34**	**0.34**	**0.35**	**0.36**	**1.71**

E. ALTERNATIVES

No alternatives were considered since failure to quickly respond to service interruptions or other urgent situations involving failed or imminently failing assets would not be compatible with Hydro One's service obligations under the Distribution System Code and would result in unacceptable reliability and safety risks.

F. EXECUTION RISK AND MITIGATION

Hydro One successfully restores power to hundreds of thousands of customers every year, and therefore does not anticipate any major risks to this program. However, where the volume of restoration work exceeds resources due to major weather events, restoration is prioritized based on the greatest benefit to the most customers.

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D-SR-07	**POLE SUSTAINMENT PROGRAM**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.22	0.22	0.23	0.23	0.24	1.14
Net Cost - Peterborough	0.31	0.32	0.33	0.34	0.35	1.64

Summary:

This investment involves the planned replacement, and chemical and mechanical refurbishment of distribution poles where they have been assessed to be in poor condition or require ground line retreatment. The primary trigger of the investment is asset condition. By proactively targeting poor condition poles, this investment is expected to help maintain reliable operation of the distribution system and reduce the number of potential interruptions to customers. Additionally, chemically retreating poles proactively mitigates ground line rot and prevents further deterioration of poles at the ground line which is expected to extend pole life.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The structural integrity of a distribution line is largely dependent on the poles that support the line. Hydro One owns and maintains 4,265 poles in Orillia, of which 98% are wood poles and 8,639 poles in Peterborough, of which 96% are wood poles. Poles are critical to the operations of the distribution system, as structurally sound poles are necessary to support conductors and other overhead assets (transformers, switches, reclosers etc.) and to provide clearance from live conductors in publicly accessible areas.

The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, and other factors that erode their structural integrity. Once a pole has deteriorated to poor condition it poses a high risk of failure. Pole failures can have a significant impact on customer reliability, which is a risk that can be mitigated through proactive planning before interruptions occur. Hydro One inspects and tests its pole population to determine asset condition. Poles in poor condition are either planned for refurbishment or replacement.

POLES IN POOR CONDITION

There are currently 112 poles in Orillia and 307 poles in Peterborough that are in poor condition and at high risk of failure.

Poles are required to be inspected every six years in rural areas and every three years in urban areas as specified in the Distribution System Code, Appendix C. In 2019, Hydro One’s pole inspection program was combined with its forestry planning process. This means that the structures are inspected in line with Forestry’s Optimal Cycle Protocol. These inspections are primarily intended to identify visual deficiencies on the pole, including woodpecker holes, mechanical surface damage, surface rot, severe leaning, broken poles, or any other potential safety issues that must be addressed immediately. As an example, Figure 1 below shows three types of pole-related defects (in order from left to right): a woodpecker nesting hole, ground-line rot, and pole damage.

Figure 1: Examples of Poor-Condition Poles

Defects identified on the lines are also recorded during inspections, including damaged cross arms, insulator defects, and missing guys.

In addition to visual inspections to assess pole condition and potential refurbishment options, Hydro One collects supplementary condition data through a Test and Treat program, as discussed further below. This process is performed on a less frequent cycle than visual inspections, and only at the ground line. It involves proactively testing poles to assess their condition and chemically retreating poles at the ground line to extend their life. The Test and Treat program involves taking detailed measurements of the pole and the size of the damage, including drilling into the pole to assess the amount of internal rot. These measurements are used to calculate the remaining strength of the pole, expressed as a percentage of its design strength. This helps identify additional poles that require replacement (in addition to poor condition poles identified through visual inspections) or that can be mechanically refurbished.

RELIABILITY

On the Hydro One system, when a pole causes a forced outage it will result in an average 9.0 hour interruption (excluding force majeure (FM) events). When a pole requires a planned outage to replace it, the average outage duration is 2.4 hours. In addition, many planned pole replacements can be completed without any customer interruption. Proactive replacement of poles avoids the otherwise prolonged outage durations associated with a run-to-fail approach.

SAFETY

As poles are usually in publicly accessible spaces, there is potential for a pole failure to impact public safety. By replacing or refurbishing poles proactively through the planned sustainment program, this safety risk is reduced. When an immediate public or worker safety risk arises, those poles are addressed either through the trouble program or through the appropriate work procedures.

POLE MANAGEMENT OPTIONS

The Pole Sustainment Program consists of three investment approaches: Test and Treat, Pole Refurbishment, and Pole Replacement. The Test and Treat investment identifies poles that require replacement or mechanical refurbishment and will chemically refurbish the poles by treating the poles at the ground line. The Pole Refurbishment investment will restore mechanical strength by adding bracing to poles that have been determined to be in poor condition and which meet the criteria for refurbishment. The Pole Replacement investment will replace poles in poor condition that cannot be refurbished.

