South Georgian Bay/Muskoka

REGIONAL INFRASTRUCTURE PLAN

August 18th, 2017

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Prepared by:
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With support from:

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

DISCLAIMER

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

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

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EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

TABLE OF CONTENTS

List of Figures

List of Tables

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Hydro One Distribution, Alectra Utilities (formerly PowerStream Inc.) ("Alectra"), Veridian Connections Inc. ("Veridian"), Innisfil Hydro Distribution Systems Ltd ("InnPower"), Orangeville Hydro Ltd ("Orangeville Hydro") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The South Georgian Bay/Muskoka region consists of the area roughly bordered by the Municipality of West Nipissing to the northwest, Algonquin Provincial Park to the northeast, Peterborough County and Hastings County to the southeast, Lake Scugog, York and Peel Regions to the south, Wellington County to the southwest and the Municipality of Grey Highlands to the west. Figure 1-1, on the following page, shows the boundaries of the South Georgian Bay/Muskoka Region.

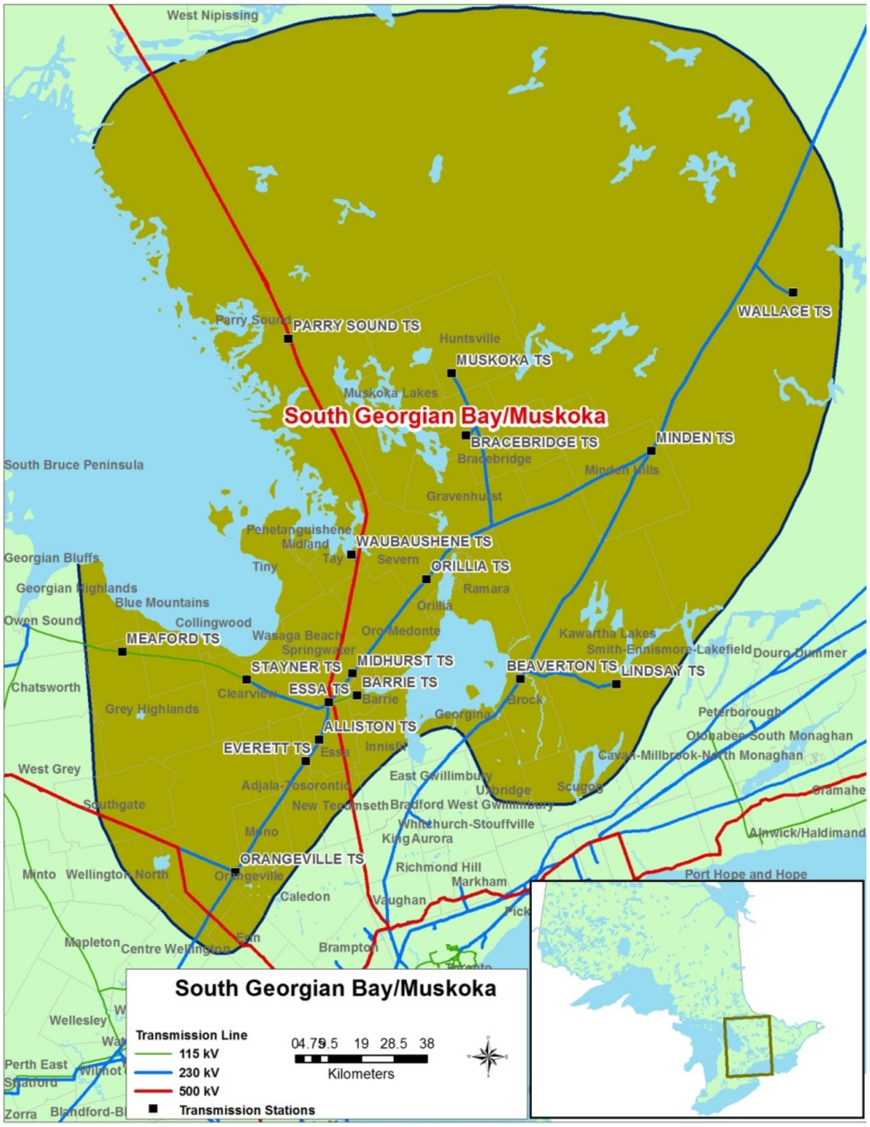

Figure 1-1 South Georgian Bay/Muskoka Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Barrie-Innisfil and Parry Sound/Muskoka sub-region IRRPs.

