1.0 TRANSMISSION SYSTEM PLAN

The sections contained in this Exhibit form Hydro One's consolidated five-year Transmission System Plan ("TSP") for the 2020 to 2024 period (the "planning period"). The TSP has been prepared in accordance with Chapter 2 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications*, issued on February 11, 2016, with further guidance from Chapter 5 of the OEB's Filing Requirements (*Consolidated Distribution System Plan Filing Requirements*), issued on March 28, 2013 and revised on July 12, 2018 (together, the "Filing Requirements"). To assist parties in their review of the TSP, Hydro One has provided the applicable references to the Filing Requirements in brackets in the heading titles throughout the TSP.

On March 16, 2018 the OEB issued a letter setting out its expectations regarding future distribution rate and transmission revenue requirement applications by Hydro One. The letter directed Hydro One to file a transmission revenue requirement application for a four-year period from 2019 to 2022. Subsequently, Hydro One experienced organizational changes in July and August, 2018, which included the appointment of a new Board of Directors. As a result, Hydro One took the opportunity to re-evaluate its transmission business plan to balance the needs of customers, system reliability and overall stewardship of its assets with a particular focus on increasing productivity and minimizing rate increases.

To permit this review to occur and adhere to the OEB's objective of a combined transmission and distribution application in the future, Hydro One adopted a two-step approach. First, Hydro One filed an application for a one-year mechanistic adjustment to Hydro One's 2019 revenue requirement (EB-2018-0130). Second, Hydro One filed this 3-year Custom Incentive Rate- Setting (IR) application with a 2020-2022 test period to allow alignment with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

Consistent with Chapter 2 of the Filing Requirements, Hydro One's TSP includes a summary of capital expenditures for five future years. However, this Application seeks approval for a revenue requirement only in respect of the 3-year period of 2020-2022. The terms "planning period" and "test period" are used accordingly throughout the TSP.

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1.1 (5.2.1) TRANSMISSION SYSTEM PLAN OVERVIEW

1.1.1 (5.2.1 A) INTRODUCTION

This is the first 5-year Transmission System Plan ("TSP") prepared by Hydro One Networks Inc. ("Hydro One"). It covers a planning horizon from 2020 to 2024. Hydro One has prepared this TSP in accordance with Section 2.4 of Chapter 2 (Revenue Requirement Applications) of the Ontario Energy Board's (the "OEB" or "Board") *Filing Requirements for Electricity Transmission Applications*, issued on February 11, 2016, with further guidance from Chapter 5 of the Filing Requirements (Consolidated Distribution System Plan Filing Requirements), issued on July 12, 2018 (together, the "Filing Requirements"). The references in heading brackets denote corresponding sections of the Filing Requirements.

Consistent with the Filing Requirements, this TSP provides a consolidated set of documentation concerning Hydro One's asset management process and capital expenditure plan for its transmission system, using a standardized approach and structure. This TSP also provides related information about Hydro One's efforts to coordinate its planning with third parties, identify and take into account customer preferences, as well as measure performance to support continuous improvement.

This TSP provides a comprehensive and detailed explanation of Hydro One's capital investment plan for its transmission system in respect of the 5-year period from 2020 to 2024. Based on OEB Staff input from its letter dated March 16, 2018, and in light of subsequent organizational changes experienced by Hydro One in July and August 2018, Hydro One adopted a two-step approach. First, on October 26, 2018, Hydro One filed an application for a one-year mechanistic adjustment to determine Hydro One's 2019 revenue requirement (EB-2018-0130). Second, Hydro One is submitting this 3-year request for revenue requirement covering the period 2020-2022. This is done to align the completion of the transmission revenue requirement period with that of the Hydro One Distribution application filed on March 31, 2017 under case number EB-2017-0049, which aligns with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement with a test period commencing in 2023. For clarity, while the revenue requirement application covers the period 2020-2022, this TSP, and the capital investment plan discussed herein, covers the 5-year period from 2020-2024 in accordance with the Filing Requirements.

This plan demonstrates how Hydro One has aligned its investment planning processes and intended outcomes with the principles and expectations articulated by the OEB in the *Renewed Regulatory Framework* ("RRF"),[1] namely by focusing on identified customer preferences; continuous improvement in productivity, reliability and cost performance; public policy responsiveness; and financial performance.

To prepare this TSP, Hydro One engaged its transmission customers, its Executive Leadership Team and employees from across the company, including functions such as Planning, Customer Care, Finance, Transmission and Stations, System Operations and Regulatory Affairs. Through this significant effort, Hydro One has endeavored to carefully consider and set out, in extensive detail, its proposed transmission investment plans over the course of the planning period, along with the myriad of processes, methodologies and other considerations that, together, have enabled Hydro One to ensure its investment plans are appropriate in their focus, scope and pacing, having regard for the needs of the system, the company and its customers. Hydro One engaged in benchmarking and third party assessments to provide feedback on the condition of its assets, the strategies and approaches it employs to manage those assets and to ensure that a consistent and thorough planning process is in place. The assessments demonstrate that

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

recent enhancements to Hydro One's planning practices and processes address gaps identified both internally and by the OEB in the Prior Proceeding, and that the investment planning process is aligned with industry best practices.

1.1.2 (5.2.1 A) FORMAT OF THE TSP

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

- **Chapter 1 – Transmission System Plan** – This chapter provides an overview of Hydro One's transmission system and the various factors and outcomes that were considered by Hydro One in developing its capital expenditure plan.
- **Chapter 2 – Asset Management Process** – This chapter reviews Hydro One's asset management and life-cycle optimization strategies, as well as its investment planning process, which determines the appropriate portfolio of investments having regard to the specific outcomes that Hydro One seeks to achieve;
- **Chapter 3 – Capital Expenditure Plan** – This chapter details Hydro One's capital expenditure plans for its transmission system for the period 2020-2024 and compares Hydro One's historical capital spending to past OEB-approved forecasts. The capital expenditure plan is the product of the investment planning process and asset management strategies described in Chapter 2, as informed and guided by the various drivers described in Chapter 1. This Chapter includes a number of Investment Summary Documents, which provide details regarding large projects with forecast spending over $3 million[2] in any given year of the 2020-2024 period.

A Table of Concordance, which aligns the sections of this TSP with the Filing Requirements, is provided in Appendix 'A'.

Unless otherwise specified, the asset information contained in this TSP is taken as of December 31, 2018. Forecast costs for the 2019 to 2024 period are as forecast in Hydro

[2] Hydro One's materiality threshold is $3 million as determined Section 2.1.1 of the OEB's Filing Requirements for Electricity Transmission Applications, dated February 11, 2016.

One's 2019-2024 Transmission Business Plan.[3] 2018 costs are based on Hydro One's Q3 forecast of 2018 and will be updated with actuals in a Blue Page update to be completed in mid-2019.

[3] The Transmission Business Plan, dated December 14, 2018, is provided as Attachment 1 to Exhibit A, Tab 3, Schedule 1.

1.1.3 RESPONSIVENESS TO OEB DECISION IN EB-2016-0160

The OEB's findings and directions in its Decision and Order on Hydro One's last transmission revenue requirement application (EB-2016-0160), have informed the preparation of this TSP. Table 1 below identifies the OEB's TSP-related areas of concern in that proceeding and describes at a high level how Hydro One has responded to that feedback in preparing the present application. Each of these aspects is elaborated upon throughout this TSP.

Table 1 – Summary of Responses to OEB Feedback on TSP in EB-2016-0160

AREA OF CONCERN	OEB FEEDBACK	HYDRO ONE ACTIONS TAKEN
Customer Engagement	The investment plan did not adequately use customer engagement feedback	Earlier, more comprehensive customer engagement Customer engagement feedback results used to inform and update risk taxonomies in line with customer needs Increased Customer Participation: Representatives from 103 customer organizations participated in the 2017 survey, relative to 62 organizations in the 2016 survey
Deficiencies in Prioritization	Questioned prioritization and optimization process	New taxonomies drive investment scoring and prioritization and optimization; Risk scores used to maximize risk mitigation per dollar spent
Asset Condition Assessments	Need a comprehensive asset condition process that informs the prioritization	Risk scores tied back to available condition assessments; Updated inventory of assets and condition assessments with identified opportunities; Third-party assessments and data initiatives performed.

AREA OF CONCERN	OEB FEEDBACK	HYDRO ONE ACTIONS TAKEN
Value Added in Review	The investment plan did not change over seven months of review	Enterprise Wide Review: Multiple challenge sessions are now held to provide a fact-based and structured approach to define the investment portfolio, with the focus on ensuring that the most valuable work to customers is included in the plan.
Sequencing	Plan was submitted for rate filing before Hydro One Board approval	Sequencing issues addressed for this filing. Plan submitted to Hydro One Board of directors in December 2018, in advance of filing
Internal Audit	Planning process had outstanding internal audit items to address	All original internal audit items are now complete; Follow up internal audit shows lower overall risk level
Work Program Delivery	Hydro One had not historically delivered its capital and OM&A programs to OEB approved level	Enhanced upfront engineering and planning deliverables; Increased governance throughout investment lifecycle; Improved estimating and scheduling tools and processes Delivered In Service Addition ("ISA") approved in 2017 rate order (872M vs. 868M) 2016 Bridge year ISA presented as part of EB-2016-0160 (910M vs. 912M)

1.1.4 (5.3.2 A, B) HYDRO ONE'S TRANSMISSION SYSTEM

This section of the TSP provides a high level description of Hydro One's transmission system, its role in Ontario's electricity system and the customers it serves. This description is provided, in part, to provide insight on how the transmission system differs from distribution systems and their associated distribution system plans. Chapter 5 of the Filing Requirements for distribution system plans was used to prepare this TSP, however, the unique aspects of Hydro One's transmission system were also necessarily taken into account in developing this TSP. Key aspects to consider include:

- Hydro One's transmission system extends to most of the province and operates in diverse geographic and climatic conditions, unlike distribution systems which generally serve smaller and more localized service territories;
- Hydro One's transmission system is a critical asset for the province, with a particularly high level of criticality for certain areas and facilities, such that significant and far-reaching impacts are likely to result from outages;
- one particularly critical aspect is the part of Hydro One's transmission system comprising the bulk electric system, which requires compliance with reliability standards established by the North American Electric Reliability Corporation ("NERC") to ensure the integrity of the interconnected North American Bulk Electric Systems;
- as the lead transmitter for most regions in the province, Hydro One must take into account Regional Planning requirements and the Long-Term Energy Plan ("LTEP") in planning its transmission investments;
- customers served by Hydro One's transmission system include large industrial end users, which depend on a reliable energy supply and high-power quality to support their facilities and industrial processes, as well as the owners and operators of local distribution systems that in turn serve end-users across the province; and
- Transmission projects tend to be multi-year in nature, as opposed to distribution projects which tend to be completed within a 12-month period.

These aspects are discussed in the sections below.

1.1.4.1 SCOPE OF THE TRANSMISSION SYSTEM AND SERVICE AREA

Hydro One is comprised of over $13 billion of transmission assets and accounts for approximately 98% of the revenues of all licensed transmitters in Ontario. The system transmits electricity throughout the Province of Ontario between supply points (i.e. generation) and delivery points (i.e. load customers). In 2017, Hydro One transmitted approximately 132 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario.

As shown in the maps provided in Figures 1 and 2, below, Hydro One's transmission service area includes both northern and southern Ontario. Whereas the majority of Ontario's population is located in the south, the northern part of the province is sparsely populated with heavy forestation. The climate across Ontario also varies significantly by location and by season. Hydro One's transmission system is susceptible to a variety of extreme weather conditions, such as blizzards, hail, ice storms, lightning, thunderstorms, extreme heat and tornadoes.

Hydro One operates its transmission system and manages responses to trouble calls from a centralized operations facility known as the Ontario Grid Control Centre ("OGCC"). A Back Up Control Centre ("BUCC") is also maintained in accordance with NERC standard Emergency Operating Procedure, EOP-008-2 "Loss of Control Centre Functionality" and the IESO Market Rules. In the event the OGCC or its computer systems are rendered unavailable, control and monitoring of the bulk electric system or IESO-controlled Grid is transferred to the BUCC. In addition, Hydro One has Service Centres located throughout the province, which serve Hydro One's transmission business as well as its distribution business, provide base locations for field crews and the materials, tools and equipment they rely upon to provide maintenance and restoration services in a timely, effective and efficient manner. Support for Hydro One's transmission system operations is provided by various corporate functions, including executive leadership, finance, human resources, legal and regulatory, which carry on business from Hydro One's head office in downtown Toronto.

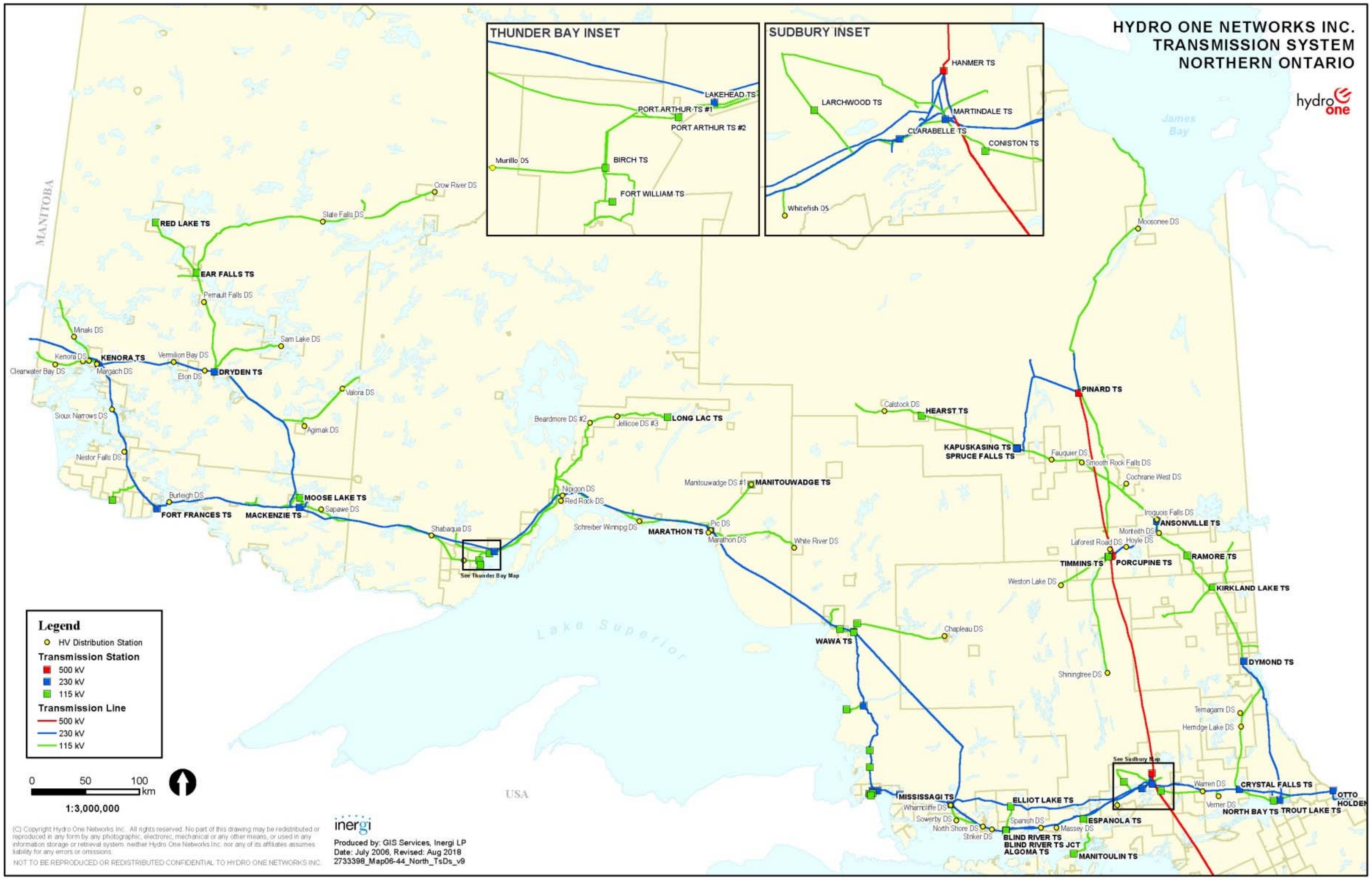

Figure 1 – Hydro One Transmission System in Northern Ontario

Witness: Bruno Jesus

Figure 2 – Hydro One Transmission System in Southern Ontario

In addition to providing connections to its customer base, Hydro One's transmission system is connected with and enables the operation of all other licensed transmission systems in Ontario, namely those that are owned and operated by Canadian Niagara Power Inc., Five Nations Energy Inc., Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP), and B2M Limited Partnership.

Hydro One's transmission system interconnects with transmission systems in five neighbouring jurisdictions in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York) and enables electricity transactions with those jurisdictions through 26[4] interconnections, as shown in Figure 3, below. Collectively, these interconnections can accommodate theoretical maximum imports of about 6,610 MW and exports of approximately 6,121 MW of electricity in the summer months.[5] Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One's system and the transmission systems in other jurisdictions.

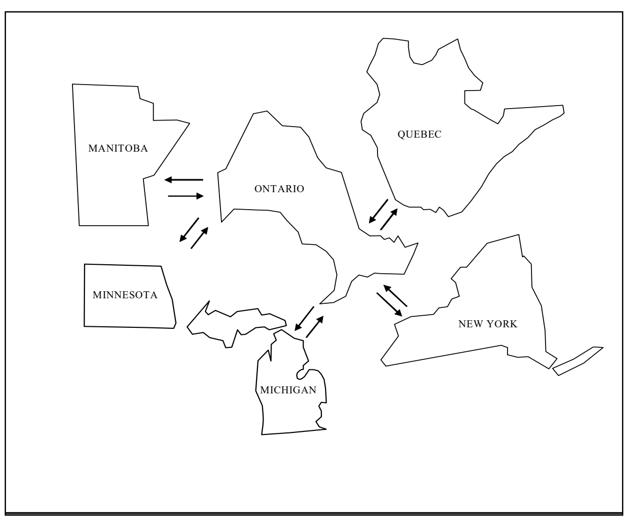

Figure 3 – Existing Ontario Transmission Interconnections

[4] The number of interconnections will increase as a result of the Lake Erie interconnection project (SS-03).
[5] From the IESO Ontario Transmission System report June 20, 2018

Hydro One's transmission system is generally comprised of three types of infrastructure – transmission lines, transmission stations and network operations facilities. A simplified figure showing how the transmission system is configured, relative to the generating stations and distribution systems that it serves, is provided in Figure 4, below.

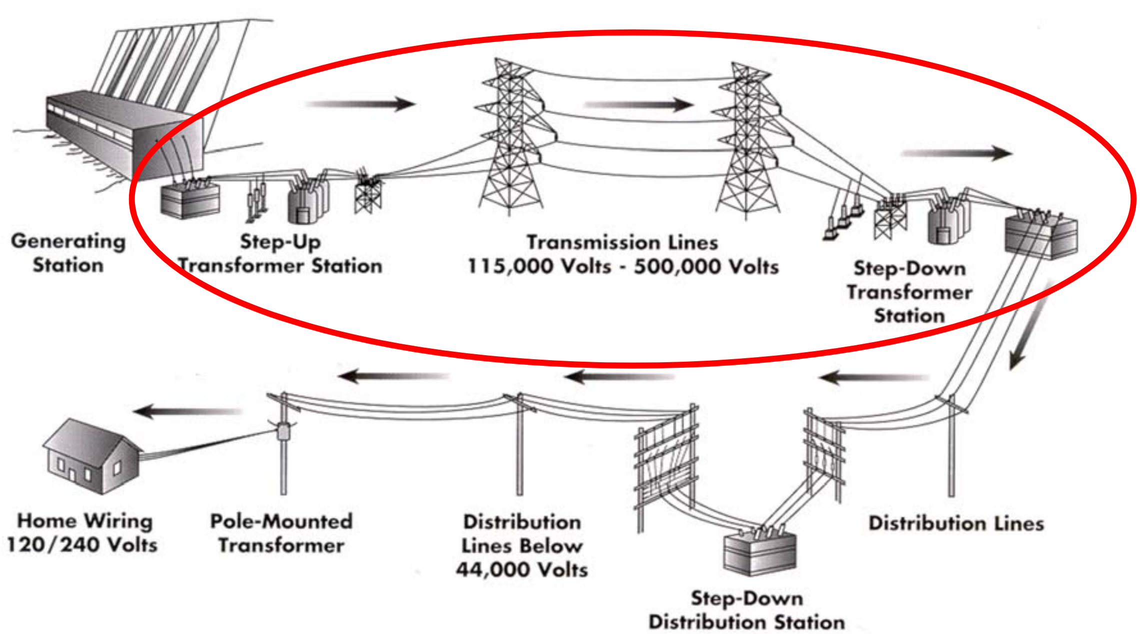

Figure 4 – Schematic Diagram of Hydro One's Transmission System

Hydro One operates transmission lines primarily at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. These lines are used to transmit electric power to connected industrial and commercial customers, as well as to LDCs who in turn distribute the power to end-use customers. Hydro One's bulk transmission lines (discussed further below) deliver power from generating stations or connections to receiving stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres. Almost all of Hydro One's transmission lines are overhead. Approximately 69% of the overhead transmission lines are erected on steel structures with the other 31% supported by wood pole structures (primarily for the 115kV system).

The major components of transmission lines include overhead conductors, underground cables, steel and wood pole structures, foundations, insulators, shield wire, switches and line hardware. Transmission lines are located on lands owned either by the Ontario government, Hydro One or other parties with whom Hydro One has agreements with respect to occupancy and access rights. Approximately 70% of the delivery points on Hydro One's transmission system are multi-circuit delivery points, meaning more than one line is normally available to supply the customers connected to such a delivery point. The remainder of the transmission system features single-circuit delivery points. The high proportion of multi-circuit delivery points on Hydro One's transmission system enables Hydro One to provide a high level of reliability for the customers that it serves.

Along with high voltage transmission lines, transmission stations are the other broad category of infrastructure that is critical to the function of Hydro One's transmission system. Transmission stations are used for the delivery of power, voltage transformation and switching, and serve as connection points for load and generator customers, as well as neighbouring Ontario transmission systems and neighbouring provincial and state jurisdictions.

Hydro One's transmission stations are designed based on a range of transformer and breaker configurations to ensure redundancy, such that a loss of any one element (such as a transformer or a breaker) at a transmission station will not result in the interruption of service to customers under normal conditions. Redundancy also allows for assets to be removed from service for maintenance without an interruption to Hydro One's ability to provide transmission service to customers. This capability helps support reliability. The major components of transmission stations include power transformers, circuit breakers, disconnect switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, protection and telecom systems, site infrastructure and buildings.

Hydro One's network operations are carried out from the Ontario Grid Control Centre, which manages all of Hydro One's transmission operations. As noted, Hydro One's system also includes a Back-Up Control Centre to support reliable operation of the system.

In addition to high voltage lines and transmission stations, Hydro One's transmission business requires a fleet of general plant assets (including real estate and facilities, transport and work equipment, as well as information technology), which do not directly form part of the transmission system but are critical to its function and reliability. A snapshot of Hydro One's key transmission system-related assets is presented in Table 2, below.

Table 2 - Hydro One's Key Transmission System Assets

System Assets	Total
Operating Centres	2
Transmission Circuits (Total Number)	515
Length of Overhead Transmission Lines (Total Circuit km)	29,107
Length of Underground Transmission Cables (Total Circuit km)	264
Transmission Stations (Total Number)	294
Installed Transformer Nameplate Capacity (MVA)	118,735

Data as of December 31, 2018

1.1.4.2 CRITICALITY OF THE TRANSMISSION SYSTEM

Given the scope of Hydro One's transmission system and the scale of the territory that it serves, Hydro One's transmission system is critical infrastructure for the Province of Ontario. The role of Hydro One's transmission system within the province is consistent with the definition of "critical infrastructure" that has been adopted by the Province for purposes of the Ontario Critical Infrastructure Assurance Program, which considers such infrastructure to include "interdependent, interactive, interconnected networks of institutions, services, systems and processes that meet vital human needs, sustain the economy, protect public safety and security, and maintain continuity of and confidence in government".[6] It is because of this critical role in Ontario's electricity system that the transmission system has been referred to as the "backbone" of Ontario's electricity system.[7]

Relative to the numerous distribution systems that serve individual communities throughout Ontario, there is perhaps a greater need to ensure the reliability of Hydro One's transmission system. A strong recognition of this need was a defining characteristic for how the transmission system, which Hydro One inherited from the former Ontario Hydro, was initially designed and it has been a quality that has endured ever since. With this focus and the historical experience of transmission customers in Ontario, these customers have expressed a strong preference for a low frequency of outages and a high level of reliability. These objectives are supported by the high degree of redundancy that is built into the design of Hydro One's system. Hydro One's transmission system, particularly in the southern portion of Ontario, provides customers with a high level of redundancy that ensures a level of reliability that is proportionate to the system's critical role within the province.

In addition to Hydro One's objective of continuing to ensure a high level of reliability for the transmission system to meet customer expectations and preferences, Hydro One's approach to maintaining, managing and investing in its transmission system is driven by its need to comply with a framework of reliability standards that specifically applies to those portions of its system that are part of the bulk electric system ("BES"). Hydro One applies the NERC definition of the BES that was approved by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2014. NERC defines the BES as

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[6] See https://www.emergencymanagementontario.ca/english/emcommunity/ProvincialPrograms/ci/ci.html
[7] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, p. 41.

including all transmission facilities greater than 100 kV, which encompasses the vast majority of Ontario's (and Hydro One's) transmission facilities.

The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted and are enforced in Ontario by the IESO. These standards are intended to ensure the integrity not only of the Ontario BES but of all of the interconnected BESs across North America. To achieve this, among its many activities, NERC develops and enforces reliability standards, monitors the bulk power system, assesses and reports on future transmission and generation adequacy, and offers education and certification programs to industry personnel.

NERC works with eight regional entities to improve the reliability of the bulk power system, including the Northeast Power Coordinating Council ("NPCC"). NPCC develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability. Hydro One is a member of NPCC and is registered under NERC's compliance registry.

Following the 2003 Northeast blackout, the U.S. *Energy Policy Act of 2005* authorized the creation of a self-regulatory Electricity Reliability Organization ("ERO") that would span North America, under the oversight of FERC in the U.S. The legislation states that compliance with reliability standards is mandatory and enforceable. In July 2006, Federal Energy Regulatory Commission ("FERC") certified NERC as the ERO in the United States. In October 2006, the OEB signed a memorandum of understanding with NERC recognizing NERC as the ERO in Ontario. According to this memorandum of understanding with NERC and the IESO's Market Rules, only the IESO is directly subject to the Compliance Monitoring and Enforcing Program of NERC and NPCC in Ontario. The IESO through its Market Assessment and Compliance Division, in turn, enforces the NERC reliability standards and NPCC criteria through the Market Rules.

As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. Hydro One actively participates with the other transmission system owners and operators on NPCC committees and task forces to coordinate planning and operations in the northeast region. There are approximately 90 Hydro One transmission stations[8] that include assets designated as part of the BES. To comply with NERC and NPCC reliability standards, these BES stations are equipped with multiple, redundant and robust protection and control systems to ensure that faults are isolated so as to prevent cascading and damage to assets near the fault. Infrastructure relating to key sites and processes is designed to adhere to NERC Critical Infrastructure Protection ("CIP") requirements. For example, sites subject to NERC and/or NPCC requirements require additional equipment, such as protection systems and station battery systems, and must meet additional CIP requirements, such as physical and electronic/cyber-security to prevent unauthorized network access. Hydro One's maintenance and investment plans are prioritized so as to maintain compliance with these requirements.

1.1.4.3 (5.2.1 G) CONSIDERATION FOR REGIONAL PLANNING AND LTEP

One of the key guiding principles from the Board's RRF is that planning transmission infrastructure with key stakeholders in a regional context helps promote the cost effective development of electricity infrastructure in Ontario. The RRF states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into the utility's planning processes.

Consistent with the important role that Hydro One's transmission business plays in Ontario's regional planning process, as well as in bulk system planning, the Chapter 2

[8] Designation of BES facilities is based on the BUS structures. Some Hydro One stations contain more than 1 BUS network.

Filing Requirements identify distinct elements that must be included in a TSP but which are not required in a distribution system plan. The TSP reflects the company's discussion of needs identified through the regional planning process, the needs and preferences of customers, overall system planning policy objectives, and commitments arising from the Long Term Energy Plan. With respect to regional planning, a TSP is specifically required to include lead transmitter documentation for all applicable regions.[9]

There are a total of 21 regional planning zones in Ontario.[10] Given Hydro One's role as the lead transmitter for 19 of these regional planning zones, the extent to which regional planning has been considered in preparing this TSP is greater than the effect of regional planning on a typical distribution system plan. As described in TSP Section 1.2, there are a total of forty-six transmission investments arising from Hydro One's involvement in regional planning initiatives that it proposes to put into service during the 2020 to 2024 planning period. In a distribution system plan, a distributor is expected to describe its involvement in any regional planning initiatives and provide a copy of the final deliverables from such initiatives or the status thereof. Whereas Ontario's distributors may be involved in regional planning initiatives in respect of perhaps one or two regional planning zones, as the upstream transmitter for all of the regional planning zones, Hydro One has participated in regional planning working groups for 19 of the 21 regional planning zones. As such, Hydro One's transmission business is actively involved in the regional planning process and leading the development of regional infrastructure plans.

1.1.4.4 (5.2.1 G) TRANSMISSION-CONNECTED CUSTOMERS

Another important distinction between Hydro One's transmission system and the distribution systems that are the subject of the distribution system plans that the OEB typically reviews is the range of customers served. Whereas an LDC typically serves a

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[9] Chapter 2 Filing Requirements, Section 2.4.2, p. 14.
[10] See Appendices 3 and 4 in Planning Process Working Group Report to the Board – The Process for Regional Infrastructure Planning in Ontario, May 17, 2013.

range of customers including residential, commercial, municipal and smaller industrial customers, and small embedded generation facilities, the customers served by Hydro One's transmission system are comprised of large electricity generators, large industrial end-users, and Ontario's LDCs. In addition, Hydro One's transmission system includes inter-jurisdictional interties that are relied upon by the IESO to balance electricity supply with system demand.

Depending on the configuration and ownership of a customer's facilities, Hydro One provides its transmission customers with one or more of the following transmission services:

- Network Connection Service – for use of assets built for the common benefit of all customers;
- Line Connection Service – for use of facilities that step down the voltage from above 50 kV to below 50 kV;
- Transformation Connection Service – for all other assets not included in the Network Connection or Line Connection pools – generally those assets built for use by a specific customer(s); and
- Wholesale Revenue Meter Service – for parties that purchase electricity in the IESO-administered markets or directly from a generator.

A profile of the customer base connected to Hydro One's transmission system is presented in Table 3, below.

Table 3 – Hydro One's Transmission-Connected Customers[11]

Customer Type	Number Served
Generators	131
End Users (Large Industrial Customers)	84
Local Distribution Companies	42

Generation customers that are directly connected to Hydro One's transmission system have a combined generation capacity of approximately 35,441 MW, which represents approximately 96% of the total generation capacity[12] in the Province of Ontario. These vital assets include most of Ontario's hydroelectric generation facilities, all natural gas fueled generation facilities, large renewable generation facilities and all of Ontario's nuclear generation facilities. A transmission outage affecting service to one of these facilities affects the generation supply for Ontario, which can affect the reliability of supply and the price of electricity for all Ontario customers. Moreover, transmission outages can affect generation facility equipment and cause those stations to shut down for extended periods at a significant cost to generators, which costs may ultimately be borne by ratepayers. These customers are actively engaged in the energy sector and, as such, are sophisticated and well aware of the trade-offs between cost and reliability risk.

The large industrial customers that are directly connected to Hydro One's transmission system are a critical part of Ontario's economy and, together, accounted for 1,785 MW of electricity demand in 2017, with an estimated 4% direct contribution to Ontario's GDP and a 28% contribution to Ontario's industrial GDP. These include, for instance, customer facilities for steel production, auto manufacturing, pulp and paper, chemical processing and mining. Typically, reliability and power quality for these large industrial customers are significant factors for their decisions to locate in and remain located in

[11] The number of customers in this table is based on the number of Transmission Connection Agreements (TCA) as required by the Transmission System Code ("TSC") with the exception of LDCs that are based on their Electricity Distribution License as of December 31, 2018. This differs from the number of business entities surveyed in the Customer Engagement survey, 156, as many entities hold multiple TCAs.
[12] Total Generation Capacity of Ontario is 36,928 MW (Source: IESO Reliability Outlook Winter 2018, December 17, 2018).

Ontario. Transmission outages or power quality issues can cause significant and costly interruptions to industrial processes and customer equipment, which in turn can affect company safety, performance, and employment. Hydro One developed a plan that brings reliability and power quality to these customers and which supports their businesses and Ontario's economy. These customers are sophisticated and well aware of the trade-offs between cost and reliability/power quality risk.

The LDCs that are served by Hydro One's transmission system serve most of Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the reliability and performance of Hydro One's transmission system include critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, as well as financial services systems. Like Hydro One's generation customers, these LDC customers are actively engaged in the energy sector and, as such, are sophisticated and well aware of the trade-offs between cost and reliability risk. So too are the neighbouring Ontario transmitters that are connected to Hydro One's transmission system, who would themselves have customers that include generators, large industrial customers and LDC customers.

1.1.5 (5.2.1 A) SUMMARY OF THE INVESTMENT PLANNING PROCESS

This section provides a summary of Hydro One's investment planning process, including (i) Hydro One's strategic priorities and the key elements of the OEB's policy framework that have informed the process, (ii) the outcomes that Hydro One seeks to achieve by implementing the investments identified through the process, (iii) the manner in which Hydro One has engaged with customers and factored the resulting feedback into its process and investment plans, (iv) the manner in which regional planning considerations have been addressed, (v) the key steps and outputs from its investment planning process, and (vi) the key aspects of the proposed capital expenditure plan arising therefrom.

1.1.5.1 STRATEGIC OBJECTIVES

The investment planning process that has informed this TSP was guided by a list of strategic priorities. These priorities are as follows:

Strategic Priorities

- **Employees**
  - Maintain a safe and inclusive workplace for all employees
  - Foster a high level of employee engagement throughout Hydro One through a new engagement approach focused on developing company –wide action plans ("Time for Action")
- **Customer Experience**
  - Deliver industry-leading customer service, in response to identified customer preferences
  - Foster innovation in the business to adapt to changing customer requirements and market opportunities
  - Advance reconciliation and work proactively to build relationships with Indigenous peoples and communities based on understanding, respect and mutual trust
- **Operational Effectiveness**
  - Invest in grid infrastructure and grid modernization to deliver a high level of reliability and quality to our customers
  - Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs
- **Government and Regulatory Relationships**
  - Maintain and build constructive, transparent relationships with governments and regulatory entities in all jurisdictions where we operate
  - Deliver on obligations mandated by government through legislation and regulatory requirements
- **Financial Strength**
  - Maintain a strong balance sheet to support continuing investment in our business
  - Invest in assets to better serve customers

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

Figure 5 – Hydro One's 2018 Strategic Priorities

Figure 6 highlights the close alignment between Hydro One's planned transmission investments and the company's strategic priorities.

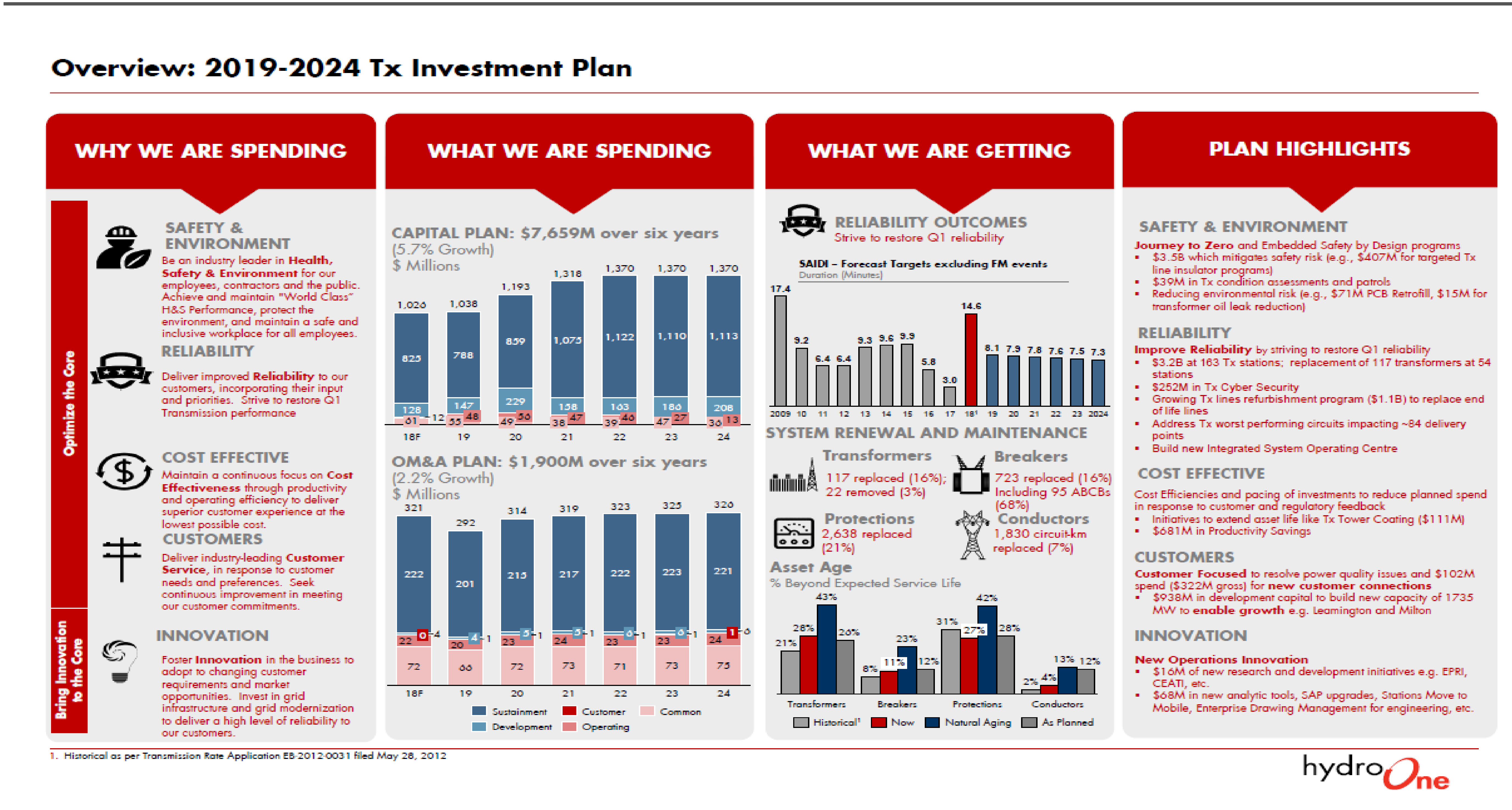


Figure 6 - Alignment Between Strategic Priorities and Planned Transmission Investments

These strategic priorities and objectives, together with the guidance provided by the OEB's policy framework, in particular, customer engagement, helped inform the investment plan that is included in this TSP. Moreover, there is close alignment between the company's priorities and objectives and the themes and outcomes that the OEB has articulated through its policy framework, discussed below.

1.1.5.2 POLICY FRAMEWORK

In this TSP, Hydro One recognizes and seeks alignment with the policy framework established by the OEB through the RRF and related guidance. Hydro One understands, and has made significant efforts to embrace, the objectives of the RRF in planning and operating its transmission system. In particular, Hydro One has developed an outcomes-based plan that provides value to its transmission customers by being responsive to their identified needs and preferences, addressing regional and bulk system needs and specific system access requirements, driving productivity improvements and promoting innovation and continuous improvement.

Through this approach, Hydro One is confident that it has achieved an appropriate balance between the imperatives of meeting its compliance requirements, providing prudent stewardship over its transmission system assets, responsibly managing health and safety risks, responding to customer needs and preferences, and achieving sustainable financial performance.

Accordingly, the TSP in general, and the asset management process and capital expenditure plan in particular, demonstrate Hydro One's orientation around the following outcomes identified by the OEB in the RRF:

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

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

1.1.5.3 OUTCOMES TO BE ACHIEVED

The key outcomes that Hydro One seeks to achieve through implementation of the asset management process and capital expenditure plan as set out in this TSP include, but are not limited to:

- **Customer Focus**: power quality improvements; improve customer reliability
- **Operational Effectiveness**: an injury-free workplace, minimized long-term costs to maintain the transmission system infrastructure and improve reliability, and restore top quartile reliability performance by mitigating risk arising from asset deterioration;
- **Public Policy Responsiveness**: continued compliance with regulatory requirements and applicable reliability standards; and
- **Financial Performance**: manageable and stable rate impacts over the course of the planning period.

The close alignment between the RRF outcomes and the outcomes that Hydro One seeks to achieve through implementation of this TSP is demonstrated from the following summary of the company's transmission business values and objectives, which is included in its 2019-2024 Transmission Business Plan and in TSP Section 1.5.

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

Figure 7 – Hydro One's Transmission Business Values and Objectives

1.1.5.4 (5.2.1 B) CUSTOMER ENGAGEMENT

Hydro One undertakes a broad range of ongoing customer engagement activities in connection with its transmission system and incorporates the feedback it receives from these activities directly into its investment planning process, both at the outset and throughout that process. Hydro One's understanding of its customer needs and preferences is derived largely from six sources, as follows.

The first source is the Large Customer Account Management Group. The Large Customer Account Management group provides a single point of contact for customers for all types of interactions other than real-time operations, operating events and outage planning. This group facilitates direct communications with transmission customers on a variety of matters including customer connection requests, sustainment and system development plans and projects, and concerns regarding service level or power quality. Communication with this group prior to the Investment Plan prioritization and optimization process enabled Hydro One to identify investments that were aligned with key customer priorities such as improving reliability and power quality. This aspect of the investment planning process is described in Section 1.3.

The second source is the OGCC's Customer Operating Support Group. The OGCC's Customer Operating Support Group has direct communications with transmission customers regarding real-time operations, the coordination of planned outages, responses to unexpected outages, and the coordination of switching activities. This group also organizes bi-annual customer meetings to coordinate outage planning and, on a weekly basis, sends individual customers reports of planned outages affecting their specific delivery point, as well as post-event investigation reports following unplanned outages. In addition, this group holds transmission-connected customer conferences to share information about Hydro One's plans for the year ahead. The key messages derived from customers through these efforts are shared with Hydro One's Large Customer Account Management group so as to help inform the ongoing tracking of customer needs and priorities.

The third source is a Large Customer Conference which is held annually for all of Hydro One's large transmission and large distribution customers. At the conference, customers are presented with information about significant Hydro One initiatives, upcoming technology changes, and other initiatives that might affect them. Specific sessions, including interactive panel discussions, are held during which Hydro One presents an overview of its upcoming investments and activities. Customers also have an opportunity to meet with and provide input and share concerns with Hydro One staff and members of the senior leadership team. Hydro One obtains initial indications about customer needs and preferences by soliciting input for the conference agenda. In addition, Hydro One's Planners attend the conference, meet directly with customers and receive a summary of feedback received through a post-conference survey.

The fourth source is a series of oversight committees established by Hydro One to actively track areas of high customer interest, where careful ongoing coordination of effort with other entities is valuable, and/or where coordinated health and safety oversight is of benefit. Committees include representatives from the various affected stakeholders and meet periodically. These are focused on Sarnia area reliability, OPG and Bruce Power switchyard oversight, Toronto Hydro, Hydro Ottawa, Metrolinx, Alectra project impacts and an LDC working group. Deliverables from these oversight committees provide Hydro One Planners with additional information to support investment candidate selection decisions.

The fifth source is customer satisfaction research. Hydro One obtains customer input by means of a formalized customer satisfaction research process that has been ongoing since 1999. All research is conducted by independent expert consumer research firms, most recently by Innovative Research Group ("IRG"), a third party research firm. Hydro One's Overall Customer Satisfaction was 90 per cent for 2018. Perhaps the most significant benefit of the survey is the comments provided by customers. These comments help Hydro One understand those areas which require investment focus over the planning cycle.

The final source is a customer survey. In anticipation of this Application, Hydro One undertook a Transmission Customer Engagement Survey to identify the needs and preferences of its transmission-connected customers. Content for the survey was the result of preliminary work performed by Hydro One to address lessons learned from the 2016 Transmission Customer Engagement effort, feedback received from intervenors in the last Transmission survey, and work performed with IRG. The objective was to craft a framework through which Hydro One could obtain information to guide its investment and business plans in an unbiased manner.

The Transmission Customer Engagement Survey was carried out on Hydro One's behalf by IRG. Customers participated in the survey through a customized website created and hosted by IRG to ensure that all data was collected in a private and secure manner. Hydro One and IRG made efforts to contact all Hydro One transmission customers to participate in this engagement, either by email, phone call or in-person. As indicated in the IRG Report, a copy of which is included in TSP Section 1.3.7, the results represent the opinions of the majority of customers as the survey response rate was 66%, or 103 of 153 customers. Response rates were 51% higher than those of the 2016 Transmission Customer Engagement that was reported on in Hydro One's last transmission rate filing (EB-2016-0160). In addition, a portion of the LDCs who participated in the survey based their input on the results of their own customer engagement activities so that feedback from LDC end-users is also reflected in the TSP. The resulting customer feedback indicated the following priorities:

- Safety, reliability, and outage restoration are Hydro One customers' top priority outcomes.
- All customer segments prefer to see investments spread out over time versus investing now with higher rates in short term and lower future increases or delaying investments with lower rates in the short term and higher future rates.
- Reducing the frequency of outages is more important than reducing the duration. However, the most important issue is to reduce the number of day-to-day interruptions.
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the 2017 to 2018 proceeding[13] by at least a three to one margin. It is seen as

[13] The total 5 year capital investment plan associated with Scenario C was $6.6B from 2019-2023. The total 5 year capital investment plan included in the 2017-2018 transmission rate application was $6.1B.

reflective of the current approach which has served the system well, and a less risky option.

- About half of end-user participants (19 of 38) rate power quality as an "extremely important" outcome.

These preferences have been consistently reiterated in Hydro One's regular touch points with its customers, as described above in this section.

The Transmission Customer Engagement Survey was carried out sufficiently in advance of the present application so as to allow an opportunity for Hydro One management to hold a series of cross functional sessions to review the findings, trends and specific customer needs and preferences identified by the survey. In addition, processes were put in place to ensure that these needs and preferences, as well as those identified through Hydro One's other customer engagement initiatives, have been appropriately captured in the investment planning process to improve alignment between individual candidate investments identified by planners and the outcomes of the customer engagement activities. Feedback obtained through Hydro One's ongoing engagement initiatives since the survey are aligned with these results.

Through the incorporation of feedback received from the broad range of customer engagement activities into the TSP, Hydro One has been able to determine a funding envelope that balances its considerations of rate impacts, customer needs and preferences, as well as operational and compliance needs. These considerations are integral to the review and final approval of the Business Plan by Hydro One's Executive Leadership Team and its Board of Directors.

In addition, the enhancements made to Hydro One's customer engagement process are responsive to the concerns raised by the OEB in its Decision and Order on Hydro One's last transmission rate application (EB-2016-0160), issued on September 28, 2017 and revised November 1, 2017. In that decision, the OEB expressed concerns with certain aspects of the customer engagement process, particularly the need for Hydro One to (i) start its customer engagement process sufficiently in advance of filing its transmission rate application to allow for customer input to be incorporated in a meaningful way and to improve the level of participation, (ii) discuss with LDC customers practical ways to seek input from their end-users, and (iii) present information to customers in a manner that is unambiguous and easy to understand.

As noted, Hydro One's Transmission Customer Engagement Survey was carried out sufficiently in advance of this Application, which allowed an opportunity for a series of cross functional sessions within the company to review findings and ensure that identified needs and preferences have been appropriately captured in investment planning. To support the survey, Hydro One worked with IRG to develop clear materials through which Hydro One could obtain information to guide its investment and business plans in an unbiased manner. In addition, a portion of the LDCs who participated in the survey based their input on the results of their own customer engagement activities so that feedback from LDC end-users is also reflected in the TSP. In response to the OEB's finding that it should seek timely and meaningful input from First Nations and Métis representatives, please see TSP Section 1.3 and Exhibit A, Tab 7, Schedule 2 of the Application.

Moving forward, Hydro One is implementing a new Ongoing Customer Engagement Questionnaire that will quantify transmission customer's satisfaction regarding a number of reliability focused measurements. The questionnaire asks about customer satisfaction with Hydro One's current work program; satisfaction with outages, power quality, and reliability; investment priorities; unplanned outages mitigation and impact; and rate impacts. The results of this annual questionnaire will input directly into Hydro One's Customer Relationship Management system and will inform the planning process. Currently, directly connected transmission customers receive an annual reliability report which summarizes performance at transmission and distribution delivery points. The report summarizes the number of Delivery Point Interruptions each customer has every year, on both the transmission and distribution system. The reliability report will allow customers to provide more informed input into customer engagement, such as Hydro One's new Ongoing Customer Engagement Questionnaire.

1.1.5.5 (5.2.1 A) REGIONAL PLANNING

The policy framework for regional planning and the extent to which it affects investment planning for Hydro One's transmission system is described in greater detail in TSP Section 1.2. The RRF requires that infrastructure planning be undertaken on a regional basis to ensure that regional issues and requirements are integrated into a utility's planning processes. As indicated, Hydro One participated in working groups comprised of representatives from the IESO, LDCs and other stakeholder groups for 19 of the 21 regions across the province where Hydro One is the lead transmitter. Hydro One's participation in these regional planning initiatives led to the identification of over 60 transmission investments, with 46 investments totalling approximately $1.4 billion in gross capital expenditures, which Hydro One proposes to implement and bring into service during the 2020 to 2024 planning period. The remaining 14 projects are planned to go in-service outside of the planning period. The number of projects by Group and Region are identified in Table 4 below, with further details on each of the projects set out in Section 1.2.

Table 4 – Number of Projects Identified in Regional Planning by Group and Region Planned for In Service between 2020-2024

Group	Region	Number of Projects
1	Burlington to Nanticoke	7
	Greater Ottawa	8
	GTA West	2
	Kitchener-Waterloo-Cambridge-Guelph	3
	Metro Toronto	12
	Northwest Ontario	1
	Windsor-Essex	6
2	London Area	2
	South Georgian Bay/Muskoka	4
3	Chatham/Lambton/Sarnia	1
	Total	**46**

1.1.5.6 (5.2.1 F) TRANSMISSION PLANNING PROCESS

Hydro One's Transmission Planning Process is comprised of a comprehensive and sophisticated process for managing its extensive transmission system assets and prudently planning its transmission investments. This process takes into account, and strives to produce, outcomes that are consistent with those identified in the RRF and that include the specific outcomes, identified through customer engagement, as described above and in TSP Section 1.3. The components of the process are set out in Figure 8 below.

Figure 8 – Hydro One's Transmission Planning Process

The core aspect of Hydro One's Transmission Planning Process is its Capital Planning Process. The Capital Planning Process refers to those aspects of the Transmission

Planning Process that involve identifying, developing and scoping investment candidates, prioritizing the portfolio of investment candidates based on risk, culminating with executive approval of a specific capital plan. Within the broader context of the Transmission Planning Process, the Capital Planning Process is informed by Hydro One's investment planning context, which includes Hydro One's strategic vision, planning and other relevant economic assumptions, customer engagement feedback, delivery of key outcomes, and overall assessment of the needs of Hydro One's assets, customers and other stakeholders.

Hydro One's Capital Planning Process consists of two interrelated functions. The first is a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition, assessing system and customer requirements through the regional planning process and customer connection process, as well as identifying and scoping investment candidates ("Asset Management"). This is followed by a risk-based investment planning process through which investment candidates are reviewed, prioritized and narrowed into an achievable set of planned investments in specific programs and projects that help drive Hydro One towards achieving its intended outcomes ("Investment Planning").

In its Decision and Order in Hydro One's last transmission rate proceeding (EB-2016-0160), the OEB required Hydro One to complete an independent third-party assessment of its TSP, including an assessment of its asset condition assessment and capital investment planning processes. Hydro One engaged Metsco Energy Solutions to review its asset condition assessment process and the Boston Consulting Group to review its capital investment planning process. The Metsco Energy Solutions and Boston Consulting Group reports are discussed and provided in TSP Section 1.4. Generally, Metsco Energy Solutions found that both the Asset Risk Assessment and Asset Analytics align with other asset management frameworks found elsewhere in the industry and are sufficiently rigorous and robust to accomplish their intended tasks from an analytical perspective. The Boston Consulting Group found that Hydro One has implemented a consistent and thorough capital investment planning process that meets or exceeds expectations for an above average utility planning process in all aspects.

Hydro One's Capital Expenditure Plan, as set out in Section 3 of this TSP, itemizes the specific programs and projects that have received executive approval for implementation through the Capital Planning Process. Hydro One's Asset Management and Investment Planning processes are summarized below and are discussed in greater detail in Section 2.

Asset Management

Hydro One's Asset Management process draws upon the company's deep expertise in a variety of disciplines - management, financial, economic, engineering, operations – to monitor its transmission system assets, identify and define needs, and determine the optimal timing for executing maintenance work and capital investments throughout the asset lifecycle. In carrying out this responsibility, Hydro One strives to ensure that it delivers, and can continue to deliver over the long-term, a level of transmission service that is responsive to identified customer needs and preferences, as well as operational needs, while managing risks and mitigating rate impacts.

The Asset Management process encompasses the initial stages of Hydro One's Capital Planning Process. During this process, Hydro One undertakes extensive and detailed technical reviews of its assets to identify a set of investment candidates. Investment candidates are potential programs and projects that are put forth for further consideration during the Investment Planning process, which is discussed in the next section.

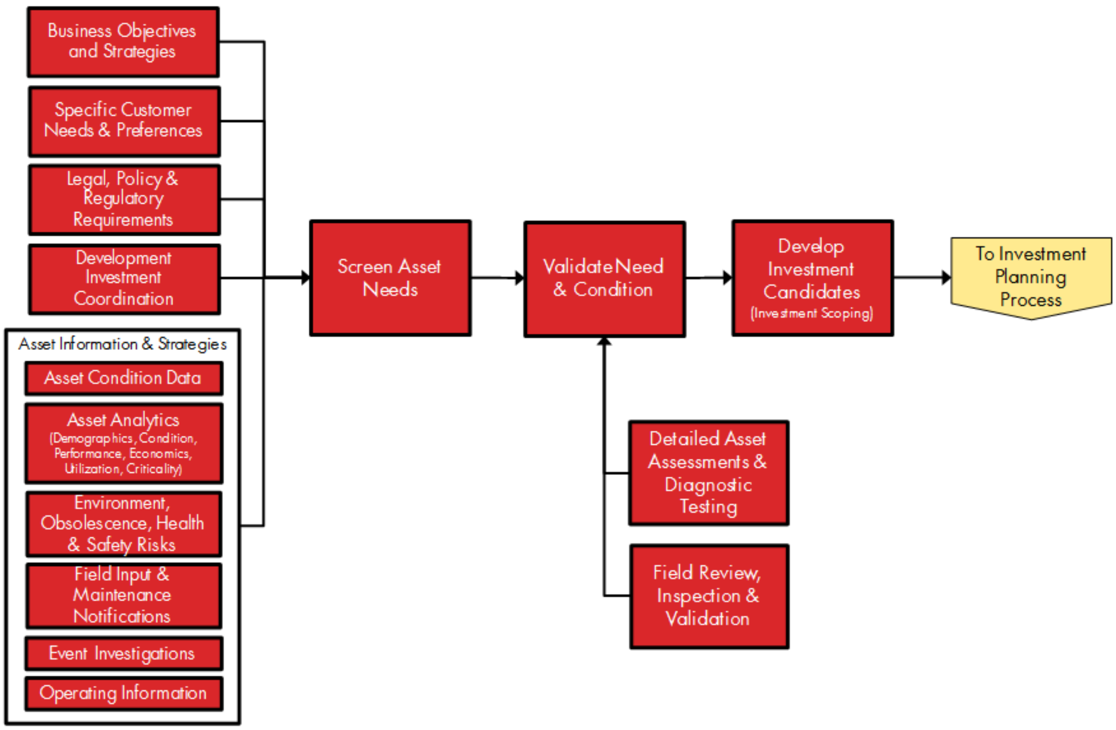


Figure 9 – Hydro One's Capital Planning Process – Asset Risk Assessment

Hydro One's Asset Management process starts with a thorough and systematic review of its transmission asset investment needs, which is reflected in Figure 9 – Hydro One's Capital Planning Process – Asset Risk Assessment. The needs assessment identifies and evaluates individual asset needs that drive the development of candidate investments and includes the collection of data which enables risk scoring to support prioritization and optimization of work undertaken later in the Investment Planning Process. The needs assessment considers (i) asset needs, (ii) customer needs and preferences, (iii) system needs (including those identified through participation in regional planning), and (iv) other external influences. The needs assessment also identifies potential hazards, vulnerabilities, threats or other risk sources that could present obstacles to achieving Hydro One's business objectives.

Hydro One carries out a continuous asset risk assessment ("ARA") process to determine individual asset needs which rely on asset condition data, engineering analysis and other information including the input of experienced planning professionals. An asset analytics system enables Hydro One planners to review aggregated information from various enterprise reporting systems. This drives efficient and effective planning decisions by ensuring a consistent view of asset information for all planners. The information contained within the asset analytics system includes condition information driven by deficiency and preventative maintenance reports, demographic information (including make, model, type and criticality to the transmission system), performance data based on equipment outages, utilization information, and economics. The asset analytics system combines information from various Hydro One databases to provide a common understanding of asset health and aids Hydro One planners in identifying asset risk and optimizing asset lifecycles. Hydro One's planners also take into account additional factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets.

The ARA process is primarily concerned with the major equipment groups that directly affect system reliability, namely transformers, conductors, breakers and protection and control systems and evaluates them on the following six risk factors:

- Condition - Risk related to the increased probability of failure that assets experience when their condition degrades over time.
- Demographics - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage.
- Criticality - Represents the impact that the failure of a specific asset would have on the transmission system
- Performance - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages

- Utilization - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized
- Economics - Risk based on the economic evaluation of the ongoing costs associated with the operation of an asset

When assessing individual asset needs, Hydro One's Planners engage in a process of grouping identified needs into logical, functional and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, might be grouped together if the same transmission station is involved. Through this process, diverse individual needs are brought together to form potential projects or programs that may be brought forward as candidate investments. These groupings of potential candidate investments are then scoped and defined based on identified asset needs, customer feedback and other inputs. Following this, Hydro One undertakes a further validation process, described below, to confirm that the need for the project or program is still there, has not evolved and will not be addressed by other means.

As part of investment development, on-site assessments are conducted to ensure site-specific factors such as the physical design, clearances, constructability and safety options requiring geographic flexibility, etc. are considered. During these on-site assessments, planners and field personnel validate and confirm asset condition and related information identified through enterprise reporting systems and asset analytics. Planners will also speak directly with Hydro One personnel who are involved in the day-to-day management and maintenance of the equipment in order to get additional insights into deficiencies and asset needs.

For high-value assets, such as transformers, Hydro One's subject matter experts perform a thorough analysis and advise on issues such as equipment obsolescence, manufacturer support and conduct "repair vs. replace" evaluations. All transformer replacements require review by subject matter experts who prepare Transformer Assessment Reports that are used to validate investment decisions.

These steps inform the development of a set of potential candidate investments. Hydro One's capital investment plans and potential candidate investments are then reviewed with internal stakeholders, such as the company's Customer Service and Transmission and Stations work delivery functions, as well as affected customers. Through this review process, Hydro One ensures that identified customer needs and preferences have been considered and used to inform the development of investment plans and specific candidate investments. Where more than one feasible alternative has been identified for meeting the identified need, a financial analysis (i.e. Net Present Value) is conducted to assist in determining the preferred alternative to put forward as a candidate investment.

The result of the aforementioned ARA process is that a portfolio of specific candidate investments is submitted for further consideration through the Investment Planning process. In that process, specific investments are prioritized to align with intended outcomes based on corporate priorities and strategic objectives, regulatory requirements, investment risks and identified constraints. Before describing the Investment Planning process, the following sections highlight some of the characteristics of asset management relating specifically to each of the main classes of transmission assets – stations and lines.

Stations Asset Management

As noted, Hydro One's transmission system includes 294 stations. Prior to 2014, Hydro One's approach to station asset management was asset-specific. Separate programs were used to consider, plan for and implement replacements for particular asset types (i.e. transformers, breakers and switches) across the province. In 2014, Hydro One transitioned to an integrated approach to station asset management to enable successful delivery of the work program in an efficient manner that minimizes customer impact by requiring fewer planned outages, and optimizing design, execution and operating efficiency. The integrated approach enables work that is required at a particular station to be bundled together and executed at once. Integration of station work and the timing for this work is oriented around key station assets (i.e. transformers, breakers, switches and protection and control equipment).

This station-focused approach addresses infrastructure that is aging and in poor condition, and integrates OM&A and capital programs across multiple disciplines. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 294 transmission stations during the cycle. This ensures that asset needs at all stations are reviewed on a recurring basis, which may or may not result in the need for investment after applying the ARA process. By developing and implementing integrated investments for each station, this approach enables Hydro One to efficiently use outages and to minimize the total number of outages required to complete necessary renewal work. The candidate investments identified through the Asset Management process include station-specific packages of work that have been developed in accordance with the established assessment cycle.

Lines Asset Management

Hydro One's approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. In particular, transmission conductors have an expected service life of 90 years. When a conductor fails or based on its condition, as confirmed by testing, has been determined to have reached end of life, replacement is the only solution. When the conductor needs replacement, this creates a rare opportunity in the asset lifecycle for Hydro One to implement a full line refurbishment of the relevant segment in order to bring the associated assets to a condition that is as close to new as possible. This includes poles, parts of steel structures, foundations and the conductors. Upon completion of a full line refurbishment, the line will be ready to return to service for another 90 years. Other transmission line components do not last this long and are therefore the subject of separate, recurring, asset replacement programs. Such programs are in place for assets such as wood poles, insulators, shield wire, aviation lighting and U-bolts. Program budgets are established through the investment planning process and are typically based on unit costs and the numbers of units that require replacement in a given year. Regardless of the type of transmission line asset, Hydro One's approach to Asset Management is condition-driven such that assets are not replaced unless their condition warrants it.

Investment Planning

Since the EB-2016-0160 proceeding, Hydro One has implemented several changes that address investment planning process concerns raised by intervenors and the OEB. These are summarized in Table 1 above and elaborated on as follows.

In response to concerns raised during the EB-2016-0160 proceeding, Hydro One has implemented an improved eight-step investment planning process. Key improvements to the investment planning process include:

- Consistent scoring for safety, reliability and environmental risk mitigation based on new standardized frameworks;
- Clear definitions of risk impacts to enable consistent scoring across investment types, and calibration sessions to ensure standardized scoring practices; and

Challenge sessions, which are facilitated sessions held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

This process is designed to provide a consistent and common understanding and prioritization and optimization of risk to cost effectively deliver the highest value for Hydro One and its customers. This allows candidate investments to be consistently assessed and prioritized based on level of risk mitigated, cost and value delivered on achieving business objectives.

The process generates an annual budget for work program Operations, Maintenance and Administration ("OM&A") and capital investments, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements for a consolidated five-year capital plan.

In summary, the investment planning process consists of the following steps:

1. Investment Planning Context: Hydro One draws on multiple sources of input in the development and prioritization and optimization of the investment plan consistent with Hydro One's Strategic Business Objectives and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback, (iv) delivery of key outcomes, and (v) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;
2. Candidate Investment Development: Through the Asset Management process described above, candidate investments are identified, developed and submitted for inclusion in the investment plan;
3. Investment Assessment and Calibration: Investments are scored for safety, reliability, and environmental risk mitigation using a clear and consistent scale based on risk taxonomies. Special, non-risk considerations are also flagged (e.g. Strategic, compliance, customer needs and preferences). Once candidate investments have been scored and flagged, the scores are reviewed in facilitated discussions among investment owners in calibration sessions.
4. Prioritization and Optimization: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments. Following the initial prioritization and optimization, facilitated challenge sessions are held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs,

5. Enterprise Engagement: Executing lines of business review the investment plan for operational/execution feasibility, strategic alignment and to challenge investment needs and assumptions;
6. Develop Final Plan: Final decisions are made to arrive at a final version of the investment plan and its outcomes against strategic, customer, and risk considerations;
7. Review and Approval: The investment plan and associated outcomes are reviewed and approved by VPs, the Executive Leadership Team, and the Hydro One Board; and
8. Execution and Performance Monitoring: The execution of the plan is monitored to ensure it is delivered as efficiently as possible.

The Investment Planning process is described in greater detail in Section 2.1 of this TSP.

1.1.5.7 (5.2.1 A) CAPITAL EXPENDITURE PLAN

Based on Hydro One's assessment of its transmission system, a significant portion of its assets have deteriorated to the point where they pose a risk to achieving business objectives for safety, reliability, environment and the customer. Therefore, over the planning period, Hydro One plans to spend approximately $6.6 billion in capital; representing a compound annual growth of 3.5% over five years, to maintain transmission reliability performance, address customer needs and preferences, and mitigate asset and operational risks. This includes delivering $590 million of capital productivity savings improvements (related to the work program) through information technology, procurement, and process efficiency improvements in executing the work.

Hydro One's capital expenditure forecast is $1.2 billion for 2020, increasing to $1.4 billion in 2024. These investments, reflected in Hydro One's TSP, are grouped into four categories: System Access, System Renewal, System Service, and General Plant. Approximately 83% of Hydro One's transmission capital plan is focused on System

Renewal investments. Tables 5 and 6 summarize the capital investment plan based on these four investment categories along with the Progressive Productivity Placeholder savings and Directive Adjustment that are applied as a reduction to the capital expenditures that are sought for rate recovery. Progressive Productivity Placeholder savings are explained further below.

Table 5 – 2020 – 2024 Capital Spending Forecast ($ Million)

Category	Forecast (Planned $M)				
	2020	**2021**	**2022**	**2023**	**2024**
System Access	24.8	11.3	11.7	12.7	4.1
System Renewal	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	204.1	148.2	151.8	174.3	204.2
General Plant	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder	(17.0)	(39.0)	(61.0)	(78.0)	(91.0)
Directive Adjustment[14]	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)
Total	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
System OM&A[15, 16]	**375.8**	*	*	**N/A**	**N/A**

Table 6 – 2020 – 2024 Capital Spending Forecast (% by Category)

Category	2020	2021	2022	2023	2024
System Access	2.1%	0.9%	0.9%	0.9%	0.3%
System Renewal	72.6%	83.7%	85.6%	85.9%	87.1%
System Service	17.1%	11.2%	11.1%	12.7%	14.9%
General Plant	9.7%	7.2%	6.9%	6.1%	4.3%
Progressive Productivity Placeholder	-1.4%	-3.0%	-4.5%	-5.7%	-6.6%
Directive Adjustment	0.0%	0.0%	0.0%	0.0%	0.0%

Investment Summary Documents ("ISD") detailing the specifics for each material investment with spending greater than $3M in any one year are listed in Section 3.3. An

[14] The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.
[15] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1
[16] Includes the Directive Adjustment described in Exhibit F, Tab 1, Schedule 1.

overview of the main factors driving the investments in each of these categories is set out below.

System Renewal

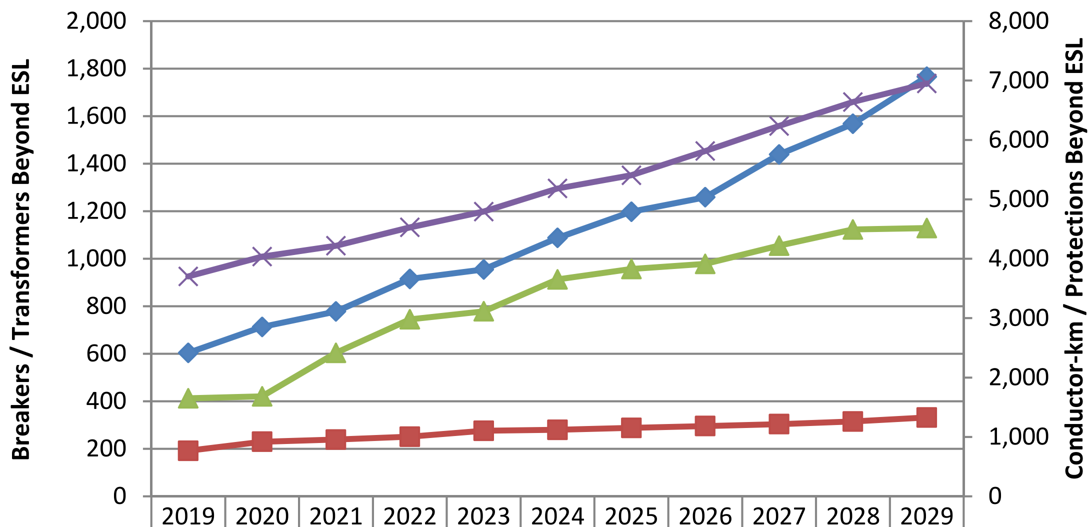
Hydro One's TSP reflects the need for continued station renewal investments at a cost of $3.5 billion, or approximately 53% of the total planned capital expenditures over the planning period, to address deteriorated station assets including transformers, circuit breakers, protection, control and telecom equipment. These replacements are expected to approximately maintain the proportion of transformers on the system that are beyond their expected service life at 26%, approximately maintain the proportion of protection systems operating beyond their expected service life at 28% and maintain the number of breakers that are beyond their expected service life at 12%. This includes the replacement of 72% of the air-blast circuit breakers (ABCBs) at a cost of $594M. ABCBs are about 10 times more expensive to maintain and about 4 times less reliable than their equivalent SF6 circuit breakers.

The TSP also delivers an increased emphasis on line renewal investments at a cost of approximately $2.0 billion to refurbish and replace end of life transmission lines, underground cables, insulators, and wood poles while continuing with tower coating of steel structures to extend their useful life, but at a reduced pacing consistent with prior direction from the OEB. While the planned rate of refurbishment does not keep pace with the overhead lines demographics, the risk is managed through the use of detailed conductor assessments to identify poor condition conductors, informing the line refurbishment program. Lines are candidates for conductor condition assessment starting at 50 years of age.

In developing the TSP, Hydro One recognized that execution of the plan will take place in the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital and

OM&A work efficiently and its ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. As a result, it has planned the pace of renewal work so that certain critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service and not subject to increased outage constraints resulting from increased failures or additional maintenance that would make the work more difficult to complete.

These investments are required to address the significant demographic pressure that Hydro One is experiencing for some key asset classes. Figure 10 shows the forecasted cumulative number of assets that will exceed their expected service life during the 2019 to 2029 period in the absence of any planned or unplanned replacements. Over this period, the number of assets that are beyond the expected service life in these asset classes would increase by 1.8 to 3.6 times current levels. This rapid and growing shift poses inherent operating and resourcing risks that Hydro One is planning for by proactively and strategically pacing its investments in order to limit pressure on both OM&A and capital costs, while providing the level of service and reliability that customers expect.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	192	230	239	251	276	280	288	296	304	315	332
Conductor	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952

Figure 10 – Number of Assets Beyond End of Service Life Per Year Summary

System Access and System Service

The TSP funds $947 million of System Access and System Service capital that is required over the planning period to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with customers, transmitters, distributors and the IESO. These investments will result in the addition of seven new transformer stations, ten customer-owned stations and 272 circuit km of new or upgraded transmission lines. Major projects include the development work for the North-West Bulk transmission expansion, new transmission switching and lines facilities to support load growth in the Leamington area, transformation and lines at Milton Switching station, and upgrades/expansion in Barrie and Toronto areas.

General Plant

This TSP funds $447 million of general plant capital that is required over the planning period to support day-to-day business and operations activities such as buildings, tools, equipment, rolling stock, as well as information technology hardware and software. This includes investing $189 million in operating infrastructure and control facilities. This amount includes the new Integrated System Operating Centre ("ISOC"), which represents an investment of $45 million over the planning period, as well as an upgrade to Hydro One's Network Management System – used for grid control, and a refresh of Hydro One's integrated voice communication telephony system.

1.1.5.8 (5.2.1 C) SOURCES OF COST SAVINGS

In its Decision and Order in EB-2016-0160, the OEB directed Hydro One to establish firm short and long-term targets for productivity improvements and associated reductions in revenue requirements as a means to drive continuous improvement and improve the company's internal and external benchmarking standings. As a result of its efforts to address those expectations, and to further its commitment to delivering outcomes that are valued by its customers, Hydro One has developed a comprehensive and rigorous process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs. Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the company. Within this framework, quantifiable productivity improvements are included in the Business Plan and corporate scorecards with clear accountabilities for delivering the anticipated savings.

Using this approach, Hydro One has identified savings opportunities in Capital and OM&A totaling approximately $704 million over the plan period. All of these savings are net savings with a direct correlation to a budget and/or spending forecast reduction. Underlying these savings are specific productivity initiatives that have been identified, reviewed, approved and made subject to tracking and reporting requirements. Hydro One has identified savings opportunities totalling approximately $704 million over the 2020-2024 TSP period. There are $353 million in capital productivity savings, $114 million in OM&A productivity savings and $237 million in undefined capital savings. This latter category of savings falls within "Progressive Productivity". Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB's decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:

1. $49 million in Progressive Operations (Defined Capital) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and
2. $237 million in Progressive Operations (Undefined Capital) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

Approximately $590 million of the identified savings opportunities are related to Operations (Operations OM&A, Operations Capital, Progressive Operations (Defined Capital) and Progressive Operations (Undefined Capital), approximately $44 million in savings are IT-related (OM&A and Capital) and approximately $70M in savings are related to Corporate Initiatives (OM&A and Capital). Further details can be found in TSP Section 1.6

Hydro One expects to achieve these significant cost savings over the forecast period through good planning and effective execution of the TSP. Hydro One's productivity framework is further described in Section 1.6 and the productivity savings that Hydro

One expects to achieve over the 2020 to 2024 forecast period are summarized in Table 7 below.

Table 7 – Productivity Savings Forecast ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations Productivity Placeholder (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Operations (Defined)	6	12	12	10	10	49
Progressive Operations Productivity Placeholder (Undefined)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

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** “Transmission” refers to Chapter 2 of the OEB’s Filing Requirements for Electricity Transmission Applications (February 11, 2016).*

1.2 (5.2.2) COORDINATION THROUGH REGIONAL PLANNING

Planning transmission infrastructure with key stakeholders in a regional context promotes transparency and the cost-effective development of electricity infrastructure in Ontario. This is one of the key guiding principles in the Board's Renewed Regulatory Framework ("RRF"), which states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into a utility's planning processes.

Hydro One Transmission is actively involved in the regional planning process and leading the development of Needs Assessments and Regional Infrastructure Plans. This is consistent with Hydro One's business objective of safely delivering a cost effective and reliable supply of electricity to meet its customers' needs.

This Exhibit provides an overview of the regional planning process and associated customer consultation processes used to engage distributors and other customer groups in regional planning activities. This Exhibit also provides a status update on each of the regions, highlighting investments arising from the regional planning, which form part of Hydro One's capital plan. Hydro One's capital plans are described in TSP Section 3.3.

1.2.1 (5.2.2) OVERVIEW OF THE REGIONAL PLANNING PROCESS

As described in the *Planning Process Working Group Report to the Board: The Process for Regional Infrastructure Planning in Ontario* (the "PPWG Report"), planning for the electricity system in Ontario is generally conducted at three levels:

1. Bulk system planning;
2. Regional system planning; and,
3. Distribution system planning.

Regional planning addresses supply and reliability issues at a regional and/or localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115kV and 230kV portions of the power system, that supply various parts of the province but can overlap with bulk system planning and/or distribution system planning at the interface points or where there may be regional resource options or distribution solutions to address the broader local area for the specific region.

Figure 1 illustrates the various phases of the regional planning process, as documented in the PPWG Report. Hydro One adheres to this process and the corresponding requirements under the Transmission System Code and Distribution System Code, as applicable.

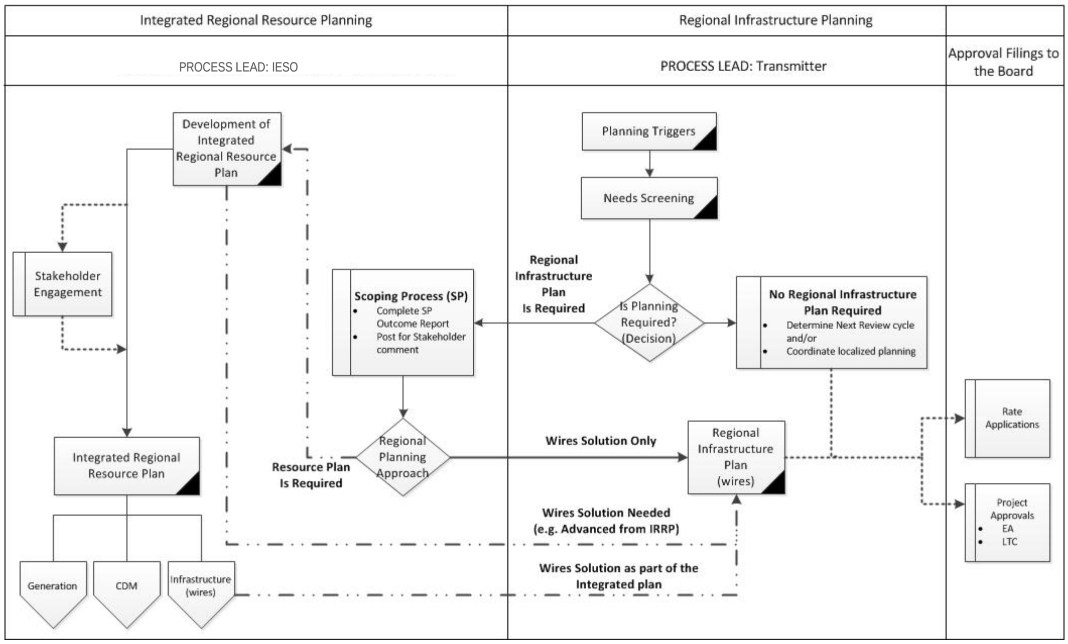

Figure 1: Regional Planning Process

The regional planning process is initiated by a planning trigger. Potential triggers include regularly scheduled Needs Screening by the transmitter, a scheduled review specified in an existing Regional Infrastructure Plan, a Government directive, a significant change to a code or standard, or an emergent need brought forward by the transmitter, distributors, customers, or the Independent Electricity System Operator ("IESO") that must be addressed before the next scheduled review. It is intended that this process is to be repeated for each of the planning regions identified in the PPWG Report every five years; though the process may be more frequent depending upon the emergence of new needs.