B. INVESTMENT DESCRIPTION

Pole sustainment investments impact sites in Orillia and Peterborough.

TEST AND TREAT

The Test and Treat investment proactively assesses the condition of poles and chemically refurbishes them through ground line treatment. The testing process involves visually assessing the exterior condition of the pole, drilling into the pole to measure the remaining strength, and inserting a copper borate retreatment product to extend the life of the pole. The data collected from this activity will supplement pole condition data that is acquired through visual inspections and help identify additional poles that require replacement or that can be mechanically refurbished.

POLE REFURBISHMENT

The Pole Refurbishment investment installs structural supports on poor-condition poles as an alternative to replacement. Poles that qualify for refurbishment include poles where the damage is isolated to the ground line, poles that are on road, and poles that do not have third-party attachments.

POLE REPLACEMENT

The Pole Replacement investment addresses the replacement of poles that are poor condition and cannot be refurbished.

PACING AND BUNDLING

The tables below outline the planned volume of poles in the proposed investment throughout the five-year period.

Table 1 - Orillia Planned Volumes

	2023	**2024**	**2025**	**2026**	**2027**
Test and Treat	360	360	360	360	360
Pole Refurbishment	4	4	4	4	4
Pole Replacement	31	31	31	31	31

Table 2 - Peterborough Planned Volumes

	2023	**2024**	**2025**	**2026**	**2027**
Test and Treat	750	750	750	750	750
Pole Refurbishment	6	6	6	6	6
Pole Replacement	40	40	40	40	40

Depending on the types of poles requiring replacement (i.e., pole height, pole class, number of circuits, etc.) and the accessibility conditions of the area, the cost of replacement can vary. Where possible, the efficiency of this investment is improved by bundling poles and replacing or refurbishing poles in close proximity to each other.

C. OUTCOMES

The pole sustainment program will result in:

- Addressing poor condition poles in order to help maintain reliability and reduce the number of potential interruptions to customers
- Refurbishment of poles where possible as a lower cost alternative to pole replacement
- Chemically retreating poles proactively to prevent further deterioration at the ground line which is expected to extend pole life.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - Outcome Summary

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing or refurbishing wood poles prior to failure.
Operational Effectiveness	• Maintain reliable operation of the distribution system by proactively targeting and addressing poor-condition poles that pose the highest reliability risk. • Extend pole life through chemically retreating poles to mitigate ground line rot and prevent further deterioration at the ground line.

D. EXPENDITURE PLAN

Costs are based on unit-price estimates that are set based on recent historic spending and the volume of work projected for the 2023-2027 period.

The factors influencing the cost of the investment include:

- The types of poles requiring replacement (i.e., pole height, pole class, number of circuits, etc.);
- The location accessibility conditions of the area in which the poles are being replaced (accessing off-road locations is typically more costly due to the use of specialized equipment); and
- The cost of material.

D.1 EXPENDITURE PLAN - ORILLIA

Table 4 below summarizes projected spending on the aggregate investment level.

Table 4 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.25	0.25	0.26	0.26	0.27	1.29
Less Removals	0.03	0.03	0.03	0.03	0.03	0.16
Capital and Minor Fixed Assets	**0.22**	**0.22**	**0.23**	**0.23**	**0.24**	**1.14**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.22**	**0.22**	**0.23**	**0.23**	**0.24**	**1.14**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 5 below summarizes projected spending on the aggregate investment level.

Table 5 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.35	0.37	0.37	0.38	0.39	1.87
Less Removals	0.04	0.04	0.04	0.05	0.05	0.22
Capital and Minor Fixed Assets	**0.31**	**0.32**	**0.33**	**0.34**	**0.35**	**1.64**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.31**	**0.32**	**0.33**	**0.34**	**0.35**	**1.64**

E. ALTERNATIVES

Hydro One adapted its existing approach to Pole Sustainment for Orillia and Peterborough, where the following alternatives would have been considered.

ALTERNATIVE 1: REACTIVE REPLACEMENTS

This alternative entails a reactive replacement approach, whereby failed poles would be addressed solely through the trouble program (ISD D-SR-05). Under this alternative, Hydro One would not test and treat poles, structurally refurbish poles, or proactively replace poles. Instead, pole condition will be monitored through the safety patrols being performed as part of the vegetation management program, and poles that have failed or have the potential to cause an immediate public safety issue will be replaced on a reactive basis. This alternative is rejected as reactive management of poles will lead to increased failures resulting in degraded reliability for Hydro One’s customers and an overall increased risk to public safety.