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

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination or comprehensive planning is required an assessment is undertaken for any necessary investments directly by the LDCs (or customers) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution.

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

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

[1] Also referred to as Needs Screening.

phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee ("LAC") in the region or sub-region.

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

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

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

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

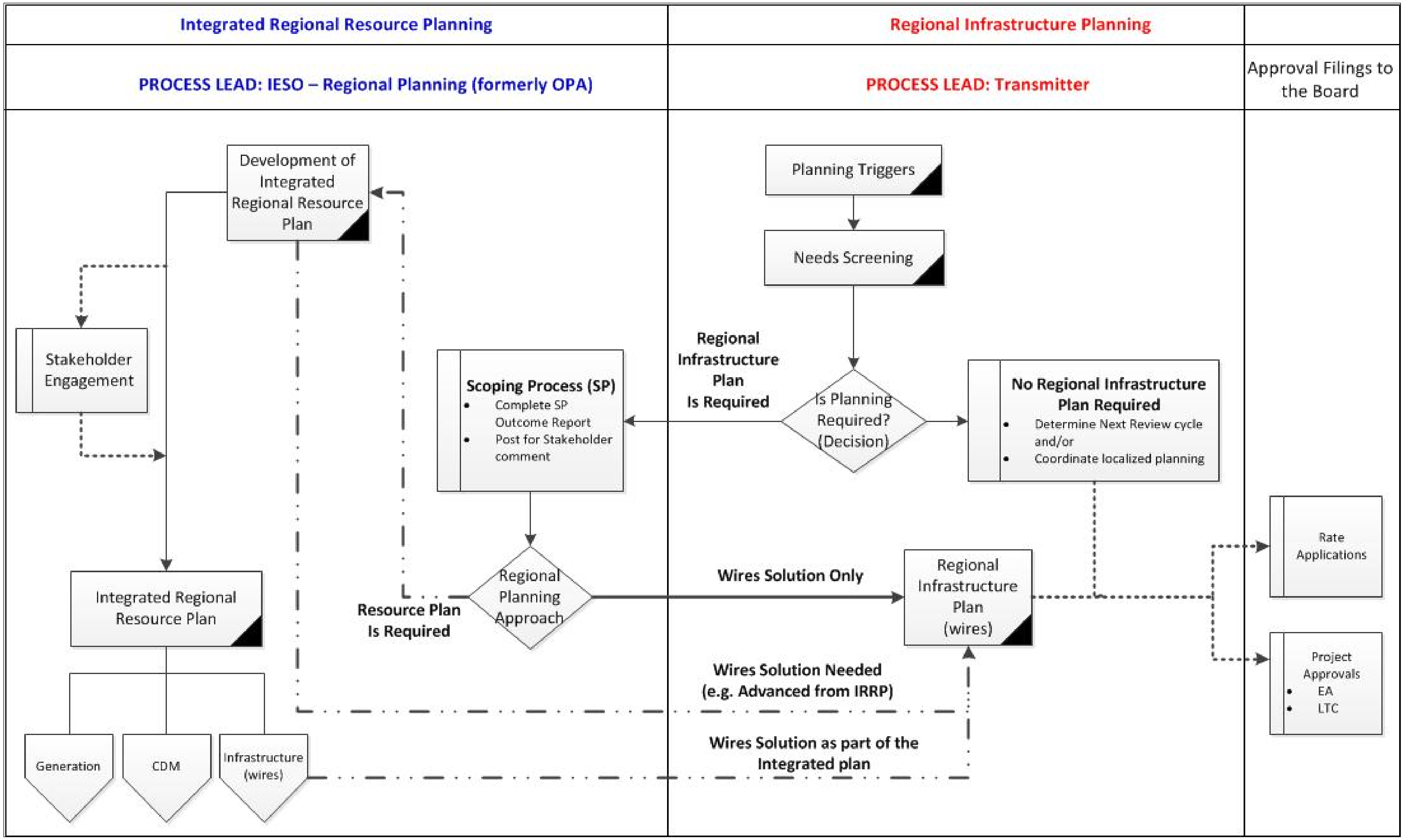

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. **Data Gathering:** The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Study Team to reconfirm or update the information as required:
   - Net peak demmand forecastt at the transformer statiion level. Thhis includes the effect oof any diistributed genneration ("DGG") or CDM pprograms;
   - EExisting area network and ccapabilities inncluding any bbulk system ppower flow asssumptions;
   - Other data andd assumptionss as applicablle such as assset conditionss, load transfefer capabilities, and prreviously commmitted transmmission and ddistribution syystem plans.
2. **Technical Assessment:** The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. **Alternative Development:** The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.
4. **Implementation Plan:** The fourth and last step is the development of the implementation plan for the preferred alternative.