Once the regional planning process is initiated by a planning trigger, the process unfolds through the following phases:

- Needs Screening (hereinafter referred to as Needs Assessment ("NA"))[1];

[1] The Needs Screening and Scoping Process phases of regional planning are as described in the PPWG Report; whereas Hydro One refers to these as the Needs Assessment and Scoping Assessment in accordance with the terminology used in the Transmission System Code.

- Scoping Process (hereinafter referred to as Scoping Assessment ("SA"))[1];
- Integrated Regional Resource Plan ("IRRP"); and
- Regional Infrastructure Plan ("RIP").

Needs Assessment

The NA, for a given region, is led by the lead transmitter in the region in consultation with the subject matter experts from the local distributors ("LDCs") and the IESO. These representatives are referred to as a "Study Team"[2]. In this phase, the Study Team identifies merging needs, and undertakes an assessment to determine potential alternatives or solutions to address the needs. During the assessment, information regarding transmission assets reaching the end of their useful life is also identified and assessed for right sizing the equipment. In cases where: (a) the needs are local in nature; (b) further review by subsequent phases in the regional planning process is not required; and (c) the needs can be addressed directly by the transmitter and local distributor(s) or other transmission connected customer(s) through transmission and/or distribution facilities (i.e., a "wires" solution), a local plan is developed. The local plan is ultimately incorporated in the RIP for the region.

Scoping Assessment

In circumstances where the Study Team considers further planning studies and coordination to be necessary, the IESO initiates the SA phase. In this phase the IESO, in collaboration with the lead transmitter and impacted LDCs, reviews the information collected during the NA phase. The IESO also considers information related to potential non-wires alternatives, and determines the most appropriate regional planning approach, i.e., whether an IRRP or a RIP, or both, is required to address the needs in the region or sub-region.

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[2] The *Working Group* as described in the PPWG report is equivalent to *Study Team* as referred to by Hydro One and is the current terminology utilized in the RIP reports.

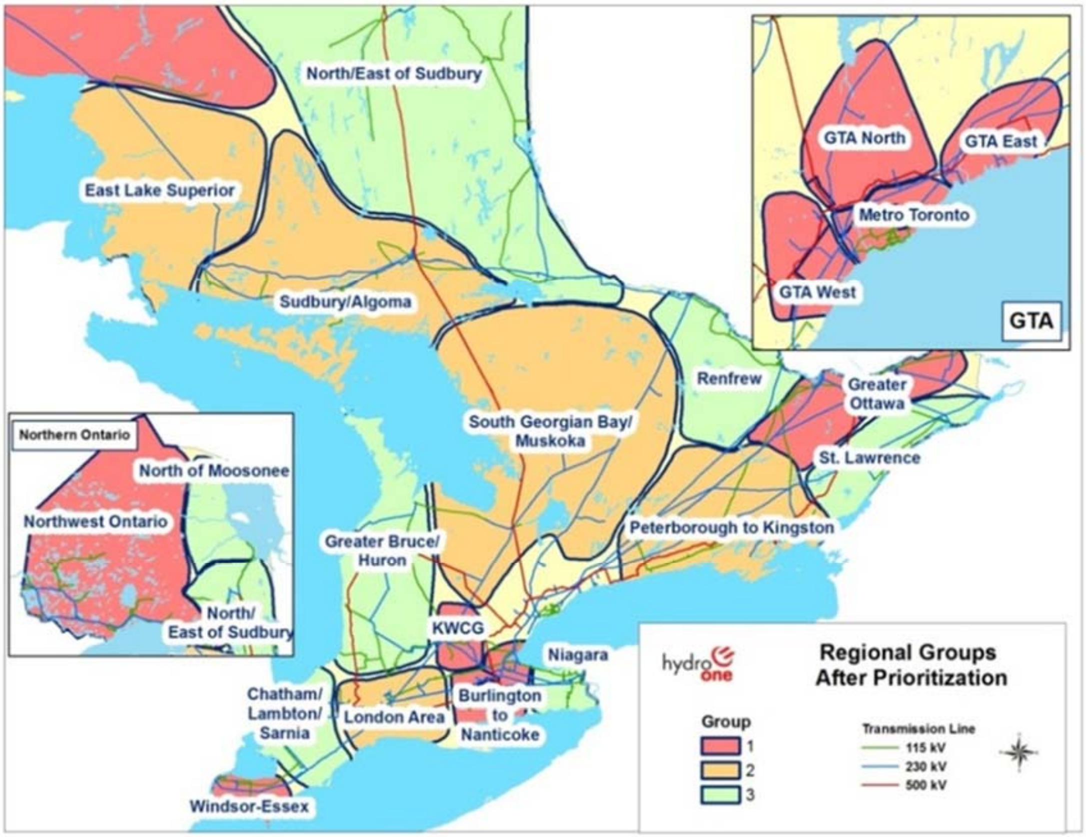
Integrated Regional Resource Plan

The IRRP process involves identifying, evaluating and integrating potential wires and non-wires solutions at the regional or sub-regional level. The IRRP phase generally assesses resource (i.e., generation and/or conservation and demand management) versus wires infrastructure options at a higher level, but with sufficient detail to allow for a comparison of options. If during this phase it is determined that resource options are best suited to meet a need, then those options are further planned by the IESO. However, if wires options are the more appropriate alternative, then those options are further assessed and/or planned as part of the RIP process.

Regional Infrastructure Plan

The RIP process is the final phase 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 (including end-of-life transmission asset needs that may influence a solution to address broader regional needs); and development of a wires plan to address the needs. This phase is led and coordinated by the transmitter, and the deliverable from this phase is a comprehensive report setting out a wires plan from a regional planning perspective. The wires plan may include distribution investments or options affecting regional needs for optimal outcomes. The recommendations related to transmission and distribution wires planning stemming from the NA, SA, and IRRP are part of the RIP report for the region. The status and corresponding documents from each phase are published on the Hydro One and/or the IESO regional planning websites.

As outlined in Figure 2, there have been 21 electrical regions defined for the purposes of implementing regional planning in Ontario. Each of the 21 regions has been assigned to one of the three regional planning groups in order to prioritize and efficiently manage the regional planning process. Hydro One Transmission is the lead transmitter in all regions, except East Lake Superior and North of Moosonee. The first full cycle of the regional planning for all three groups, which took place over a period of approximately four years, was completed in August 2017 and the second cycle is now in progress commencing with Group 1.



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	1. East Lake Superior (3)	1. Chatham/Lambton/Sarnia
2. Greater Ottawa	2. London Area	2. Greater Bruce/Huron
3. GTA East (1)	3. Peterborough to Kingston	3. Niagara
4. GTA North	4. South Georgian Bay/Muskoka	4. North of Moosonee (3)
5. GTA West	5. Sudbury/Algoma	5. North/East of Sudbury
6. KWCG (2)		6. Renfrew
7. Metro Toronto		7. St. Lawrence
8. Northwest Ontario		
9. Windsor-Essex		

Notes: *(1) Subsequent to the PPWG Report, GTA East was moved from Group 2 to Group 1*
(2)"KWCG" stands for Kitchener-Waterloo-Cambridge-Guelph
(3) Hydro One Transmission is not the lead transmitter in this region

Figure 2: Regional Planning Regions

1.2.2 (5.2.2 A) REGIONAL PLANNING CONSULTATIONS

As part of the regional planning process, Hydro One undertakes extensive consultation with the LDCs and the IESO to identify needs and develop plans as envisioned by the Board in its RRF. Hydro One also reaches out to its large transmission-connected customers to obtain and update their future plans and electricity load forecasts.

Study Teams have been established in all of the 19 regions across the province, where Hydro One Transmission is the lead transmitter, in order to undertake regional planning. Approximately 70 LDCs along with the IESO participated during the first cycle and continue to be active in the second cycle of the regional planning process. In the Northwest Ontario region, the Study Team led by the IESO also sought input from other stakeholder groups such as: Northwestern Ontario Municipal Association, Common Voice, Ontario Mining Association and municipalities. This unique approach was required due to the vast geographic area, uncertainties related to changing resources and industrial/mining load and challenges not normally seen in other parts of the province.

At each phase of the regional planning process, and for each of the regions, Hydro One has undertaken a combination of the following consultation activities to ensure the involvement and engagement of Study Team members:

1. **Pre-meeting Conference Calls/Webinars:** At the beginning of each phase, LDCs and the IESO are notified in advance of upcoming regional planning activities and are provided an overview of the process.

2. **Kick-off Meetings/Conference Calls/Webinars:** Kick-off meetings with the Study Team are organized to initiate each of the phases of the regional planning process and provide templates for the collection of information/data.

3. **Additional Face to Face Meetings/Conference Calls/Webinars:** The Study Team meets on a regular basis to discuss planning matters, such as: assessment methodology, customer needs, and regional needs and timing before recommending a preferred solution.

In addition to the Study Team members, other customers and stakeholders, such as local municipalities, indigenous communities, business groups, citizen groups, consumers and environmental and conservation groups are contacted and have an opportunity to provide input as part of the IESO-led engagement during the SA and IRRP phases. If continued community input and broader engagement is needed for the regional planning, then a Local Advisory Committee ("LAC") made up of representatives from public and various interested customer and stakeholder groups is formed. In areas where there are a large number of First Nations communities, a First Nations local advisory committee may also be established and representatives from this committee would then be appointed as members of the regional LAC.

The LAC is an advisory body and a forum for communities to provide their input and stay informed about regional planning activities within their region. As an advisory body, the LAC members represent communities and bring forward their interests within the study area and provide insight into their values and perspectives. The LAC input is amongst many inputs that are considered by the Study Team, including information on local priorities (such as municipal or community energy plans), when developing options identified in the plan and ideas on the design of community engagement strategies.

Currently, there are ten active LACs that have been formed to engage communities in the regional planning process, as indicated below:

- Three in the Northwest Ontario region to represent three of the sub-regions: Greenstone-Marathon, City of Thunder Bay, and West of Thunder Bay;

- Two in the South Georgian Bay / Muskoka region to represent the two sub-regions: Parry Sound / Muskoka, and Barrie / Innisfil;
- One in the GTA North region to represent the York sub-region; and
- Four to represent the following four regions: GTA East, Greater Ottawa, Metro Toronto, and Windsor-Essex.

Hydro One also undertakes a broader and comprehensive engagement with the public and other stakeholders at the project development level. All major transmission projects go through the environmental assessment process in accordance with the *Ontario Environmental Assessment Act* and/or the leave to construct approval process in accordance with Section 92 of the *Ontario Energy Board Act*. Each of these processes requires extensive public and stakeholder consultation on projects through such methods as meetings, presentations, public information centres, notices and newspaper advertisements.

In addition to the publication of regional planning reports on Hydro One's website, these consultations ensure transparency in regional planning activities that may influence stakeholders' local plans (such as municipal planning or the development of community energy plans) and they demonstrate Hydro One's responsiveness to public policy and commitment to being a vital partner in the continued economic success of the province.

For specific information on the participants involved in the planning process for particular regions, please refer to the regional planning reports filed as Attachments to this Exhibit or to Hydro One's Regional Planning website, noted below.

https://www.hydroone.com/about/corporate-information/regional-plans

1.2.3 (5.2.2 B) REGIONAL PLANNING OUTCOMES AND STATUS UPDATE

As the lead transmitter, Hydro One Transmission leads the NA and RIP phases of the regional planning process, and actively participates in the SA and IRRP phases led by the IESO.

Hydro One is required, by Section 3C.3.3 of the Transmission System Code, to submit a report to the Board annually on the status of the regional planning activities for all regions. Hydro One filed its 2018 Status Report with the Board on November 1, 2018.[3] As explained in the 2018 Status Report, Hydro One continues to make progress on the second cycle of the regional planning process; including several enhancements that will be reflected in the RIP reports. Table 1 below provides a summary of the current status for each region and sub-region showing the planning phases that are underway or completed. The Sections that follow provide further descriptions of the regional planning activities and investment recommendations scheduled for each of the regions and sub-regions over the 2020 to 2024 period for which Hydro One is the lead transmitter. A letter from the IESO on the overall regional planning status is presented in Attachment 1.

Hydro One is also required by Section 3C.2.2 of the Transmission System Code to provide Planning Status Letters to licensed distributors and transmitters confirming the status of regional planning for a region, suitable for the purpose of supporting an application proposed to be filed with the Board by the distributor or requesting transmitter. In addition to the Planning Status Letters outlined in Appendix B of the 2018 Status Report, Hydro One has recently provided a Planning Status Letter to Kitchener-Wilmot Hydro Inc., Algoma Power Inc., and Alectra Utilities Corporation.

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[3] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/Documents/HONI_RegionalPlanningStatusReport_20181101.pdf

Table 1: Regional Planning Status Summary

Group	Region	Sub-region	1st Cycle (2013-2017)				2nd Cycle (2017->)		
			NA	SA	IRRP	RIP	NA	SA	IRRP
1	**Burlington to Nanticoke**	Brant	May, 2014	Sep, 2014	Apr, 2015	Feb, 2017	May, 2017	Aug 2017	Feb 2019 *(RIP now in progress)*
		Bronte			Jun, 2016				
		Greater Hamilton			*Not Required*				
		Caledonia-Norfolk		*Not Required*	*Not Required*				
	Greater Ottawa	Ottawa	Jul, 2014	Nov, 2014	Apr, 2015	Dec, 2015	Jun, 2018	Sept, 2018	*In Progress*
		Outer Ottawa		*Not Required*	*Not Required*				
	GTA East	Pickering-Ajax-Whitby	Aug, 2014	Sep, 2014	Jun, 2016	Jan, 2017	Q3 2019		
		Oshawa-Clarington			*Not Required*				
	GTA North	York	Jun, 2014	*Note1*	Apr, 2015	Feb, 2016	Mar, 2018	Aug, 2018	*In Progress*
		Western		*Not Required*	*Not Required*				
	GTA West	Northwestern	May, 2014	Sep, 2014	Apr, 2015	Jan, 2016	Q2 2019		
		Southern			*Not Required*				
	Kitchener-Waterloo-Cambridge-Guelph		*Note1*		Apr, 2015	Dec, 2015	Dec, 2018	Apr, 2019	*In Progress*
	Metro Toronto	Central Downtown	Jun, 2014	*Note1*	Apr, 2015	Jan, 2016	Oct, 2017	Feb, 2018	*In Progress*
		Northern		*Not Required*	*Not Required*				
	Northwest Ontario	North of Dryden	Note1	Jan, 2015	Jan, 2015	Jun, 2017	Q2 2019		
		Greenstone-Marathon			Jun, 2016				
		Thunder Bay			Dec, 2016				
		West of Thunder Bay			Jul, 2016				
	Windsor-Essex		*Note1*		Apr, 2015	Dec, 2015	Oct, 2017	Mar, 2018	*In Progress*
2	**East Lake Superior**		*Hydro One Transmission is not the lead transmitter in this region. Status to be provided by lead transmitter.*						
	London Area	Greater London	Apr, 2015	Aug, 2015	Jan, 2017	Aug, 2017	Group 2 expected to commence 2nd cycle in 2019.		
		Alymer-Tillsonburg			*Not Required*				
		Strathroy			*Not Required*				
		Woodstock			*Not Required*				
		St. Thomas			*Not Required*				
	Peterborough to Kingston		Feb, 2015	*Not Required*	*Not Required*	Jul, 2016			
	South Georgian Bay/Muskoka	Barrie/Innisfil	Mar, 2015	Jun, 2015	Dec, 2015	Aug, 2017			
		Parry Sound/Muskoka			Dec, 2015				
	Sudbury/Algoma		Mar, 2015	*Not Required*	*Not Required*	Jun, 2016			
3	**North of Moosonee**		*Hydro One Transmission is not the lead transmitter in this region. Status to be provided by lead transmitter.*						
	Chatham/Lambton/Sarnia		Jun, 2016	*Not Required*	*Not Required*	Aug, 2017	Group 3 expected to commence 2nd cycle in 2020.		
	Greater Bruce/Huron		May, 2016	*Not Required*	*Not Required*	Aug, 2017			
	Niagara		Apr, 2016	*Not Required*	*Not Required*	Mar, 2017			
	North/East of Sudbury		Apr, 2016	*Not Required*	*Not Required*	Apr, 2017			
	Renfrew		Mar, 2016	*Not Required*	*Not Required*	Jul, 2016			
	St. Lawrence		Apr, 2016	*Not Required*	*Not Required*	Jul, 2016			

Note 1: The planning activity in the region was already in progress prior to the commencement of the regional planning process; hence the NA/SA was deemed to be already completed by the Study Team.

The Study Teams in the various regions, with input from relevant stakeholders, have recommended more than 60 projects related to transmission investments through the first cycle of regional planning process; with additional needs being identified in the second cycle. The scope and details of these projects are discussed in the corresponding regional planning reports. The specific information on the status of the regional planning process and investments arising from the recommendations of the Study Team that form part of Hydro One's capital plans over the 2020 to 2024 period are highlighted below by each Region Group.

Regions in Group 1

There are nine regions identified in Group 1. Hydro One Transmission is the lead transmitter for all regions in this group. The first cycle of regional planning process has been completed and the second cycle has commenced in six of the nine regions.

Burlington to Nanticoke

The Burlington to Nanticoke region is comprised of four sub-regions: **Brant, Bronte, Greater Hamilton,** and **Caledonia-Norfolk**. The participants in the region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Horizon Utilities Corp.)
- Brantford Power Inc.
- Burlington Hydro Electric Inc.
- Energy + Inc.
- Hydro One Networks Inc. (Distribution)
- Oakville Hydro Electricity Distribution Inc.

The first cycle RIP for this region was completed in February 2017 and is presented in Attachment 2 of this Exhibit. In addition to advancing the work from the IRRP presented in Hydro One's previous rate application (EB-2016-0160), the RIP also identified additional needs related to end-of-life transmission assets in the Hamilton area. The plans to address these end-of-life needs have been developed by Hydro One and confirmed by the region's LDC's.

As documented in Hydro One's previous rate application, the project to install 115kV switching facilities at Brant TS *(Project D09 in EB-2016-0160)* was identified as one of the transmission infrastructure investments required for the region. This investment along with the following system renewal investments, recommended in the RIP are continuing to be developed and are expected for in-service in 2019.

- **Beach TS:** Transformer (T3/T4) Replacement; and
- **Bronte TS:** Transformer (T5/T6) and DESN Refurbishment.

In response to the remaining RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Beach TS:** Auto-Transformer (T7/T8) Replacement and DESN Switchgear (Part of SR-03);
- **Birmingham TS:** MV Metalclad Switchgear Refurbishment (Part of SR-05);
- **Dundas TS:** MV Switchyard Refurbishment (Part of SR-06);
- **Dundas TS #2:** Two New Feeder Positions (SA Other Projects);
- **Elgin TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Gage TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Kenilworth TS:** Transformer and DESN Reconfiguration (Part of SR-02);
- **Lake TS:** LV Switchyard Refurbishment (Part of SR-06);
- **Newton TS:** Station Refurbishment (Part of SR-05);
- **115kV B3/B4 Transmission Line:** Refurbish line sections from Horning Mountain Junction to Glanford Junction (Part of SR-19); and

- **115kV B7/B8 Transmission Line:** Refurbish line sections from Burlington TS to Nelson Junction (SR Other Projects).

The second cycle NA report[4] for this region was completed in May 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- **Burlington TS:** LV Switchyard Refurbishment (Part of SR-06); and
- **Norfolk TS:** LV Switchyard Refurbishment (Part of SR-06).

The second cycle IRRP phase led by the IESO was completed in February 2019; and now the RIP phase led by Hydro One is currently underway.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Greater Ottawa

The Greater Ottawa Region is comprised of two sub-regions: **Ottawa Area** and **Outer Ottawa**. The participants in the region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro Ottawa Limited
- Ottawa River Power Corporation

[4] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/burlingtontonanticoke/Documents/Needs%20Assessment_Burlington%20to%20Nanticoke_May15_2017.pdf

The RIP for this region was completed in December 2015 and was provided in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 3 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified the following three transmission infrastructure investments that were expected to be completed over the 2017 to 2019 period:

- **Circuit A4K Capacity:** Addition of 115kV tap *(Project D10 in EB-2016-0160);*
- **Lisgar TS:** Transformer Replacement *(Project D16 in EB-2016-0160)*; and
- **Overbrook TS:** Transformer (T1/T2) Replacement.

These investments are either complete or are continuing to be developed for in-service in 2019, with the exception of the Lisgar TS investment that has been deferred after further evaluation of the need. Load growth in the region will be monitored for further reassessment in the next regional planning cycle to determine the need for this project.

In response to the remaining RIP recommendations for this region, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Hawthorne TS:** Transformer (T7/T8) Replacement (Part of SR-05);
- **Hawthorne TS:** Autotransformer (T5/T6) Replacement (SS Other Projects);
- **King Edward TS:** Transformer Replacement (Part of SR-05); and
- **Supply for New Station in Southwest Area** (Project SS-11).

The second cycle NA report[5] for this region was published in June 2018. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

[5] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Greater%20Ottawa%20Needs%20Assessment%202018.pdf

- **Arnprior TS:** Transformer (T1/T2) Replacement (Part of SR-02);
- **Longueuil TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Slater TS:** Transformer (T1/T2/T3) Replacement (Part of SR-02); and
- **115kV S7M Transmission Line:** Refurbish line sections (SR Other Projects).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

GTA East

The GTA East Region is comprised of two sub-regions: **Pickering-Ajax-Whitby** and **Oshawa-Clarington**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation

The RIP for this region was completed in January 2017 and is provided in Attachment 4 to this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160) with no additional needs or investment plans identified.

As documented in Hydro One's previous rate application, there were two transmission infrastructure investments identified for the region, including:

- Connection of a new station "**Enfield TS**" *(Project D21 in EB-2016-0160)*; and
- Connection of a new station "**Seaton MTS**" *(Project D17 in EB-2016-0160)*.

These investments are continuing to be developed and are expected in-service in the 2019 to 2020 period.

At this time, no further regional planning transmission infrastructure investments are expected over the 2020 to 2024 planning period.

GTA North

The GTA North Region is comprised of two sub-regions: **York** and **Western**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Enersource Hydro Mississauga Inc., Hydro One Brampton Networks Inc. and PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited ("THESL")

The RIP for this region was completed in February 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 5 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified three transmission infrastructure investments over the 2017 to 2018 period. These investments have been completed and placed in-service, including the connection of a new load station "Vaughan #4 MTS"; the installation of breakers and switches at Holland TS; and the installation of two inline switches on the 230kV circuits V71P/V75P at Grainger Junction.

The second cycle NA report[6] for this region was completed in March 2018. The NA has identified the need for the following investments over the 2020 to 2024 period:

- Connection of a new load station "**Markham #5 MTS**" (SA Other Projects); and
- **Woodbridge TS:** Transformer (T5) Replacement (Part of SR-05).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

GTA West

The GTA West Region is comprised of two sub-regions: **Northwestern** and **Southern**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

[6] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

- Alectra Inc. (formerly Enersource Hydro Mississauga Inc. and Hydro One Brampton Networks Inc.)
- Burlington Hydro Electric Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The RIP for this region was completed in January 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 6 to this Exhibit.

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- Connection of a new load station "**Halton TS #2**" (Project SA-03);
- **Milton SS:** Station Expansion and Connect 230kV circuits (Project SS-07); and
- **Reconductor 230kV H29/H30 Transmission Line** (SA Other Projects).

Further details on this investment are provided in TSP Section 3.3.8 Investment Summary Documents.

Kitchener-Waterloo-Cambridge-Guelph ("KWCG")

The KWCG Region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and associated townships in the area. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Kitchener-Wilmot Hydro Inc.
- Milton Hydro Distribution Inc.
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

The RIP for this region was completed in December 2015 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is included in Attachment 7 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several transmission infrastructure investments to be completed over the 2016 to 2017 period. These investments have been completed and placed in-service, including the investment for the installation of in-line switches on circuits M20D/M21D at Galt Junction.

The second cycle NA report[7] for this region was published in December 2018. The NA has identified the need for the following system renewal investments over the 2020 to 2024 period:

- **Cedar TS:** Transformer (T7/T8) Replacement (Part of SR-05);
- **Detweiler TS:** Autotransformer (T2/T4) Replacement (Part of SR-03);
- **Hanlon TS:** Transformer (T1/T2) Replacement (Part of SR-05); and
- **Preston TS**: Transformer (T3/T4) Replacement (Part of SR-05).

[7] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/kitchenerwaterloocambridgeguelph/Documents/KWCG%20Needs%20Assessment%202018.pdf

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Metro Toronto

The Metro Toronto Region is comprised of two sub-regions: **Central Downtown** and **Northern**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Enersource Hydro Mississauga Inc. and PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- THESL
- Veridian Connections Inc.

The RIP for this region was completed in January 2016 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 8 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several near-term transmission infrastructure investments for the region, including:

- **Horner TS:** Addition of a second transformer station (Project SA-02);
- **Manby TS:** Autotransformer overload protection scheme;
- **Runnymede TS:** Expansion of transformer station and reconductor the 115kV circuits (*Project D19 in EB-2016-0160*); and
- **Southwest GTA Transmission Reinforcement** (Project SS-14).

The investments at Runnymede TS and Manby TS were completed and placed in-service in 2018. The other two investments, along with the connection for Copeland MTS Phase 2, are expected to be in-service over the 2020 to 2024 period.

The second cycle NA report[8] for this region was published in October 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- **Bermondsey TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Bridgman TS:** Transformer (T11-T13) Replacement (Part of SR-05);
- **Charles TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Duplex TS:** Transformer (T1/T2) Replacement (Part of SR-05);
- **Fairbank TS:** Transformer (T1-T4) Replacement (Part of SR-02);
- **Fairchild TS:** Transformer (T1/T2) Replacement (Part of SR-05);
- **John TS:** Station Reinvestment (Part of SR-08);
- **Leslie TS:** Transformer (T1) Replacement (Part of SR-05);
- **Main TS:** Transformer (T3/T4) Replacement (Part of SR-05);
- **Manby TS:** Transformer (T7/T9/T12/T13) and 230kV Component Replacement (Part of SR-03);
- **Runnymede TS:** Transformer (T3/T4) Replacement (Part of SR-02);
- **Sheppard TS:** Transformer (T3/T4) Replacement (Part of SR-02);
- **Strachan TS:** Transformer (T12) Replacement (Part of SR-05);
- **115kV C5E/C7E Underground Cables:** Refurbish cable sections from Esplanade TS to Terauley TS (Part of SR-27);
- **115kV H1L/H3L/H6LC/H8LC Transmission Lines**: Refurbish line sections from Leaside Junction to Bloor St. Junction (Part of SR-19); and

[8] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

- **115kV L9C/L12C Transmission Lines:** Refurbish line sections from Leaside TS to Balfour Junction (SR Other Projects).

The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Northwest Ontario

The Northwest Ontario Region is comprised of several sub-regions: **North of Dryden, Greenstone-Marathon, City of Thunder Bay,** and **West of Thunder Bay**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Hydro One Networks Inc. (Distribution)
- Kenora Hydro Electric Corporation Ltd.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.

The RIP for this region was completed in June 2017 and is presented in Attachment 9 to this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160).

In response to the RIP recommendations, this TSP contemplates the following investment over the 2020 to 2024 period:

- Connection to the new 230kV transmission line from Dryden/Ignace area to Pickle Lake (Project SS-02).

Further details on this investment are provided in TSP Section 3.3.8 Investment Summary Documents.

Windsor-Essex

The Windsor-Essex Region is in the southern-most part of Ontario, extending from Chatham southwest to Windsor. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in December 2015 and was presented in Hydro One's previous rate application (EB-2016-0160). For completeness, a copy is provided in Attachment 10 to this Exhibit.

As documented in Hydro One's previous rate application, the RIP identified several near-term transmission infrastructure investments for this region, including:

- **Keith TS:** Autotransformer Replacement (Part of SR-03);
- **Keith TS:** Reconfiguration due to the Gordie Howe International Bridge;

- **Kingsville TS:** Transformer Replacement (Part of SR-05); and
- **Supply to Essex County Transmission Reinforcement.**

These investments are either complete and/or continue to be developed for in-service in 2019; with the exception for the second Kingsville TS transformer and the Keith transformer replacements that are planned for in-service over the 2020 to 2024 period.

The second cycle NA report[9] for this region was completed in October 2017. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following investments over the 2020 to 2024 period:

- **Malden TS:** Additional feeder positions (SA Other Projects); and
- **Lauzon TS:** Transformer (T6/T8) and Component Replacement (Part of SR-05).

In addition to these investments, the need for transmission reinforcement in the Leamington Area has been highlighted in assessment work undertaken by the IESO in the development of their 2019 Windsor-Essex Integrated Regional Resource Plan. To ensure customer needs are addressed in a timely manner, this TSP contemplates the Leamington Area transmission reinforcement and the building of a second 230/27.6kV DESN (Project SS-13) to address the need.

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Regions in Group 2

There are five regions in Group 2 for which the first cycle of the regional planning process has been completed. Hydro One Transmission is the lead transmitter for all regions in this group with the exception of the East Lake Superior region.

[9] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment_Windsor-Essex_Final.pdf

London Area

The London Area Region is comprised of five sub-regions: **Greater London, Aylmer-Tillsonburg, Strathroy, Woodstock,** and **St. Thomas**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 11 of this Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160).

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Aylmer-Tillsonburg Area Transmission Reinforcement** (Project SS-12); and
- **Wonderland TS:** Station Refurbishment (Part of SR-02).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

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 in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Kingston Hydro
- Peterborough Distribution Inc.
- Veridian Connections Inc.

The RIP for this region was completed in July 2016 and is provided in Attachment 12 of this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans have been developed by Hydro One and the impacted LDCs in the area to balance the Gardiner TS load. In addition, the IESO will assess and develop a plan for contingencies associated with the 115kV circuit (Q6S) and 230kV circuit (P15C) as part of the IESO-led bulk system planning study. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

South Georgian Bay/Muskoka

The South Georgian Bay/Muskoka Region is comprised of two sub-regions: **Barrie/Innisfil** and **Parry Sound/Muskoka**. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Alectra Inc. (formerly PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Veridian Connections Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 13 of the Exhibit. This RIP advances the work from the IRRP documented in Hydro One's previous rate application (EB-2016-0160) and interim letter from the IESO to commence work to address equipment approaching end-of-life at Barrie TS.

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- **Barrie Area Transmission Upgrade** (Project SS-09);
- **Minden TS:** Transformer Replacement, LV Switchyard Rebuild (Part of SR-05);
- **Orangeville TS:** Transformer (T1/T2) Replacement (Part of SR-05); and
- **Parry Sound TS:** Transformer Replacement (Part of SR-05).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Sudbury/Algoma

The Sudbury/Algoma Region includes the Greater Sudbury Area, Manitoulin Island, and Townships of Verner, Warren, Elliot Lake, Blind River, and Walden. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Greater Sudbury Hydro

- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in June 2016 and is provided in Attachment 14 of this Exhibit. Local plans have been implemented by Hydro One to address the Manitoulin TS Low Voltage Regulation. Furthermore, the recommendation for a new 230/44kV Station at Hanmer TS identified in the RIP and documented in Hydro One's previous rate application for in-service in 2019 has been deferred after further evaluation of the need and customer consultation. Load growth in the region will be monitored for further reassessment in the next regional planning cycle to determine the need for this project.

At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

East Lake Superior

The East Lake Superior region spans the area from Wawa to north of Thessalon. Formerly, Great Lakes Power Transmission LP ("GLPT") was the lead transmitter for this region. GLPT conducted the regional process in late 2014 including representatives from the IESO, Hydro One Networks, Algoma Power Inc., PUC Distribution and Chapleau Public Utility Corporation. Through this process, it was determined that there were no electricity needs in the next ten years requiring regional coordination.

In October 2016, Hydro One Inc. acquired GLPT and is operating the transmission business through a separate subsidiary known as Hydro One Sault Saint Marie ("Hydro One SSM"). As such, the lead transmitter for this region is now Hydro One SSM. This TSP does not contemplate any regional planning transmission infrastructure investments in this region during the 2020 to 2024 planning period.

Regions in Group 3

There are seven regions in Group 3 for which the first cycle of the regional planning process has been completed. Hydro One Transmission is the lead transmitter for all regions in this group with the exception of the North of Moosonee region.

Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia Region includes the municipalities of Lambton Shores and Chatham-Kent, as well as associated townships in the area. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Bluewater Power Distribution Corporation
- Entegrus Powerlines Inc.
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in August 2017 and is provided in Attachment 15 of this Exhibit. The RIP identified that the needs for this region were strictly local in nature and no transmission infrastructure investment is required. Local plans have been implemented by Hydro One to address a capacity issue at Kent TS. In addition to the local needs, the RIP also identified several system renewal investments for the region. In response to the recommendations made in the RIP report, this TSP contemplates the following investments over the 2020 to 2024 period:

- **St. Andrews TS:** Transformer (T3/T4) Replacement and DESN Refurbishment (Part of SR-02); and
- **Sarnia Scott TS:** Transformer (T5) and component Replacement (Part of SR-03).

Further details on these investments are provided in TSP Section 3.3.8 Investment Summary Documents.

Greater Bruce / Huron

The Greater Bruce/Huron region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula, and South Bruce. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Festival Hydro Inc.
- Goderich Hydro - West Coast Huron Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Wellington North Power Inc.
- Westario Power Inc.

The RIP for this region was completed in August 2017 and is provided in Attachment 16 to this Exhibit. The RIP identified a local need to improve L7S customer delivery point performance. Further assessment work outside the regional planning process is in progress for this local need to identify alternatives and develop mitigation plans. At this time, no further regional planning transmission infrastructure investments are expected over the 2020 to 2024 planning period.

Niagara

The Niagara Region comprises twelve municipalities in the southern end of the Golden Horseshoe. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Alectra Inc. (formerly Horizon Utilities Corp.)
- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Niagara Peninsula Energy Inc.
- Niagara-on-the-Lake Hydro Inc.
- Welland Hydro Electric System Corp.

The RIP for this region was completed in March 2017 and is provided in Attachment 17 to this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans have been implemented by Hydro One to address thermal overloading of the 115kV circuit (Q4N) by upgrading the conductor on a section of Q4N from Beck 1 SS to Portal Junction. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

North/East of Sudbury

The North/East of Sudbury Region is the area roughly bordered by Moosonee to the North, Hearst to the North-West, Ferris to the South, and Kirkland Lake to the East. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hearst Power Ltd.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.

The RIP for this region was completed in April 2017 and is provided in Attachment 18 to this Exhibit. The RIP identified that the needs for this region were strictly local in nature. Local plans were developed by Hydro One and the impacted LDCs in the area to address Timmins TS/Kirkland Lake TS voltage regulation issues. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2020 to 2024 planning period.

Renfrew

The Renfrew Region includes all of Renfrew County. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Ottawa River Power Corporation
- Renfrew Hydro Inc.

The RIP for the region was completed in July 2016 and is provided in Attachment 19 to this Exhibit. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, this TSP does not contemplate any transmission infrastructure investments for this region over the 2020 to 2024 period resulting from the regional planning process.

St. Lawrence

The St. Lawrence Region covers the southeastern part of Ontario bordering the St. Lawrence River. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)

- IESO
- Hydro One Networks Inc. (Distribution)

The RIP for this region was completed in July 2016 and is provided in Attachment 20 to this Exhibit. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, this TSP does not contemplate any transmission infrastructure investment for this region over the 2020 to 2024 period resulting from the regional planning process.

North of Moosonee

Five Nations Energy Inc. ("FNEI") is the lead transmitter for this region and is therefore responsible for the RIP. This TSP does not contemplate any regional planning transmission infrastructure investments in this region.

1.2.4 (5.2.2 B / C) ATTACHMENTS: IESO REGIONAL PLANNING STATUS LETTER AND REGIONAL INFRASTRUCTURE PLAN REPORTS

Attachment 1 – IESO Regional Planning Progress Update Letter to Hydro One
Attachment 2 – RIP Report: Burlington to Nanticoke
Attachment 3 – RIP Report: Greater Ottawa
Attachment 4 – RIP Report: GTA East
Attachment 5 – RIP Report: GTA North
Attachment 6 – RIP Report: GTA West
Attachment 7 – RIP Report: KWCG
Attachment 8 – RIP Report: Metro Toronto
Attachment 9 – RIP Report: Northwest Ontario
Attachment 10 – RIP Report: Windsor-Essex
Attachment 11 – RIP Report: London Area
Attachment 12 – RIP Report: Peterborough to Kingston
Attachment 13 – RIP Report: South Georgian Bay / Muskoka
Attachment 14 – RIP Report: Sudbury / Algoma
Attachment 15 – RIP Report: Chatham / Lambton / Sarnia
Attachment 16 – RIP Report: Greater Bruce / Huron
Attachment 17 – RIP Report: Niagara
Attachment 18 – RIP Report: North/East of Sudbury
Attachment 19 – RIP Report: Renfrew
Attachment 20 – RIP Report: St. Lawrence

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February 4, 2019

VIA EMAIL

Mr. Ajay Garg
Manager, Regional Transmission Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Mr. Garg:

Re: Independent Electricity System Operator
Regional Planning Progress Update

The Independent Electricity System Operator ("IESO") has been notified by Hydro One Networks Inc. ("Hydro One") of its upcoming 2020-2022 rate application to the Ontario Energy Board ("OEB") and has been requested to provide Hydro One with a regional planning status update for the planning regions in the province. This request includes regional planning areas undergoing either a Needs Assessment ("NA"), Scoping Assessment ("SA") or an Integrated Regional Resource Planning ("IRRP").

Hydro One's request is based on the requirement of section 2.4.2 of the OEB's Chapter 2 Filing Requirements for Electricity Transmission Applications which states:

> *Where regional planning is underway, but a Regional Infrastructure Plan has not yet been completed for the applicable region, the applicant shall submit a letter from the Independent Electricity System Operator ("IESO"), identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.*

Pursuant to the above referenced filing requirements, the IESO hereby provides the status of regional planning as follows.

The first cycle of regional planning for all 21 regions was completed in Q3, 2017 and the second cycle has started for some of the regions in Group 1. The table below provides the status of the regional plans that are presently underway; regional planning for regions that are not listed in this table have not yet started.

Table 1: Active regions in second round of Regional Planning

Group 1 Regions	Sub-Regions	Status	Expected Completion Date of the Stage that is in Progress
Burlington to Nanticoke	Brant	NA/SA completed. IRRP in progress for the Greater Hamilton sub-region.	Q1 2019
	Bronte		
	Greater Hamilton		
	Caledonia-Norfolk		
Greater Ottawa	Ottawa	NA/SA completed. IRRP in progress for the Outer Ottawa sub-region.	Q3/Q4 2019
	Outer Ottawa		
GTA North	York	NA/SA completed. IRRP in progress for the York sub-region.	Q4 2019
	Western		
GTA West	Northwestern	NA underway.	Q1 2019
	Southern		
KWCG	No sub-regions	NA completed. SA in progress.	Q1 2019
Toronto	No sub-regions	NA/SA completed. IRRP in progress.	Q4 2019
Northwest Ontario	North of Dryden	NA in progress.	Q1 2019
	Greenstone-Marathon		
	Thunder Bay		
	West of Thunder Bay		
Windsor-Essex	No sub-regions	NA/SA completed. IRRP in progress.	Q3 2019

During the second cycle of regional planning, the Regional Planning Study Team is giving greater consideration to assets reaching end of life. More specifically, they are considering opportunities to "right size" equipment, the potential reliability impact of the longer-term outages required to carry out significant replacement projects, and the potential to optimize the system design as part of the scope of the asset replacement. Therefore, while investments would most likely be necessary to address assets reaching end of life, in some cases the specific investment required may depend on the outcome of the regional planning processes that are presently underway.

If you have any questions about the IESO's comments please contact me directly at 905-855-6340 or Devon.Huber@ieso.ca.

Yours truly,

Devon Huber
Senior Manager, Regulatory Affairs

cc: Bob Chow, Director, Transmission Planning, IESO
Ahmed Maria, Director, Transmission Planning, IESO

Burlington to Nanticoke

REGIONAL INFRASTRUCTURE PLAN

February 7, 2017

hydro one

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Prepared and supported by:

Company
Brantford Power Inc.
Burlington Hydro Inc.
Energy + Inc.
Alectra Utilities Corporation (former Horizon Utilities Inc.)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Oakville Hydro
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2015-2025) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

Working Group 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 WITH PARTICIPATION AND INPUT FROM THE RIP WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE BURLINGTON TO NANTICOKE REGION.

The participants of the RIP Working Group included members from the following organizations:

- Brantford Power Inc.
- Burlington Hydro Inc.
- Energy + Inc.
- Alectra Utilities Corporation (former Horizon Utilities Inc.)
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (IESO)
- Oakville Hydro
- Hydro One Networks Inc. (Lead Transmitter)

In general, the RIP is the final phase of the regional planning process and, in this case, it follows the completion of the Integrated Regional Resource Plans ("IRRP") for Brant Sub-Region and Bronte Sub-Region in March 2015 and June 2016, respectively, and the Burlington to Nanticoke Region's Needs Assessment ("NA") in May 2014. This RIP provides a consolidated summary of the needs and recommended plans for the Burlington to Nanticoke Region for the near-term (up to 5 years) and the mid-term (5 to 10 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known to the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later also reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan.

The needs and/or plans in the near-term (2016-2020) and the mid- to long-term (beyond 2020) are provided below in Table 1 and Table 2, respectively, along with their planned in-service date and estimated cost, where applicable. Table 1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from. The table also indicates the needs identified after the completion of the NA and SA (Scoping Assessment) processes.

Table 1: Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS #2	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (2)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (2)	Replace Beach TS T3/T4 Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct.(2)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct.(2)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (2)	Replace EOL transformers & refurbish switchgears	Committed	2018	37
12	Bronte TS – EOL T5/T6 DESN (2)	Replace EOL transformers & refurbish switchgear	Committed	2019	34

No.	Needs	Plans	Status	I/S Date	Cost ($M)
13	Elgin TS – EOL transformers & switchgears	Replace transformers and switchgears and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) To Be Decided
(2) New needs identified by HONI

Table 2: Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment (1)	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD (2)	TBD (2)

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

Further details of needs, alternatives, and recommended plans for the above needs are provided in Section 7. The preliminary plans and needs identified in Table 2 will be further assessed in the next planning cycle. A summary of the current recommendations for these mid- and long-term needs is provided in Section 8.

The RIP Working Group recommends the following outcomes and next steps:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and

b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE BURLINGTON TO NANTICOKE REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the needs, assessments and recommended plan. The members of the RIP WG included representative from Brantford Power Inc. (“Brantford Power”), Burlington Hydro Inc. (“Burlington Hydro”), Energy + Inc. (“Energy +”), Alectra Utilities Corporation (former Horizon Utilities Inc. “Alectra Utilities”), Hydro One Distribution, the Independent Electricity System Operator (“IESO”) and Oakville Hydro Electricity Distribution Inc. (“Oakville Hydro”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Burlington to Nanticoke region covers the City of Brantford, municipality of Hamilton, counties of Brant, Haldimand and Norfolk. The portions of Cities of Burlington and Oakville south of Dundas Street are included in the Burlington to Nanticoke region up to Third Line road in the east. Electrical supply to the Region is provided from thirty-one 230 kV and 115 kV step-down transformer stations. The summer 2015 load of the Region was about 1831 MW. The boundaries of the Region are shown in Figure 1-1 below.

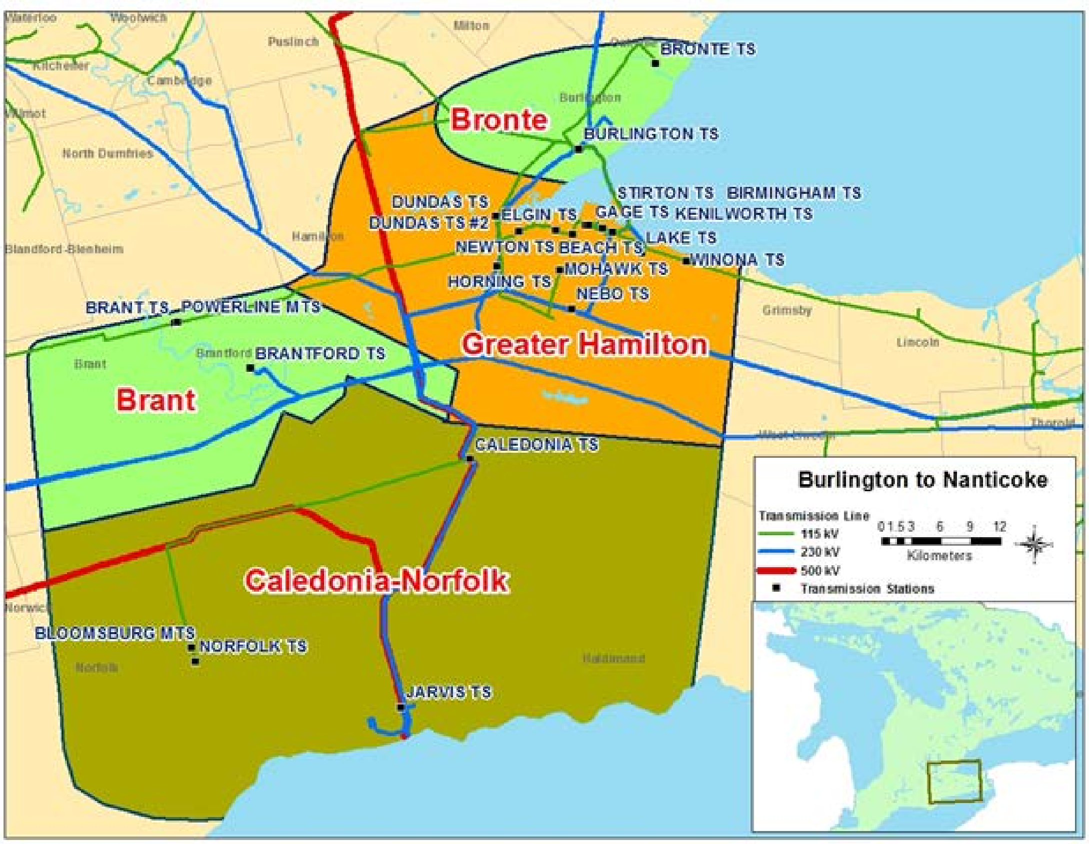

Figure 1-1 Burlington to Nanticoke Region

1.1 Objective and Scope

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

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

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

The scope of this RIP is as follows:

- A consolidated summary of the wires plan developed during LP (Local Planning), SA (Scoping Assessment), and/or as identified in IRRP.
- Discussion of any other major transmission infrastructure investment plans over the near and mid-term (0-10 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. The Brant Sub-Region IESO led IRRP was initiated prior to the new regional planning process and was completed in March 2015. The need for Bronte Sub-Region IRRP was identified during the Need Assessment for Burlington to Nanticoke region and was completed in June 2016.

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

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

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

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

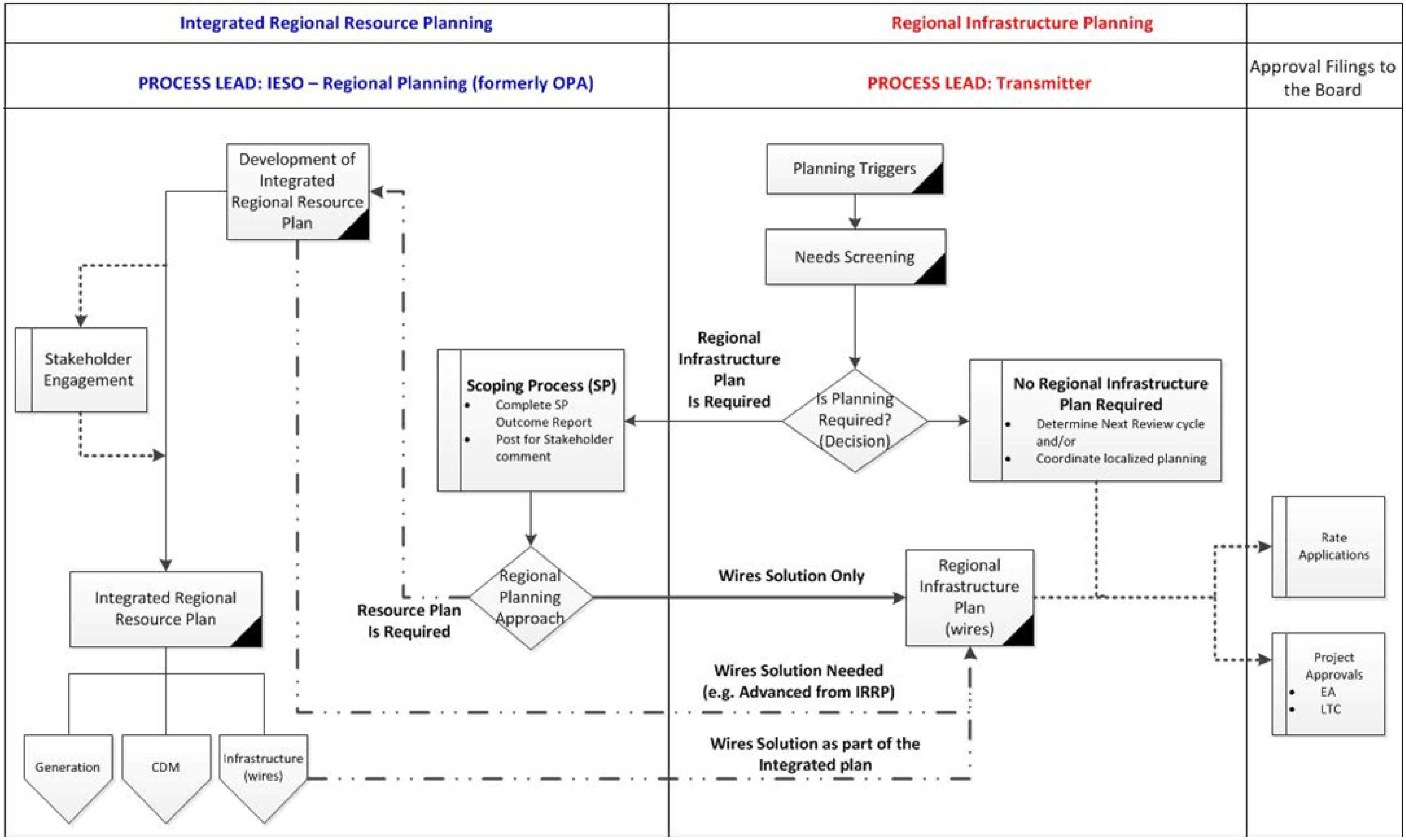

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

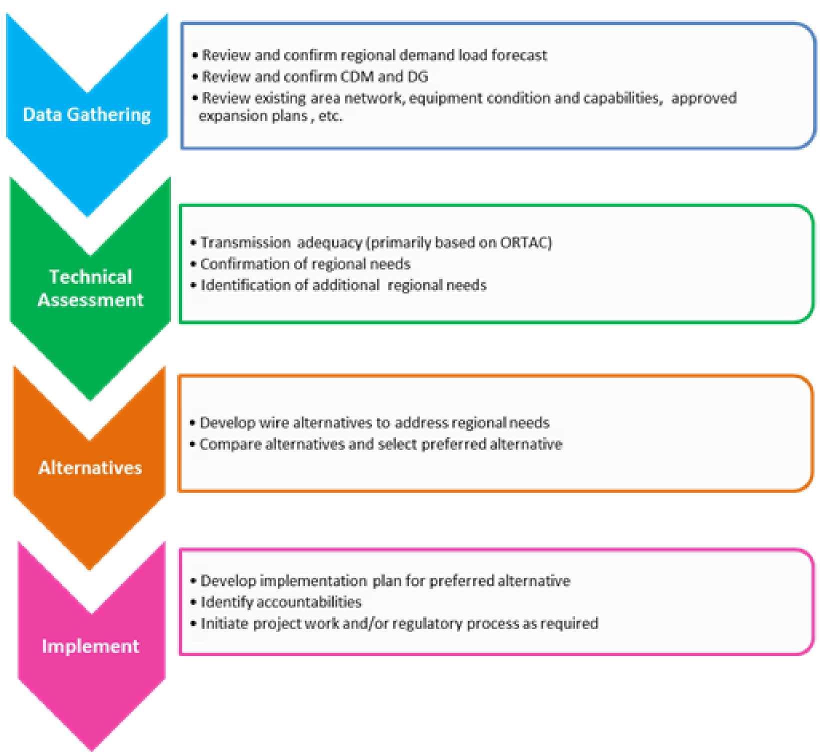

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE BURLINGTON TO NANTICOKE REGION COVERS THE CITY OF BRANTFORD, MUNICIPALITY OF HAMILTON, COUNTIES OF BRANT, HALDIMAND AND NORFOLK. SOME OF THE ELECTRICAL INFRASTRUCTURE IN THE REGION IS ONE OF THE OLDEST INSTALLATIONS IN THE PROVINCE. THE PORTIONS OF CITIES OF BURLINGTON AND OAKVILLE SOUTH OF DUNDAS STREET ARE INCLUDED IN THE BURLINGTON TO NANTICOKE REGION UP TO THIRD LINE ROAD IN THE EAST.

Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV Nanticoke TS and Middleport TS and 230 kV circuits from Middleport TS, Nanticoke TS and Beck TS. The 115 kV network is supplied by 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS. The area loads are supplied by a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into four sub-regions as shown in Figure 1-1 and described below:

- The Brant Sub-Region encompasses the County of Brant, City of Brantford and surrounding areas. Electricity supply to the sub-region is provided by:
  - Brant TS and Powerline MTS supplied by 115 kV double circuit line B12/B13.
  - Brantford TS supplied by the 230 kV double circuit transmission line M32W/M33W.

  The Brant Sub-Region transmission facilities are shown in Figure 3-1.

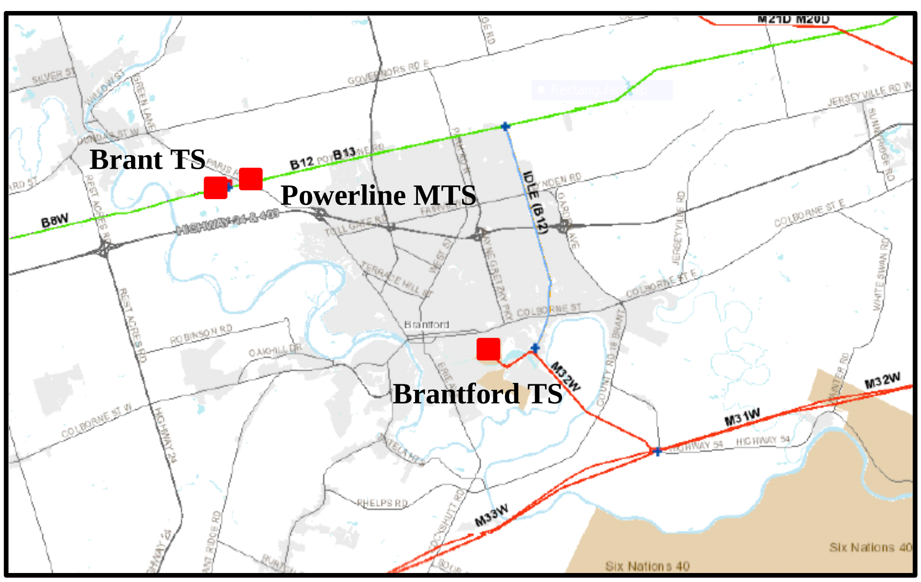

Figure 3-1 Brant Sub-Region

The total peak demand of the three stations was about 263 MW in 2015. Energy + Inc. and Brantford Power Inc. are the main LDCs that serve the electricity demand for the City of Brantford. Hydro One Distribution supplies load in the outlying areas of the sub-region. The electricity demand is comprised of residential, commercial and industrial customers.

- The Bronte Sub-Region covers the City of Burlington and the western part of the City of Oakville up to Third Line. Electricity supply to the sub-region is provided by:

  - Bronte TS supplied by 115 kV double circuit line B7/B8.
  - Burlington TS supplied by 230 kV double circuit line Q23BM/ Q25BM.
  - Cumberland TS supplied from 230 kV double circuit transmission line B40C/B41C.

  The Bronte Sub-Region transmission facilities are shown in Figure 3-2.

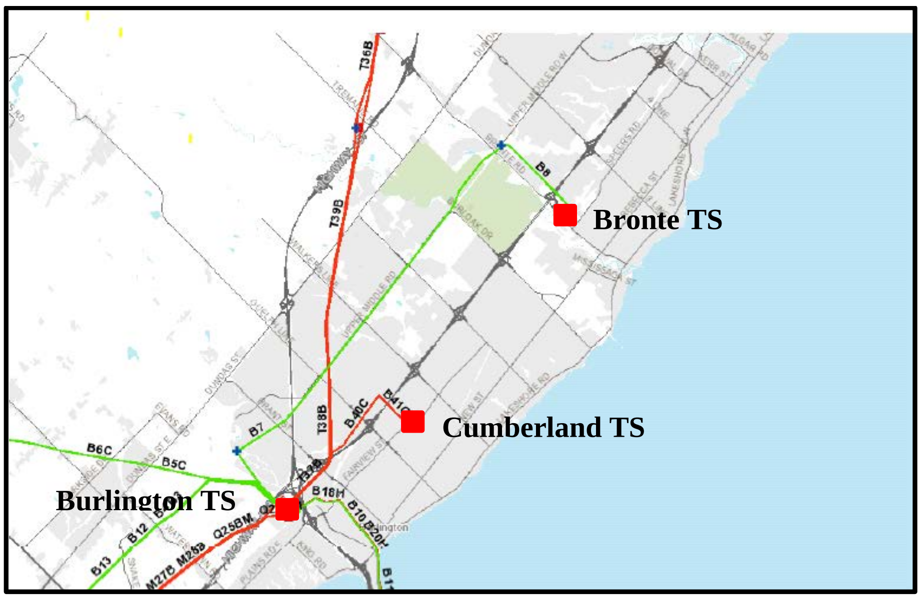

Figure 3-2 Bronte Sub-Region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial and industrial customers. The total peak station demand of the three stations was about 402 MW in 2015.

- The Greater Hamilton Sub-Region encompasses the City of Hamilton that includes Townships of Flamborough and Glanbrook and towns of Dundas and Stoney Creek. Some of the electrical infrastructure in the sub-region was built over 50 years ago and is one of the oldest installations in the province. Electricity supply to the sub-region is grouped as follows:

  - Beach TS 115 kV area which includes five 115 kV step down stations Beach TS T3/T4 DESN, Birmingham TS, Kenilworth TS, Stirton TS, Winona TS and a CTS supplied from the 230/115 kV autotransformers at Beach TS.

- Burlington TS 115 kV area which includes Dundas TS, Dundas #2, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned CTS supplied from the 230/115 kV autotransformers at Burlington TS.

- 230 kV area which includes Beach TS T5/T6 DESN, Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230 kV circuits connecting into Beach TS and Burlington TS.

The Greater Hamilton Sub-Region transmission facilities are shown in Figure 3-3.

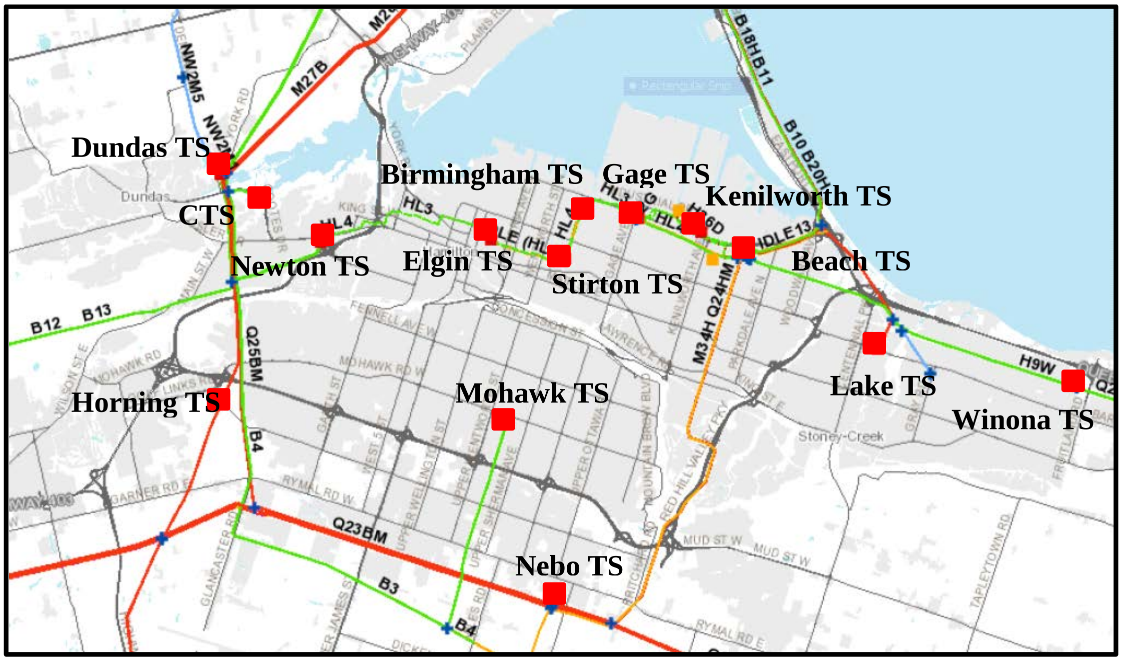

Figure 3-3 Greater Hamilton Sub-Region

The total peak station demand of the Greater Hamilton Sub-Region was about 1394 MW in 2015. The area is served by Alectra Utilities, Hydro One Distribution and CTSs comprises a significant number of large industrial customers along with commercial and residential customers.

- The Caledonia Norfolk Sub-Region covers the eastern part of Norfolk County and the western part of Haldimand County. Electricity supply to the Sub-region is provided by:

  - Caledonia TS supplied by 230 kV double circuit line N5M/S39M.
  - Jarvis TS supplied from the 230 kV double circuit line N21J/N22J.
  - Bloomsburg DS and Norfolk TS supplied from 115 kV double circuit transmission line C9/C12.

The Caledonia Norfolk Sub-Region transmission facilities are shown in Figure 3-4.

The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial and industrial uses. The peak demand of the stations in the Sub-Region was approximately 334 MW in 2015.

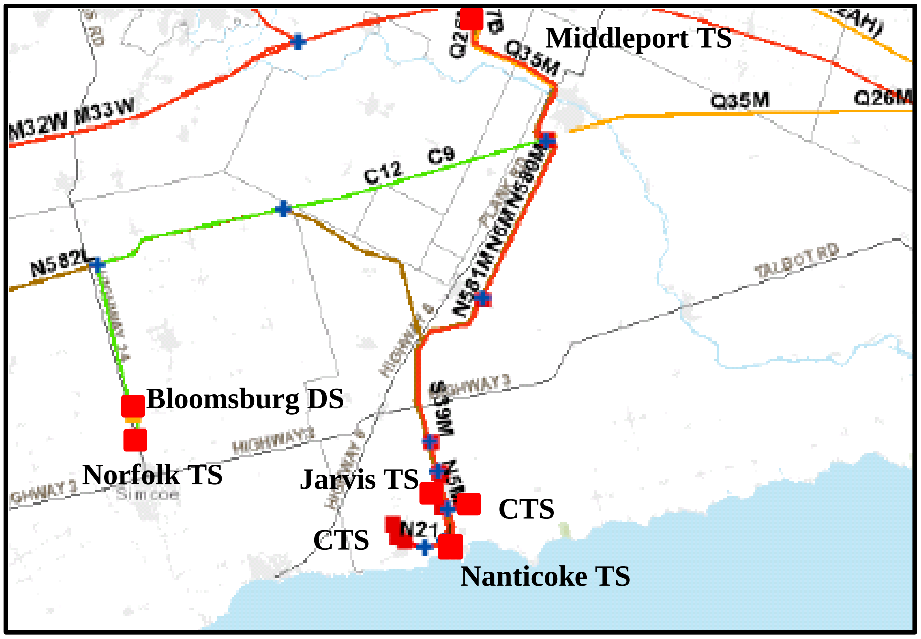

Figure 3-4 Caledonia Norfolk Sub-Region

Electrical single line diagrams for the Burlington to Nanticoke Region 500 kV/ 220 kV facilities and 115 kV facilities are shown below in Figure 3-5 and Figure 3-6.

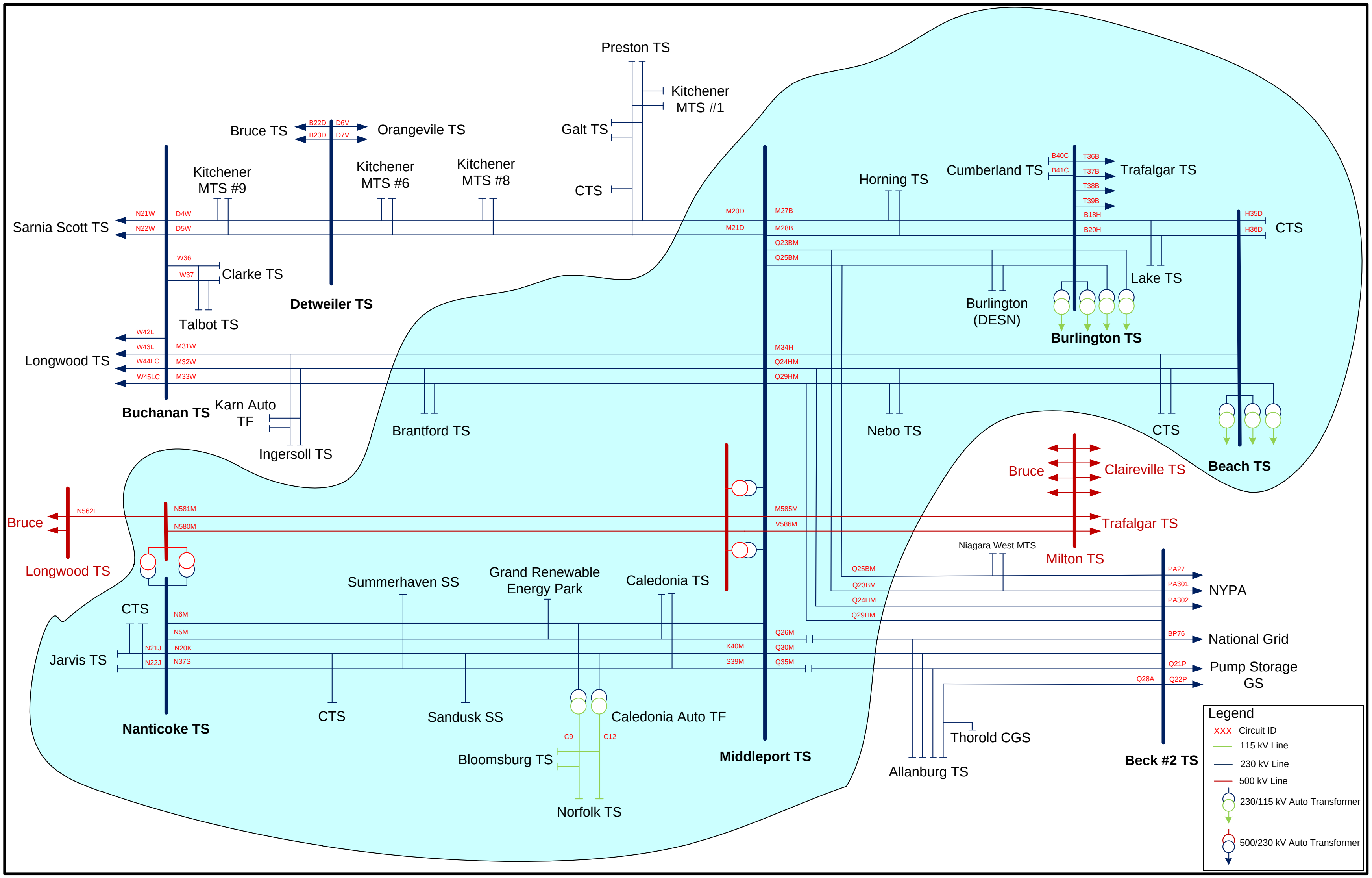

Figure 3-5 Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

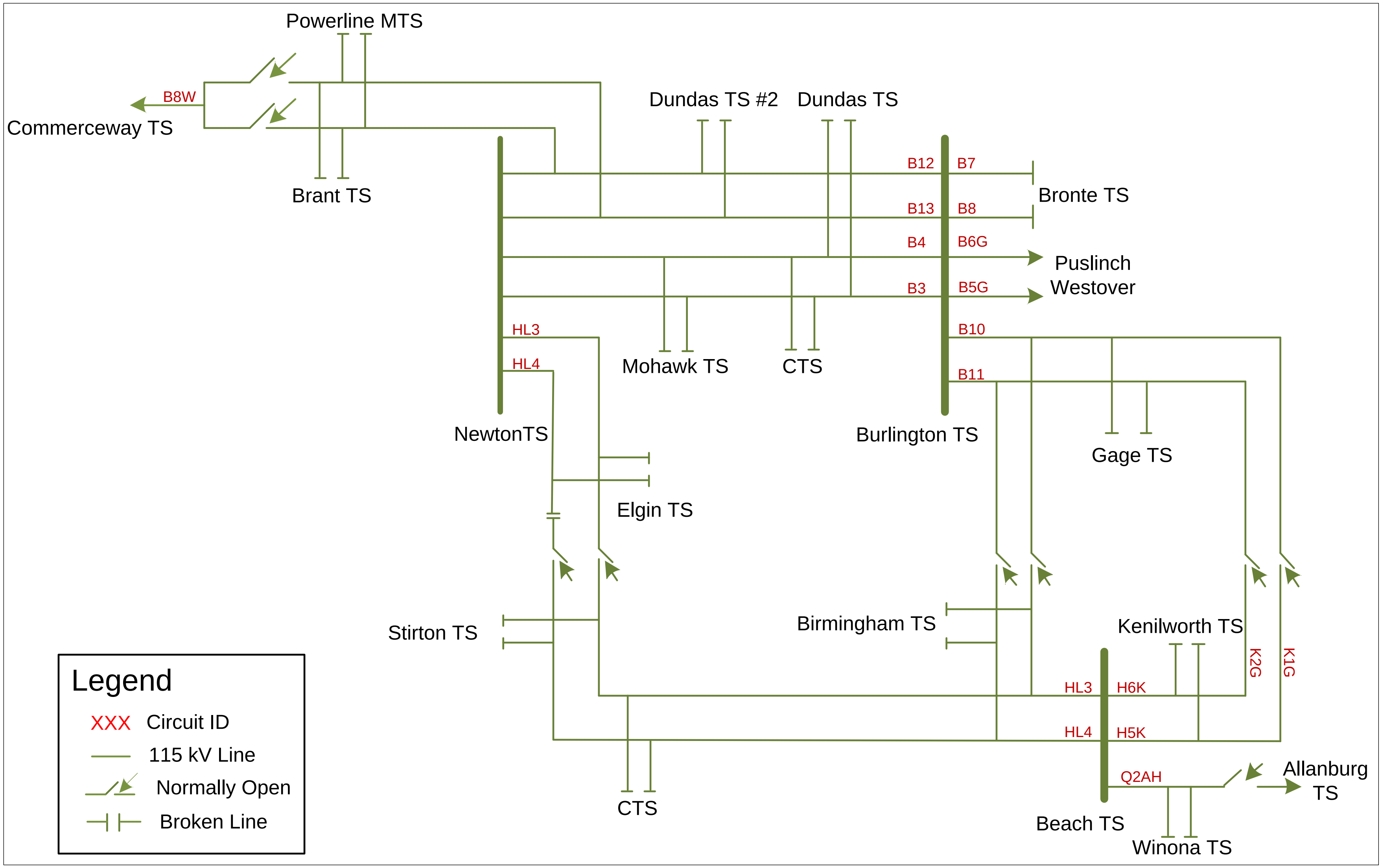

Figure 3-6 115 kV Network Supplied by Burlington TS and Beach TS

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE BURLINGTON TO NANTICOKE REGION.

A brief listing of some of the major projects completed over the last ten years are as follows:

- Bronte TS (2008) - added a new low voltage breaker between T5/T6 DESN and T2 DESN units at Bronte TS.
- Burlington TS (2009) - replaced 230 kV/115 kV autotransformer T6 following failure.
- 2nd 115 kV Supply to Norfolk TS and Bloomsburg DS (2009) – Built 12 km of new 115 kV circuit to provide 2nd supply to Norfolk TS and Bloomsburg DS.
- Jarvis TS (2011) and Caledonia TS (2012) – installed LV reactors to reduce short circuit levels below the TSC limits and to allow increased generation connection capability at these stations.
- Nebo TS (2013) – replaced T1/T2 230 kV/ 27.6 kV transformers with larger size standard units and added six new breaker positions to meet customer needs.
- Burlington TS (2016) – installed an additional 230 kV circuit breaker to reduce probability of the simultaneous loss of two autotransformers at this station improving supply reliability to the stations supplied from 115 kV Burlington TS bus.
- Transformer replacement at stations: Bronte TS (2006), Norfolk TS (2009), Birmingham TS (2010), Cumberland TS (2012), Brantford TS (2013), Kenilworth TS (2014), Dundas TS (2015) and Brant TS (2016).
- Feeder Positions – added four new breaker positions at Horning TS (2006) and two new feeder breaker positions at Bronte TS (2008) to meet the customer needs.

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5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Burlington to Nanticoke Region is growing at a slow rate with a decline of industrial loads in the region. Currently, load is forecast to increase at an average annual rate of approximately 0.24% up to 2035. The growth rate varies across the Region – with the highest growth rate of 1.37% in the Brant Sub Region.

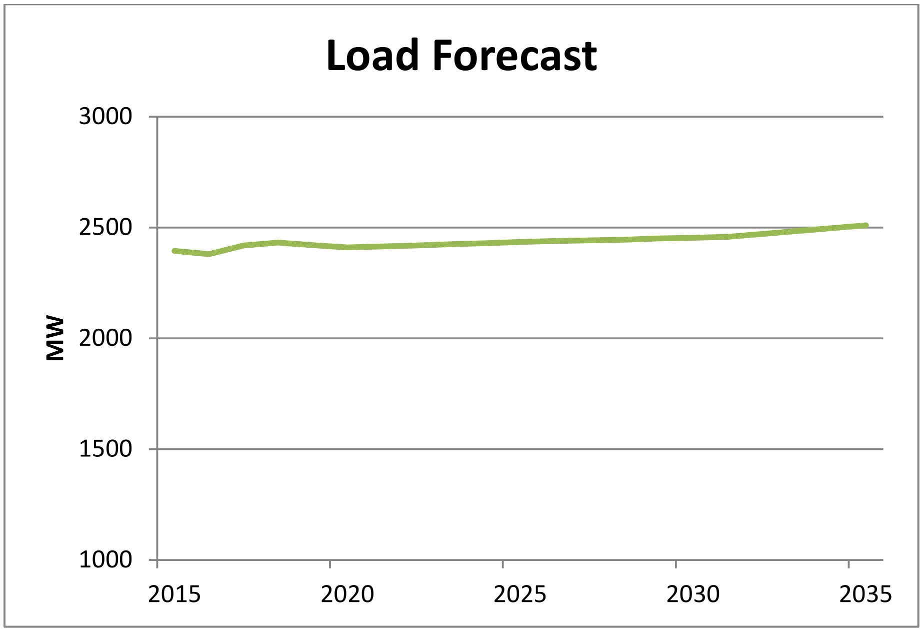

Figure 5-1 Burlington to Nanticoke Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Burlington to Nanticoke Region peak summer non-coincident load forecast. This forecast is based on the 2015 extreme weather corrected loads. The non-coincident forecast represents the sum of the individual station's peak load and is used to determine the need for stations and line capacity. Regional non-coincident load forecast for the individual stations in the Burlington to Nanticoke Region is given in Appendix D.

The RIP load forecast was developed as follows:

- Load forecast for stations in the Bronte Sub region was taken from the IESO Bronte Sub- Region IRRP completed on June 30, 2016.
- Load forecast for Brant TS and Powerline MTS in the Brant Sub-Region was prepared by input and discussions with the LDCs recently (2016) as part of detailed planning for Brant switching station.
- Load forecast for the remaining stations was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The net station loads account for CDM measures and connected DG in the region.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2025.
- All planned facilities listed in Section 4 are assumed to be in-service.
- Where applicable, future industrial loads have been reduced based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE BURLINGTON TO NANTICOKE REGION OVER THE 2015-2025 PERIOD.

Within the current regional planning cycle three regional assessments have been conducted for the Burlington to Nanticoke Region. These studies are:

1) NA Report - Burlington to Nanticoke Region, May 23 , 2014
2) IRRP Report - Brant Sub-Region, April 28, 2015
3) Local Planning (“LP”) Report – Burlington to Nanticoke Region, October 28, 2015
4) IRRP Report - Bronte Sub-Region, June 30, 2016

The NA and IRRP reports identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the Burlington to Nanticoke Region was also carried out as part of the RIP report using the latest regional forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

6.1 500 and 230 kV Transmission Facilities

The 500 kV and most of the 230 kV transmission circuits in the Burlington to Nanticoke Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. In addition there are three 230 kV double circuit lines H35D/ H36D, B40C/ B41C and N21J/ N22J that supply only local loads. The circuits supplying local loads in the region are as follows (refer to Figure 3-5):

1. Middleport TS to Burlington TS 230 kV transmission circuits M27B/ M28B - supply Horning TS.
2. Middleport TS to Beck #2 TS to Burlington TS 230 kV transmission circuits Q23BM/ Q25BM /Q24HM/ Q29HM - supply Burlington (DESN) TS, Nebo TS and one customer owned CTS.
3. Middleport TS to Buchanan TS 230 kV transmission circuits M32W/ M33W - supply Brantford TS.
4. Middleport TS to Nanticoke TS 230 kV transmission circuits N5M/ S39M / N20K - supply Caledonia TS and one customer owned CTS.
5. Burlington TS to Beach TS 230 kV transmission circuits B18H/ B20H - supply Lake TS.
6. Nanticoke TS to Jarvis TS 230 kV transmission circuits N21J/ N22J - supply Jarvis TS and one customer owned CTS.
7. Beach TS to one customer owned CTS 230 kV transmission circuits H35D/ H36D.
8. Burlington TS to Cumberland TS 230 kV transmission circuits B40C/ B41C - supply Cumberland TS.