ALTERNATIVE 2: RECOMMENDED

Under this preferred alternative, Hydro One Distribution will test and treat poles on a 10-year cycle, structurally refurbish poles when possible, and replace approximately 71 poles per year across both Orillia and Peterborough. This alternative is recommended because it addresses the risk of poor condition poles failing within the planning period.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Investment include access to the assets depending on the season, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders. In the event a necessary outage cannot be obtained, the order of pole replacements will be adjusted as appropriate to ensure that program work execution is not disrupted.

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D-SR-08	**DISTRIBUTION LINES MINOR COMPONENT REPLACEMENT**
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.04	0.04	0.04	0.04	0.04	0.20
Net Cost - Peterborough	0.14	0.14	0.14	0.15	0.15	0.72

Summary:

This investment involves the replacement of several minor distribution lines components that are not specifically addressed under other lines-related distribution capital investments. The scope of this investment includes the replacement of cross arms in poor condition, the replacement of substandard and obsolete transformers, the installation of bird nest platforms, and the replacement of failed sentinel lights. The triggers of this investment are condition (in the case of cross arms), obsolescence (in the case of substandard transformers), and compliance (in the case of nest platforms and sentinel lights). This investment is expected to improve reliability and to help meet Hydro One's obligations with respect to the affected assets.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system includes 241 circuit kilometers of primary lines in Orillia and 545 circuit kilometers of primary lines in Peterborough. These lines are the primary means by which electricity is delivered to distribution customers.

Hydro One performs line patrols to assess the condition of a large variety of components on these distribution lines. These condition assessments can identify line components that are in poor condition. Additionally, some line components on the distribution system can be obsolete or can pose safety or environmental risks. Where applicable, Hydro One replaces or refurbishes these components to mitigate these risks and/or to maintain reliability of the system.

Planned replacements and refurbishments of line components in poor condition are primarily addressed via larger capital investments, as described in D-SR-07 (poles) and D-SR-10 (distribution lines sustainment initiatives). Additionally, component issues that are suitable for maintenance or corrective actions are addressed through OM&A expenditures.

Aside from these capital investments and OM&A expenditures, there remains a need to address several other line components. This 'Distribution Lines Minor Component Replacement' investment addresses these specific operational risks and/or customer service obligations. Based on the requirements of the Hydro One distribution system, these line components may include:

- Cross arms;
- Substandard transformers;
- Nest platforms; and
- Sentinel lights.

This investment summary document describes these other capital component replacement investments in more detail.

B. INVESTMENT DESCRIPTION

This investment addresses the individual replacement or refurbishment of distribution line components in Orillia and Peterborough when it is not economical to integrate the work into other lines-related capital investments (namely, D-SR-07 and D-SR-10). This investment can include the following types of work:

CROSS ARMS

Overhead conductors are often supported by cross members known as “cross arms”. Cross arms are typically made of wood, although composite and steel cross arms may be used when increased strength is required. Cross arms are visually inspected on a regular basis, and broken, cracked, or otherwise damaged arms are identified for replacement.

SUBSTANDARD TRANSFORMERS

Certain types of line transformers have been identified as being obsolete or substandard. These transformer types include:

- Overhead transformers installed in underground-type enclosures;
- Transformers installed within steel poles; and
- Specific delta-wye connected transformers.

Installations of this type are obsolete and are replaced to mitigate operational and/or safety risks.

NEST PLATFORMS

Bird nests on distribution poles can potentially interfere with the safe and reliable operation of the distribution system. The presence of large nests increases the risk of pole fires. In addition, the birds themselves can contact distribution lines, causing outages to downstream customers and leading to the injury or death of the bird.

Bird nests are identified through regular inspection of distribution lines. When such nests are identified, they need to be relocated to safeguard the integrity of the distribution system and comply with all applicable regulations, including under the *Migratory Birds Convention Act, 1994*.

SENTINEL LIGHTS

Sentinel lighting is a service offered by Hydro One to install and maintain overhead dusk-to-dawn lighting for Hydro One customers (typically in rural settings without street lighting). While Hydro One no longer offers to install new sentinel lighting for customers, it is contractually obligated to maintain existing installations. Sentinel light failures are generally identified by Hydro One customers directly and are reactively addressed as they occur.

C. OUTCOMES

Hydro One aims to achieve the following outcomes as a result of the investment:

- Maintaining reliability by replacing poor-condition cross arms;
- Reducing the risk of long-duration outages and increasing operational flexibility by replacing substandard and obsolete transformers;
- Reducing reliability risks due to bird nests while complying with applicable environmental legislation; and
- Replacing and removing sentinel lights in accordance with existing rental agreements.

OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintain reliability for customers by reducing the number of interruptions due to equipment failures. • Meet customer service obligations by replacing or removing sentinel lights.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing deteriorated or substandard equipment.
Public Policy Responsiveness	• Relocate bird nests on distribution poles in accordance with applicable regulatory obligations, including under the *Migratory Birds Convention Act, 1994*.

D. EXPENDITURE PLAN

This investment has been forecast for the 2023-2027 period based on Hydro One's historical costs and anticipated volumes of work in Orillia and Peterborough.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.04	0.04	0.05	0.05	0.05	0.23
Less Removals	0.01	0.01	0.01	0.01	0.01	0.03
Capital and Minor Fixed Assets	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.20**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.20**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.16	0.16	0.16	0.17	0.17	0.82
Less Removals	0.02	0.02	0.02	0.02	0.02	0.10
Capital and Minor Fixed Assets	**0.14**	**0.14**	**0.14**	**0.15**	**0.15**	**0.72**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.14**	**0.14**	**0.14**	**0.15**	**0.15**	**0.72**

The primary factor influencing the cost of the investment is the number of deficient lines component identified and planned for replacement during the 2023-2027 period, along with the number of demand-driven nest relocations and sentinel light replacement requests that occur.

E. ALTERNATIVES

Hydro One adapted its existing approach to Minor Component Replacement for Orillia and Peterborough. Hydro One's approach considered the alternatives listed below and the recommended alternative was then scaled for the Orillia and Peterborough systems.

Given that Hydro One is proposing to replace sentinel lights and address nests on a demand basis, the alternative approaches discussed below apply only to cross arms and substandard transformers.

ALTERNATIVE 1: REACTIVE REPLACEMENT

Reactive Replacements of Line Components as they fail.

This alternative was considered and rejected for both cross arms and substandard transformers due to unacceptable reliability risks. In the case of cross arms, failures could result in a high number of customers interrupted. In the case of some substandard transformers, failure could result in long outages for the customers supplied. Running these transformers to failure would also not resolve any safety risks associated with their obsolete designs.

ALTERNATIVE 2: PLANNED COMPONENT REPLACEMENT (RECOMMENDED)

Planned Replacement of Line Components at the Proposed Rate.

This alternative is recommended as it addresses high-priority operational risks related to cross arms and substandard transformers. In the case of cross arms, individual units are prioritized according to the number of downstream customers potentially impacted by a failure. In the case of substandard transformers, proactive replacement of these units mitigates operational and safety risks while also being more efficient and cost effective than reactive replacement.

F. EXECUTION RISK AND MITIGATION

Since the Orillia and Peterborough systems are relatively small, no material execution risks are anticipated.

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D-SR-10	**DISTRIBUTION LINES SUSTAINMENT INITIATIVES**
Primary Trigger:	Asset Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.06	0.06	0.06	0.06	0.06	0.30
Net Cost - Peterborough	0.30	0.31	0.31	0.32	0.33	1.56

Summary:

The investment is expected to address overhead feeders that contain poor condition assets and, as a result, require rebuilding and often relocation from off-road locations to the road side. The primary trigger of the investment is asset condition. These investments propose to address sections of feeders that have been identified to be in poor condition in a coordinated manner to maintain the reliability of the feeder, and in the cases of relocation of off-road sections to the road side, improve reliability.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system consists of 241 circuit kilometers of primary lines in Orillia and 545 circuit kilometers of primary lines in Peterborough. Feeders are made up of multiple components, including conductors, poles, insulators, cross arms, and guy wires. Some poles also support overhead transformers, switches, reclosers, and capacitor banks. While most Hydro One distribution feeders in Orillia and Peterborough are overhead (about 69%), a smaller portion (about 31%) are underground and submarine feeders that primarily consist of cables, pad-mount transformers, and underground switching equipment (i.e., kiosks).

The Distribution Lines Sustainment Initiatives addresses overhead feeder sections that contain a large proportion of poor condition assets and, as a result, require rebuilding and often relocation from off-road locations to the road side. The work involves rebuilding and often relocating the entire feeder section, including poles, conductor, and hardware. This contrasts with the investments in the ISD D-SR-07, which focus on replacing individual poles and their associated hardware in their existing place.

OVERHEAD FEEDERS

Hydro One assesses the condition of its distribution assets, including the components that comprise its distribution feeders. These assessments identify assets requiring replacement due to poor condition. The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, and other factors that reduce their structural integrity. Once a pole's condition has deteriorated to poor condition, the pole is at risk of failure.

Compounding this failure risk associated with poor-condition assets, where overhead feeders are located away from the road side, Hydro One distribution crews face significant challenges with respect to restoration activities. In general, when off-road equipment fails, replacing it takes substantially longer than replacing a similar asset that is road side. For example, off-road access for pole setting typically requires specialized bucket-truck and remote boom derricks with off-road treads rather than traditional road-worthy tires. Transporting such equipment to the off-road lines presents its own additional challenges, which increase the time and effort required to restore affected customers.