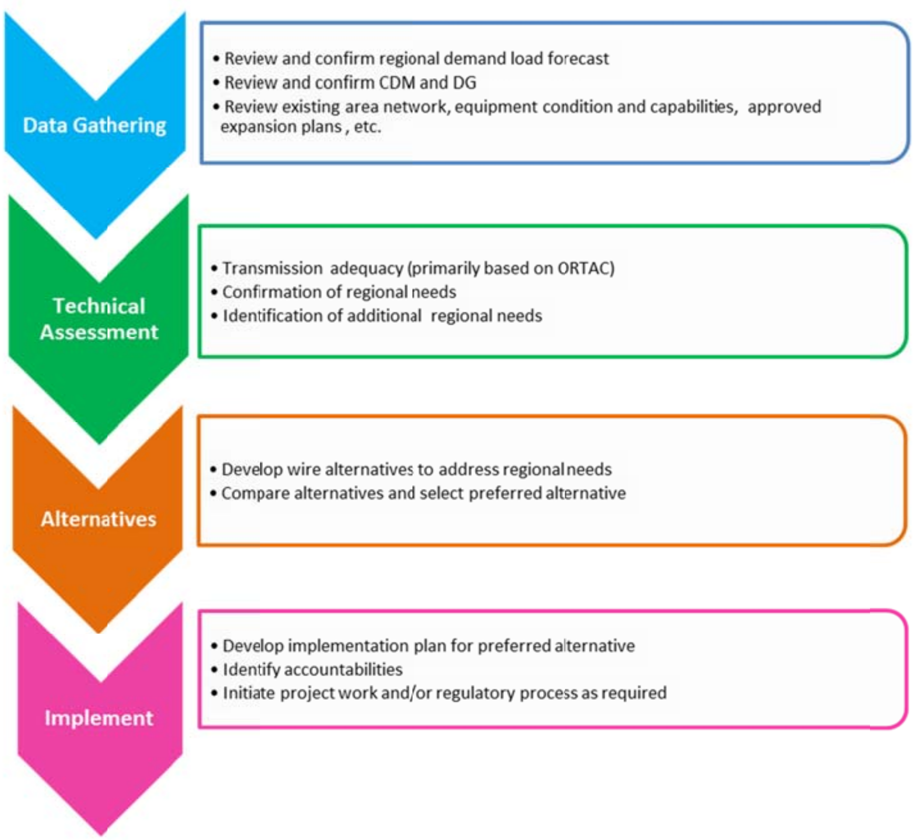

Figure 2-2 RIP Methoddology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS. THE 2015 WINTER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1,350 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

There are sixteen Hydro One-owned step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