Bulk system planning is conducted by the IESO and is informed by government policy, including policy outlined in the long term energy plan ("LTEP"). Government engagement on the next LTEP is currently underway, with a new LTEP expected to be issued in Q2/Q3 2017. Bulk system needs, options and recommendations for Power System facilities serving this region will be determined by the IESO as part of the implementation plan for the 2017 LTEP.

6.2 230/115 kV Transformation Facilities

Almost half of the Region's load is supplied from the 115 kV transmission systems. The primary source of 115 kV supply is from three 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS.

Table 6-1 summarizes the loading levels for all three 230 /115 kV auto transformers in the Burlington to Nanticoke region.

Table 6-1 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	MVA Load Meeting Capability	2015 MVA Loading	Need Date
Burlington TS 230/115 kV autotransformers	912	745	-[1]
Beach TS 230/115 kV autotransformers	582	348	-[1]
Caledonia TS 230/115 kV autotransformer	187	88	-[1]

[1] Adequate over the study period (2015- 2025)

The autotransformers in the Burlington to Nanticoke region are of adequate capacity over the study period (2015-2025). The Needs Assessment identified a stuck breaker scenario at Burlington TS that could result in simultaneous loss of two of the four autotransformers at Burlington TS. This is a low probability scenario under which the loading on the remaining two autotransformers could exceed their short time emergency rating.

However, recently an additional 230 kV breaker has been added to the scheme reducing the possibility of simultaneous loss of two autotransformers at Burlington TS under a single contingency scenario. In addition, installation of the new 230/115 kV autotransformers at Cedar TS and 115 kV switching at Brant TS, to be in-service by 2019, will further reduce loading on the Burlington TS autotransformers.

The loading on the Burlington TS 230/115 kV autotransformers, for the simultaneous loss of two autotransformers, is therefore expected to remain within the short term rating of the two remaining in-service autotransformers at Burlington TS. No further action is required.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities can be divided in three main sections: Please see Figure 3-5 and 3-6 for the single line diagrams.

1. Burlington 115 kV – has twelve 115 kV circuits B3/B4, B5/B6, B7/B8, B10/B11, B12/B13 and HL3/ HL4. All circuits are adequate over the study period except for sections of the B7/B8 and B12/B13 circuits as given below in Table 6-2. These needs have been identified in the earlier phases of the regional planning process and are being addressed by Hydro One as per the recommendations in respective IRRPs and further discussed in this RIP (Section 7).

   The loading on the limiting sections of 115 kV circuits is summarized below in Table 6-2.

Table 6-2 Limiting Sections of 115 kV Circuits

Line Section	Overloaded Circuit	Reference Section	Capacity (MW)	Contingency	2015 Loading (MW)	Need Date
Palermo Jct. to Bronte TS	B7/ B8	Section 7.1	135	B7	129	2018
Horning Mountain Jct. to Brant TS	B12/B13	Section 7.5	125	B12/B13	119	2019

   The HL3/ HL4 115 kV double circuit cable consist of two sections:
   i. HL3/ HL4 Newton TS to Elgin TS
   ii. HL3/ HL4 Elgin TS to Stirton TS (HL4 is idle)

   These cables provide normal and backup supply to Elgin TS. The supply capacity of 115 kV HL3/ HL4 cables is adequate over the study period (2015-2025).

2. Beach 115 kV– has five 115 kV circuits H5K/ H6K, HL3/ HL4 and Q2AH expected to be adequate over the study period. There are two associated 115 kV double circuit cable sections:
   i. K1G/ K2G Kenilworth TS to Gage TS
   ii. H5K/ H6K Kenilworth TS to Beach TS

   These cables provide normal and backup supply to Kenilworth TS. The supply capacity of Beach 115 kV cables and lines is adequate over the study period (2015-2025).

3. Norfolk Caledonia – has two 115 kV circuits C9 and C12 supplying Norfolk TS and Bloomsburg DS. The need of additional supply capacity for C9/C12 double circuit line was identified during the earlier phases of the regional planning cycle.

   The updated load forecast and further assessment as part of this RIP shows that the combined load of Norfolk TS and Bloomsburg DS will remain below the supply capacity of 87 MW of C9/ C12 line during the study period and no further action is required.

The list of all the 230 kV and 115 kV circuits is given in Appendix A.

6.4 Step-Down Transformation Facilities

There are a total of 31 step-down transmission connected transformer stations in the Burlington to Nanticoke Region. The stations have been grouped based on the geographical area and supply configuration. The station loading in each area and the associated station capacity is provided in Table 6-3 below. The complete list of all the stations in the Burlington to Nanticoke region and their supply circuits is given in Appendix B.

Table 6-3 Adequacy of Step-Down Transformer Stations

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Brant Sub-Region	403	263	-[2]
Bronte Sub-Region	530	402	-[2]
Greater Hamilton Sub-Region [1]	1919	1108	-[2]
Caledonia Norfolk Sub-Region [1]	351	211	-[2]

(1) Excludes Customer Transformer Stations (CTS)
(2) Adequate over the study period (2015-2025)

Dundas TS has two DESN units T1/T2 and T5/T6. During the earlier phases of the Regional Planning cycle T1/T2 DESN at Dundas TS was found to be loaded over its supply capacity due to unbalanced loading between the two Dundas TS DESNs. The current loading at both DESNs at Dundas TS is within each DESN's supply capacity. Further assessment as part of this RIP based on current forecast confirms that the loads on each of the Dundas TS DESNs will remain within its supply capacity during the study period. No further action is required.

Nebo TS 13.8 kV T3/T4 DESN was also identified as marginally over loaded during an earlier phase of the regional planning cycle. Further assessment as part of this RIP based on updated forecast confirms that the loads on the Nebo TS T3/T4 DESN will remain within its supply capacity during the study period. No further action is required.

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.

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

It is expected that all loads can be restored within 8 hours in the Burlington to Nanticoke Region over the study period. None of the transmission circuits in the Burlington to Nanticoke region will be supplying total loads in excess of 250 MW. The following double circuit lines in the Burlington to Nanticoke Region are expected to supply the loads in excess of 150 MW at peak times:

- B12/ B13
- B3/ B4
- H35D/ H36D
- HL3/ HL4
- M32W/ M33W
- Q23BM/ Q25BM
- Q24HM/ Q29HM

Based on the historical performance and reliability data for these circuits in the region, the Working Group recommended that no action is required at this time.

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7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS FOR THE BURLINGTON TO NANTICOKE REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THESE NEEDS. THESE NEEDS INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NEEDS ASSESSMENT, SCOPING ASSESSMENT, IRRPS FOR THE BRANT, AND BRONTE SUB-REGIONS, ASSESSMENTS CARRIED OUT IN SECTION 6 AS WELL AS EMERGING NEEDS DUE TO AGING INFRASTRUCTURE AND END OF LIFE ISSUES.

This section outlines and discusses infrastructure needs and plans identified for the Burlington to Nanticoke Region and recommended plans and/or next steps for the near-term (up to 5 years) and the mid-to long-term (beyond 5 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known by the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is already or nearly underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan. These needs will be assessed in the next planning cycle. A summary of all of these needs in the near-term (2016-2020) and mid to long-term (beyond 2020) are listed in Table 7-1 and Table 7-2, respectively, along with their in-service date, where applicable. Table 7-1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from and provide reference to sub-sections with further details for each of the need. The table also indicates the needs identified after the completion of the NA and SA processes.

Table 7-1 Identified Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
Projects Developed in Local Planning or an IRRP			
1	115 kV B7/B8 Transmission Line Capacity	7.1	2018
2	115 kV B12/B13 Transmission Line Capacity	7.2	2019
3	Two New Feeders at Dundas TS	7.3	2019
4	Cumberland TS – Power Factor Correction	7.4	TBD
5	Kenilworth TS – Power Factor Correction	7.5	TBD
Projects Developed by HONI & the LDC(s), Reviewed by IESO			
6	Kenilworth TS – EOL transformers & switchgear (1)	7.6	2018
7	Beach TS – EOL T3/T4 DESN Transformers (1)	7.7	2019
8	Gage TS – EOL transformers & switchgear	7.8	2019
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	7.9	2020
Projects Developed by HONI & the LDC(s)			
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	7.10	2018
11	Horning TS – EOL transformers & switchgears (1)	7.11	2018
12	Bronte TS – EOL T5/T6 DESN (1)	7.12	2019
13	Elgin TS – EOL transformers & switchgears	7.13	2019
14	Mohawk TS (T1/T2) – Station Capacity & EOL T1/T2 Transformers	7.14	2019

(1) New needs identified by HONI

The mid- and long-term (2021-2025) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-2. Where available, a preliminary plan to address that need is provided in the corresponding sub-section.

Table 7-2 Identified Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Birmingham TS EOL Metalclad Switchgears	7.15	2021
2	Dundas TS EOL T1/T2 Switchgear	7.16	2021
3	Newton TS EOL Transformers, Switchgears, Breakers	7.17	2021
4	Brantford TS EOL Switchgear	7.18	2022
5	Lake TS EOL Switchgear	7.18	2022

No.	Needs	Section	Timing
6	Stirton TS EOL Switchgear	7.18	2022
7	Beach TS EOL T7/T8 Auto-transformers and T5/T6 Switchgear	7.19	2025
8	EOL Cables in Hamilton area: H5K/H6K, K1G/K2G, HL3/HL4	7.20	TBD

The needs identified in the Burlington to Nanticoke Region in the above Tables 7-1 and Table 7-2 are further discussed below.

7.1 115 kV Circuit B7/B8 Transmission Line Capacity (Burlington TS to Bronte TS)

7.1.1 Description

Bronte TS is radially supplied by the 115 kV double circuit B7/ B8 line from Burlington TS. The supply capacity of Bronte area is limited to 135 MW due to loading on B7/B8 exceeding its thermal capacity following a loss of either of the circuits starting in 2018. In 2021, the post contingency voltage drop for the loss of either circuit will also exceed the ORTAC limit of 10% at Bronte TS. The load in Bronte area is forecasted to exceed the 135 MW supply limit and reach about 150 MW during the study period.

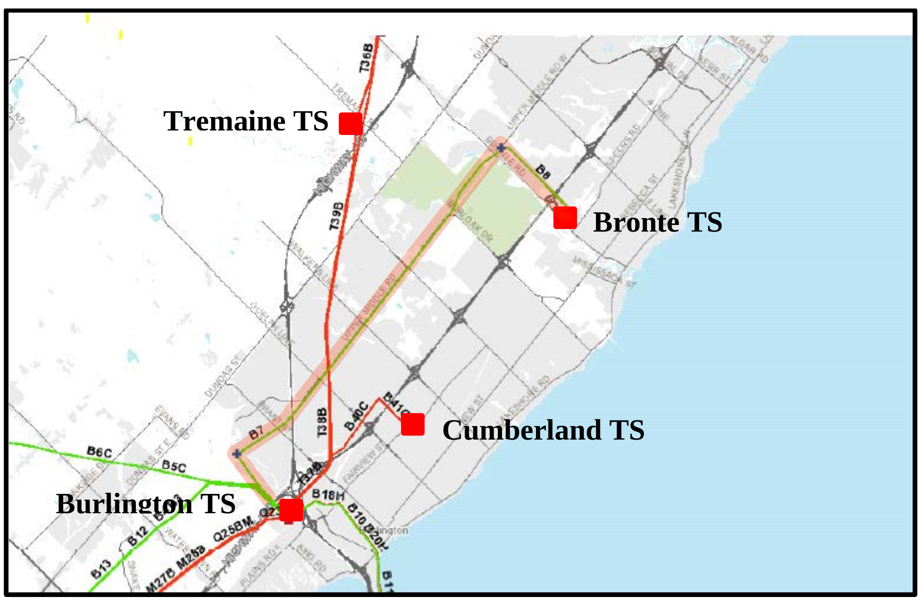

Figure 7-1 Bronte TS Supply Circuits B7/B8

7.1.2 Recommended Plan

The Working Group considered and reviewed different options to provide relief to the 115 kV circuits supplying Bronte TS as part of the Bronte area IRRP. The options included: a) upgrading of transmission system to mitigate the limitation on the 115 kV B7/ B8 circuits and b) Distribution option to transfer load from Bronte TS to neighboring station(s). Upgrading of transmission system was neither economical nor a practical solution.

Consistent with the WG recommendations in the IRRP, the most cost effective and preferred alternative is for LDC(s) to transfer loads from Bronte TS to other neighboring stations and to maintain Bronte TS loading below 135 MW.

Hydro One and the affected LDCs will develop a plan by the end of 2017 for transferring approximately 15 MW of load from Bronte TS to the neighboring station(s). The estimated cost of investments for the distribution load transfer is currently expected to be in the order of $1-3 million.

7.2 115 kV Circuit B12/B13 Transmission Line Capacity (Burlington TS to Brant TS)

7.2.1 Description

Brant TS and Powerline MTS in Brant County are supplied by the 115 kV double circuits B12/B13 line from Burlington TS. The Brant area is experiencing higher growth with a number of new industrial customers planning to connect over the next few years. The combined load of Brant TS and Powerline MTS was 119 MW in summer 2015 and exceeds the 104 MW supply capacity of the B12/B13 line.

7.2.2 Recommended Plan

As per the IRRP recommendations, first phase was to provide additional capacity for the Brant Area's 115 kV supply that included installation of 40 MVAR capacitor banks at Powerline MTS in July 2015. This has increased the line supply capacity to 125 MW.

In addition, the IRRP Working Group considered other options to provide additional 115 kV capacity to supply Brant TS and Powerline MTS to address future load growth over the near-term. The most economical option that was recommended by the WG is to install a three breaker switching station at Brant TS and using the existing backup supply from 115 kV circuit B8W (from Karn TS) as third supply. A single line diagram of the new switching facilities at Brant TS is shown below in Figure 7.2.

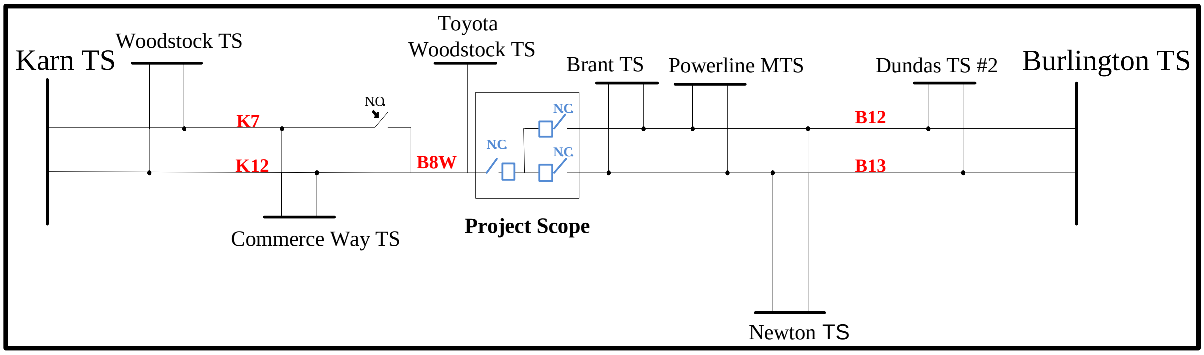

Figure 7-2 Brant Sub-Region Proposed Configuration

Hydro One has initiated detailed engineering work and design. The project is expected to be in-service by spring 2019 and is estimated to cost approximately $12 million. The installation of the switching station will reclassify some of the line connection assets as Network Assets. The project cost will be recoverable from the rate revenue and/or capital contribution from the LDCs in accordance with the TSC.

7.3 Two New Feeders at Dundas TS

7.3.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and a station supply capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period.

A LDC currently supplied from the T1/T2 DESN is planning to transfer load to T5/T6 DESN and supplied from two existing spare breaker positions to meet increased load needs. This will also help in balancing the loads between the two Dundas TS DESNs.

7.3.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address customer's needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's needs.
- Transfer customer load to T5/T6 DESN: Move portion of LDC customer loads from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions at T5/T6 DESN. This will require reconfiguring of distribution assets by the LDC and will also help improving load balancing between two Dundas TS DESNs.

The preferred plan is to proceed with moving portion of the LDC's customer load from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions. The transfer of load from T1/T2 DESN to T5/T6 DESN is planned to be completed in 2019 at an estimated cost of $8 million.

7.4 Cumberland TS Power Factor Correction

7.4.1 Description

The Cumberland TS supplies up to 123 MW of loads in the city of Burlington. The historical loading data of Cumberland TS indicated that under peak load conditions the power factor at Cumberland TS is lagging slightly below the ORTAC requirement of 0.9.

7.4.2 Recommended Plan and Current Status

The Needs Assessment identified this need and it was recommended that Burlington Hydro to work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system as required to meet the minimum power factor requirements of 0.9.

Burlington Hydro is currently perusing different options to improve the power factor of customer loads supplied by Cumberland TS to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.5 Kenilworth TS Power Factor Correction

7.5.1 Description

There are two supply stations inside Kenilworth TS T1/T4 and T2/T3 supplying about 60 MW of loads in the city of Hamilton. The historical loading data of Kenilworth TS indicated that under peak load conditions the power factor at Kenilworth TS is lagging below the ORTAC requirement of 0.9.

7.5.2 Alternatives and Recommended Plan

The Needs Assessment identified this need and it was recommended that Alectra Utilities to install capacitor bank on distribution system and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9.

Alectra Utilities is currently perusing option on cost and location to install equipment to improve power factor to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.6 Kenilworth TS End of Life Assets

7.6.1 Description

There are two DESN units T1/T4 and T2/T3 inside Kenilworth TS supplying loads in the city of Hamilton and built in 1950's and 1960's respectively. The load at Kenilworth TS is currently about 60 MW. The T1/T4 transformers are rated at 67 MVA each while the T2/T3 transformers are 100MVA and 120 MVA, respectively, which are non-standard as per current standards. Non-standard and obsolete equipment results in complexity with failures and difficulty in getting similar spare equipment along with their installation. The original 120 MVA T2 transformer was replaced with a standard 100 MVA transformer unit in 2014 due to failure. In addition, one of the three metalclad switchgears at Kenilworth TS is presently out of service while the second in-service metalclad switchgear is approaching end of its useful life. As a result, near-term plan is developed to address the failure and EOL issues.

7.6.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life issue at Kenilworth TS:

- 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 reduce supply reliability to the customers.
- “Like-for-Like” replacement of the assets: This alternative would require maintaining four transformers and the associated three switchgears which is not justifiable based on the load forecast.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Kenilworth TS. This alternative was considered but is not feasible due to: a) unique electrical characteristics and requirements of industrial costumer load in the area, and b) higher costs associated with reconfigurations and transfer of customer loads.
- Reconfiguration of the station reducing to two supply transformers and two switchgears: This option will reconfigure and adequately downsize the station. In this configuration, station will be reduced from four transformers to only two transformers supplying two switchgears.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. The recently replaced transformer and one of the existing metalclad switchgear will be utilized while one transformer and switchgear will be required to be replaced. The new transformer will be a standard unit similar to T2 that was replaced in 2014. This refurbishment project is currently planned to be completed by the year 2018 at an estimated cost of $19 million.

7.7 Beach TS EOL T3/T4 DESN Transformers

7.7.1 Description

Beach TS has two DESN units T3/T4 and T5/T6 supplying loads in the city of Hamilton and built in 1950’s and 1960’s respectively. The T3/T4 DESN is supplied by the 115 kV bus while the T5/T6 DESN is supplied from the 230 kV bus at Beach TS. The 115/13.8 kV T3/T4 DESN transformers have been identified by Hydro One approaching the end of their useful life and require replacement. The load at Beach TS T3/T4 DESN is currently about 32 MW and is forecasted to stay at the same level in the foreseeable future.

7.7.2 Alternatives and Recommended Plan

The following alternatives are considered to address Beach TS T3/T4 supply transformer end of life issue:

- Continue to maintain the assets (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 reduce supply reliability to the customers.
- “Like-for-Like” replacement of the assets: Replacing existing EOL 115/ 13.8 kV T3/T4 DESN transformers with similarly sized units.

- Reconfigure 115 kV T3/T4 transformers to a 230 kV configuration by replacing the existing non-standard 115/ 13.8 kV (67 MVA + 75 MVA) transformers with standard 100 MVA 230/13.8 kV units.

Keeping the existing supply configuration at 115 kV of T3/T4 transformers at Beach TS is not possible as it does not meet safety clearance requirements. In light of this and the fact that moving the transformer supply configuration from 115 kV to 230 kV bus is similar in cost plus has other long-term advantages, such as the 230 kV supply option will result in reduced loading levels of 230/115 kV Beach TS autotransformers resulting in freeing up capacity and improve supply reliability.

The preferred plan is for Hydro One to proceed with reconfiguring the 115 kV T3/T4 DESN to a 230 kV configuration by replacing the existing non-standard transformers with standard 100 MVA 230/13.8 kV units is the most suitable option. The project is currently underway, and is expected to be completed in 2019. The cost of this investment is currently estimated at about $17 million.

7.8 Gage TS End of Life T3/T4/T5/T6 Transformers and a Switchgear

7.8.1 Description

Gage TS has three DESNs (T3/T4, T5/T6, and T8/T9) predominantly supplying large industrial customer loads in Hamilton. T3/T4 and T5/T6 DESNs were built in the 1940's with each transformer rated at 63 MVA LTR, while T8/T9 DESN was built in 1960's with each transformer rated at 137 MVA LTR. These transformers are non-standard with unique electrical characteristics with high short circuit requirements of the customer. The transformers T3, T4, T5, and T6, as well as T5/T6 DESN at Gage TS have been identified by Hydro One at their EOL and have been previously deferred to better understand customer load requirements. Transformer T5 has failed multiple times and breakers in the T5/T6 DESN have experienced recurring problems. No issues or refurbishment needs have been identified at T8/T9 DESN at this time.

The load at Gage TS has reduced over the years to approximately 48 MW, and is currently expected to stay at this level over the study period. The existing station capacity (of the three DESNs) is about 240 MW. Although there seems to be over-capacity at Gage TS, unique short-circuit and connection requirements of industrial loads at this station limits the feasibility of some of the alternatives/solutions.

7.8.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Gage TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining six transformers and the associated three switchgears. This option is extremely costly and cannot be justified since the load has significantly reduced at this station.

- Station/load consolidation: Moving loads to neighboring station(s) and retiring Gage TS. This alternative is not feasible due to: a) unique costumer load requirements (i.e., high short circuit currents are required to operate customer's large arc furnaces and large motors without significant impact to power quality), and b) higher costs associated with reconfigurations of LV cables and transfer of customer loads to other stations.
- Reconfiguration of the station and downsize the station from three DESN to two DESN station: In this option, the station will be reconfigured and downsized from the existing six transformers to four transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it from 3 DESNs to 2 DESNs. Under this plan, T3/T4 and T5/T6 DESNs will be replaced by a single T10/T11 DESN with two 100 MVA standard units and switchgear currently supplied by T5/T6 transformers will also be replaced. This option will also provide future flexibility to eliminate T8/T9 DESN when it approached EOL.

The refurbishment of Gage TS is currently expected to be completed in 2019 at an estimated cost of $37 million.

7.9 115 kV Circuit B7/B8 End of Life Section (Burlington TS to Nelson Junction)

7.9.1 Description

The 115 kV double circuit line B7/B8 line supplies about 130 MW of Burlington and Oakville area loads through Bronte TS. The line section from Burlington TS to Nelson junction (about 2.3 km) was built in 1920's. Hydro One has identified that the conductor on this line section from Burlington TS to Nelson junction has reached end of useful life.

7.9.2 Alternatives and Recommended Plan

The following alternatives are considered to address 115 kV B7/B8 end of life line section from Burlington TS to Nelson junction:

- Maintain status quo: This alternative was considered and rejected as it does not address the EOL issue, risk of failures resulting in poor supply reliability and would result in increased maintenance expenses.
- Refurbishment of EOL line section: Refurbish 2.3 km of EOL line conductor section of B7/B8 line section.

The preferred plan is to proceed with the refurbishment of the 115 kV B7/ B8 line section from Burlington TS to Nelson junction supplying Bronte TS using similar ACSR conductor. The refurbishment work is planned to be completed by the year 2020 and estimated to cost approximately $2 million.

7.10 115 kV B3/B4 End of Life Line Section (Horning Mountain Jct. to Glanford Jct.)

7.10.1 Description

The 115 kV B3/B4 line supplies Hamilton area loads through Dundas TS (T1/T2 DESN), a CTS and Mohawk TS. Mohawk TS is supplied from B3/B4 line through about 16 km long line-tap supplying about 84 MW of load. A section of this line tap has a solid copper conductor from Horning Mountain Jct. to Glanford Jct. which is approximately 100 year old and has reached end of useful life.

7.10.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above need:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the frequent failure, increased maintenance expenses and poor supply reliability.
- Refurbishment of EOL line section: Replace EOL copper conductor with 605 kcmil ACSR conductor Mohawk TS line tap section.

The preferred plan is for Hydro One to replace this EOL copper conductor with 605 kcmil ACSR from Horning Mountain Jct. to Glanford Jct. supplying Mohawk TS. This work is currently planned to be completed by 2018 at an estimated cost of $8 million.

7.11 Horning TS End of Life Assets

7.11.1 Description

Horning TS is a 230/13.8 kV DESN station built in 1967 and supplies Alectra Utilities loads in the Hamilton area. It has two station supply transformers of 100 MVA each supplying load through its two metalclad switchgears. Recent equipment failures in 2016 due to aging low voltage switchgear have adversely impacted supply to customers in the Hamilton area along with safe operations.

In addition, both the transformers and both low voltage switchgears at Horning TS are approaching end of expected useful life and have been identified by Hydro One for replacement. The load at Horning TS is currently about 70 MW and is forecasted to stay at the same level during the study period.

7.11.2 Alternatives and Recommended Plan

The following alternatives are considered to address Horning TS end of life issue:

- Continue to maintain the assets (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 reduce supply reliability to the customers.

- "Like-for-Like" replacement of the assets: This alternative would continue maintaining current station configuration and only replace existing transformers will similar units and refurbish both metalclad switchgears.

The preferred plan is for Hydro One to proceed with Like-for-Like replacements replacing supply transformers with similar 100 MVA units and refurbishing EOL low voltage metalclad switchgears. The new replaced transformers and refurbished switchgear will provide sufficient capacity to serve the load over the study period. The project is currently underway, and is expected to be completed in 2018. The cost of this investment is estimated to be about $37 million.

7.12 Bronte TS End of Life T5/T6 DESN

7.12.1 Description

Bronte TS was placed in service in 1963 and is radially supplied from Burlington TS via 115 kV B7/ B8 circuits. The total load at Bronte TS is currently about 129 MW and is forecasted to stay at about 135 MW with load transfers as proposed in section 7.1.

There are three transformers, T2 (single transformer configuration), and T5/T6 DESN (83 MVA), at Bronte TS supplying loads in the cities of Oakville and Burlington. Transformer T2 was replaced in 2006 and the T5/T6 DESN transformers at Bronte TS and LV switchgear is approaching end of expected useful life. Hydro One has identified that these transformers require replacement.

7.12.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life Bronte TS T5/T6 DESN refurbishment:

- Continue to maintain the assets (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 reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: Replacing existing EOL 115/ 27.6 kV T5/T6 DESN transformers with similar size standard units and refurbish switchgear.

The preferred plan is for Hydro One to proceed with Like-for-Like replacement. This will include replacing existing 83 MVA T5/T6 transformers with similar units and refurbishing associated switchgear. This investment is estimated to be approximately $34 million with planned in-service of 2019.

7.13 Elgin TS End of Life Assets

7.13.1 Description

Elgin TS has two DESNs (T1/T2 and T3/T4) built in 1960's supplying loads in the city of Hamilton through three switchgears. The current load at Elgin TS is approximately 85 MW, and is currently expected to stay at this level over the study period.

The T1/T2 transformers are 75 MVA units while the T3/T4 units are non-standard 33 MVA units. All existing four transformers (T1, T2, T3, and T4) and three switchgears at Elgin TS have been identified by Hydro One as approaching end of their useful life. This need was identified in the Needs Assessment phase.

7.13.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Elgin TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining four transformers and the associated three switchgears. This option is extremely costly and cannot be justified with load forecast not showing any growth at this station.
- Reconfiguration and downsize the station from two DESNs to one DESN station: In this option, the station will be reconfigured and downsized from the existing four transformers to two transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. Under this plan, T1/T2 and T3/T4 DESNs will be replaced by a single T5/T6 DESN with two 100 MVA standard units and four new switchgears. This will maintain adequate supply capacity to the loads through the four new switchgears. The cost of this investment is expected to be $58 million with a planned in service of 2019.

7.14 Mohawk TS Station Supply Capacity & End of Life T1/T2 Transformers

7.14.1 Description

Mohawk TS is a 115/13.8 kV step down transformer station supplied from 115 kV circuit B3/B4 from Burlington TS supplying loads in the city of Hamilton. The station supply capacity is limited to 80 MW by the LTR of transformers. The 2015 summer peak load was 84 MW and the station is marginally over its supply limits during peak load periods. In addition, transformers at Mohawk TS are over 50 years old and condition assessment has identified Mohawk TS transformers approaching end of their useful life.

7.14.2 Alternatives and Recommended Plan

The following alternatives were considered to address Mohawk TS end of life transformer issue:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, poor supply reliability and would result in increased maintenance expenses. In addition option will not address the capacity needs at the station,
- Transformer replacement: Replacing the existing non-standard (67 MVA) end of life transformers with new standard (75 MVA) units.

The preferred plan is for Hydro One to proceed with the replacement of existing nonstandard supply transformers at Mohawk TS with the standard 75 MVA units. This will address the issue of: a) EOL transformers, b) replace non-standard equipment with standard units, and c) will provide sufficient station supply capacity. In the interim, Alectra Utilities will manage the overloads (under contingency) by distribution loads transfers. The transformer replacement project is currently expected to be in service by 2019 at an estimated cost of $14 million.

7.15 Birmingham TS End of Life Switchgear

7.15.1 Description

Birmingham TS is located in the city of Hamilton having two DESN units T1/T2 and T3/T4 of 75 MVA each. Both the DESNs at Birmingham TS can supply a total load of about 185 MVA (LTR). The Birmingham TS currently supplies a large industrial customer with unique connection requirements. The load at Birmingham TS is forecasted at about 75 MW.

At this time transformers and/or other HV equipment at this station has not been identified as EOL over the study period. However, two 13.8 kV LV metalclad switchgears are at EOL and have been identified by Hydro One for refurbishment.

7.15.2 Recommended Plan

The two end of life 13.8 kV LV end of life metalclad switchgears at Birmingham TS are required to be replaced to meet the unique connection needs of the customer at this station. Not replacing the end of life switchgears will increase the risk of failure due to asset condition and adversely impact supply to a large industrial customer. Currently Hydro One plans to complete this by 2021. This need will be further reviewed in the next regional planning cycle.

7.16 Dundas TS End of Life Switchgear

7.16.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and station capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period. The T1/T2 transformers at Dundas TS have recently been replaced in 2015. The Dundas TS T1/T2 27.6 kV MV switchgear has been identified by Hydro One at end of life requiring refurbishment.

7.16.2 Alternatives and Recommended Plan

Hydro One has identified MV 27.6 kV T1/T2 switchgear at Dundas TS at end of life requiring refurbishment. Keeping status quo not refurbishing this switchgear will increase the risk of failure due to asset condition reducing supply reliability to the customers and would result in increased maintenance expenses.

The refurbishment switchgear is currently planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.17 Newton TS End of Life Transformers and Switchgear

7.17.1 Description

Newton TS is a 115 kV/ 13.8 kV DESN station having transformers built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. It has two station supply transformer of 67 MVA each supplying loads through its 13.8 kV switchyards. The customer load at the station is about 50 MW and is forecasted to stay at the same level in the foreseeable future. Hydro One in initial assessment has identified that both transformers and switchgear requiring refurbishment. The scope of refurbishment is subject to final asset condition assessment of Newton TS to be completed in 2017.

7.17.2 Alternatives and Recommended Plan

The following alternatives are considered to address Newton TS end of life asset issue:

- <u>Maintain status quo</u>: 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 cost.
- <u>Replacement of the assets</u>: Replace existing EOL non-standard transformers with similarly sized units and refurbish switchgear to current standards.

The current plan is to refurbish Newton TS with new equipment built to current standards including two 75 MVA units replacing existing 67 MVA transformers and LV switchgear. This is the preferred alternative since it addresses the needs at Newton TS and maintaining station's operability and reliability of supply. This refurbishment work at Newton TS is planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.18 Mid-Term End of Life LV Switchyard Refurbishment

7.18.1 Description

Hydro One has identified the LV switchyards reaching end-of-life by 2022 and need to be refurbished at the following stations:

1. Brantford TS
2. Lake TS
3. Stirton TS

7.18.2 Recommended Plan

The Working Group is recommending that these needs to be further reviewed in the next regional planning cycle.

7.19 Beach TS End of Life T7/T8 Autotransformers and T5/T6 DESN LV Switchgear

7.19.1 Description

Beach TS is a major switching and transformer station in East Hamilton. Station facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T1/T7/T8), a 115 kV switchyard, a 230/13.8 kV DESN T5/T6 and a 115/13.8 kV DESN T3/T4.

Hydro One has determined that autotransformers T7 and T8 and the T5/T6 DESN LV Metalclad switchgear are expected to reach end of life by 2025 and will need to be replaced.

7.19.2 Recommended Plan

The Working Group is recommending that this need be further reviewed in the next regional planning cycle.

7.20 End of Life Cables in Hamilton Area: HL3/HL4, K1G/K2G, H5K/H6K

Underground cables in Hamilton area (listed below) are expected to be approaching end-of-life over the next 10 years or so.

- 115 kV H5K/H6K Cable (Beach TS to Kenilworth TS)
- 115 kV K1G/K2G Cable (Kenilworth TS to Gage TS)
- 115 kV HL3/HL4 Cable (Newton TS to Elgin TS)
- 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)

In light that replacement of the high voltage underground cables can be complicated, affect upstream transmission system and expensive requires alternative/s to be developed and assessed ahead of time. The WG has recommended further review of the cable replacement needs and development of a tentative plan in the next regional planning cycle.

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8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE BURLINGTON TO NANTICOKE REGION.

A list and summary of all the needs and/or plans in the near-term (2016-2020) and mid to long term (beyond 2020) is provided below in Table 8-1 and Table 8-2, respectively, along with their in-service date and estimated cost, where applicable. Where available, preliminary plans to address the mid- to long-term needs were also provided.

Table 8-1 Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (1)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (1)	Replace Beach TS T3/T4 DESN Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (1)	Replace EOL transformers & refurbish switchgears	Committed	2018	37

No.	Needs	Plans	Status	I/S Date	Cost ($M)
12	Bronte TS – EOL T5/T6 DESN [1]	Replace EOL transformers & refurbish switchgear	Committed	2019	34
13	Elgin TS – EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) New needs identified by HONI

Table 8-2 Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment [1]	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD [2]	TBD [2]

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

It is the recommendation of RIP Working Group:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and

b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

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APPENDIX A: TRANSMISSION LINES IN THE BURLINGTON TO NANTICOKE REGION

No.	Location	Circuit Designations	Voltage (kV)
1	Beach TS - CTS	H35D, H36D	230
2	Beach TS - Burlington TS	B18H, B20H	230
3	Beach TS - Middleport TS	M34H	230
4	Beach TS - Middleport TS - Beck #2 TS	Q24HM, Q29HM	230
5	Burlington TS - Cumberland TS	B40C, B41C	230
6	Burlington TS - Middleport TS	M27B, M28B	230
7	Burlington TS - Middleport TS - Beck #2 TS	Q23BM, Q25BM	230
8	Middleport TS - Beck #2 TS	Q30M	230
9	Middleport TS - Buchanan TS	M31W, M32W, M33W	230
10	Middleport TS - Detweiler TS	M20D, M21D	230
11	Middleport TS - Nanticoke TS	N5M, N6M	230
12	Middleport TS - Summerhaven SS	S39M	230
13	Middleport TS - Sandusk SS	K40M	230
14	Nanticoke TS - Jarvis TS	N21J, N22J	230
15	Summerhaven SS - Nanticoke TS	N37S	230
16	Sandusk SS - Nanticoke TS	N20K	230
17	Beach TS - Gage TS	B10, B11	115
18	Beach TS - Kenilworth TS	H5K, H6K	115
19	Beach TS - Newton TS	HL3, HL4	115
20	Beach TS - Winona TS	Q2AH	115
21	Beach TS - CSS	H9W	115
22	Burlington TS - Brant TS	B12, B13	115
23	Burlington TS - Bronte TS	B7, B8	115
24	Burlington TS - Cedar TS	B5G, B6G	115
25	Burlington TS - Newton TS	B3, B4	115
26	Caledonia TS - Norfolk TS	C9, C12	115
27	Kenilworth TS - Gage TS (Idle)	K1G, K2G	115

APPENDIX B: STATIONS IN THE BURLINGTON TO NANTICOKE REGION

No.	Station	Voltage (kV)	Supply Circuits
1	CTS	230	H35D, H36D
2	Beach TS	230	Beach TS 230 kV Bus (1)
3	Beach TS	115	Beach TS 115 kV Bus (2)
4	Birmingham TS	115	HL3, HL4
5	Bloomsburg DS	115	C9, C12
6	Brant TS	115	B12, B13
7	Brantford TS	230	M32W, M33W
8	Bronte TS	115	B7, B8
9	Burlington TS DESN	230	Q23BM, Q25BM
10	Caledonia TS	230	N5M, S39M
11	Cumberland TS	230	B40C, B41C
12	CTS	230	Q24HM, Q29HM
13	Dundas TS	115	B3, B4
14	Dundas TS #2	115	B12, B13
15	Elgin TS	115	HL3, HL4
16	Gage TS	115	B10, B11
17	Horning TS	230	M27B, M28B
18	CTS	230	N20K
19	Jarvis TS	230	N21J, N22J
20	Kenilworth TS	115	H5K, H6K
21	Lake TS	230	B18H, B20H
22	CTS	115	B3, B4
23	Mohawk TS	115	B3, B4
24	Nebo TS	230	Q24HM, Q29HM
25	Newton TS	115	Newton TS 115 kV Bus (3)
26	Norfolk TS	115	C9, C12
27	Powerline MTS	115	B12, B13
28	CTS	115	HL3, HL4
29	Stirton TS	115	HL3, HL4
30	CTS	230	N21J, N22J
31	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits
(2) Beach TS 115 kV bus is supplied by three 230 kV/ 115 kV autotransformers at Beach TS
(3) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12 and B13 circuits

APPENDIX C: DISTRIBUTORS IN THE BURLINGTON TO NANTICOKE REGION

Distributor Name	Station Name	Connection Type
Energy + Inc.	Brant TS	Dx, Tx
	Brantford TS	Dx
Brantford Power Inc.	Brant TS	Tx
	Brantford TS	Tx
Brantford Power Inc. and Energy + Inc.	Powerline MTS	Tx
Burlington Hydro Inc.	Bronte TS	Tx
	Burlington TS	Tx
	Cumberland TS	Tx
Haldimand County Hydro Inc.	Caledonia TS	Dx, Tx
	Jarvis TS	Dx, Tx
Alectra Utilities Corporation	Beach TS	Tx
	Birmingham TS	Tx
	Dundas TS	Dx, Tx
	Dundas TS #2	Tx
	Elgin TS	Tx
	Gage TS	Tx
	Horning TS	Tx
	Kenilworth TS	Tx
	Lake TS	Dx, Tx
	Mohawk TS	Tx
	Nebo TS	Dx, Tx
	Newton TS	Tx
	Stirton TS	Tx
	Winona TS	Tx
Hydro One Networks Inc.	Brant TS	Tx
	Caledonia TS	Tx
	Dundas TS	Tx
	Dundas TS #2	Tx
	Jarvis TS	Tx
	Lake TS	Tx
	Nebo TS	Tx
	Norfolk TS	Dx, Tx
	Bloomsburg DS	Dx, Tx
Oakville Hydro Electricity Distribution Inc.	Bronte TS	Tx

APPENDIX D: AREA STATIONS NON COINCIDENT NET LOAD FORECAST (MW)

Sub-Region	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Brant 115 kV	Brant TS	101	59	61	63	67	68	69	70	72	74	76	79	81	84	86
	Powerline MTS	114	69	67	70	71	72	73	75	77	80	83	86	89	92	95
	Total	215	128	128	134	138	140	143	145	149	154	159	165	170	175	181
Brant 230 kV	Brantford TS	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
	Total	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
Bronte 115 kV	Bronte TS (T2)	75	59	60	62	63	64	65	66	67	68	68	68	68	69	70
	Bronte TS (T5/T6)	96	70	71	72	74	75	76	77	79	80	80	80	80	81	82
	Total	171	129	131	134	138	139	141	143	146	148	148	148	148	150	152
Bronte 230 kV	Burlington (DESN) TS	185	151	153	154	154	155	156	157	159	160	163	165	168	170	171
	Cumberland TS	174	123	122	122	122	123	124	124	126	127	129	131	133	135	136
	Total	359	273	275	276	277	278	279	281	284	288	291	296	301	304	307
Greater Hamilton 115 kV	Beach TS (T3/T4)	75	32	32	32	31	31	31	31	31	30	30	30	30	30	30
	Birmingham TS (T1/T2)	76	32	31	31	31	31	30	30	30	30	30	30	29	30	30
	Birmingham TS (T3/T4)	91	46	46	46	45	45	45	44	44	44	44	43	43	43	43
	Dundas TS	99	85	91	93	93	93	84	84	84	84	85	85	85	86	87
	Dundas TS #2	89	63	65	68	70	72	72	71	71	71	70	70	69	70	70
	Elgin TS (T1/T2)	80	63	62	62	62	61	59	58	58	58	57	57	57	57	57
	Elgin TS (T3/T4)	42	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T3/T4)	60	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T5/T6)	57	11	11	11	11	11	11	11	10	10	10	10	10	10	10
	Gage TS (T8/T9)	123	15	15	15	15	15	15	15	15	14	14	14	14	14	14
	Kenilworth TS (T1/T4)	36	29	28	28	28	28	28	28	27	27	27	27	27	27	27
	Kenilworth TS (T2/T3)	64	31	31	31	31	30	30	30	30	30	30	29	29	29	29
	Mohawk TS	80	84	83	83	83	83	82	82	82	81	81	80	79	80	80
	Newton TS	78	47	47	48	47	47	47	47	46	46	46	45	45	45	46
	Stirton TS	112	50	50	50	49	49	49	49	48	48	48	47	47	47	48
	Winona TS	89	46	48	51	51	50	50	50	49	49	49	49	48	48	49
	Total CTS		59	59	60	60	61	61	61	61	61	61	61	61	61	61
	Total		736	745	752	750	749	735	732	729	726	723	719	715	719	723
Greater Hamilton 230 kV	Beach TS (T5/T6)	91	41	44	43	43	47	47	47	46	46	46	46	45	45	46
	Horning TS	102	71	73	76	76	76	75	75	75	74	74	73	73	73	73
	Lake TS (T1/T2)	94	57	57	56	56	55	55	55	54	54	54	53	53	53	54
	Lake TS (T3/T4)	113	55	54	54	55	55	54	54	54	54	53	53	53	53	53
	Nebo TS (T1/T2)	178	119	113	116	119	123	123	124	127	129	131	133	136	140	144
	Nebo TS (T3/T4)	51	50	49	50	51	51	50	50	50	50	49	49	49	49	49
	Total CTS		265	265	265	265	244	244	244	244	244	244	244	244	244	244
	Total		658	655	661	665	651	650	650	650	651	652	652	652	658	663
Caledonia Norfolk 115 kV	Norfolk TS	97	59	56	55	55	54	54	54	53	53	53	52	52	52	52
	Bloomsburg DS	56	42	30	29	27	27	27	27	27	27	27	27	27	27	27
	Total	153	101	87	85	82	82	81	81	80	80	80	79	78	79	80
Caledonia Norfolk 230 kV	Caledonia TS	99	45	41	42	42	42	42	43	44	45	45	46	47	48	50
	Jarvis TS	99	66	62	61	61	61	61	61	62	62	63	63	63	64	66
	Total CTS		123	123	123	123	123	123	123	123	123	123	123	123	123	123
	Total		233	226	226	226	226	226	227	228	230	231	232	233	235	238
Regional Total			2394	2379	2419	2432	2421	2411	2415	2425	2434	2442	2450	2458	2483	2509

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

Greater Ottawa

REGIONAL INFRASTRUCTURE PLAN

December 2, 2015

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Hydro Ottawa Limited
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Hydro Hawkesbury Inc.
Ottawa River Power Corporation

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DISCLAIMER

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

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

Working Group 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 AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER OTTAWA REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro Ottawa Limited
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation

This RIP provides a consolidated summary of needs and recommended plans for both the Ottawa Area Sub-Region and Outer Ottawa Area Sub-Region that make up the Greater Ottawa Region for the near term (up to 5 years) and the mid-term (5 to 10 years). No long term needs and associated plans (10 to 20 years) have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Ottawa Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the Outer Ottawa Area Sub-Region's Needs Assessment ("NA") Study by Hydro One in July 2014.

The major infrastructure investments planned for the Greater Ottawa Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	November 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	December 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	June 2018	$1.1M(1)
6	115kV Circuit A6R: additional tap to off load Circuit A4K	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	October 2019	$1.1M(2)
8	King Edward TS: Replace Transformer T4	June 2021	$12M

(1) The transformers are at end of life and are being replaced as part of Hydro One sustainment program. The cost shown here represents the incremental cost of installing the next larger size units.
(2) Incremental cost for larger transformer only.

The IRRP study had also identified the need for additional 230/115 kV autotransformation capacity at Merivale TS and provision for a supply for a new station in the southwest area. The options to address these needs are still being studied by the Working Group and as part of the IESO community engagement activities. The Working Group expects to finalize recommendation to address these needs by summer 2016.

Investments to address the other mid-term needs, for cases where a decision is not required until 2020, will be reviewed and finalized in the next regional planning cycle.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER OTTAWA REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Hydro Ottawa Limited ("Hydro Ottawa"), Hydro Hawkesbury Inc. ("Hydro Hawkesbury"), Ottawa River Power Corporation ("ORPC") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of Highway 43. At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two 230 kV and 115 kV step-down transformer stations. The summer 2015 area load of the Region was about 1800 MW. The boundaries of the Region are shown in Figure 1-1 below.

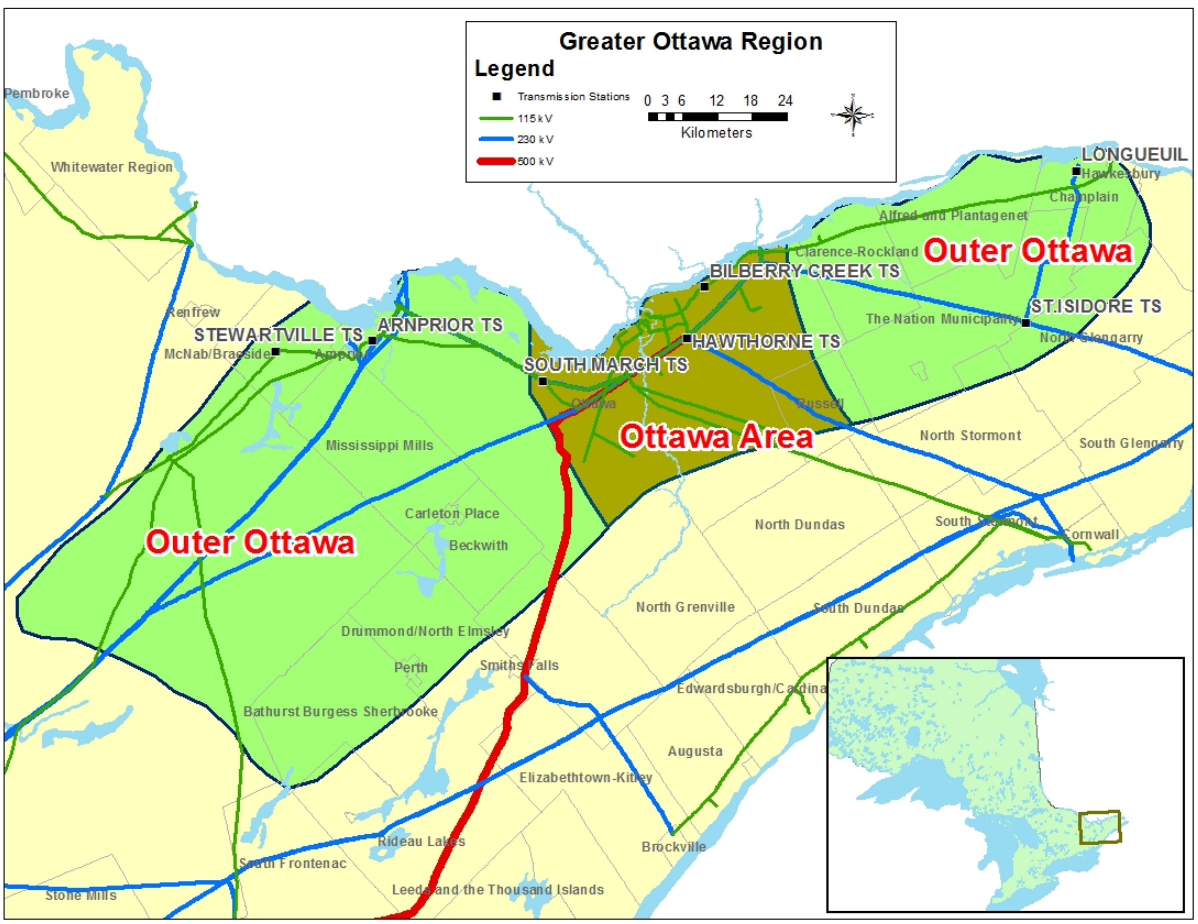

Figure 1-1 Greater Ottawa Region

1.1 Scope and Objectives

This RIP report examines the needs in the Greater Ottawa Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Local Plan, and/or Integrated Regional Resource Plan); assess and develop a wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

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 region.
- 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 needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Ottawa Sub-Region was in transition to the new regional planning process, the IESO led IRRP engagement for this sub-region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. No specific period has been specified for the RIP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The only exception would be the case where major regional transmission is required for an area with limited or no transmission facilities. In these cases the RIP would review and assess longer term needs if identified in the IRRP.

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.

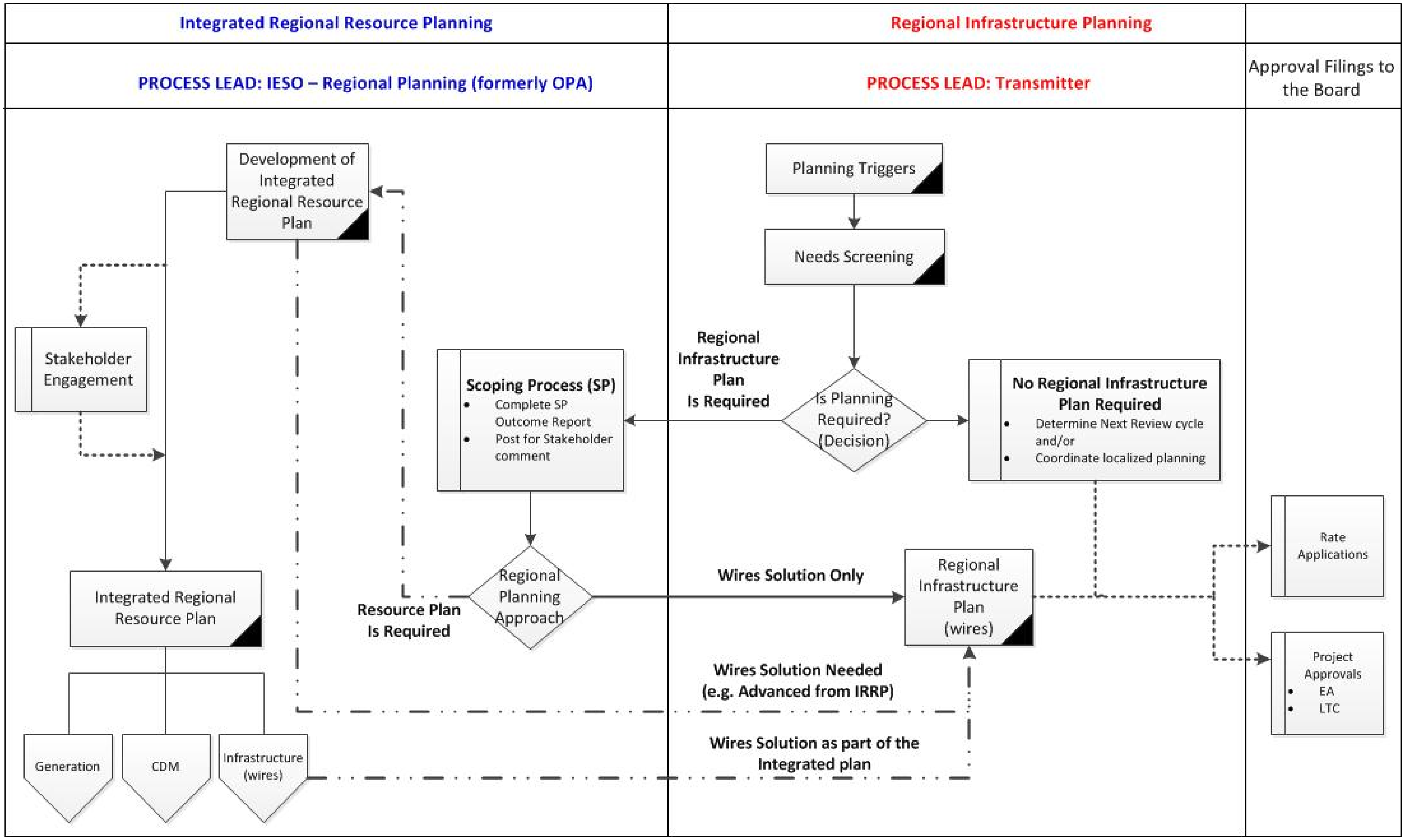

Figure 2-1 Regional Planning Process Flowchart

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 this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

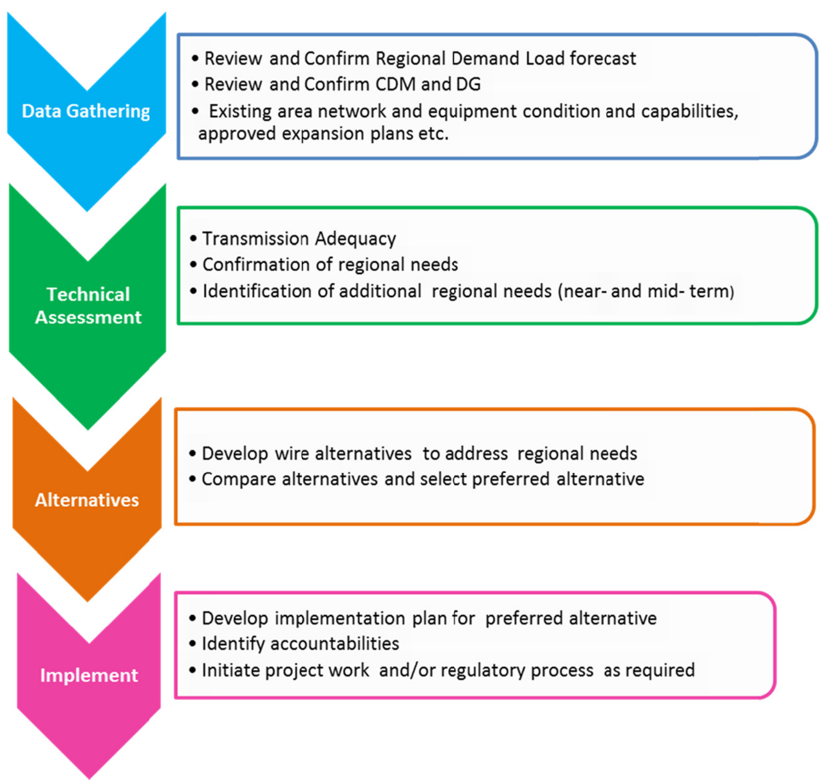

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER OTTAWA REGION COVERS THE MUNICIPALITIES BORDERING THE OTTAWA RIVER FROM ARNPRIOR IN THE WEST TO HAWKESBURY IN THE EAST AND NORTH OF HIGHWAY 43. AT THE CENTER OF THIS REGION IS THE CITY OF OTTAWA (SEE FIGURE 3-1). ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTY-TWO 230 KV AND 115 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1840 MW.

Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 1-1 and described below:

- The Ottawa Sub-Region comprises primarily the City of Ottawa. It is supplied by two 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS, eight 230 kV and thirty-three 115 kV transformer stations stepping down to a lower voltage. Local generation in the area consists of the 74 MW Ottawa Health Science Non-Utility Generator ("NUG") located near the downtown area and connected to the 115 kV network. The Ottawa Sub-Region is shown in Figure 3-1 below.

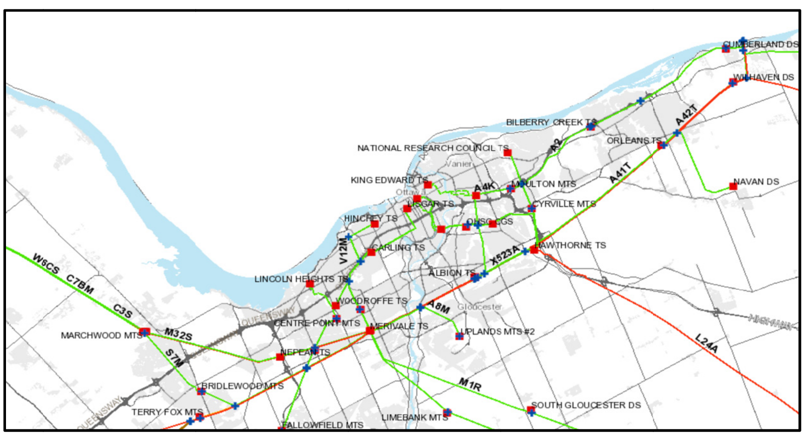

Figure 3-1 Ottawa Sub-Region

Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to the end users, i.e. industrial, commercial and residential customers.

- The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area (shown in Figure 3-2) is served by three 230 and five 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to the end use customers. It also includes a large industrial customer, Ivaco Rolling Mills, in L'Orignal, Ontario.

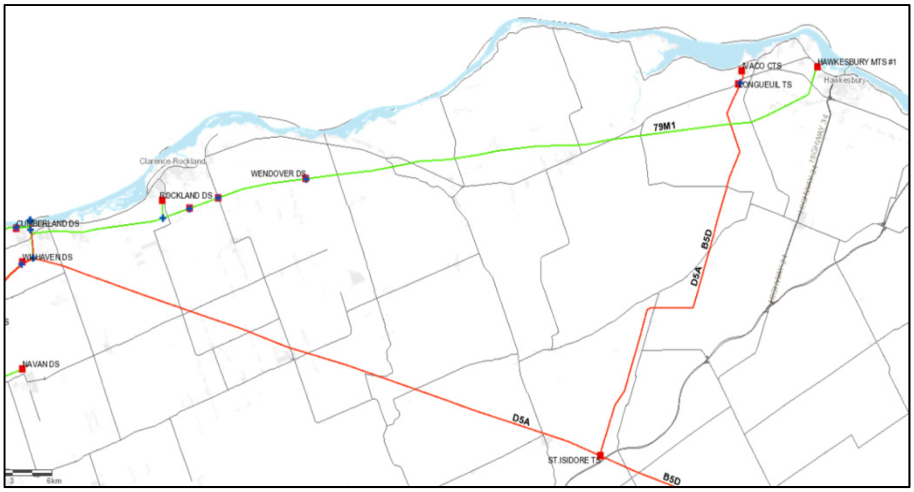

Figure 3-2 Outer Ottawa Sub-Region, Eastern Area

The western area of the Outer Ottawa Sub-Region is served by one 230 kV and two 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies end use customers for these stations. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

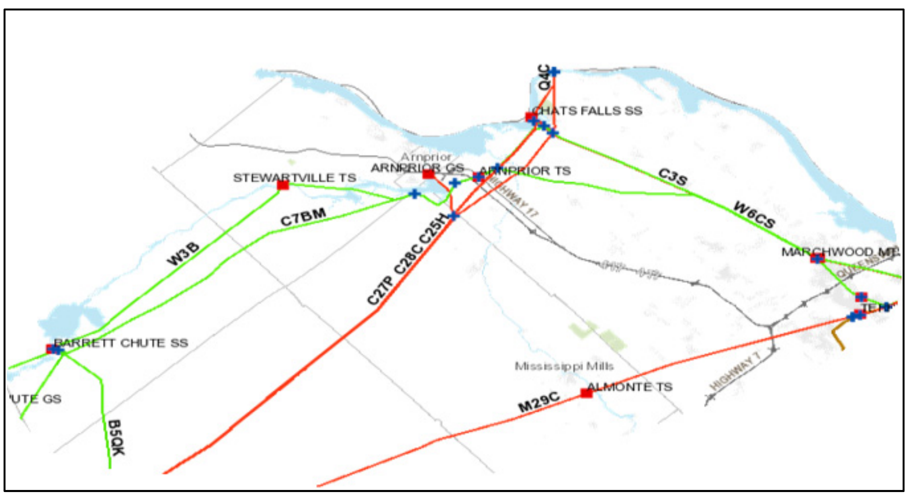

Figure 3-3 Outer Ottawa, Western Area

An electrical single line diagram for the Greater Ottawa Region facilities is shown in Figure 3-4.

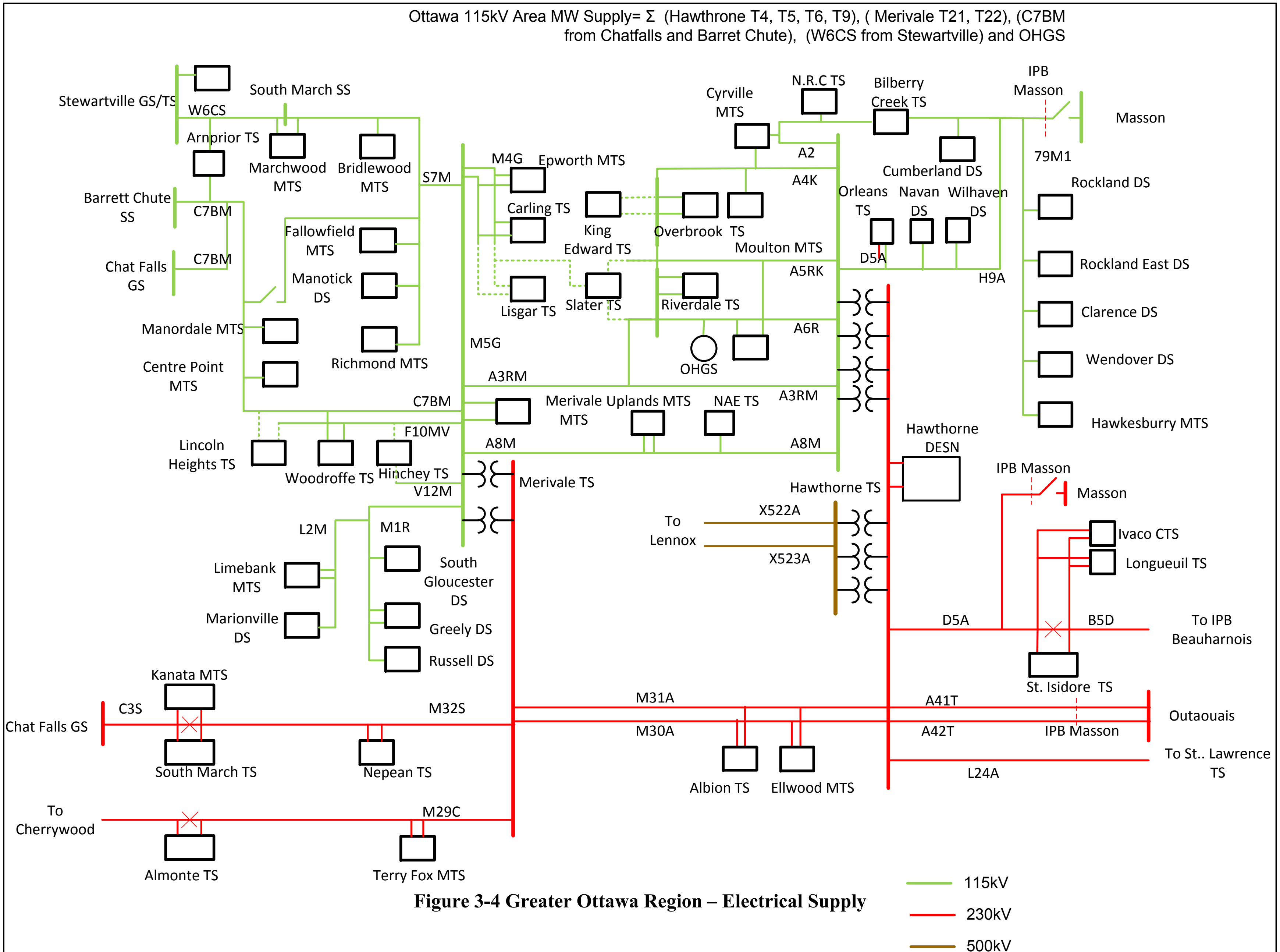

Figure 3-4 Greater Ottawa Region – Electrical Supply

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4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER OTTAWA REGION IN GENERAL AND THE CITY OF OTTAWA IN PARTICULAR.

These projects were identified as a result of either: joint Hydro One, IESO and Hydro Ottawa planning studies to meet the needs of Hydro Ottawa or Hydro One Distribution; and/or, to meet provincial government policies. A brief listing of the completed projects over the last 10 years is given below:

- Hawthorne TS x Gamble Junction double circuit 230 kV Overhead line (2008) – the single 115 kV circuit H9A was rebuilt as a two circuit 230 kV tower line with increased capacity. Connect Cyrville MTS (2008) – connected new Hydro Ottawa owned Cyrville TS to 115 kV circuits A4K and A2.
- Hawthorne TS x Outaouais TS double circuit 230 kV line (2009) – built to provide up to 1250MW of transfer capability with Hydro Quebec as part of the new HVDC interconnection.
- Connect Ellwood MTS (2012) – connected new Hydro Ottawa owned Ellwood TS to 230 kV circuits M30A and M31A.
- Connect Terry Fox MTS (2013) – connected new Hydro Ottawa owned Terry Fox MTS to 230 kV circuit M29C.
- Hawthorne TS 115 kV switchyard Upgrade (2014) – replaced 115 kV breakers with inadequate short circuit capability with new breakers of higher short circuit capability. This work improved system reliability by allowing 115kV switchyards to be operated with bus tie closed. This work also facilitated incorporation of DG in the Ottawa area.
- Build new Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuits H9A. This station will provide additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It will also provide improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
- Hinchey TS (2015) – Connect idle winding of transformer T1/T2 to new Hydro Ottawa metalclad switchgear.

The following projects are currently underway:

- Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – to improve reliability of supply for Almonte TS and Terry Fox MTS.
- Replace 45/75 MVA, 115/13.2 kV step down transformers with new 60/100 MVA, 115/13.2 kV at Overbrook TS (2017) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

- Replace 225 MVA, 230/115 kV autotransformers T5 and T6 at Hawthorne TS with new 250 MVA, 230/115 kV autotransformers (2018) – the existing transformers have inadequate capacity and were identified and recommended for replacement during the IRRP phase for the Ottawa Sub-Region [1].
- Replace 50/83 MVA, 230/44 kV step down transformers with new 75/125 MVA, 230/44 kV units at Hawthorne TS (2019) – the existing transformers are at end-of-life and the new replacement transformers have a higher rated capacity and will provide additional load meeting capability.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Ottawa Area is forecast to increase at an average rate of approximately 2.25% annually up to 2020, at 0.96% between 2020 and 2025 and at 0.45% beyond 2025. The growth rate varies across the Region with most of the growth concentrated in the Ottawa Sub-region.

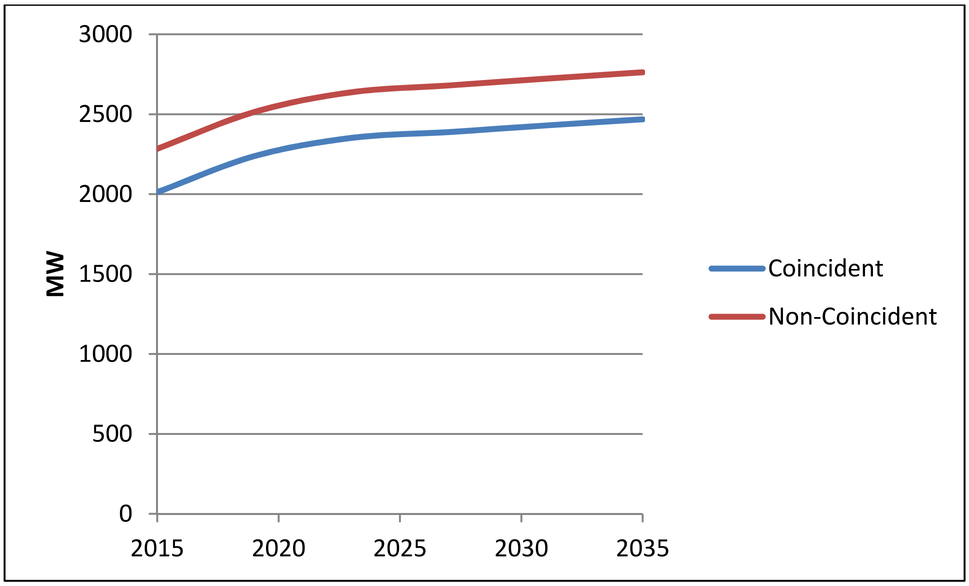

Figure 5-1 Greater Ottawa Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Greater Ottawa Region extreme weather peak summer coincident and non-coincident load forecast. The coincident forecast represents the sum of the peak load at the time of the region's peak load and represents loads that would be seen by the autotransformer stations and is used to determine the need for additional auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for stations and line capacity. Coincident and Non-coincident load forecasts for the individual stations in the Greater Ottawa Region are given in Appendix A.

The RIP load forecast was developed as follows:

- RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IESO's 2015 IRRP for the Ottawa Sub-Region[1] and Hydro One's 2014 NA [2] was still valid and there were no changes.
- The station coincident loads used in the RIP are as given in the IRRP for Ottawa Sub-Region and NA for the Outer Ottawa Sub-Region. The coincident loading is used for evaluating the adequacy of bulk transmission circuits and the 230/115kV autotransformers.

- Stations non-coincident load forecast was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates as identified in the IRRP and NA. The non-coincident forecast is used to determine adequacy of station capacity. The net growth rate accounts for CDM measures and connected DG. Details on the CDM and connected DG are provided in the IRRP [1] and NA for Ottawa Sub-Region [2] and are not repeated here.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2025.
- 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 based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GREATER OTTAWA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Within the current regional planning cycle two regional assessments have been conducted for the Greater Ottawa Region. The April 2015 Ottawa Sub-Region IRRP report [1] was prepared by the IESO in conjunction with Hydro One and Hydro Ottawa. The July 2014 Outer Ottawa Sub-Region NA report [2] was prepared by Hydro One and considered the remainder of the Greater Ottawa region.

The IRRP [1] and NA [2] planning assessments identified a number of regional needs to meet the area forecast load demand over the near to mid-term between 2015 and 2025. These regional needs are summarized in Table 6.1 and include needs for which work is already underway and/or being addressed by an LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Greater Ottawa Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Near and Mid-Term Regional Needs

Type	Section	Needs	Timing(4)
Needs identified in IRRP [1] and NA [2]			
230/115kV Transformation Capacity	7.1	Hawthorne TS T5 and T6 – LTR(1) exceeded	2018(2)
	7.2.1	Merivale TS T22 - LTR(1) exceeded	2019
Transmission Circuit Capacity	7.2.2	S7M Circuit – Capacity	2019 and 2026
	7.3	A4K Circuit - Capacity	2019(2)
Station Capacity	7.4	Center 115kV Area - Capacity	2017-2021(3)
	7.5	Hawthorne TS T7 and T8 – LTR(1) exceeded	2019
	7.2.2	South West Area - Capacity	2020
	7.6	Bilberry Creek TS - Refurbishment	2023
Supply Security, Reliability and Restoration	7.7	Almonte TS/Terry Fox MTS - Reliability	2015
	7.8	Orleans TS - Reliability	No plan recommended(5)
	7.9	B5D+D5A Circuits – Restoration	No plan recommended(5)
	7.10	Load Loss for S7M Contingency	No plan recommended(5)
Voltage Regulation	7.11	79M1 Circuit – Voltage Regulation	2023
	7.12	Stewartville TS – Voltage Regulation	No plan recommended(5)
	7.13	Almonte TS/Terry Fox MTS –Voltage Regulation	No plan recommended(5)
	7.14	Almonte TS – Low Power Factor	No plan recommended(5)
Additional Needs identified in RIP			
	7.2.1	Merivale TS T22 and Hawthorne TS T9 – Continuous ratings exceeded	2024/25
	7.4.2.4	King Edward TS – Capacity	2021

(1) LTR – Limited time ratings to accommodate emergency loading for a short time under contingency conditions
(2) Projects have been initiated.
(3) Miscellaneous stations. Some are already in execution.
(4) Timing shows the proposed in service date for project underway, and the need date for the projects not yet started.
(5) Review did not recommend plan for mitigation. Please see the need details in Section 7.

6.1 500 and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the Greater Ottawa Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and to the Hydro Quebec transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. These circuits are as follows (refer to Figure 3-4):

1. Hawthorne TS to Merivale TS 230 kV transmission circuits M30A/M31A – supply Albion TS and Ellwood TS.
2. Hawthorne TS to Cornwall 230 kV transmission circuits D5A/B5D/B31L – supply Orleans TS, St. Isidore TS and Longueuil TS. Also connects to Hydro Quebec at Beauharnois Station and to Lievre Power at Masson GS.
3. Merivale TS to Chats Falls 230 kV transmission circuits M32S/C3S – supply Nepean TS, South March TS and Kanata MTS
4. Merivale TS x Cherrywood TS 230 kV transmission circuits E29C/E34M (M29C) – supply Terry Fox MTS and Almonte TS.

Based on current forecast station loadings and bulk transfers, the M30A/M31A circuits will require reinforcement by 2020. The M30A/M31A upgrade will be addressed by Hydro One based on the recommendation stemming from an IESO Bulk System Planning study [6]. All other 230 kV circuits are expected to be adequate over the study period.

6.2 230/115 kV Transformation Facilities

Almost sixty percent of the Region load is supplied from the 115 kV transmission system. The primary source of 115 kV supply is from 230/115 kV autotransformers at Hawthorne TS and Merivale TS. Additional support is provided from 115 kV generation at Barrett Chute GS, Stewartville GS, part of Chats Falls GS, and the Ottawa Health Science NUG and the Ottawa River generation at Chaudière. Support from DG and CDM was considered as part of the load forecast.

Table 6-2 summarizes the results of the adequacy studies and gives the need dates for reinforcement of the 230/115 kV autotransformer facilities at Hawthorne TS and Merivale TS. Assuming no change in the system configuration, the forecasted loading will result in the Limited Time Rating ("LTR") of the Merivale autotransformer being exceeded by 2019 and the continuous rating of the Merivale and Hawthorne autotransformers by 2024/25.

The need dates are sensitive to the availability of hydraulic generation from Barrett Chute GS, Stewartville GS and Chats Falls GS and are based on 98% dependable generation availability as per ORTAC criteria. This corresponds to about 18 MW of available generation. A higher level of generator output from these stations would defer the need dates.

The need dates assume that the Hawthorne TS 225 MVA, 230/115 kV autotransformers T5 and T6 have been replaced with new 250 MVA units. The T5 and T6 replacement work is underway and is therefore not identified in the table below.

Table 6-2 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	2015 MVA Loading	MVA Load Meeting Capability	Limiting Contingency	Need Date
Merivale TS 230/115kV autotransformer T22	261	312(1)	T21	2019
Merivale TS 230/115kV autotransformer T21	182	250	(2)	2024
Hawthorne TS 230/115kV autotransformer T9	189	250	(2)	2025

(1) Limited time rating exceeded.

(2) Continuous rating exceeded with all elements in service based on existing system configuration

6.3 115 kV Transmission Facilities

The Greater Ottawa Region 115 kV transmission facilities can be divided in five main sections: Please see Figure 3-4 for the single line diagram.

1. Hawthorne 115 kV Center – has four circuits A3RM, A4K, A5RK and A6R. Reinforcement is required for the A4K circuit as a loss of the A5RK circuit would result in the loading exceeding the rating on the A4K circuit between Hawthorne TS and Moulton MTS (for details see Section 7.3).
2. Hawthorne 115 kV East – has two circuits A2 and H9A/79M1. These are expected to be adequate over the study period.
3. Merivale 115 kV Center – has two circuits M4G and M5G. These are expected to be adequate over the study period.
4. Merivale 115 kV West – has five circuits C7BM, F10MV, S7M, V12M and W6CS. Upgrading is required of the S7M tap to Fallowfield TS since forecasted loading will exceed circuit continuous rating (for details see section 7.4)
5. Merivale 115 kV South – has two circuits L2M and M1R. These circuits are adequate for the study period.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Adequacy of 115 kV Circuits

Corridor	Section	Overloaded Circuit	Rating (A)	Contingency	2015 Loading (A)	Need Date
1. Hawthorne TS x Blackburn Jct. x Overbrook TS	Hawthorne TS x Moulton TS	A4K	1070	A5RK	1006	2017
4. S7M tap to Fallowfield MTS	STR R14-R15 x Fallowfield Jct.[2]	S7M	590	All facilities in-service[1]	278	2024

[1] Continuous rating exceeded.
[2] Please see Figure 7-4.

6.4 Step-Down Transformation Facilities

There are a total of fifty-two step-down transmission connected transformer stations in the Greater Ottawa Region. The stations have been grouped based on the geographical area and supply configuration. The non-coincident station loading in each area and the associated station capacity and need date for relief is provided in Table 6-4 below. As shown areas requiring additional transformation capacity are the Center 115kV area, the South West 115kV area and the South 115kV area. Table 6-5 shows the non-coincident station loads for all areas which are adequate over the 2015-2025 study period. Details of the areas and associated stations are given in Appendix B.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Center 115	569[1]	516	2018
South West 115	70	60	2019
South 115	182	151	2024

[1] With Overbrook TS 45/75 MVA transformers replaced with larger 60/100 MVA units.

Table 6-5 Adequacy of Step-Down Transformer Stations – Areas Adequate

Area/Supply	Capacity (MW)	2015 Loading (MW)	2025 Loading (MW)
East 115	340	231	229
West 115	504	351	425
Center 230/13.2kV	147	121	126
Center 230/44kV	153[(1)]	103	136
West 230	397	382	389
Outer East 115	80	56	62
Outer West 115	106	83	96
Outer East 230	149[(2)]	92	90
Outer West 230	100	48	45

[(1)] With Hawthorne TS 50/83 MVA transformers replaced with larger 75/125 MVA size units.