By addressing line segments that have high concentrations of poor condition assets, Hydro One's Distribution Lines Sustainment Initiatives are expected to minimize the risk of failure arising from these deteriorated assets. Further, by relocating off-road and poor condition poles and equipment along the road side, the Distribution Lines Sustainment Initiatives are expected to reduce the duration of restoration activities in the event of outages on these off-road sections.

Based on available condition information of overhead and underground feeders, approximately 10 kilometers of distribution line sections will require rebuilding due to poor condition in the 2023-2027 period. This rebuilt feeder sections will, when practicable, be relocated to the road side. As a result of overhead Distribution Line Sustainment initiatives, reliability of the feeders will be maintained. In the cases where an off-road feeder section is being relocated on to road side a reliability improvement for customers supplied from the subject feeders is expected.

B. INVESTMENT DESCRIPTION

This ISD is comprised of small investments which vary in scope. The investments are described below.

OVERHEAD FEEDERS

Distribution Line Sustainment Initiatives address overhead feeder sections in an integrated manner by addressing line equipment that is in poor condition and that would negatively impact customer reliability in the event of failure. Feeder sections are identified and prioritized for inclusion in this investment based on the condition of the feeder asset components and associated consequences in the event of failure.

Rebuilding a feeder section is preferred when (1) the condition of asset components is deteriorated and the cost of maintaining or replacing individual components on a case-by-case basis on that section becomes less economical than rebuilding the line section, or (2) the poor condition feeder sections are located off-road, creating a physical barrier to timely restoration in the event of outages. The proposed investments are expected to maintain reliability on these feeder sections and in the case of off-road sections, reduce outage impact to customers.

In general, the scope of work involved in a feeder rebuild or relocation is the replacement of all poles, and all equipment connected to those poles, in a particular line section. The preferred approach is to address feeder sections that have a large number of poor condition assets in close proximity through one line rebuild/relocation investment, as this eliminates the need to mobilize crews multiple times to address different feeder components on the same section. By addressing poor condition assets and performing relocations in a planned and integrated manner, Hydro One also has the opportunity to bring assets up to current standards and to meet anticipated operational needs, including, for example: (1) increased pole height and framing to accommodate additional anticipated circuits; and/or (2) installation of larger and less resistive conductor to increase feeder voltage performance and provide additional load-carrying capacity.

The planned Distribution Lines Sustainment Initiatives include rebuilding approximately 10 kilometers of distribution line sections in Orillia and Peterborough, due to their condition, often relocating them to the road side.

C. OUTCOMES

Distribution Line Sustainment initiatives will:

- Rebuild approximately 10 kilometers of distribution line sections and relocate off-road assets to the road side;
- Maintain reliability on feeders with poor condition assets that warrant rebuilding sections in place;
- Improve reliability where off-road sections are relocated on to roadside for customers supplied from the subject feeders;

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintain reliability for customers by reducing the likelihood of outages on distribution lines. • Improve restoration time for customers by relocating off-road line sections to more accessible locations.
Operational Effectiveness	• Maintain reliability on feeder sections and in the case of off-road section relocations, improve reliability by reducing the outage impact to customers. • Maintain safe and reliable operation of the distribution system by proactively addressing lines equipment in an integrated manner.

D. EXPENDITURE PLAN

The forecast for Distribution Lines Sustainment Investments are based on historical project costs and the volume of work identified over the 2023-2027 period.

The factors influencing the cost of the investment include:

- The number and length of distribution circuits on the section of line that is being relocated;
- The accessibility and length of the feeder being removed and length of the new feeder being constructed;
- The extent of forestry work required at the new feeder location;
- The set-backs required by the road authority or property owner at the new location;
- Unforeseen property/easement issues; and

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.07	0.07	0.07	0.07	0.07	0.33
Less Removals	0.01	0.01	0.01	0.01	0.01	0.03
Capital and Minor Fixed Assets	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.30**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.30**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.34	0.35	0.35	0.36	0.37	1.77
Less Removals	0.04	0.04	0.04	0.04	0.04	0.21
Capital and Minor Fixed Assets	**0.30**	**0.31**	**0.31**	**0.32**	**0.33**	**1.56**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.30**	**0.31**	**0.31**	**0.32**	**0.33**	**1.56**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENT

This alternative would involve reactively replacing distribution line equipment after they fail. This alternative is rejected, as emergency replacements typically lead to prolonged outages (especially for off-road feeder sections) and may be more costly as resources may be required outside of normal working hours. Moreover, reactive management of the distribution line equipment will lead to increased failures, resulting in degradation of reliability for Hydro One's customers.