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

3.1 Barrie/Innisfil Sub-Region

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

3.2 Parry Sound/Muskoka Sub-Region

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

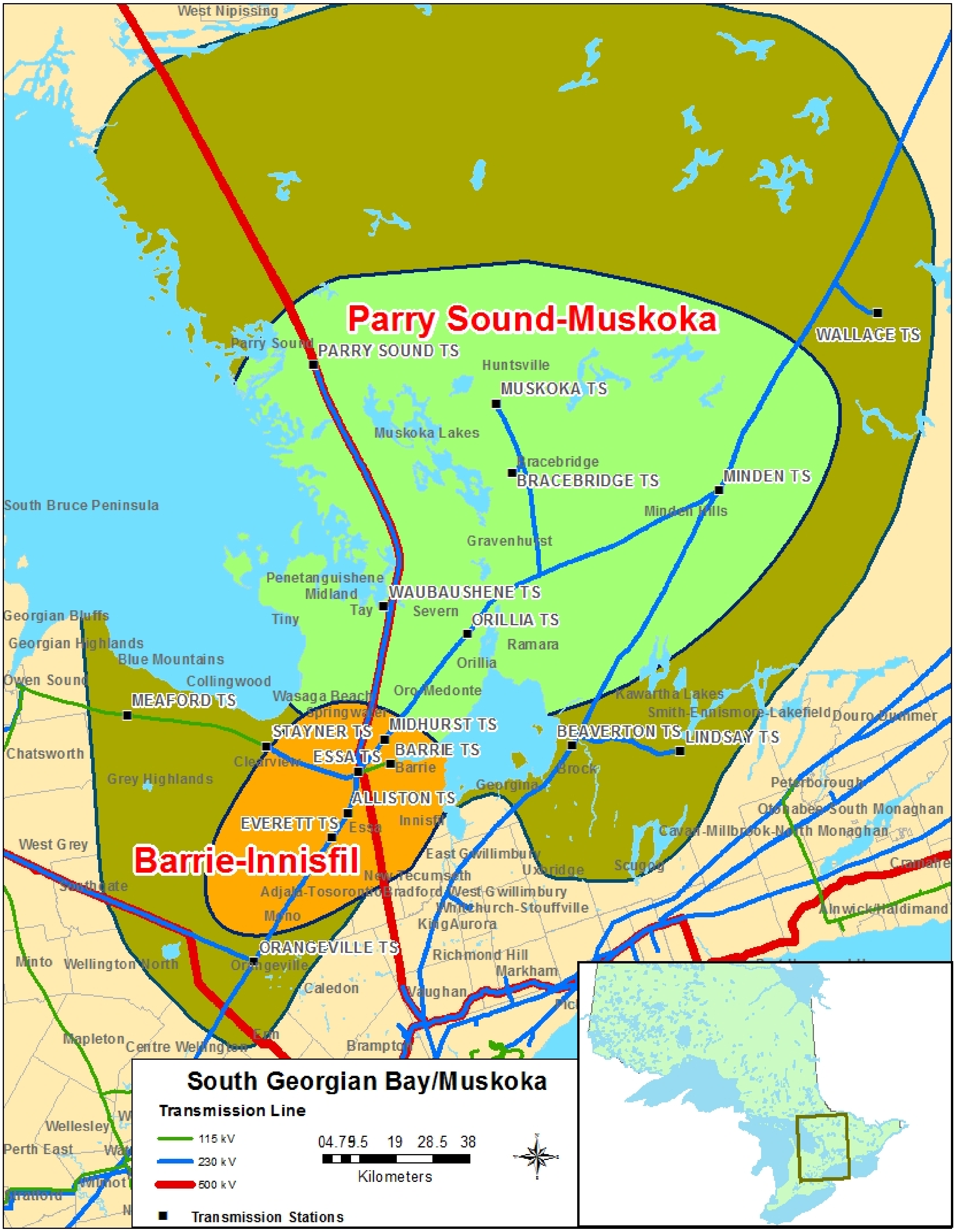

Figure 3-1 South Georgian Bay/Muskoka – Supply Areas