[(2)] Includes Longueuil TS and St Isidore TS load.

7. REGIONAL PLANS

This section discusses needs, presents wires alternatives and the current preferred wires solution for addressing the electrical supply needs for the Greater Ottawa Region. These needs are listed in table 6-1 and include needs previously identified in the IRRP for the Ottawa Sub-Region [1] and the NA for the Outer Ottawa Sub-Region [2] as well as the adequacy assessment carried out as part of the current RIP report.

7.1 Hawthorne Autotransformer T5 and T6

7.1.1 Description

Hawthorne TS is a major supply point for the city of Ottawa (Figure 7 -1). The station has four 230kV/115 kV autotransformers. Two of these autotransformers, T5 and T6, have lower ratings, with 225 MVA continuous and 256 MVA LTR, respectively. Under contingency conditions, i.e. one of the autotransformers out of service, the ratings of these two autotransformers are exceeded and this limits the supply to the 115 kV network from the 230 kV system. As the load continues to grow on the 115 kV network, this limitation needs to be addressed. This had been identified as a near term need in the Ottawa Sub-Region IRRP [1] and was included in the Ontario Power Authority's ("OPA", now part of IESO) June 2014 letter to Hydro One [5].

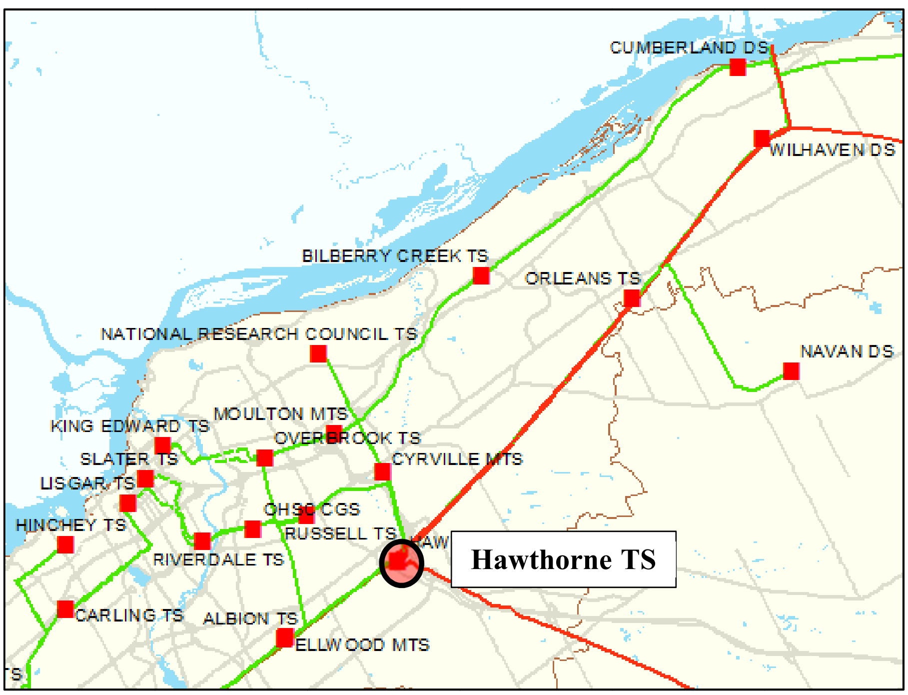

Figure 7-1 Hawthorne TS

7.1.2 Recommended Plan and Current Status

Hydro One has established a project to replace autotransformers T5 and T6 with new higher rated autotransformers. These autotransformers will have an LTR of at least 350 MVA. This investment will provide additional capacity and meet the needs of the area. It is expected that the project will be completed in 2018.

The cost of this project is expected to be $15.7 million. The project will be a transmission pool investment as the autotransformers provide supply to all customers in the Greater Ottawa Region.

7.2 Autotransformation Capacity and South West Area Station Capacity

7.2.1 Merivale TS Autotransformers T21 and T22/Hawthorne Autotransformer T9

Merivale TS has two 230 kV/115 kV autotransformers with an LTR station capacity of 312 MVA. The station is supplied from Hawthorne TS and from generators located west of Ottawa, along the Ottawa River and the Madawaska River. Merivale TS is shown in Figure 7-2.

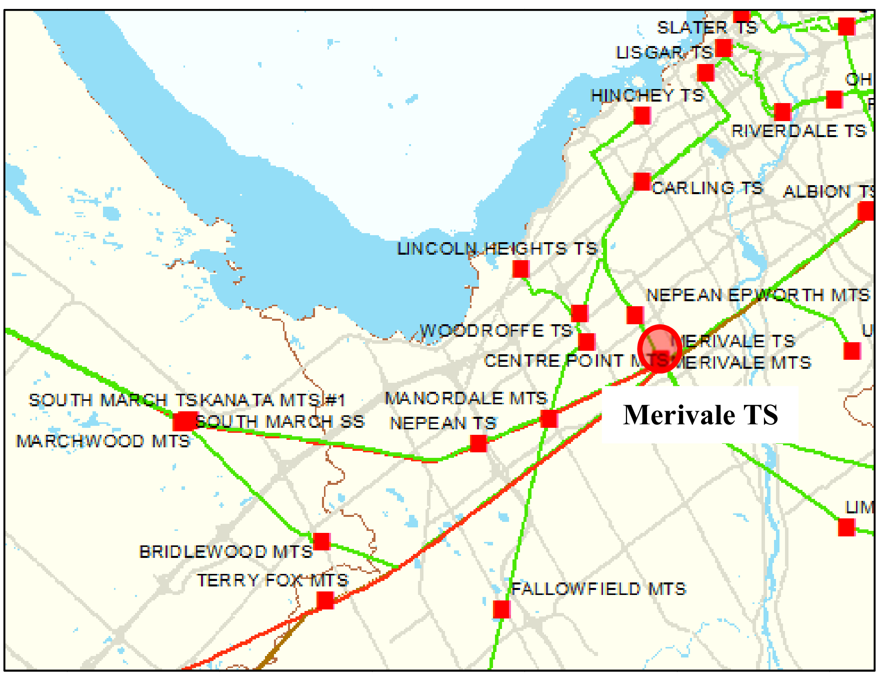

Figure 7-2 Merivale TS

The expected load growth provided by the LDCs and the minimum hydro generation assumption described in Section 6.2 causes the station capacity to be exceeded under contingency conditions by 2019. In addition, it is expected that autotransformers at Merivale TS and Hawthorne TS will reach their continuous loading limits of 250 MVA by 2024 and 2025. The exact timing of the autotransformer needs is dependent on the following factors:

- The South West area load forecast includes a proposed connection of a single large load increase coming into service in 2019.
- The need date is sensitive to generation at Stewartville GS, Barrett Chute GS and Chats Falls GS as its effect is to reduce the flow through the autotransformers.
- A potential solution to the need for additional supply capacity in the South West Area is a new 230 kV supply station which would remove some of the demand growth and existing load from the 115 kV network (see Section 7.2.2 for a complete description of this issue). This work would also help defer the need for additional autotransformer capacity at Merivale TS.

In order to address the Merivale TS autotransformer capacity concerns, additional 230/115 kV transformation capacity or load transfer from the 115 kV to the 230 kV system is required.

The provision of additional transformation capacity requires replacing the Merivale TS T22 autotransformer with a newer higher rated transformer in 2019 and adding a third autotransformer at the station in 2024. Alternatively a third transformer can be added at Merivale TS by 2019. To meet the required 2019 need date a decision on the autotransformer work is required by summer 2016.

Transferring load to the 230kV system requires establishing a new 230/27.6kV transformer station in the South West area to pick up some of the existing load and all of the new load growth. This is described in the following section.

7.2.2 Supply to South West Area – Line and Station Capacity

The South West area is served by Fallowfield MTS, Richmond MTS and Manotick DS connected to the 115kV circuit S7M out of Merivale TS. Load demand in the area is expected to increase by 52 MW in the next 10 years and both the line and station capacity are forecast to be exceeded by 2019.

The line limitation was identified in the OPA's June 2014 letter [5] to Hydro One. A section of the S7M circuit between the main line at STR R14-R15 JCT and Fallowfield Junction (see Figure 7-3 below) had a capacity of 420A. Hydro One review of the line capacity showed that the line rating was limited to respect safety clearances due to an underbuilt distribution feeder at Fallowfield MTS. This issue has been resolved with Hydro Ottawa carrying out the necessary work to lower the distribution feeder and increase the transmission line clearance. The line rating has been increased to 590A and is now adequate to meet forecast load until 2026.

Additional transformation capacity is required in the South West Area and both Fallowfield MTS and Richmond DS require load relief. Hydro Ottawa is planning for a capacity increase at Richmond DS and potentially a new station to relieve Fallowfield MTS in the Barrhaven area.

The IESO has initiated a public engagement process to gather community input for a preferred supply plan for the area including consideration of the potential for incremental CDM and DG resources and/or transmission expansion in the form of a new TS. The IRRP [1] recommended that given the required timeline, it would be beneficial for early transmission planning options to be started in parallel to the engagement process, prior to completing the integrated plan.

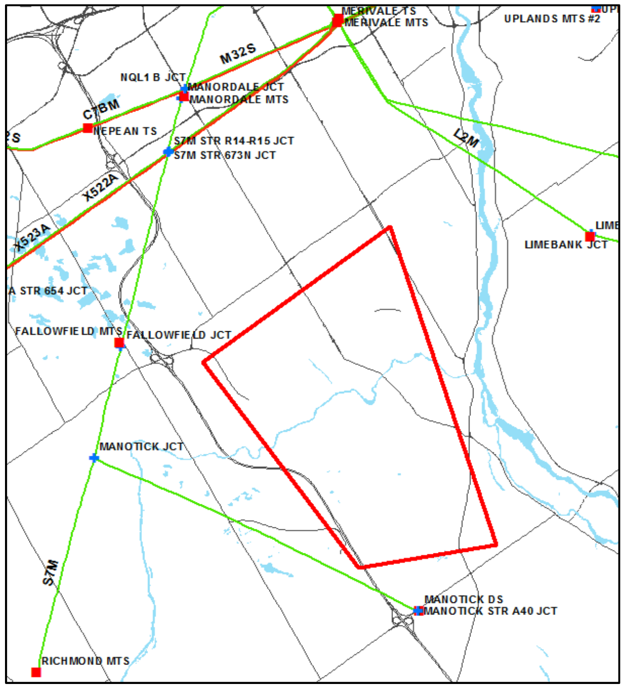

Figure 7-3 South West Area

At a high level, there are two main wire options to supply the South West area:

a) 115kV Option: Build a new 115/27.6kV transformer station and reinforce the existing 115 kV supply
b) 230kV option: Build a new 230/27.6kV transformer station and provide a new 230 kV transmission supply to the area.

The main advantage of the 115 kV option is that it defers the need for new transmission line until 2026. It however has a number of disadvantages: (a) loading will continue to increase on the 115kV system necessitating additional transformation capacity a Merivale TS by 2019 and Hawthorne TS by 2025, (b) all area stations remain on a single line supply until new transmission is built, and (c) the new 115 kV supply will provide less incremental capacity for the future.

The 230 kV option has the advantage of providing relief for the 230/115 kV autotransformers at Merivale TS and Hawthorne TS as well as provide more capacity to serve the area load. It also improves the area reliability by providing a second source of supply. The disadvantage is that transmission reinforcement will be required by 2019 and decision needs to be made as soon as possible.

The RIP has considered two options as examples for providing 230 kV supply to the area. Both examples consider building new double circuit 230 kV lines on existing Right of Way ("ROW") in accordance with the provincial government policy to maximize ROW use. The two options are described below (also refer to Figure 7-3).

- *S7M Based Option - Rebuild S7M as a double circuit 230 kV line.*

  This option would require rebuilding the existing single circuit115 kV circuit S7M tap to Fallowfield MTS as a new double circuit 230 kV line. The line would extend from the S7M STR R14-R15 JCT (on the main line) to Manotick Jct. Depending on the station location, a part of S7M from Manotick JCT to Manotick DS would also have to be rebuilt for a total line rebuild of up to 15.5 km. One circuit would be operated at 115 kV and continue to supply Fallowfield MTS, Richmond DS and Manotick DS. The other circuit would be tapped off the 230 kV circuit M29C which is adjacent to S7M at STR R14-R15 JCT and will be used to supply the new Hydro Ottawa station. This option may require sections of the existing ROW to be widened to accommodate the 230 kV circuits. Additional real estate rights will have to be obtained. EA and OEB Leave to Construct (Section 92) approvals will also be required.

- *L2M Based Option - Rebuild L2M as a double circuit 230 kV Line*

  This option would require rebuilding the existing 115 kV circuit L2M from Merivale TS to past Limebank MTS as a new double circuit 230 kV line. This section of the line would be constructed using the existing L2M ROW for a distance of 8.5 km. A new 6-8 km long ROW would need to be acquired going west from the L2M ROW to bring the transmission line to the load area, crossing the Rideau River. One circuit on the new line would remain L2M and be operated at 115 kV. The other circuit would connect to circuit M32S at Merivale TS and be operated at 230 kV. The new station will be supplied from the 230 kV circuit.

7.2.3 Recommended Plan and Current Status

The needs for autotransformation capacity and a new station in south west are interrelated. Further analysis is required to determine the impact of the 230 kV supply options for the new south west station on the Merivale TS and Hawthorne TS autotransformers. The planning assessment will consider whether a 115kV supply to the new station in combination with the addition of an autotransformer at Merivale is more cost effective than a 230kV supply.

The IESO is currently carrying out community engagement activities in the Ottawa region. The Working Group will be discussing the supply options for the South West area in conjunction with the autotransformer upgrade work at Merivale TS and expect to recommend a preferred plan for the area by summer 2016.

7.3 115 kV Transmission Circuit A4K Supply Capacity

7.3.1 Description

Circuit A4K is a 115 kV circuit supplying four downtown stations: Overbrook TS, King Edward TS, Cyrville MTS and Moulton MTS. Loading on the A4K this circuit can exceed its rating under peak load conditions for loss of 115 kV circuit A5RK. This need was identified as a near term need in the Ottawa Sub-Region IRRP [1] and included in the OPA's June 2014 letter to Hydro One [5]. In this letter, the preferred plan to relieve circuit A4K is outlined. This plan consists of rebuilding an approximately 2 km long section of single circuit 115 kV circuit A5RK between Overbrook TS to Riverdale Jct. as a double circuit line (see Figure 7-4). One of the circuits would remain A5RK and the other would be tapped to circuit A6R. Overbrook TS will be reconfigured to be supplied from circuits A5RK/A6R instead A4K/A5RK. This reconfiguration would remove Overbrook TS load from 115 kV circuit A4K and eliminate the overloading on A4K for the loss of A5RK.

7.3.2 Current Status

Hydro One has initiated the development work for this line rebuild. The project is currently in the engineering and estimating phase. The project is not expected to require Leave to Construct (Section 92) approval, but will require Environmental Assessment ("EA") approvals.

The project is expected to be in service by spring 2019 and preliminary estimates suggest the cost to be approximately $9 million to $11 million. This work will be part of the Line Connection pool and costs will be recovered from the rate revenue and/or customer capital contribution in accordance with the TSC. As a result, the LDC may be required to make a capital contribution.

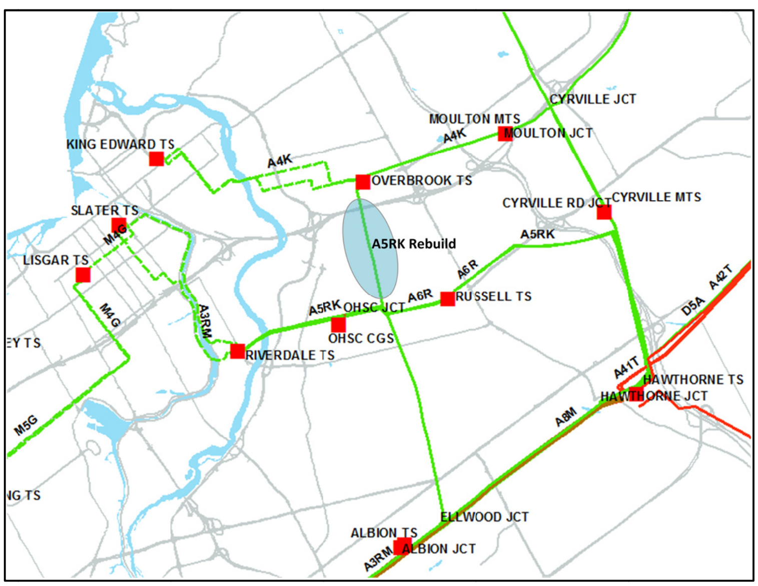

Figure 7-4 Option to Rebuild A5RK as Double-Circuit 115 kV Line

In the interim, Hydro One and Hydro Ottawa have operational mitigating measures to manage the overload on 115 kV circuit A4K if it becomes of concern before Hydro One has completed the line rebuild work. These measures include the transfer of Cyrville MTS to single supply from circuit A2 only by opening the A4K breaker at Cyrville MTS, and the transfer of some load from Moulton MTS to other stations in the area.

7.4 Station Capacity – Ottawa Centre 115 kV Area

7.4.1 Description

The Ottawa Center 115 kV area covers the City of Ottawa downtown district and extends from the Ottawa River in the north to Smyth Road in the south as shown in Figure 7-5 below. It is served by six 115/13.2 kV step-down transformer stations – King Edward TS, Lisgar TS, Overbrook TS, Riverdale TS, Russell TS and Slater TS. Most of the area stations are at or near capacity. Even with the Overbrook upgrade work now underway additional load meeting capability is forecast to be required by 2018 as shown in Table 6.3.

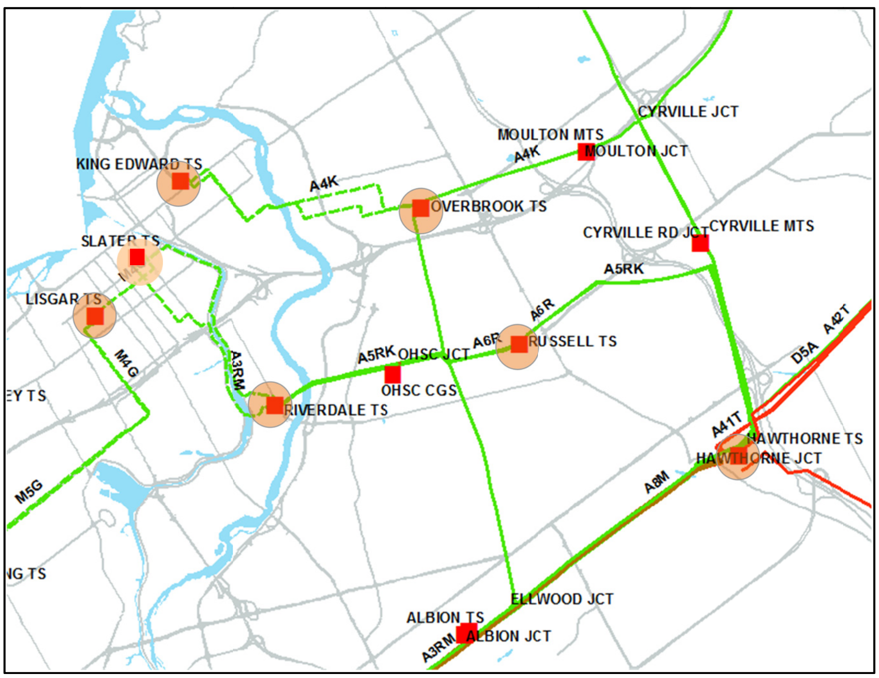

Figure 7-5 Downtown Ottawa Stations

7.4.2 Recommended Plan and Current Status

The existing step-down stations in the area are equipped with older 45/75 MVA transformers which have a LTR of between 70-80 MW. The preferred alternative to provide additional transformation capacity in the area is to replace these units with larger sized 100 MVA units where possible with an LTR of up to 130 MW.

During this regional planning cycle, the Working Group participants agreed to take advantage of transformer replacements necessitated by end-of-life considerations as this was the lowest cost and most practical option to provide additional capacity. The alternative of building a new station to provide capacity was ruled out because of the high cost and the difficulty in acquiring an appropriate site.

Upgrade of the end of life transformers at Overbrook TS is currently underway. In the future, the Working Group will continue to look for opportunities to upgrade based on end-of-life considerations of transformers. Hydro One will keep the Working Group informed of these opportunities. In addition, load transfers are also recommended to utilize available capacity at adjacent stations.

7.4.2.1 Russell TS and Riverdale TS

The loading on these stations will be kept within limits by Hydro Ottawa building feeder ties to transfer excess loads to other area stations. This will keep the loading on the transformers at these stations within their rating. A high level cost estimate of Hydro Ottawa's distribution work is $2 million.

7.4.2.2 Overbrook TS

Hydro One had identified that the step-down transformers at Overbrook TS were approaching end-of-life and consideration was therefore given to upgrading the transformers at the station. Accordingly Overbrook TS transformers are being replaced with larger sized units which will increase the station capacity from 72 MW to 130 MW. The work is underway and planned to be completed in Q2 2018. The incremental cost of upgrading to larger transformers is estimated to be $1.1 million. The cost of upgrading is expected to be recovered from incremental rate revenue in accordance with the TSC. Based on current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.4.2.3 Lisgar TS

Lisgar TS has two 75 MVA transformers. To meet the forecast load requirement additional transformation capacity is required in the Central 115kV area. Hydro Ottawa has therefore asked that the Lisgar TS transformers be replaced with larger 100 MVA units. The cost of the work is estimated to be about $14 million and will be recovered from rate revenue and customer capital contribution in accordance with the TSC. The target in-service date is Q4 2017.

7.4.2.4 King Edward TS

The capacity at King Edward TS is 71 MW. By replacing the limiting transformer T4 and additional low voltage ("LV") components such as circuit breakers and cable, a higher capacity of up to 130 MW can be achieved at King Edward TS.

Considering the Overbrook TS and Lisgar TS upgrades, adequate capacity will be available in the Center area until 2021. After discussion with Hydro Ottawa, the King Edward TS transformer upgrade work is tentatively scheduled for an in-service date of 2021. The project cost is estimated to be about $12M and will be recovered from rate revenue and customer capital contribution in accordance with the TSC.

7.5 Station Capacity - Hawthorne TS 44kV

Hawthorne TS has two 50/83 MVA, 230/44kV transformers with an LTR of 89 MW. Additional 44kV capacity is required at the station. Hydro One identified that the step- down transformers at Hawthorne TS were approaching end-of-life and needed to be replaced. The lowest cost alternative to provide this additional capacity was to take advantage of the transformer replacement work and install larger 75/125 MVA transformers with an LTR of 153 MW. This work is currently underway and planned to be completed by summer 2019.

Additional 44kV feeder positions will be required to utilize this increased capacity. These feeders will be added as required.

The incremental cost of upgrading to larger transformers is estimated to be approximately $1.1 million. Feeder position costs have not been estimated at this time. Incremental transformer costs and the feeder costs will be recovered in accordance with the TSC. Based on the current forecast Hydro Ottawa is not expected to pay any capital contribution for this project.

7.6 Bilberry Creek TS End of Life

7.6.1 Description

Bilberry Creek TS is a 115/27.6 kV step-down transformer in East Ottawa, supplying up to 85 MW of load customers to both Hydro Ottawa and Hydro One Distribution. The station was built in 1964 and a number of its key components have been identified for replacement by Hydro One. This station's refurbishment work is to be complete by 2023. A decision will be required by 2020 on whether to refurbish the station and keep the load on the 115 kV system or to retire the station and move the load over to the 230 kV system by supplying it from the newly built Orleans TS.

A Local Plan [3] carried out by Hydro One shows that the two options are similar in costs. The retirement option however, may be more attractive particularly if 115 kV load growth rate is high in the Ottawa Center area. The retirement option will reduce the loading of the 230 kV/115 kV autotransformers at Hawthorne TS and Merivale TS and make it available for the Ottawa Center 115 kV load. Figure 7-6 shows the area under consideration.

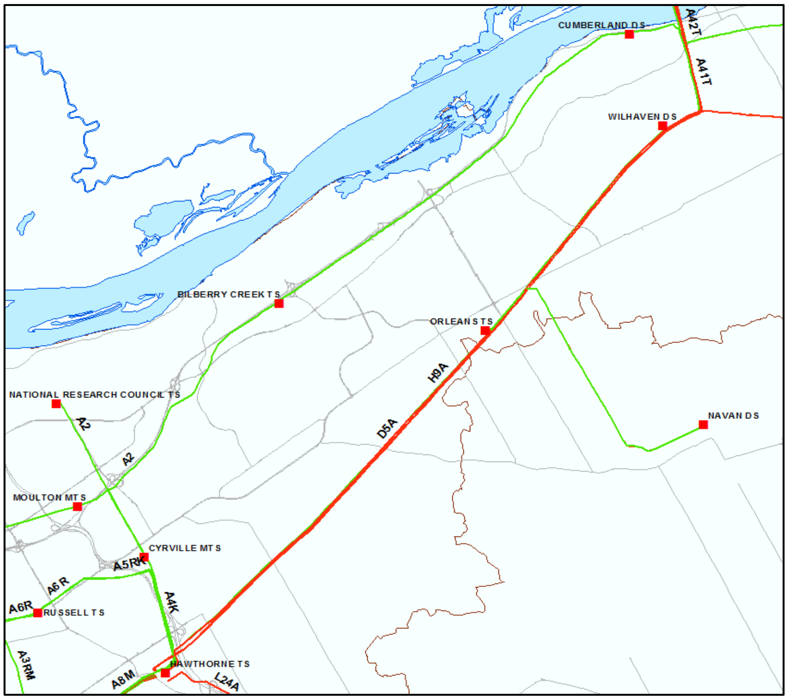

Figure 7-6 Bilberry Creek TS and the East Ottawa Area

7.6.2 Recommended Plan and Current Status

The two alternatives are very similar in cost and each has its own pros and cons. The refurbishment option minimizes work on the distribution system, but leaves the load on the 115kV system and with lower overall capacity to meet long term growth. The retirement option moves Bilberry Creek load to the 230kV system with higher long term load meeting capability but involves relocating distribution feeders from Bilberry Creek TS to Orleans TS.

The Working Group has recommended that a decision on Bilberry Creek refurbishment be deferred to the next regional planning cycle as there is still sufficient time to make an investment decision.

7.7 Almonte TS and Terry Fox TS Reliability

7.7.1 Description

Almonte TS and Terry Fox MTS are supplied from the 319 km long 230kV circuit M29C, see Figure 7-7. Due to the long length of the line the exposure to outages is high. The line has averaged approximately 6-7 interruptions per year over the last 10 years. With Terry Fox MTS coming into service in 2013, concerns were expressed about the number of outages that would be seen by the station. This issue was identified in the Ottawa Sub-Region IRRP [1] and the OPA's June 2014 letter [5].

7.7.2 Recommended Plan and Current Status

Hydro One had initiated a project in 2012 to install a 230 kV circuit breaker at Almonte TS. This breaker would sectionalize the M29C line into two sections: E29C – 281 km Cherrywood TS to Almonte TS; and E34M – 38 km Almonte TS to Merivale TS. This breaker will help with the number of interruptions at Almonte TS and Terry Fox MTS by eliminating outages due to the Almonte TS x Cherrywood section of the circuit.

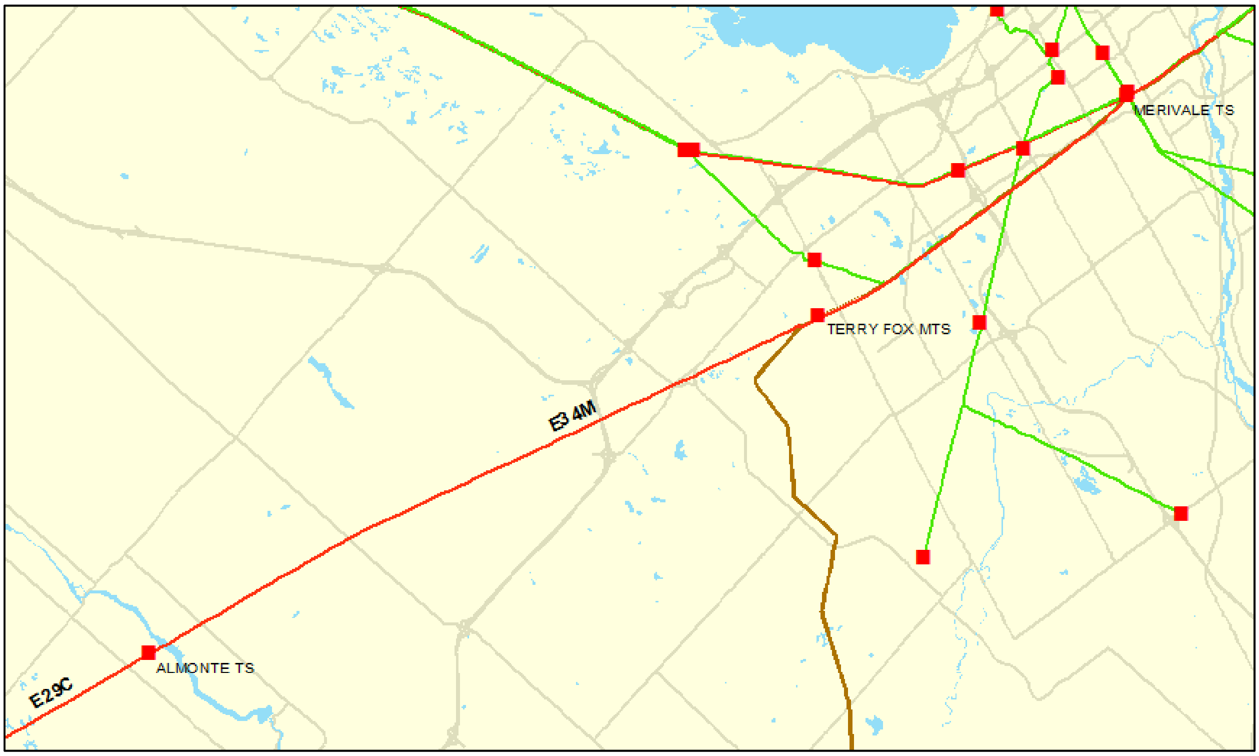

Figure 7-7 Lines E29C and E34M (M29C). In-Line Breaker at Almonte TS.

The total cost of this project is estimated to be $4.7 million and the project is scheduled to be completed by December 2015.

A second supply from Merivale TS to Terry Fox MTS was previously considered as an option to improve reliability. However it was decided to install the in-line breaker at Almonte TS since it was the cost effective and provided reliability improvement to both Almonte TS and Terry Fox MTS.

It should be noted that the Terry Fox TS is operated with the LV bus tie open. This arrangement has the disadvantage that in case of a transformer outage, the load connected to that transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side. A second supply to Terry Fox MTS can still be considered to address this issue as the load increases as part of a longer term supply plan. This will continue to be reviewed.

7.8 Orleans TS Reliability

7.8.1 Description

Orleans TS is a new station Hydro One built in East Ottawa to provide additional transformation capability and improve supply reliability for Hydro One Distribution customers connected to the 115 kV circuit H9A.

The Orleans TS is built adjacent to the double circuit H9A/D5A line about 10 km from Hawthorne TS and has one step-down transformer station supplied from 230 kV circuit D5A and the second step-down transformer supplied from the 115 kV circuit H9A. The station is operated with the LV bus tie open so as to avoid any power flow between the 230 kV and 115 kV systems through the station transformers. This arrangement has the disadvantage that in case of a circuit or transformer outage, the load connected to that circuit or transformer will be lost momentarily before the bus tie is closed to allow all loads to be supplied from the other side.

7.8.2 Recommended Plan and Current Status

Orleans TS has greatly improved the reliability of customers previous supplied from Wilhaven DS and Navan DS connected to 115kV circuit H9A. The customers experienced sustained interruptions every time circuit H9A had an outage. With the Orleans TS LV bus tie arrangement customer are exposed to a momentary interruption only as the load is picked up by closing the bus tie. This arrangement was accepted as a cost effective alternative to building 10 km of transmission line between Hawthorne TS and Orleans TS to provide a dual supply to Orleans TS.

Depending on the decision taken for Bilberry Creek TS described in section 7.6, Orleans TS could be converted to a 230 kV station and the LV bus tie closed. This option would be preferred if Bilberry Creek TS is recommended to be retired. If Bilberry Creek TS is refurbished then the plan will see Orleans TS continued operation with two different voltage supplies.

The Working Group recommendation is to monitor the performance of Orleans TS to see if mitigation measures are warranted. The Working Group will further review this issue in the next regional planning cycle as part of the Bilberry TS retirement study. No further action is required at this time.

7.9 Load Restoration for the Loss of B5D/D5A

7.9.1 Description and Current Status

The NA report for the Outer Ottawa Sub-Region [2] identified that the combined loss of circuits D5A and B5D would result in a load loss of up to 174 MW. The stations considered in this analysis are St Isidore TS, Longueil TS, and Ivaco CTS. Orleans TS is also supplied by D5A however; its second supply is H9A and is not considered for the combined loss of D5A/B5D. As indicated in ORTAC, any load lost above 150 MW must be restored within 4 hours and all load be restored within 8 hours.

A LP report [4] carried out by Hydro One shows that historically, the coincidental occurrence of forced sustained outages of B5D and D5A are rare and in all cases one of the circuits was restored in less than 4 hours as per ORTAC. The report concludes that no further action is required at this time.

7.10 Load Loss for S7M Contingency

7.10.1 Description and Current Status

Circuit S7M is the single supply for the following stations: Bridlewood MTS, Fallowfield MTS, Manotick DS, and Richmond DS. The combined load at these four stations is expected to exceed 150 MW by 2022. The ORTAC requires that not more than 150MW of load may be interrupted by configuration. However, given that the 150 MW limit is anticipated in the long term, no action is required at this time.

7.11 Voltage Regulation on 115kV Circuit 79M1

7.11.1 Description and Current Status

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS. The NA for Outer Ottawa Sub-Region [2] identified that the voltage at Hawkesbury TS will approach operating limits under peak load and contingency conditions by 2023.

As mentioned in the Outer Ottawa Sub-Region NA report [2], Hydro One monitors the status of the network. Given the timing for this need, this will be reassessed during the next regional planning cycle.

7.12 Voltage at Stewartville TS

7.12.1 Description and Current Status

The load on the Stewartville TS is expected to increase significantly as a result of the connection of a large utility load forecasted for 2018. This load may require reactive support to help maintain the voltages within limits during peak load conditions and no generation at Stewartville GS.

A connection impact assessment will be undertaken by Hydro One as part of connecting the utility load. Any requirements to connect the load, including reactive power support, will be outlined in the document.

7.13 Voltage Drop at Terry Fox MTS for E34M open at the Merivale End

7.13.1 Description

Circuit E34M/E29C (new name for circuit M29C following the installation of a breaker at Almonte TS) is a 319 km line between Cherrywood TS in Pickering, and Merivale TS in Ottawa. If the circuit E34M (Almonte-Merivale) is open at the Merivale end, Terry Fox MTS and Almonte TS will be supplied radially by Cherrywood TS. Given the distance between the Greater Ottawa stations and Cherrywood TS, voltages are lower than acceptable limits during normal and peak load periods and only load of up to 25 MW can be supplied with acceptable voltage. The 2012 IESO System Impact Assessment ("SIA") recommended the installation of 20 MVARs of capacitor banks at Terry Fox MTS to meet a peak load of up to 48 MW.

7.13.2 Recommended Plan and Current Status

It is recommended that Hydro Ottawa install 20 MVARs of capacitor banks at Terry Fox MTS. This should be adequate for the near term.

Terry Fox MTS is part of the Ottawa Area under voltage load rejection scheme ("UVLS"). This scheme is designed to shed the station load if the 230 kV supply voltage to the station drops below 204 kV when it is activated. Currently the scheme is only armed when the entire Ottawa Area UVLS is armed. It is proposed to modify the scheme so that it can be selectively armed when loading levels are higher than 48MW and under conditions that may result in a circuit M29C line end open at Merivale TS.

Historically the probability of this line end open occurring is low and it would typically occur while terminal maintenance is done at Merivale. By scheduling maintenance during off peak periods, the impact can be significantly reduced. No mitigation measures are therefore recommended at this time. Hydro One and Hydro Ottawa will be monitoring the system performance and the matter will be reconsidered in the next planning cycle based on operating experience.

7.14 Low Power Factor at Almonte TS

7.14.1 Description and Current Status

The IESO's SIA for Almonte T3 replacement noted a low power factor at Almonte TS. This potential issue was also reported in the Outer Ottawa Sub-Region NA report [2].

Hydro One has reviewed the power factor at Almonte TS. The station power factor varies from 0.89 to 0.95 at the LV bus which translates into approximately 0.86 to 0.92 on the HV bus. Part of the reason for the lower power factor is that the station has 29 MW of DG which generally operates at unity power factor. The generation reduces the net power in MW seen at the metering point. This reduction in power results in a lower power factor as seen from the HV bus since the generation does not offset the reactive power demand of the station. No action is required as the load power factor without DG is within the acceptable limits.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER OTTAWA 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 near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near term needs are summarized in the Table 8-1 below.

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 8-2.

No long term needs were identified at this time. As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years.. The region will continue to be monitored and 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.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost
1	Almonte TS: addition of breaker to sectionalize line M29C	Construction in the final stages	Hydro One	Dec. 2015	$4.7M
2	Russell TS and Riverdale TS: construction of feeder ties to allow extra load transfers	LDC will lead this work	Hydro Ottawa	2017-2020	$2.0M
3	Lisgar TS: replacement of transformers T1 and T2	Transmitter to carry out this work	Hydro One	Dec. 2017	$13.9M
4	Hawthorne TS: replacement of autotransformers T5 and T6	Transmitter to carry out this work	Hydro One	May 2018	$15.7M
5	Overbrook TS: replacement of transformers T3 and T4	Transmitter to carry out this work	Hydro One	June 2018	$1.1M(1)
6	A6R: additional tap to offload A4K	Transmitter to carry out this work	Hydro One	June 2019	$9-11M
7	Hawthorne TS: replacement of transformers T7 and T8 and add one 44kV feeder position	Transmitter to carry out this work	Hydro One	Oct. 2019	$1.1M(2)
8	New South West Station And Merivale 230/115kV Transformation Capacity	IESO and Hydro Ottawa leading consultation	IESO/Hydro Ottawa	2020	--- (3)
9	King Edward TS: Replace Transformer T4	Transmitter to carry out this work	Hydro One	June 2021	$12M

(1) Incremental cost for larger transformer only.
(2) Incremental cost for larger transformer only. Feeder costs have not been estimated at this time.
(3) The Working Group expects to make a final recommendation on this plan by early 2016.

Table 8-2 List of Mid-Term Needs to be Reviewed in Next Regional Planning Cycle

No.	Need	Timing
1	Bilberry Creek TS - Refurbishment	2023
2	Orleans TS - Reliability	2023[1]
3	79M1 Circuit – Voltage regulation	2023

(1) Performance will be monitored to see if mitigation measures are warranted. Need will be reviewed along with Bilberry Creek TS refurbishment.

9. REFERENCES

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[3]. Hydro One, "Local Planning Report – Supply to East Ottawa Area", 26 November 2015.
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[4]. Hydro One, "Local Planning Report - B5D-D5A Load Restoration", 22 September 2015.
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[5]. Hydro One, "OPA Letter – Ottawa Area Regional Planning", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Letter%20to%20H1%20RE%20Ottawa.pdf

[6]. Independent Electricity System Operator, "Review of Ontario Interties", 14 October 2014.
http://www.ieso.ca/Documents/IntertieReport-20141014.pdf

APPENDIX A: STATIONS IN THE GREATER OTTAWA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	M29C (E34M, E29C)
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Carling TS	115	M4G, M5G
7	Centrepoint MTS	115	C7BM
8	Clarence DS	115	79M1
9	Cumberland DS	115	H9A
10	Cyrville MTS	115	A2, A4K
11	Ellwood TS	230	M30A, M31A
12	Epworth MTS	115	M4G, M5G
13	Fallowfield DS	115	S7M
14	Greely DS	115	M1R
15	Hawkesbury MTS	115	79M1
16	Hawthorne	230	-
18	Ivaco	230	D5A
19	Kanata MTS	230	C3S, M32S
20	King Edward TS	115	A4K, A5RK
21	Limebank MTS	115	L2M
22	Lincoln Heights TS	115	C7BM, F10MV
23	Lisgar TS	115	M4G, M5G
24	Longueuil TS	115	B5D, D5A
25	Manordale MTS	115	C7BM
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M
29	Merivale TS	115	-
30	Moulton MTS	115	A4RK
31	Nation Research TS	115	A2
32	National Aeronautical CTS	115	A8M
33	Navan DS	115	H9A
34	Nepean TS	115	M32S
35	Orleans TS	230 & 115	D5A, H9A
36	Overbrook TS	115	A4K, A5RK
38	Riverdale TS	115	A3RM, A5RK
39	Rockland DS	115	79M1
40	Rockland East DS	115	79M1

41	Russell DS	115	M1R
42	Russell TS	115	A5RK, A6R
43	Slater TS	115	A3RM, A5RK, M4G
44	South Gloucester DS	115	M1R
45	South March	230	C3S, M32S
46	St. Isidore TS	230	B5D, D5A
47	Stewartville TS	115	W3B, W6CS
48	Terry Fox MTS	230	M29C (E34M)
49	Uplands MTS	115	A8M
50	Wendover DS	115	79M1
51	Wilhaven DS	115	H9A
52	Woodroffe TS	115	C7BM, F10MV

APPENDIX B: TRANSMISSION LINES IN THE GREATER OTTAWA REGION

Location	Circuit Designations	Voltage (kV)
Hawthorne TS – Merivale TS	M30A, M31A	230
Hawthorne TS – St Isidore TS	D5A	230
Merivale TS – Almonte TS	E34C (formally M29C)	230
Merivale TS – South March TS	M32S	230
South March SS – Chats Falls SS	C3S	230
Hawthorne TS – Bilberry Creek TS	A2	115
Hawthorne TS - Merivale TS	A3RM, A8M	115
Hawthorne TS – Overbrook TS	A4K, A5RK	115
Hawthorne TS – Riverdale TS	A6R	115
Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
Merivale TS – Chats Falls TS	C7BM	115
Merivale TS – Hinchey TS	F10MV, V12M	115
Merivale TS – Lisgar TS	M4G, M5G	115
Merivale TS – South March SS	S7M	115
Stewartville TS – South March SS	W6CS	115
Stewartville TS – Barrett Chute TS	W3B	115

APPENDIX C: DISTRIBUTORS IN THE GREATER OTTAWA REGION

Distributor Name	Station Name	Connection Type
Hydro 2000	Longueuil TS	Dx
Hydro Hawkesbury	Hawkesbury MTS	Tx
	Longueil TS	Dx
Hydro One	Almonte TS	Tx
	Arnprior TS	Tx
	Bilberry Creek TS	Tx
	Clarence DS	Tx
	Cumberland DS	Tx
	Greely DS	Tx
	Hawthorne TS	Tx
	Longueil TS	Tx
	Manotick DS	Tx
	Marionville DS	Tx
	Navan DS	Tx
	Orleans TS	Tx
	Rockland DS	Tx
	Rockland East DS	Tx
	Russell DS	Tx
	South Gloucester DS	Tx
	St Isidore TS	Tx
	Stewartville TS	Tx
	Wilhaven DS	Tx
Hydro Ottawa	Albion TS	Tx
	Almonte TS	Dx
	Bilberry Creek TS	Tx
	Bridlewood MTS	Tx
	Carling TS	Tx
	Centrepoint MTS	Tx
	Cyrville MTS	Tx
	Ellwood MTS	Tx
	Nepean Epworth MTS	Tx
	Fallowfield DS	Tx
	Hawthorne TS	Dx, Tx
	Hinchey TS	Tx
	Kanata MTS	Tx
	King Edward TS	Tx

Hydro Ottawa	Limebank MTS	Tx
	Lincoln Heights TS	Tx
	Lisgar TS	Tx
	Manordale MTS	Tx
	Marchwood MTS	Tx
	Moulton MTS	Tx
	Merivale MTS	Tx
	Nepean TS	Tx
	Orleans TS	Tx
	Overbrook TS	Tx
	Richmond MTS	Tx
	Riverdale TS	Tx
	Russell TS	Tx
	Slater TS	Tx
	South Gloucester DS	Dx
	South March TS	Dx, Tx
	St Isidore TS	Dx
	Terry Fox MTS	Tx
	Upland MTS	Tx
	Woodroffe TS	Tx
Ottawa River Power Corporation	Almonte TS	Dx
Renfrew Hydro	Stewartville TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1 Stations Coincident Load Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	70	67	69	75	75	75	76	77	78	77	77	78	77	77
	Lisgar TS	75	64	67	71	74	74	75	75	87	88	90	90	90	89	89
	Overbrook TS	130	85	91	94	100	101	102	108	110	111	112	113	114	115	116
	Riverdale TS	105	102	99	102	111	112	112	114	118	119	120	121	123	123	124
	Russell TS	69	61	63	65	73	73	73	73	73	73	73	73	73	73	73
	Slater TS	118	106	113	114	116	115	114	114	113	112	112	111	110	110	110
	Total	**569**	**488**	**501**	**515**	**549**	**549**	**550**	**559**	**578**	**581**	**584**	**586**	**588**	**589**	**590**
Center 230	Albion	88	71	72	73	73	73	73	74	74	75	75	76	77	77	77
	Ellwood TS	59	27	28	28	28	28	28	28	28	28	28	28	28	29	29
	Hawthorne	153	107	117	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**206**	**217**	**221**	**225**	**227**	**229**	**234**	**239**	**239**	**243**	**243**	**244**	**243**	**243**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	5	6	6	6	6	6	6	6	6	6	6	6	7	7
	Cyrville MTS	59	24	30	35	35	37	38	40	42	44	44	44	44	44	44
	Moulton MTS	34	31	32	32	32	32	32	32	33	33	33	33	34	34	34
	Nation Research TS	25	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	6	6	6	6	6	6	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	49	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**221**	**193**	**201**	**202**	**205**	**208**	**210**	**215**	**221**	**224**	**226**	**228**	**232**	**237**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	51	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	17	18	18	18	18	18	18	18	18	18	19	19	19	19
	Limebank MTS	68	44	47	49	52	54	56	59	64	70	76	82	89	88	88
	Marionville DS	28	13	14	14	14	14	14	14	14	14	14	14	15	15	15
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	3	3	3	3	3	3	3	3	3	3	3	3	3	4
	South Gloucester DS	8	4	4	4	4	4	4	4	4	4	5	5	5	5	5
	Uplands MTS	30	25	26	26	27	27	27	27	28	29	29	30	30	30	30
	Total	**182**	**109**	**112**	**115**	**118**	**121**	**123**	**126**	**133**	**140**	**147**	**154**	**161**	**161**	**161**
South West 115	Fallowfield DS	48	36	39	38	41	49	51	54	58	61	67	71	76	82	89
	Manotick DS	17	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Richmond DS	5	9	10	11	13	31	34	36	36	37	38	39	38	38	38
	Total	**70**	**52**	**56**	**56**	**61**	**87**	**92**	**97**	**101**	**106**	**112**	**118**	**122**	**127**	**134**

West 115	Bridlewood MTS	37	22	22	23	22	22	22	23	39	39	39	39	39	39	39
	Carling TS	93	82	83	84	85	86	86	87	93	95	96	98	99	100	102
	Centrepoint MTS	35	17	17	17	17	17	16	16	16	16	16	16	16	16	16
	Epworth	25	15	15	16	16	16	16	15	15	15	15	15	15	15	15
	Hinchey TS	77	58	60	62	66	68	70	72	67	71	75	79	83	87	90
	Lincoln Heights TS	71	45	45	45	45	44	44	44	49	49	49	48	48	48	48
	Manordale MTS	22	11	11	11	11	11	11	11	11	11	11	11	10	10	10
	Marchwood MTS	34	34	34	34	35	34	34	34	35	34	35	35	35	36	37
	Merivale TS	18	14	14	13	15	15	15	15	16	17	19	20	20	19	19
	Woodroffe TS	92	39	40	41	42	42	43	43	53	54	55	56	56	57	58
	Total	**504**	**336**	**340**	**346**	**353**	**355**	**356**	**362**	**395**	**402**	**410**	**417**	**421**	**427**	**434**
West 230	Kanata MTS	55	46	47	47	47	47	46	47	47	48	48	48	48	48	48
	Nepean TS	144	145	144	143	143	141	139	138	136	134	132	130	128	127	127
	South March	109	116	110	115	119	123	126	131	123	104	104	104	104	103	104
	Terry Fox MTS	90	39	50	78	83	65	65	64	63	63	62	61	60	60	60
	Total	**397**	**346**	**351**	**383**	**391**	**376**	**376**	**380**	**370**	**349**	**345**	**343**	**340**	**337**	**338**
Outer East 115	Clarence DS	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Hawkesbury MTS	18	15	15	15	15	15	15	15	15	16	16	16	16	16	16
	Rockland DS	9	8	8	8	8	8	8	9	9	9	9	9	9	9	9
	Rockland East DS	15	12	12	12	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	12	12	12	12	12	12	12	14	14	14	14	13	13	13
	Total	**80**	**49**	**49**	**50**	**50**	**50**	**50**	**51**	**55**	**55**	**55**	**55**	**55**	**55**	**56**
Outer East 230	Ivaco	100	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	Longueuil TS	98	31	31	31	31	30	30	30	30	30	30	30	30	30	30
	St. Isidore TS	52	35	35	36	35	35	35	35	35	35	35	35	35	35	35
	Total	**249**	**106**	**106**	**106**	**106**	**106**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**
Outer West 115	Arnprior TS	51	36	36	36	36	35	35	35	34	34	34	34	34	34	34
	Stewartville TS	55	30	30	30	46	46	45	45	45	45	45	45	45	45	45
	Total	**106**	**66**	**66**	**66**	**82**	**81**	**80**	**80**	**79**	**79**	**79**	**79**	**79**	**79**	**79**
Outer West 230	Almonte TS	100	35	34	34	34	34	33	33	33	33	33	33	33	33	33
	Total	**100**	**35**	**34**	**34**	**34**	**34**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**
Regional Total		**2948**	**2013**	**2069**	**2140**	**2219**	**2238**	**2249**	**2285**	**2352**	**2360**	**2388**	**2411**	**2430**	**2445**	**2468**

Table D-2 Stations Non Coincident Forecast (MW)

Area	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Center 115	King Edward TS	71	88	84	87	93	93	93	94	96	97	97	96	97	96	96
	Lisgar TS	75	67	70	74	78	78	78	79	91	92	94	94	94	93	93
	Overbrook TS	130	84	91	93	99	100	102	107	109	110	111	112	113	114	115
	Riverdale TS	105	78	76	78	84	85	86	87	90	91	92	93	93	94	95
	Russell TS	69	74	77	80	90	89	89	89	89	89	89	90	90	90	90
	Slater TS	118	125	133	134	136	135	134	134	133	132	131	131	130	129	129
	Total	**569**	**516**	**530**	**546**	**580**	**581**	**581**	**590**	**608**	**612**	**614**	**615**	**617**	**617**	**619**
Center 230	Albion	88	77	79	80	80	80	80	80	81	82	82	83	84	84	84
	Ellwood TS	59	43	43	44	44	44	43	44	44	44	44	44	45	45	45
	Hawthorne	153	103	115	120	124	126	128	132	137	136	140	138	139	138	138
	Total	**300**	**223**	**238**	**243**	**248**	**250**	**251**	**256**	**262**	**262**	**266**	**266**	**267**	**266**	**267**
East 115	Bilberry Creek TS	85	87	54	54	54	54	54	54	54	55	55	55	55	55	56
	Cumberland DS	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Cyrville MTS	59	25	31	37	37	39	40	42	44	47	47	47	47	47	47
	Moulton MTS	34	40	40	40	41	40	40	41	41	41	42	42	42	43	43
	Nation Research TS	25	18	19	19	19	19	18	19	19	19	18	18	18	18	18
	Navan DS	15	6	6	6	6	6	5	5	5	5	5	5	5	5	5
	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Wilhaven DS	58	53	4	5	5	6	6	6	7	10	11	12	12	14	16
	Total	**340**	**231**	**200**	**208**	**209**	**212**	**215**	**217**	**223**	**229**	**231**	**234**	**236**	**240**	**244**
East 230	Orleans TS	51	0	45	46	46	47	48	48	50	50	51	52	54	55	57
	Total	**51**	**0**	**45**	**46**	**46**	**47**	**48**	**48**	**50**	**50**	**51**	**52**	**54**	**55**	**57**
South 115	Greely DS	40	35	35	36	36	36	36	36	36	37	37	37	38	38	38
	Limebank MTS	68	47	49	52	54	56	59	61	67	73	79	86	93	92	92
	Marionville DS	28	31	31	31	32	32	31	32	32	32	33	33	33	34	34
	National Aeronautical CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Russell DS	8	12	13	13	13	13	13	13	13	13	13	13	13	13	13
	South Gloucester DS	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Uplands MTS	30	20	20	20	21	21	21	21	22	22	23	23	24	23	23
	Total	**182**	**151**	**155**	**159**	**162**	**165**	**167**	**171**	**178**	**185**	**193**	**201**	**209**	**209**	**209**
South West 115	Fallowfield DS	48	45	49	48	51	61	64	68	72	76	84	89	95	102	111
	Manotick DS	17	8	8	9	9	9	9	9	9	9	9	9	9	9	9
	Richmond DS	5	7	7	8	10	22	24	25	26	27	27	28	28	27	27
	Total	**70**	**60**	**64**	**65**	**69**	**92**	**97**	**102**	**107**	**112**	**120**	**126**	**131**	**139**	**147**

West 115	Bridlewood MTS	37	34	34	35	35	34	34	35	61	61	60	61	61	60	60
	Carling TS	93	88	89	90	91	92	92	93	100	102	103	105	106	107	109
	Centrepoint MTS	35	21	21	21	21	21	21	21	21	21	20	20	20	20	20
	Epworth	25	15	15	16	16	16	16	16	16	15	15	15	15	15	15
	Hinchey TS	77	47	49	51	54	55	57	59	54	57	61	64	67	70	73
	Lincoln Heights TS	71	48	48	48	48	47	47	47	53	52	52	52	51	51	51
	Manordale MTS	22	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Marchwood MTS	34	35	35	35	36	35	35	36	36	36	36	36	36	37	38
	Merivale TS	18	18	19	18	20	20	20	20	22	23	26	27	26	26	26
	Woodroffe TS	92	35	36	36	37	38	38	39	47	48	49	49	50	51	51
	Total	**504**	**351**	**355**	**361**	**368**	**369**	**369**	**375**	**419**	**425**	**432**	**439**	**443**	**448**	**454**
West 230	Kanata MTS	55	87	88	88	88	88	87	88	89	89	90	90	90	90	90
	Nepean TS	144	153	152	151	150	148	146	145	144	141	139	137	135	133	133
	South March	109	98	93	97	101	104	107	110	102	87	87	87	87	86	87
	Terry Fox MTS	90	44	57	88	93	74	73	72	71	71	70	69	68	67	67
	Total	**397**	**382**	**390**	**424**	**432**	**414**	**412**	**416**	**406**	**389**	**385**	**383**	**379**	**377**	**377**
Outer East 115	Clarence DS	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Hawkesbury MTS	18	17	17	17	17	17	17	17	18	18	18	18	18	19	19
	Rockland DS	9	17	17	17	18	18	18	18	19	19	19	19	19	19	19
	Rockland East DS	15	11	11	11	12	12	12	12	13	13	13	13	13	13	13
	Wendover TS	34	9	9	9	9	9	9	10	11	11	11	10	10	10	10
	Total	**80**	**56**	**56**	**56**	**57**	**57**	**57**	**57**	**62**	**62**	**63**	**63**	**63**	**63**	**63**
Outer East 230	Ivaco	100	92	92	92	92	92	92	92	92	92	92	92	92	92	92
	Longueuil TS	98	44	44	44	44	43	43	43	43	43	43	43	43	43	43
	St. Isidore TS	52	48	48	48	48	47	47	47	47	47	47	47	47	47	47
	Total	**249**	**184**	**184**	**184**	**184**	**183**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**	**182**
Outer West 115	Arnprior TS	51	51	51	51	51	50	49	49	49	49	49	49	49	49	49
	Stewartville TS	55	32	32	32	49	49	48	48	48	48	48	48	48	48	48
	Total	**106**	**83**	**82**	**82**	**100**	**99**	**97**	**97**	**96**	**96**	**96**	**96**	**96**	**96**	**96**
Outer West 230	Almonte TS	100	48	48	47	47	47	46	46	45	45	45	45	45	45	45
	Total	**100**	**48**	**48**	**47**	**47**	**47**	**46**	**46**	**45**	**45**	**45**	**45**	**45**	**45**	**45**
Region Total		**2948**	**2284**	**2346**	**2421**	**2503**	**2514**	**2522**	**2558**	**2637**	**2650**	**2680**	**2702**	**2722**	**2738**	**2762**

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

GTA East

REGIONAL INFRASTRUCTURE PLAN

January 9th, 2017

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

With support from:

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Veridian Connections Inc.
Whitby Hydro Electric Corporation

DISCLAIMER

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA EAST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA East Region which consists of the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. It follows the completion of the GTA East Region's Needs Assessment ("NA") in August 2014, the Oshawa-Clarington Sub-Region's Local Plan ("LP") in May 2015, and the Pickering-Ajax-Whitby Sub-Region's Integrated Regional Resource Plan ("IRRP") in June 2016.

This RIP provides a consolidated summary of needs and recommended plans for the entire GTA East Region that includes the Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The major transmission and distribution infrastructure investments planned for the GTA East Region over the near and mid-term, as identified in the regional planning process are given below.

No.	**Project**	**I/S Date**	**Cost**
1	Enfield TS; new 230/44kV station	2019	$34M[1]
2	Seaton MTS; new 230/27.6/27.6kV station	2019	$43M-$48M[2]

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

---

[1] Considers 6x44kV feeder breaker positions initially without capacitor banks
[2] Class Environmental Assessment (EA) not complete at time of RIP. Range of costs includes all sites under consideration – includes transmission line rebuild costs and all station equipment less capacitor banks for 12x27.6kV feeders and a spare transformer.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Hydro One Distribution, Oshawa PUC Networks Inc. ("OPUCN"), Veridian Connections Inc. ("Veridian"), Whitby Hydro Electric Corporation ("Whitby Hydro") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and Clarington. Electrical supply to the Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station ("TS") and five[3] 230kV transmission lines that supply the four local area step-down transformer stations. The boundaries of the Region are shown in Figure 1-1 below.

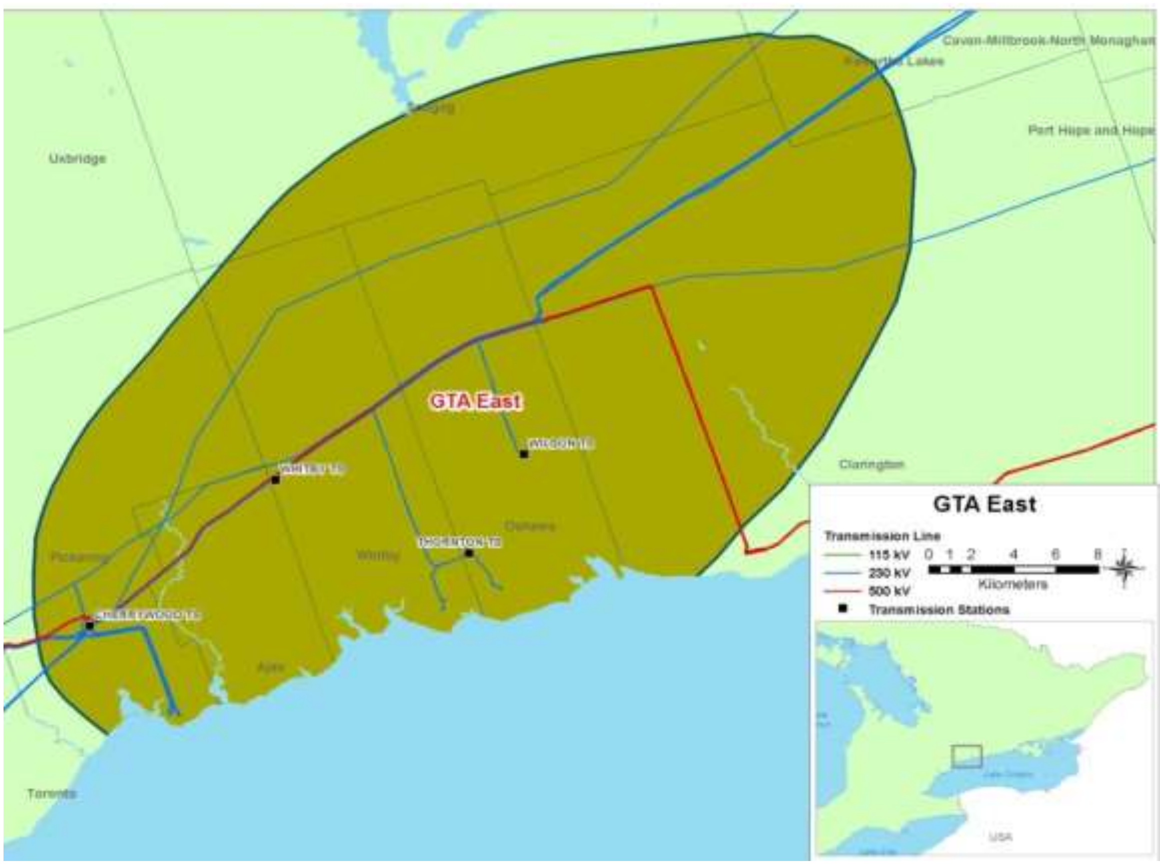

Figure 1-1 GTA East Region

[3] Including 230kV circuit C28C (T28C with Clarington TS) which extends 2km north from Cherrywood TS to Duffin Jct. and then extends 26km east to be terminated at Clarington TS in 2018

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Pickering-Ajax-Whitby Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[4] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customer) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited investments of wires (transmission or distribution) solutions c) does not require upstream transmission investments d) does not require plan level stakeholder engagement and e) other approvals such as Leave to Construct (S92) application or Environmental Approval.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. If there are needs that do not required regional coordination, Working Group can recommend them to be undertaken as part of the LP approach discussed above. Else, the approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

[4] Also referred to as Needs Screening.

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

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

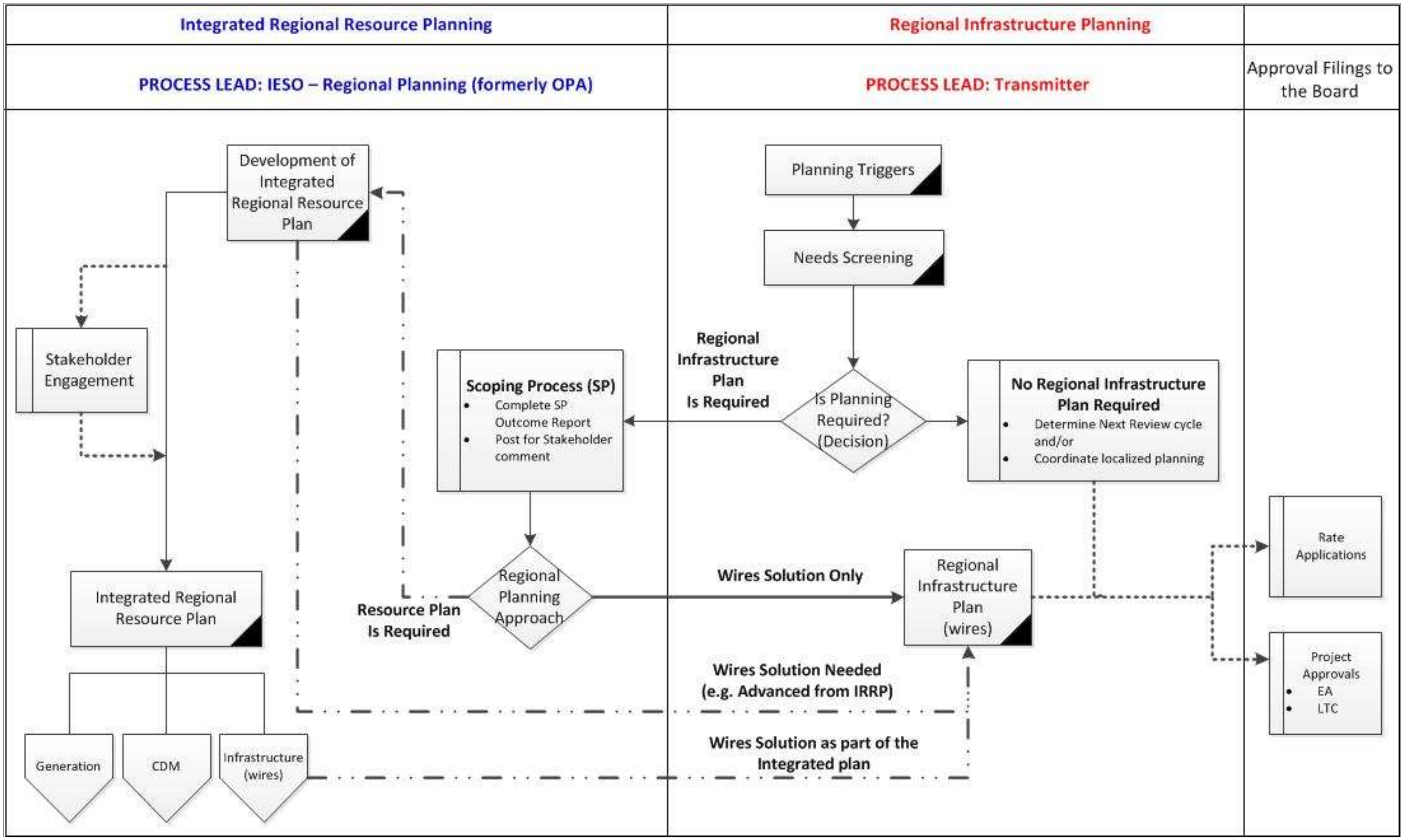

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required.

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

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

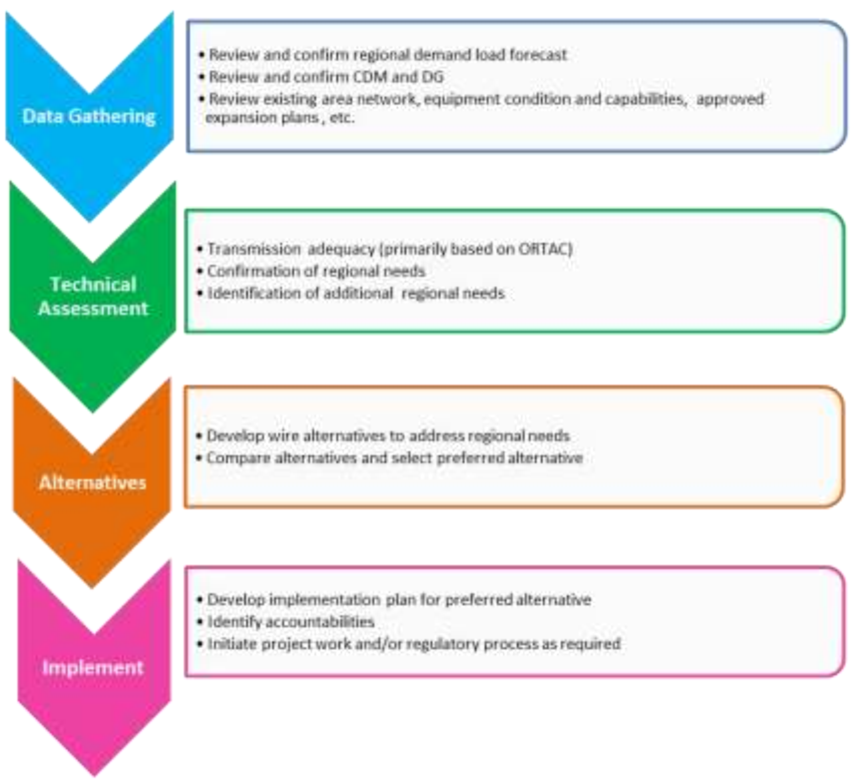

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FOUR 230KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 938.5 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS, a major 500/230kV autotransformer station in the City of Pickering, and five 230kV circuits emanating east from Cherrywood TS that supply four local area step-down transformer stations and four other direct transmission connected load customers. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2014 GTA East Region NA report, prepared by Hydro One, considered the GTA East Region as a whole. Subsequently, the GTA East Region was divided into two sub-regions, Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The IRRP report focused on the needs in the Pickering-Ajax-Whitby Sub-Region. The May 2015 Oshawa-Clarington Sub-Region LP report focused solely on the Oshawa-Clarington Sub-Region. A map of the GTA East Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Pickering-Ajax-Whitby Sub-Region

The Pickering-Ajax-Whitby Sub-Region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-Region are Hydro One Distribution, Veridian, and Whitby Hydro.

3.2 Oshawa-Clarington Sub-Region

The Oshawa-Clarington Sub-Region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV, and four other direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit H26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby Sub-Region. The LDCs supplied in the Sub-Region are Whitby Hydro, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington (called Clarington TS) is also being developed and is expected to be in-service in 2018. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS. The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principal supply source for the GTA East Region load.

A single line diagram of the GTA East Region transmission system including the connection of Clarington TS is shown in Figure 3-2.

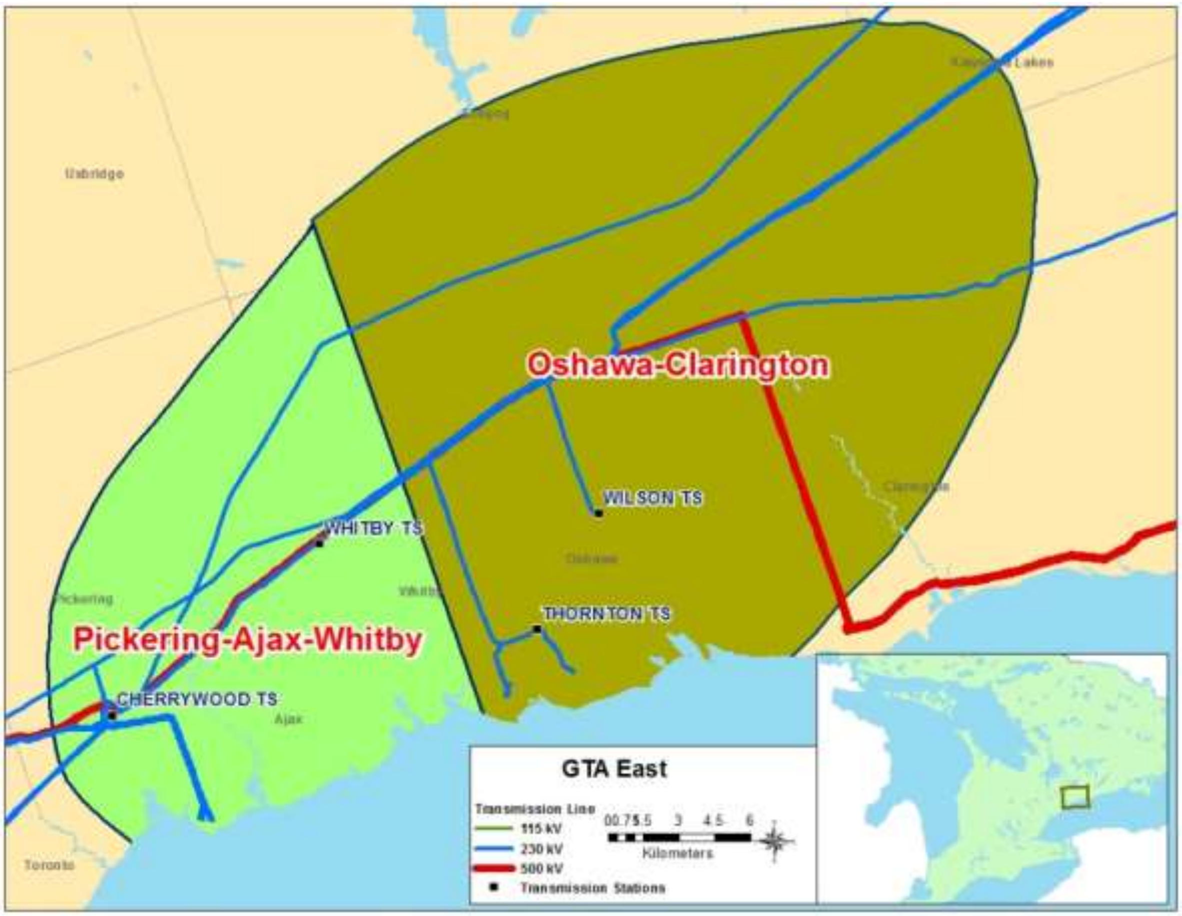

Figure 3-1 GTA East Region – Supply Areas

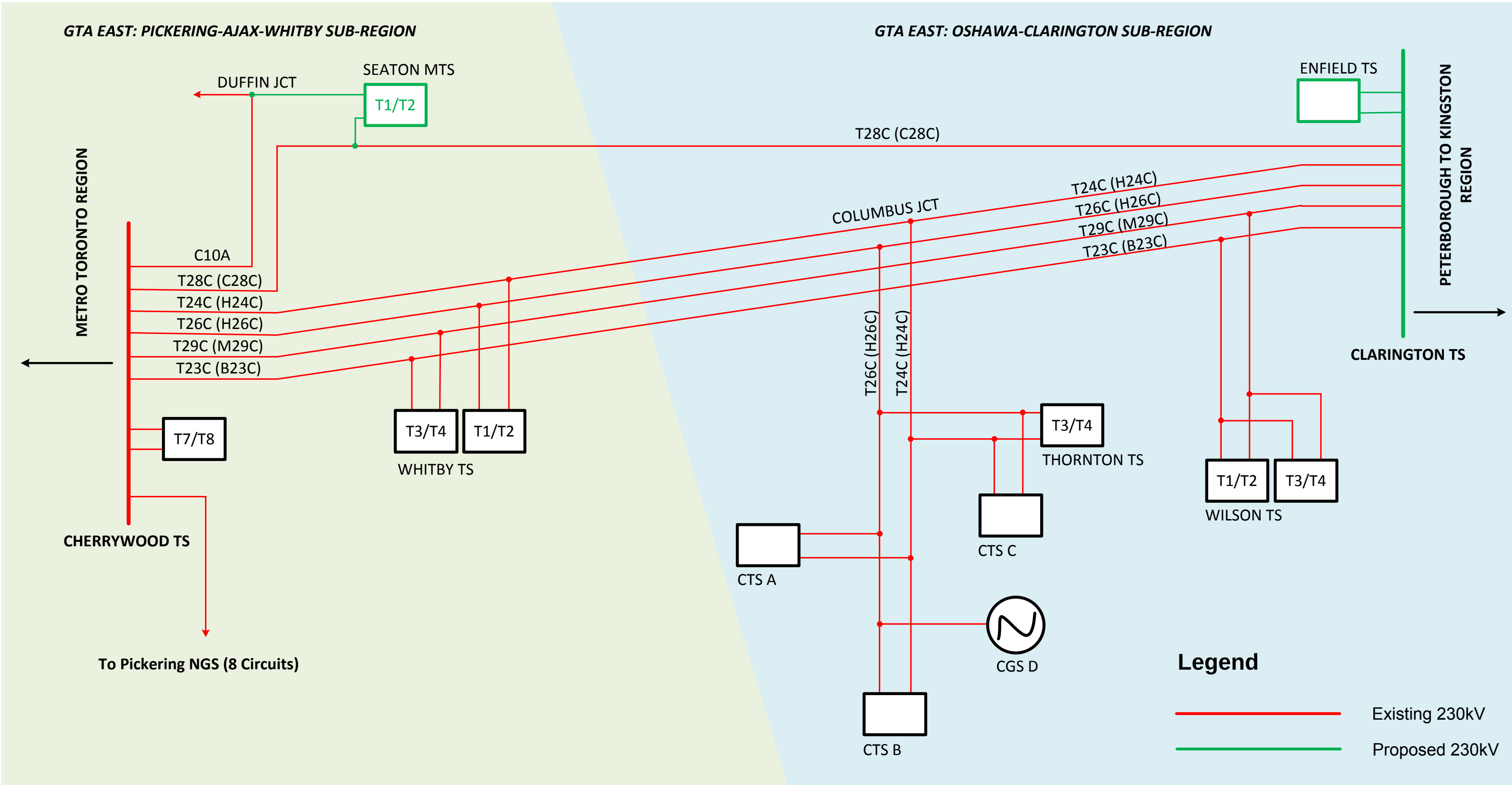

Figure 3-2 GTA East Region Single Line Diagram

Note: Current circuit designations (before Clarington TS is in-service) are provided in brackets

4. TRANSMISSION FACILITIES COMPLETED OR CURRENTLY UNDERWAY OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built new step-down transformer station supplied from 230kV circuits H24C and H26C in municipality of Whitby to increase transformation capacity for Whitby Hydro and Veridian requirements.

- Installed LV neutral grounding reactors at Wilson TS T1/T2 DESN1 (2015) – to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 transformer replacements and install LV neutral grounding reactors (2016) – to replace end-of-life transformers and reduce line-to-ground short circuit fault levels to facilitate DG connections.

The following development projects are currently underway:

- Clarington TS (2018) – a 500/230kV autotransformer station at the Oshawa Area Jct. to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region. The thermal limits of the 230kV circuits supplying the Region will be upgraded and will be terminated at Clarington TS.

- Seaton MTS (2019) – a 230/27.6/27.6kV municipal transformer station to increase supply capacity in the Pickering-Ajax-Whitby Sub-Region and provide relief to Whitby TS 27.6kV following the development of new community of Seaton. The station will be serviced by two parallel 230kV circuits, C10A and C28C, emanating from Cherrywood TS. C10A will be extended eastward from Duffin Jct. to the site of the station.

- Enfield TS (2019) – a 230/44kV DESN to increase supply capacity in the Oshawa-Clarington Sub-Region and provide relief to Wilson TS. This station will be located at the Oshawa Area Jct. and will be directly connected to Clarington TS 230kV bus.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA East Region is expected to increase at an annual rate of approximately 2% between 2016 and 2025. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

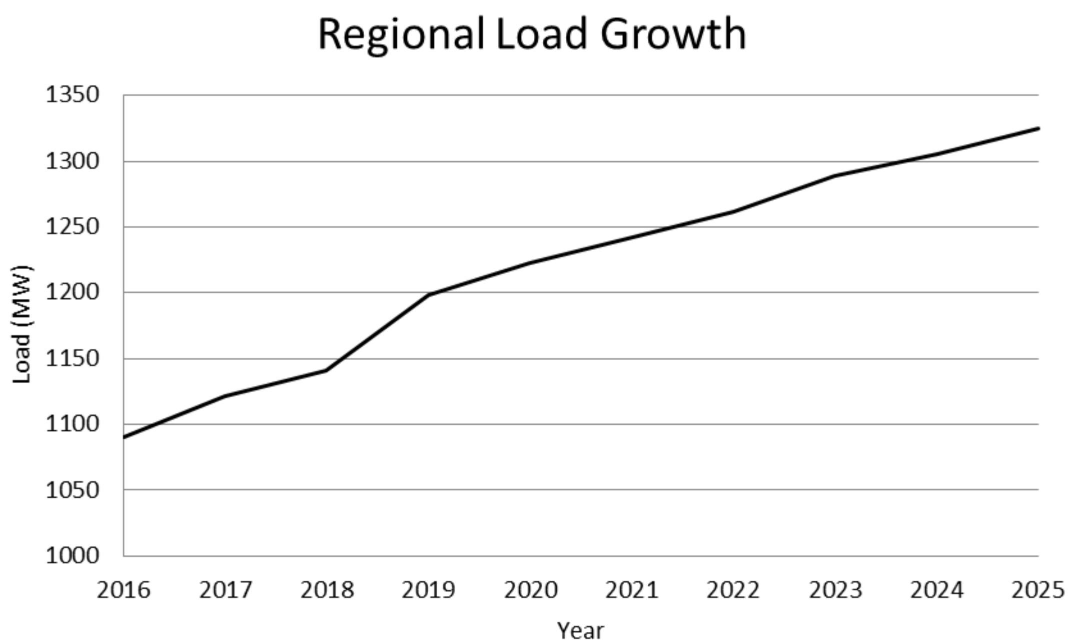

Figure 5-1 GTA East Region Coincident Net Load Forecast

Prior to the RIP's kick-off, the Working Group were asked to confirm load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for Pickering-Ajax-Whitby Sub-Region did not have a significant revision compared to the IRRP's load forecast. However, the revised forecasted non-coincident stations' peaks for Wilson TS and Thornton TS in the Oshawa-Clarington Sub-Region had a significant increase; therefore, the needs identified in previous assessments were reconfirmed.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2025.
- Pickering NGS is assumed to be out-of-service by 2024.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA EAST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA East Region. The findings of these studies are input to the RIP:

1. IESO's Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan – June 30, 2016[1]
2. Hydro One's Oshawa-Clarington Sub-Region Local Planning Report – May 15, 2015[2]
3. Hydro One's GTA East Region Needs Assessment Report – August 11, 2014[3]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the GTA East Region assuming Clarington TS will be in-service by 2018, Seaton MTS and Enfield TS by 2019, and Pickering NGS out-of-service between 2018 and 2024.

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

Table 6-1 Near and Mid-Term Needs in the GTA East Region

<table>
<tr><th>Type</th><th>Section</th><th>Needs</th><th>Timing</th></tr>
<tr><td rowspan="2">Step-down Transformation Capacity</td><td>7.1</td><td>Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region</td><td>2019</td></tr>
<tr><td>7.2</td><td>Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region</td><td>Immediately</td></tr>
<tr><td>Load Restoration</td><td>7.3</td><td>Load Restoration for loss of B23C/M29C or H24C/H26C</td><td>No action required at this time</td></tr>
<tr><td>Short Circuit Constraint</td><td>7.4</td><td>Short Circuit Constraint at Cherrywood TS T7/T8</td><td>Pending outcome</td></tr>
</table>

6.1 500kV and 230kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, B23C/M29C, H24C/H26C, and C28C, supplying both the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. Refer to Figure 3-2 for existing and proposed facilities to be operational in the Region in near future.

Bulk system planning is conducted by the IESO and is informed by government policy such as the long term energy plan (“LTEP”). The next LTEP is expected to be issued in 2017. Any outcomes from this level of planning that impact regional planning are expected to be integrated into the respective regions as necessary.

6.2 Pickering-Ajax-Whitby Sub-Region’s Step-Down Transformer Station Facilities

There are two step-down transformer stations in the Pickering-Ajax-Whitby Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Pickering-Ajax-Whitby Sub-Region

Station	DESN	Voltage Transformation
Cherrywood TS	T7/T8	230/44kV
Whitby TS	T1/T2	230/44/27.6kV
	T3/T4	230/44kV

Based on the LTR of these load stations, additional 27.6kV capacity is required at Whitby TS T1/T2 in 2019 which will be addressed by the proposed Seaton MTS (see details in Section 7.1). Cherrywood TS T7/T8 may be slightly overloaded initially, however, due to CDM and commissioning of Seaton MTS, the capacity need is expected to be eliminated by 2019. Forecast loads at Whitby TS T1/T2 44kV windings, and Whitby TS T3/T4 44kV windings are adequate over the study period.

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

Table 6-3 Transformation Capacities in the Pickering-Ajax-Whitby Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Cherrywood TS T7/T8 44kV	175	156	-
Whitby TS T1/T2 27.6kV	90	41	2019
Whitby TS T1/T2 44kV	90	56	-
Whitby TS T3/T4 44kV	187	161	-

6.3 Oshawa-Clarington Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations and four direct-connected customers in the Oshawa-Clarington Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Oshawa-Clarington Sub-Region

Station	DESN	Voltage Transformation
Wilson TS	T1/T2	230/44kV
	T3/T4	230/44kV
Thornton TS	T3/T4	230/44kV
Industrial Customer TS x4	-	-

Based on the LTR of these load stations, additional 44kV capacity is immediately required to provide relief to Wilson TS. Under certain conditions, overloading at Wilson TS T3/T4 was significant enough to plan for emergency rotating load shedding, if and when required. Plan to address this need is discussed further in Section 7.2. Thornton TS is adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Oshawa-Clarington Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Wilson TS T1/T2 44kV	161	167	Immediately
Wilson TS T3/T4 44kV	133	146	Immediately
Thornton TS T3/T4 44kV	159	126	-

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

7. REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA East Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the Pickering-Ajax-Whitby Sub-Region and the NA and LP for the Oshawa-Clarington Sub-Region. Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.1% annually.

Based on the DG and CDM forecasts in the Sub-Region, adequate 44kV transformation capacity is available at Cherrywood TS T7/T8 and Whitby TS to maintain reliable supply to meet the demand over the study period.

With the proceeding of a new residential and mixed use commercial area in the Sub-Region, called Seaton, significant increase in load demand is expected at 27.6kV level resulting in a shortage transformation capacity by 2019. The gross demand in the new development of Seaton is expected to be 88MW at the end of the study period (2025) and will continue to grow over long term period. The growth resulting from Seaton will have a significant impact on the 27.6kV transformation capacity in the Sub-Region.

Recommended Plan and Current Status

During the regional planning process, the Working Group considered multiple alternatives to address the transformation capacity in the Sub-Region. Preference was given to already existing facilities to ensure system's maximum capacity had been considered in line with the future demand. Other alternatives included CDM, local generation, and transmission & distribution facilities.

After considering estimated DG and CDM targets over the study period, the stations' capacities in the Sub-Region can be relieved to a certain extent. However, existing facilities alone will not be adequate to meet the future demand resulting from the new Seaton community load planned to be supplied at 27.6kV level.

As a result, an investment in wires infrastructure development in the Sub-Region is mandatory to connect and supply the development of Seaton via transmission/distribution facilities. Following the completion of the IRRP, the Working Group recommended Seaton MTS as the best solution to meet the transformation capacity need in the Sub-Region. Veridian Connections Inc. and Hydro One Networks Inc. have jointly submitted an EA application for the proposed station site and related 230kV transmission line work. Consistent with the regional planning studies, Veridian Connections Inc. is developing a plan for a new transformation station called Seaton MTS in northern Pickering. As confirmed by Veridian, the in-service timeline of this transformation station has been deferred to 2019 due to revised 2018 load forecast.

Class Environmental Assessment (EA) is in progress for the three potential construction sites for Seaton MTS illustrated in Figure 7-1.

Figure 7-1 Seaton MTS: Proposed Construction Sites

The project will have the following connection arrangement:

- From Duffin Jct, extend the circuit C10A east to proposed location under EA process
- Connect 2x75/125MVA, 230/27.6/27.6kV transformers to 230kV circuits; C10A and T28C[5]
- Supply 12x27.6kV feeders with a normally open tie-breaker configuration

The total cost of this project is estimated to be \$43M – \$48M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection

[5] T28C circuit nomenclature to replace C28C following Clarington TS (2018)

arrangements as defined above, feeder egress to the distribution risers outside of the station, and a spare transformer.

7.2 Increase Transformation capacity in Oshawa-Clarington Sub-Region

Description

The load forecast reflects an annual growth of 1.85% in Oshawa and Clarington area throughout the study period. Based on the 2015 historical demand and station's net demand forecast, Wilson TS T1/T2 and T3/T4 have already exceeded their respective normal supply capacities and will continue to do so over the study period. Overloading at Wilson TS T3/T4 has been significant enough that plans were put in place for emergency rotating load shedding, if and when required. Thornton TS may briefly exceed its transformation capacity in 2018 and 2019 but is adequate over the study period as well as long term period due to CDM contributions and distribution load transfer capability.

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

Recommended Plan and Current Status

To accommodate the load growth of Hydro One Distribution's and OPUCN's feeders at Wilson TS, a new transformer station, Enfield TS, is recommended to relief the transformation capacity. The proposed transformer options to be evaluated for the DESN are as follows:

1. 2x75/125MVA, 230/44kV transformers with 6x44kV feeder breaker positions, with space for future 2x44kV feeder positions and capacitor banks (Preliminary Cost Estimate: $23 million)
2. 2x75/125MVA, 230/44kV transformers with 8x44kV feeder breaker positions (Preliminary Cost Estimate: $27 million)

The Working Group recommends option 1 to address the transformation capacity need in the Sub-Region. Six feeders will be adequate to supply demand over the study period. Also, option 2 is not considered the best economic solution since option 1 will reserve extra space for 2x44kV feeder positions and capacitor banks for future, when required.

The new DESN, 2x75/125MVA 230/44kV transformers with 6x44kV feeder breaker positions with 2x44kV spare feeder positions, is proposed to be located at the Oshawa Area Junction in the municipality of Clarington. This junction is on the ROW of the Bowmanville and Cherrywood transmission line corridor illustrated in Figure 7-2. The property is already owned by HONI and it is also the site of the new 500/230kV autotransformer Clarington TS supplied by circuits B540C and B543C. The proposed in-service date for the new DESN has a preliminary cost estimate of $34M including feeders egress to the distribution risers outside the station and will be aligned with Clarington TS which is scheduled for 2018.

Figure 7-2 Enfield TS: Proposed Construction Site

Advantages in proceeding with this particular location are as follows:

- The land proposed has already been purchased as part of the property where Clarington TS will be situated resulting in one less station footprint in the Sub-Region.
- Class EA approval has been already obtained for the construction of new TS on Hydro One land at the Clarington TS site.
- The site is also near new development areas which results in minimizing the length of supply feeders from the station.

7.3 GTA East Load Restoration Assessment

Description

GTA East load restoration need was identified in the NA and IRRP reports as the Working Group recommended that further assessment was required to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria and requires further assessment.

Recommended Plan and Current Status

In collaboration with the Working Group, a detailed report[6] was completed to make a recommendation for the load restoration need identified in the Region. The Working Group's assessments in the report, attached in the Appendix F, concluded the following:

- The historical performance of the circuits over the last 15 years has been excellent with little or no impact on supply reliability and security.

- Working Group is recommending that further investment in motorized disconnect switch (MDS) at this time is not a feasible solution to the load restoration need because the risk and/or probability of loss of load is small based on past performances. Therefore, no further action is required at this time.

7.4 Short Circuit Constraint at Cherrywood TS T7/T8

Description

Currently, new DG is restricted from connecting to Cherrywood TS T7/T8 due to short circuit capacity constraints. Veridian Connections Inc., supplied by this station, has indicated that they have several customers that have expressed interest in connecting DG (over 5MW) to Cherrywood TS T7/T8 but are prevented due to the existing restriction. There is an existing 30MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the short circuit capacity restriction. This generating unit has been shut down and/or has not generated electricity now for more than one year.

Recommended Plan and Current Status

The short circuit capacity is currently held by an earlier landfill generation connection. Although the facility has not been generating and partially dismantled, there is an uncertainty about availability of the short circuit capacity. Hydro One and the IESO will continue to assess this issue to have this capacity reservation released.

[6] GTA East: Load Restoration, Transmission Planning Report, circulated within the Working Group on August 31, 2016

7.5 Long Term Regional Plan

As discussed in Section 5, the electricity demand in GTA East Region is forecasted to grow at 2% annually over the next 10 years. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1.3% annually from year 2026 to 2036. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the Pickering-Ajax-Whitby Sub-Region were identified in the IRRP. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades. As indicated in the IRRP, official plans by the municipalities expect the lakeshore area in the southern part of Pickering-Ajax-Whitby Sub-Region to grow due to development of high rise residential and commercial buildings. With Pickering NGS expected to retire by 2024, the 230kV transmission lines can be utilized along with a new step-down transformer station to address capacity needs in the southern part of the Sub-Region.

The current forecast did not consider future Pickering Airport which may have an impact on transformation capacity in the long term. Such potential needs will be monitored and system supply capability will be reviewed in the next planning cycle based on the official plans released by the municipalities.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will mainly provide relief to Wilson TS by supplying the excess load through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
II	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
III	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
IV	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome
V	Additional transformation capacity for Oshawa-Clarington Sub-Region	Long term

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

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

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Seaton MTS and associated line work	Veridian and Hydro One	2019	$43M-$48M	I
2	Enfield TS	OPUCN and Hydro One	2019	$34M	II

GTA East load restoration need, Need ID III, has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended (see Appendix F). Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

Hydro One is working with the IESO to explore the best course of action to relieve the short circuit constraint at Cherrywood TS, Need ID IV.

Additional transformation capacity for Oshawa-Clarington Sub-Region, Need ID V, will be reviewed as part of the next Regional Planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

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APPENDICES

Appendix A: Stations in the GTA East Region

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, Bus DK
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	H24C/H26C
Whitby TS T3/T4	230/44kV	B23C/M29C
Wilson TS T1/T2	230/44kV	B23C/M29C
Wilson TS T3/T4	230/44kV	B23C/M29C
Thornton TS T3/T4	230/44kV	H24C/H26C

Appendix B: Transmission Lines in the GTA East Region

Location	Circuit Designation	Voltage Level
Cherrywood TS to Whitby TS T3/T4, Wilson TS, and Clarington TS	B23C/M29C	230kV
Cherrywood TS to Whitby TS T1/T2, Thornton TS, and Clarington TS	H24C/H26C	230kV
Cherrywood TS to Clarington TS	C28C	230kV

Appendix C: Non-Coincident Load Forecast 2016-2025

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
					Gross Peak Load				180	180	180	180	180	180	180	180	176	176
Cherrywood TS	Veridian	*T7/T8*	*BY (44kV)*	*175*	CDM				2	3	5	7	8	10	11	12	13	15
					Net Load Forecast	163	143	156	178	177	175	173	172	170	169	168	163	161
	Veridian		*BY (27.6kV)*	*90*	Gross Peak Load				61	76	80	90	90	90	90	90	90	90
	Whitby Hydro		*EZ (44kV)*	*90*	Gross Peak Load				54	55	56	57	57	58	59	60	61	62
Whitby TS		*T1/T2*			DG				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					CDM				2	3	4	6	7	8	9	10	12	13
					Net Load Forecast	77	88	97	113	128	132	141	141	140	140	140	139	139
	Veridian				Gross Peak Load				70	70	74	74	74	74	74	74	74	74
	Whitby Hydro				Gross Peak Load				108	110	111	113	115	116	118	120	122	124
Whitby TS		*T3/T4*	*JQ (44kV)*	*187*	DG				18	18	18	18	18	18	18	18	18	18
					CDM				2	3	5	6	8	9	11	13	15	17
					Net Load Forecast	175	161	162	159	160	163	164	163	164	164	164	163	163
					Gross Peak Load							5	16	27	40	60	75	88
Seaton MTS	Veridian	*T1/T2*	*(27.6kV)*	*153*	CDM								1	1	2	3	4	6
					Net Load Forecast	0	0	0	0	0	0	5	15	26	38	57	71	82
	OPUC				Gross Peak Load				156	161	167	148	145	142	140	140	140	140
	Hydro One				Gross Peak Load				30	31	35	35	41	41	41	41	41	41
Wilson TS		*T1/T2*	*BY (44kV)*	*161*	CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	157	174	167	184	189	197	176	177	173	170	170	169	168
	OPUC				Gross Peak Load				25	26	27	25	25	25	25	25	25	25
	Hydro One				Gross Peak Load				150	151	152	152	153	154	155	156	157	158
Wilson TS		*T3/T4*	*JQ (44kV)*	*134*	CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	166	133	146	173	174	174	171	170	170	170	170	170	170

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thornton TS	Whitby Hydro	*T3/T4*	*BY (44kV)*	*160*	Gross Peak Load				52	58	63	79	80.0	81	82	82	83	84
	OPUC				Gross Peak Load				100	101	103	95	88	86	84	80	80	80
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast	157	103	126	151	156	162	168	160	158	156	152	152	152
Enfield TS	OPUC	T1/T2	*(44kV)*	*153*	Gross Peak Load				0.0	0.0	0.0	38	57	71	84	98	108	118
	Hydro One				Gross Peak Load				0.0	0.0	0.0	26	33	34	35	36	37	38
					CDM							3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast				0	0	0	62	86	100	113	126	135	145
CTS A					Gross Peak Load				20.0	20.0	20.2	20.6	21.0	21.2	21.4	21.6	21.7	21.9
					Net Load Forecast			19.5	19.8	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.2	20.3
CTS B					Gross Peak Load				97.0	97.5	98.0	99.8	101.6	102.2	103.0	103.4	103.9	104.4
					Net Load Forecast			96.3	96.0	96.1	96.2	96.3	96.3	96.4	96.5	96.6	96.6	96.7
CTS C					Gross Peak Load				47.5	52.8	53.3	54.5	55.7	56.3	57.0	57.5	58.0	58.5
					Net Load Forecast			52	47.0	52.0	52.3	52.6	52.8	53.1	53.4	53.7	53.9	54.2
CGS D					Gross Peak Load				0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
					Net Load Forecast			0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Appendix D: Coincident Load Forecast 2016-2025

Stations	DESN ID	Historical (MW)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	T7/T8	156	173	172	170	168	167	165	164	163	158	156
Whitby TS (27.6kV)*	T1/T2	33	59	74	78	87	87	87	87	87	87	87
Whitby TS (44kV)*	T1/T2	39	52	53	54	55	56	56	57	58	59	60
Whitby TS	T3/T4	145	154	155	158	159	158	159	159	159	158	158
Seaton MTS	T1/T2	0	0	0	0	5	15	25	37	55	69	80
Wilson TS	T1/T2	128	179	184	192	172	173	169	166	166	165	164
Wilson TS	T3/T4	144	168	169	169	166	165	165	165	165	165	165
Thornton TS	T3/T4	125	146	151	157	163	155	153	151	147	147	147
Enfield TS	T1/T2	0	0	0	0	60	83	97	110	122	131	141
CTS A		19.5	19	19	19	19	19	19	19	20	20	20
CTS B		96.3	93	93	93	93	93	93	94	94	94	94
CTS C		52	46	50	51	51	51	51	52	52	52	53
CGS D		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

*DG/CDM contribution excluded from 2016-2036 coincident forecast

GTA East Coincident Load	**938.5**	**1091**	**1122**	**1141**	**1199**	**1223**	**1242**	**1262**	**1289**	**1306**	**1324**
Region's Annual Growth Rate		2%									

Appendix E: List of Acronyms

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

Appendix F: GTA East Load Restoration Report

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

TRANSMISSION PLANNING REPORT

GTA East: Load Restoration

Revision: Final
Date: August 31, 2016

Prepared by: Hydro One Networks Inc.

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Executive Summary

REGION	GTA East (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	August 31, 2016

1. INTRODUCTION

The purpose of this Transmission Planning (TP) report is to undertake a comprehensive assessment of the load restoration need identified in the Needs Assessment (NA) and Integrated Regional Resource Plan (IRRP) and develop a preferred recommendation. The recommendations of this TP report will become part of the Regional Infrastructure Plan (RIP) and is intended to facilitate the regional planning process as set out by Ontario Energy Board's (OEB) in the Transmission System Code (TSC) and the Planning Process Working Group (PPWG) report to the Board.

Based on Section 6 of the NA and IRRP report, the study team recommended that further assessment was required to address the load restoration need during peak load in the GTA East region. The NA and IRRP report indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration may exceed load restoration criteria and requires further assessment. The IESO led IRRP recommended this need be further assessed in the RIP, to be completed in Q4 2016. This report provides a detailed assessment along with options and the WG recommendation to be included in the RIP report.

2. REGIONAL NEED ADDRESSED IN THIS REPORT

The circuits M29C/B23C and H24C/H26C are on the same tower line in the GTA East Region 230kV corridor. The loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively.

3. OPTIONS CONSIDERED

Hydro One Transmission along with the WG members have considered the following options to addressing the load restoration need:

Option 1 – a) Status quo/Current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

See Sections 4 & 5 for detailed assessment.

4. PREFERRED SOLUTION

At this time, B23C, M29C, H24C, and H26C are approximately 120km-300km long and the historical performance since 2000 has been excellent with no relevant outages. With the new Clarington TS in 2018, the line exposure in the region will reduce to only 46km including tap sections. The assessment concluded that

a) The annual carrying cost of the switches is not justified compared to the annual outage cost, and
b) The installation of Motorized Disconnect Switches will not result in significant enhancement to the reliability of the system after the Clarington TS is in service in 2018.

Option 1 is the preferred solution recommended by the WG at this time. Further details of the assessment and justification are provided in Sections 4 & 5.

5. NEXT STEPS

There are no further actions required at this time.

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1 Region Description and Connection Configuration

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

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Region. Whitby TS DESN2, Thornton TS, and other CTS in the Region are supplied by H24C/H26C while Whitby TS DESN1 and Wilson TS are supplied by B23C/M29C.

A new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is expected to be in service by 2018. The assessments in this report evaluate the reliability impact of Clarington TS in the region as well as the installation of Motorized Disconnect Switches (MDS). The new Clarington TS will provide additional load meeting capability in the Region and will eliminate any overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 1[1].

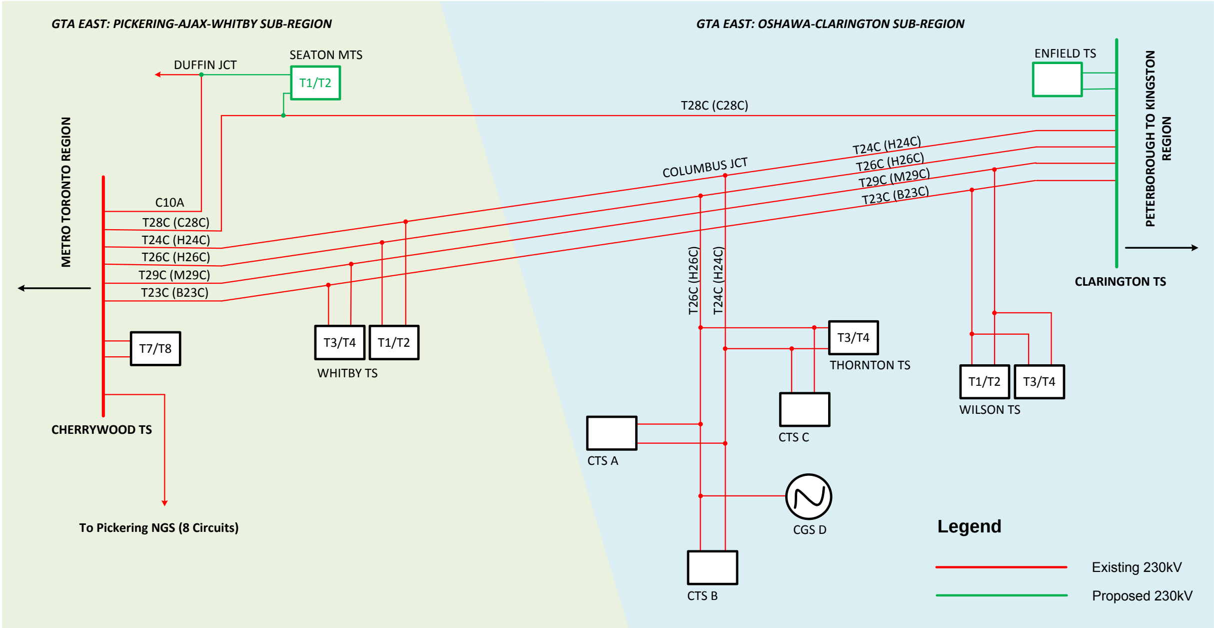

Figure 1 **GTA East Region - Single Line Diagram**

[1] Circuits' nomenclature is shown following the commissioning of Clarington TS (2018) with current convention in parentheses

2 Identified Need

2.1 Load Restoration Criteria

In case of contingencies on the transmission system, the Ontario Resource Transmission Assessment Criteria (ORTAC) provides the load restoration times relative to the amount of load affected. Planned system configuration must not exceed 600MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

In addition, ORTAC also provides a provision for exemption from the above restoration criteria on a case-by-case basis.

Figure 2 illustrates the load restoration timelines as discussed above.

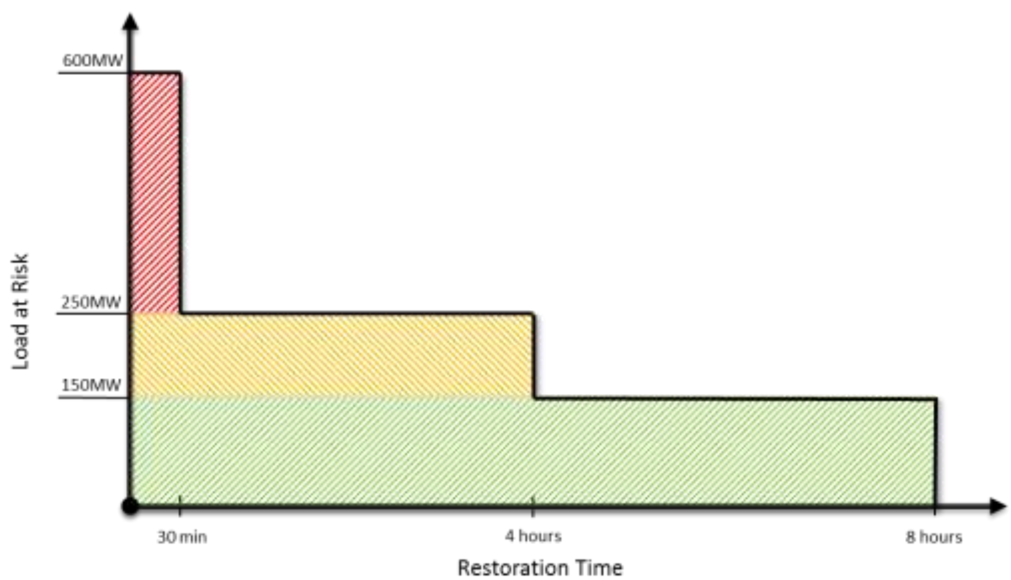

Figure 2 **Load Restoration Criteria**

2.2 Shortfall Need

In 2015, H24C/H26C and M29C/B23C supplied a coincident peak demand of approximately 366MW and 417MW, respectively.

It is expected and assumed that all loads can be restored within 8 hours. However, consistent with the NA and IRRP reports, during peak load periods all loads cannot be restored in the region subsequent of a double circuit contingency between Cherrywood TS and Clarington TS within 30 minutes to 4 hours.

Further findings from the Local Distribution Companies (LDC) in the Region and as reported in the IRRP[2], up to 57MW and 142MW can be restored for customers supplied by H24C/H26C through distribution transfers within 30 minutes and 4 hours, respectively. This leaves the maximum shortfall of 59MW after 30 minutes, and 74MW after 4 hours to be restored from these circuits.

Similarly, for the M29C/B23C, up to 105MW can be restored through distribution transfers within 30 minutes and 257MW within 4 hours for customers supplied by these circuits under the current supply arrangement. This leaves the maximum shortfall of 62MW after 30 minutes, and 10MW after 4 hours to be restored from these circuits.

Table 1 summarizes the 2015 peak demands for each pair of circuit and differentiates between restorable load and the shortage load for 30-minutes and 4-hour periods as discussed above.

Table 1 **Load Restoration/Shortfall in 2015**

2015 Coincident Peak					
Load Pocket	**Actual Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	366	57	59	142	74
M29C/B23C: Whitby TS DESN2, Wilson TS	417	105	62	257	10

By the end of 2025, the load that cannot be restored increases due to load growth in the region illustrated in Table 2.

Table 2 **Load Restoration/Shortfall in 2025**[3]

2025 Coincident Peak (Net Forecast)					
Load Pocket	**Forecast Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	445	57	138	142	153
M29C/B23C: Whitby TS DESN2, Wilson TS	425	105	70	257	18

[2] Published in June, 2016
[3] Load forecast is subject to change

2.3 Options considered

An option to build a new 26km of line would have resulted in a cost of more than $75M, obtaining new right-of-way and was not further considered. Following options were further assessed:

Option 1a is status quo and option 1b includes Clarington TS to be in-service by 2018. Accordingly, following two options are further evaluated against each other:

Option 1 – a) Status quo/current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

A conceptual configuration of the switches (marked by the red X) is shown for Option 2 in Figure 3.

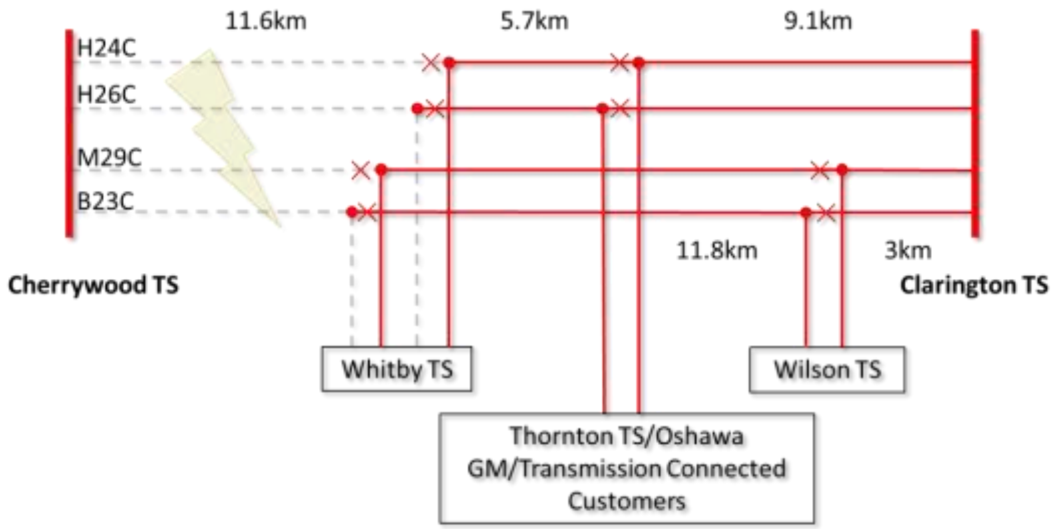

Figure 3 **MDS: Conceptual Configuration**

Similar cases can be shown to isolate faults on other sections of the corridor to restore the loads. It must be noted that although the corridor is protected using 8 MDSs as shown above, the tap offs will still remain unprotected. Further, a common mode fault (refer to section 4) at the tap off line sections will cause an outage regardless of installed switches. With the use of 8 MDS, the optimal locations of the switches are the junction points and 2 switches per circuit as shown in Figure 3.

3 Evaluation Method & Assumptions

The options identified in the previous section were evaluated from the reliability and cost points of view. The reliability indices for overlap outages were evaluated with the help of the AREP Program (Area Reliability Evaluation Program). The reliability for each option is expressed in terms of the frequency and duration of supply interruptions to customers.

Two cost components, one representing the capital cost and one representing the outage cost were evaluated for each option. The two annual costs are given as follows:

Annual cost of carrying charge = C*R,

Where: C – Capital cost of the switches
R – Annual discount rate

The annual outage cost (or risk cost) = F*P*I,

Where: F – Annual duration of load interruption in hours
P – Average kW interrupted including load factor
I – Customer interruption cost ($/KWh)

The following assumptions were made in the assessments:

1. All MDSs are assumed to be perfect (100% reliable).
2. Outages on line tap sections are excluded in common mode outages assessment in section 4.
3. All customer loads are restored within 8 hours for Option 1 and within 30 minutes for Option 2.
4. In case of overlap outages, switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour.
5. Faults do not occur on lines section where MDSs are located.

The assessment data used in the benefit/cost analysis for all options is provided in Table 3.

Table 3 **Data Used in Reliability Studies**

Assessment Data	
No. of circuit pairs on same towers	27
Total circuit length	551.347km
Circuit years in service	26 years
Distance between Cherrywood TS and Clarington TS	26km
2015 Peak load supplied from B23C and M29C, P	417MW
2015 Peak load supplied from H24C and H26C, P	366MW
Load factor for all load stations	0.6
Customer interruption cost, I	\$10–\$30/kWh[4]
Load restoration time without switches	8 hours
Load restoration time with switches	30 minutes
Cost of one switch (x4 per pair, C)	\$3 Million (\$12 Million)
Annual discount rate, R	5%

[4] Known as Value of Lost Load (VOLL), range is consistent with a Canadian Regulatory Application conducted in 2006 after considering customer composition and provincial GDP – IRRP (2016)

4 Impact of Common Mode Outages

A common mode outage is defined as an event involving two or more outages with the same initiating cause and where the outages are not consequences of each other and occur nearly simultaneously.

4.1 Line Outage Data

The historical common mode outage data for all 230 kV circuits on same structures and east of Cherrywood TS from 1990 to 2015 was used to compute the frequency and duration of common mode line outages. A summary of the common mode line outage events, along with the duration, over the period of 25 years is given in Table 4.

Table 4 **Common Mode Outage Events (from 1990 to 2015)**

Event #	Circuits Involved	Year	Outage Duration	Outage Cause
1	X3H and X4H	1992	927.6h	High winds toppled 16 towers
2	D5A and B5D	1998	0.15h or 9m	Electrical storm
3	B23C and M29C	2008	2.02h	Human error, relay settings
4	L21H and L22H	2011	0.08h or 5m	Relay problems

Only 4 common mode outages have been recorded in eastern Ontario in the last 25 years, of which, only one event is of relevance for this assessment. Hence, Event # 1, in Table 4 is the only one used in calculating the frequency of common mode line outages. This event occurred in November 1992 where adverse weather toppled multiple towers. The other outage events are not relevant to common mode outages because either the outage duration is less than 30 minutes (time assumed for switches to restore power supply to customers) or the outage was preventable or both.

NOTE: Event #1 has never occurred on the GTA East 230kV corridor which is the scope of this assessment but used as a proxy for assessment.

4.2 Reliability Results

The annual frequency of line common mode outages for 230 kV circuits east of Cherrywood TS was calculated by dividing the number of common mode line outages in 25 years by the product of the number of circuit in service years and the total circuit km over the 25 years period. The annual frequency was found to be **0.00007 outages/km** for all of eastern Ontario's 230kV transmission circuits. A low reliability index indicates the circuits in eastern Ontario have performed exceptionally well.

The commissioning of Clarington TS, Option 1b, does not affect the reliability indices for the common mode line outages because of the location of the station at the Oshawa Area Junction. All four 230 kV circuits currently emanate east on single towers from Cherrywood TS to the Oshawa Area junction point. From there on, B23C disperses south towards Belleville TS while the remaining three circuits emanate east on individual towers towards eastern Ontario. Therefore, a common mode line outage on these circuits cannot occur east of Oshawa Area

Junction, future site for Clarington TS.

It is also emphasized that the MDS would have no impact on the frequency of supply interruptions to customers. However, depending upon the location of a permanent fault, the switches can reduce the duration of interruption to customers by isolating the faulted section of the line and restoring the load from the alternative path.

The frequency and duration indices for all options are given in Table 5. The 8 hour restoration time for Option 1a and 1b, without switches, is in accordance with the standard outlined in ORTAC.

Table 5 **Reliability Indices, Common Mode Line Outages**

Options	Annual Frequency of Loss of Supply to any Customer	Duration of loss of Supply in Hours per Occurrence	Annual Duration of Supply Interruptions, F
Option 1a or 1b	0.00182	8	0.01456h or 52.4s
Option 2	0.00182	0.5	0.00091h or 3.3s

4.3 Cost Results

The capital cost and outage cost components were evaluated for all options using the formulae stated earlier. Table 6 shows the results for Circuits B23C and M29C while Table 7 shows the results for Circuits H24C and H26C.

Table 6 **Cost Results, Common Mode Line Outages (B23C/M29C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$36.43-$109.29	$36.43-$109.29
Option 2	$600.00	$2.28-$6.84	$602.28-$606.84

Table 7 **Cost Results, Common Mode Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$31.97-$95.92	$31.97-$95.92
Option 2	$600.00	$2.00-$6.00	$602.00-$606.00

The reliability and cost benefit assessment for the common mode line outages is based on the past 25 years of historical performance of 230kV circuits in eastern Ontario. Based on these findings, the annual reliability index for the GTA East region is only 0.00182 outages. As stated earlier, the installation of switches will not have an impact on the frequency index of events. Rather, as seen in Table 5, the duration of an event is the only dependent variable where the annual duration of an outage is reduced from 52.4s to 3.3s with the installation of switches.

The cost analysis in each option is dependent on the reliability index and is calculated using the assessment data provided in Table 3. Using the cost calculation formulas in Section 3, annual carrying cost of the switches and annual outage costs are calculated for B23C/M29C and

H24C/H26C. The annual carrying cost of the 4 switches per circuit pair is based on the minimum operating period of 20 years while the annual outage costs are based on the duration of outages, calculated from the reliability index, with and without the installation of switches.

The annual cost for just common mode line outages for each pair in the region is approximately $32k-$109k while the annual carrying cost of switches, including cost of outages, for each pair is nearly 5-19 times more, $602k-$607k. Also, the annual outage cost due to a common mode line outage is calculated on a very small probability of an event occurring. The annual frequency of loss of supply to any customer in the region is only 0.00182 outages, 1 in over 549 years, with or without switches as MDS have no impact on the frequency of supply interruptions.

As shown, the annual reliability and cost benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The installation of switches improves the outage duration, if occurred, from 52.4s to 3.3s for a certain annual investment of over $1.2M for both pairs of circuits. The annual benefits will still be lower than the carrying costs even if higher values are used for the frequency of common mode line outages. In addition, MDS are assumed to be 100% reliable in this assessment while they introduce a weak link on the system. The reliability and cost analysis show that the installation of MDS is not justifiable.

5 Impact of Overlap Outages

An overlap outage is referred to an event where two or more components are out of service at the same time. The outage initiating causes are different and outages can start at different time. The overlap outage may occur as one of two types; Forced-Forced or Planned-Forced.

5.1 Line Outage Data

The historical outage data from 1990 to 2014 was used to compute the frequency and duration of H24C/H26C line sections and line terminal indices due to forced and planned outages. A reliability model was developed using Area Reliability Evaluation Program (AREP) for both options. The reliability indices were then used to calculate the annual frequency and annual duration of loss of supply to customers. It is expected that circuits B23C/M29C will have similar reliability indices, if not better, due to comparable characteristics and load as circuits H24C/H26C.

5.2 Reliability Results

Currently, the four circuits collectively supply eastern Ontario for 120–300km. In spite of this long distance, the reliability and security of the transmission lines in this part of the province has been exceptional based on the historical performances. Given that these 230kV circuits will now be terminating at Clarington TS, the exposure will reduce to 26km, the region's security and reliability is expected to improve substantially. Table 8 illustrates the reliability indices for the loss of supply to customers considering both types of overlap events: Forced-Forced and Planned-Forced.

Table 8 **Reliability Indices, Overlap Line Outages**

Options	Annual Frequency of Loss of Supply	Annual Duration of Supply Interruptions
Option 1a	0.01	0.12h or 7.02m
Option 1b	0.0008	0.007h or 26.60s
Option 2, Whitby TS DESN 1	0.0001	0.0003h or 1.26s
Option 2, Thornton TS/CTSs	0.0004	0.002h or 8.47s

For each reliability index above, two sets of reliability indices were considered: one due to the overlap of forced outages (Forced-Forced) only and one with the overlap of planned and forced outages (Planned-Forced). In the course of the overlap outages' assessment, it was observed that the Planned-Forced type outages had the dominant impact on the final reliability indices when compared to Forced-Forced type outages.

Further, two types of outages in each set, namely the permanent outages and the switching outages, were computed. In the permanent outage, the supply to customers is restored after repairing the failed components while in the switching outage; the supply to customers is restored by switching off the failed components and restoring the healthy ones to service. The switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour except in the case of Option 2 where MDSs are expected to operate within 30 minutes.

It is observed in Table 8 that with the commissioning of Clarington TS in 2018, the reliability improves by over 92% while an additional investment in MDSs of over $24 million yields another increment of only 7% to the system reliability. With Clarington TS in service, Option 1b, the reliability indices improve significantly when compared to the reliability of the existing supply system. Also, the annual duration of supply interruption is reduced to just 26.6 seconds from 7 minutes with Clarington TS in the region.

5.3 Cost Results

The capital (carrying) cost and outage cost components were evaluated for the both options using the formulae stated earlier and the results are shown in Table 9. These costs are mainly dependent on the annual duration of supply interruption in Table 8. Since the annual duration of supply interruption in the region is expected to be reduced to merely 26.6s with Clarington TS soon to be in service, the annual expected outage cost has dropped by almost 94%.

Table 9 illustrates that the annual benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The performance of H24C/H26C is expected to be exceptionally good following the commissioning of Clarington TS with an expected annual cost of $15.37k-$46.12k, a very well improvement from the current system and at least 13 times more economical than the annual cost with the switches. With the inclusion of Clarington TS by 2018, the system is projected to be most cost-effective and reliable.

Table 9 **Cost Results, Overlap Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a	$0.00	$263.52-$790.56	$263.52-$790.56
Option 1b	$0.00	$15.37-$46.12	$15.37-$46.12
Option 2	$600.00	$3.66-$10.97	$603.66-$610.97

6 Conclusion

6.1 Common Mode Outages

The following concluding remarks can be made regarding the impact of the common mode outages:

i) All options have the same frequency of supply interruptions to customers.
ii) Only one common mode outage, relative to this assessment, has occurred in the eastern Ontario in the past 25 years. This event occurred in 1992 due to high winds toppling multiple towers.
iii) The reliability and cost analysis show that it is not justifiable to invest $24M for marginal improvement.

6.2 Overlap Outages

The following concluding remarks can be made regarding the impact of overlap outages:

i) A significant improvement in reliability is observed after the commissioning of Clarington TS in 2018, Option 1b. However, the installation of MDS, Option 2, does not result in a substantial improvement in the reliability indices for an additional cost of approximately $24M.
ii) The result of reliability/cost analysis for circuits B23C/M29C is expected to be similar to H24C/H26C due to similar regional characteristics and loading conditions, therefore, same conclusion can be drawn for both pairs.

6.3 Summary

Based on historical data and a technical analysis on how outages impact the loads supplied by the GTA East 230kV corridor currently, post-Clarington TS, and with MDS, Table 10 illustrates that Clarington TS alone improves the reliability in the region by 77.8% while with additional investment of $24M in MDS, further reliability improvement is insignificant (less than 4%).

Table 10 **Summary of Results**

Options	Total Annual Cost ($k)	Annual Frequency of Interruption	% Reliability Improvement
Option 1a, Current System	$632.16-$1,896.49	0.02364	-
Option 1b, post Clarington TS	$101.28-$303.87	0.00524	77.8%
Option 2, MDS post Clarington TS	$1,211.47-$1,234.37	0.00444	81.2%

In conclusion, the performance of all 4 circuits has been very good over the last 20 years. With Clarington TS in service in 2018 the risk exposure on these circuits will be significantly less; therefore, it is not justifiable to further invest $24M.

Finally, these costs will have to be recovered from the customers or rate payers consistent with the TSC. Furthermore, MDS were considered to be ideal and 100% reliable in the course of this assessment but in reality introduce a weak link in the system.

WG is recommending that based on this assessment, Option 1b is considered to be the most economical and reliable state of the system. No further action is required at this time.

7 Next Steps

Hydro One will continue with the Clarington TS and keep the LDCs informed of any delays with the project. The finding of this study will be included in the GTA East RIP report expected to be completed in Q4 2016.

8 References

[1] Line Switches Reliability Study by Gomaa HAMOUD, Hydro One – May, 2016
[2] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May, 2013
[3] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
[4] GTA East Needs Assessment Report – April, 2013
[5] GTA East Integrated Regional Resource Plan (IRRP) Report – June, 2016

GTA North

Regional Infrastructure Plan

February 5, 2016

hydro one

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DISCLAIMER

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

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

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

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE ("TSC") REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN FACILITIES THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA NORTH REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region's Integrated Regional Resource Planning ("IRRP") by the IESO in April 2015 and the Western Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

The major infrastructure investments planned for the GTA North Region over the near-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream's station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

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1 INTRODUCTION

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

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

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

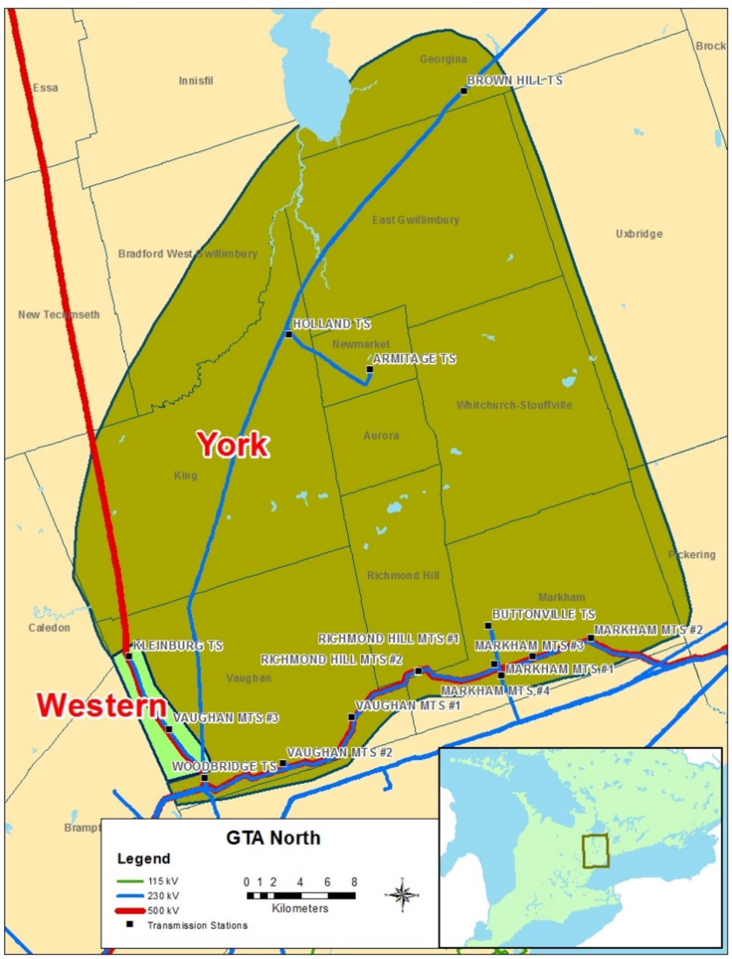

Figure 1-1 GTA North Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which 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

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- NA, SA, and LP phases of regional planning; and,
- 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.

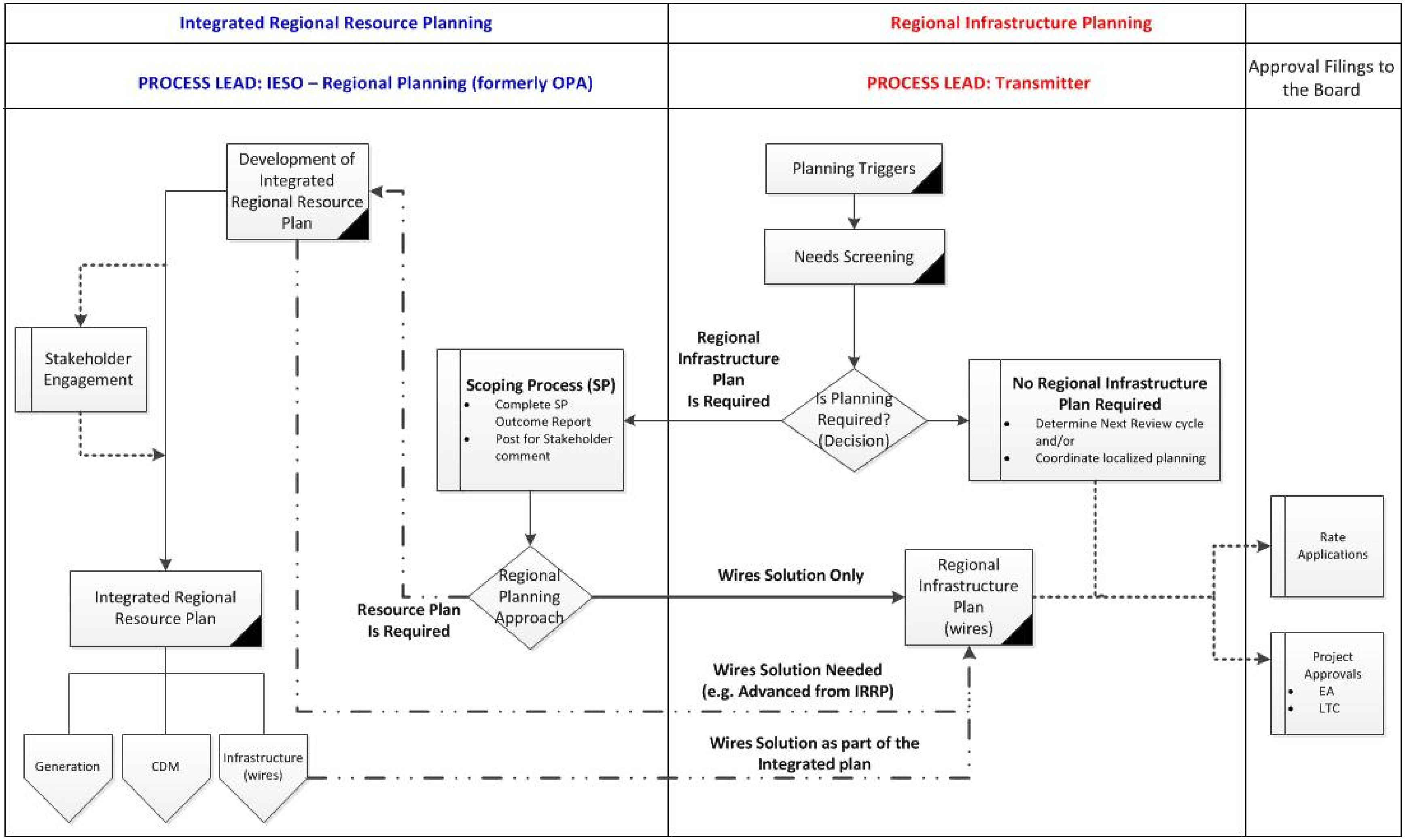

Figure 2-1 Regional Planning Process Flowchart

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 this information and reviews it with the Working Group 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 DG or CDM programs.
   - Existing area network and capabilities including any bulk system power flow assumptions; and,
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

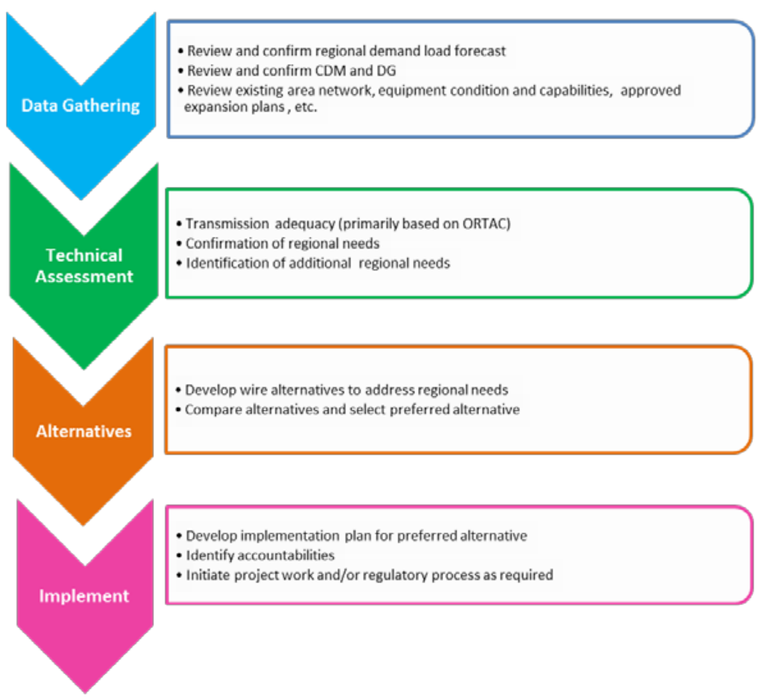

Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan ("IRRP"), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region's electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

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

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.
During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

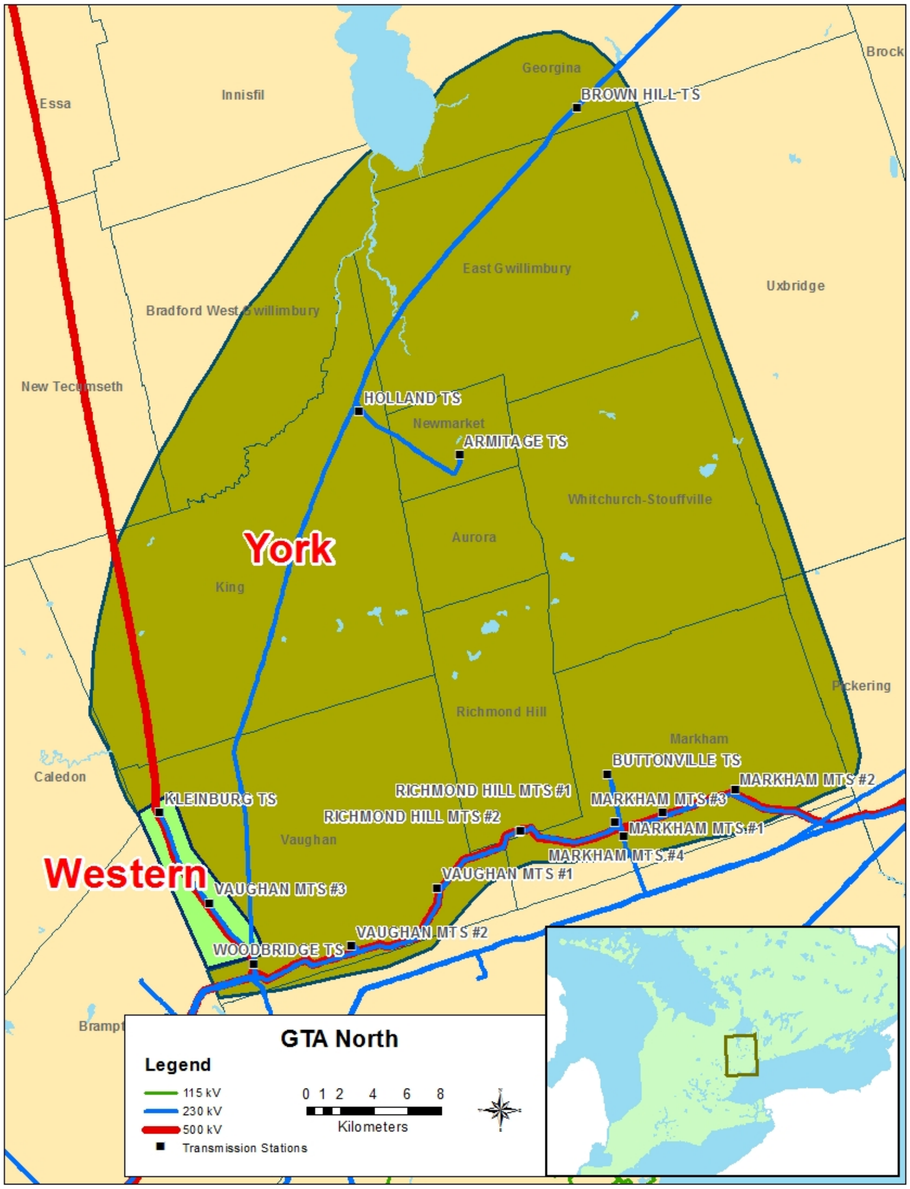

Figure 3-1 GTA North Region – Supply Areas

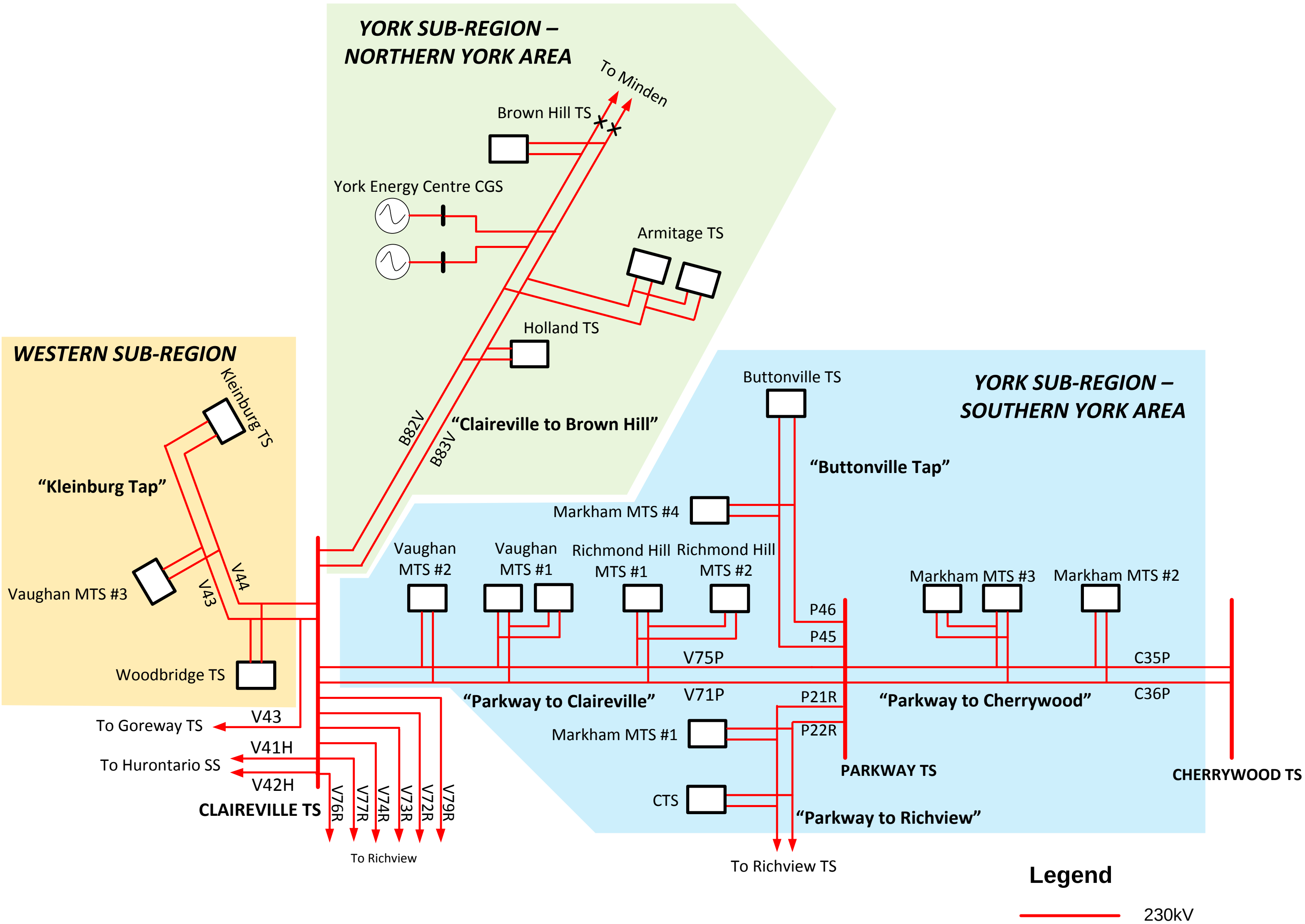

Figure 3-2 GTA North Transmission Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA NORTH REGION.

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

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.

- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North

- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area

- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.

- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.

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

The following development projects are currently underway:

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

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

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

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

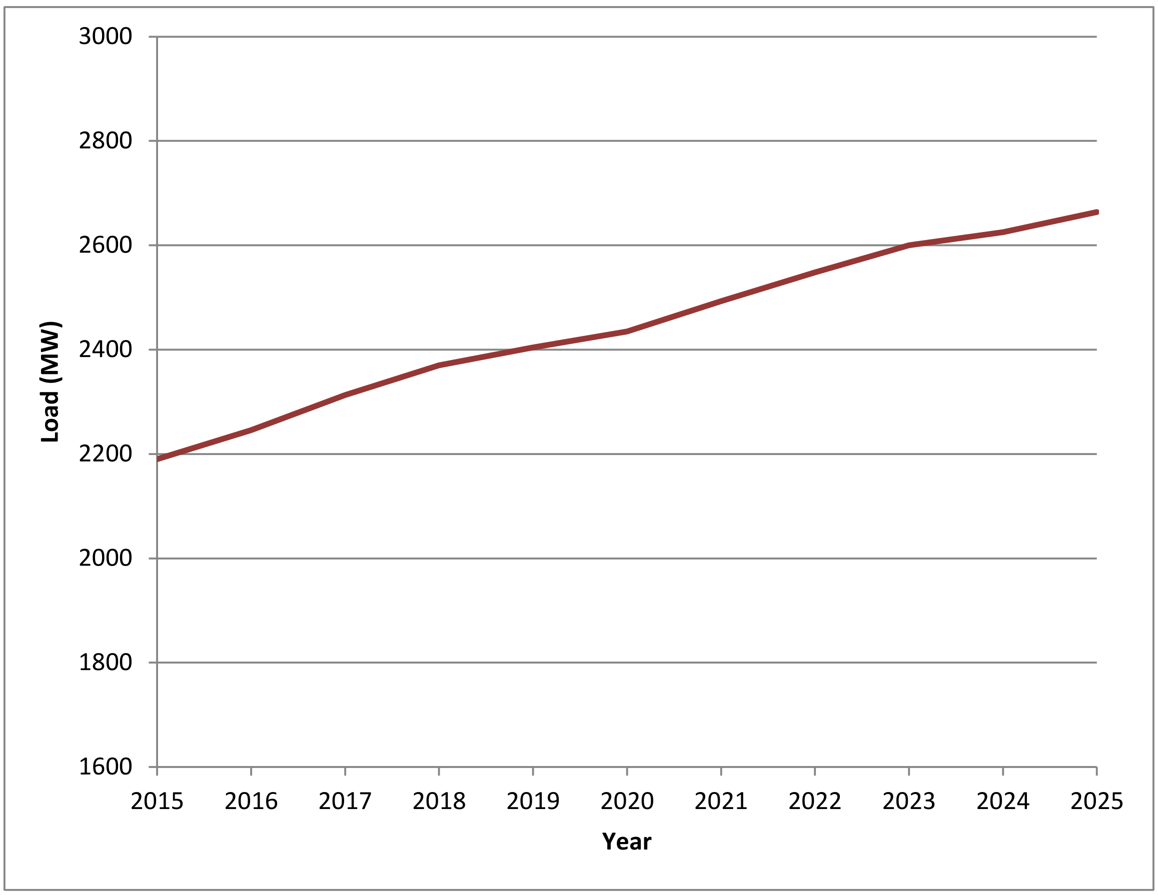

Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- 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 which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6 ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA NORTH REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

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

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

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

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP

** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

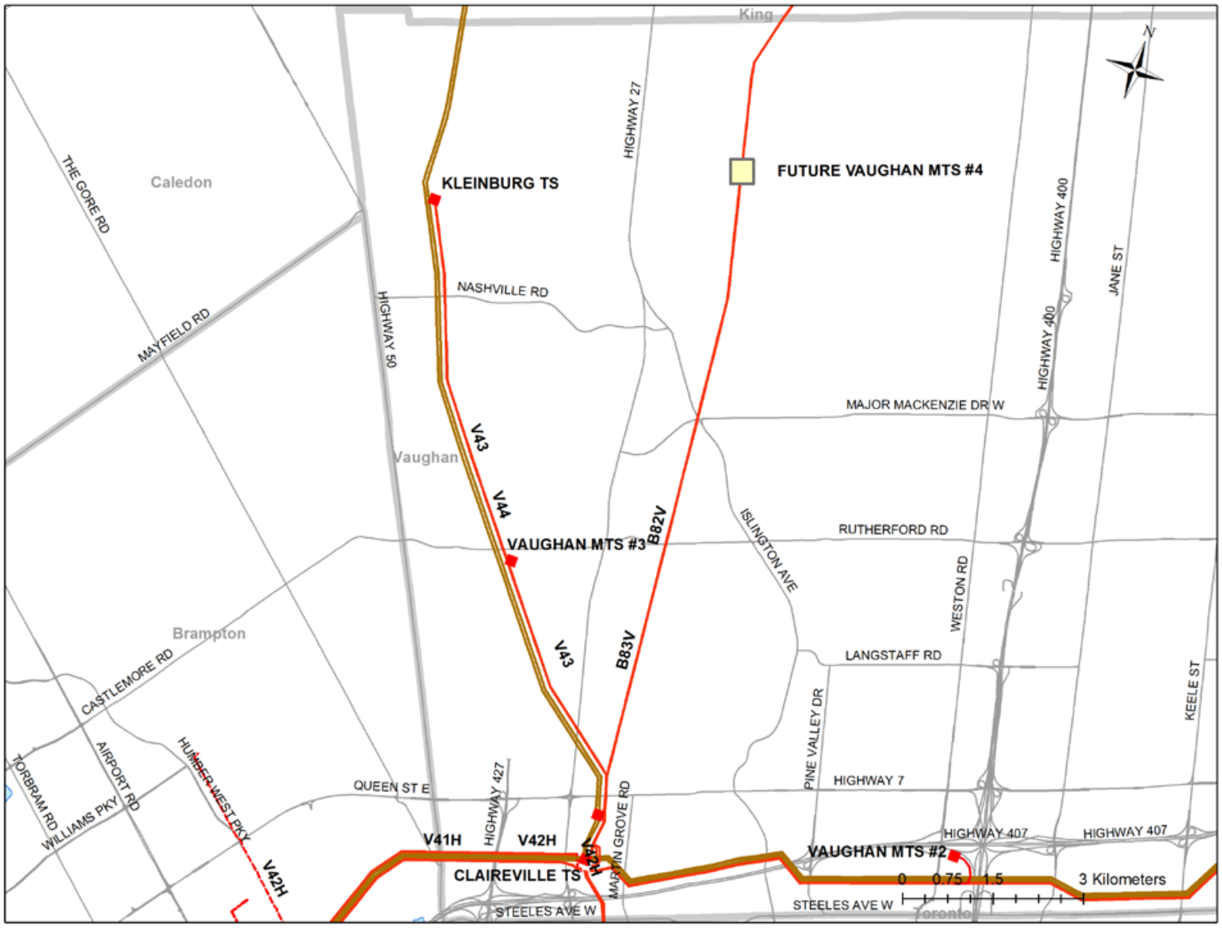

Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme ("SPS"). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP, under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH 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

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

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APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type	Area/Region
Enersource Hydro Mississauga Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Brampton Networks Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Networks Inc. (Distribution)	Armitage TS	Tx	Northern York Area
	Brown Hill TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Woodbridge TS	Tx	Western Sub-Region
Newmarket-Tay Power Distribution Ltd.	Armitage TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
PowerStream Inc.	Armitage TS	Dx	Northern York Area
		Tx	Northern York Area
	Buttonville TS	Tx	Southern York Area
	Holland TS	Dx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Markham MTS #1	Tx	Southern York Area
	Markham MTS #2	Tx	Southern York Area
	Markham MTS #3	Tx	Southern York Area
	Markham MTS #4	Tx	Southern York Area
	Richmond Hill MTS #1	Tx	Southern York Area
	Richmond Hill MTS #2	Tx	Southern York Area
	Vaughan MTS #1	Tx	Southern York Area
	Vaughan MTS #2	Tx	Southern York Area
	Vaughan MTS #3	Tx	Western Sub-Region
	Woodbridge TS	Dx	Western Sub-Region
		Tx	Western Sub-Region
PowerStream Inc.[Barrie]	Holland TS	Dx	Northern York Area
Toronto Hydro Electric System Limited	Woodbridge TS	Dx	Western Sub-Region
Veridian Connections Inc.	Armitage TS	Dx	Northern York Area

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

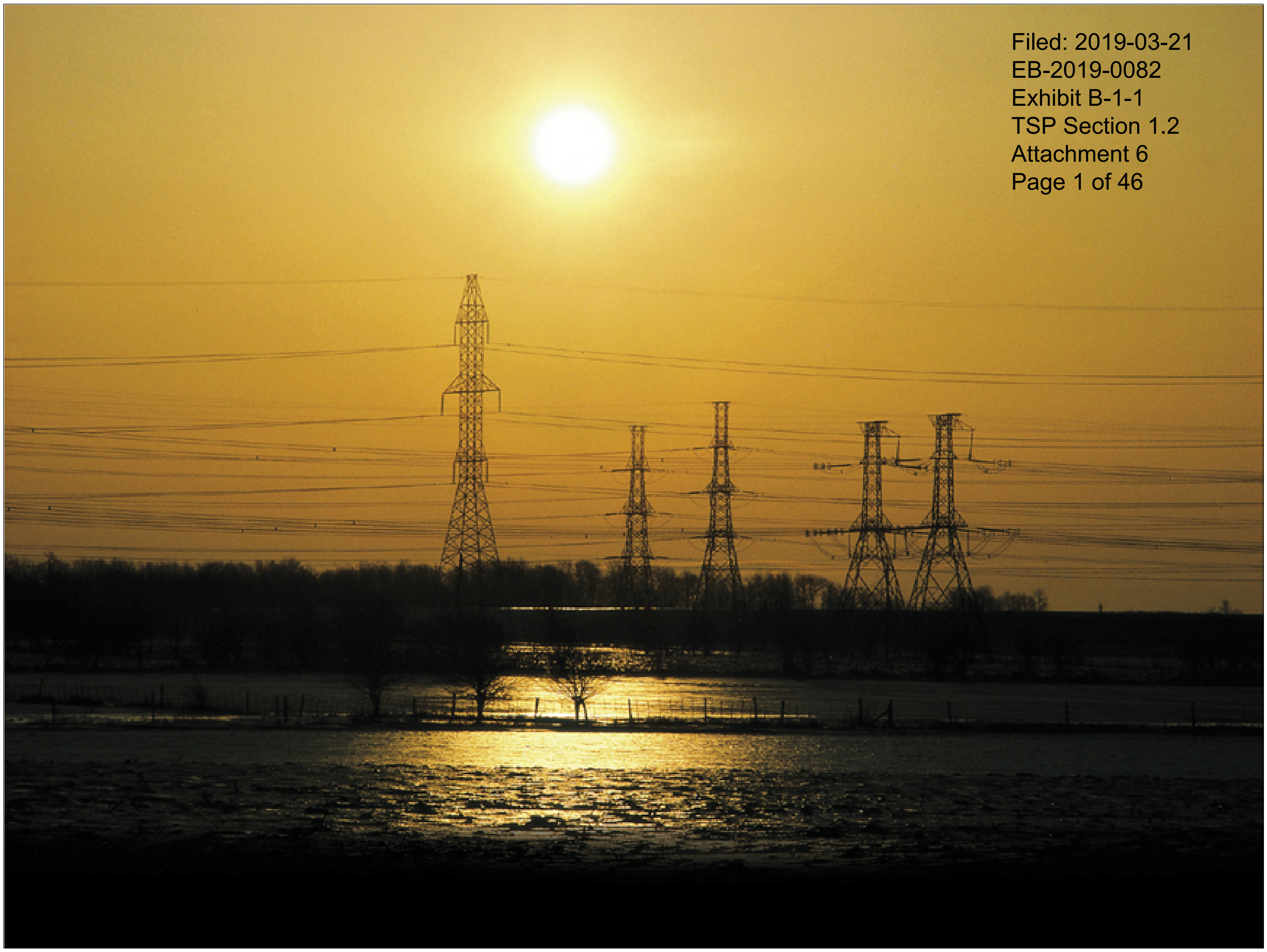
Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

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



GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

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

With support from:

Company
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Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution 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 electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

Working Group 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 WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA WEST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan ("IRRP") in April 2015; and the GTA West Southern Sub-Region's Needs Assessment ("NA") and Scoping Assessment ("SA") in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	$19M [(1)]
2	Build new Halton TS #2	2020	$29M [(1)]
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	$5M
4	Upgrade (reconductor) circuits H29/H30 [(2)]	2023-2026	$6.5M

Notes:

(1) Excludes cost for distribution infrastructure

(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA WEST REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Working Group in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville. The region includes the area roughly bordered geographically by Highway 27 to the north-east, Highway 427 to the south-east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

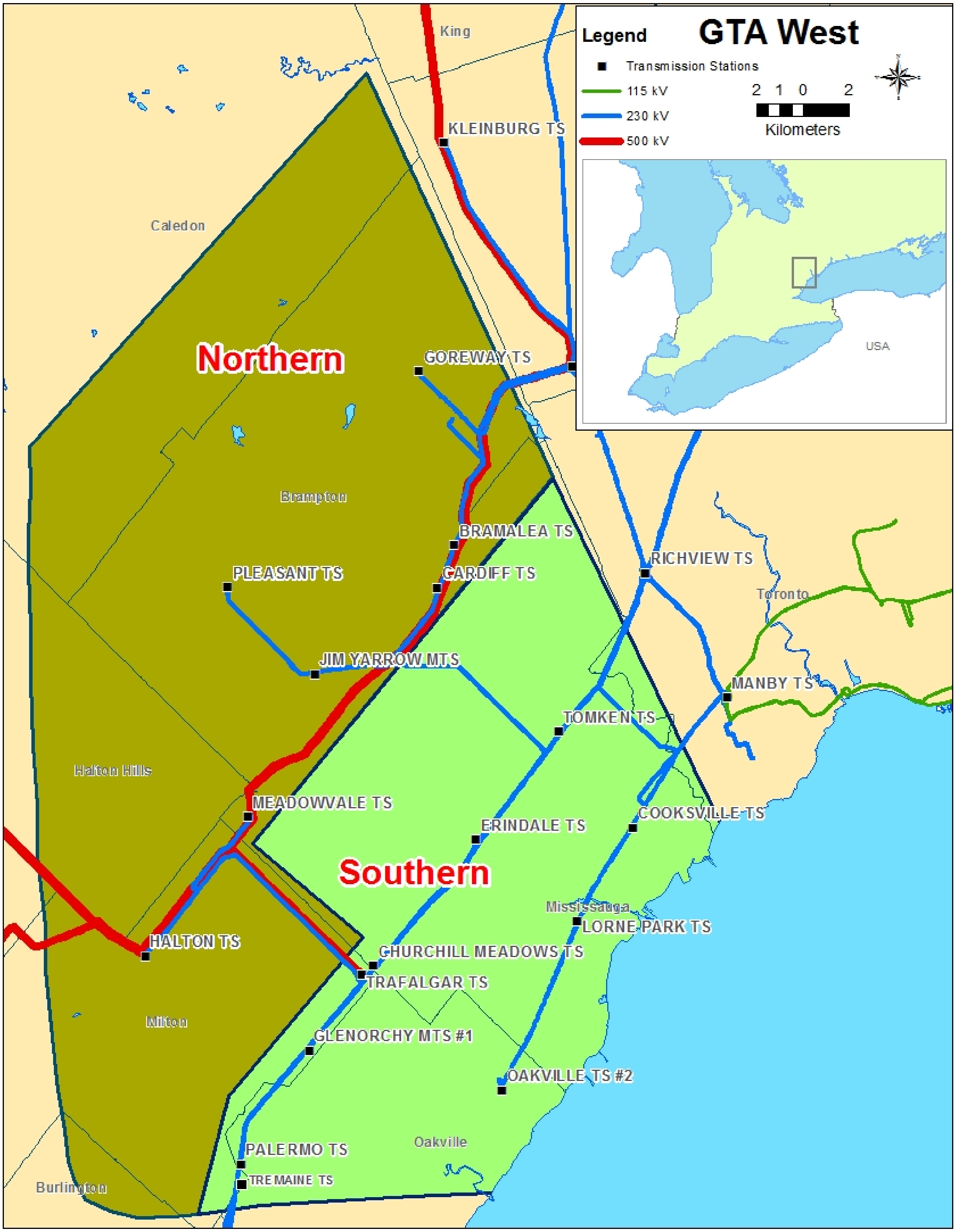

Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and wires plans to address these needs based on new and/or updated information;
- Develop a plan to address any longer terms needs identified by the Working Group.

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 region;
- 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 needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board 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 Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] also referred to as Needs Screening

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

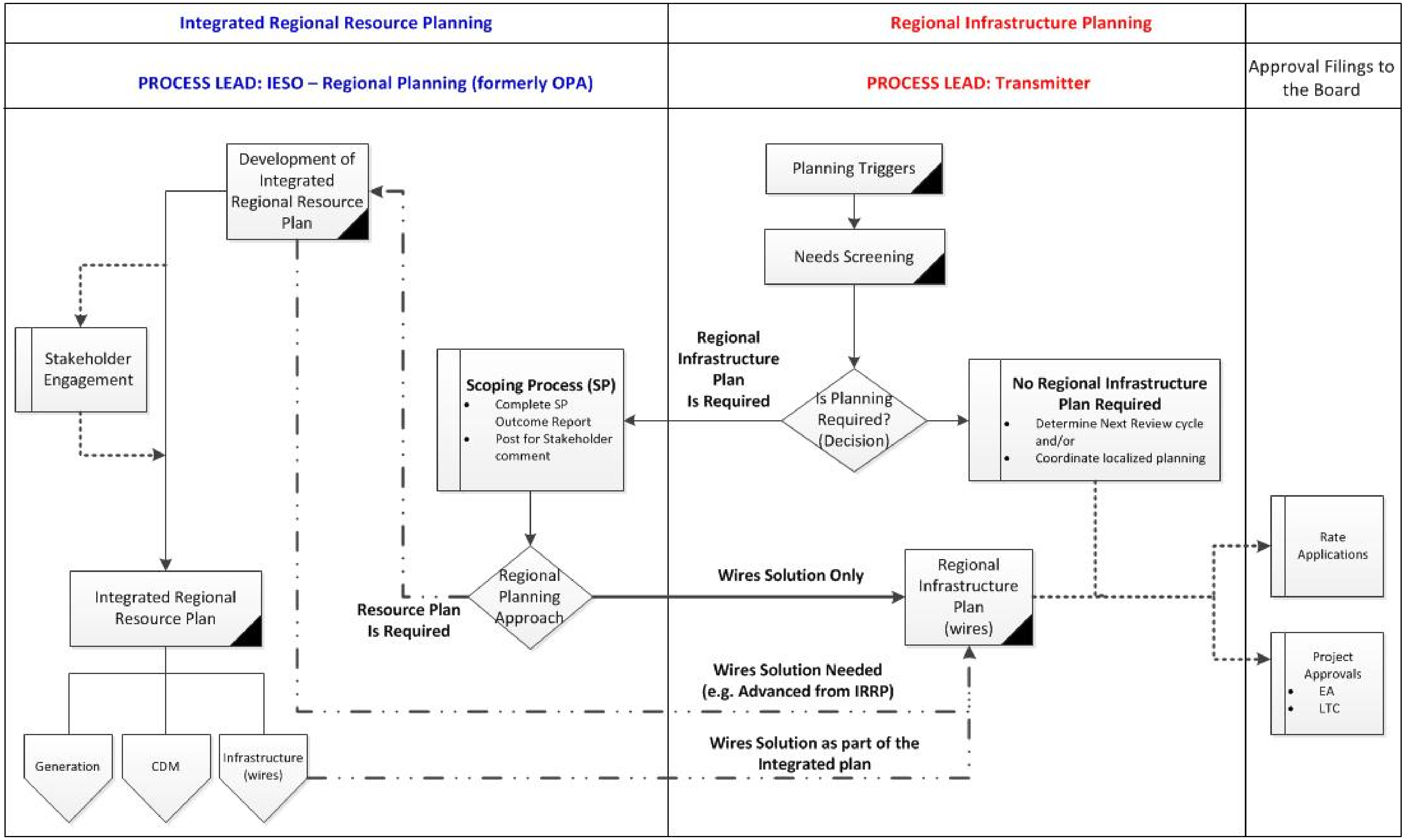

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (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 stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

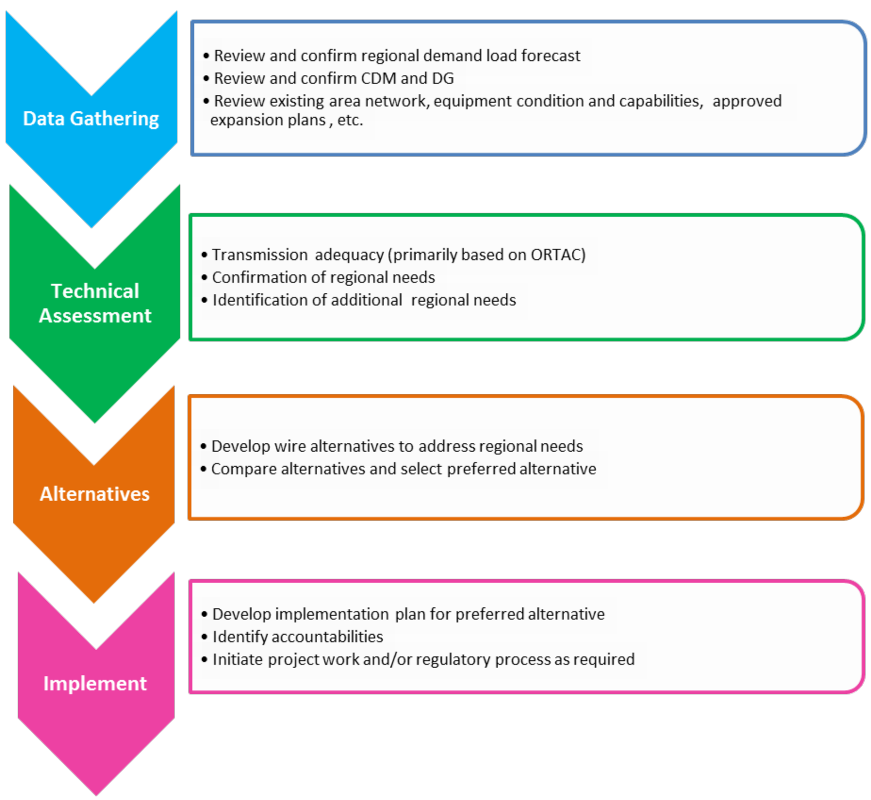

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

The GTA West – Northern Sub-Region was identified as a “transitional” sub-region, as planning activities in this sub-region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. The Northwest GTA IRRP was completed for the Northern Sub-Region in April 2015.

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

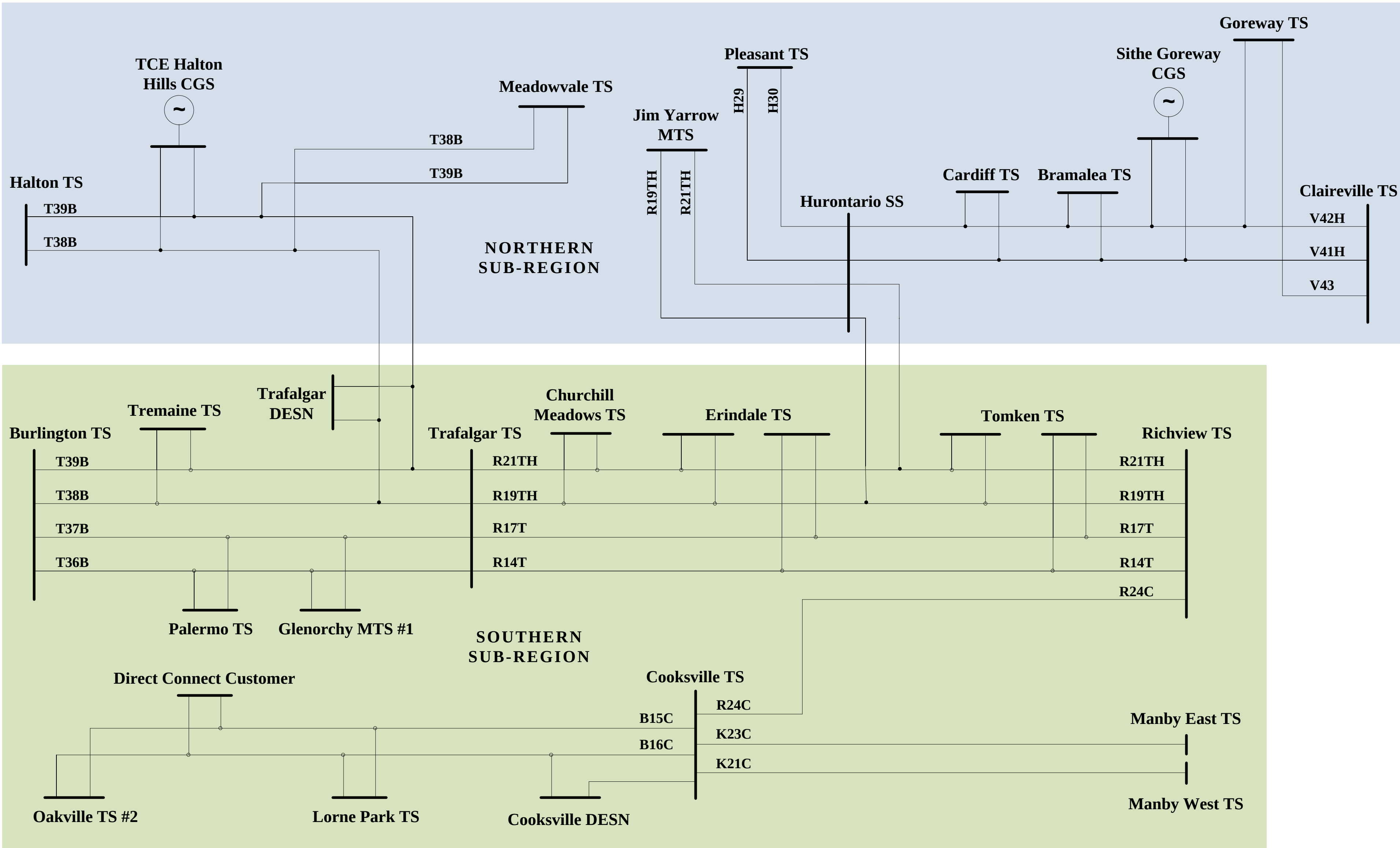

Figure 3-1 GTA West Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY IN THE LAST TEN YEARS

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.
- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).
- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Hurontario SS and underground cable work - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow TS (2010). The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills CGS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. Non-coincident forecast for the individual stations in the region is available in Appendix A, and is used to determine any need for station capacity relief.

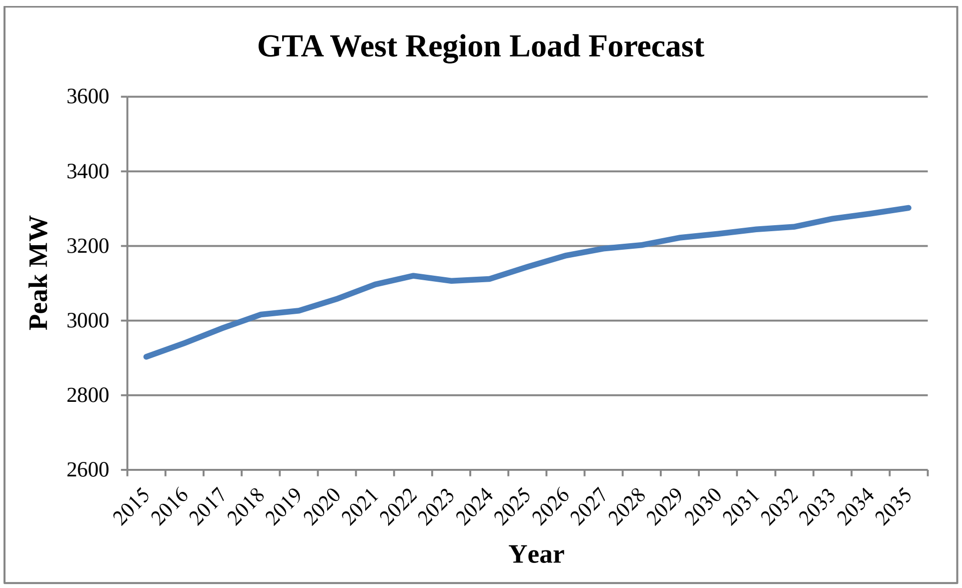

Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2035.
- 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 based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region's Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region's Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region (1): - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess “Kleinburg Radial Pocket” supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS
3. Trafalgar TS to Burlington TS, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region's NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the "Higher Growth" scenario, while 2033 under the "Expected Growth" scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

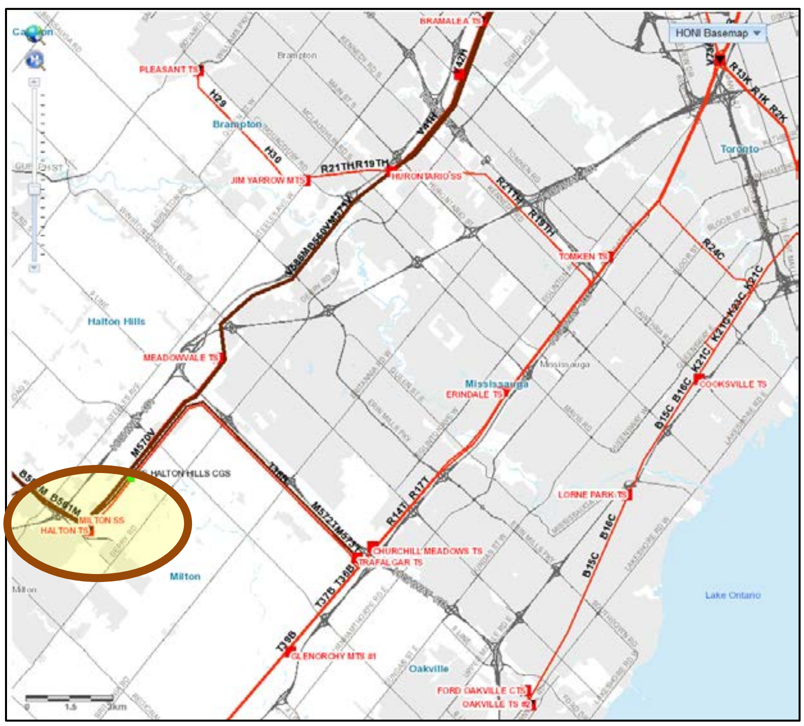

Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro proceed to gain the necessary approvals to construct, own, and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

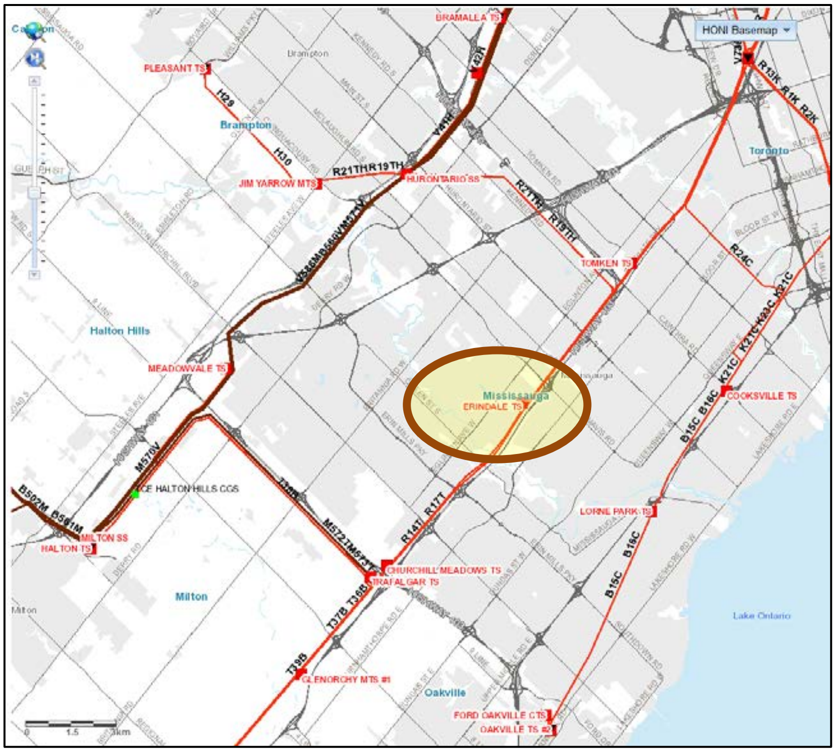

Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA WEST 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 the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans - Next Steps, Lead Responsibility and Plan In-Service Dates

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator. “Northwest GTA Integrated Regional Resource Plan”. April 28, 2015.
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[2] GTA West Southern Sub-Region Study Team. “Needs Screening Report – GTA West Southern Sub-Region”. May 30, 2014.
http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

[3] GTA West Southern Sub-Region Study Team. “GTA West Southern Sub-Region Scoping Assessment Outcome Report”. September 19, 2014.
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. “Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region”. July 9, 2015.
http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Local%20Planning%20Report%20-%20Erindale%20TS%20Capacity%20-%209_July_2015.pdf

[5] Ministry of Infrastructure. Places to Grow: “Growth Plan for the Greater Golden Horseshoe, 2006”. Office Consolidation June 2013.
https://placestogrow.ca/content/ggh/2013-06-10-Growth-Plan-for-the-GGH-EN.pdf

Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
Pleasant TS (T1/T2)	230/44	H29/H30
Pleasant TS (T5/T6)	230/27.6	H29/H30
Pleasant TS (T7/T8)	230/27.6	H29/H30
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
Erindale TS (T1/T2)	230/27.6	R14T/R17T
Erindale TS (T3/T4)	230/44	R14T/R17T
Erindale TS (T5/T6)	230/44	R19TH/R21TH
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	S	172.5	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	S	119.8	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	S	119.7	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	S	181.3	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	S	193.0	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	S	195.1	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	S	153.0	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	S	144.6	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	S	185.2	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	S	109.5	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	S	173.3	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	S	192.8	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	S	124.0	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	S	189.5	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

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

Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

The participants of the RIP Working Group included members from the following organizations:

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE KWCG REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. (“Kitchener-Wilmot Hydro”), Waterloo North Hydro Inc. (“WNH”), Cambridge & North Dumfries Hydro Inc. (“CND”), Guelph Hydro Electric Systems Inc. (“Guelph Hydro”), Hydro One Distribution and the Independent Electricity System Operator (“IESO”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

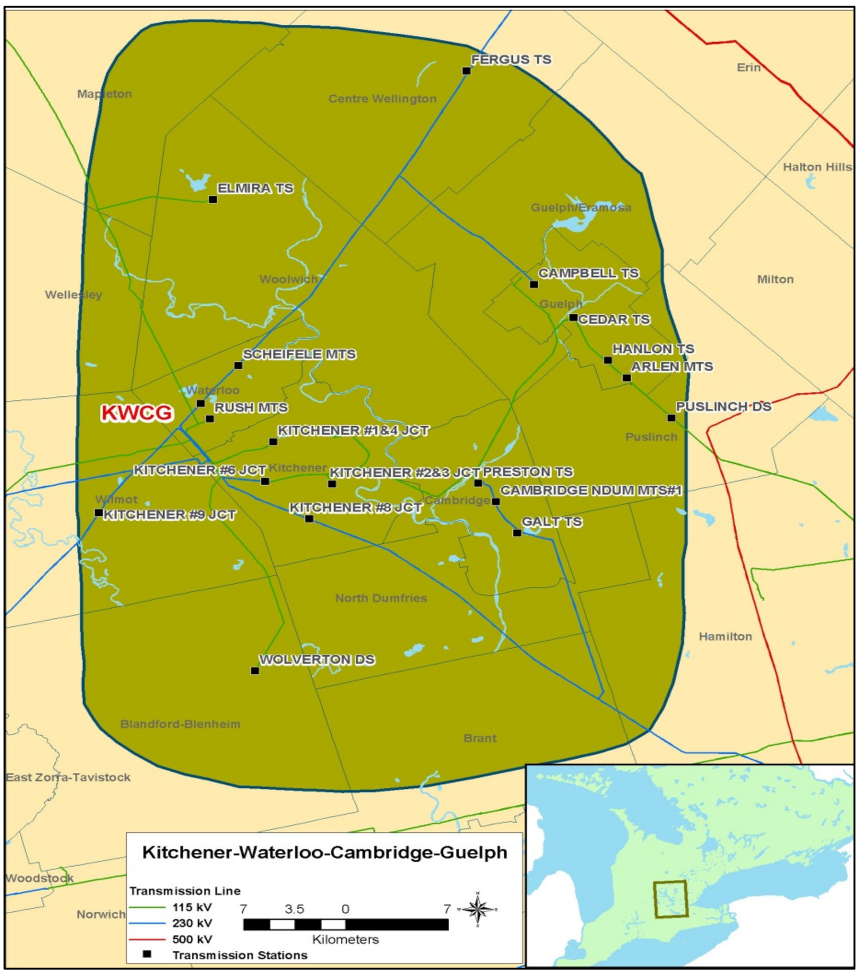

Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG Region. Its objectives are:

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

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated RIP phase information
- Develop a plan to address any longer term needs identified by the Working Group

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- 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 needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the 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 Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best

[1] Also referred to a Needs Screening

suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

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 timeliness 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 steps of the regional planning process (NA, SA, IRRP and RIP) and their respective phase trigger, lead, and outcome.

Note that as the KWCG Region was identified as a "transitional" region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

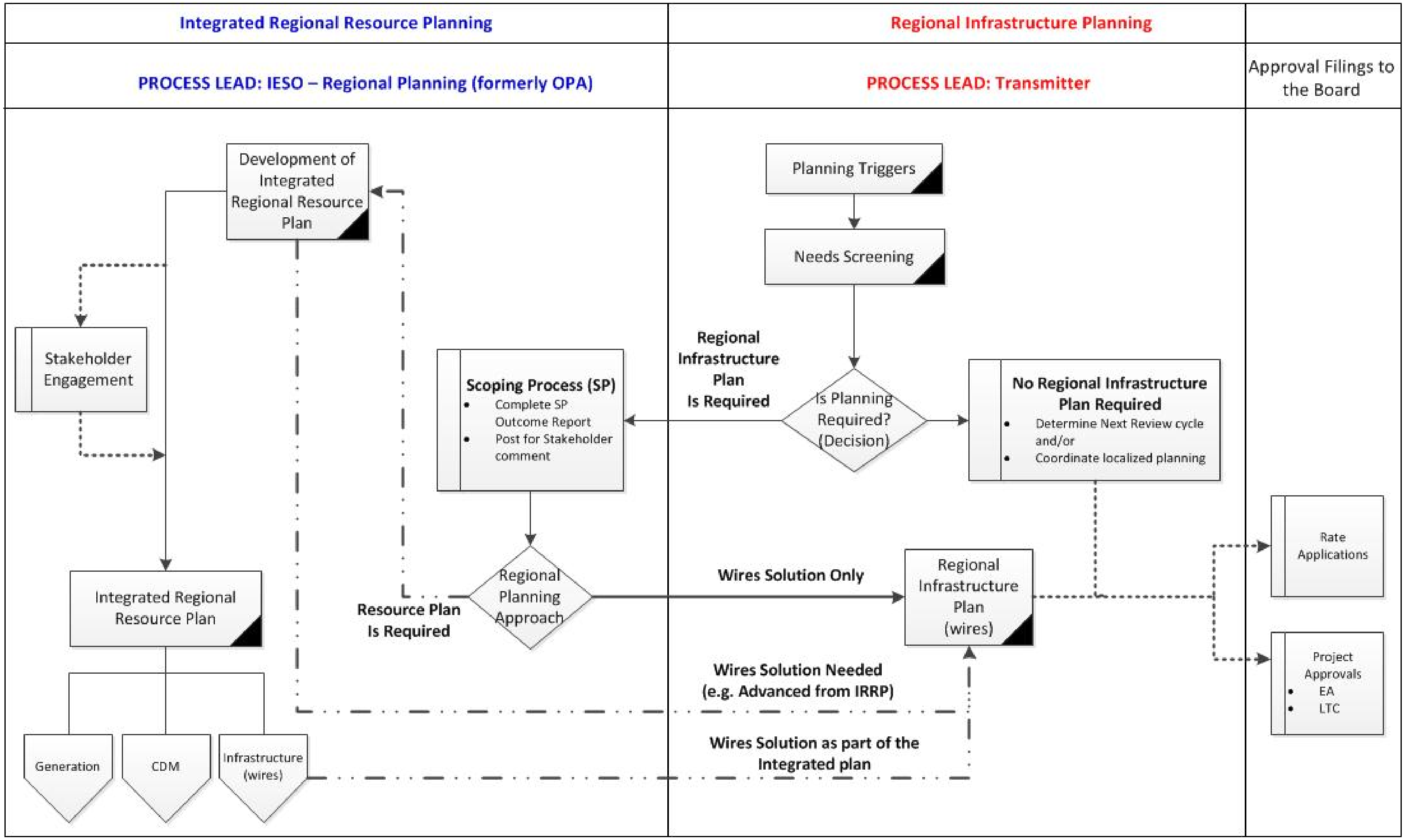

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

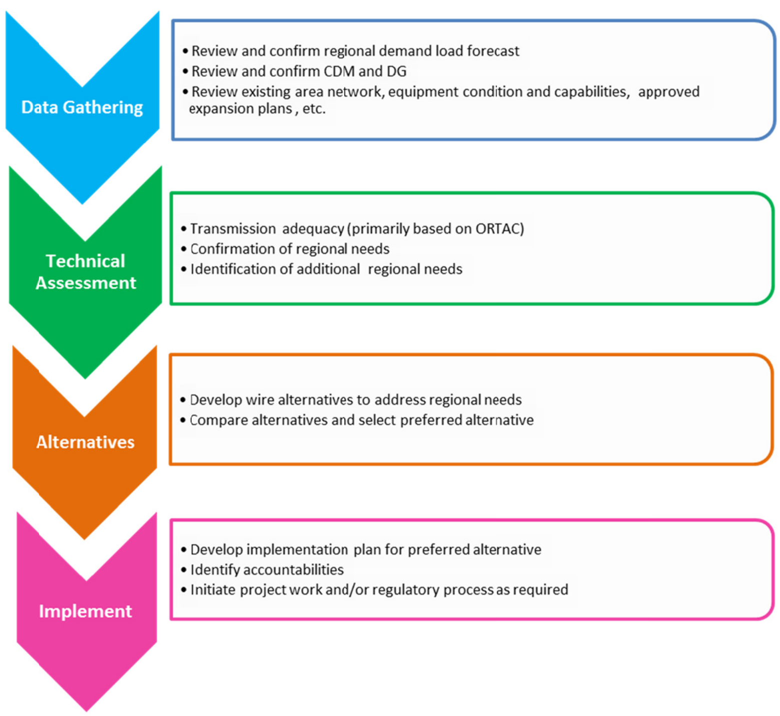

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

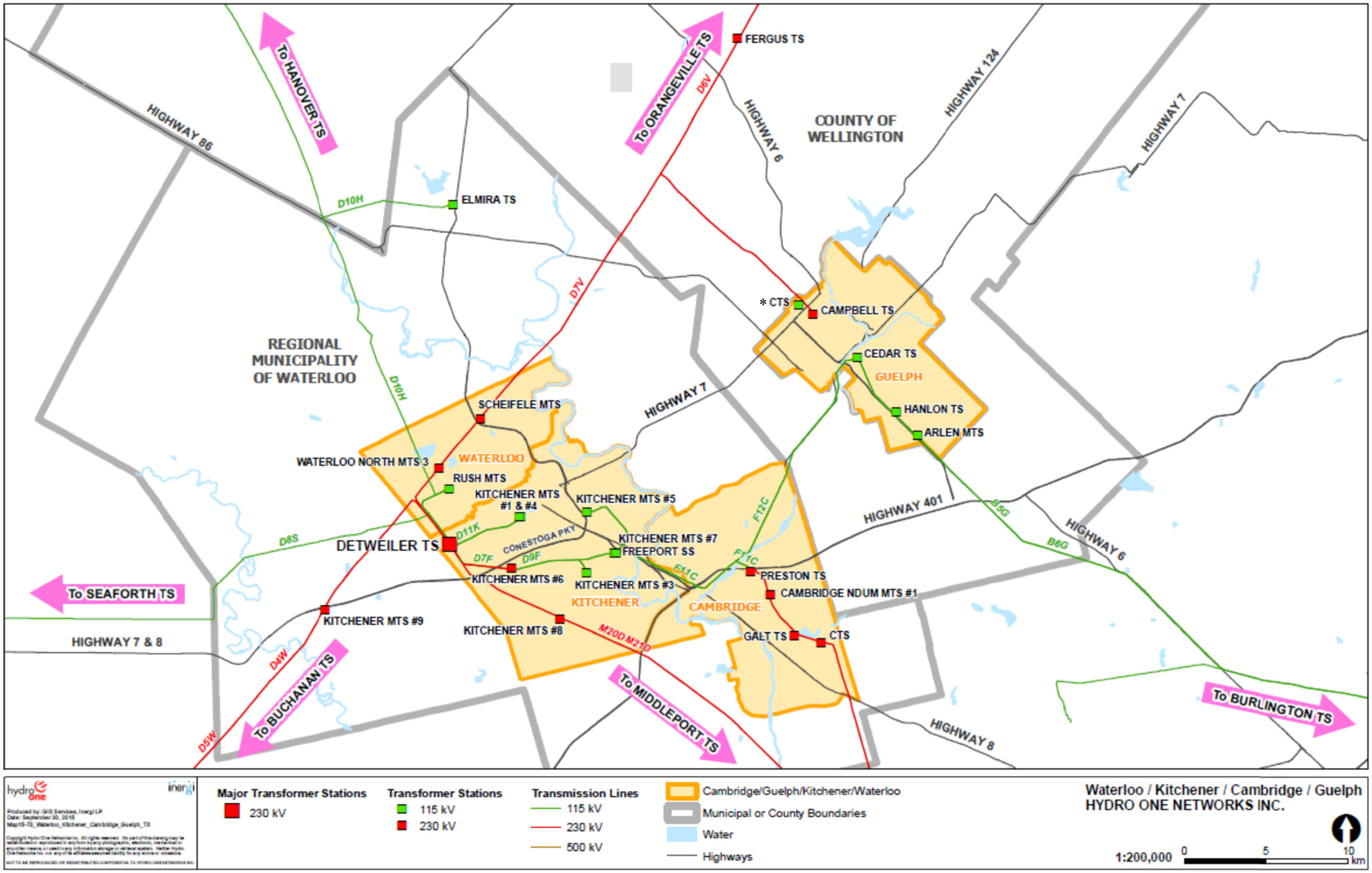

Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

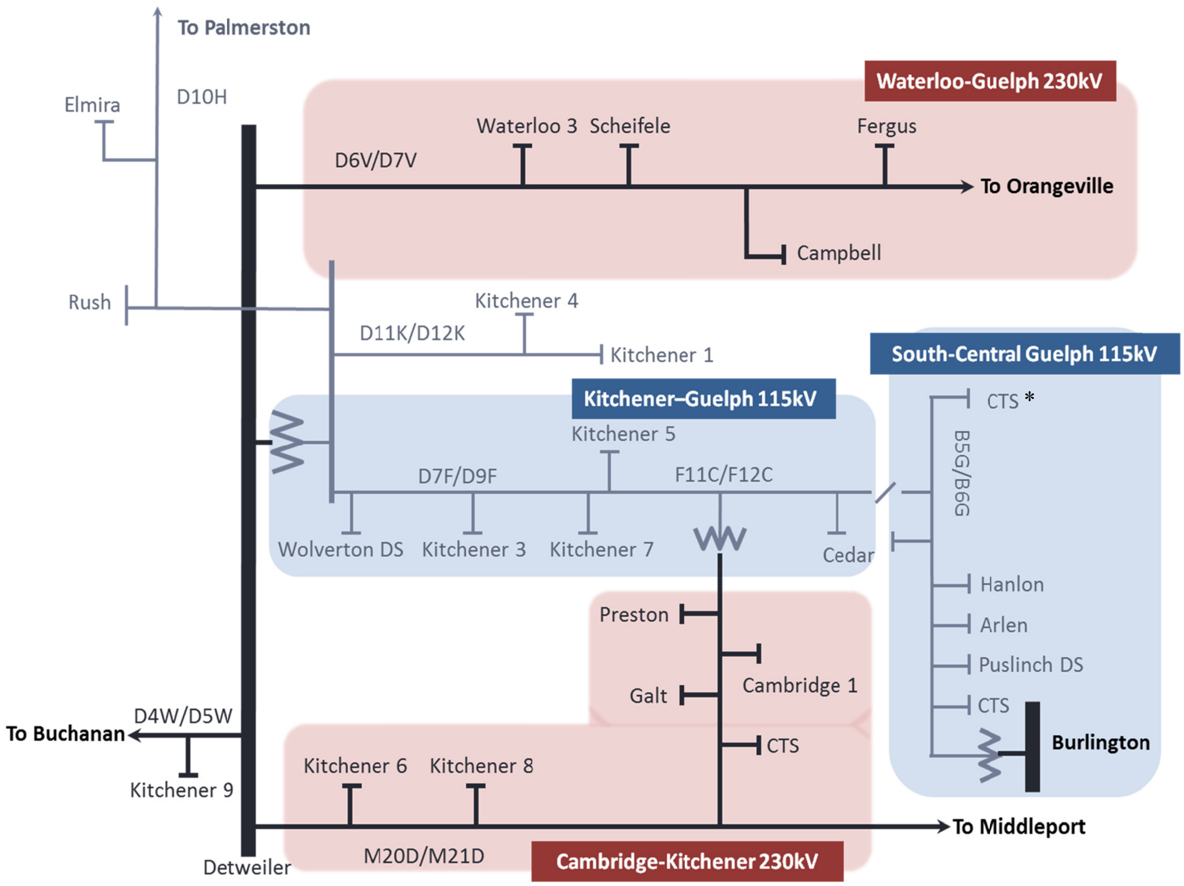

Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE KWCG REGION.

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

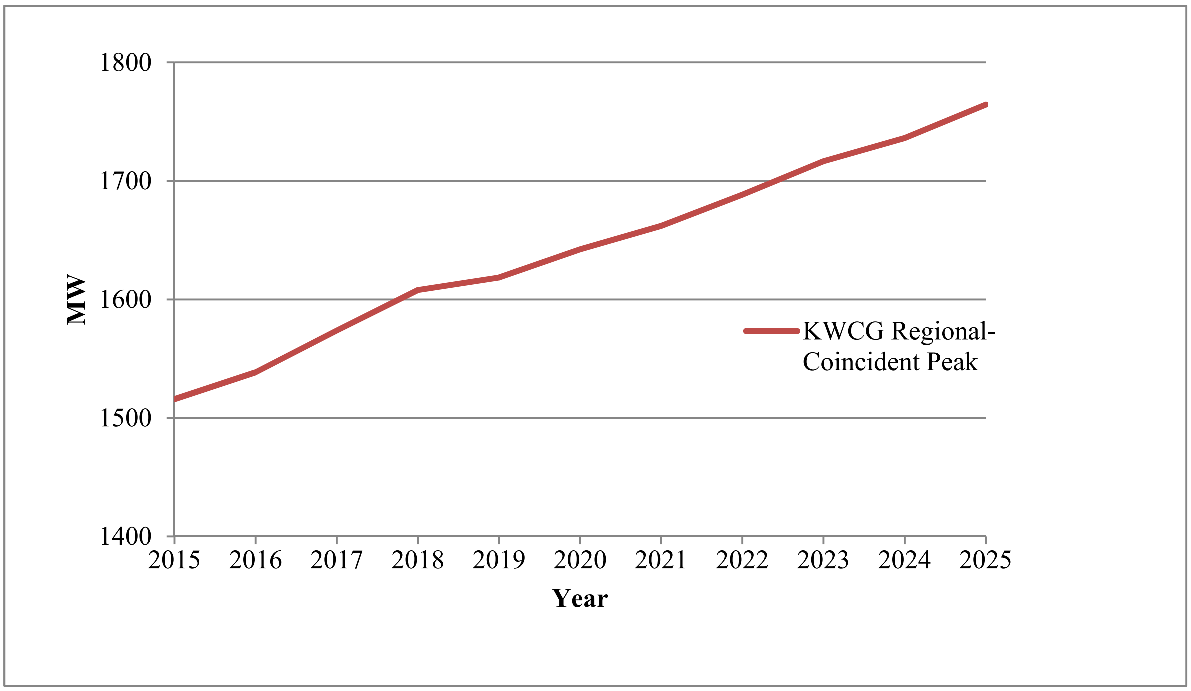

Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG 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 are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation Facilities

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

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment (“SIA”) [4] was performed for Hydro One’s application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG 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.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013. http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro ("CND") has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro ("WNH") are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

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

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
Kitchener-Wilmot Hydro	Shaun Wang L. Frank G. Cameron
Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
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Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

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EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the “London area”) that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 KV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 KV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 Load Restoration Capability Analysis

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 Impact of Contingencies on the BPS to the KWCG Area

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: "These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility."

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 Summary of Needs

Figure 1 illustrates the Needs timeline for the KWCG region.

Figure 1: Transmission Needs in the KWCG Area

4.0 Options to Address the Need

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric “initial capital cost/MW of load restored” was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 “C&ND load only” means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) Immediate Action: Install 230 kV In-Line Switches

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

Local Area Performance

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

BPS Performance

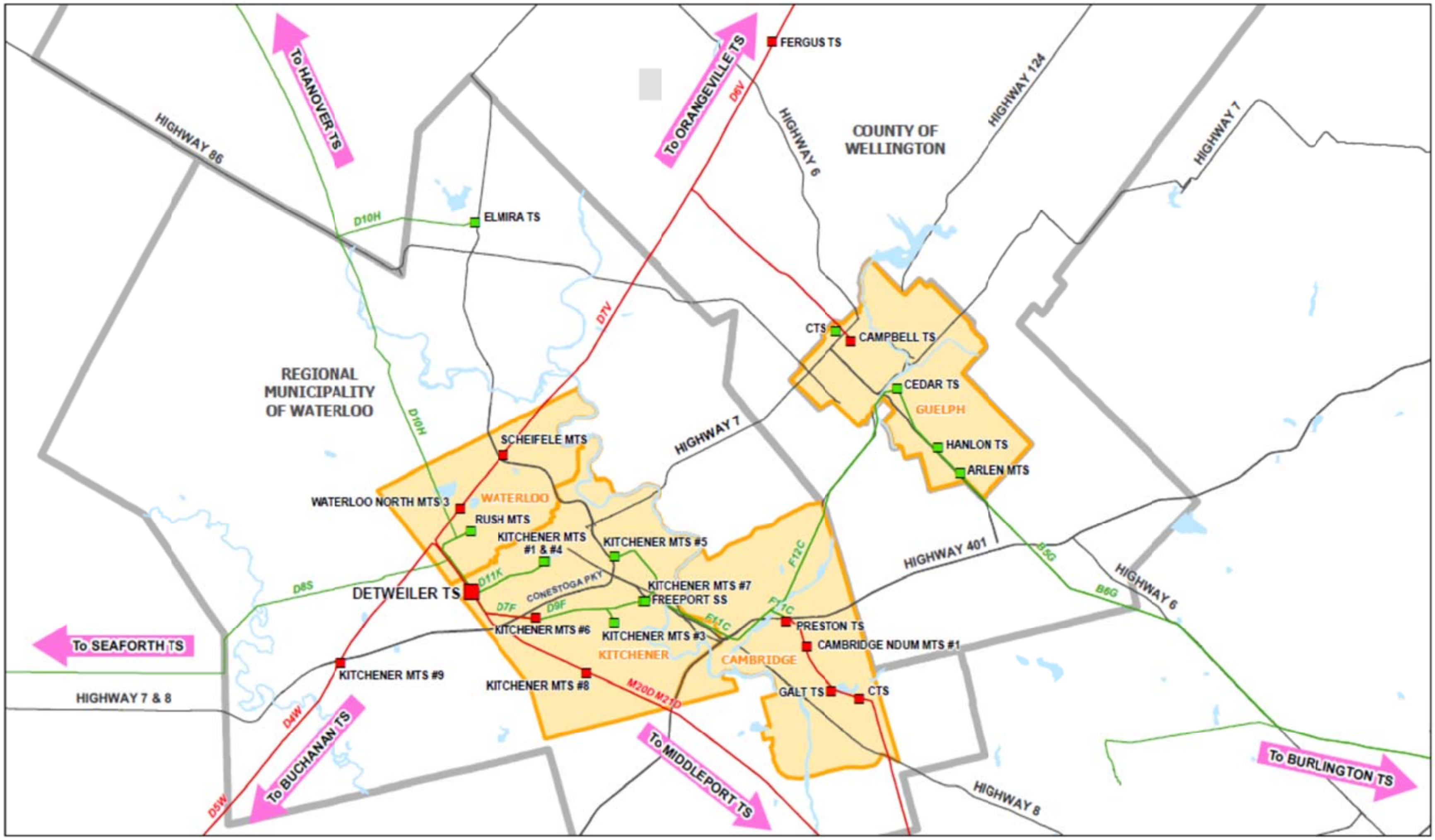
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

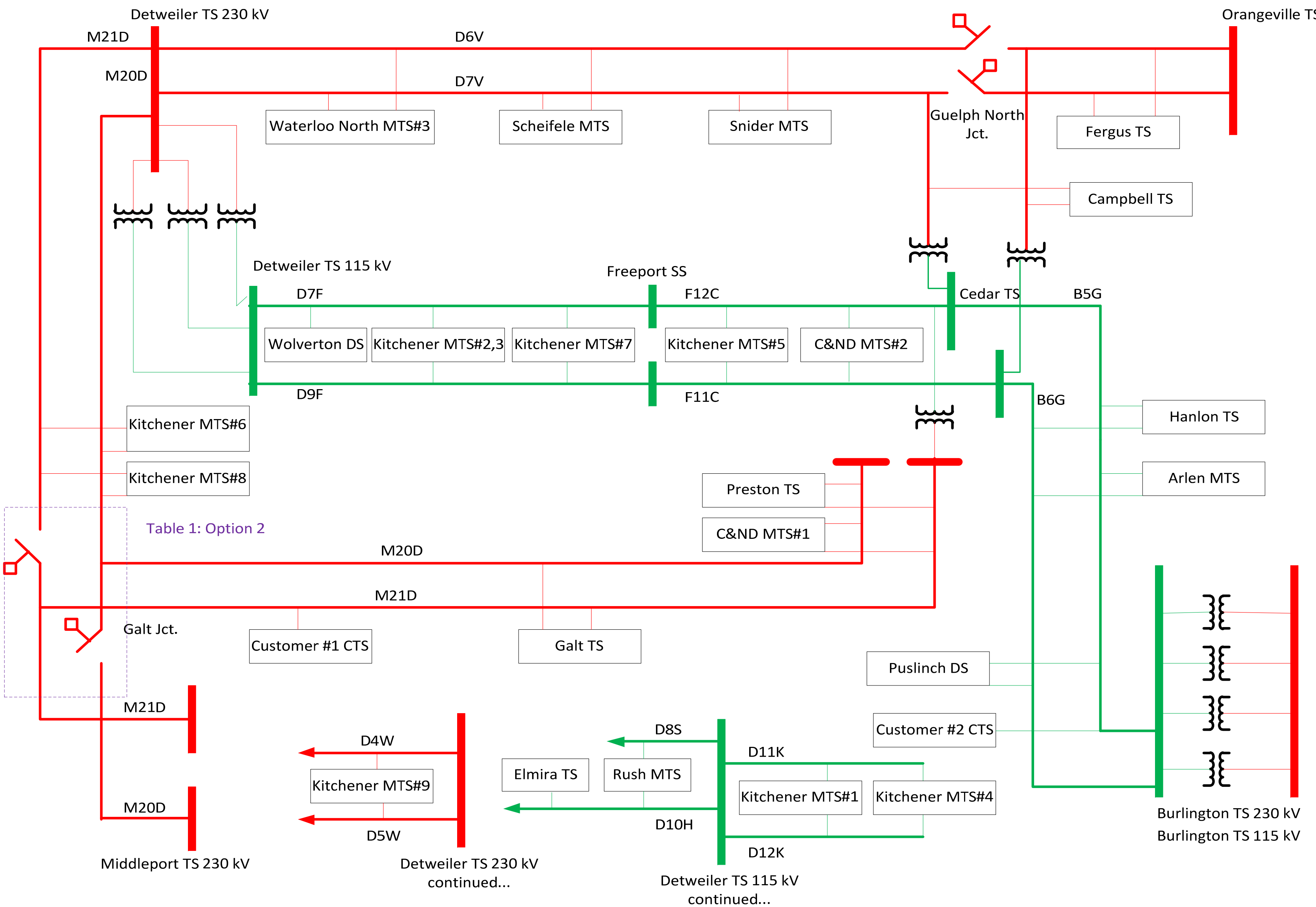
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

<table>
<tr><th colspan="6">Loss of a Single Circuit (N-1)</th></tr>
<tr><td>D11K</td><td>D12K</td><td>D8S</td><td>D10H</td><td>D7F</td><td>D9F</td></tr>
<tr><td>F11C</td><td>F12C</td><td>B5G</td><td>B6G</td><td>D4W</td><td>D5W</td></tr>
<tr><td>M20D*</td><td>M21D**</td><td>D6V***</td><td>D7V****</td><td></td><td></td></tr>
<tr><th colspan="6">Loss of a Single Autotransformer (N-1)</th></tr>
<tr><td>Detw. T2</td><td>Detw. T3♦</td><td>Detw. T4♦♦</td><td>Cedar T3♦♦♦</td><td>Cedar T4♦♦♦♦</td><td>Preston T2**</td></tr>
<tr><td colspan="2">Middleport T3♦♦♦♦♦</td><td colspan="2">Middleport T6♦♦♦♦♦♦</td><td></td><td></td></tr>
<tr><th colspan="6">Loss of a Single HV Reactive Element (N-1)</th></tr>
<tr><td>Detweiler 230 kV cap. bank</td><td>Middleport 230 kV cap. bank(K1D1)</td><td>Orangeville 230 kV cap. bank</td><td colspan="3">Burlington 230 kV cap. bank</td></tr>
<tr><td>Detweiler 230 kV SVC</td><td>Middleport 230 kV cap. bank(K2D2)</td><td>Detweiler 115 kV cap bank</td><td colspan="3">Burlington 115 kV cap bank</td></tr>
</table>

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line		
D7F and D9F	F11C and F12C	B5G and B6G
D4W and D5W	M20D and M21D	D11K and D12K
D6V and D6V		

Loss of Two Autotransformers[7]

Station	Detweiler Auto	Preston Auto	Cedar Auto	Burlington Auto
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	Contingency	%STE
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station’s reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D4/5W</u>

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D7/9F</u>

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D8S/D10H</u>

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	Transformer Capacity (10-day LTR)	Year 2025 Load Forecast
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	Contingency	D10H – Detweiler TS x Waterloo Jct.	D8S – Detweiler TS x Leong Jct.
		590 A Continuous *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	*590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

hydro one

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

With support from:

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

Working Group 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 WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE METRO TORONTO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator ("IESO"), PowerStream Inc., Toronto Hydro-Electric System ("THESL"), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

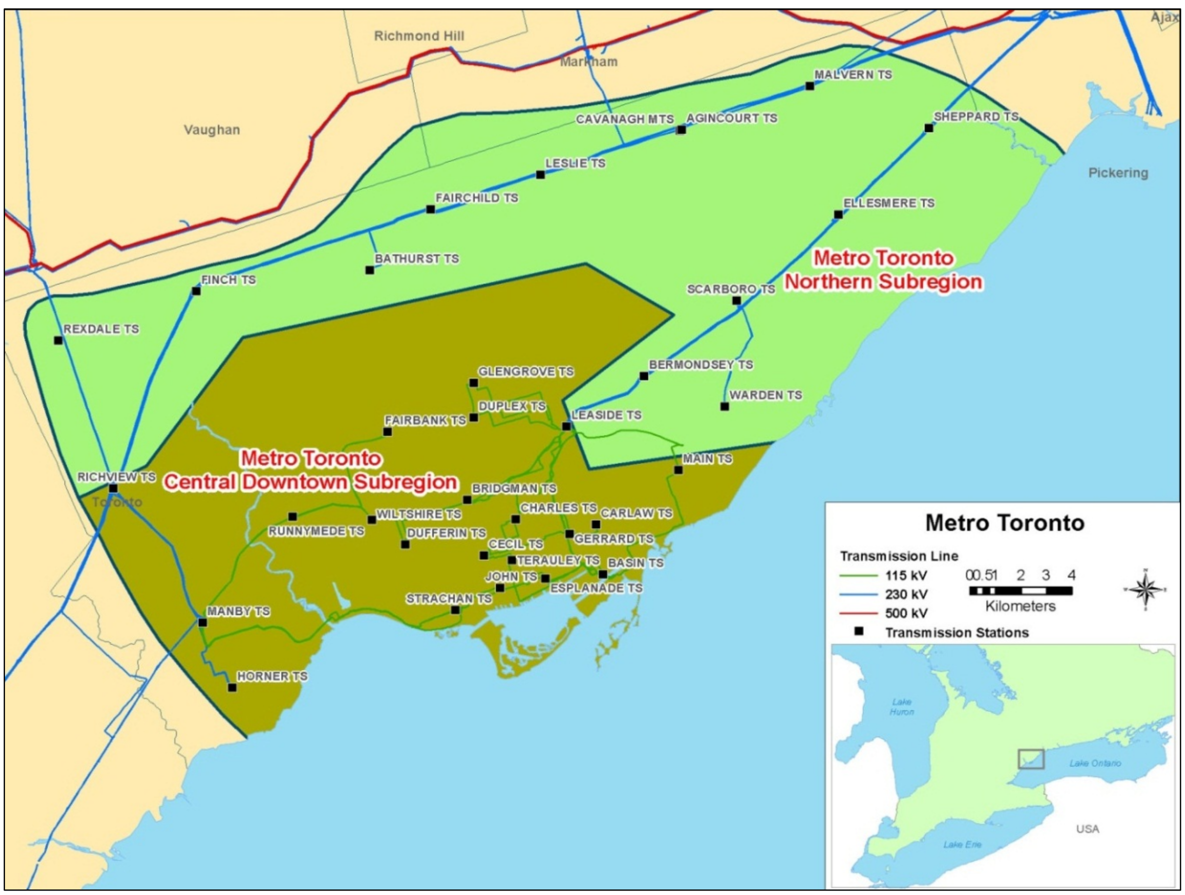

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

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 region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board 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 Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which 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. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

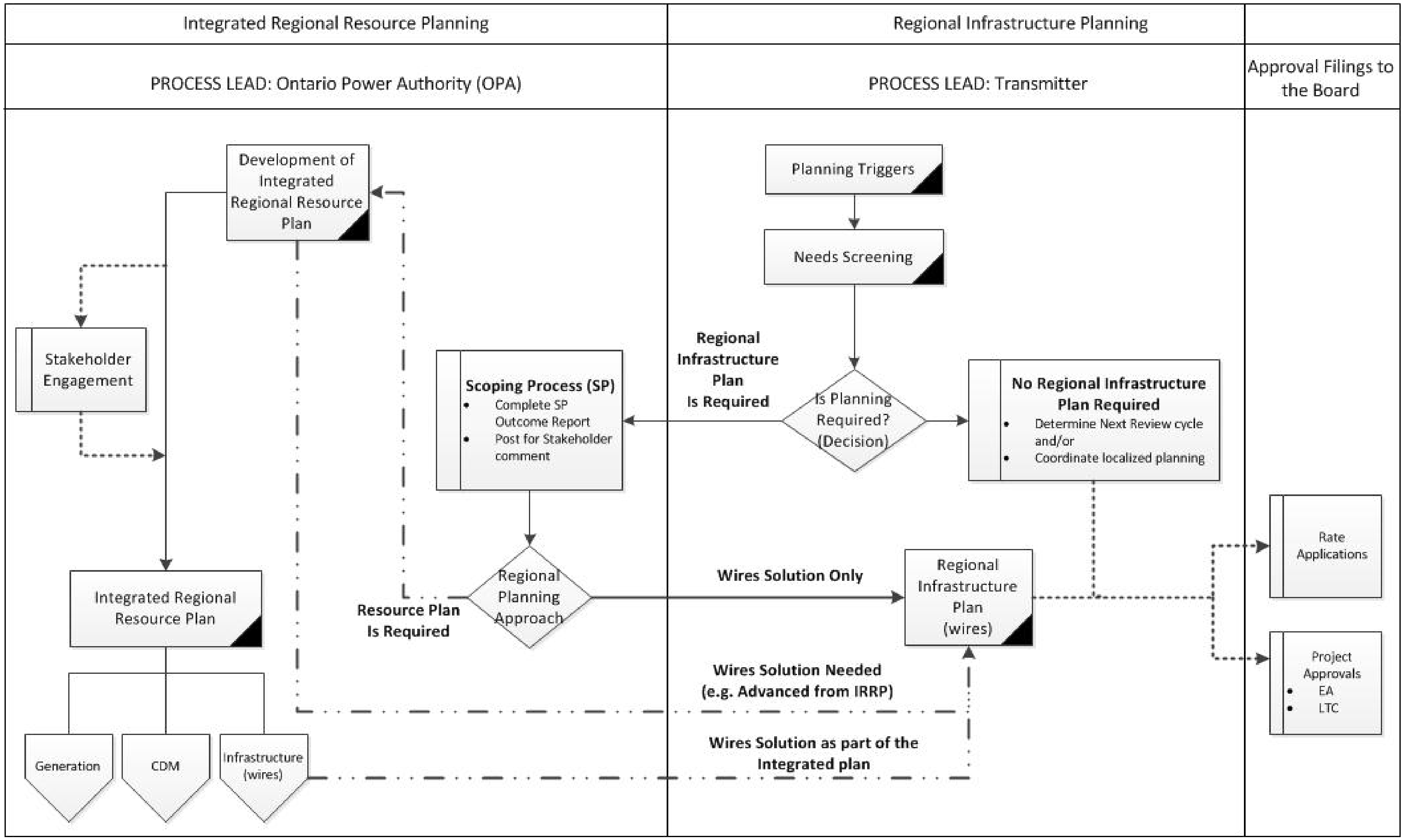

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (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 stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

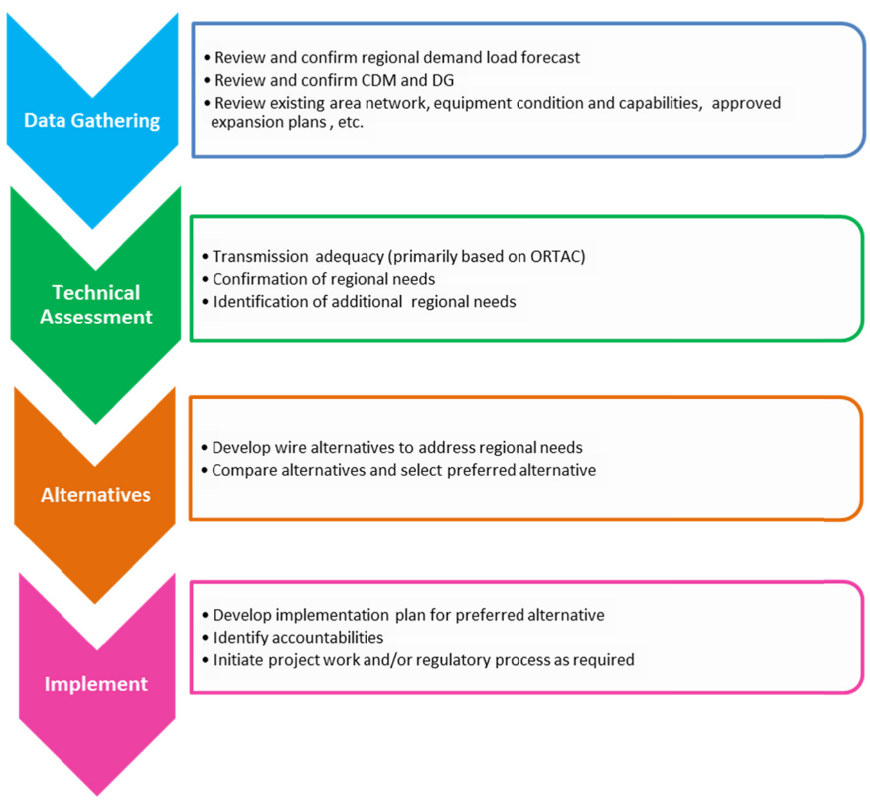

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

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

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

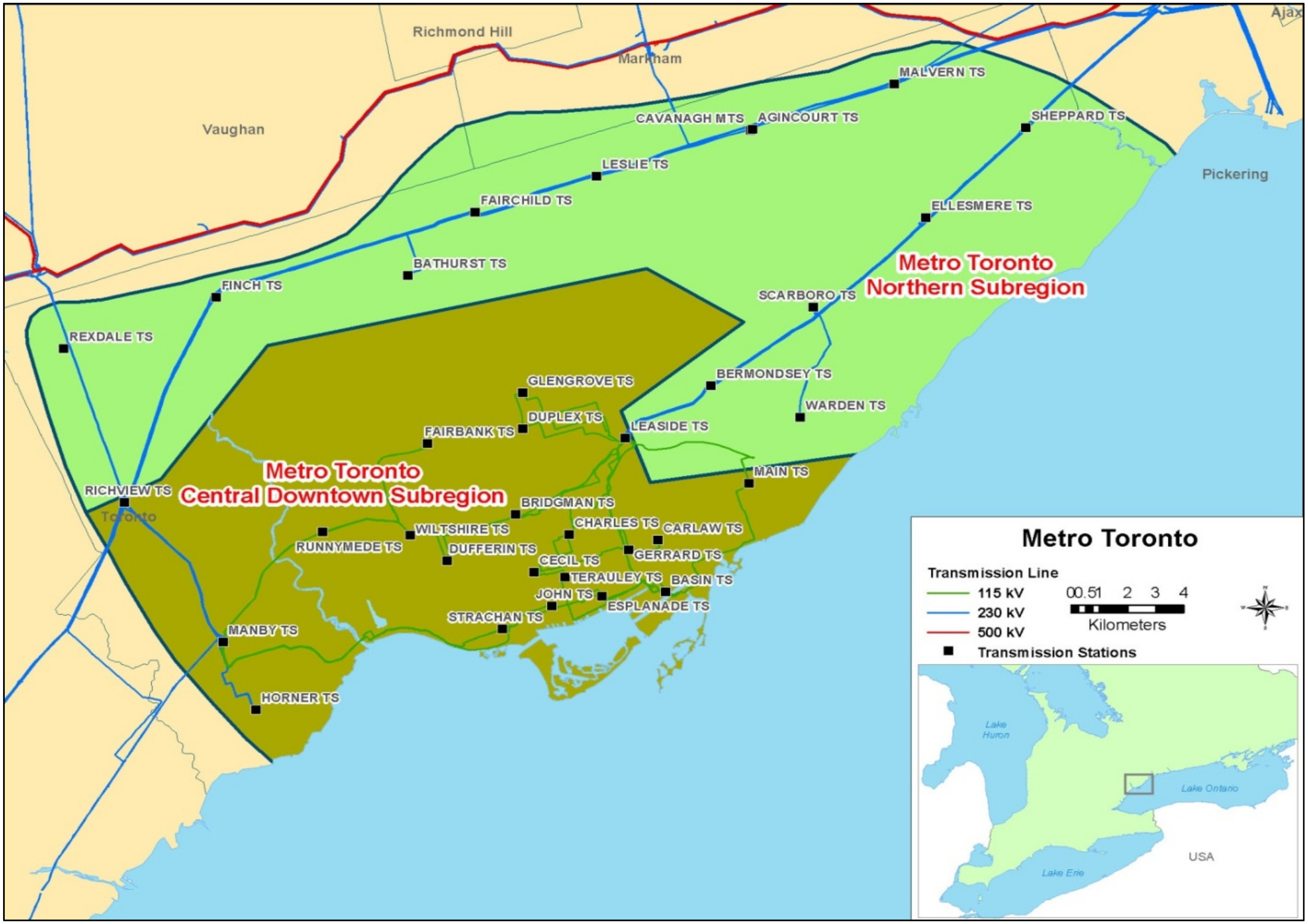

Figure 3-1 Metro Toronto Region – Supply Areas

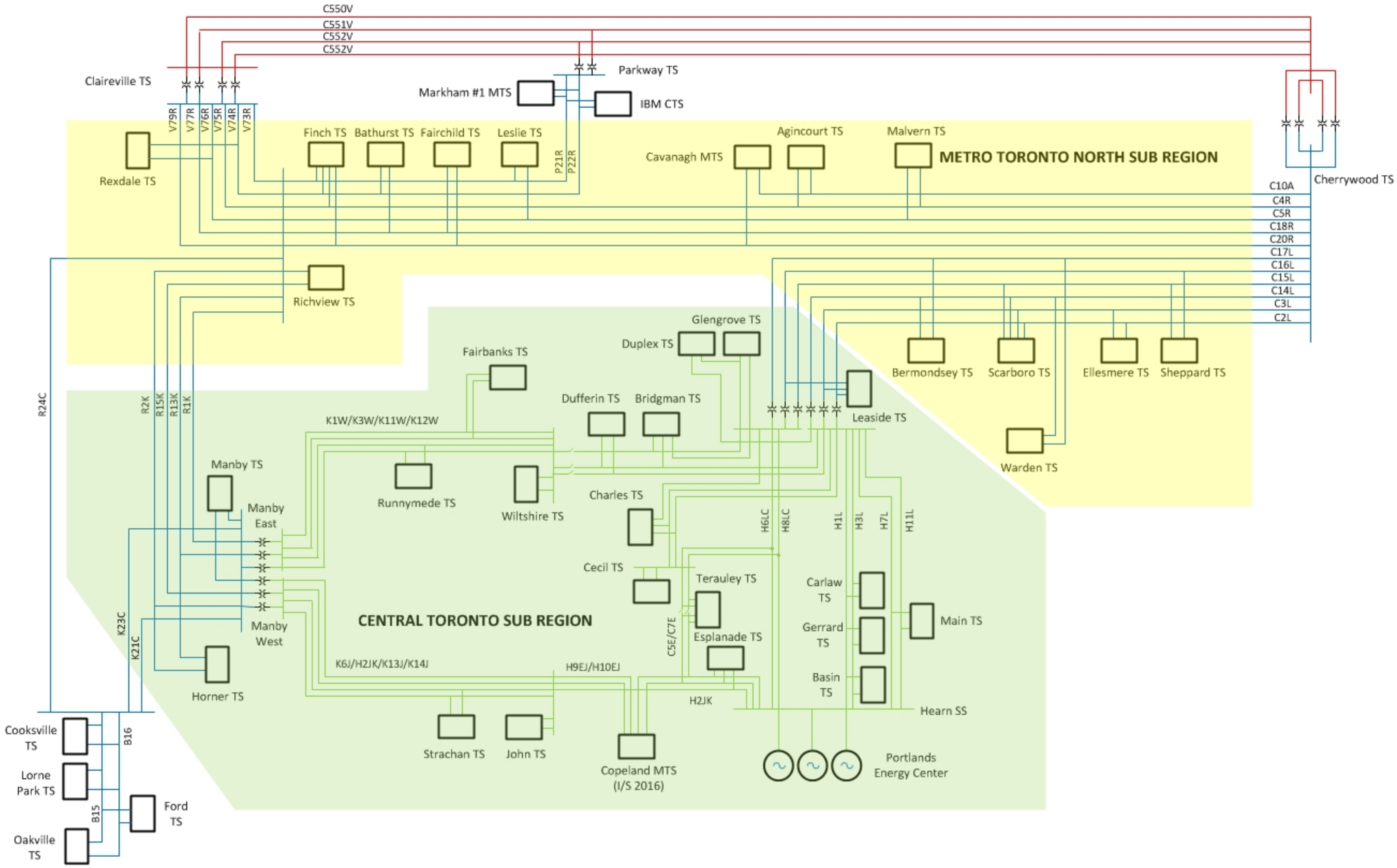

Figure 3-2 Metro Toronto Region – Single Line Diagram

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.

- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.

- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.

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

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

- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

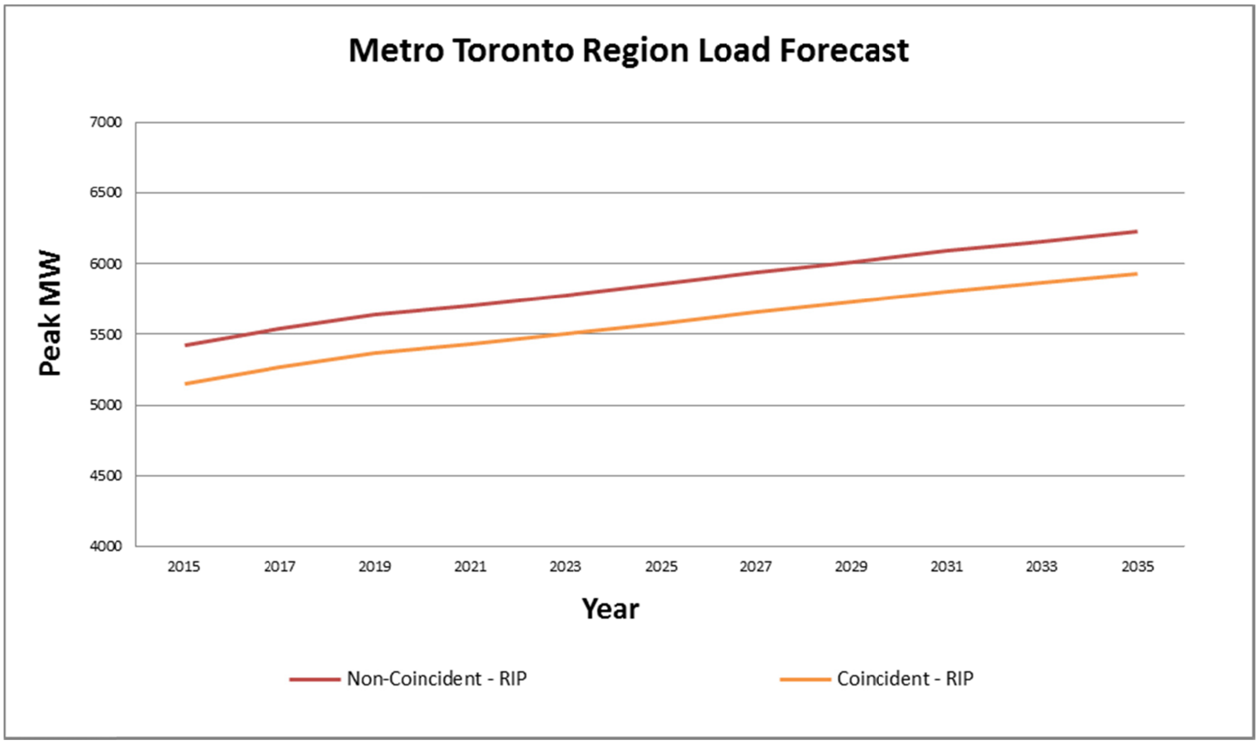

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

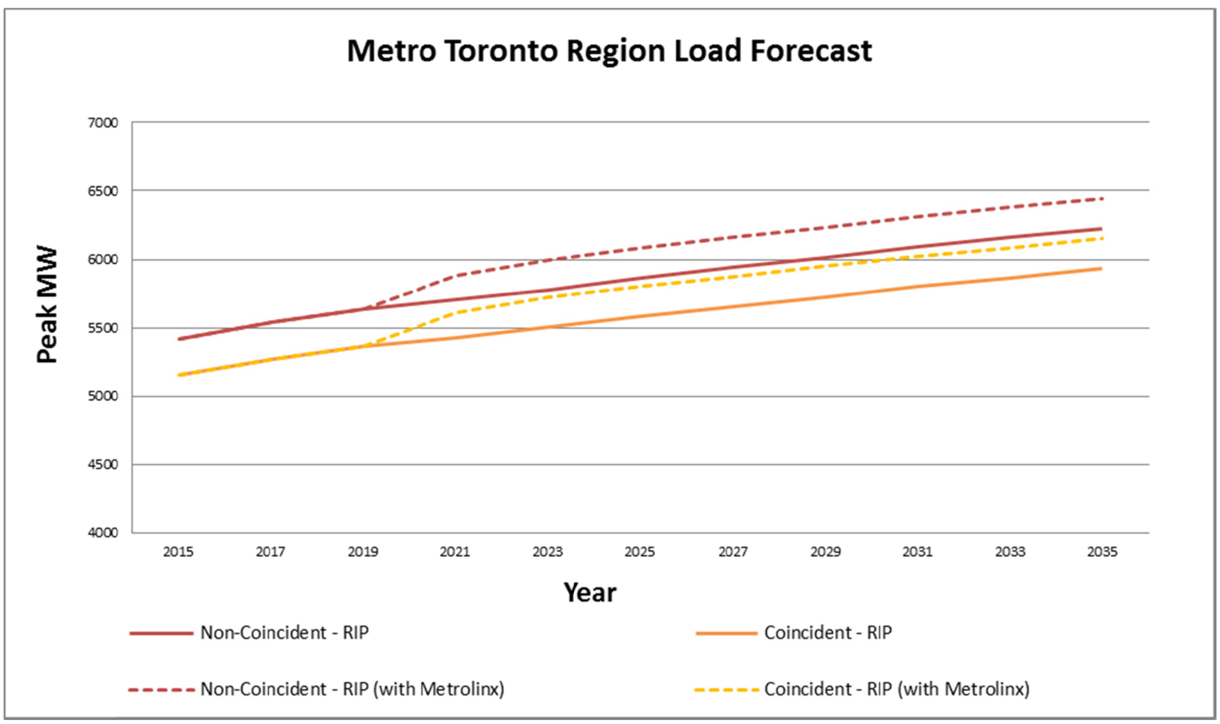

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- 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 non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

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

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC[(1)] Area)	2020+[(2)]
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

(1) JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

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

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

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

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.

(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.

(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.

(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	**Capacity (MW)**	**2015 Loading (MW)**	**Need Date**
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit (“LRT”) project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

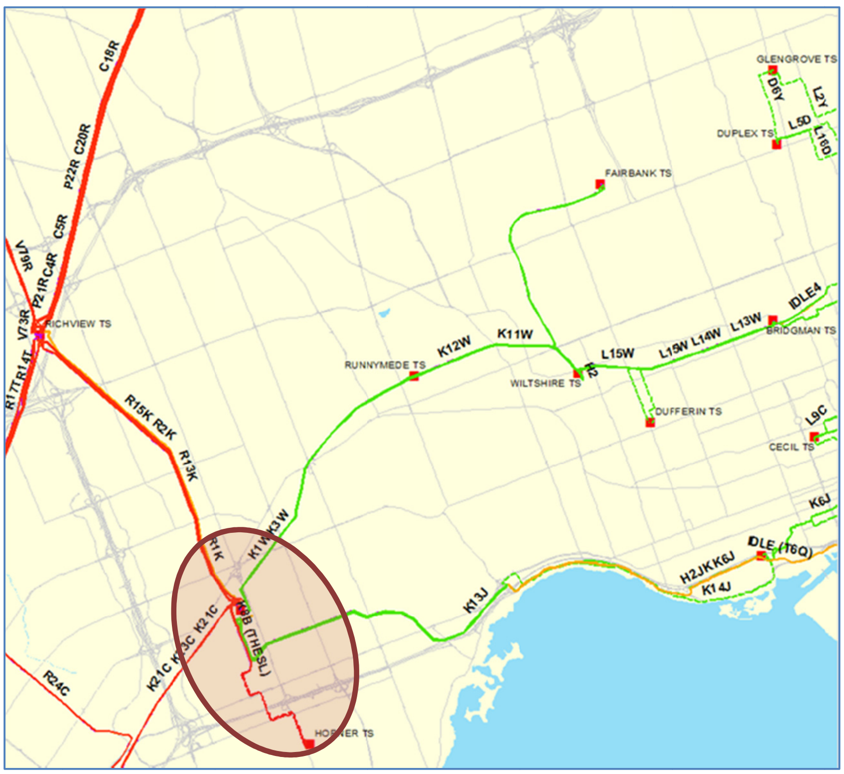

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

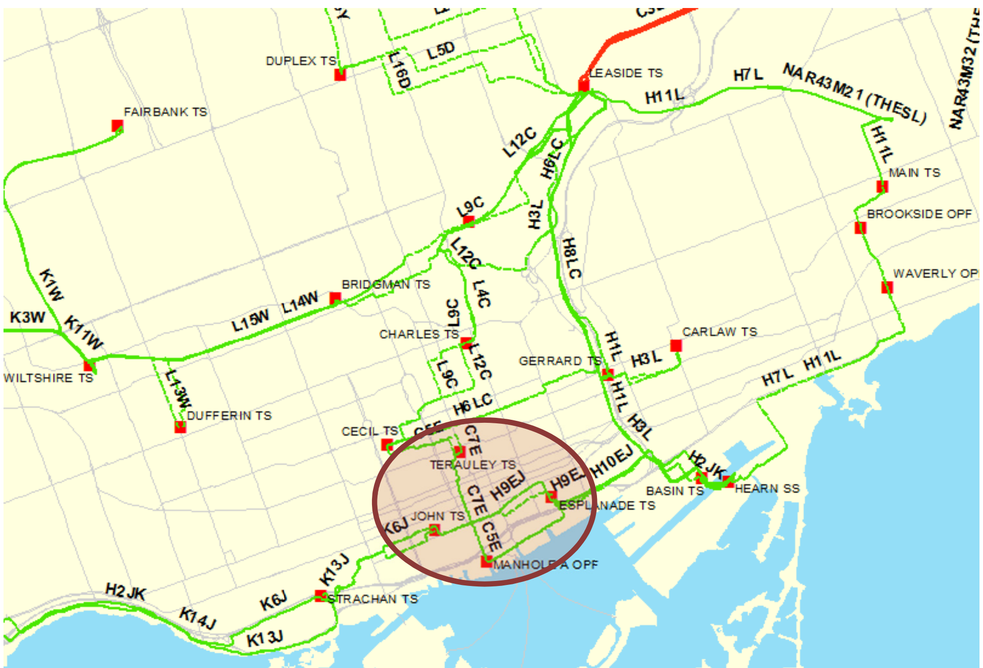

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

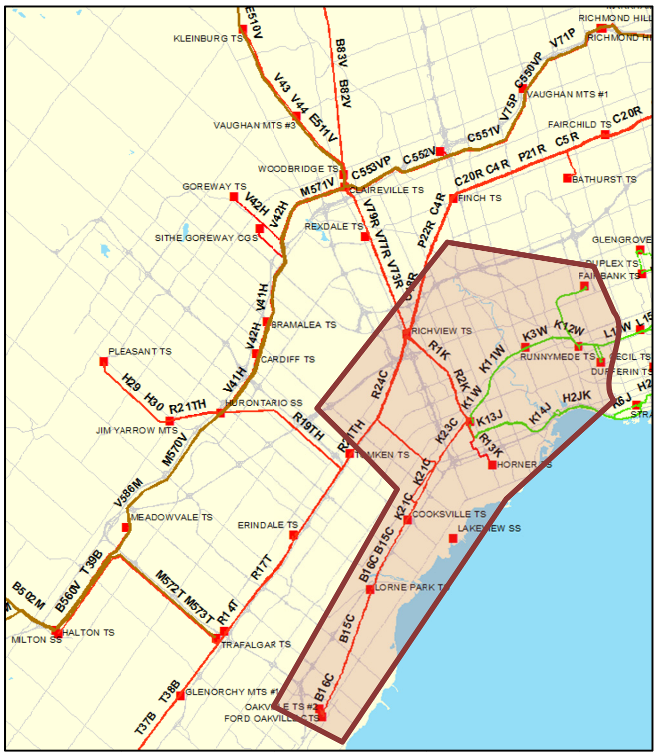

Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO 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 the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

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

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

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

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	Runnymede	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	Manby230	Horner	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	**Runnymede**	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	**Manby230**	**Horner**	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

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

Northwest Ontario

REGIONAL INFRASTRUCTURE PLAN

June 9, 2017

hydro one

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

With support from:

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Atikokan Hydro Inc.
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Independent Electricity System Operator
Kenora Hydro Electric Corporation Ltd.
Thunder Bay Hydro Electricity Distribution Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

Working Group 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 WITH INPUT AND SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE NORTHWEST ONTARIO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Atikokan Hydro Inc.
- Kenora Hydro Electric Corporation Ltd.
- Thunder Bay Hydro Electricity Distribution Inc.
- Sioux Lookout Hydro Inc.
- Fort Frances Power Corporation

This RIP is the final phase of the regional planning process and it follows the completion of Integrated Regional Resource Plan ("IRRP") by the IESO for the North of Dryden Sub-Region in January 2015, Greenstone-Marathon Sub-Region in June 2016, and West of Thunder Bay in July 2016 and for Thunder Bay Sub-Region in December 2016 [2-5]. This report also references the IESO Draft Remote Community Connection Plan report [6].

This RIP provides a consolidated summary of needs and recommended plans for North of Dryden, Greenstone-Marathon, West of Thunder Bay, and Thunder Bay Sub -Regions that make up the Northwest Ontario Region. The potential needs of the bulk system is not within the scope of the Regional Planning, however, some aspects of the bulk system needs and plans are discussed in this report in the context of regional plans.

The Working Group has reassessed and updated the LDC load forecasts, which have remained consistent with the forecasts used in the IRRPs. Accordingly, this RIP has confirmed the needs and the proposed or recommended infrastructure (wires) plans for the sub-regions as indicated in the IRRP reports.

The needs in the region are largely driven by the industrial load growth, particularly the mining sector. Considering the uncertainties in the forecast of the industrial loads, this RIP uses the forecast scenarios and assumptions developed for the Northwest IRRPs. The connection of remote communities to the electricity grid, as well as the load growth as a result of economic developments, are also contributing factors. Since the development timelines and plans for connection of the mining and other industrial loads are uncertain and frequently depend on the customer decision, the IRRP and RIP have both considered low, medium (or reference) and high load growth scenarios and identified alternatives and recommended plans to address the needs under each scenario in near-term (present-5 years), mid-term (5-10 years) and long term (10-20 years).

The following is the summary of the currently recommended or proposed near/mid/long-term wires plans for the sub-regions under low, medium and high load growth scenarios. The current status of these plans is also indicated in the following.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

[1] The Medium growth scenario for North-of-Dryden sub-region corresponds to the "Reference Scenario" in the IRRP

[2] The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario "A" of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario "B" of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario "D" of Greenstone, scenario "C" of Marathon and scenario "A" of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

West of Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

The IRRP for Thunder Bay sub-region identified a near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This upgrade has been completed in Q4 2016.

Most of the above plans are highly dependent on the needs of industrial customers in the region. Proceeding to the Development phase for the customer-driven projects requires request by, and agreement with, the customer(s). Currently, only Project No. 1 has proceeded to the Development phase. The only supply point in the region which is presently at its load-meeting capability limit is Pickle Lake and Project No. 1 will address the need at this location.

Additionally, the IESO Draft Remote Community Connection Plan report [6] has recommended the connection of 21 First Nations communities in the northern part of the region to the electricity grid. An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's transmitter licence to develop and seek approvals for the connection of sixteen remote communities and the Dryden-Pickle Lake transmission line, i.e. Project No. 1 identified above.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. There is adequate time to review the proposed or recommended plans to meet the long-term needs and develop preferred alternatives in the next planning cycle. Should there be a need that emerges prior to the next planning cycle such as but not limited to change in load forecast, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE NORTHWEST ONTARIO REGION.

The report was prepared by Hydro One Networks Inc. - Transmission ("Hydro One") with input and on behalf of the Working Group that consists of Hydro One, Hydro One Networks Inc. - Distribution, the Independent Electricity System Operator ("IESO"), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Thunder Bay Hydro Electricity Distribution Inc., Sioux Lookout Hydro Inc. and Fort Frances Power Corporation in accordance with the Regional Planning process established by the Ontario Energy Board in 2013.

Northwest Ontario region is divided into 4 sub-regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, and Greenstone-Marathon. The IESO has also assessed the economic case for connecting the Remote Communities north of Red Lake and Pickle Lake to the provincial grid. Electrical supply to the Region is provided by fifty two 230kV and 115kV transmission and distribution stations. Some of the stations are shown in Figure 1-1.

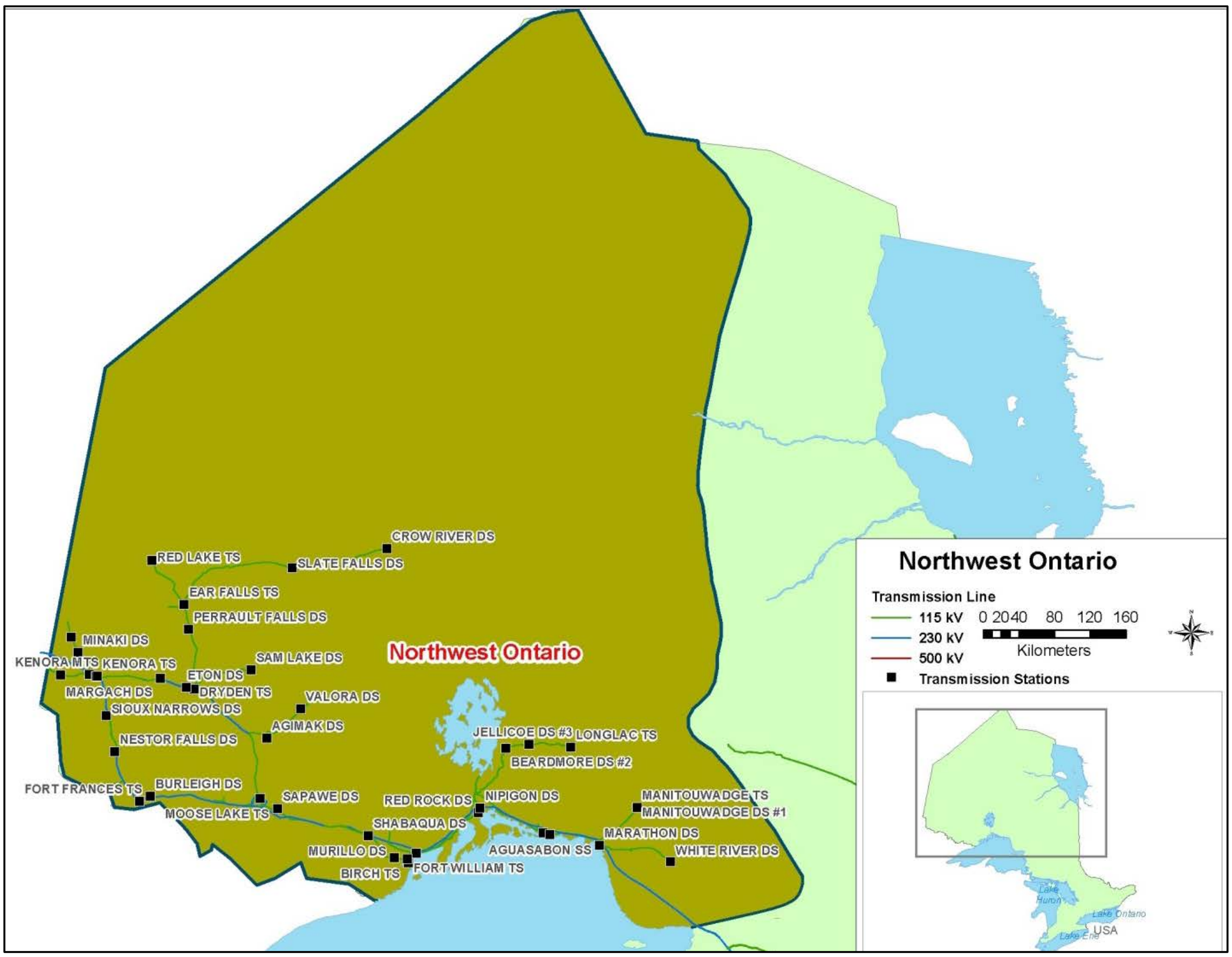


Figure 1-1 Map of Northwest Ontario Region

1.1 Scope and Objectives

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Review of needs (near and medium-term) identified through the IRRP process.
- Develop a wires plan to address all needs where wires solution is the most appropriate.
- Discuss long-term needs identified during the planning process

The RIP reviews factors such as the LDC load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), 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 wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period;
- Develop an approach to address any longer term needs identified by the Working Group.

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 region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 discusses the needs and provides the alternatives and preferred solutions;
- Section 7 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board 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. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address one or more of the needs. If no further regional coordination is required and localized needs cannot be met by non-wires solutions, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and a Local Plan ("LP") is developed to address localized needs. Ultimately, local plans are also incorporated into the RIP report.

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

The IRRP phase will generally assess integrated alternatives consisting of infrastructure (wires) and/or resource (CDM and Distributed Generation). Detailed information regarding wires options may not be available or necessary within the scope of the IRRP. The level of detail for wires options as part of the IRRP will be to a level which is 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 refine the assessment of specific wires alternatives, and recommend a preferred

[3] Also referred to as Needs Screening.

wires solution. Similarly, resource options which 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 may establish Local Advisory Committees (LAC) in the region or sub-region. For the Northwest Ontario Region, community engagement through a number of LACs is on-going.

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 wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

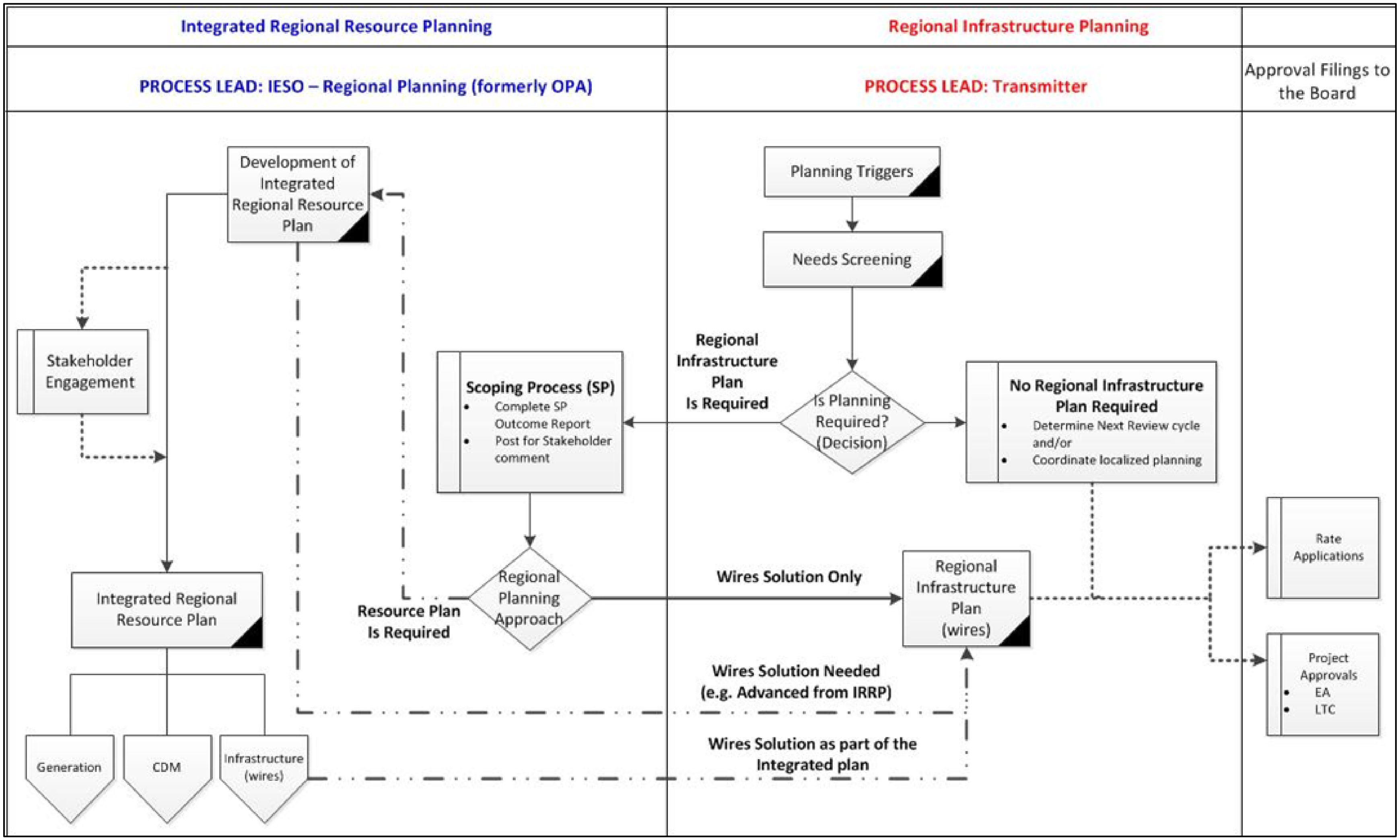


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (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 stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. 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.

The extent and scope of each step naturally depends on the outcome of the previous step. The outcome of the previous stage of the regional planning process, i.e., IRRP, also influences the scope of Step 2 to a large extent.

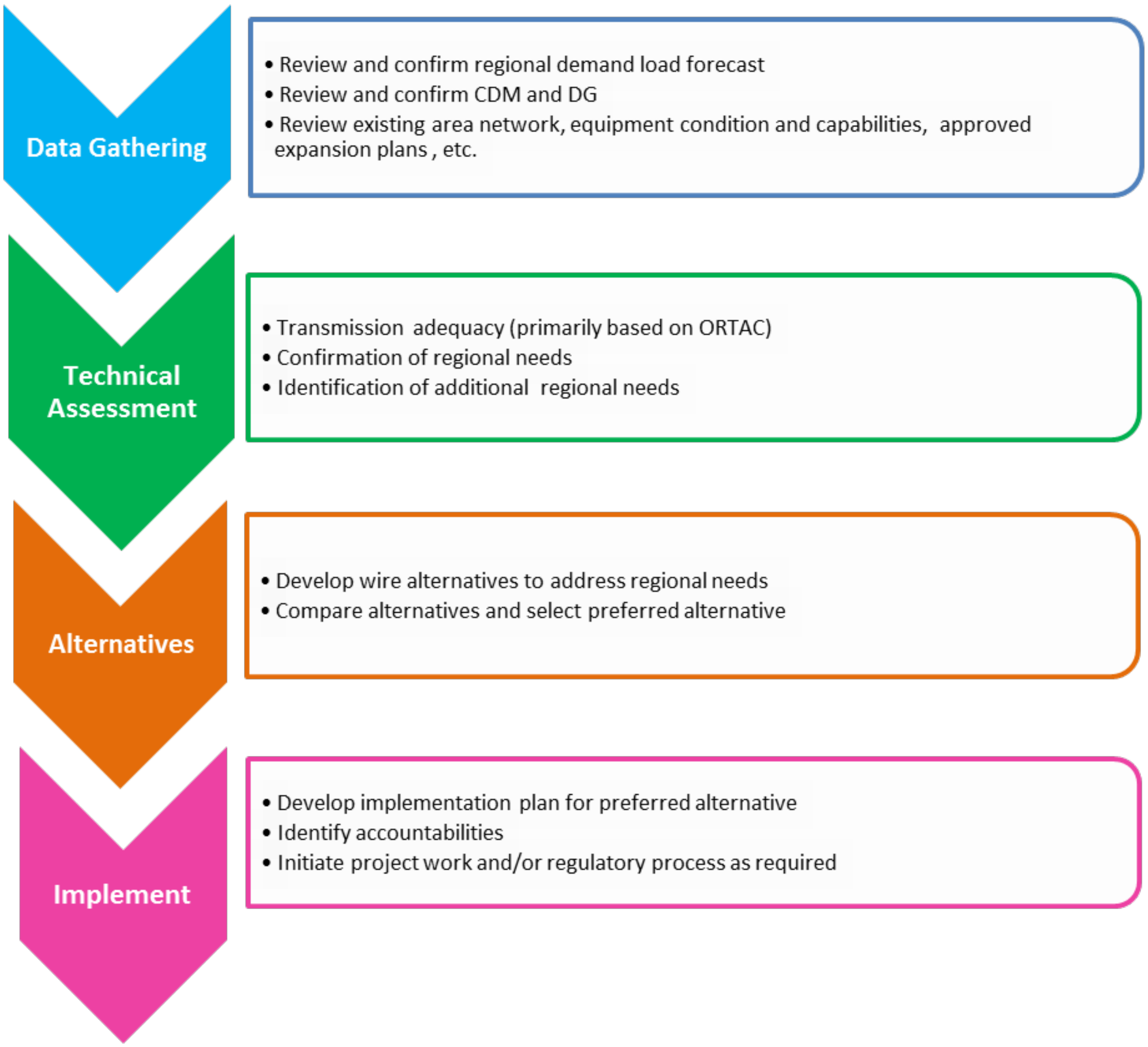


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

NORTHWEST ONTARIO REGION IS ROUGHLY BORDERED BY WEST OF HUDSON BAY AND JAMES BAY, NORTH AND WEST OF THE LAKE SUPERIOR, AND EAST OF THE CANADIAN PROVINCE OF MANITOBA. THE REGION CONSISTS OF THE DISTRICTS OF THUNDER BAY, KENORA AND RAINY RIVER. ALMOST 54 PERCENT OF REGION'S ENTIRE POPULATION LIVES IN THUNDER BAY. THE REGION ACCOUNTS FOR APPROXIMATELY 60 PERCENT OF LAND AREA OF THE PROVINCE AND ABOUT TWO PERCENT OF ONTARIO'S TOTAL POPULATION.

Bulk electrical supply to the Northwest Ontario Region is provided through a combination of local generation stations connected to the 230 kV and 115 kV network, and the East-West Tie transmission corridor.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Sioux Lookout Hydro Inc., Thunder Bay Hydro Electricity Distribution Inc., and Fort Frances Power Corporation. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDC. A map and a single line diagram showing the electrical facilities of the Northwest Ontario Region, consisting of the sub-regions, is shown in Figure 3-1 and Figure 3-2, respectively.

3.1 North of Dryden Sub-Region

A radial single-circuit 115 kV transmission line ("E4D") supplies electricity to the customers in the North of Dryden sub-region from Dryden TS. The major supplying station for this sub-region is Dryden TS, where the voltage is stepped down from the 230 kV to 115 kV, to serve local and industrial customers. Electricity demand in the North of Dryden sub-region is also supplied by local hydroelectric generation.

3.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station ("SS"). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with two 230 kV lines - W21M and W22M. Marathon TS steps down 230 kV to 115 kV and supplies customers in the

Town of Marathon, White River and Manitouwadge through a 115 kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS.

Alexander SS connects Alexander Generating Station (“GS”), Cameron Falls GS, and Pine Portage GS - to the system. A 115 kV single-circuit A4L, connected to the Alexander SS, supplies electricity to the Municipality of Greenstone and its surrounding areas. Nipigon GS is also connected to the circuit A4L.

3.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230 kV transmission system consisting of the Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230 kV to 115 kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba’s electrical system through two 230 kV transmission lines – K21W and K22W. Fort Frances TS steps down 230 kV to 115 kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota’s electrical system through a 115 kV transmission line – F3M. Dryden TS steps down 230 kV to 115 kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230 kV to 115 kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities

3.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230 kV step-down transformation facility which steps down 230 kV to 115 kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115 kV by three step-down transformer stations - Birch TS, Fort William TS, and Port Arthur TS #1.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

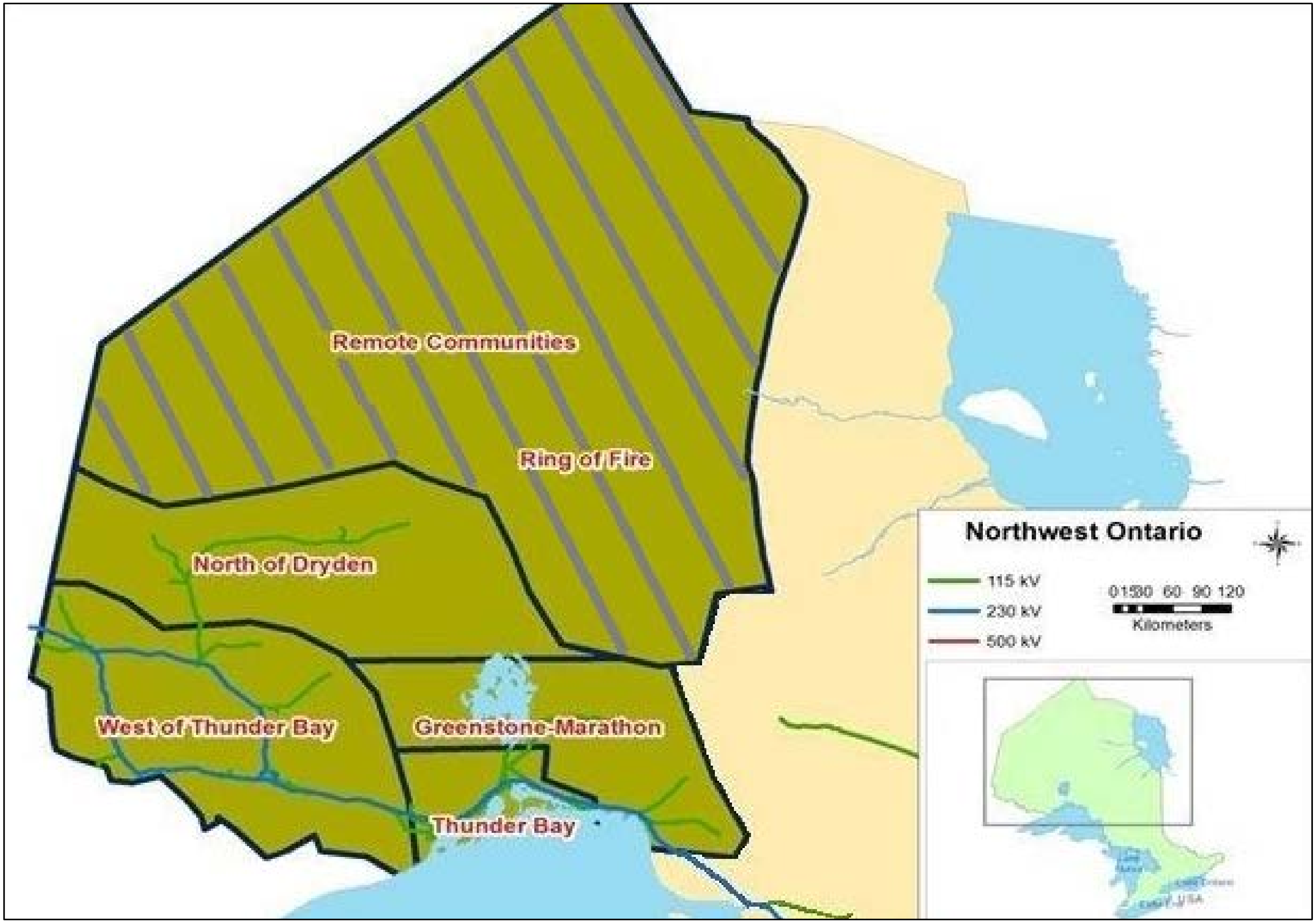


Figure 3-1 Northwest Ontario Region – Supply Areas

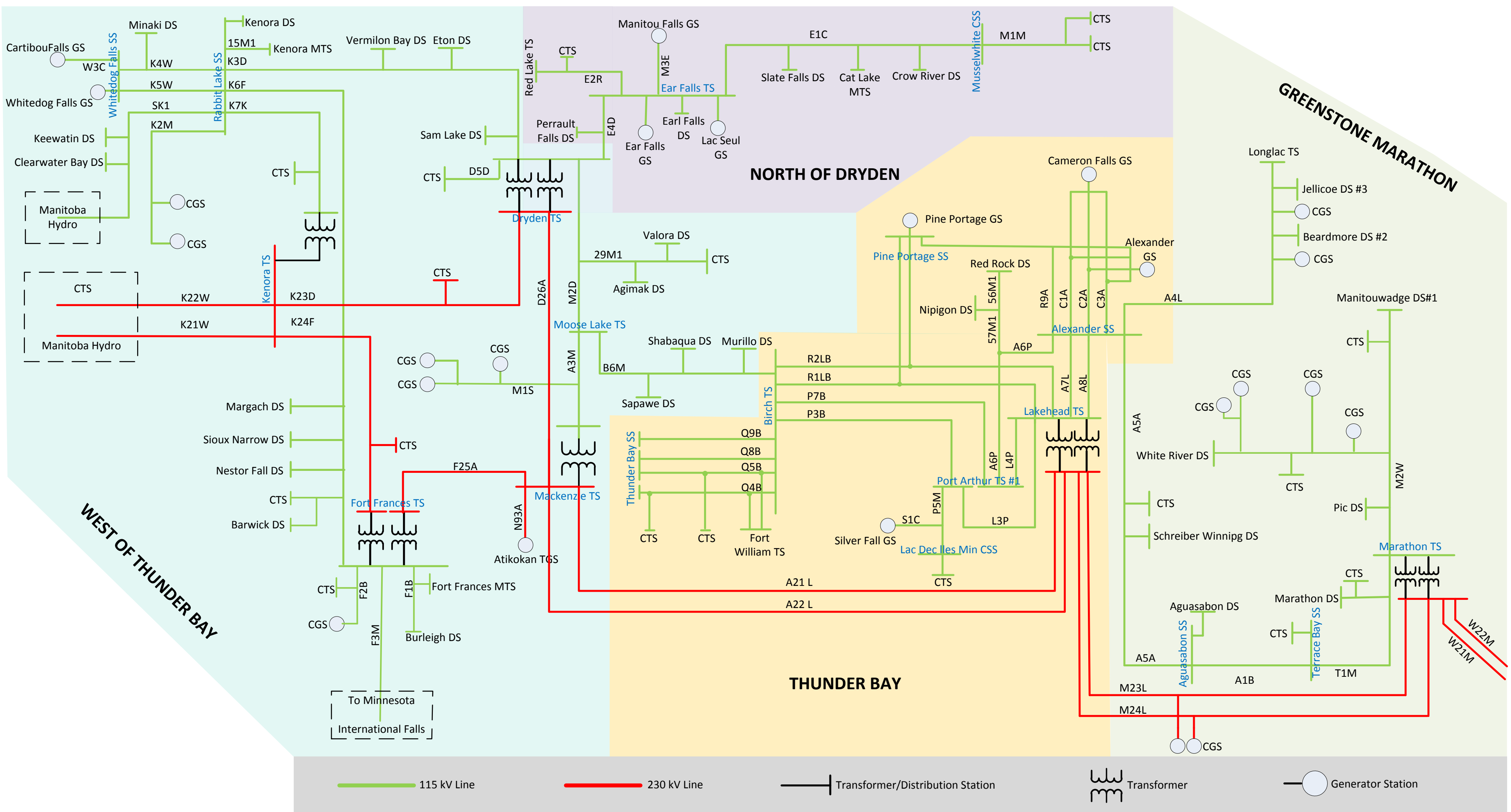


Figure 3-2 Northwest Ontario Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS AND PLANNED FOR NEAR FUTURE

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, ARE UNDERWAY, OR ARE PLANNED FOR THE COMING YEARS, AIMED AT IMPROVING THE SUPPLY TO THE NORTHWEST ONTARIO REGION IN GENERAL.

This section describes the completed development and sustainment projects in the region, as well as the sustainment projects that are in the execution stage or planned for the coming years.

4.1 Past Major Projects

In the past 10 years, the following are some of the major projects completed in the Northwest Ontario Region.

1. **Barwick TS** –Barwick TS was built in the second and third quarter of 2013 to replace load-serving facilities at Fort Frances TS as majority of these assets were reaching the end of their useful life. The new facilities include: two 42 MVA 115/44 kV transformers and the associated breakers, switches, surge arresters, etc. and two cap banks, each rated 4.9 MVAR at 44 kV, and the associated breakers and switches.

2. **Birch TS –** One of three 42 MVA step down transformers (115/25 kV) at Birch TS was replaced in December 2015.

3. **Dryden TS** – In addition to replacing 5 HV breakers, 2 LV breakers and 12 switches between 2014-2016, 2x40 MVAR Shunt reactors at Dryden TS were installed in Q3 2014.

4. **Fort Frances** – In addition to replacing 2 LV breakers and 8 switches (2010-2016), 21.6 MVAR/13.8 kV capacitor bank was installed at Fort Frances in November 2010.

5. **Kenora TS** – 1 LV breaker and 4 switches were replaced between 2009 and 2015.

6. **Lakehead TS** – 3 HV breakers, 1 LV breaker, 5 switches, and 1 autotransformer (230/13.9 kV) were replaced between 2009 and 2016 as part of the sustainment work. In addition, one synchronous condenser at Lakehead TS was replaced by a +60/-40 MVAR SVC in December 2009.

7. **Longlac TS** –Transformers T2 and T3 were replaced with two 42 MVA 115/44 kV transformers and associated equipment protections i.e. breakers, switches, surge arresters, etc. In addition, four capacitor banks; each rated at 4.9 MVAR at 44 kV with associated breaker and switches were installed. This work was completed mid-2011.

8. **Manitouwadge TS** – 1 LV breaker, 1 switch, and 1 step down transformer (115/44 kV) were replaced in July 2016.

9. **Marathon TS** – In addition to replacing 1 HV breaker, 2 LV breakers, and 4 switches between 2009 and 2016, 2x40 MVAR shunt reactors were installed in December 2013 and March 2014.

10. **Moose Lake TS** – 5 HV breakers were replaced in 2014.

11. **Port Arthur TS #1** – 10 switches were replaced between 2009 and 2015. In addition, 2x0.5 ohms LV current limiting reactors were replaced with 2x1 ohm reactor. Work was completed in December 2014.

12. **Rabbit Lake SS** – 2 HV breakers and 4 switches were replaced between 2011 and 2016.

13. **Red Lake TS** –Five capacitor banks were upgraded by 2.5 MVAR each to 7.4 MVAR (at 44 kV). This work also included upgrading associated breakers and switches and was completed between December 2015 and July 2016.

4.2 Current or Planned Major Sustainment Projects

The following major sustainment projects are currently under execution or planned for the coming years. These projects are based on the assessment of end of life issues of the aging station's equipment and replacing those that represent risk to the security of the bulk transmission system and reliability for connected customers.

1. **Dryden TS**– is located in the city of Dryden and supplies majority of the customers in the area. It consists of three 115/44 kV power transformers rated at 15MVA each, which are non-standard units and are about 69 years old.

   Hydro One has planned to replace the three EOL transformers with two new standard-size transformers, rated at 42MVA each. The scope of work also includes the replacement of other deteriorating infrastructure, such as LV switchyard (which will be built to current standard), 115 kV OCBs, and select switches.

   This project is currently planned to be completed in 2018.

2. **Ear Falls TS** – supplies customers in the city of Ear Falls in the North of Dryden Sub-Region, through a single transformer T5 (115/44 kV, 19 MVA), backed-up by a spare transformer T5SP (115/44 kV, 8 MVA). The 44 kV LV voltage is further stepped-down to 12.5 kV through Ear Falls DS transformer T1 (44/12.5 kV). Ear Falls TS transformers T5 and T5SP are approximately 47 and 69 years old, respectively, while Ear Falls DS T1 is currently 49 years old.

   Hydro One has planned to eliminate the need for 44 kV to 12.5 kV conversion at Ear Falls DS by replacing T5 and T5SP transformers with 115/13.2 kV transformer units (rated at 12.5 MVA each). The scope of work also involves replacing 44kV equipment with 13.2 kV, replacing 115 kV circuit breakers, and replacing EOL protections, controls, and telecom in new relay building to ensure the integrity of power system protection is maintained.

   This project is currently planned to be completed in 2018.

3. **Alexander SS** – is a 115 kV switching station located in the Thunder Bay Sub-Region and was originally built in 1955. The station terminates five 115 kV circuits for the supply of customers in the area and connects 161 MW of generation from the Nipigon River and Cameron Falls. It consists of ten 115 kV breakers, nine of which are non-standard.

Hydro One has planned to replace all non-standard and EOL equipment at the station. The scope of work involves replacing 115 kV oil circuit breakers with new SF6 breakers, replacing select switches, upgrade of all protection & control facilities and AC station service system.

This project is currently planned to be completed in 2019.

4. **Birch TS** – is a 115 kV transmission station located in City of Thunder Bay in the Thunder Bay Sub-Region and was put in-service in 1955. Birch TS is comprised of a DESN station which supplies local load in the port area of Thunder Bay, as well as being a 115 kV bulk station with 9 lines and the three DESN transformers connected to it.

   Due to the criticality of the station to both transmission and distribution systems, protection and control equipment that is presently located in the basement will be relocated to a new relay building. The scope of work involves replacing 115 kV circuit breakers and 25 kV capacitor banks, and replacing/relocating end of life protections in the new relay building.

   This project is currently planned to be completed in 2019.

5. **Pine Portage SS** – is a 115 kV switching station located in the Greenstone-Marathon Sub-Region and was put in-service in 1954. The switching station has three outgoing 115 kV transmission lines connecting to Lakehead TS, Birch TS and Alexander SS. Pine Portage GS is also connected to this switching station.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing five 115 kV oil circuit breakers with new 2000A SF6 breakers, associated disconnect switches, protection, control and teleprotection facilities.

   This project is currently planned to be completed in 2020-2023.

6. **Aguasabon SS** – is a 115 kV switching station in Greenstone-Marathon Sub-Region and was put in-service in 1948. The station has two transmission lines connecting to Alexander SS and Terrace Bay SS. The station is also critical to the connection of Aguasabon DS.

   Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service, and replacing equipment protections.

   This project is currently planned to be completed in 2021-2024.

7. **Port Arthur TS #1** – Port Arthur TS #1 is a 115/25 kV station located in the Thunder Bay Sub-Region and was put in-service in 1950.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing AC/DC station service systems, 25kV switchyard and associated protection equipment in the new building, and 115 kV associated protection equipment in the existing building

   This project is currently planned to be completed in 2021-2024.

8. **Rabbit Lake SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has seven 115 kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection with Manitoba Hydro. There are six 115 kV oil circuit breakers and two 115 kV SF6 circuit breakers in the yard.

Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing EOL 115 kV circuit breakers, select switches, and equipment protections.

This project is currently planned to be completed in 2021-2024.

9. **Terrace Bay SS** – is located in the Greenstone-Marathon Sub-Region and was put in-service in 1973. The switching station has two 115 kV transmission lines connecting to Marathon TS and Aguasabon SS. The station is also critical to the connection of a Customer Transformer Station (CTS).

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing protections, controls, telecom, select switches, and AC/DC station service system.

   This project work is currently planned to be completed in 2021-2024

10. **Whitedog Falls SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has three 115 kV transmission lines, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing 115 kV circuit breakers and select switches. In addition, scope of work includes replacing/upgrading of DC station supply system.

    This project is currently planned to be completed in 2021-2024.

11. **Moose Lake TS** – is a 115/44 kV transformer station built in 1948. It is located on Moose Lake near Atikokan in the West of Thunder Bay Sub-Region. Moose Lake TS consists of two non-standard step-down transformers T2 and T3 rated at 8MVA and 15MVA, respectively. In addition, the two transformers are 69 years old.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing the two non-standard power transformers (T2, T3) with standard 110-44 kV, 25/41.7 MVA units, two low voltage oil circuit breakers with new SF6 breakers, and replacing and upgrading the protection, control and AC/DC station service facilities

    This project is currently planned to be completed in 2022-2025

12. **Kenora TS** – is a 230/115 kV station located in the West of Thunder Bay Sub-Region and critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service systems and replacing protection equipment.

    This project is currently planned to be completed in 2024-2027.

13. **Mackenzie TS** – is a 230/115 kV station is located in the West of Thunder Bay Sub-Region. Mackenzie TS has six 230 kV breakers which are about 46 years old.

Hydro One has planned to replace all EOL equipment at the station. The scope of work involves replacing 230 kV circuit breakers, select protections, and AC/DC station service system.

This project is currently planned to be completed in 2024-2027.

14. **Fort Frances TS** – is located in the Town of Fort Frances and was put in-service in 1947.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service system and protection equipment.

    This project is currently planned to be completed in 2025-2028.

15. **Lakehead TS** – is a 230/115 kV transformer station located in the Thunder Bay Sub-Region and was put in-service in 1955. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing four LV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115 kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

    This project is currently planned to be completed in 2025-2028.

16. **Marathon TS** – is a 230/115 kV transformer station, located in the City of Marathon in the Greenstone-Marathon Sub-Region. It was put in-serviced in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115 kV oil circuit breakers at the station are about 40 years old. Whereas, three 230 kV circuit breaker at the station are about 48 years old.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to customers. The scope of work involves replacing three EOL 230 kV circuit breakers with new SF6 breakers, and four EOL 115 kV circuit breakers with new SF6 breakers. In addition, the scope of work also includes replacing disconnect switches, protection equipment, and AC station service system.

    This project is currently planned to be completed in 2025-2028.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast Scenarios

For the purpose of this RIP, the LDCs reviewed their load forecasts and confirmed that they have not changed significantly from the load forecasts reported in the Northwest IRRPs. Based on the load forecasts from the LDCs and the industrial (mining) load forecasts of the Northwest IRRPs, three scenarios of future demand has been considered for each Northwest sub-region in this RIP. Table 5-1, Table 5-2, Table 5-3, and Table 5-4 show the forecasted load for the Low, Medium and High growth scenarios.

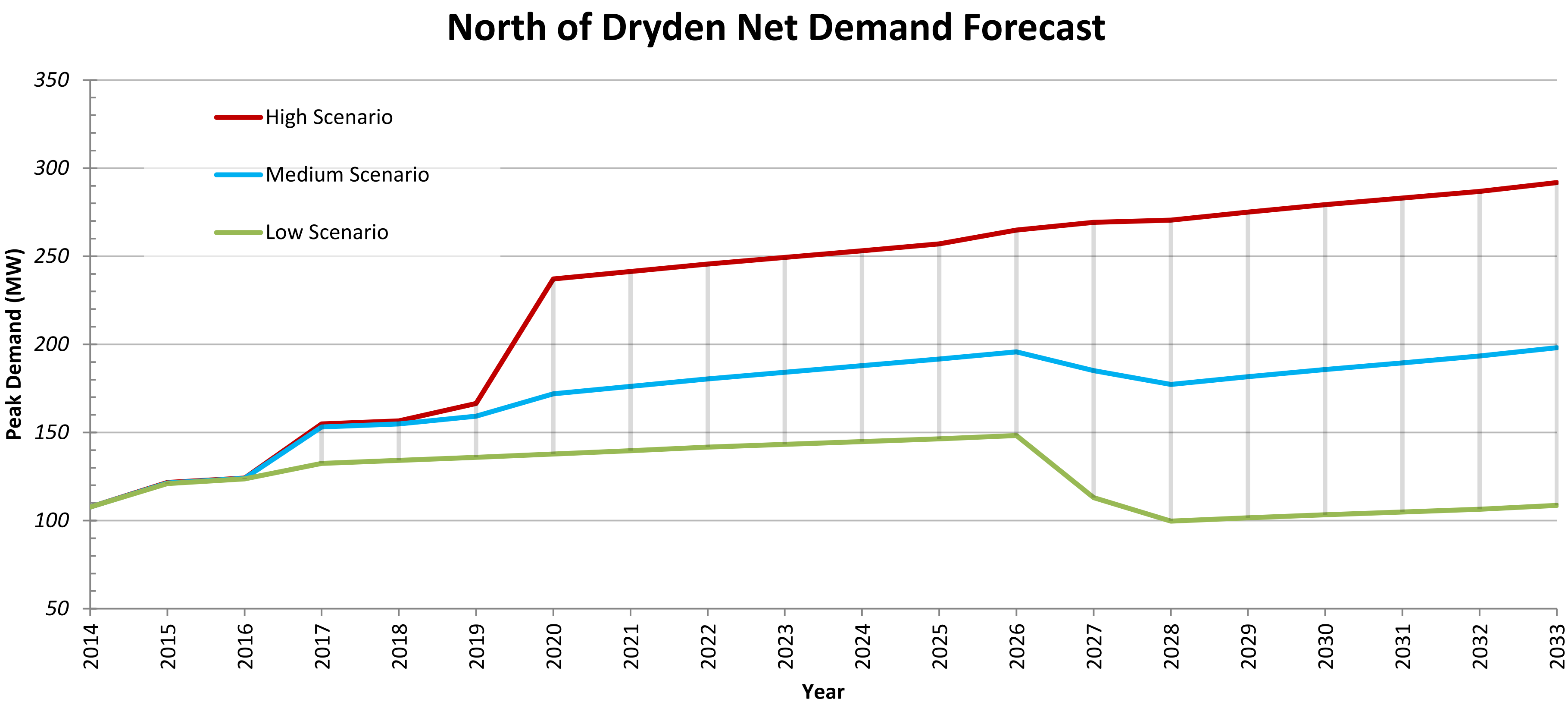
5.2 Other Study Assumptions

The other assumptions made in this RIP report include,

- The study period is 2016-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be available by the specified in-service dates.
- Since in the Northwest region winter peak is more critical than the summer peak, the study is based on winter peak conditions.

Table 5-1 North of Dryden Load Forecast Scenarios

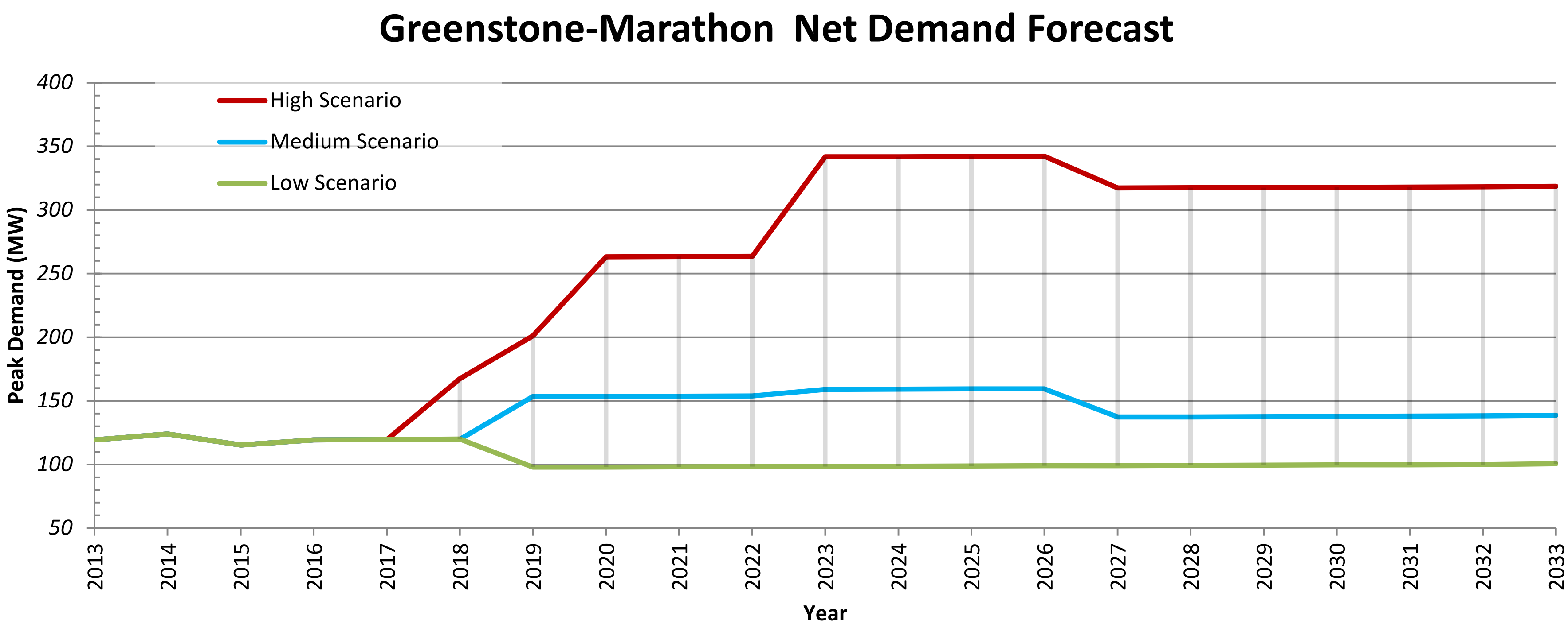
Net Demand Forecast (MW)																				
Scenario	2014 Historic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low	107.6	121.1	123.7	132.4	134.1	135.9	137.8	139.7	141.7	143.3	144.8	146.5	148.2	113.0	99.7	101.6	103.3	104.9	106.5	108.7
Medium[5]		121.4	124.0	153.1	154.8	159.3	171.9	176.1	180.3	184.1	187.9	191.7	195.7	185.2	177.3	181.6	185.7	189.5	193.3	198.0
High		121.6	124.2	154.9	156.6	166.5	237.1	241.3	245.5	249.3	253.1	256.9	264.9	269.3	270.6	275.0	279.2	283.1	286.8	291.7



[4] In the North of Dryden IRRP, load forecast starts from year 2015. For consistency, instead of the actual load in 2015 and 2016, the above table shows the IRRP load forecast for these years.
[5] The Medium scenario in the above table corresponds to the Reference scenario in the North of Dryden IRRP

Table 5-2 Greenstone-Marathon Load Forecast Scenarios[7]

Net Demand Forecast (MW)																					
Scenario	2013 Historical	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low	119.2	124.0	115.2	119.3	119.5	120.0	97.9	97.9	98.2	98.3	98.5	98.6	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.6
Medium	119.2	124.0	115.2	119.3	119.5	119.9	153.4	153.4	153.7	153.8	159.0	159.1	159.3	159.5	137.3	137.4	137.6	137.8	137.9	138.1	138.7
High	119.2	124.0	115.2	119.3	119.5	167.4	201.0	263.3	263.5	263.6	341.8	341.9	342.1	342.2	317.4	317.5	317.6	317.8	317.9	318.1	318.6

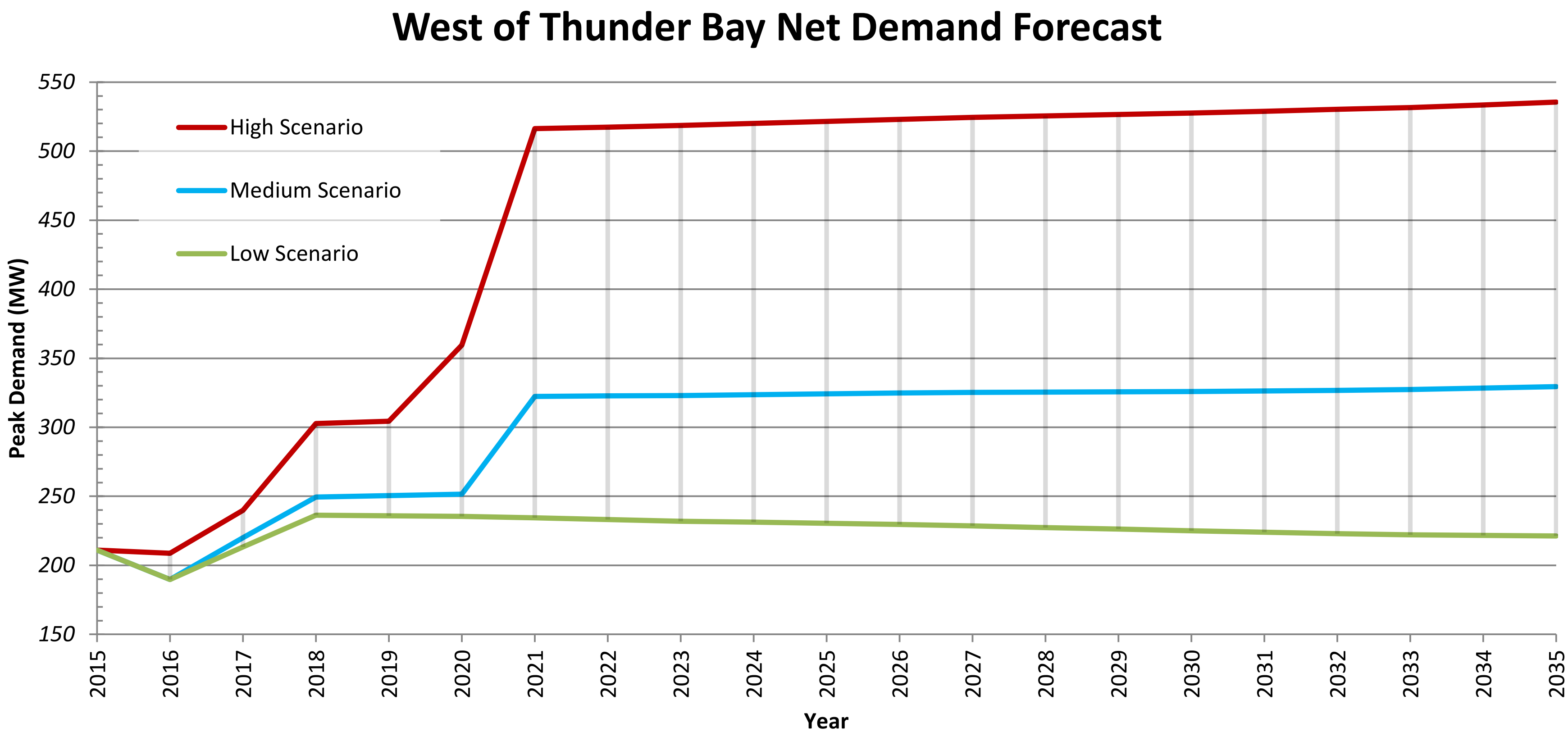


[6] In the Greenstone-Marathon IRRP, load forecast starts from year 2014. For consistency, instead of the actual load in 2014 to 2017, the above table is based on the IRRP load forecast for these years.

[7] . The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario "A" of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario "B" of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario "D" of Greenstone, scenario "C" of Marathon and scenario "A" of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

Table 5-3 West of Thunder Bay Load Forecasts Scenarios

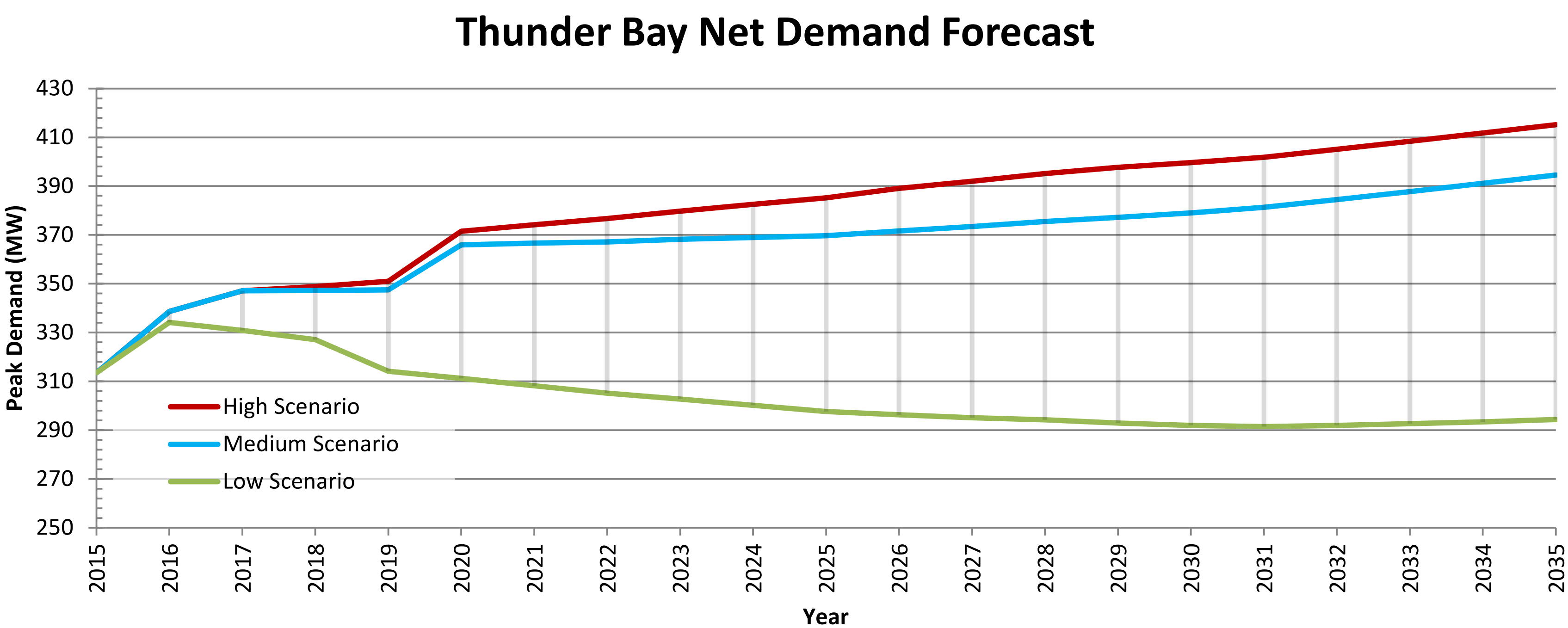
Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low	211.1	189.7	213.4	236.3	235.9	235.5	234.4	233.2	232.0	231.2	230.4	229.5	228.6	227.4	226.2	225.0	223.9	223.0	222.1	221.7	221.3
Medium		189.8	220.1	249.6	250.5	251.6	322.4	322.7	322.9	323.6	324.2	324.8	325.3	325.4	325.7	325.9	326.3	326.8	327.3	328.3	329.4
High		208.8	239.9	302.6	304.5	359.6	516.3	517.4	518.5	520.0	521.5	523.0	524.4	525.4	526.6	527.6	528.9	530.2	531.6	533.5	535.4



[8] In the West of Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

Table 5-4 Thunder Bay Load Forecast Scenarios

Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low	313.6	334.1	330.9	327.1	314.2	311.2	308.2	305.1	302.7	300.2	297.6	296.4	295.1	294.2	292.9	292.0	291.5	292.0	292.6	293.4	294.3
Medium		338.7	347.1	347.3	347.5	365.9	366.7	367.1	368.2	369.0	369.7	371.6	373.4	375.5	377.1	379.0	381.3	384.5	387.8	391.2	394.6
High		338.7	347.1	348.8	351.0	371.5	374.2	376.7	379.7	382.5	385.2	389.1	391.9	395.1	397.7	399.6	401.9	405.1	408.4	411.7	415.1



[9] In the Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

6. SUMMARY OF REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE WIRE NEEDS FOR THE NORTHWEST ONTARIO REGION AND SUMMARIZES THE RECOMMENDED WIRES PLANS FOR ADDRESSING THE NEEDS.

This section provides a summary of the needs and plans for the four Northwest sub-regions. The load forecasts from the LDCs have not materially changed since the completion of the previous phase (IRRP) of Regional Planning for the Northwest. Therefore, the assumptions and load growth scenario for industrial loads, as well as the needs and plans identified in this RIP are consistent with the Northwest IRRPs. The needs and recommended plans in the region are largely driven by the industrial load growth, particularly the mining sector. Proceeding to the Development phase of the customer-driven projects requires formal request by the customers and commercial agreements between Hydro One and the customers.

6.1 North of Dryden Sub-Region

Most of the demand in the North of Dryden sub-region is from the mining sector. The demand growth is driven by the expansion of this sector, as well as the connection of up to 21 remote communities in the northern parts of the region to Red Lake and Pickle Lake and growth in the mining sector, including potential developments in the Ring of Fire which may be supplied from Pickle Lake.

The North of Dryden IRRP [2] for this sub-region has assumed Low, Medium (referred to as Reference in IRRP [2]) and High load growth scenarios. Based on these scenarios, it has identified the needs and recommended wires plans in near-term, mid-term and long-term. The following are summaries of the needs and recommended plans for this sub-region, which consists of Pickle Lake sub-system, Red Lake sub-system, and Ring of Fire sub-system.

6.1.1 Pickle Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the existing single supply to Pickle Lake, i.e. the 115 kV circuit E1C, is serving 24 MW of load and is at its capacity. Any load growth in the near-term from the existing mine or connection of remote communities will require increase of LMC. The additional capacity needs, based on the medium (reference) load growth scenario are 18 MW, 28 MW and 47 MW in near-term, mid-term and long-term, respectively.

Pickle Lake LMC is limited by voltage stability. Providing dynamic voltage support, e.g. installing Static VAR Compensator (SVC) at Pickle Lake offers moderate increase in LMC, assuming the remaining capacity of circuit E4D will be available for this load increase. One alternative assessed in the IRRP is to install a new 115 kV single-circuit line from Valora, south of Dryden, to Pickle Lake to provide additional LMC that meets the near-term needs of Pickle Lake and releases some capacity on circuit E4D. However, in the long-term, with the development of new mines and potential for connection of the Ring of Fire to Pickle Lake (one the alternatives identified in the IRRP), an increase of over 130 MW in LMC may be required under the high growth forecast. As a result, the recommendation is to proceed with a plan required to meet the needs of the medium (reference) and high growth scenarios in the long-term. This plan can make the full capacity of circuit E4D available to serve the Red Lake sub-system.

<u>Recommended Plan:</u>

- Install a new 230 kV transmission line to Pickle Lake from either the Dryden area (e.g. Dinorwic) or Ignace area;

- Install a new 230 kV switching station to connect the new line to the existing circuits D26A;
- Install a new 230/115 kV auto-transformer at the end of the new line in Pickle Lake;
- Install new 115 kV switching facilities (circuit breakers) to connect the existing circuit E1C, existing customers at Pickle Lake and the new connections of the remote communities to the new auto-transformer; and
- Install required reactive compensation for voltage control

An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's (Watay Power) licence for Watay Power to develop and seek approvals for the Line to Pickle Lake and the connection of sixteen remote communities. Watay Power has initiated the Development phase of the project for these connections. Currently the planned in-service date of the 230 kV line to Pickle Lake is Q2 2020, based on Watay Power's active connection assessment with the IESO.

6.1.2 Red Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the current LMC of 61 MW at Red Lake, supplied by circuits E2R and E4D, is insufficient to meet the needs of the mining load, based on the expected growth at this location, even in near-term. The additional capacity needs, based on the medium (reference) load growth scenario are 30 MW, 44 MW and 48 MW in near-term, mid-term and long-term, respectively. Additional capacity needs increase to 75 MW under high load growth scenario.

The wires plans to meet the near-term needs are the following.

Recommended Plan:

- Upgrade circuit E4D to a summer rating of 660 A
- Upgrade circuit E2R to a summer rating of 610 A
- Provide additional voltage control at Ear Falls and/or Red Lake

However, since the load increase in the mining sector has not materialized at the same pace as previously anticipated, the initial plans for the upgrade of circuits E4D and E2R have been put on hold, awaiting customer request. A recent System Impact Assessment by the IESO for a load increase at Red Lake has determined that although the existing system can meet the demand, circuit E4D is reaching its thermal limit. Therefore, the above plan for the upgrade of circuit E4D (and E2R) can proceed in case of a request by, and agreement with, customers for additional load. Alternatively, operating measures can be used until additional firm capacity becomes available in the mid-term.

In the mid/long-term, assuming that the planned 230 kV line to Pickle Lake (see the previous section) is completed, which can make the full capacity of circuit E4D available to serve the Red Lake sub-system, there will be sufficient capacity to meet the needs under medium (reference) and high load growth scenarios. Only if the needs exceed the high growth forecast of this planning horizon, or the planned 230 kV line to Pickle Lake is not completed, a new 115 kV or 230 kV line from Dryden to Ear Falls will be one of the alternatives for meeting the demand.

6.1.3 Ring of Fire Sub-system Needs and Potential Options

The North of Dryden IRRP [2] has indicated that as the Ring of Fire sub-system is remote from the existing transmission system, any additional capacity needs would require new facilities. The IRRP has also indicated that transmission supply is the most economic option under all of the forecast scenarios, which considers the five remote communities in the vicinity of the Ring of Fire that have been identified as being economic to connect in the IESO's Remote Community Connection Plan [6] as well as possible mining customers. If mining load does not fully materialize, the North of Dryden IRRP [2] concluded that an east-west supply from the Pickle Lake area was the most economic option. If mining load fully materializes, the IRRP concluded that the economic option is either an east-west supply from the Pickle Lake area or a north-south supply from a point along the East-West Tie. Development in the area is still at an early stage and no firm recommendations can be made at this time.

6.2 Greenstone-Marathon Sub-Region:

The identified needs and recommended wire plans for this sub-region are directly related to a few large industrial developments. Based on the current load meeting capability (LMC) of the sub-region, all circuits except circuit A4L in Greenstone-Marathon sub-region are adequate to meet the projected demand forecast under all scenarios during the planning cycle. Circuit A4L is also adequate under the low demand scenario. The IRRP report [3] has recommended near term (present-5 years), medium term (5-10 years) and long term (10-20 years) actions to address the A4L limitations under the medium and high demand scenarios as described below.

6.2.1 Low Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Low Scenario assumptions are as follows:

- Hydro One Distribution customer growth
- Two saw mill re-starts

The existing circuits have sufficient LMC to meet Low Scenario's forecasted demand.

No wire plans are required for this scenario.

6.2.2 Medium Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Medium Scenario assumptions are as follows:

- Low Scenario assumptions
- Development of Geraldton mine
- Development of Beardmore mine
- Life extension of the existing Marathon Area mine

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Geraldton mine – Increase Circuit A4L Capacity:

Single-circuit 115 kV line A4L runs from Alexander SS to Longlac TS. A mining development in Geraldton area, with the proposed in-service date of 2019, would increase the near-term demand on circuit A4L to 51 MW, which is higher than its current LMC of approximately 25 MW. The LMC of circuit A4L is limited by voltage.

A major deciding factor in the recommendation for meeting the forecasted demand is the lead time relative to the proposed timelines for the mine development.

<u>Recommended Plan:</u>

If the proposed in service date of 2019 does not change, Installing Reactive Compensation and gas-fired generation in the near term is the recommended solution.

Installing reactive compensation of about +40 MVARs in the form of either synchronous condenser or Static Synchronous Compensators (STATCOM) at the Geraldton mine site would increase the LMC of circuit A4L to 45 MW, making full thermal capability of the circuit available. This form of Reactive Compensation is recommended considering the low short-circuit level at the end of circuit A4L relative to the requirements of the mine. The remaining short fall of approximately 6 MW to meet the needs of the mine can be provided by a customer-based grid-connected gas-fired generation plant with sufficient redundancy, for example, installing two 10 MW gas-fired units.

If the in-service date of the mine is delayed, replacing a section of circuit A4L, between Nipigon and Longlac, along with the installation of the above reactive compensation, would increase the LMC of circuit A4L to about 60 MW. Replacing the section of circuit A4L has a lead time of approximately five years.

Accommodate Beardmore mine – Increase Circuit A4L Capacity

A potential gold mine near Beardmore may be operational within the medium term. If Geraldton mine doesn't connect to circuit A4L as described above, the existing system would be sufficient to support the Beardmore mine.

If the Geraldton mine connects to circuit A4L and the plans for the high-demand scenario (described below) do not proceed, in order to accommodate the Beardmore mine, additional capacity would be required.

<u>Recommended Plan:</u>

Upgrading a section of circuit A4L from Alexander SS to Beardmore Junction is a medium term wires option for supplying the potential mine.

6.2.3 High Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, High Scenario assumptions are as follows

- Medium Scenario assumptions
- Development of the proposed Energy East pipeline
- Development of additional mines in Marathon Area
- Development of Ring of Fire, with connection to the Greenstone area

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Energy East Pipeline and, potentially, the Ring of Fire – Install New Wires:

Potential Energy East load is subjected to customers' request for connection of the pumping stations to the provincial electricity grid. The medium or long term recommended plans for the High Scenario depend on the Energy East plans and timelines for connecting some or all of the pumping stations, in one or two phases.

The Greenstone-Marathon Sub-Region IRRP [3] also indicates that the Ring of Fire could be potentially connected by an east-west corridor to Pickle Lake or by a north-south corridor to the Nipigon or Marathon areas.

<u>Recommended Plan:</u>

According to the IRRP report [3], the preferred option under the High Scenario, with or without the potential connection of the Ring of Fire, is the following wires plan.

- Install a new 230 kV transmission line to Longlac TS from either from the Nipigon area or from the Marathon (or Terrance Bay) area;
- Install a new 230 kV switching station to connect the new line to the existing circuits M23L-M24L;
- Install a new 230/115 kV auto-transformer at Longlac TS;

- Install required reactive compensation for voltage control and short-circuit level requirements at the mine; and
- Install a new 115 kV Line from Longlac TS to Manitouwadge TS to supply all the pumping stations in the area, possibly in the second phase.

Advancing the plan for the new transmission line and transformer, in order to meet the timelines of the Geraldton mine and the Beardemore mine developments, is an alternative to the upgrade of circuit A4L described under the Medium Scenario above. During outages of the new line or transformer, the new mines and industrial loads need to be interrupted to maintain the loading on circuit A4L below its LMC.

The above plan will improve the reliability for the customers served from Longlac TS by maintaining their supply through the new transmission line and transformer during outages of circuit A4L.

6.3 West of Thunder Bay Sub-Region

This sub-region, as described in the IRRP report [4], consists of four main sub-systems, Moose Lake, Fort Frances, Kenora and Dryden. The West of Thunder Bay Sub-Region is also a source of supply to the North of Dryden sub-region (through the Dryden 115 kV system) and therefore the needs and recommendations from the North of Dryden IRRP (described in the previous sections) were considered in the West of Thunder Bay IRRP.

Similar to the other sub-regions described above, because of the uncertainty in the development plans and connection options, the IRRP has considered low, medium (or reference) and high load growth scenarios in the West of Thunder Bay sub-region and has identified near/mid/long-term needs and recommendations for each scenario.

The low load growth scenario has forecasted a peak demand of close to 240 MW in 2017 (with the startup of a new mine near Rainy River) which will remain fairly flat until 2034.

In the medium load growth scenario, involving new mines and industrial load (pumping stations of the pipeline conversion project), the load forecast increases from 252 MW in 2017 to 345 MW in 2034.

In the high load growth scenario, involving additional mines, the load forecast increases from 305 MW in 2017 to 551 MW in 2034.

6.3.1 Dryden Needs and Plans

The Dryden 115 kV sub-system can provide up to 240 MW of continuous supply to the Dryden and North of Dryden Sub-Region. Under the low and medium (reference) load growth scenarios, this LMC is sufficient to meet the demand of this sub-system.

Under the high load growth scenario, additional capacity of 50 MW will be required on the 115 kV system at Dryden by the mid-2020s. This scenario considers high growth in the North of Dryden Sub-Region, and assumes that all load on circuit E1Cwill be supplied by the proposed 230 kV line to Pickle Lake. The IRRP identified one option for meeting the need of the 115 kV system to install a third autotransformer at Dryden TS. A recommended plan has not been finalized at this time given the long lead time and uncertainty associated with potential developments in the area. The next cycle of Regional Planning will reassess the need.

6.3.2 Kenora Needs and Plans

The transformer station supplying the City of Kenora and surrounding areas ("Kenora MTS") can supply 25 MW. This transformer station currently supplies up to 20 MW. Since the increase in the residential and commercial load in the Kenora area is forecast to be modest over the planning period, the remaining 5 MW margin will be adequate for the Kenora area.

The IRRP has identified that an industrial customer, currently supplied by a local generating station is considering pursuing an alternative supply arrangement from Kenora MTS. Furthermore, potential developments at the former Abitibi mill site may also require additional transformer station capacity in the Kenora area. The magnitude and timing of these developments remains uncertain and is not expected to have major regional implications. No actions were recommended in the IRRP to address the need at this time.

6.3.3 Moose Lake Needs and Plans

The Moose Lake 115 kV sub-system has sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.3.4 Fort Frances Needs and Plans

The Fort Frances 115 kV sub-system was found to have sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.4 Thunder Bay Sub-Region

The IRRP for the Thunder Bay sub-region [5] considered low, medium and high load growth scenarios and identified near/mid/long-term needs and recommendations for each scenario. The assessments of this sub-region have assumed that the most impactful scenario in the Greenstone sub-system will materialize, resulting in 60 MW supply need from the Thunder Bay sub-region (i.e. on circuit A4L in case it would be upgraded).

The low load growth scenario has forecast the peak demand of close to 325 MW in 2015 will decline to about 300 MW by 2035 as a result of continuing decline in the pulp and paper sector and without new mining or industrial developments in Thunder Bay.

In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035. This is comparable to the sub-region's historic peak demand in 2006/2007.

In the high load growth scenario, involving additional transmission connected mining developments north of Thunder Bay; the load is forecasted to increase to 415 MW by the end of planning period.

In addition to the potential long-term wires options for medium/high growth scenarios described below, the IRRP for Thunder Bay sub-region identified the near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This work has been completed.

6.4.1 Long-Term Needs and Plans

Port Arthur TS - Transformation Capacity

The long-term load forecast indicates that the demand from the customers supplied by Port Arthur TS will exceed the station's current capacity by 2033, and additional station capacity will be required if this load growth materializes.

Currently, the low voltage equipment at Port Arthur TS are limiting the station capacity to 55 MW. The station transformers provide up to 59 MW of capacity.

<u>Wires Option:</u>

The low voltage equipment, which are limiting the station capacity are nearing end-of-life and are planned to be replaced and upgraded in mid-term. This upgrade would bring the station capacity up to 59 MW, sufficient to meet the need beyond 2035. No additional plan is required at this time and load at Port Arthur TS will be monitored and supply options will be assessed in the next cycle of Regional Planning.

Lakehead TS and Birch TS - Transformation Capacity

Currently the Thunder Bay 115 kV system can accommodate approximately 150 MW of additional load growth. This capacity is sufficient under the low and medium load growth scenarios in the long-term.

Under the High growth scenario, and assuming the most impactful Greenstone sub-system scenario (60 MW, as described above), the Thunder Bay system would require additional supply capacity of approximately 20 MW by 2030.

The Thunder Bay IRRP indicates that a firm plan to increase the LMC of the Thunder Bay 115 kV system is not required at this time, as the large margin remaining on the system provides significant lead time for the Working Group to monitor demand growth and study options. The IRRP report explored various wires and non-wires options as potential long term solutions to increase the LMC of the system, however no action beyond monitoring is recommended at this time.

The wires options discussed in the Thunder Bay IRRP are described below:

1. Installing a third 230/115 kV 250 MVA autotransformer at Lakehead TS to increase the LMC of Lakehead TS by approximately 240 MW.

2. A new 230 kV line from Lakehead TS to Birch TS and a 230 kV 250 MVA autotransformer at Birch TS to create a supply point for the southern part of Thunder Bay, with a supply capacity of 240 MW. The new 230 kV line would require a new Right-of-Way and would take 5 years or longer to build.

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7. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE NORTHWEST ONTARIO 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 section provides a summary of the Needs and Plans for the Northwest Region as identified in this RIP.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

West of Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

8. REFERENCES

[1]. Northwest Region Scoping Assessment (SA) Outcome Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf

[2]. North of Dryden Sub-Region Integrated Regional Resource Plan (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf

[3]. Greenstone-Marathon Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/2016-Greenstone-Marathon-IRRP-Report.pdf

[4]. West of Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/West_of_Thunder_Bay/2016-West-of-Thunder-Bay-IRRP.pdf

[5]. Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Thunder-Bay-IRRP.pdf

[6]. 2014 Draft Remote Community Connection Plan
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Remote_Community/OPA-technical-report-2014-08-21.pdf

Appendix A. Stations in the Northwest Ontario Region

Sub-Region	Station	Voltage (kV)	Supply Circuits
North of Dryden	Ear Falls TS	115/44	M3E, E4D, E1C, E2R
	Red Lake TS	115/44	E2R
	Cat Lake MTS	115/25	E1C
	Crow River DS	115/25	E1C
	Perrault Falls DS	115/12.5	E4D
	Slate Falls DS	115/24.9	E1C
Greenstone-Marathon	Longlac TS	115/44	A4L
	Manitouwadge TS	115/44	M2W
	Marathon TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
	Beardmore DS #2	115/25	A4L
	Jellicoe DS #3	115/12.5	A4L
	Manitouwadge DS #1	115/12.5	M2W
	Marathon DS	115/25	T1M
	Pic DS	115/25	M2W
	Schreiber Winnipeg DS	115/12.5	A5A
	White River DS	115/25	M2W
West of Thunder Bay	Barwick TS	115/44	K6F
	Dryden TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
	Fort Frances TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
	Kenora TS	230/115	K24F, K7K, K21W, K23D, K22W
	Mackenzie TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
	Moose Lake TS	115/44	A3M, M1S, M2D, B6M
	Fort Frances MTS	115/12.47	F1B
	Kenora MTS	115/12.5	15M1
	Agimak DS	115/25	29M1
	Burleigh DS	115/12.5	F1B
	Clearwater Bay DS	115/25	SK1
	Eton DS	115/12.48	K3D
	Keewatin DS	115/12.5	SK1
	Margach DS	115/25	K6F
	Minaki DS	115/25	K4W
	Nestor Falls DS	115/13.2	K6F
	Sam Lake DS	115/26.4	K3D
	Sapawe DS	115/12.5	B6M
	Shabaqua DS	115/12.5	B6M
	Sioux Narrows DS	115/12.5	K6F
	Valora DS	115/25	29M1
	Vermilion Bay DS	115/12.5	K3D
Thunder Bay	Birch TS	115/28.4	Q9B, P7B, Q8B, Q5B, R2LB, P3B, Q4B, R1LB, B6M
	Fort William TS	115/25	Q5B, Q4B
	Lakehead TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
	Port Arthur TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
	Murillo DS	115/26.40	B6M
	Nipigon DS	115/4.16	57M1
	Red Rock DS	115/12.5	56M1

Appendix B. Transmission Lines in the Northwest Ontario Region

Circuit(s)	Location	Voltage (kV)
D26A	Mackenzie x Dryden	230
F25A	Mackenzie x Fort Frances	230
K23D	Dryden x TCPL Vermill Bay x Kenora	230
K24F	Fort Frances x Kenora	230
N93A	Mackenzie x Marmion Lake x Atikokan	230
K21W, K22W	Kenora x Whiteshell (Manitoba Hydro)	230
A21L, A22L	Mackenzie x Lakehead	230
M23L, M24L	Marathon x Lakehead	230
15M1	Kenora x Rabbit Lake	115
29M1	Ignace x Camp Lake x Valora x Mattabi	115
A3M	Mackenzie x Moose Lake	115
B6M	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	115
D5D	Dryden x Domtar Dryden	115
F1B	Fort Frances x Burleigh	115
F3M	Fort Frances x Internat Fls (Minnesota Power)	115
K2M	Kenora x Norman	115
K3D	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	115
K4W	White Dog x Minaki x Rabbit Lake	115
K6F	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	115
K7K	Kenora x Weyerhaeuser Ken x Rabbit Lake	115
M1S	Moose Lake x Valerie Falls x Mill Creek	115
M2D	Moose Lake x Ignace x Dryden	115
SK1	Rabbit Lake x Keewatin x Forgie	115
W3C	White Dog x Caribou Falls	115
56M1	Nipignon x Red Rock	115
57M1	Reserve x Nipignon	115
A6P	Alexander x Port Arthur	115
L3P, L4P	Lakehead x Port Arthur	115
P3B, P7B	Port Arthur x Birch	115
P5M	Port Arthur x Conmee	115
Q4B, Q5B, Q8B, Q9B	Thunder Bay x Birch	115
R1LB, R2LB	Lakehead x Pine Portage x Birch	115
S1C	Silver Falls x Lac Des Iles x Conmee	115
A1B	Aguasabon x Terrace Bay	115
A4L	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	115
A5A	Alexander x Minnova x Schreiber x Aguasabon	115
C1A, C2A, C3A	Alexander x Cameron Falls	115
GA1	Upper White River x Lower White River	115
M2W	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	115
R9A	Alexander x Pine Portage	115
E1C	Ear Falls x Selco x Slate Falls x Cat Lake x Crow River x Musselwhite	115
E2R	Ear Falls x Balmer x Red Lake	115
E4D	Ear Falls x Scout Lake x Dryden	115
M3E	Manitou Falls x Ear Falls	115
T1M	Terrace Bay x Marathon	115

Appendix C. Distributors in the Northwest Ontario Region

Distributor Name	Station Name	Connection
ATIKOKAN HYDRO INC.	Moose Lake TS	Tx
FORT FRANCES POWER CORPORATION	Fort Frances MTS	Tx
HYDRO ONE NETWORKS INC.	Agimak DS	Tx
	Aguasabon GS	Tx
	Barwick TS	Tx
	Beardmore DS #2	Tx
	Burleigh DS	Tx
	Cat Lake MTS	Tx
	Clearwater Bay DS	Tx
	Crow River DS	Tx
	Dryden TS	Tx
	Ear Falls DS	Tx
	Ear Falls TS	Tx
	Eton DS	Tx
	Fort Frances TS	Tx
	H2O Pwr SturgFls CGS	Tx
	Jellicoe DS #3	Tx
	Keewatin DS	Tx
	Kenora DS	Tx
	Longlac TS	Tx
	Manitouwadge DS #1	Tx
	Manitouwadge TS	Tx
	Marathon DS	Tx
	Margach DS	Tx
	Minaki DS	Tx
	Murillo DS	Tx
	Nestor Falls DS	Tx
	Nipigon DS	Tx
	Perrault Falls DS	Tx
	Pic DS	Tx
	Port Arthur TS #1	Tx
	Red Lake TS	Tx
	Red Rock DS	Tx
	Sam Lake DS	Tx
	Sapawe DS	Tx
	Schreiber Winnipg DS	Tx
	Shabaqua DS	Tx
	Sioux Narrows DS	Tx
	Slate Falls DS	Tx
	Valora DS	Tx
	Vermilion Bay DS	Tx
	White River DS	Tx
	Whitedog Falls GS	Tx
	Whitedog DS	Tx
KENORA HYDRO ELECTRIC CORPORATION	Kenora MTS	Tx
SIOUX LOOKOUT HYDRO INC.	Sam Lake DS	Dx
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	Birch TS	Tx
	Fort William TS	Tx
	Port Arthur TS #1	Tx

Appendix D. Northwest Ontario Stations Non Coincident Load Forecast (2016-2025)

Table D-1 Stations Non Coincident Net Load Forecast (MW)

Station LDCs
Atikokan Hydro
Fort Frances Power Corp
Kenora Hydro
Thunder Bay Hydro
Hydro One Distribution

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Moose Lake TS*	Non Coincidental Gross						6.10	6.16	6.22	6.28	6.35	6.38	6.41	6.44	6.48	6.51
		CDM						0.04	0.07	0.12	0.17	0.21	0.24	0.28	0.31	0.33	0.37
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.50	4.30	4.53	4.93	6.06	6.06	6.09	6.10	6.11	6.14	6.13	6.13	6.13	6.14	6.13
West of Thunder Bay	*Fort Frances MTS*	Non Coincidental Gross						17.10	17.02	16.93	17.10	17.27	17.45	17.62	17.80	17.97	18.15
		CDM						0.11	0.18	0.32	0.46	0.56	0.66	0.76	0.85	0.92	1.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	16.93	16.29	17.17	17.92	16.79	16.99	16.83	16.61	16.64	16.70	16.78	16.85	16.95	17.05	17.11
West of Thunder Bay	*Fort Frances TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	15.60	16.37	16.73	16.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Barwick TS*	Non Coincidental Gross						17.07	17.07	17.29	17.56	17.69	17.81	17.93	18.04	18.19	18.33
		CDM						0.11	0.19	0.32	0.47	0.58	0.68	0.78	0.86	0.93	1.04
		DG						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Non Coincidental Net					14.00	15.96	15.88	15.96	16.08	16.11	16.13	16.15	16.18	16.25	16.28
West of Thunder Bay	*Kenora MTS*	Non Coincidental Gross						21.45	21.66	21.88	22.10	22.10	22.32	22.32	22.54	22.76	22.99
		CDM						0.14	0.24	0.41	0.59	0.72	0.85	0.97	1.07	1.17	1.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	20.49	20.77	21.27	21.62	20.57	21.30	21.41	21.46	21.49	21.37	21.46	21.34	21.45	21.58	21.66
Thunder Bay	*Birch TS*	Non Coincidental Gross						77.88	78.54	78.80	79.31	79.81	80.32	80.55	81.34	81.96	82.52
		CDM						0.51	0.85	1.48	2.13	2.60	3.06	3.50	3.87	4.21	4.70
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Non Coincidental Net	70.48	70.02	86.01	87.04	74.01	77.33	77.64	77.28	77.14	77.17	77.22	77.01	77.43	77.71	77.77

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thunder Bay	*Fort Williams TS*	Non Coincidental Gross						77.90	78.14	80.46	81.23	83.61	87.49	91.88	91.11	89.64	89.29
		CDM						0.51	0.85	1.51	2.18	2.73	3.33	3.99	4.33	4.60	5.09
		DG						4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45
		Non Coincidental Net	74.99	73.18	80.22	80.81	79.20	72.94	72.84	74.50	74.59	76.43	79.70	83.44	82.33	80.59	79.76
Thunder Bay	*Port Arthur TS#1*	Non Coincidental Gross						37.00	37.40	37.90	38.50	39.10	39.60	40.20	40.90	41.50	42.20
		CDM						0.24	0.41	0.71	1.03	1.27	1.51	1.74	1.94	2.13	2.40
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	34.92	35.73	35.36	39.98	30.70	36.74	36.98	37.18	37.45	37.81	38.08	38.44	38.94	39.36	39.78
Thunder Bay	*Port Arthur TS #1*	Non Coincidental Gross						8.54	8.65	8.77	8.80	8.94	9.10	9.19	9.28	9.36	9.44
		CDM						0.06	0.09	0.16	0.24	0.29	0.35	0.40	0.44	0.48	0.54
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.12	7.48	8.52	8.52	7.90	8.49	8.56	8.60	8.56	8.65	8.76	8.79	8.84	8.88	8.90
West of Thunder Bay	*Agimak DS*	Non Coincidental Gross						3.32	3.33	3.39	3.46	3.50	3.53	3.57	3.60	3.65	3.69
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.19	0.21
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.96	3.04	3.24	3.70	4.30	3.30	3.30	3.33	3.36	3.38	3.40	3.41	3.43	3.46	3.48
Greenstone-Marathon	*Beardmore DS #2*	Non Coincidental Gross						1.23	1.23	1.25	1.28	1.29	1.30	1.31	1.33	1.34	1.36
		CDM						0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.19	1.30	1.21	1.17	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Burleigh DS*	Non Coincidental Gross						4.12	4.12	4.18	4.24	4.27	4.30	4.33	4.35	4.39	4.42
		CDM						0.03	0.04	0.08	0.11	0.14	0.16	0.19	0.21	0.23	0.25
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.63	3.80	4.10	4.05	3.70	4.09	4.08	4.10	4.13	4.13	4.14	4.14	4.14	4.16	4.17
North of Dryden	*Cat Lake MTS*	Non Coincidental Gross						0.82	0.83	0.85	0.86	0.88	0.89	0.90	0.91	0.92	0.94
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.79	0.69	0.80	0.72	0.74	0.82	0.82	0.83	0.84	0.85	0.85	0.86	0.87	0.88	0.88
West of Thunder Bay	*Clearwater Bay DS*	Non Coincidental Gross						5.47	5.47	5.54	5.61	5.65	5.68	5.71	5.74	5.78	5.83
		CDM						0.04	0.06	0.10	0.15	0.18	0.22	0.25	0.27	0.30	0.33
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.66	4.94	5.38	5.32	4.50	5.43	5.41	5.43	5.46	5.47	5.47	5.46	5.47	5.49	5.49
West of Thunder Bay	*Crilly DS*	Non Coincidental Gross						2.17	2.21	2.25	2.29	2.33	2.36	2.40	2.43	2.46	2.49
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.02	1.98	2.02	1.99	2.05	2.15	2.19	2.21	2.23	2.25	2.27	2.29	2.32	2.33	2.35