ALTERNATIVE 2: PLANNED COMPONENTS REPLACEMENTS

This alternative would involve the planned replacement of distribution line equipment in deteriorated or substandard condition, on a "like-for-like" component basis. This alternative is viable where an individual component of standard design on a distribution line is in deteriorated condition. However, it is not efficient when multiple components are in deteriorated condition or the components are of substandard design, as individual replacement work lacks the cost efficiencies associated with the integrated replacement of multiple assets near each other. Moreover, custom-engineered designs would be necessary to address substandard equipment that is no longer supported at Hydro One. Furthermore, this alternative would not address off-road accessibility concerns, and as such would result in longer restoration durations for off-road assets.

ALTERNATIVE 3: PLANNED LINES SUSTAINMENT INITIATIVES (RECOMMENDED)

This alternative involves the planned rebuilding of feeder sections and relocation of off-road sections to the road side, where the components of the distribution line section have been identified as being in poor condition. This alternative is recommended as it addresses the needs identified on distribution lines to maintain, and in the case of off-road locations improve, the reliability of the distribution system in the most cost-effective manner.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment may include seasonal access limitations, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders.

D-SR-11	**LIFE CYCLE OPTIMIZATION & OPERATIONAL EFFICIENCY PROJECTS**
Primary Trigger:	Load Growth
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.20	0.61	3.32	0.44	0.19	4.76
Net Cost - Peterborough	-	-	-	-	-	-

Summary:

This investment involves the optimization of the distribution system by eliminating assets through system modifications or voltage conversion. The primary triggers of this investment are load growth and addressing property-related environmental concerns. This investment is expected to reduce costs and increase operational efficiencies.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

While Hydro One may typically address system issues by addressing the needs of a specific asset, in some situations system needs can be better met by reconfiguring the system through other, more cost-effective alternatives. These alternatives vary in scope but are most often characterized by voltage conversion or system modifications such as load transfers. The elimination of assets, typically distribution stations, in lieu of direct replacements, form the basis for investments within this ISD.

The stations that are candidates for decommissioning through this ISD were designed and constructed decades ago, and presently supply a distribution system that has evolved from what the original designers may have envisioned. Life cycle optimization investments are an opportunity to revisit and update the electrical distribution network to best reflect current system needs.

B. INVESTMENT DESCRIPTION

The investments planned under this ISD for the 2023-2027 period are in Orillia. There are no investments for Peterborough over the same planning period. Localized voltage conversion and upgrades at James DS are planned to facilitate the decommissioning of two stations: Central DS, and Couchiching DS. Couchiching DS is being decommissioned to address environmental concerns with the property, and its loads transferred to James DS. Central DS is being decommissioned due to the limitation imposed by the 4.16kV feeders which cannot accommodate additional load growth and to address the condition of the station transformer. By decommissioning this station and converting Central DS feeders to 13.8kV, the capacity limitations and transformer condition will be addressed.

C. OUTCOMES

Life Cycle Optimization investments focus on the efficient use of assets. By considering not only asset needs, but also the degree to which assets are utilized, Hydro One can eliminate assets where practically feasible, leading to a reduction in the assets required to own, operate, and maintain the distribution system.

C.1 OEB RRF OUTCOMES

The following table presents the anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Avoid customer interruptions by reducing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of distribution stations by addressing asset needs in a cost-effective manner. • Increase operational efficiencies by reconfiguring the system where practically feasible, and by unifying operating voltage. • Minimize costs by choosing the lowest-cost alternative that addresses the area supply needs.

D. EXPENDITURE PLAN

Table 2 below summarizes projected annual expenditures on the aggregate level. Since this ISD is comprised of unique investments, with different planned execution timelines, the associated expenditures vary year-over-year. A detailed breakdown of all expenditures that constitute this ISD can be found in Appendix A.

The factors influencing the cost of the investment include:

- Construction costs for voltage conversion work can vary depending on conditions such as ground conditions and the number of circuits on the pole line.
- Older lines tend to require more replacement and upgrading to current standards.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.20	0.62	3.66	0.56	0.28	5.32
Less Removals	0.00	0.01	0.34	0.12	0.09	0.57
Capital and Minor Fixed Assets	**0.20**	**0.61**	**3.32**	**0.44**	**0.19**	**4.76**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.20**	**0.61**	**3.32**	**0.44**	**0.19**	**4.76**

D.2 EXPENDITURE PLAN - PETERBOROUGH

There are no forecast capital investments for this ISD in Peterborough.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Not proceeding with this investment would fail to address load growth limitation and transformer condition at Central DS and would not address the liability associated with the contaminated site at Couchiching DS.

ALTERNATIVE 2: ADDRESS SYSTEM NEEDS THROUGH VOLTAGE CONVERSION (RECOMMENDED)

Voltage conversion is to be employed to facilitate the decommissioning of two stations: Central DS, and Couchiching DS. The property that Couchiching DS is situated on has environmental concerns. To address these environmental concerns, Couchiching DS will be decommissioned. Central DS will be decommissioned to address its loading limitations imposed by its 4.16kV feeders which cannot accommodate additional load growth, and to address transformer condition. By decommissioning the station and converting the feeder voltage to 13.8kV, both the condition and capacity issues will be addressed.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment may include seasonal access limitations, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders.

APPENDIX A – DESCRIPTION OF INVESTMENTS

Project Name		Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
James Substation Upgrade		Upgrade capacity at James DS (13.8kV) to facilitate the decommissioning of Central DS (4.16kV) and Couchiching DS (13.8kV).	0.20	0.53	2.83	0.00	0.00
Central F1 Voltage Conversion		Transfer Central DS F1 loads to Couchiching DS F2 (13.8kV), to enable the decommissioning of Central DS (4.16kV), by voltage converting from 4.16kV to 13.8kV.	0.00	0.08	0.32	0.00	0.00
Central DS F2 Voltage Conversion		Transfer Central DS F2 loads to Westmount DS (13.8kV), to enable the decommissioning of Central DS (4.16kV), by voltage converting from 4:16kV to 13.8kV where required.	0.00	0.00	0.08	0.17	0.00
Market St U/G Rebuild		Decommission Central DS (4.16kV). Reconfigure system to create tie-point capabilities between Westmount DS (13.8kV) and James DS (13.8kV).	0.00	0.00	0.00	0.09	0.19
James DS New Feeder		Decommission Couchiching DS (13.8kV). Transfer Couchiching DS loads to James DS (13.8kV), by building a fourth feeder out of James DS (13.8kV) and perform switching changes.	0.00	0.00	0.09	0.18	0.00
Other Projects (<$10k)			-	-	-	-	-
Total			**0.20**	**0.61**	**3.32**	**0.44**	**0.19**

D-SS-03	**DEMAND SYSTEM MODIFICATIONS**
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.21	0.21	0.22	0.22	0.22	1.08
Net Cost - Peterborough	0.24	0.24	0.24	0.24	0.25	1.20

Summary:

This non-discretionary investment addresses near term system needs that arise because of localized growth on the distribution system, resulting in equipment overload or power quality issues. The primary trigger of this investment is capacity. Demand-driven system modifications are minor investments that enable localized load growth by promptly addressing capacity limitations.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Demand system modifications are non-discretionary investments that address near-term system needs that arise from naturally occurring changes to the distribution system, which are usually caused by localized load growth. Load growth can cause a variety of issues such as power quality violations, system inefficiencies, or overloading of protection equipment. Under section 3.3 (Enhancements) of the Distribution System Code, Hydro One is required to continue to plan and build its distribution system to mitigate such issues and accommodate reasonable forecast load growth.

B. INVESTMENT DESCRIPTION

Demand system modifications are minor investments driven by immediate or near-term needs in Orillia and Peterborough. The execution of these investments may be:

1. Reactive in nature – investments typically in response to urgent issues such as power quality complaints.[1]
2. Proactive in nature – investments typically in response to customer connections, and are required to enable continued growth in localized areas.

Upon identification of an issue, Hydro One performs an evaluation to outline the feasible mitigating alternatives. Technical criteria such as voltage delivery standards are used to assess power quality issues, and equipment thermal limits are used to assess capacity issues.

Investments that are performed as Demand System Modifications usually include system changes such as new or upgraded protection devices, new or upgraded voltage regulators or shunt capacitors, and system modifications such as feeder rebalancing.

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[1] Demand system modifications address changes or upgrades required to maintain the quality of supply to multiple customers, where supply issues affect a general area of the distribution system. By contrast, power quality investments in D-SS-06 encompass changes and upgrades that are narrow in scope, and are in response to a specific customer complaint with a focused corrective solution.

C. OUTCOMES

This investment's primary outcome is to maintain reliability and power quality, which will in turn maintain customer satisfaction. This outcome will be achieved by addressing system needs such as equipment thermal limitations or by addressing delivery standard violations to align with the criteria in Hydro One's Conditions of Service (namely, CSA CAN-C235-83).

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintain customer satisfaction by responding to customer complaints and maintaining power quality.
Operational Effectiveness	• Maintain reliability and power quality by managing equipment thermal loading, feeder balance, and protection settings and coordination.
Public Policy Responsiveness	• Meet requirements of Section 3.3 Enhancements of the DSC to plan the system to accommodate reasonable forecast load growth.