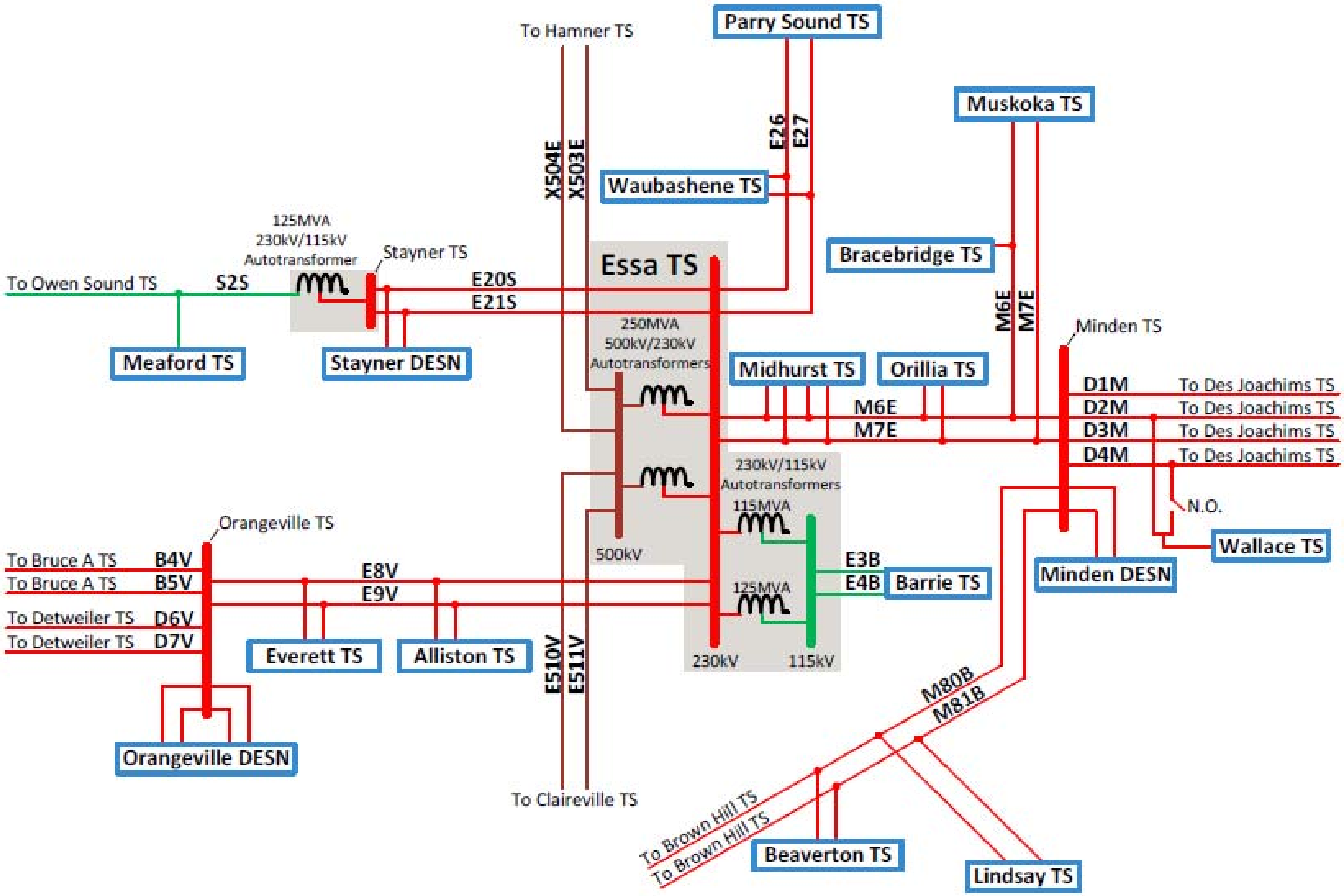

Figure 3-2 South Georgian Bay/Muskoka Region Single Line Diagram (Current)

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR HAVE BEEN INITIATED, AIMED AT IMPROVING THE SUPPLY TO THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