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North of Dryden	*Crow River DS*	Non Coincidental Gross						2.70	2.70	2.74	2.79	2.81	2.84	2.86	2.88	2.90	2.93
		CDM						0.02	0.03	0.05	0.07	0.09	0.11	0.12	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.89	2.52	2.64	2.58	2.12	2.68	2.68	2.69	2.72	2.72	2.73	2.73	2.74	2.75	2.76
West of Thunder Bay	*Dryden TS*	Non Coincidental Gross						21.14	21.33	21.80	22.31	22.65	22.99	23.31	23.63	24.02	24.41
		CDM						0.14	0.23	0.41	0.60	0.74	0.88	1.01	1.12	1.23	1.39
		DG						0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
		Non Coincidental Net	18.66	19.07	20.21	19.94	19.61	20.59	20.69	20.99	21.31	21.51	21.71	21.89	22.10	22.38	22.62
North of Dryden	*Ear Falls DS*	Non Coincidental Gross						4.29	4.32	4.34	4.37	4.39	4.42	4.44	4.46	4.49	4.51
		CDM						0.03	0.05	0.08	0.12	0.14	0.17	0.19	0.21	0.23	0.26
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.43	2.46	2.74	4.23	4.55	4.26	4.27	4.26	4.25	4.25	4.25	4.25	4.25	4.26	4.25
West of Thunder Bay	*Eton DS*	Non Coincidental Gross						5.04	5.04	5.10	5.17	5.21	5.24	5.27	5.30	5.34	5.38
		CDM						0.03	0.05	0.10	0.14	0.17	0.20	0.23	0.25	0.27	0.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.06	4.16	4.00	3.97	3.74	5.00	4.98	5.00	5.03	5.03	5.03	5.04	5.04	5.06	5.07
Greenstone-Marathon	*Jellicoe DS #3*	Non Coincidental Gross						0.47	0.47	0.48	0.49	0.49	0.50	0.50	0.50	0.51	0.51
		CDM						0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.48	0.47	0.46	0.45	0.33	0.47	0.47	0.47	0.48	0.48	0.48	0.48	0.48	0.48	0.48
West of Thunder Bay	*Kenora DS*	Non Coincidental Gross						6.88	6.88	6.97	7.10	7.17	7.24	7.30	7.37	7.44	7.51
		CDM						0.05	0.07	0.13	0.19	0.23	0.28	0.32	0.35	0.38	0.43
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	11.44	12.50	6.73	6.67	5.93	6.83	6.80	6.84	6.90	6.93	6.96	6.98	7.02	7.06	7.08
West of Thunder Bay	*Keewatin DS*	Non Coincidental Gross						5.55	5.55	5.62	5.73	5.79	5.84	5.89	5.95	6.00	6.06
		CDM						0.04	0.06	0.11	0.15	0.19	0.22	0.26	0.28	0.31	0.35
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net		5.29	5.43	5.41	4.62	5.51	5.49	5.52	5.57	5.60	5.62	5.64	5.66	5.70	5.72
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						12.79	13.00	18.00	18.19	18.38	18.57	18.76	18.96	19.15	19.35
		CDM						0.08	0.14	0.34	0.49	0.60	0.71	0.81	0.90	0.98	1.10
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	10.78	12.66	12.60	11.94	12.70	12.86	17.66	17.70	17.78	17.86	17.95	18.06	18.17	18.25

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Manitouwadge DS #1*	Non Coincidental Gross						1.56	1.56	1.59	1.61	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.01	0.02	0.03	0.04	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.86	1.36	1.54	1.34	1.29	1.55	1.55	1.56	1.56	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Manitouwadge TS*	Non Coincidental Gross						11.07	11.10	11.28	11.48	13.21	13.33	13.44	13.55	13.69	13.83
		CDM						0.07	0.12	0.21	0.31	0.43	0.51	0.58	0.64	0.70	0.79
		DG						7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84
		Non Coincidental Net	9.48	10.37	10.79	9.66	9.05	3.15	3.14	3.23	3.33	4.94	4.98	5.02	5.06	5.15	5.20
Greenstone-Marathon	*Marathon DS*	Non Coincidental Gross						11.16	11.21	11.42	11.64	11.78	11.91	12.03	12.16	12.31	12.47
		CDM						0.07	0.12	0.21	0.31	0.38	0.45	0.52	0.58	0.63	0.71
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	7.22	8.08	10.71	10.57	7.56	11.08	11.09	11.20	11.33	11.39	11.45	11.51	11.58	11.68	11.76
West of Thunder Bay	*Margach DS*	Non Coincidental Gross						9.60	9.60	9.73	9.88	9.95	10.01	10.07	10.12	10.21	10.29
		CDM						0.06	0.10	0.18	0.27	0.32	0.38	0.44	0.48	0.52	0.59
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.77	9.38	9.44	9.37	8.82	9.53	9.50	9.55	9.61	9.62	9.63	9.63	9.64	9.68	9.70
West of Thunder Bay	*Minaki DS*	Non Coincidental Gross						0.99	0.99	1.00	1.02	1.02	1.03	1.03	1.04	1.05	1.06
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.94	1.06	0.97	0.93	1.00	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	1.00
Thunder Bay	*Murillo DS*	Non Coincidental Gross						19.37	19.61	19.88	19.95	20.27	20.64	20.84	21.03	21.21	21.39
		CDM						0.13	0.21	0.37	0.54	0.66	0.79	0.90	1.00	1.09	1.22
		DG						0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.12	0.12
		Non Coincidental Net	12.12	12.93	12.43	11.34	15.35	19.22	19.37	19.48	19.39	19.59	19.83	19.91	20.01	20.00	20.05
West of Thunder Bay	*Nestor Falls DS*	Non Coincidental Gross						3.36	3.36	3.41	3.46	3.48	3.50	3.52	3.54	3.56	3.59
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.18	0.20
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.22	3.32	3.33	3.29	3.05	3.34	3.33	3.34	3.36	3.36	3.37	3.36	3.37	3.38	3.39
Thunder Bay	*Nipigon DS*	Non Coincidental Gross						2.21	2.24	2.27	2.29	2.33	2.38	2.41	2.44	2.47	2.50
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.32	2.19	2.31	2.23	2.17	2.19	2.21	2.23	2.23	2.26	2.29	2.31	2.32	2.34	2.36
North of Dryden	*Perrault Falls DS*	Non Coincidental Gross						0.79	0.80	0.81	0.83	0.83	0.84	0.85	0.86	0.87	0.88
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.89	0.91	0.78	0.86	0.86	0.79	0.79	0.79	0.80	0.81	0.81	0.81	0.82	0.82	0.83

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Pic DS*	Non Coincidental Gross						6.57	6.58	6.67	6.78	6.84	6.89	6.94	6.98	7.05	7.11
		CDM						0.04	0.07	0.12	0.18	0.22	0.26	0.30	0.33	0.36	0.41
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.96	6.94	6.37	6.50	6.38	6.52	6.50	6.55	6.60	6.61	6.62	6.63	6.65	6.68	6.71
North of Dryden	*Red Lake TS*	Non Coincidental Gross						26.58	26.81	27.04	27.27	27.41	27.64	27.88	28.12	28.36	28.61
		CDM						0.18	0.29	0.51	0.73	0.89	1.05	1.21	1.34	1.46	1.63
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	45.06	47.55	48.55	49.17	50.28	26.40	26.52	26.53	26.54	26.51	26.59	26.67	26.78	26.91	26.98
Thunder Bay	*Red Rock DS*	Non Coincidental Gross						4.01	4.02	4.04	4.02	4.06	4.09	4.10	4.10	4.11	4.11
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.21	0.23
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.23	0.23
		Non Coincidental Net	3.97	3.87	4.08	4.09	4.02	3.95	3.94	3.93	3.88	3.88	3.90	3.88	3.87	3.67	3.64
West of Thunder Bay	*Sam Lake DS*	Non Coincidental Gross						23.97	24.05	24.44	24.88	25.12	25.36	25.57	25.79	26.07	26.36
		CDM						0.16	0.26	0.46	0.67	0.82	0.97	1.11	1.23	1.34	1.50
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	19.80	22.25	23.23	23.00	23.42	23.80	23.78	23.98	24.20	24.30	24.38	24.46	24.56	24.73	24.85
West of Thunder Bay	*Sapawe DS*	Non Coincidental Gross						0.95	0.95	0.97	0.98	0.99	1.00	1.01	1.01	1.02	1.03
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.95	0.80	0.94	0.92	2.61	0.95	0.94	0.95	0.96	0.96	0.96	0.96	0.97	0.97	0.97
Greenstone-Marathon	*Schreiber Winnipg DS*	Non Coincidental Gross						5.19	5.20	5.29	5.38	5.43	5.48	5.52	5.57	5.63	5.69
		CDM						0.03	0.06	0.10	0.14	0.18	0.21	0.24	0.26	0.29	0.32
		DG						0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.47	5.21	5.19	5.07	5.32	5.15	5.15	5.19	5.22	5.24	5.26	5.27	5.29	5.33	5.35
West of Thunder Bay	*Shabaqua DS*	Non Coincidental Gross						2.80	2.81	2.85	2.89	2.92	2.94	2.96	2.98	3.01	3.04
		CDM						0.02	0.03	0.05	0.08	0.10	0.11	0.13	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.64	2.83	2.83	2.81	2.74	2.78	2.77	2.79	2.81	2.82	2.83	2.83	2.84	2.85	2.86
West of Thunder Bay	*Sioux Narrows DS*	Non Coincidental Gross						4.49	4.49	4.55	4.62	4.65	4.68	4.71	4.73	4.77	4.81
		CDM						0.03	0.05	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.27
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.09	4.25	4.37	4.34	4.22	4.46	4.44	4.46	4.49	4.50	4.50	4.50	4.51	4.53	4.54
North of Dryden	*Slate Falls DS*	Non Coincidental Gross						0.64	0.64	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.70
		CDM						0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.56	0.63	0.62	0.61	0.61	0.64	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.66

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Valora DS*	Non Coincidental Gross						0.77	0.78	0.79	0.81	0.83	0.84	0.85	0.86	0.88	0.89
		CDM						0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.64	0.70	0.74	0.73	0.69	0.77	0.77	0.78	0.79	0.80	0.81	0.81	0.82	0.83	0.84
West of Thunder Bay	*Vermilion Bay DS*	Non Coincidental Gross						3.95	3.97	4.01	4.06	4.09	4.12	4.15	4.18	4.21	4.25
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.22	0.24
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.22	2.36	2.37	2.43	2.10	3.93	3.92	3.94	3.95	3.96	3.96	3.97	3.98	3.99	4.00
West of Thunder Bay	*Whitedog DS*	Non Coincidental Gross						2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56	2.59
		CDM						0.02	0.03	0.05	0.07	0.08	0.09	0.11	0.12	0.13	0.15
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.97	2.19	2.30	2.40	2.31	2.35	2.36	2.37	2.37	2.38	2.39	2.40	2.42	2.43	2.44
Greenstone-Marathon	*White River DS*	Non Coincidental Gross						7.02	7.06	7.18	7.32	7.41	7.49	7.56	7.64	7.73	7.83
		CDM						0.05	0.08	0.13	0.20	0.24	0.29	0.33	0.36	0.40	0.45
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.20	3.20	6.80	6.74	6.44	6.98	6.98	7.05	7.13	7.16	7.20	7.23	7.28	7.34	7.38

Appendix E. Past Sustainment Activities in Northwest Ontario

Station	I/S Date	Asset Class
ALEXANDER SS	8-Dec-16	Breaker: SF6_115 kV
BIRCH TS	3-Dec-15	Transformer: Step-down_115 kV
DRYDEN TS	29-Aug-16	Breaker: SF6_115 kV
	14-Jul-16	Breaker: SF6_115 kV
	20-Oct-16	Breaker: SF6_115 kV
	10-Nov-16	Breaker: SF6_115 kV
	29-May-16	Breaker: SF6_115 kV
	23-Jul-14	Breaker: SF6_13.8 kV
	4-Sep-14	Breaker: SF6_13.8 kV
	29-Aug-16	Switch: Air Break_115 kV
	29-Aug-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	31-Aug-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	10-Nov-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	29-May-16	Switch: Air Break_115 kV
	1-Nov-16	Switch: Air Break_115 kV
	23-Jul-14	Switch: Air Break_13.8 kV
	4-Sep-14	Switch: Air Break_ 13.8 kV
FORT FRANCES TS	23-Nov-10	Breaker: SF6_13.8 kV
	2-Sep-10	Breaker: SF6_13.8 kV
	2-Oct-13	Switch: Air Break_115 kV
	27-Nov-15	Switch: Air Break_230 kV
	2-Oct-13	Switch: Ground_115 kV
	27-Nov-15	Switch: Ground_230 kV
	2-Sep-10	Switch: Air Break_ 13.8 kV
	2-Oct-16	Switch: Air Break_115 kV
	12-Sep-14	Switch: Ground_ 44 kV
	23-Nov-10	Switch: Air Break_ 13.8 kV
LAKEHEAD TS	27-Sep-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	1-Dec-09	Breaker: SF6_13.8 kV
	4-Apr-12	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Air Break_ 13.8 kV
	21-Oct-09	Switch: Ground_ 13.8 kV
	21-Oct-09	Switch: Air Break_ 13.8 kV
	12-Sep-16	Transformer: Autotransformer_230 kV

Station	I/S Date	Asset Class
KENORA TS	15-Jul-2009	Breaker: SF6_13.8 kV
KENORA TS	29-May-2015	Switch: Air Break_230 kV
KENORA TS	29-May-2015	Switch: Ground_230 kV
KENORA TS	26-Feb-2013	Switch: Air Break_230 kV
KENORA TS	15-Jul-2009	Switch: Air Break_ 13.8 kV
MACKENZIE TS	17-Jun-2010	Breaker: SF6_13.8 kV
MANITOUWADGE TS	2-Jul-2016	Breaker: SF6_27.6 kV
MANITOUWADGE TS	10-Jul-2016	Switch: Air Break_ 44 kV
MANITOUWADGE TS	9-Jul-2016	Transformer: Step-down_115 kV
MARATHON TS	25-May-2009	Breaker: SF6_230 kV
MARATHON TS	26-Mar-2014	Breaker: SF6_13.8 kV
MARATHON TS	18-Dec-2013	Breaker: SF6_13.8 kV
MARATHON TS	23-Dec-2016	Switch: Air Break_230 kV
MARATHON TS	23-Dec-2016	Switch: Ground_230 kV
MARATHON TS	26-Mar-2014	Switch: Air Break_ 13.8 kV
MARATHON TS	18-Dec-2013	Switch: Air Break_ 13.8 kV
MOOSELAKE TS	8-Sep-2014	Breaker: SF6_115 kV
MOOSELAKE TS	31-Jul-2014	Breaker: SF6_115 kV
MOOSELAKE TS	29-May-2014	Breaker: SF6_115 kV
MOOSELAKE TS	8-Sep-2014	Breaker: SF6_115 kV
MOOSELAKE TS	11-Jul-2014	Breaker: SF6_115 kV
PORT ARTHUR TS #1	11-Aug-2015	Switch: Air Break_115 kV
PORT ARTHUR TS #1	25-Nov-2009	Switch: Air Break_115 kV
PORT ARTHUR TS #1	11-Nov-2009	Switch: Air Break_115 kV
PORT ARTHUR TS #1	21-Sep-2012	Switch: Air Break_115 kV
PORT ARTHUR TS #1	20-Nov-2009	Switch: Air Break_115 kV
PORT ARTHUR TS #1	6-Nov-2009	Switch: Air Break_115 kV
PORT ARTHUR TS #1	22-Jun-2015	Switch: Air Break_115 kV
PORT ARTHUR TS #1	2-Jun-2015	Switch: Air Break_115 kV
PORT ARTHUR TS #1	21-Sep-2012	Switch: Air Break_115 kV
PORT ARTHUR TS #1	21-Sep-2012	Switch: Ground_115 kV
RABBIT LAKE SS	16-Dec-2011	Breaker: SF6_115 kV
RABBIT LAKE SS	10-Nov-2011	Breaker: SF6_115 kV
RABBIT LAKE SS	22-Oct-2011	Switch: Air Break_115 kV
RABBIT LAKE SS	25-Nov-2016	Switch: Air Break_115 kV
RABBIT LAKE SS	15-Nov-2016	Switch: Ground_115 kV
RABBIT LAKE SS	23-Oct-2011	Switch: Air Break_115 kV

Appendix F. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
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

Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

December 22, 2015

hydro one

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Prepared and endorsed by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)

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DISCLAIMER

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

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

Working Group 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 AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE WINDSOR-ESSEX REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

This RIP provides a consolidated summary of needs and recommended plans for Windsor-Essex Region. No long-term needs (10 to 20 years) and associated plans have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Windsor-Essex Region Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 [1].

The major infrastructure investments planned, or being planned, for the Windsor-Essex Region over the near and medium-term identified in the various phases of the regional planning process are given in the table below.

No.	Project	I/S Date	Cost
1*	Supply to Essex County Transmission Reinforcement (SECTR TX) Project	June 2018	$77.4M
2*	Supply to Essex County Transmission Reinforcement (SECTR DX) Project	June 2018	$19.3M
3	Replacement of Keith end-of-life autotransformers	2020	$45M
4	Replacement of Kingsville end-of-life transformers	2018	$12M
5	230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	2018	$63M
6	Additional feeder position at Malden TS	TBD	TBD
7	Decommission of Tilbury TS	2019	TBD
8	Decommission of T1 Transformer at Keith TS	TBD	TBD

* These projects address the needs identified in the Windsor-Essex IRRP study for the region in the near and medium-term.

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. Should there be any new needs that emerge due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE WINDSOR-ESSEX REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) and documents the results of the joint study carried out by Hydro One, EnWin Utilities Ltd. (“EnWin”), Essex Powerlines Corporation, E.L.K. Energy Inc. (“E.L.K Energy”), Entegrus Inc. (“Entegrus”), Hydro One Networks Inc. (Distribution) (“Hydro One Distribution), and the Independent Electricity System Operator (“IESO”) in accordance with the regional planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Windsor-Essex Region comprises the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The map of the region is shown in Figure 1-1 below.

The Windsor-Essex area is supplied from a combination of generation located in the region and from the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations. The region peak electricity demand of about 800 MW is provided from three 230 kV and fourteen 115 kV step-down transformer stations.

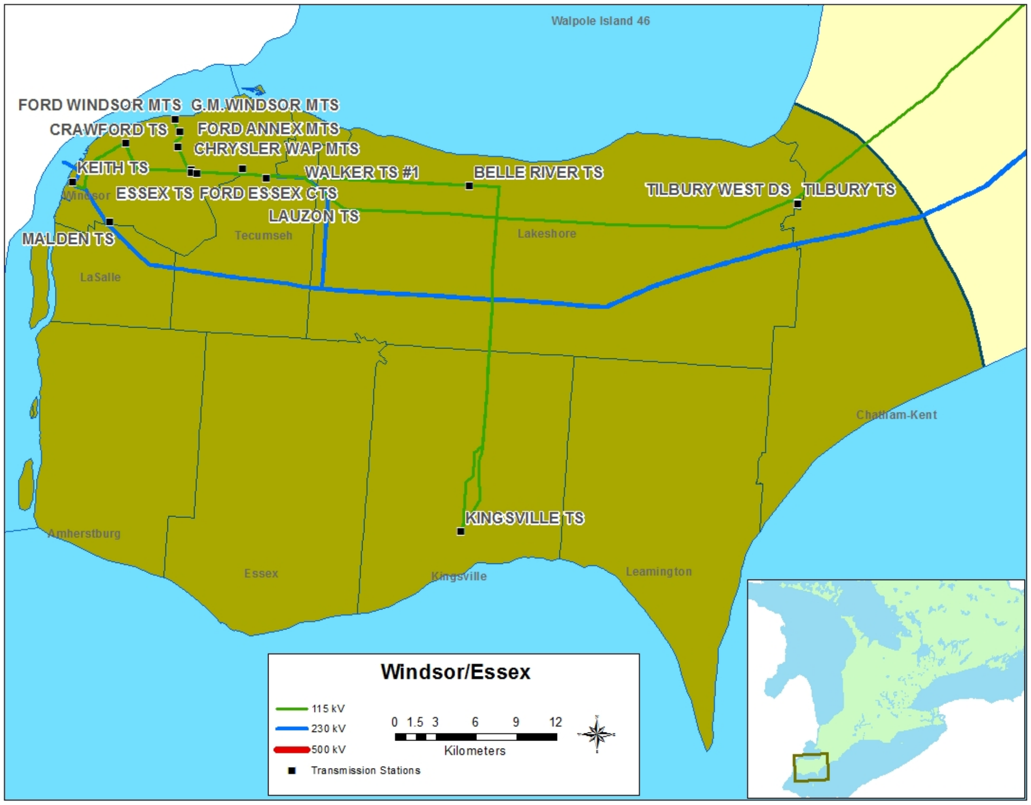

Figure 1-1 Geographical Map of Windsor-Essex Region

1.1 Scope and Objectives

This RIP report examines the needs in the Windsor-Essex Region. Its objectives are to: identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), Local Plan ("LP"), and/or Integrated Regional Resource Plan ("IRRP")); assess and develop wires plans to address these needs; provide the status of wires planning currently underway or completed for specific needs; and identify investments in transmission and distribution facilities or both that should be developed and implemented to meet the electricity infrastructure needs within the region.

Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete and the Windsor-Essex Region was identified as a "transitional" region. The planning status for the region was considered to be in the IRRP phase of the regional planning process. An IRRP for the region was completed in April 2015.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (NA, SA, LP, and/or IRRP).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group.

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

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 region.
- 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 regional needs.
- Section 7 provides a summary of regional plans.
- Section 8 provides summary of other projects.
- Section 9 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board 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 Working Group 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. 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. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a

[1] Also referred to as Needs Screening

need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Windsor-Essex Region was in transition to the new regional planning process, the IESO led IRRP engagement for this region was initiated after the completion of the IRRP.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The regional planning process specifies a 20 year planning assessment period for the IRRP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The exception would be the case where major transmission infrastructure investments are required. In these cases the RIP would review and assess longer term needs and develop a longer term plan.

To efficiently manage the regional planning process in the region, 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.
- Participating in and conducting wires planning as part of the IRRP for the region.
- Working and planning connection capacity requirements with the LDCs.

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.

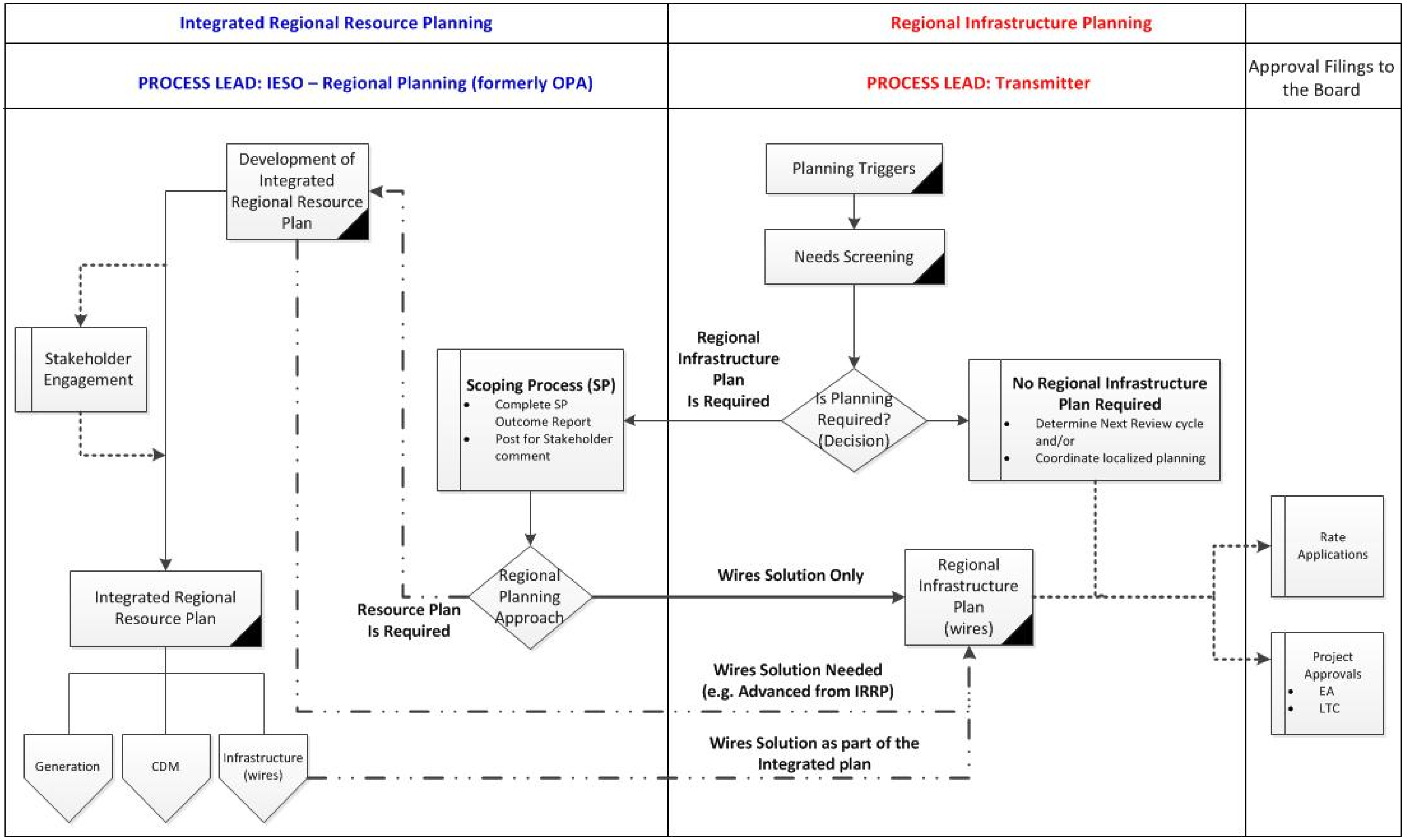

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP process is a four step process as shown in Figure 2-2 below.

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

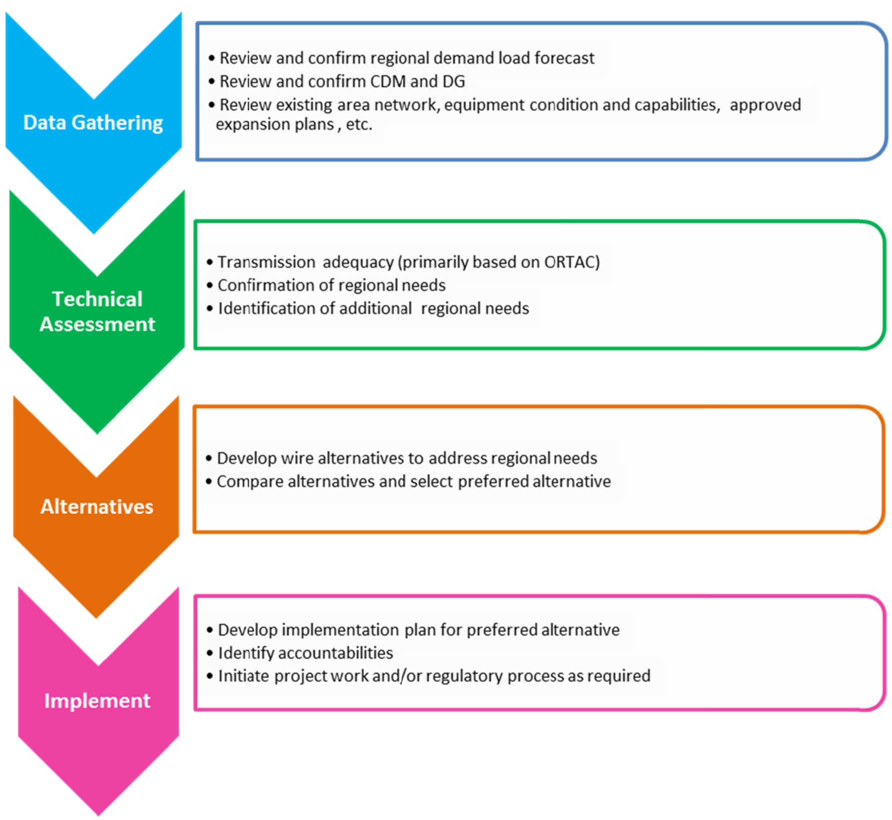

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION COMPRISES THE CITY OF WINDSOR, TOWN OF AMHERSTBURG, TOWN OF ESSEX, TOWN OF KINGSVILLE, TOWN OF LAKESHORE, TOWN OF LASALLE, MUNICIPALITY OF LEAMINGTON, TOWN OF TECUMSEH, THE WESTERN PORTION OF THE MUNICIPALITY OF CHATHAM-KENT AND THE TOWNSHIP OF PELEE ISLAND.

The region is served by five LDCs: EnWin, Essex Powerlines Corporation, E.L.K. Energy, Entegrus, and Hydro One Distribution, whose service territories are shown in Figure 3-1. EnWin and Hydro One Distribution are directly connected to the transmission system, while the three other LDCs have low voltage connections.

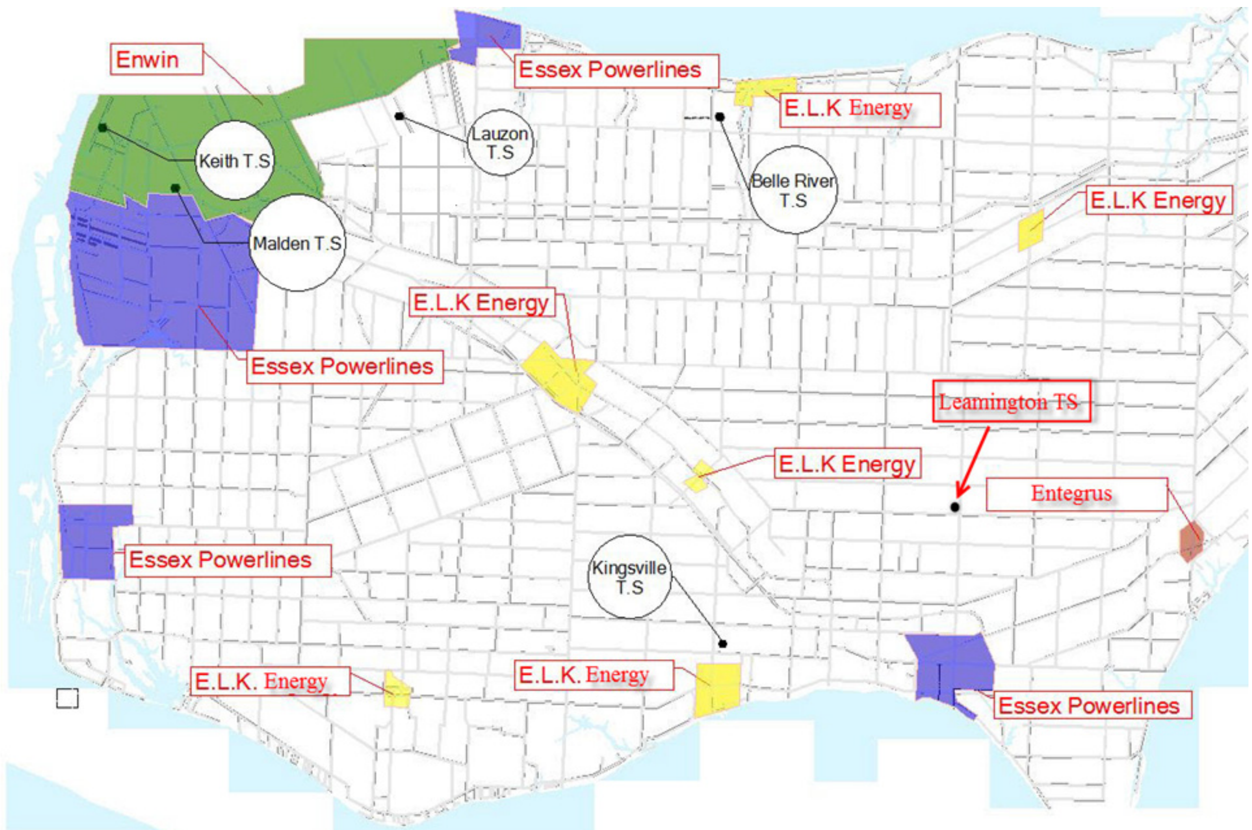

Figure 3-1 LDC Service Territories

The region peak electricity demand of about 800 MW is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 3-2 below.

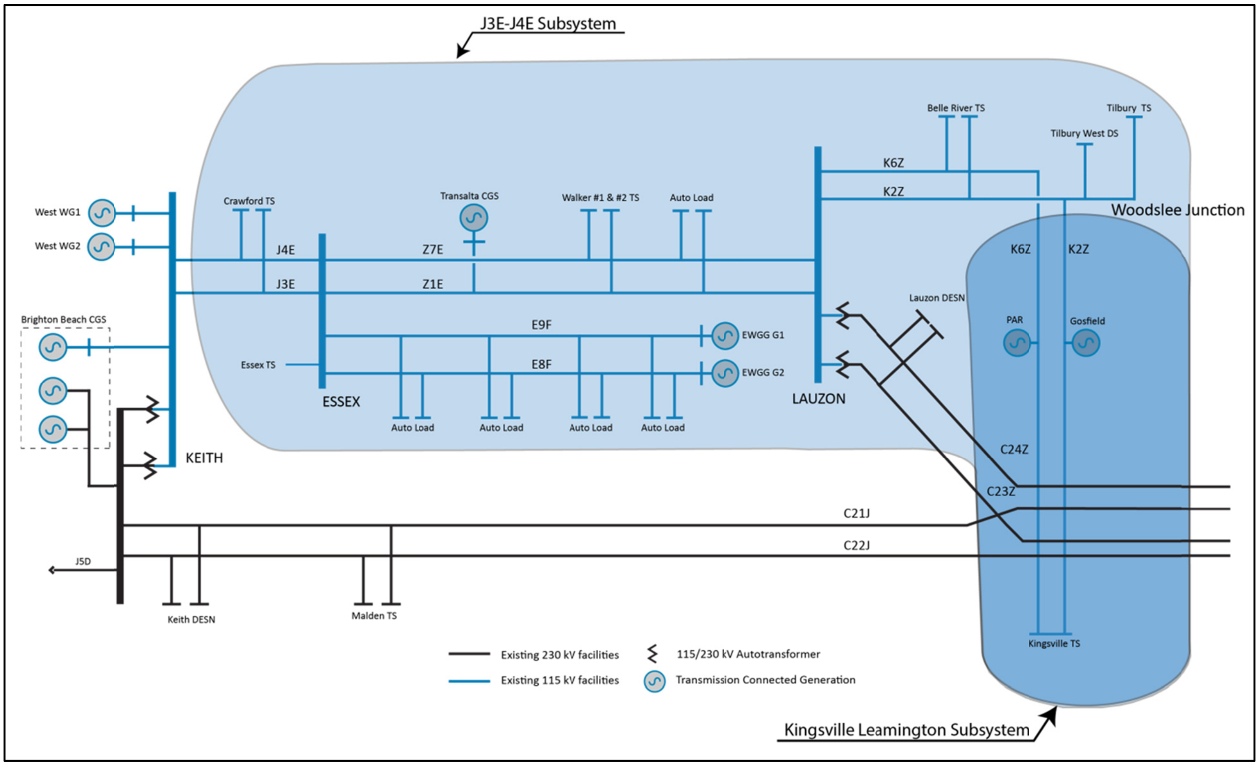

Figure 3-2 Windsor-Essex Area Subsystems/Single Line Diagram

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two auto-transformers in each station. About 65% of the area load is supplied by fourteen step-down transformers stations connected to the 115 kV network, while the balance is supplied by three step-down transformer stations connected to the 230 kV network. Table 3-1 lists the region's step-down transformer stations.

There are six customer-owned generating plants in the region connecting at the 230 kV and 115 kV levels with a combined contract capacity of 927 MW. In addition, the distributed generation connected at various locations to low-voltage ("LV") feeders in the region account for about 65 MW of effective capacity. Table 3-1 list the region's transmission connected generations.

The transmission system in the region can be divided into two “nested” sub-systems:

- The Kingsville-Leamington subsystem: customers supplied from Kingsville TS and
- The J3E-J4E subsystem: customers supplied from stations connected to the Windsor-Essex 115 kV system, as well as customers supplied from the 230/27.6 kV Lauzon DESN.

As can be noted in Figure 3-2 below, the Kingsville-Leamington subsystem is nested within the J3E-J4E subsystem. Therefore, increasing supply to the Kingsville-Leamington subsystem or transferring load from the existing Kingsville TS to a new 230 kV TS will impact the supply and demand balance in the J3E-J4E subsystem.

Table 3-1 Stations Included in the Windsor-Essex Region

Station (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customer(s)
Belle River TS (T1/T2)	115/27.6	K2Z/K6Z	Hydro One Distribution
Kingsville TS (T1/T2/T3/T4)	115/27.6	K2Z/K6Z	E.L.K. Energy Essex Powerlines Corp. Hydro One Networks Inc.
Lauzon TS (T5/T6/T7/T8)	230/27.6	C23Z/C24Z	EnWin Utilities Ltd. Hydro One Distribution
Tilbury West DS	115/27.6	K2Z	Hydro One Distribution
Tilbury TS (T1)	115/27.6	K2Z	Hydro One Distribution
Chrysler WAP MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Crawford TS (T3/T4)	115/27.6	J3E/J4E	EnWin Utilities Ltd.
Essex TS (T5/T6)	115/27.6	Z7E/	EnWin Utilities Ltd.
Ford Annex MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Ford Essex CTS	115/13.8	Z1E/Z7E	EnWin Utilities Ltd.
Ford Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
G.M. Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Keith TS (T1)	115/27.6	C21J/C22J	Brighton Beach Power LP West Windsor Power EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Keith TS (T22/T23)	230/27.6	C21J/C22J	
Malden TS (T1/T2)	230/ 27.6	C21J/C22J	EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Walker MTS #2	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.
Walker TS #1 (T3/T4)	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.

Table 3-2 Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	Dec. 31, 2024	Keith TS	541	526
Combined Heat and Power (CHP)	West Windsor Power	May 31, 2031	J2N (Keith TS)	128	107
	TransAlta Windsor	Dec. 1, 2031	Z1E	74	74
	East Windsor Cogeneration Centre	Nov. 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	Jan. 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	Dec. 5, 2031	K6Z	49	8

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED OR ARE UNDERWAY BY HYDRO ONE, AIMED AT IMPROVING THE SUPPLY TO THE WINDSOR-ESSEX REGION. A BRIEF LISTING OF THE COMPLETED PROJECTS OVER THE LAST 10 YEARS IS GIVEN BELOW:

- Belle River TS (May 2006): Built a new 2-25/33/42 MVA 115/27.6 kV transformer station in the Town of Lakeshore supplied from 115 kV circuits K2Z/K6Z. The station provides additional load supply capability to meet the load requirements of Hydro One Distribution customers in the Town of Lakeshore. The connection of new station required the untwining of K6Z to obtain two circuits (K2Z and K6Z) with K6Z on the north side of the towers. The new K2Z circuit section which only extends to Belle River TS was then connected to the then existing K2Z circuit just outside of Lauzon TS.

- Essex TS (October 2008): The station was refurbished with new 2-50/66/83 MVA 115/27.6 kV transformers. The 115 kV supply circuits were reconfigured to mitigate exposure to customer load loss for loss of a single transmission element under certain system conditions.

- Malden TS: Transformer T2 75/100/125 230/27.6 kV was replaced (July 2010) and T1 was replaced (December 2011).

- Keith TS: T23 transformer 50/67/83 MVA 230/27.6 kV was replaced (October 2008) and T22 transformer 50/67/83 MVA 230/27.6 kV was replaced (December 2013).

- Walker TS #1: Reactor installation for short circuit mitigation (June 2011).

- Kingsville TS: Reactor installation for short circuit mitigation (November 2011).

- Keith TS: Reactor installation for short circuit mitigation (April 2012).

- Lauzon TS: Three breakers were replaced: SC2Q (June 2012), SC3E (April 2012) and SC4J (April 2012).

- Keith TS: Six breakers were replaced: SC11K (May 2014), SC11SC (May 2014), SC1B (June 2014), T11P (August 2014), T12P (October 2014), SC2Y (January 2015).

The following projects are currently underway:

- Crawford TS: is a 115/28 kV, with two 50/67/83 MVA units in Windsor. It supplies the downtown Windsor area with a current peak load of 60 MW. The existing T3 transformer is at the end-of-life with leaky fittings and headboard. The T3 fire suppression system and separation wall also needs to be upgraded to current standards. The current plan is to replace T3 transformer and install neutral grounding reactors on the T3 and T4 transformer units. The project includes protection and control upgrades and relocation of battery, necessary spill containment facilities at Crawford TS. The project is under execution for $8.46 million with an in-service date of December 15, 2016. There are no cost implications for the LDCs. Once this project is complete the station will meet the current design standards.

5. LOAD FORECAST AND OTHER ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The peak demand in the Windsor-Essex Region has declined from a high of 1060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014.

Figure 5-1 shows the historical summer peak demand observed in the region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both contributed to a decline in electricity use in the region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the region's growth and electricity use. The five-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the region, including advanced manufacturing, tourism, and agri-business.

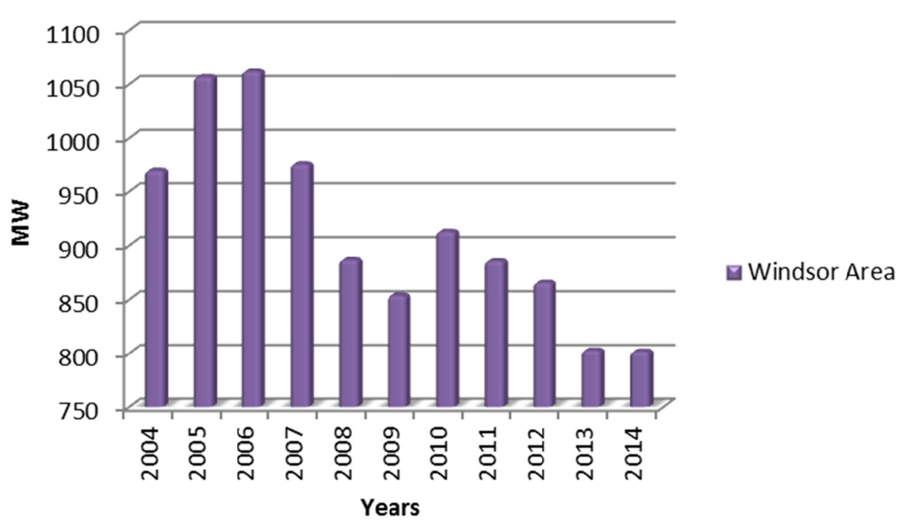

Figure 5-1 Historical Load Demand in Windsor-Essex Region

The peak demand in the Kingsville-Leamington area has also experienced fluctuations over the 2004-2014 period as shown in Figure 6-1.

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the Windsor-Essex Region:

a) First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
b) Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, and projected province-wide CDM programs. This information is provided by the IESO.
c) Lastly, a "planning forecast" is determined by reducing net demand by the contribution in the area from existing, committed and forecast DG. This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Summer peak gross non-coincident demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One Distribution, the two LDCs which are directly connected to the transmission system, for each of the transformer stations in the area. The forecasts from Hydro One Distribution include forecasts provided by the appropriate embedded LDCs.

The development of the load forecast for this RIP report followed a two-stage process:

(a) Using the forecast provided by the LDCs, the year by year growth rate for each station was first developed.
(b) The 2014 summer actual peak load, corrected for extreme weather, for each station was obtained.
(c) The growth rates from (a) were then applied to the 2014 summer peak load of (b) to obtain the gross load forecast for each station for extreme weather conditions.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. This load forecast reflects the following:

- A shift of load, commencing in 2016, from Walker TS #1 and #2 to Essex TS and GM MTS.
- Reduction in Kingsville TS load.
- Increase in loads at Keith TS, Crawford TS and Lauzon TS.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. Figure 5-2 is a graph of the Windsor – Essex Region extreme weather peak summer non-coincident load forecast. The overall region will experience an average annual growth rate of just less than 1%, while the Kingsville-Leamington area average growth rate would be about 1.6%.

Figure 5-2 also shows the load forecast from the IRRP report. The two forecasts are not materially different; hence the load forecast in this RIP report will not alter the conclusions of the IRRP.

The Reference Planning forecast (Appendix D) for each station is obtained by reducing the gross load forecast for the station by the amount of forecast conservation and DG. The conservation forecast (Appendix B) and the DG forecast (Appendix C) are the same as used in the IRRP report.

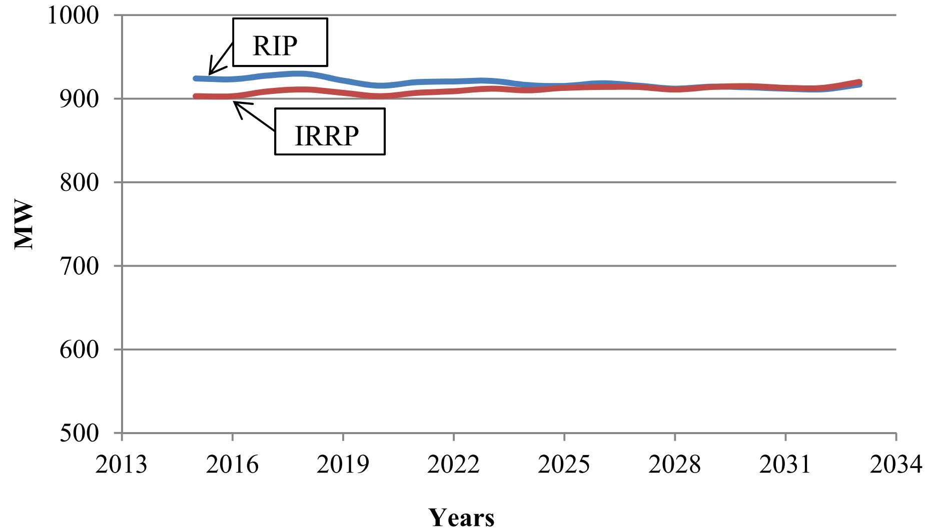

Figure 5-2 Reference Forecast in Windsor-Essex Region

5.4 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity. Load is assumed at 90% lagging power factor, unless known.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.

6. REGIONAL NEEDS

THIS SECTION SUMMARIZES THE WINDSOR-ESSEX REGION NEEDS OVER THE NEAR AND MID TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Earlier studies by the IESO, ("Windsor-Essex Region Integrated Regional Resource Plan" - April 28, 2015, Supply to Essex County Transmission Reinforcement Project, January 2014) identified two near-term needs in the region. These needs are:

- **Minimize the Impact of Supply Interruptions in the J3E-J4E Subsystem:**
  The existing system lacks the capability to restore power to customers in the J3E-J4E subsystem in accordance with the ORTAC criteria, i.e., restoration of all loads within 8 hours. Based on current and forecast demand, up to 170 MW 0f the load interrupted cannot be restored by 2017.

- **Additional Supply Capacity in the Kingsville-Leamington Area:**
  Demand in the Kingsville-Leamington subsystem has already exceeded the load meeting capability of 120 MW in recent 3 years and is expected to continue to exceed the supply capacity over the forecast period. Figure 6-1 below shows the historical and forecast demand and supply capabilities in the Kingsville-Leamington subsystem after conservation and DG are taken into consideration.

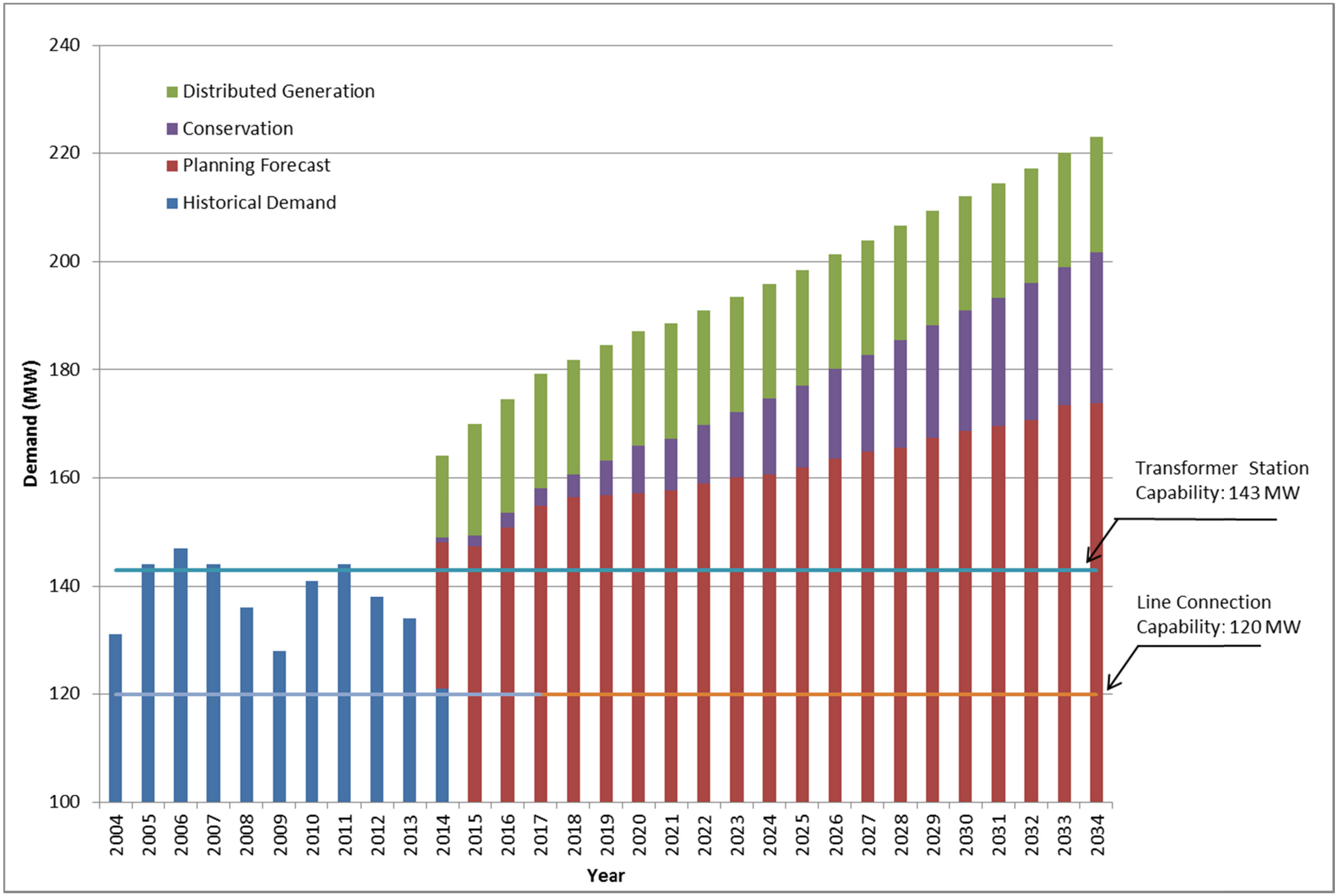

Figure 6-1 Historical and Forecast Demand of Kingsville-Leamington Subsystem

In addition, Hydro One has also identified infrastructure and major equipment which need replacement during the study period. The current plan is essentially a like-for-like replacement of 3 step-down transformers at Kingsville TS and 2 auto-transformers at Keith TS.

These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

Table 6-1 Summary of Needs

Type	Needs	Timeline	Process
Capacity to Meet Demand	Kingsville-Leamington Subsystem	2018	**IRRP**
Minimize the Impact of Interruption	J3E-J4E Subsystem	2018	**IRRP**
Aging Equipment Replacement	3 transformers at Kingsville TS are at end-of-life	Near-Term	**RIP**
Aging Equipment Replacement	2 autotransformers at Keith TS are at end-of-life	Near-Term	**RIP**

7. REGIONAL INFRASTRUCTURE PLANS

THIS SECTION PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE WINDSOR-ESSEX REGION.

7.1 Supply to Essex County Transmission Reinforcement (SECTR) Project

7.1.1 Description

The SECTR project as presented in the IRRP is an integrated solution to address both the J3E-J4E subsystem restoration need and the Kingsville – Leamington capacity need. As illustrated in Figure 7-1 the project consists of the installation of a new 230 kV supplied transformer station near Leamington connected to the existing C21J/C22J circuits via a new 13 km double-circuit 230 kV connection line on a new right-of-way.

The total cost of this project is $96.7M made up of:

(a) Build 230/27.6 – 27.6 kV 75/100/125 MVA Leamington TS with six LV breaker positions, plus other required switchgear: $32.1M
(b) Build a 13 km 2-circuit 230 kV line on a new right-of-way tapping into existing 230 kV circuits C21J/C22J plus Optical Ground Wire: $45.3M.
(c) Carry out distribution work for Leamington TS: $19.3M. Other additional distribution work includes two additional feeder positions at Leamington TS, and protection upgrades for in-service Kingsville DG transferred to Leamington TS.

With the establishment of Leamington TS, load will be transferred from Kingsville TS to the new station, such that the Kingsville TS load will be reduced to about 50 MW. As discussed in the IRRP report, this presents an opportunity to downsize the station from four transformers to two transformers, and would result in a combined supply capability in the Kingsville-Leamington area of 210 MW.

Figure 7-2 is a preliminary plan for the transfer of Kingsville TS feeders to Leamington TS. Feeders which are shown in blue will be completely transferred to Leamington TS, and the ones shown in green will be partially transferred to Leamington TS.

7.1.2 Recommended Plan and Current Status

Hydro One filed an application on January 22, 2014 with the OEB under Section 92 of the OEB Act for an order granting leave to construct approximately 13 km of new 230 kV transmission lines on steel lattice towers on a new right of way in the Windsor-Essex area and the installation of optic ground wire for system telecommunication purposes on existing C21J/C23Z towers near Leamington Junction and on new 230 kV towers. The application included a request for OEB approval of the methodology for allocating project cost to Hydro One Distribution, embedded LDCs and Sub-Transmission class customers.

On February 12, 2015, Hydro One filed an updated application that included the new 230/27.6 kV Leamington Transformer Station (Leamington TS). The OEB decided that the proceeding would be addressed in two phases. Phase 1 would only deal with the leave to construct application and Phase 2 of the proceeding would deal with cost allocation. Phase 1 of the SECTR S.92 proceeding has concluded and the "Leave to Construct" approval was granted by the OEB on July 16, 2015. The expected in-service date for the SECTR Project is June 2018. Phase 2 of the proceeding is continuing via an OEB policy review rather than the originally planned adjudicative process.

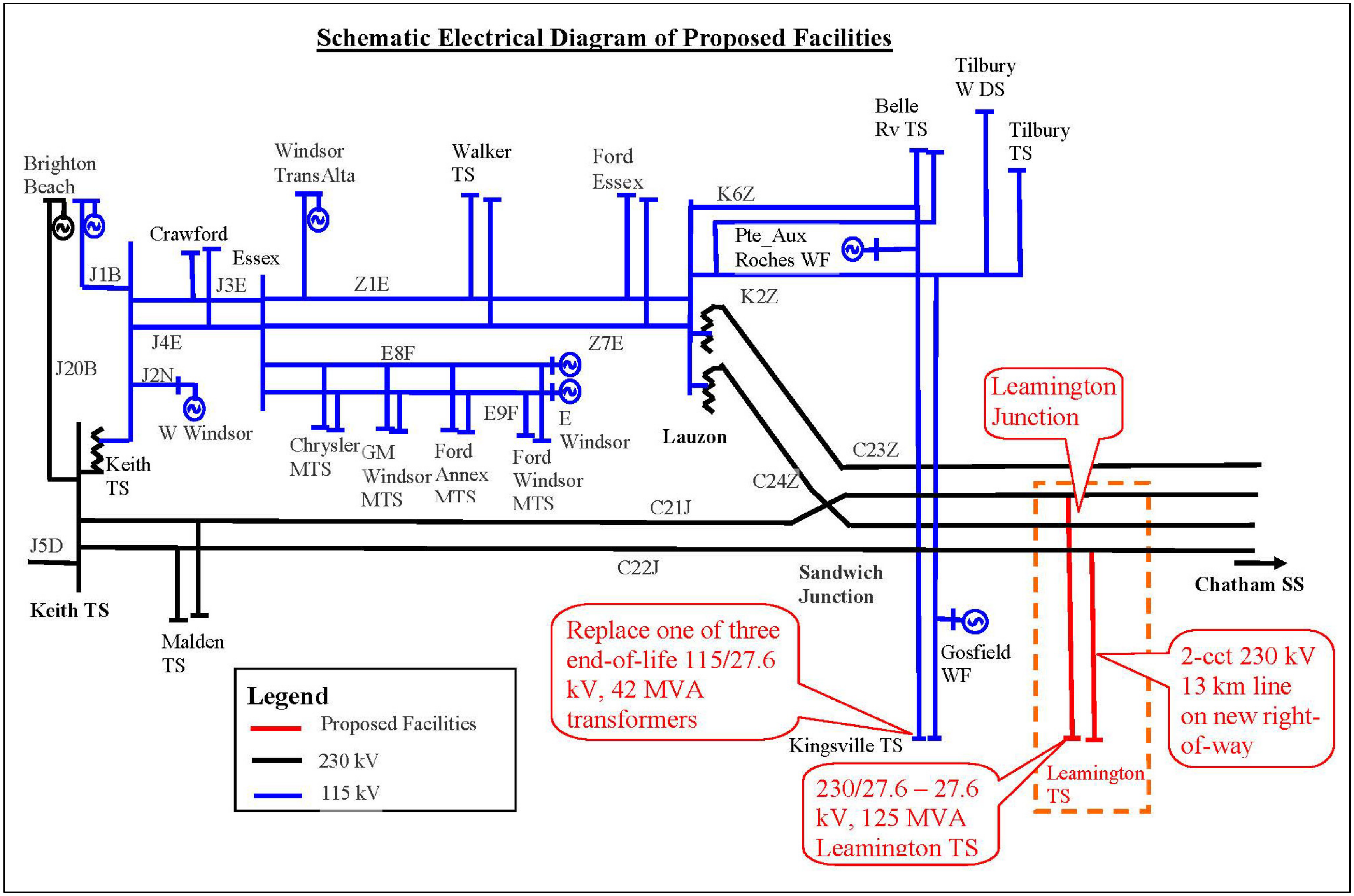

Figure 7-1 Schematic Electrical Diagram of the Proposed Facilities

Figure 7-2 Preliminary Distribution Feeder Plans for SECTR Project

7.2 Keith TS End-of-Life Auto-Transformer Replacement

7.2.1 Description

Keith TS is equipped with 2-230/115 kV 115 MVA autotransformers. These autotransformers are 1950's vintage and near end-of-life and require replacement.

7.2.2 Recommended Plan and Current Status

Due to SECTR project additional capacity will not be required and the end-of-life autotransformers at Keith TS will be replaced with equivalent like-for-like 125 MVA units. The expected in-service date is 2020. There are no cost implications for the LDCs.

7.3 Kingsville TS End-of-Life Transformer Replacement

7.3.1 Description

Kingsville TS is equipped with 4-115/27.6 kV 25/33/42 MVA transformers. One of these transformers was recently replaced, but the other three are 1950's vintage and will require replacement in the near future.

Due to SECTR project and the associated reduction in load at Kingsville TS, the station may be downsized and reconfigured as a two-transformer station. Hydro One Distribution is further reassessing to justify retaining the four-transformer arrangement if they receive additional request for connections at Kingsville area.

7.3.2 Recommended Plan

Hydro One Distribution to complete their connection capacity assessment as part of distribution system planning before Q3 2016 so that replacement and reconfiguration plan can be finalized by Hydro One in a timely manner.

7.4 Gordie Howe International Bridge (GHIB)

7.4.1 Description

The Gordie Howe International Bridge (GHIB) is a construction project under a bi-lateral agreement between the federal governments of Canada and the USA, and the governments of Ontario and Michigan, to construct a new border crossing between Windsor and Detroit. It will comprise a 12 km westerly extension of Hwy 401 to a site near Keith Transformer Station, where a new customs plaza and a new bridge over the Detroit River will be constructed. The highway will be extended by the Ministry of Transportation of Ontario (MTO), while the customs plaza and the bridge will be constructed by Transport Canada.

The GHIB project is multi-faceted in its impacts on Hydro One facilities and operations at Keith TS including: transmission lines, fiber lines and feeders relocation; insulation contamination due to salt spray effects from new bridge; relocation of access routes; possible security issues for staff accessing and working at the station; impacts on existing utilities (water/sewer/gas). In addition, the GHIB project will reduce the footprint of the station and encumber egress from the station. Consequently, this project will impact future expansion work at the station and possibly limit the extent to which the station can be developed relative to its ultimate plan development over the long term.

7.4.2 Recommended Plan and Current Status

In order to mitigate these impacts, as illustrated in Figure 7-3 below, additional real estate is required for future expansion to the north of McKee Rd. The existing transmission lines and feeders will also need to egress the station via underground cables so as not to interfere with the bridge operations.

The cost of this project will be fully recovered from the Windsor Detroit Bridge Authority (WDBA). A Transmission Assets Modification Agreement (TAMA) with the WDBA is expected to be finalized by early January 2016. Approvals for executing the project are expected by March 2016 for a planned in-service date by the end of 2018.

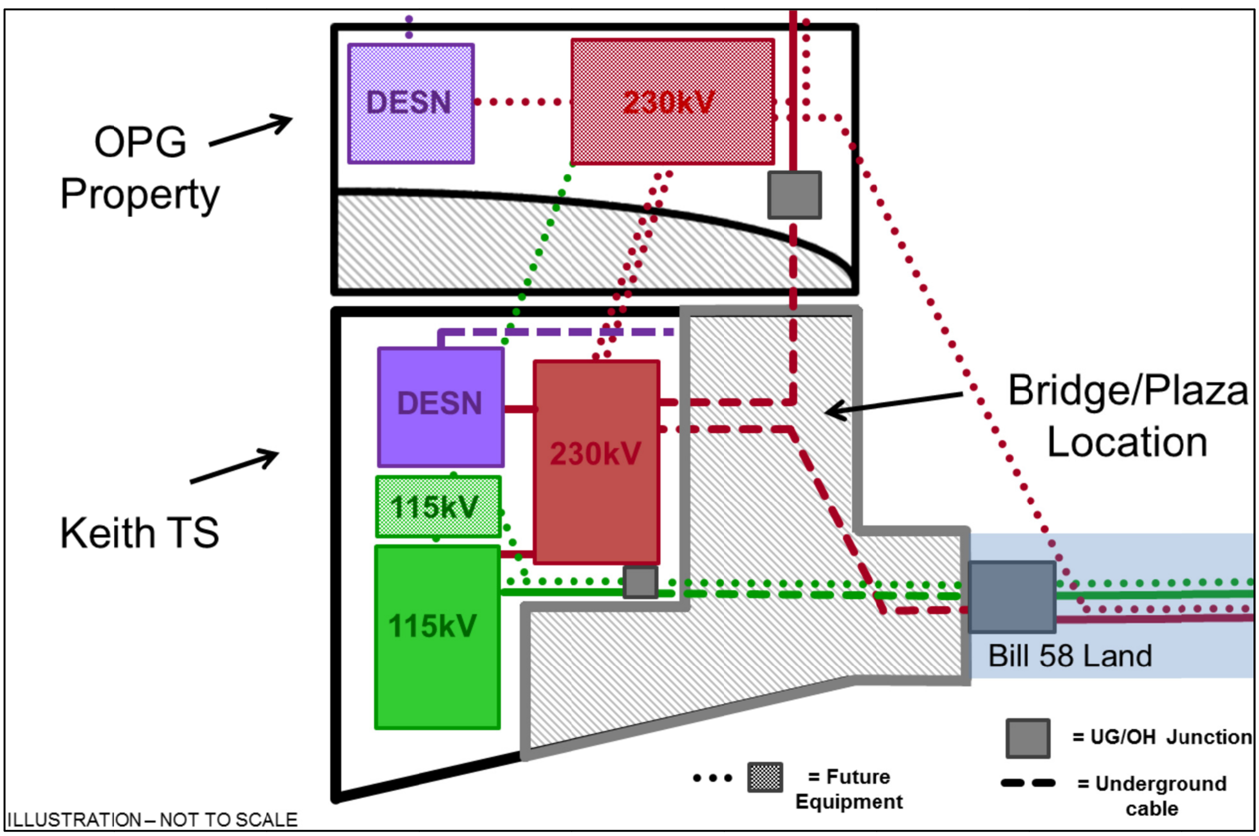

Figure 7-3 Gordie Howe International Bridge (GHIB) Project

8. OTHER PROJECTS

There are other wires projects that are currently under development and pending decision in the Windsor-Essex Region. These projects are local in nature and being planned and developed by Hydro One and relevant LDC as discussed below.

8.1 Malden TS Additional Feeder Positions

8.1.1 Description

Due to the load increase that's expected from the planned Detroit River International Crossing work and local highway construction, Essex Power has identified a need for two additional 28 kV feeder positions to be constructed at Malden TS.

The Malden transformer station is currently equipped with two 75/125 MVA transformers, 12 feeder positions and two capacitor banks and this plan involves expanding the station to 14 feeders. The two transformers at Malden TS were recently replaced, and there is additional capacity available at the station to meet the load requirement of the customer.

Based on a preliminary estimate the following will be the cost for the different layouts:

- Installation of two 28kV feeder breaker positions with feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $1.1M
- Installation of one 28kV feeder breaker position with no feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $875k
- Installation of one 28kV feeder breaker position with a break before make connection to alternate bus with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $925k

8.1.2 Recommended Plan and/or Current Status

The above options have been provided to Essex Powerlines Corp. Hydro One is awaiting its decision on the preferred option expected to be made in 2016.

8.2 Tilbury TS Transformer End-of-Life Replacement

8.2.1 Description

Tilbury West HVDS and Tilbury TS are both supplied from 115 kV circuit K2Z and are adjacent to each other. The two stations supply the Town of Tilbury and surrounding area. Tilbury West HVDS consists of 2 x 15/20/25 MVA, 115/27.6 kV transformers of 1980's vintage with two feeder positions; and Tilbury TS consists of 1 x 6/8 MVA 115/27.6 kV transformer of 1950's vintage with one feeder position. The

2014 peak load at Tilbury TS was 1.0 MW, and 16 MW at Tilbury West HVDS. The future load levels over the next 10 years at these stations are not expected to grow significantly.

Tilbury TS is near its end-of-life, and a decision to replace or retire should be made by 2017. Following three options are under consideration for Tilbury TS:

(1) Transfer Tilbury TS load (M1 feeder) to Tilbury West DS and decommission Tilbury TS at a cost of about $1.7M. This option is feasible as there is sufficient capacity at Tilbury West HVDS to accommodate both the Tilbury West HVDS forecast load and the Tilbury TS forecast load into the long term. Further, Tilbury West HVDS has sufficient capacity to accommodate its existing DG connections plus the existing 5 MW solar DG currently connected to Tilbury TS.

(2) Refurbish Tilbury TS at a cost of about $5M. This option would retain the supply capacity level and supply diversity that currently exists.

(3) Build a new DESN station at Tilbury TS with dual 115kV circuit supply from the K2Z and K6Z for an expected cost of about $20M. This would include building the 115kV line out from Tilbury Junction to the TS and a complete new station.

8.2.2 Recommended Plan and Current Status

Option 1 is the least cost alternative. It is recommended that Hydro One will have further discussions with the LDCs regarding these options and associated costs. These discussions are expected in 2016, and a decision is expected to be made by no later than 2017. Project construction is planned to commence in 2018 for an expected in-service in 2019. Depending on the option selected, costs may have to be recovered from the LDCs consistent with the TSC.

8.3 Keith TS T1 Transformer End-of-Life Replacement

8.3.1 Description

Keith TS transformer T1 (25/33/42 MVA 115/27.6 kV) is of 1950's vintage and it is approaching end-of-life. EnWin is the only LDC supplied from this Keith T1 and exclusively serves a single customer Nemak. The peak load was 8 MW in 2014. The load growth is expected to remain at this level in the long-term.

There is sufficient capacity at the Keith DESN station to accommodate both the forecast at Keith DESN load plus the forecast Keith TS T1 load over the next 10 years.

Following three possible options are considered to address the end-of life issue for Keith TS T1:

(1) Replace Keith TS T1.

(2) Transfer Keith TS T1 load to Keith T22/T23 DESN station.

(3) Resupply Nemak from another EnWin feeder connected to Keith T22/T23 DESN.

8.3.2 Recommended Plan and Current Status

It is recommended to develop cost estimates for each of the option. Following that Hydro One will initiate discussions with EnWin to review the options and decide on a preferred option.

Cost estimates are expected in Q1 of 2016 and selection of a preferred option is expected before the end of 2016. Discussions will then ensue with Hydro One and EnWin regarding planned construction dates.

9. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX 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 provides a single consolidated source of information for infrastructure plans in the Windsor-Essex Region. It develops and outlines a plan for investments in transmission and/or distribution facilities to meet the electricity needs within the region. The RIP report was developed in collaboration of a Technical Working Group consisting of representation from the LDCs in the region, the IESO, and led by Hydro One consistent with the requirements set out in the TSC, DSC and the PPWG report.

This report highlights several near-term needs in the region for which implementation plans have already been developed and are planned for completion in the next five years. Table 9-1 provides a status of these projects along with their cost and timelines. Projects requiring further planning on scoping and pending decisions on the preferred alternative are provided in Table 9-2. Over the next five years, the total transmission and distribution investments associated with these projects is approximately $215M - $225M.

Table 9-1 Project Under Development

Project/Plan	Cost	I/S	Performed by
Supply to Essex County Transmission Reinforcement “SECTR TX”	$77.4 Million	March 2018	Hydro One
Supply to Essex County Transmission Reinforcement “SECTR DX”	$19.3 Million	March 2018 (first stage)	Hydro One Distribution
Replacement of Keith end-of-life autotransformers	$45 Million	2020	Hydro One
Replacement of Kingsville end-of-life transformers	$12 Million	2018	Hydro One
230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	$63 Million	October 2018	Hydro One
Transformer replacement and station refurbishment at Crawford TS	$8.46 Million	December 2016	Hydro One

Table 9-2 Project Pending Decision

Project/Plan	Cost	I/S	Performed by
Additional feeder position at Malden TS	TBD	TBD	Hydro One
Replacement of Tilbury end-of-life transformer	TBD	2019	Hydro One
Keith TS end-of-life T1 Transformer	TBD	TBD	Hydro One

There are no long-term needs in this region that requires plans to be developed at this time. As with any region, the Windsor-Essex Region is monitored as part of Hydro One and LDC operations. Should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

10. REFERENCES

[1] Independent Electricity System Operator. "Windsor-Essex Region Integrated Regional Resource Plan". April 28, 2015. http://www.ieso.ca/Documents/Regional-Planning/Windsor_Essex/2015-Windsor-Essex-IRRP-Report.pdf

APPENDIX A. GROSS FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		Forecast																			
Kingsville TS	158	133	137	141	145	146	147	148	149	150	151	152	153	155	156	157	158	159	160	161	162
Belle River TS	59	46	46	47	48	49	50	51	52	53	53	54	55	56	57	58	59	60	61	62	63
Tilbury West DS	34	17	17	17	17	18	18	18	18	18	19	19	19	19	19	19	19	19	19	20	20
Tilbury TS	10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lauzon TS	225	191	193	195	197	199	201	203	204	206	208	209	211	213	215	217	219	221	223	224	226
Walker TS #1	99	71	79	76	77	77	78	78	79	79	80	80	81	81	82	82	83	83	84	84	85
Walker TS #2	99	95	111	92	92	93	93	94	94	95	96	96	97	97	98	99	99	100	100	101	102
Essex TS	116	55	63	73	73	74	74	75	75	76	76	77	77	78	78	78	79	79	80	80	81
Crawford TS	90	83	84	84	85	85	86	86	87	87	88	88	89	89	90	90	91	91	92	93	93
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**807**	**816**	**824**	**830**	**836**	**843**	**849**	**854**	**860**	**866**	**872**	**878**	**884**	**891**	**897**	**903**	**909**	**916**	**922**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		Forecast																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	67	67	67	67	67	67	68	68	68	68	68	68	68	68	68	69	69	69	69
Malden TS	200	117	118	119	120	120	121	122	124	124	125	126	127	127	128	129	130	131	131	132	133
Windsor Essex Total	**N/A**	**962**	**1000**	**1009**	**1019**	**1026**	**1033**	**1041**	**1048**	**1055**	**1061**	**1068**	**1074**	**1082**	**1089**	**1096**	**1104**	**1111**	**1118**	**1125**	**1133**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (weather normal)		Forecast																			
Total	**N/A**	**155**	**160**	**165**	**169**	**172**	**174**	**177**	**178**	**181**	**183**	**186**	**188**	**191**	**193**	**196**	**199**	**201**	**204**	**206**	**209**

APPENDIX B. CONSERVATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*
Conservation		*Forecast*																			
Kingsville TS	158	1	2	3	3	4	6	9	10	11	12	14	15	16	18	20	21	22	24	25	26
Belle River TS	59	0	1	1	1	1	2	3	3	3	4	4	5	5	5	6	6	7	7	8	8
Tilbury West DS	34	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3
Tilbury TS	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lauzon TS	225	1	3	4	4	5	8	11	12	13	14	17	18	19	21	23	24	26	28	29	30
Walker TS #1	99	1	1	2	2	2	4	5	5	6	6	7	8	8	9	10	11	11	12	13	13
Walker TS #2	99	1	1	2	2	3	4	6	6	7	8	9	10	10	11	13	13	14	15	16	16
Essex TS	116	0	1	1	1	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	9
Crawford TS	90	1	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10	11	11
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**5**	**10**	**14**	**16**	**20**	**31**	**41**	**45**	**50**	**55**	**64**	**69**	**75**	**81**	**89**	**94**	**100**	**107**	**114**	**115**

Additional Stations in the Windsor-Essex Region	LTR	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*
Conservation		*Forecast*																			
Keith TS T1	54	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Keith TS T22/T23	114	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Malden TS	200	1	2	2	3	3	5	7	7	8	9	11	11	12	14	15	16	17	18	19	19
Windsor Essex Total	**N/A**	**7**	**12**	**18**	**20**	**26**	**40**	**53**	**58**	**65**	**72**	**83**	**89**	**97**	**105**	**116**	**122**	**130**	**139**	**148**	**149**

Kingsville-Leamington Sub-system	LTR	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*
Conservation		*Forecast*																			
Total	**N/A**	**1**	**2**	**3**	**3**	**4**	**6**	**9**	**10**	**11**	**12**	**14**	**15**	**16**	**18**	**20**	**21**	**22**	**24**	**25**	**26**

APPENDIX C. DISTRIBUTED GENERATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		*Forecast*																			
Kingsville TS	158	15	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Belle River TS	59	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tilbury West DS	34	2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tilbury TS	10	2	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lauzon TS	225	8	16	18	19	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Walker TS #1	99	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Walker TS #2	99	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Essex TS	116	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crawford TS	90	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**35**	**59**	**64**	**66**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		*Forecast*																			
Keith TS T1	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keith TS T22/T23	114	21	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Malden TS	200	9	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Windsor Essex Total	**N/A**	**65**	**63**	**69**	**71**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation		*Forecast*																			
Total	**N/A**	**15**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**

APPENDIX D. REFERENCE PLANNING FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Kingsville TS	158	133	114	117	121	121	120	118	118	118	118	117	117	118	117	116	116	116	115	115	115
Belle River TS	59	46	43	44	44	45	45	45	46	47	46	47	47	48	49	49	50	50	51	51	52
Tilbury West DS	34	17	7	7	7	8	7	7	7	7	8	7	7	7	7	7	7	7	6	7	7
Tilbury TS	10	1	-6	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Lauzon TS	225	191	174	173	174	174	173	172	172	173	174	172	173	174	174	174	175	175	175	175	176
Walker TS #1	99	71	76	72	73	73	72	71	72	71	72	71	71	71	71	70	70	70	70	69	70
Walker TS #2	99	95	109	89	89	89	88	87	87	87	87	86	86	86	86	85	85	85	84	84	85
Essex TS	116	55	62	71	71	71	70	71	70	71	70	71	70	71	70	70	70	70	70	70	71
Crawford TS	90	83	82	82	81	81	81	80	81	80	81	80	80	80	80	79	80	79	80	80	80
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**737**	**738**	**742**	**743**	**737**	**733**	**736**	**736**	**737**	**734**	**733**	**737**	**735**	**733**	**735**	**735**	**733**	**734**	**738**

Additional Stations in the Windsor-Essex Region Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	64	64	64	64	63	62	63	63	63	62	62	61	61	60	60	60	60	59	59
Malden TS	200	117	115	114	114	114	113	112	114	113	113	112	113	112	111	111	111	111	110	110	111
Windsor Essex Total	**N/A**	**962**	**924**	**923**	**928**	**930**	**922**	**916**	**920**	**921**	**921**	**916**	**915**	**919**	**916**	**912**	**915**	**914**	**912**	**911**	**917**

Kingsville-Leamington Sub-system Gross Demand (weather normal)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Total	**N/A**	**155**	**147**	**151**	**155**	**156**	**157**	**157**	**158**	**159**	**160**	**161**	**162**	**164**	**165**	**166**	**167**	**169**	**169**	**171**	**173**

APPENDIX E. LIST OF ACRONYMS

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
DS	Distribution Station
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
HVDS	High Voltage Distribution Station
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
OPG	Ontario Power Generation
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