D. EXPENDITURE PLAN

The factors influencing the cost of Demand System Modifications are dictated by the capability of the existing assets to support localized growth, as well as the complexity of the work to resolve identified issues.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.23	0.23	0.23	0.24	0.24	1.17
Less Removals	0.02	0.02	0.02	0.02	0.02	0.09
Capital and Minor Fixed Assets	**0.21**	**0.21**	**0.22**	**0.22**	**0.22**	**1.08**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.21**	**0.21**	**0.22**	**0.22**	**0.22**	**1.08**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.26	0.26	0.26	0.26	0.27	1.31
Less Removals	0.02	0.02	0.02	0.02	0.02	0.10
Capital and Minor Fixed Assets	**0.24**	**0.24**	**0.24**	**0.24**	**0.25**	**1.20**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.24**	**0.24**	**0.24**	**0.24**	**0.25**	**1.20**

E. ALTERNATIVES

No alternatives are considered, since failure to respond to near term system needs that arise because of localized growth would violate the Distribution System Code and may result in unacceptable system performance.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated for this investment.

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D-SS-06	**POWER QUALITY AND STRAY VOLTAGE**
Primary Trigger:	Power Quality
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost - Orillia	0.01	0.01	0.01	0.01	0.01	0.06
Net Cost - Peterborough	0.01	0.01	0.01	0.01	0.01	0.06

Summary:

This non-discretionary investment involves the investigation and resolution of power quality and stray voltage issues that adversely impact customer experience. The power quality and stray voltage issues are typically identified through customer complaints. The investment is expected to mitigate the customer issues and ensure the system is operating as intended.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is needed to respond to customer complaints resulting from power quality and stray voltage issues by investigating and performing the necessary corrective work as required in compliance with the Distribution System Code, Section 4.1.

Power quality issues include instances when the voltage, frequency, or phase balance of the supply do not conform to established specifications.

Stray voltage is a specific type of power quality issue where a small electrical potential between two conductive surfaces exists. It usually causes no harm and is the by-product of the normal delivery and use of electricity. However, if the voltage level is high enough, it may result in electric shock and, for farm customers, may affect livestock behaviour and health.

B. INVESTMENT DESCRIPTION

This demand program encompasses the capital costs associated with responding to power quality and stray voltage issues in Orillia and Peterborough. Hydro One performs several measures to address power quality and stray voltage, including the examination of the integrity of neutral and grounding systems, balancing the load and upgrading the neutral conductor of the supply system.

The power quality and stray voltage program includes investigation and resolution of the following conditions:

- Power Quality including high voltage, low voltage, phase imbalance, flicker
- Farm Stray Voltage
- Residential Stray Voltage

Power quality investments encompass changes and upgrades that are narrow in scope and are in response to a specific customer complaint with a focused corrective solution. By contrast, power quality system modifications in D-SS-03 are the changes and upgrades required to maintain the quality of supply to multiple customers, in cases where supply issues affect a general area of the distribution system.

C. OUTCOMES

The Power Quality and Stray Voltage program will result in:

- Mitigating risks associated with power quality and stray voltage issues, and
- Compliance with Distribution System Code sections 4.1 Quality of Supply and 4.7 Farm Stray Voltage.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Respond to customer complaints related to power quality and stray voltage.
Operational Effectiveness	• Maintain acceptable performance of the distribution system by addressing power quality and stray voltage issues • Maintain the safe operation of the distribution system by mitigating potential safety hazards caused by stray voltage.
Public Policy Responsiveness	• Comply with the Distribution System Code sections 4.1 Quality of Supply and 4.7 Farm Stray Voltage

D. EXPENDITURE PLAN

The factors affecting the cost of the investment include:

- The amount of power quality and stray voltage issues that arise each year
- The scope of the work involved to fix the issues

The forecast expenditures for this demand program are based on recent expenditures.

D.1 EXPENDITURE PLAN - ORILLIA

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Orillia Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.01	0.01	0.01	0.01	0.02	0.07
Less Removals	0.00	0.00	0.00	0.00	0.00	0.01
Capital and Minor Fixed Assets	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**

D.2 EXPENDITURE PLAN - PETERBOROUGH

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Peterborough Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	0.01	0.01	0.01	0.01	0.02	0.07
Less Removals	0.00	0.00	0.00	0.00	0.00	0.01
Capital and Minor Fixed Assets	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**
Less Capital Contributions	0.00	0.00	0.00	0.00	0.00	0.00
Net Investment Cost	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**

E. ALTERNATIVES

No alternatives are considered since this investment is non-discretionary. Failure to respond to power quality and stray voltage complaints violates the Distribution System Code and may result in unacceptable system performance.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated for this investment.

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