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

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

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

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

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

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

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

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

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

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

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

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

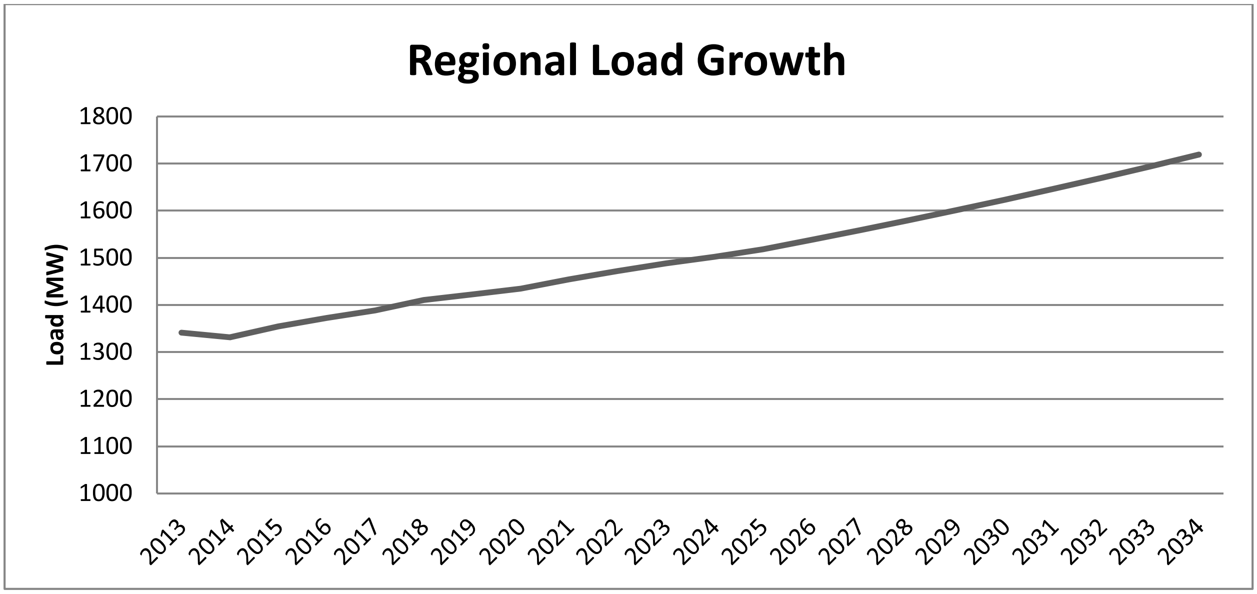

Figure 5-1 South Georgian Bay/Muskoka Region Winter Coincident Net Load Forecast

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

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2014 – 2034.
- The Region is winter peaking, however five out of sixteen stations in the Region are summer peaking (Alliston TS, Barrie TS, Everett TS, Midhurst TS and Orangeville TS T1/T2 DESN). Therefore, this assessment is based on both winter and summer peak loads, as appropriate.
- "Barrie Area Transmission Upgrade project" to be completed by the end of 2020.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-

voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.[2] Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR") or the winter 10-Day LTR depending on what season the station peaks.

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

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

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

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

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

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

The NA, IRRP, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the South Georgian Bay/Muskoka Region assuming Essa/Barrie and E3B/E4B upgrade to be completed by 2020/2021, Minden DESN transformer replacement and 44kV upgrade to be completed by November 2020/2021, and Orangeville transformer replacement and station reconfiguration to be completed by October 2024/2025.

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

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

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

6.1 115kV and 230kV Transmission Facilities

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Muskoka TS, Orillia TS and Bracebridge TS are adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Parry Sound/Muskoka Sub-Region

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

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

6.4 Areas outside of Sub-region

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

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

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

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

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

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

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

End-of-Life Equipment Replacements

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

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

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

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

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

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

7. REGIONAL PLANS

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

The near-term needs arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Barrie/Innisfil Sub-Region

Description

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

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

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

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

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

Recommended Plan and Current Status

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

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

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

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

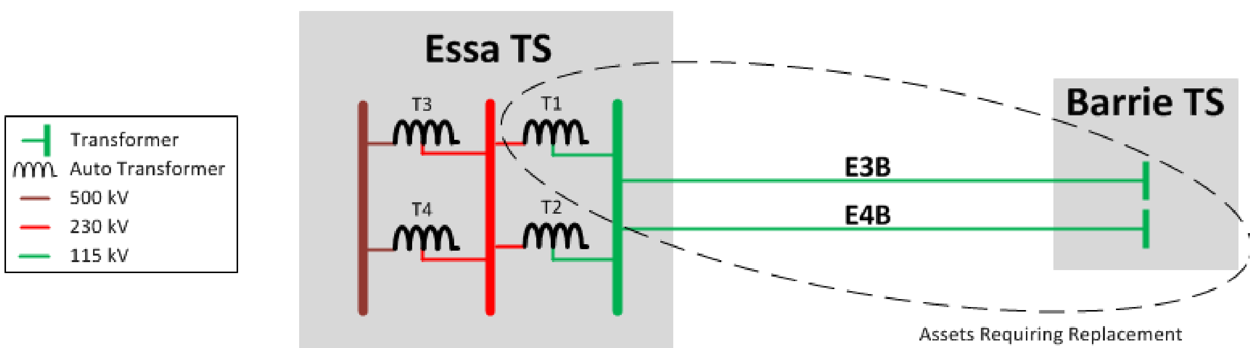

Figure 7-1 Current Arrangement of Essa TS, Barrie TS, and Circuits E3B/E4B

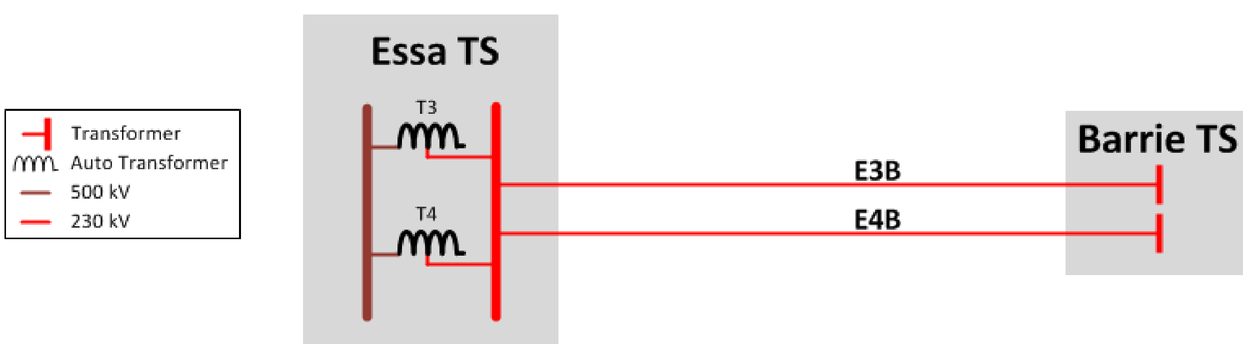

Figure 7-2 New Configuration of Essa/Barrie Supply to Barrie DESN

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

7.2 Transformation Capacity Need at Uprated Barrie TS

Description

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

Proposed Alternatives and Recommended Plan

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

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

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

Description

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

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

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

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

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

Recommended Plan and Current Status

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

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

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

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

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

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

7.4 Parry Sound/Muskoka Load Restoration Assessment

Description

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

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

Proposed Alternatives and Recommended Plan

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

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

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

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

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

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

Description

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

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

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

Recommended Plan and Current Status

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

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

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

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

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

7.6 Distribution Feeder Capacity to Supply InnPower

Description

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

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

Recommended Plan and Current Status

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

7.7 Long Term Regional Plan

As discussed in Section 5, the electricity demand in South Georgian Bay/Muskoka Region is forecasted to grow at 1.46% annually over the next 10 years, and at a slightly lower average rate of 1.17% from 2016-2034. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1% annually from year 2024 to 2034 in the Parry Sound/Muskoka Sub-Region, while 1.9% in the Barrie/Innisfil Sub-Region. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

Parry Sound/Muskoka

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

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

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

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

Barrie/Innisfil

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

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

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

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

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

7.8 Minden TS End of Life Assets

Description

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

Alternatives and Recommended Plan

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

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

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

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

7.9 Orangeville TS End of Life Assets

Description

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

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

Alternatives and Recommended Plan

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

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

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

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

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for 115kV Barrie TS	Today
II	Additional transformation capacity for the uprated 230kV Barrie TS	Long-term[10]
III	Additional transformation capacity for Parry Sound TS	Today
IV	Transmission Line Capacity for E3B/E4B	2019
V	Load restoration for loss of M6E/M7E	Today
VI	Mitigate frequency and duration of outages on the 44kV Parry Sound/Muskoka sub-region	Today
VII	Additional feeder position for InnPower supplied from Barrie TS	2020
VIII	Additional capacity required for Barrie/Innisfil Sub-Region and Barrie sub-area	Long-term
IX	Additional transformation capacity for Waubaushene TS	Long-term[11]
X	Additional transformation capacity for Everett TS	Long-term
XI	LMC and Load Security for M6E/M7E	Long-term

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

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

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

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

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

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

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

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

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

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

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] "Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario". May 17, 2013.
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

[2] Hydro One, "Needs Assessment Report, South Georgian Bay-Muskoka. March 3, 2015.
http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

[3] Independent Electricity System Operator, "South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report. June 22, 2015.
http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Documents/South-Georgian%20Bay-Muskoka%20Region%20Scoping%20Assessment%20Report.aspx

[4] Hydro One, "Local Planning Report – Orangeville TS EOL Replacement". May 27, 2016.
http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

[5] Independent Electricity System Operator, "Barrie-Innisfil Sub-Region Integrated Regional Resource Plan". December 16, 2016.
http://www.ieso.ca/get-involved/regional-planning/gta-and-central-ontario/barrie-innisfil

[6] Independent Electricity System Operator, "Parry Sound/Muskoka Sub-Region Integrated Regional Resource Plan". December 16, 2016.
http://www.ieso.ca/get-involved/regional-planning/gta-and-central-ontario/parry-sound-muskoka

APPENDICES

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

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

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

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

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

Note: 2014 values in grey are actuals from IRRP

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

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

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

Note: 2014 values in grey are actuals from IRRP

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

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

Appendix E: List of Acronyms

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

UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme