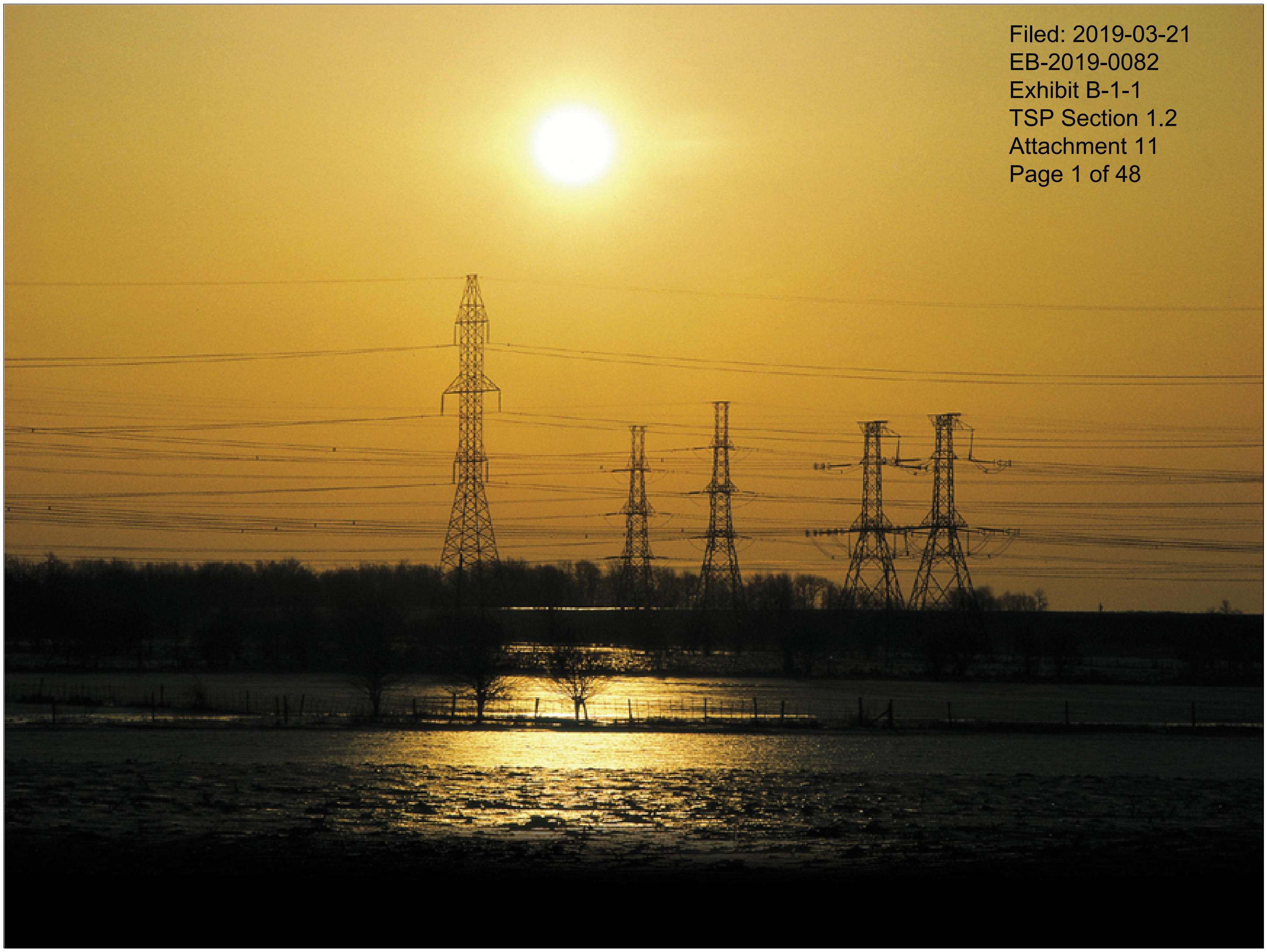

London Area

REGIONAL INFRASTRUCTURE PLAN

August 25th, 2017

hydro one

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

With support from:

Organizations
Independent Electricity System Operator
Entegrus Inc.
Erie Thames Power Lines Corporation
London Hydro Inc.
St. Thomas Energy Inc.
Tillsonburg Hydro Inc.
Hydro One Networks Inc. (Distribution)

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 re-evaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP 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 LONDON AREA REGION.

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

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Entegrus Inc.
- Erie Thames Power Lines Corporation
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the London Area Region which consists of the Strathroy Sub-Region, Greater London Sub-Region, Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region, and the St. Thomas Sub-Region. It follows the completion of the London Area Region's Needs Assessment ("NA") in April 2015, the London Area Region Scoping Assessment ("SA") in August 2015, the Strathroy TS Transformer Capacity Local Plan ("LP") in September 2016, the Greater London Sub-Region Integrated Regional Resource Plan ("IRRP") in January 2017, and the Woodstock Sub-Region Restoration Local Plan ("LP") in May 2017.

This RIP provides a consolidated summary of needs and recommended plans for the entire London Area Region. Needs which are to be addressed include:

- Load restoration in Woodstock Sub-Region
- Load restoration in Greater London Sub-Region
- Voltage constraints, thermal constrains and delivery point performance in Aylmer-Tillsonburg Sub-Region

The major infrastructure investments planned for the region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Estimated Cost[1]
1	Distribution System Upgrades in the Greater London Sub-Region	2023	$1.8-4M ($180/kW)
2	Wonderland TS Reinvestment: Replace transformer T5	2022	$15-20M

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] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Independent Electricity System Operator, Entegrus Inc., Erie Thames Power Lines Corporation, London Hydro Inc., St. Thomas Energy Inc., Tillsonburg Hydro Inc., and Hydro One Networks Inc. (Distribution) in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The London Area is located in South Western Ontario and includes all or part of the following Counties, and Cities: Oxford County, Middlesex County, Elgin County, Norfolk County, the City of Woodstock, the City of London, and the City of St. Thomas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

The region also includes the following First Nations: Chippewas of the Thames, Oneida Nation of the Thames, and Munsee-Delaware Nation.

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS's, four direct transmission connected load customers and three transmission connected generators in the London Area. The distribution system consists of voltage levels 27.6 kV and 4.16kV.The boundaries of the Region are shown in Figure 1-1 below.

Within the current regional planning cycle, four regional assessments have been conducted for the London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016
4. Hydro One's London Area Region Needs Assessment Report – April, 2015

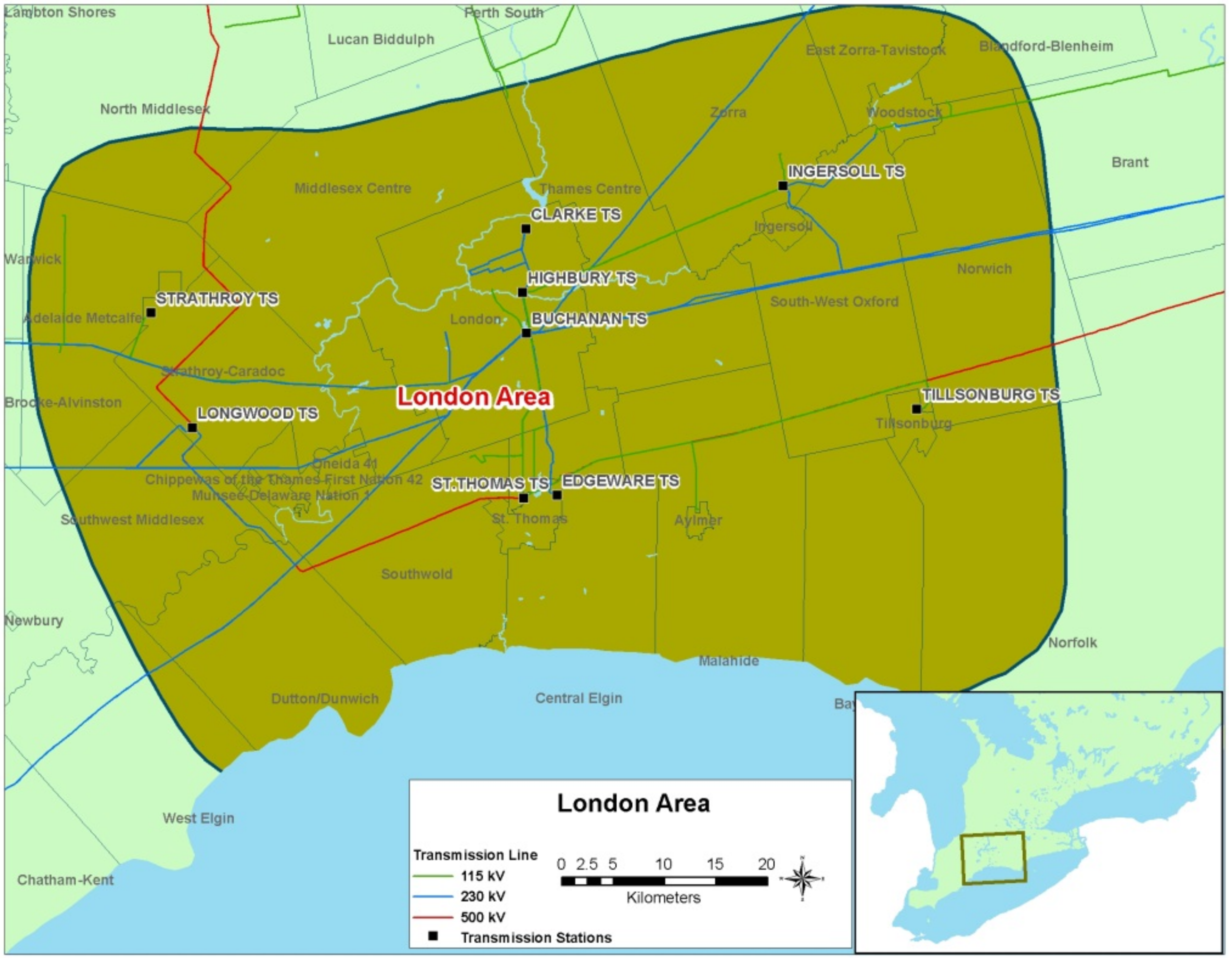


Figure 1-1 London Area Region

1.1 Scope and Objectives

This RIP report examines the needs in the London Area Region and its objectives are to:

- Confirm supply needs identified in previous planning phases;
- 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 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 Greater London 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 major High Voltage 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 evaluates 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[2] ("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 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. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited to investments in wires (transmission or distribution) solutions c) do not require upstream transmission investments d) do not require plan level stakeholder engagement and e) do not require other approvals such as Leave to Construct (S92) approval 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 require regional coordination, the Working Group can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, the approach is to complete either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-

[2] Also referred to as Needs Screening.

region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

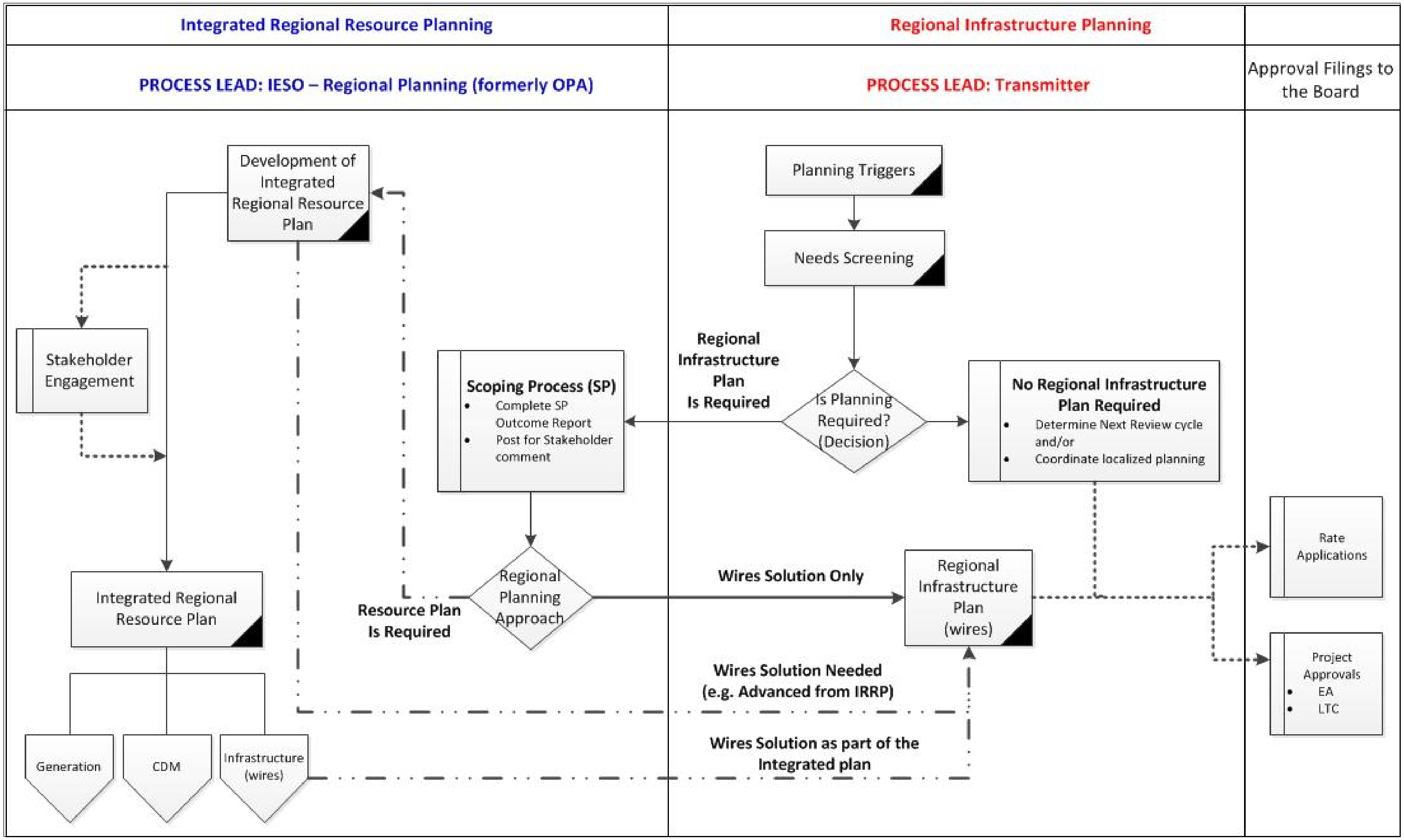


Figure 2-1 Regional Planning Process Flowchart

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.

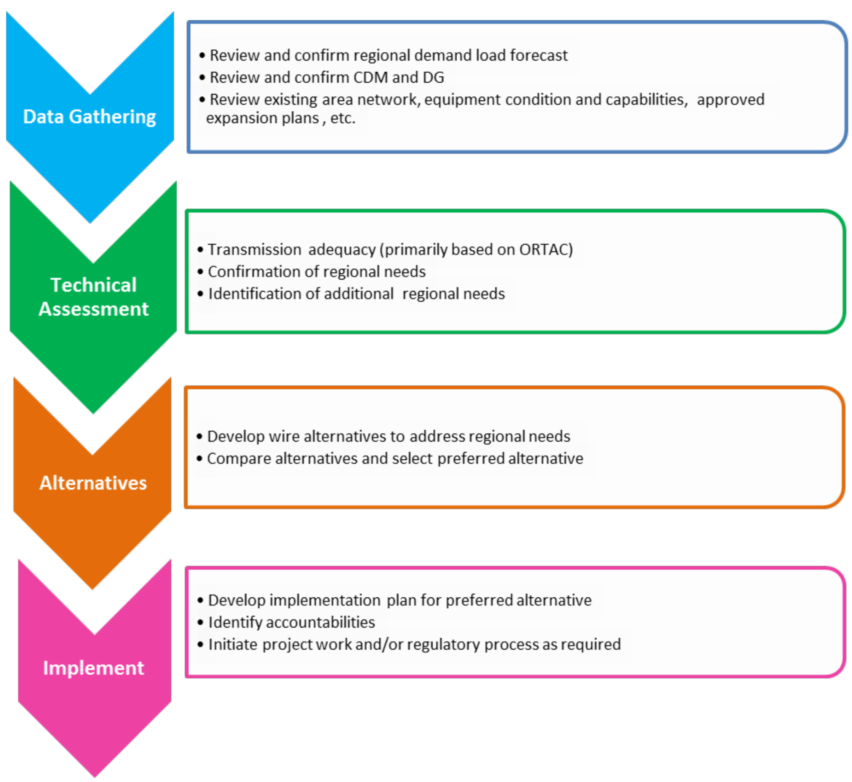


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE LONDON AREA IS LOCATED IN SOUTH WESTERN ONTARIO AND INCLUDES ALL OR PART OF OXFORD COUNTY, MIDDLESEX COUNTY, ELGIN COUNTY, NORFOLK COUNTY, THE CITY OF WOODSTOCK, THE CITY OF LONDON, AND THE CITY OF ST. THOMAS. THE REGION ALSO INCLUDES THE FOLLOWING FIRST NATIONS: CHIPPEWAS OF THE THAMES, ONEIDA NATION OF THE THAMES, AND MUNSEE-DELAWARE NATION. LONDON AREA REGION IS DIVIDED INTO FIVE SUB-REGIONS: STATHROY SUB-REGION, GREATER LONDON SUB-REGION, WOODSTOCK SUB-REGION, AYLMER-TILLSONBURG SUB-REGION, AND THE ST. THOMAS SUB-REGION.

Electrical supply to the London Area Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS', four direct transmission connected load customers and three transmission connected generators. The region is summer-peaking and has a peak demand of approximately 1,250 MW including direct transmission connected customers. A map of the London Area Region (highlighting the sub-regions) and a single line diagram of the transmission system are shown in Figure 3-1 and Figure 3.2.

Table 3-1 Sub-Region Details

Sub-Region	Station Name (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customers
Strathroy Sub-Region	Strathroy TS (T7/T8)	230/27.6	W2S, S2N	• Hydro One Distribution • Entegrus
	Longwood TS (T13/T14)	230/27.6	L24L, L26L	• Hydro One Distribution
Greater London Sub-Region	Talbot TS (T1/T2, T3/T4)	230/27.6	W36, W37	• London Hydro • Hydro One Distribution
	Clark TS (T3/T4)	230/27.6	W36, W37	
	Wonderland TS (T5/T6)	230/27.6	N21W, N22W	
	Buchanan TS (T13/T14)	230/27.6	W42L, W43L	
	Nelson TS (T1/T2)	115/13.8	W5N, W6NL	
	Highbury TS (T3/T4)	115/27.6	W6NL, W9L	
Woodstock Sub-Region	Ingersoll TS (T5/T6)	230/27.6	M31W, M32W	• Hydro One Distribution • Erie Thames Powerlines
	Woodstock TS (T1/T2)	115/27.6	K7, K12	
	Commerceway TS (T1/T2)	115/27.6	K7, K12	
Aylmer Sub-Region	Aylmer TS (T2/T3)	115/27.6	WT1A, W8T, T11T	• Hydro One Distribution, • Erie Thames Powerlines • Tillsonburg Hydro
	Tillsonburg TS (T1/T3)	115/27.6	WT1T, W8T, T11T	
St.Thomas Sub-Region	St. Thomas TS	115/27.6kV	W3T, W4T, T11T	Station is planned for decommissioning, no remaining customers connected.
	Edgeware TS	230/27.6kV	W45LS, W44LC	• Hydro One Distribution • St. Thomas Energy • London Hydro

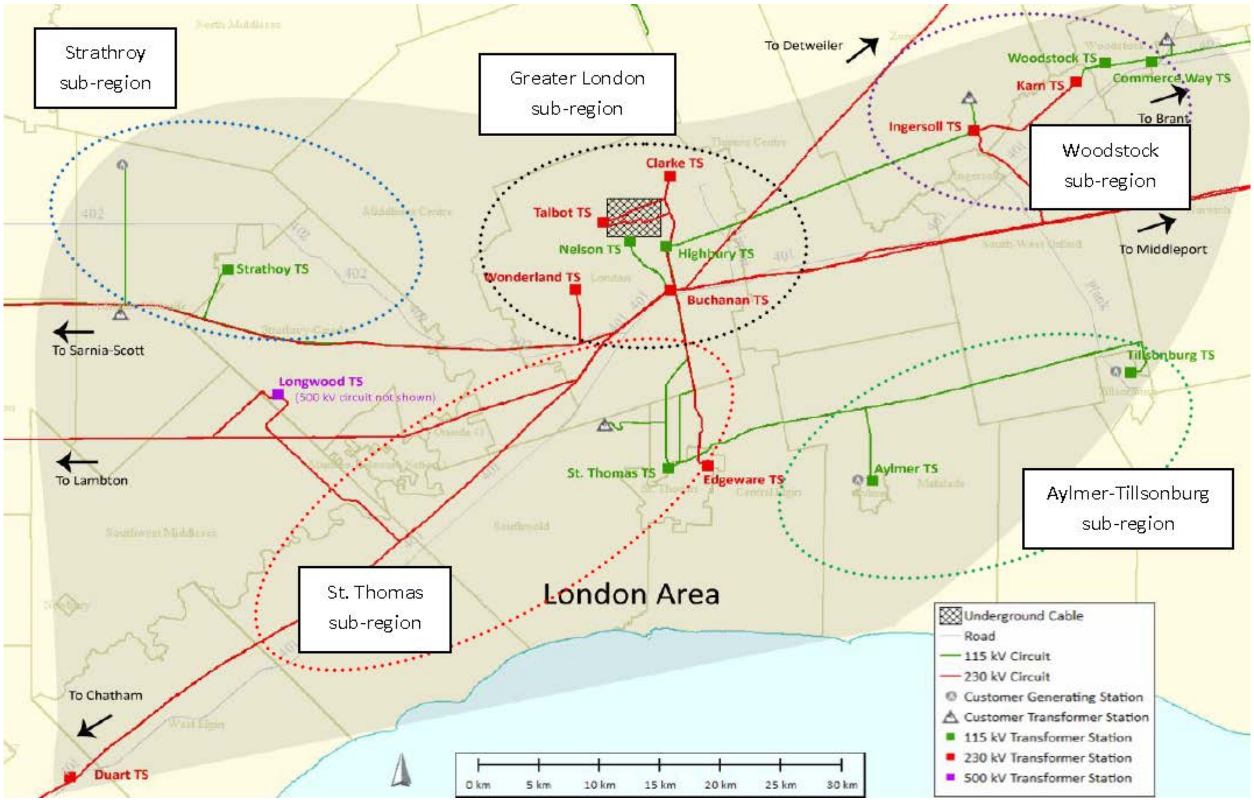
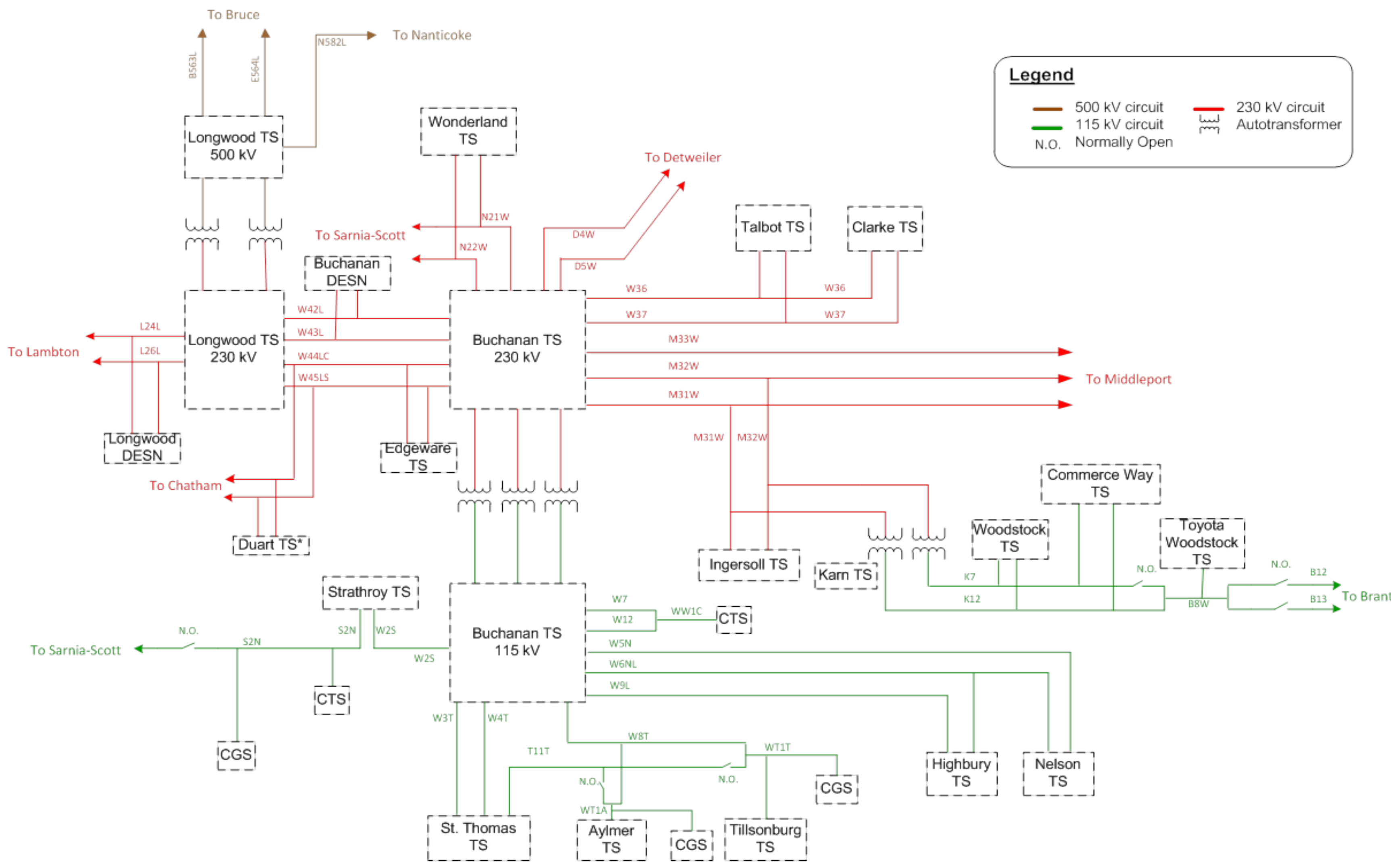


Figure 3-1 London Area Region – Supply Areas



* Part of Chatham-Kent/Sarnia/Lambtion Regional Planning, shown here for completeness

Figure 3-2 London Area Region Single Line Diagram

4. TRANSMISSION PROJECTS COMPLETED OR CURRENTLY UNDERWAY

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 LONDON AREA REGION.

A brief listing of the major projects completed over the last 10 years is given below:

- Talbot TS Expansion (2007) – Expansion of the existing Talbot TS and construction of a second 50/83 MVA 230/27.6 kV transformer station to alleviate load from existing transformer stations in the area, which were loaded beyond its capacity and provide additional capacity for the load growth in the London area.
- Highbury TS Transformer Replacement (2009) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformer T4 that was over 60 years old and nearing end-of-life.
- Commerce Way TS (2010) – Construction of a new 50/83 MVA 115/27.6 kV Commerce Way transformer station to alleviate load from Woodstock TS, which was loaded beyond its capacity and provide additional capacity for the load growth in the Woodstock area.
- Strathroy TS Transformer Replacement (2012) – Like-for-like replacement of 25/42 MVA 115/27.6 kV transformer T2 due to failure.
- Ingersoll TS Transformer Replacement (2012) – Like-for-like replacement of 75/125 MVA 230/27.6 kV transformers T5 & T6 that were approximately 35 years old. The transformers were identified to have a design weakness and were replaced to mitigate the risk of failures, improve restoration time and maintain system performance.
- Woodstock TS Transformer Replacement (2014) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformers T1 & T2 that were approximately 50 years old and were nearing end-of-life.

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

1. **Aylmer TS**: is located in Southwestern Ontario and is comprised of two 11/15 MVA, 110-28 kV transformers (T2 & T3) and two 27.6 kV feeder breaker positions M1, M2. The station is supplied by a single 115kV line WT1A and it supplies Erie Thames Powerlines Corp. and Hydro One Distribution at 27.6 kV.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T2 & T3) and LV switchyard, qualifies it as a candidate for a complete station rebuild. To address the urgent need, the existing station will be replaced with a new DESN with two 25/33/42 MVA transformers. The replacement work also includes all 28kV LV switching facilities, the addition of two new feeder positions, and an upgrade to associated protection and control systems.

   This project is currently under execution and planned to be completed before end of 2017.

2. **Strathroy TS**: is located in Middlesex County in Southwestern Ontario and is comprised of two 25/33/42 MVA 110-28 kV transformers (T1 & T2) and four 27.6 kV feeder breaker positions. Strathroy TS supplies Entegrus Powerlines Inc. and Hydro One Distribution at 27.6 kV.

   Due to deteriorating asset condition, Hydro One has planned to replace the T1 transformer with similar type 42MVA transformer, replace all LV switching facilities, and upgrade associated protection and control facilities and AC/DC station ancillary infrastructure.

   This project is currently under execution and planned to be completed in 2017.

3. **Nelson TS**: is located in the City of London in Southwestern Ontario and is comprised of two DESN stations (the "T1/T2 DESN" and the "T3/T4 DESN") which are both supplied from the 115 kV circuits W5N and W6NL. The T1/T2 DESN consists of two 18/27/33 MVA, 115/ 13.8 kV transformers with two LV yards (outdoor and indoor), and the T3/T4 DESN consists of two 60/80/100 MVA, 115/ 13.8 kV transformers with two LV yards (both indoor). The T1/T2 DESN supplies about 17 MW of 13.8kV load in the London downtown area and the T3/T4 DESN supplies approximately 31 MW of 13.8 kV load, also in the London downtown area.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T1 & T2) and LV switchyard, qualifies it as a candidate for a complete station rebuild. In addition, London Hydro has requested that Hydro One rebuild the LV at 27.6kV rather than at 13.8kV so that the station can be integrated into London Hydro's 27.6kV distribution system to provide load support. As a result, Hydro one is building a new station within the existing Nelson TS yard. The new station will consist of two new 115/27.6 kV, 50/83 MVA DESNs and new LV switchyard with 8 feeder positions and 2 capacitor bank positions. All associated protection and control systems and station ancillary infrastructure will be upgraded. The work will also involve decommissioning of the existing DESN substation consisting of T1 and T2 transformers and the 13.8kV air insulated outdoor switchyard.

   This project is currently under execution and planned to be completed in 2018.

5. FORECAST AND STUDY 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 London Area regional peak load has been relatively constant over the past 5 years (approximate decline of -0.4%).

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the London Region:

- 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.
- 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, projected province-wide CDM programs, committed and forecast DG . This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Prior to the RIP's kick-off, the Working Group was asked to confirm the load forecasts for all stations in the Region provided for previous assessments. The RIP's load forecast was updated according the revised load forecasts provided by the LDCs.

The load in the London Area Region including CDM targets and DG contributions is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). The growth rate varies across the region but an overall coincident net load forecast 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 B and C.

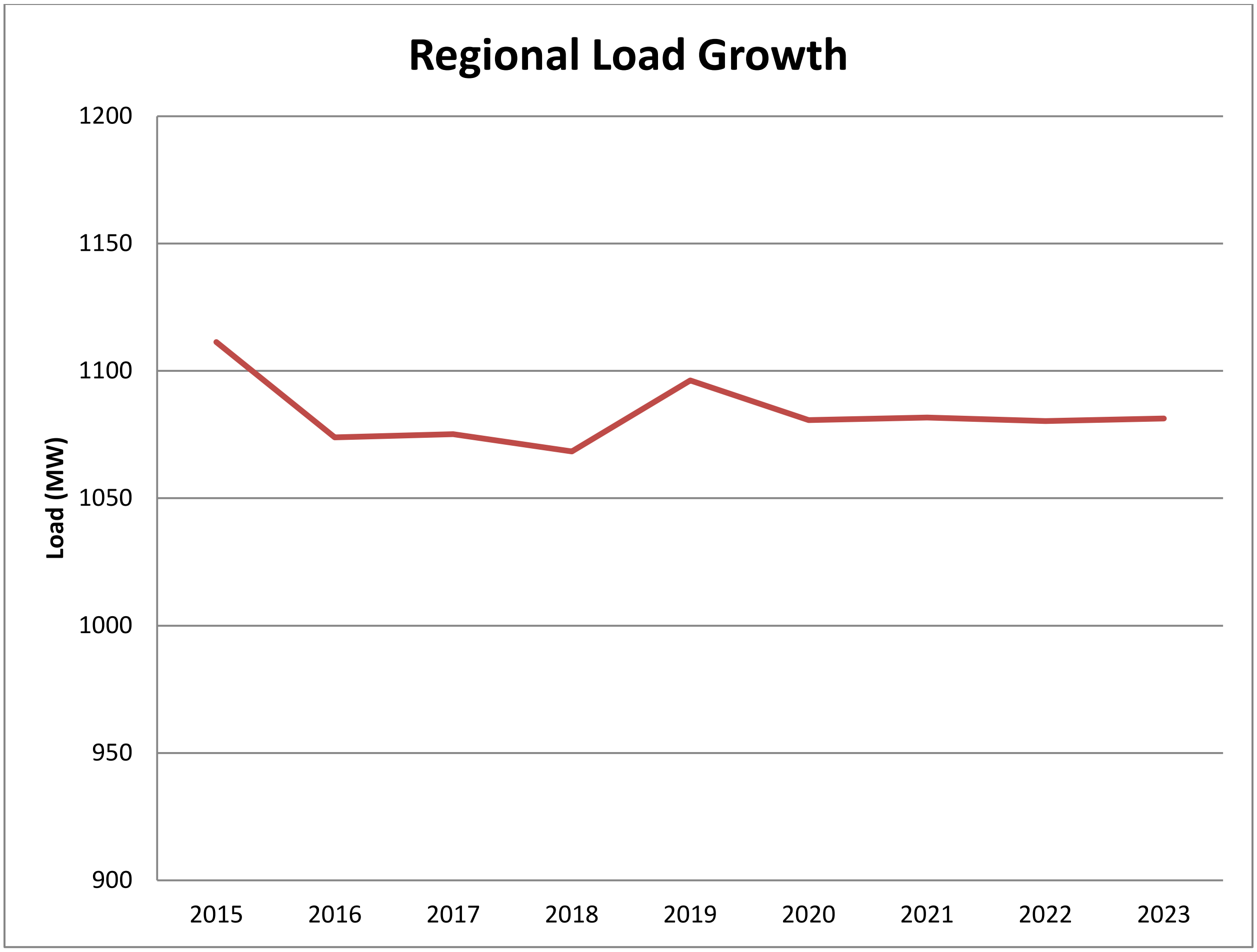


Figure 5-1 London Area Region Coincident Net Load Forecast

5.4 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2023.
- 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

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE LONDON AREA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017[1]
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017[2]
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016[3]
4. Hydro One's London Area Region Needs Assessment Report – April, 2015[4]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the London Area Region assuming the new Nelson TS DESN will be in-service by the end of 2018, and the new Aylmer TS DESN will be in-service by the end of 2017. Further detailed description and status of plans to meet these needs is provided in Section 7.

6.1 Transmission Line Facilities

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. The main features of the electrical supply system in the London Area are as follows:

- Longwood TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Buchanan TS and Karn TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Fifteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, St. Thomas TS, Talbot TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.
- Four Customer Transformer Stations (CTS) are supplied in the London Area: Ford Talbotville CTS, Enbridge Keyser CTS, Lafarge Woodstock CTS, and Toyota Woodstock CTS.
- There are 3 existing transmission connected generating stations in the London Area as follows:

- Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
- Erie Shores Wind Farm GS is a 99 MW wind farm connected to 115kV circuit near Tillsonburg TS
- Silver Creek GS is a 10 MW solar generator connected to 115kV circuit near Aylmer TS

The 500kV system is part of the bulk system planning conducted by the IESO and is not studied as part of this RIP

Table 6-1 provides 230 kV and 115 kV circuit network that supplies to the London Area.

Table 6-1 230 kV and 115 kV circuits network in the London Area

Voltage	Circuit Designations	Location
230 kV	N21W, N22W	Scott TS to Buchanan TS
	W42L, W43L	Longwood TS to Buchanan TS
	W44LC	Longwood TS to Chatham TS to Buchanan TS
	W45LS	Longwood TS to Spence SS to Buchanan TS
	W36, W37	Buchanan TS to Talbot TS
	D4W, D5W	Buchanan TS to Detweiler TS
	M31W, M32W	Buchanan TS to Ingersoll TS to Middleport TS
	M33W	Buchanan TS to Brantford TS
115 kV	W2S	Buchanan TS to Strathroy TS
	W5N	Buchanan TS to Nelson TS
	W6NL	Buchanan TS to Highbury TS to Nelson TS
	W9L	Buchanan TS to Highbury TS
	W7, W12 WW1C W8T T11T WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to Cranberry JCT Erie Shore Wind Farm JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT exceeds its planning rating under pre-contingency conditions in the near term based on the gross load forecast. Such thermal overload is deferred to the medium term based on the net load forecast. The transmission line constraint is further described in section 7.2.2 of this report. The remaining 115 kV and 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single element in the area.

6.2 Step-Down Transformation Facilities

There are a total of fifteen step-down transmission connected transformer stations in the London Area Region. The stations have been grouped based on the geographical area and supply configuration. The station loading and the associated station capacity and the need date in each sub-region is provided in Table 6-3 below. The findings of the transformation capacity assessment are as follows:

- As confirmed in the "Strathroy TS Transformer Capacity Local Plan (LP)", based on the limited time rating ("LTR") of the station, the transformation capacity is adequate in Strathroy Sub-Region over the study period.
- As confirmed in the "Greater London Sub-Region Integrated Regional Resource Plan (IRRP)", based on the LTR of the stations, the transformation capacity is adequate in Greater London Sub-Region over the study period.
- Based on the LTR of the load stations, the transformation capacity is adequate in Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region and the St. Thomas Sub-Region over the study period.

Table 6-2 Transformation Capacities in the Sub-Regions

Sub-Region	Station	LTR (MW)	2015 Non Coincident Peak (MW)	Need Date
Strathroy Sub-Region	Strathroy TS	50	45	-[3]
	Longwood TS	128	33	-[3]
Greater London Sub-Region	Talbot TS	290	268	-[3]
	Clark TS	110	106	-[3]
	Wonderland TS	99	109[4]	-[3]
	Buchanan TS	183	143	-[3]
	Nelson TS	105[5]	23	-[3]
	Highbury TS	114	93	-[3]
Woodstock Sub-Region	Ingersoll TS	167	75	-[3]
	Woodstock TS	87	56	-[3]
	Commerceway TS	112	33	-[3]
Aylmer Sub-Region	Aylmer TS	55[6]	21	-[3]
	Tillsonburg TS	109	88	-[3]
St.Thomas Sub-Region	St.Thomas TS	50	0	-[3]
	Edgeware TS	191	113	-[3]

[3] Adequate over the study period
[4] Peak loading at Wonderland TS is forecasted to reduce to within its 10-day LTR rating by 2017
[5] Nelson TS LTR reflects the Station Rebuild Project under execution - planned to be completed in 2018
[6] Aylmer TS LTR reflects the Transformer Replacement Project under execution - planned to be completed in 2017

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

6.3 System Reliability and Load Restoration

In case of incidents on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

In the London Area Region it is expected that all loads can be restored within the ORTAC load restoration requirements with exception of:

- Loss of M31W/M32W – Woodstock Sub-Region
- Loss of W36/W37 or W42L/W43L – Greater London Sub-Region

The load restoration constraints are further described in section 7.1 of this report.

6.4 Voltage

Under pre-contingency conditions with all facilities in service, ORTAC provides requirements for acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. These values are obtained from Chapter 4 of the IESO "Market Rules" and CSA standards for distribution voltages below 50 kV.

Table 6-3 Pre-Contingency Voltage Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus
Maximum Continuous (kV)	550	250	127*	106%
Minimum Continuous (kV)	490	220	113	98%

*Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 115 kV system can be as high as 132 kV.

With all planned facilities in service pre-contingency, ORTAC provides requirements for system voltage changes in the period immediately following a contingency as indicated in Table 6-4.

Table 6-4 Post-Contingency Voltage Change Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus		
				44	27.6	13.8
% voltage change **before** tap changer action	10%	10%	10%	10%		
% voltage change **after** tap changer action	10%	10%	10%	5%		
AND within the range						
Maximum* (kV)	550	250	127	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

*The maximum and minimum voltage ranges are applicable following a contingency. After the system is re-dispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages.

The Aylmer-Tillsonburg Sub-Region is normally supplied by a single 115 kV transmission circuit W8T which is approximately 60 km in length. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T.

Under pre-contingency conditions and with Erie Shores Wind Farm unavailable, the voltage at Tillsonburg TS 115 kV bus does not meet ORTAC criteria (113 kV) under existing peak load conditions and may reach as low as 100 kV. The transformer ULTCs at Tillsonburg TS is however maintaining the LV bus voltage above ORTAC criteria of 27 kV (98% of nominal voltage). Study results indicate that the LV voltage cannot be maintained at desirable levels when the load in the Aylmer-Tillsonburg Sub-Region exceeds 115 MW. Based on the latest load forecasts, this loading level may be reached as early as 2019.

The voltage constraint is further described in section 7.2.1 of this report.

6.5 Customer Delivery Point Performance

In accordance with Section 2.5 of the Transmission System Code, Hydro One Networks Inc. (Networks) is required to develop performance standards at the customer delivery point level, consistent with system wide standards that reflect:

- typical transmission-system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- historical performance at the customer delivery point level;
- acceptable bands of performance at the customer delivery point level for the transmission system configurations; geographic area, load, and capacity levels; and

- defined triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, exemptions from such standards, and study triggers and results.

The Customer Delivery Point Performance Standards and triggers are based on the size of load being served (as measured in megawatts by a delivery point's total average station load) are provided in Table 6-4 below.

Table 6-4 Customer Delivery Point Performance Standards

Performance Measure	Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		**15-40 MW**		**40-80 MW**		**>80 MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	4.1	**9.0**	1.1	**3.5**	0.5	**1.5**	0.3	**1.0**
DP Interruption Duration (min/year)	89	**360**	22	**140**	11	**55**	5	**25**

The minimum standards of performance are to be used as triggers by Networks to initiate technical and financial evaluations with affected customers. These bands are to:

- accommodate normal year-to-year delivery point performance variations;
- limit the number of delivery points that are to be considered "performance outliers" to a manageable/affordable level;
- deliver a level of reliability that is commensurate with customer value i.e. the larger the load, the greater the level of reliability provided; and
- direct/focus efforts for reliability improvements at the "worst" performing delivery points.

The customer delivery points serving THI and HONI distribution at Tillsonburg TS is not meeting CDPPS requirements with regards to frequency of interruptions. This customer delivery point has averaged approximately 3.3 interruptions per year over the past 10 years, doubling the performance target of 1.5.

The Customer Delivery Point Performance need is further described in section 7.2.3 of this report.

6.6 End-of-Life Equipment Replacements

Recent condition assessment of Wonderland TS has revealed that one of the existing power transformers at the station (T5) is in poor condition and must be replaced in the near-term. The facility was originally built in the 1960s and its assets are degrading in condition and require replacement by 2022. The existing 230/28kV T6 power transformer was replaced in 2004 due to failure. The existing 230/28 kV T5 power transformer will be replaced with a similar unit (230kV-28kV 83 MVA) to match the ratings of transformer T6. After the transformer replacement is completed, the LTR of Wonderland TS is expected to increase to approximately 114MW.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS, POSSIBLE WIRES ALTERNATIVES AND SUMMARIZES THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE LONDON AREA REGION

The needs listed in Table 7-1 include needs previously identified in the IRRP for the Greater London Sub-Region and the NA and LP's for the Strathroy, Woodstock, Aylmer-Tillsonburg and St. Thomas Sub-Regions.

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).

Table 7-1 Identified Near-Term Needs in London Region

Sub-Region	Type	Section	Needs	Timing
Woodstock Sub-Region	Load Restoration	7.1.1	Loss of M31W/M32W	No action required at this time
Greater London Sub-Region		7.1.2	Loss of W36/W37 or W42L/W43L	Now
Aylmer-Tillsonburg Sub-Region	Voltage Constraint	7.2.1	Voltage at Tillsonburg TS below ORTAC criteria	Now
	Thermal Constraint	7.2.2	Thermal constraint on 115kV line W8T	Now
	Delivery Point Performance	7.2.3	Poor delivery point performance at Tillsonburg TS	Now

7.1 Load Restoration

7.1.1 Woodstock Sub-Region: Loss of M31W/M32W

Description

The Woodstock Sub-Region load restoration need was identified in the NA and LP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that in case of loss of two transmission elements (M31W/M32W), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria.

Recommended Plan and Current Status

A local planning report[7] was completed to develop a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

For Woodstock Sub-Region, the critical line section is M31W/M32W tap between Salford Junction and Ingersoll Junction. Should a contingency on this line section occur, all of the sub-region's load, which amounted to 188 MW in 2016, would be interrupted by configuration.

Under such emergency conditions, depending on system performance and availability of switching facilities, all or a portion of a load station could be restored by transferring load to neighbouring unaffected supply. Hydro One Distribution estimated that 10 MW of load at Ingersoll TS could be transferred to Highbury TS. Another 8 MW could be transferred from Commerce Way TS to Tillsonburg TS on the feeder level. On the transmission side, the supply from Brant TS will be able to restore about 20 MW of load in the Woodstock Sub-Region.

These measures can be deployed remotely to manage and mitigate the impact of the loss of two transmission elements within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London Area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.1.2 Greater London Sub-Region: Loss of W36/W37 or W24L/W43L

The Greater London Sub-Region load restoration need was identified in the NA and IRRP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (W36/W37 or W42L/W43L), the load interrupted with the current circuit configuration during peak periods may exceed load restoration criteria.

W36/W37 – Clarke TS and Talbot TS

Description

Clarke TS and Talbot TS are supplied by 230 kV transmission circuits W36/W37 and have a total peak demand of 370 MW. Following the loss of both W36 and W37, supply to Clarke TS and Talbot TS would be interrupted.

[7] Woodstock Restoration Local Planning Report – May 30, 2017

Under such emergency conditions, London Hydro can currently restore up to 55 MW of interrupted load through distribution system transfers within 30 minutes and up to 105 MW within four hours. The interrupted load would be transferred to Wonderland TS, Buchanan TS and Highbury TS during such events. As part of the rebuild of Nelson TS in 2018, the station's LV bus will be converted from 13.8 kV to 27.6 kV. After the conversion, Nelson TS will be able to provide additional backup capacity to support meeting the ORTAC timelines in the event of a double circuit outage. With the new 27.6 kV Nelson TS, a total of 95 MW of load can be restored within 30 minutes, and 150 MW of load within four hours. This reduces the 30 minute shortfall to 25 MW and the four hour shortfall to 71 MW in 2019.

Recommended Plan and Current Status

The Greater London Sub-Region IRRP [8] developed a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

Currently, London Hydro has 28 distribution feeders in total that emanate from Clarke TS and Talbot TS. Only half of these feeders are presently interconnected to other non-Clarke and non-Talbot feeders (i.e., Highbury, Buchanan, and Wonderland TS feeders). Installing approximately 10 additional automated switching devices in strategic locations on the distribution feeders could provide an additional 25 MW of load transfer capability within 30 minutes for Clarke TS and Talbot TS load. These switching devices are estimated to cost approximately $0.6 million.

An additional 10-15 MW of load restoration support for longer-term relief (more than 30 minutes) could be provided by extending the 14 existing Clarke and Talbot feeders to connect with feeders from non-connected neighboring stations. For example, a 3.7 km Talbot feeder line extension to connect to a Wonderland feeder at an approximate cost of $1.2 million could provide support to 10-15 MW of load for the Clarke TS and Talbot TS load pockets.

For a unit cost of $180/kW, the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

These solutions would also maximize the use of existing distribution infrastructure and provide flexibility to London Hydro to manage load between different stations in its service territory.

It is important to note that the feeder capacity margins are not static and will reduce as the 20-year projected load growth at the transformer stations materializes. Hence, the amount of load that can be restored using the distribution system in the event of a double element loss of supply to Clarke TS and Talbot TS will reduce over time. Consequently, part of the recommendation is that London Hydro continues to monitor load growth and relevant feeder limits in its service territory. The Working Group recommends the actions described below to meet the restoration need identified for the Greater London

[8] Greater London Sub-Region, Integrated Regional Resource Plan – January 20, 2017

Sub-region. Successful implementation of this plan will substantially address the restoration need in this sub-region for the next decade.

W42L/W43L – Buchanan TS

In case of loss of theW42L/W43L transmission lines, the load supplied from Buchanan TS which reaches slightly over 150 MW would be interrupted by configuration.

Under such emergency conditions, London Hydro can transfer any interrupted load in excess of 150 MW to adjacent stations within the service area. These measures to manage and mitigate the impact of the equipment loss can be deployed within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.2 Aylmer-Tillsonburg Sub-Region: Voltage/Thermal Constraint & Delivery Point Performance

The Aylmer-Tillsonburg Sub-Region is primarily supplied by a single 115 kV transmission circuit W8T. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T. The Tillsonburg TS voltage constraint and the W8T thermal constraint need was identified in the NA report and further assessment was recommended to address these needs. Following the NA report, the Working Group further identified Delivery Point Performance needs at Tillsonburg TS. These needs are assessed as part of this RIP.

7.2.1 Voltage Constraint

The voltage constraint observed on the 115 kV bus at Tillsonburg TS results from having a long 65 km 115 kV single circuit supply, a large 90 MW Tillsonburg TS load at the end of the transmission line, and a lack of reactive power support at the station to compensate. To mitigate the voltage constraints at Tillsonburg TS, the Working Group considered the following options.

Installation of Shunt Capacitors at Tillsonburg TS

One method to mitigate the voltage constraints at Tillsonburg TS is to provide reactive power compensation at the station. Installation of shunt capacitor banks (2 x 21 Mvar) on the 27.6 kV bus at Tillsonburg TS provides the necessary reactive compensation to meet the ORTAC voltage criteria (113 kV) for the peak load forecast over the study period of 89 MW at Tillsonburg TS. Further, the shunt capacitors are capable of supporting future load growth beyond the study period up to 109 MW – equal to the LTR rating of Tillsonburg TS. These shunt capacitor banks are estimated to cost approximately $8 million.

Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits

Another method to mitigate the voltage constraints at Tillsonburg TS is to reconfigure the 115 kV circuits supplying the Aylmer-Tillsonburg Sub-Region. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the decommissioning of St. Thomas TS is shown in Figure 7-1.

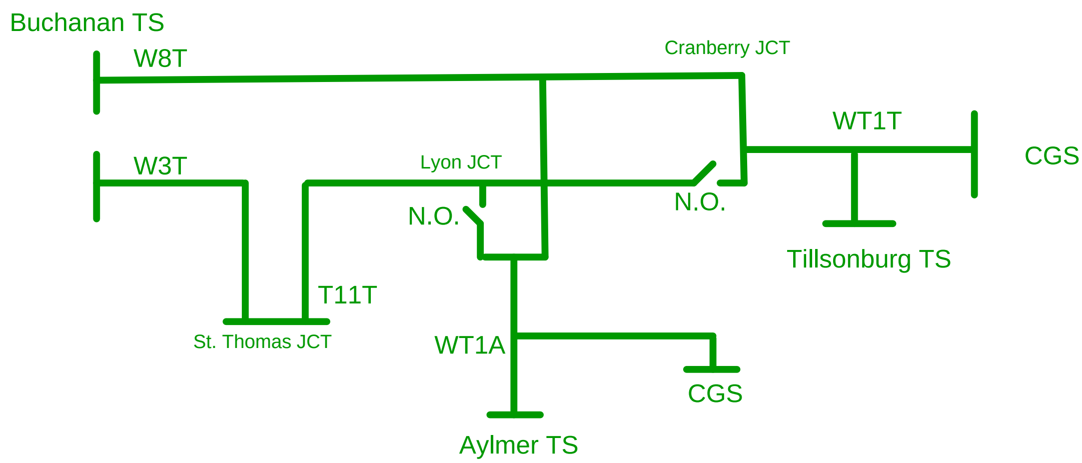


Figure 7-1 Existing Single Line Diagram of Aylmer-Tillsonburg Sub-Region

Aylmer TS and Tillsonburg TS are normally supplied by 115 kV circuit W8T. Reconfiguring the system so that Aylmer TS and Tillsonburg TS are normally supplied by both W8T and T11T reduces the system impedance and improves the voltages in the area. The reconfiguration of the 115 kV system requires installing new switches at Buchanan TS to tie 115 kV circuits W8T and W3T. The "normally open" switches at Lyon JCT and Cranberry JCT will be changed to "normally closed". Lastly the protection relaying at Buchanan TS will require upgrades/modification. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the reconfiguration is shown in Figure 7-2.

The voltages at the Tillsonburg TS 115 kV bus after the reconfiguration improve to 113 kV, meeting the ORTAC voltage criteria for the peak load forecast over the study period. Any further load growth beyond the peak load forecast of 89 MW at Tillsonburg TS will cause the voltage at Tillsonburg TS 115 kV bus to fall below the ORTAC voltage criteria of 113 kV. Similar to the current situation, the transformer ULTCs at Tillsonburg TS can maintain the LV bus voltage above the ORTAC criteria of 27 kV (98% of nominal voltage) for load growth up to 109 MW – equal to the LTR rating of Tillsonburg TS. Reconfiguration of the 115 kV system is estimated to cost approximately $4 million.

While the reconfiguration of the 115 kV system mitigates the voltage constraint need over the study period, it potentially worsens the customer delivery point performance of Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS. Frequency of outages is expected to increase slightly resulting from higher exposure to lightning and wind events. In addition, restoration times are expected to increase slightly due to the incremental switching requirements.

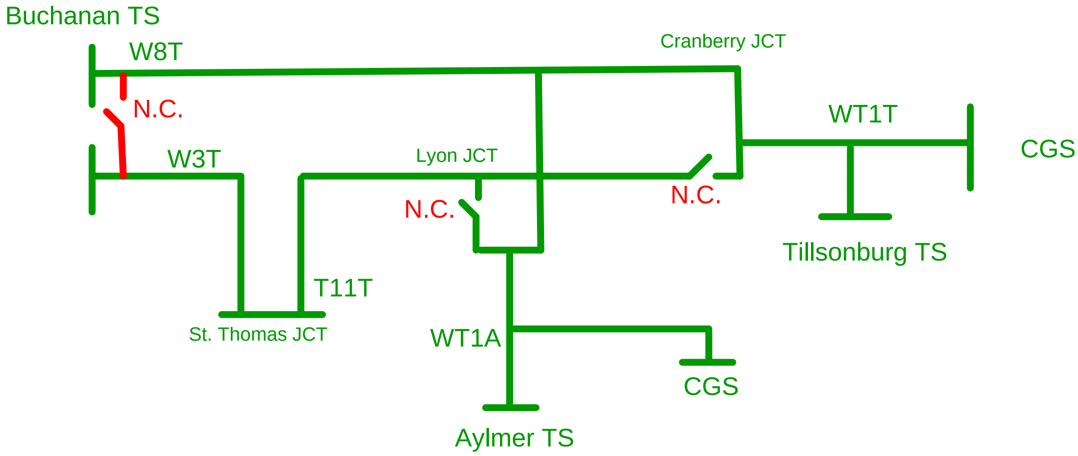


Figure 7-2 Single Line Diagram of Aylmer-Tillsonburg Sub-Region after Reconfiguration

7.2.2 Thermal Constraint

Thermal constraints are observed on a section of line approximately 1.5 km long on 115 kV circuit W8T between Buchanan TS and Edgeware JCT. Under pre-contingency conditions, the thermal loading on this section line reaches 140% of its planning rating of 590A based on the peak load forecast over the study period. Implementing either one of the options in section 7.2.1 to mitigate the voltage constraint at Tillsonburg TS substantially improves the thermal loading on this section line.

Reconfiguring the 115 kV system in the Aylmer-Tillsonburg Sub-Region and installing new switches at Buchanan TS to mitigate the voltage constraint at Tillsonburg TS also mitigates the thermal constraint on circuit W8T.

Installing capacitor banks at Tillsonburg TS reduces the loading on this section of W8T to 106% of its planning rating. As a result, upgrading this section of line would be required to increase the planning to rating to address the thermal overload based on the peak load forecast over the study period. Thirteen poles are required to be replaced at an estimated cost of $1.5 million. This will raise the planning rating of the line to match the other sections of circuit W8T.

A thermal constraint on a section of line approximately 1.5 km long on 115 kV circuit WT1T between Cranberry JCT and Tillsonburg TS was previously identified in the NA report. Tillsonburg Hydro has since provided a revised load forecast and there is no longer an overloading in this section of line.

7.2.3 Customer Delivery Point Performance

The Tillsonburg TS customer delivery point performance need was identified by the Working Group after the NA report was completed. Historical values indicated that the frequency of outages to Tillsonburg Hydro and Hydro One Distribution fall below the standards per Hydro One's "Customer Delivery Point Performance Standard" which is approved by the OEB.

The vast majority of interruptions to Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS results from having only one normal transmission supply to Tillsonburg TS. One method which substantially improves customer delivery point performance is to provide a second transmission circuit to supply Tillsonburg TS. In most situations, a second supply is normally cost prohibitive. Tillsonburg TS however is in a situation where there is an existing backup 115 kV circuit T11T within 3.5 km of the station. A second transmission supply to Tillsonburg TS would require extending 115kV circuit T11T from Cranberry JCT to Tillsonburg TS, HV bus work at Tillsonburg TS and protection relaying modifications and upgrades at Buchanan TS. Providing a second transmission supply to Tillsonburg TS is estimated to cost approximately $16 million.

7.2.4 Aylmer-Tillsonburg Sub-Region Recommended Plan

The Working Group examined various options to address the voltage, thermal and customer delivery point performance needs of the Sub-Region. The needs, options and alternatives are summarized in Tables 7-2, 7-3 and 7-4 respectively.

Table 7-2 Aylmer-Tillsonburg Sub-Region Needs

Need ID	Needs	Timing
I	Voltage constraint at Tillsonburg TS	Existing
II	Thermal constraint on W8T (Buchannan X Edgeware JCT)	Existing
III	Customer Delivery Point Performance below standards at Tillsonburg TS	Existing

Table 7-3 Aylmer-Tillsonburg Sub-Region Need Mitigation Options

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Installation of Shunt Capacitors at Tillsonburg TS	HONI	2021	$8M	I
2	Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits	HONI	2019	$4M	I & II
3	W8T Circuit Upgrade	HONI	2021	$1.5M	II
4	Second transmission circuit supply to Tillsonburg TS	THI & HONI	2021	$16M	II & III

After further assessing the needs in Aylmer-Tillsonburg Sub-Region, the Working Group proposed a number of different options to mitigate the voltage, thermal and customer delivery point performance needs. Due to the complexity of the projects examined, it was determined that further assessment to clarify scope and specifically the cost details is needed. As such, the Working Group recommends Hydro One to pursue Budgetary Cost Estimates in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

Hydro One plans to obtain Budgetary Cost Estimates for the alternatives proposed and provide back the results to the Working Group by Q4 2018 in order to continue the planning activities for the Sub-Region.

Table 7-4 Aylmer-Tillsonburg Sub-Region Alternatives

Alternatives	Benefits/	Total Cost
I	Proceed with Projects I, III and IV -Resolves all three needs in the sub-region	$25.5M
II	Proceed with Project II -Resolves need I & II of the sub-region -Increase in the frequency interruptions at Tillsonburg TS -Lengthens restoration time (slightly) during forced outages -During planned or forced outages to W8T or T11T, switches at Buchanan, Lyon JCT and Cranberry JCT will be opened negating the voltage support effects	$4M
III	Proceed with Projects I and III -Resolves needs I & II in the sub-region	$9.5M

7.3 Long Term Regional Plan

As discussed in Section 5, the electricity demand in the London Area Region is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). Load growth over the long term period is expected to be moderate (up to 1.5%) from 2027 to 2037. 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 London Area Region have been identified at this time. If new needs emerge due to a change in load forecast or any other reason, a new regional planning cycle will be initiated ahead of the 5-year planning cycle.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE LONDON AREA 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	Woodstock Sub-Region load restoration	Now
II	Greater London Sub-Region load restoration	Now
III	Voltage constraint at Tillsonburg TS	Now
IV	Thermal constraint on W8T	Now
V	Poor delivery point performance at Tillsonburg TS	Now
VI	EOL Asset – Wonderland TS transformer T5	2022

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[9]	Mitigated Need ID
1	Distribution System Upgrades in the Greater London Sub-Region	London Hydro Inc.	2023	$1.8-4M ($180/kW)	II
2	Wonderland TS Reinvestment: Replace transformer T5	Hydro One Transmission	2022	$15-20M	VI

Woodstock Sub-Region load restoration need (Need ID I) was assessed by the Working Group during Local Planning and "status quo/do nothing" course of action has been recommended. Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

[9] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

Greater London Sub-Region load restoration need (Need ID II) was further assessed during Integrated Regional Resource Planning and the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

Due to the various needs of the Aylmer-Tillsonburg Sub-Region and the complexity of the options proposed, the Working Group is recommending Budgetary Cost Estimates be completed in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

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 London Area Region

Station Name	Voltage Level	Supply Circuits
Strathroy TS	230/27.6kV	W2S, S2N
Talbot TS	230/27.6kV	W36, W37
Clark TS	230/27.6kV	W36, W37
Wonderland TS	230/27.6kV	N21W, N22W
Buchanan TS	230/27.6kV	W42L, W43L
Nelson TS	115/27.6kV[10]	W5N, W6NL
Longwood TS	230/27.6kV	L24L, L26L
Highbury TS	115/27.6kV	W6NL, W9L
Ingersoll TS	230/27.6kV	M31W, M32W
Woodstock TS	115/27.6kV	K7, K12
Commerceway TS	115/27.6kV	K7, K12
Aylmer TS	115/27.6kV	W8T, T11T, WT1A
Tillsonburg TS	115/27.6kV	W8T, T11T, WT1T
St. Thomas TS	115/27.6kV	W3T, W4T, T11T
Edgeware TS	230/27.6kV	W45LS, W44LC

[10] As part of the Nelson TS rebuild planned to be completed by year end 2018, the low voltage bus is being converted from 13.8 kV to 27.6 kV

Appendix B: Non-Coincident Load Forecast 2016-2025

*Gross Load Forecast - Median Weather

Transformer Station Name	LDC/Customer	DESN 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
Aylmer TS	Hydro One	*T2/T3*	*18.4*	Gross Peak Load				7	7	7	7	7	7	7	7
	Erie Thames			Gross Peak Load				15	19	19	26	27	27	27	28
				DG				0	0	0	0	0	0	0	0
				CDM				0	1	1	1	2	2	2	2
				Net Load Forecast	21	21	21	21	25	25	32	32	32	33	33
Buchanan TS	Hydro One	*T13/T14*	*183*	Gross Peak Load				10	11	11	11	11	11	11	11
	London Hydro			Gross Peak Load				127	144	146	145	147	148	150	151
				DG				1	1	1	1	1	1	1	1
				CDM				2	4	5	6	8	8	9	10
				Net Load Forecast	147	149	143	134	150	151	149	149	150	151	151
Clark TS	Hydro One	*T3/T4*	*110*	Gross Peak Load				14	14	14	14	14	14	15	15
	London Hydro			Gross Peak Load				95	96	97	98	99	93	94	95
				DG				2	3	3	3	3	3	3	3
				CDM				2	2	3	4	5	6	7	7
				Net Load Forecast	107	111	106	105	106	106	106	106	99	100	101
Commerceway TS	Hydro One	*T1/T2*	*112*	Gross Peak Load				38	34	34	34	34	34	34	34
				DG				0	0	0	0	0	0	0	0
								0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	2
				Net Load Forecast	42	33	33	37	33	33	32	32	32	32	32
Edgeware TS	Hydro One	*T1/T2*	*191*	Gross Peak Load				57	57	57	58	59	59	60	60
	London Hydro			Gross Peak Load				1	1	1	1	1	1	1	1
	St. Thomas			Gross Peak Load				52	52	52	52	53	53	53	53
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	5	6	7	7	8
				Net Load Forecast	116	97	98	106	106	106	105	105	105	105	105

Transformer Station Name	LDC/Customer	DESN 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
Highbury TS	Hydro One	*T3/T4*	*114*	Gross Peak Load				6	7	7	7	7	7	7	7
	London Hydro			Gross Peak Load				88	88	89	83	84	91	92	93
				DG				4	4	4	4	4	4	4	4
				CDM				2	2	3	4	5	6	6	7
				Net Load Forecast	92	93	93	88	88	89	82	82	88	88	89
Ingersoll TS	Hydro One	*T5/T6*	*167*	Gross Peak Load				38	38	38	38	38	38	38	38
	Erie Thames			Gross Peak Load				39	40	40	40	40	40	40	40
				DG				6	6	6	6	6	6	6	6
				CDM				1	2	2	3	4	5	5	6
				Net Load Forecast	76	74	75	70	70	69	68	67	67	67	66
Longwood TS	Hydro One	*T13/T14*	*128*	Gross Peak Load				33	33	34	34	35	36	36	37
				DG				0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	3
				Net Load Forecast	39	32	30	32	32	32	33	33	33	34	34
Nelson TS	London Hydro	*T1/T2*	*105*	Gross Peak Load				16	17	15	52	58	59	60	61
				DG				0	0	0	0	15	15	15	15
				CDM				1	1	1	2	2	2	2	2
				Net Load Forecast	45	42	23	16	16	14	50	42	42	43	44
St Thomas TS	St. Thomas	*T3/T4*	*50*	Gross Peak Load				0	0	0	0	0	0	0	0
				DG				0	0	0	0	0	0	0	0
								0	0	0	0	0	0	0	0
				CDM				0	0	0	0	0	0	0	0
				Net Load Forecast	5	1	1	0	0	0	0	0	0	0	0

Transformer Station Name	LDC/Customer	DESN 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
Strathroy TS	Hydro One	*T1/T2*	*50*	Gross Peak Load				15	15	15	16	16	16	16	16
	Entegrus			Gross Peak Load				33	34	34	34	35	35	35	36
				DG				1	1	1	1	1	1	1	1
				CDM				1	1	1	2	3	3	3	4
				Net Load Forecast	44	45	45	46	46	47	46	46	47	47	47
Talbot TS	London Hydro	*T1/T2/T3/T4*	*290*	Gross Peak Load				273	277	282	258	254	256	263	265
				DG				0	0	0	0	0	0	0	0
				CDM				5	7	10	13	14	15	17	18
				Net Load Forecast	242	247	268	268	270	272	245	240	241	246	247
Tillsonburg TS	Hydro One	*T1/T3*	*109*	Gross Peak Load				50	50	51	51	52	53	53	54
	Tillsonburg Hydro			Gross Peak Load				37	38	39	40	41	41	42	42
				DG				0	0	0	0	0	0	0	0
				CDM				2	2	2	4	5	6	6	7
				Net Load Forecast	94	81	88	85	86	87	88	88	89	89	89
Wonderland TS	Hydro One	*T5/T6*	*99*	Gross Peak Load				9	9	9	9	9	9	9	9
	London Hydro			Gross Peak Load				104	90	92	90	92	94	90	92
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	4	5	5	6	7
				Net Load Forecast	109	109	109	110	96	97	94	95	97	92	93
Woodstock TS	Hydro One	*T1/T2*	*87*	Gross Peak Load				68	68	68	69	69	69	69	70
				DG				3	3	3	3	3	3	3	3
				CDM				1	1	2	3	4	4	4	5
				Net Load Forecast	62	55	56	64	64	64	63	62	62	62	62

Appendix C: Coincident Load Forecast 2016-2025

Station	Historical MW	Near Term Forecast (MW)					Medium Term Forecast (MW)		
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aylmer TS	18	18	20	21	22	23	25	27	28
Buchanan TS	126	125	127	129	131	133	135	138	141
Clark TS	96	92	92	91	90	89	88	87	88
Commerceway TS	25	24	23	23	22	21	21	20	20
Edgeware TS	105	103	103	103	102	102	102	102	102
Highbury TS	77	72	72	72	72	71	71	71	71
Ingersoll TS	70	63	63	62	61	60	60	60	59
Longwood TS	31	30	30	31	31	31	31	31	32
Nelson TS	16	16	16	14	50	42	42	43	44
St Thomas TS	0	0	0	0	0	0	0	0	0
Talbot TS	267	261	257	253	249	247	245	242	240
Tillsonburg TS	91	91	92	92	92	92	93	94	95
Wonderland TS	103	98	97	94	92	89	88	85	83
Woodstock TS	58	54	54	54	53	53	53	52	52

Appendix D: 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

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Peterborough to Kingston Region

Regional Infrastructure Plan ("RIP")

July 8th, 2016

Kingston Hydro
Hydro One Networks Inc. (Distribution)

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County.

The Needs Assessment ("NA") report for the Peterborough to Kingston region was completed in February, 2015 (see attached). The report concluded that there were only two needs in the region and that they should be addressed as follows:

a) Transformation capacity relief for Gardiner TS T1/T2 DESN1: to be addressed by a Local Plan ("LP").
b) Loading constraints on circuit Q6S: to be addressed by Bulk System Planning and not as part of Regional Planning.

An LP was undertaken by Hydro One Networks Inc. (Transmitter), Hydro One Networks Inc. (Distribution) and Kingston Hydro to address the transformation capacity relief for Gardiner TS T1/T2 DESN1 . The LP recommended re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. The estimated cost of this project is approximately $1.5M. An LP report was prepared and published by the Working Group for the Peterborough to Kingston region in October, 2015 (also attached).

There are no other major development projects planned for the Peterborough to Kingston Region over the near and mid-term

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the ("RIP") for the Sudbury/Algoma Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2014) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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NEEDS ASSESSMENT REPORT

Region: Peterborough to Kingston

Revision: Final
Date: February 10, 2015

Prepared by: Peterborough to Kingston Region Study Team

Peterborough to Kingston Region Study Team	
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Kingston Hydro	Thomas Brackenbury
Peterborough Distribution Inc.	Jeff Guilbeault
Hydro One Networks Inc. (Distribution)	Ashley LeBel

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment 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 Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Peterborough to Kingston Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	December 12, 2014	**END DATE**	Feb 10, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Peterborough to Kingston Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This NA included a study of transmission system connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Peterborough to Kingston Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.
- Under high Transfer East of Cherrywood and low water conditions in the east, P15C may be loaded near its continuous rating under pre-contingency conditions. This issue will be further assessed by the IESO as part of bulk system planning.

C. 115kV Transmission Lines

- With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S may reach its LTE ratings in the near term based on the gross load forecast. The net load in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.
- The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
- With the loss of 230 kV circuits P15C and C27P and expected load additional loading in Renfrew area in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue will be further assessed by the IESO as part of bulk system planning.

D. 230 kV and 115 kV Connection Facilities

- Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast with planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted load over the study period. It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region. Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of two elements, the load interrupted by configuration may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, the load interrupted by configuration does not exceed 150 MW. No action is required at this time.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace major equipment do not affect the needs identified.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that

- "localized" wires only solutions be developed in the near-term to adequately and efficiently address the needs associated with transformation capacity relief for Gardiner TS T1/T2 DESN1 as indicated above through planning between Hydro One Networks Inc. and the impacted distributors. See Section 7 for further details, and
- IESO to assess loading constraints on circuit Q6S for the loss of two elements, and P15C under high transfers as part of their bulk system planning

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Peterborough to Kingston Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Peterborough to Kingston Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the Peterborough to Kingston Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the IESO.

Table 1: Study Team Participants for Peterborough to Kingston Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
3.	Independent Electricity System Operator ("IESO")
4.	Kingston Hydro Corporation ("Kingston Hydro")
5.	Peterborough Distribution Inc. ("Peterborough Distribution")
6.	Veridian Connections Inc. ("Veridian")
7.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Peterborough to Kingston Region over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station and line thermal capacity and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Peterborough to Kingston Region Description and Connection Configuration

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The boundaries of the Peterborough to Kingston Region are shown below in Figure 1.

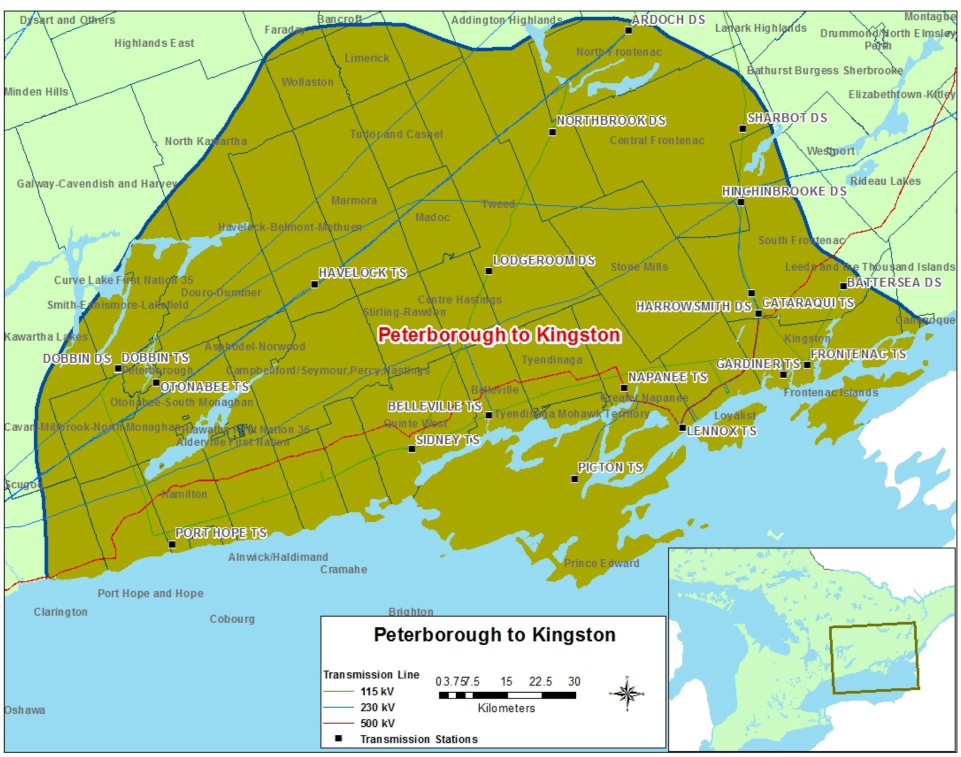

Figure 1: Peterborough to Kingston Region Map

Electrical supply to the Peterborough to Kingston Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS. There are ten Hydro One step-down TS's, eight high voltage distribution stations (HVDS), and five other direct transmission connected load customers in the Region. The distribution system consists of voltage levels 44 kV, 27.6 kV, 12.5 kV, 8.32kV, and 4.16kV. The main generation facility in the Region is the 2000 MW Lennox Generation Station (GS) connected to Lennox TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS.

- Five Customer Transformer Stations (CTS) are supplied in the Region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

- There are 3 existing Transmission connected generating stations in the Region as follows:
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS

- A 910 MW gas-fired plant (Napanee GS) is expected to connect to Lennox TS at the 500kV level in 2018.

- Up to 535 MW of additional transmission connected renewable generation could be in service in the Region by the year 2023.

- There are a network of 230 kV and 115 kV circuits that provide supply to the Region, as shown in Table 2 below:

Table 2: Transmission Lines in Peterborough to Kingston Region

Voltage	Circuit Designations	Location
230 kV	X1H, X2H, X3H, X4H	Hinchinbrooke SS to Lennox TS
	X21, X22	Picton TS to Lennox TS
	H23B	Belleville TS to Hinchinbrooke SS
	H27H	Hinchinbrooke SS to Havelock TS
	X1P	Dobbin TS to Chenaux TS
	C27P	Dobbin TS to Chat Falls GS
	H24C, H26C	Cherrywood TS to Havelock TS
	C28C	Cherrywood TS to Chat Falls GS
	P15C	Cherrywood TS to Dobbin TS
	B23C	Cherrywood TS to Belleville TS
115 kV	P3S, P4S	Dobbin TS to Sidney TS
	Q6S	Cataraqui TS to Sidney TS
	B1S	Barrett Chute TS to Sidney TS
	Q3K	Cataraqui TS to Frontenac TS
	B5QK	Cataraqui TS to Frontenac TS to Barrett Chute TS

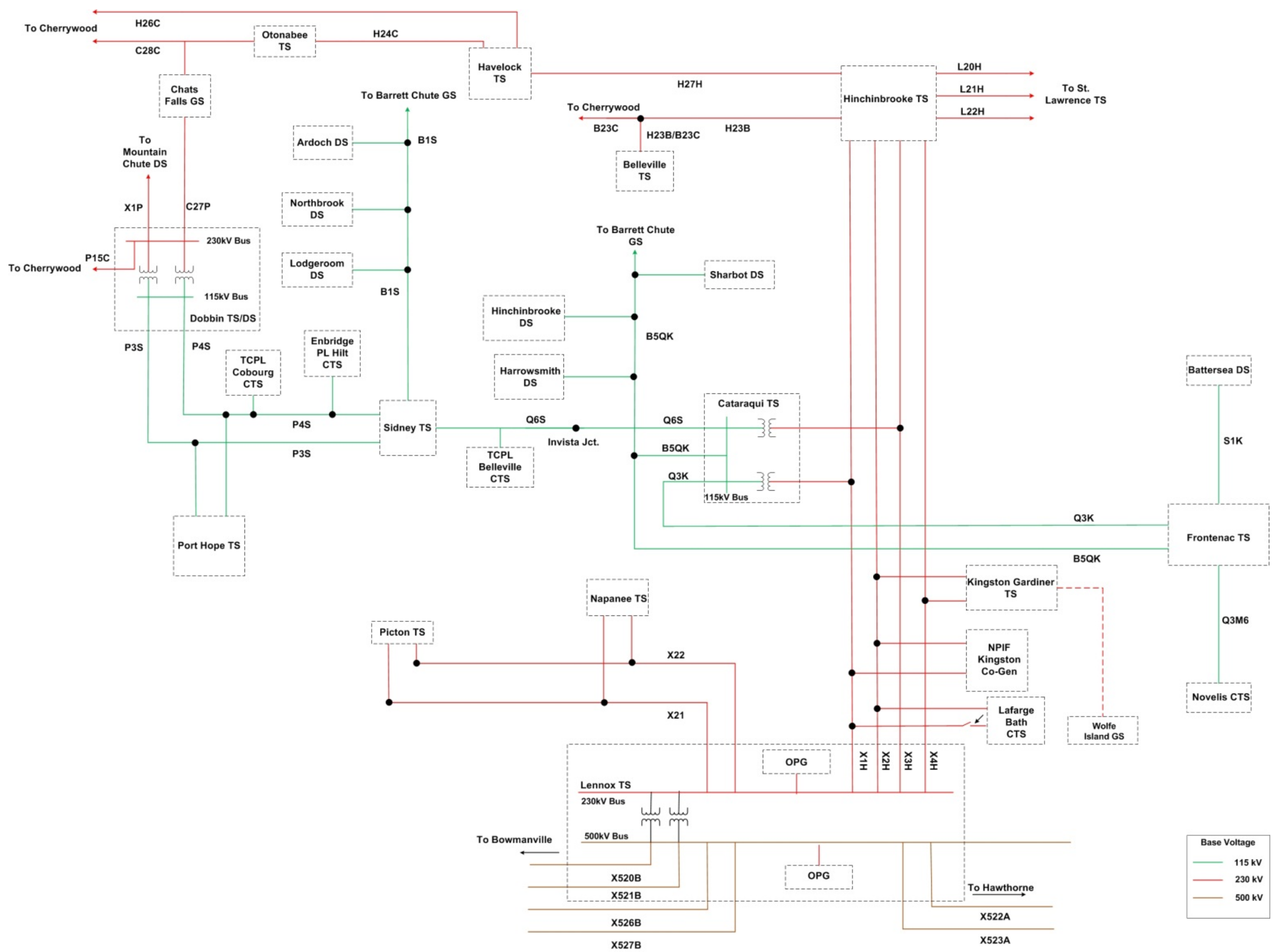

Figure 2: Single Line Diagram – Peterborough to Kingston Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical 2013 regional coincident peak load and station non-coincident peak load
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load, and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Gross Load Forecast

As per the data provided by the study team, the gross load in the Peterborough to Kingston Region is expected to grow at an average rate of approximately 0.4% annually from 2014-2023.

4.2 Net Load Forecast

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.6% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region consists of both winter and summer peaking stations. Therefore, this assessment is based on both winter and summer peak loads, as appropriate.

2. Forecast loads are provided by the Region's LDCs. LaFarge Canada had provided a load forecast for LaFarge Canada CTS. Load data was not received by the other industrial customers in the region (Enbridge Pipeline Inc, TransCanada Pipeline Ltd.). For these stations, the load was assumed to be consistent with historical loads.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer/winter peak load as a reference point.

4. The 2013 summer/winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred.

   A coincident version of the gross and net load forecast was used to assess the transformer capacity needs (section 6.1.1), 230 kV transmission line needs (section 6.1.2), 115 kV transmission line needs (6.1.3) and system reliability operation and restoration needs (6.2).

   A non-coincident version of the gross and net load forecast was used to assess the station capacity as presented in section 6.1.4.

   A coincident peak load forecast and a non-coincident peak load forecast were produced for each gross load and net load forecasts.

6. Review impact of any on-going and/or planned development projects in the Region during the study period.

7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.

8. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer or winter 10-Day Limited Time Rating (LTR), as appropriate.

9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer or winter 10-Day LTR, as appropriate.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) (Section 4.2) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC (Section 7.2) criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Peterborough to Kingston Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high Transfer East of Cherrywood and low water conditions in Eastern Ontario, the 230 kV circuit P15C may be loaded near its continuous rating under pre-contingency conditions. This issue should be further assessed by the IESO as part of bulk system planning.

6.1.3 115kV Transmission Lines

With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S from Invista Jct to Sidney TS may reach its LTE rating in the near term based on the gross load forecast. The net load forecast in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

With the loss of 230 kV circuits P15C and C27P and expected additional loading in the Renfrew region in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue should be further assessed by the IESO as part of bulk system planning.

The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs and HVDSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

Gardiner TS

Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted demand over the study period.

It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

All the other TSs and HVDSs in the Region are forecasted to remain within their normal supply capacity during the study period. Therefore, no action is required at this time and the capacity needs will be reviewed in the next planning cycle.

6.2 System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region.

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of circuits X2H and X4H, the load interrupted by configuration at Gardiner TS may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, which accounts for CDM and DG, the load interrupted by configuration does not exceed 150 MW. Therefore, no action is required at this time and this will be reviewed in the next planning cycle.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.

During the study period:

- Replacement (like-for-like) of both transformers (T1 and T2) at Gardiner TS DESN1 is scheduled in 2020. The replacement plan does not affect the results of this NA study.

- Replacement of two autotransformers, T2 and T5 (78 MVA and 115 MVA respectively), at Dobbin TS with a single 150/250 MVA autotransformer is scheduled in 2019. The third autotransformer (T1) will remain the same. The replacement plan does not affect the results of this NA study.

- There are no significant lines sustainment plans that will affect the results of this NA study.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required.

Rather the study team recommends the following to address the identified needs:

a) Hydro One transmission will lead the assessment and develop a local plan ("Gardiner TS Load Balancing") with the relevant LDCs to balance load between the two DESNs at Gardiner TS; and,

b) IESO to assess and develop a plan for the contingencies associated with circuit Q6S for the loss of two elements and loading constraints on circuit P15C under high transfers within the context of a bulk planning study for the area.

8 NEXT STEPS

Hydro One Transmission and impacted LDCs will address the recommendation in Section 7a and develop a local plan.

IESO to initiate a bulk planning study for the area.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
IESO	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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GARDINER TS LOAD BALANCING

Region: Peterborough to Kingston

Revision: FINAL
Date: October 7, 2015

Prepared by: "Peterborough to Kingston" Region Local Planning Study Team

Peterborough to Kingston Region Local Planning Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Peterborough to Kingston (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	April 10, 2015	**END DATE**	October 7, 2015

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

2. LOCAL NEED ADDRESSED IN THIS REPORT

The Needs Assessment (NA) report for the Peterborough to Kingston Region indicated that Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity in the near term. Gardiner TS T3/T4 DESN2 is lightly loaded. The local need addressed in this report will be how to best alleviate the station capacity issue at Gardiner TS T1/T2 DESN1.

3. ALTERNATIVES CONSIDERED

The alternatives considered were:

1) Transfer load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN
2) Do Nothing

4. PREFERRED ALTERNATIVE

Transferring load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the preferred alternative as it addresses the station capacity issue at Gardiner TS T1/T2 DESN1. Transferring some of the existing load at Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the most straight forward and cost effective option.

5. RECOMMENDATIONS

Hydro One Distribution will proceed with a detailed estimate for the load transfer work at Gardiner TS. The detailed estimate for the load transfer work is expected to be completed mid-2016. The expected in-service date for this work is end of 2018.

Table of Contents

1 Introduction

The Needs Assessment (NA) for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 Regions is complete and will be initiated for Group 3 Regions later this year. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015. The NA for the Peterborough to Kingston Region was prepared jointly by the study team, including Local Distribution Companies (LDC), Independent Electric System Operator (IESO), Ontario Power Authority (merged with IESO as of January 2015 and herein referred to as IESO), and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Peterborough to Kingston Region over the next ten years (2014 to 2023) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

This report was prepared by the Peterborough to Kingston Region LP study team (Table 1) and led by the transmitter, Hydro One Networks Inc. (Hydro One). The report captures the results of the assessment based on information provided by LDCs and Hydro One.

Table 1: Study Team Participants for Peterborough to Kingston Region

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

2 Regional Description

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. Please refer to the NA Report for further details. The Peterborough to Kingston Region and its approximate boundaries are shown in Figure 1. The facilities in the Region are depicted in the single line diagram shown in Figure 2.

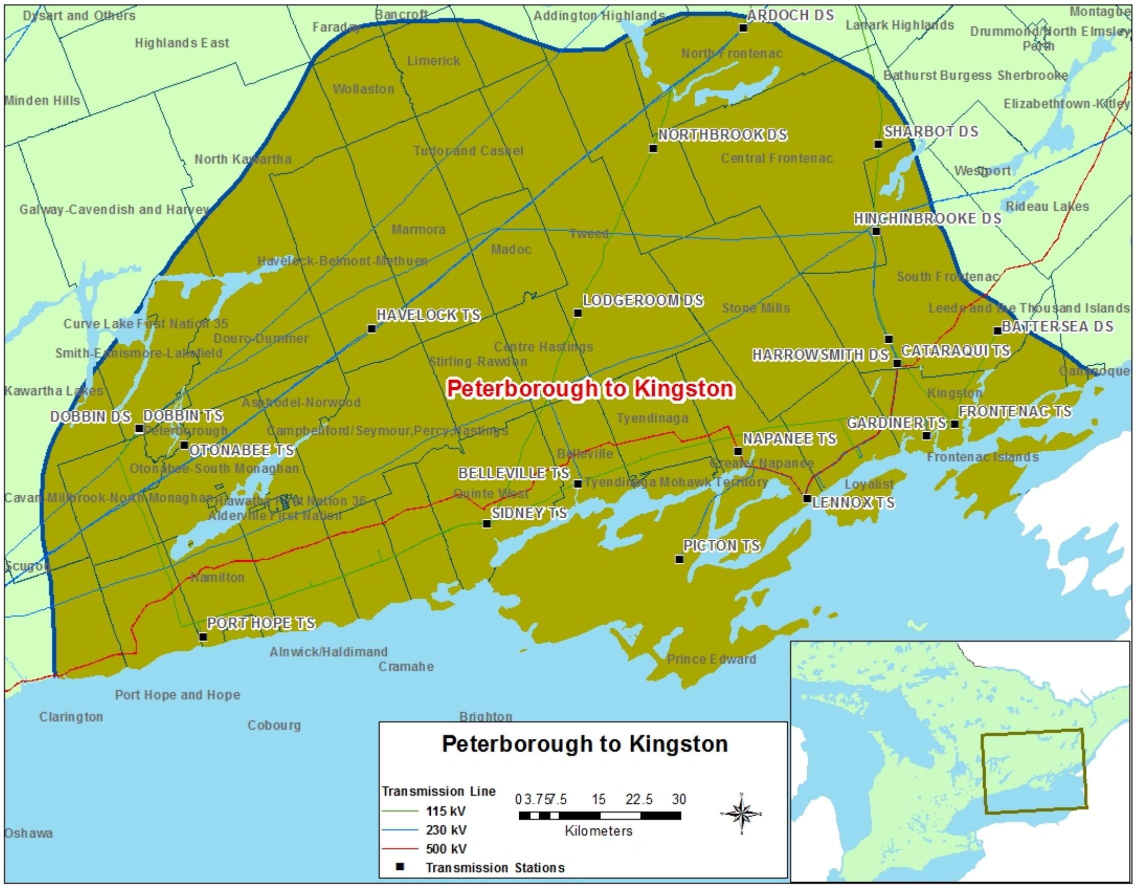

Figure 1: Peterborough to Kingston Region Map

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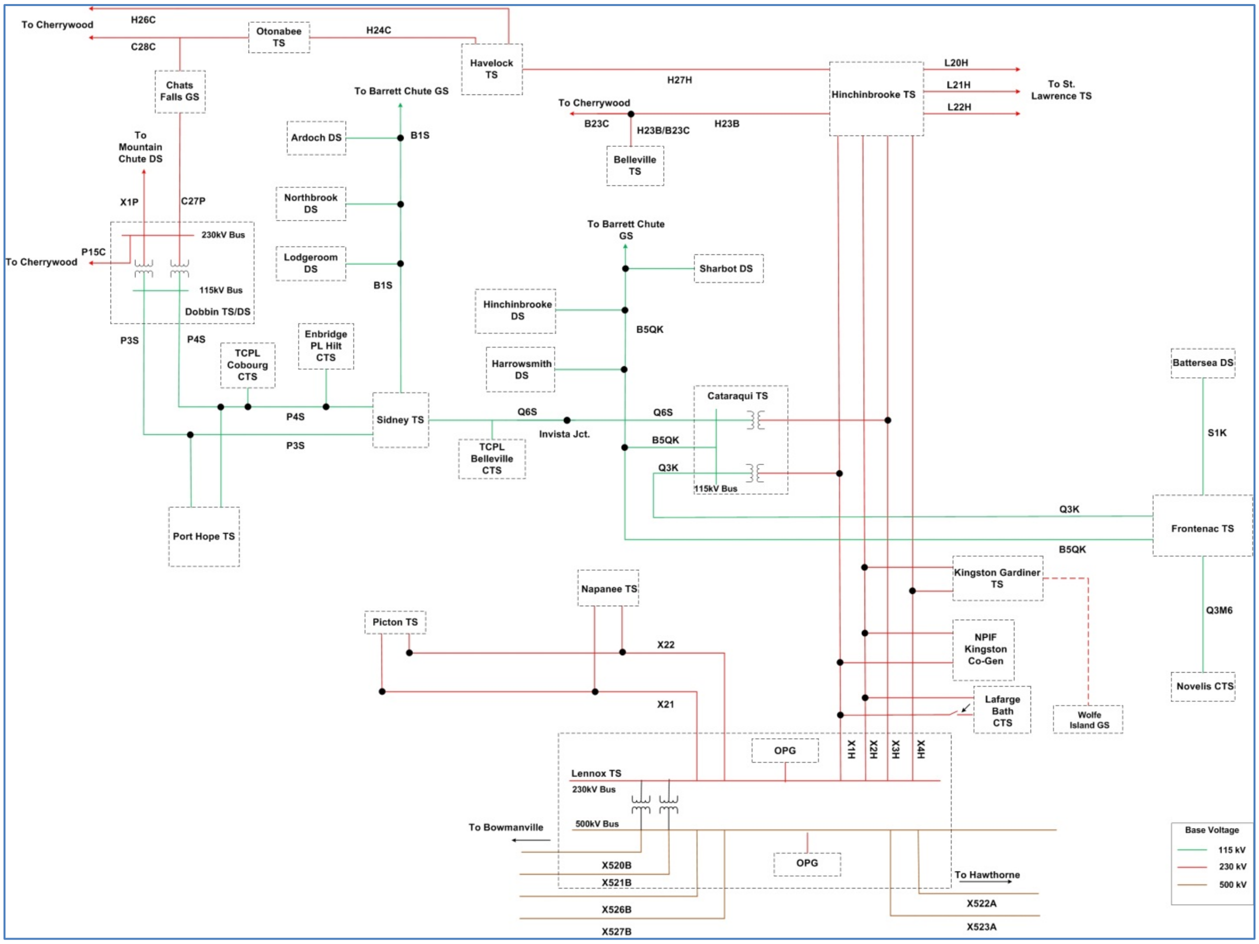

Figure 2: Single Line Diagram – Peterborough to Kingston Region

3 Peterborough to Kingston Region Needs

As an outcome of the NA process, the study team identified a need to address the normal supply capacity at Gardiner TS T1/T2 DESN1. Since this need can be clearly addressed by a straightforward wires solution, the study team agreed that it should be further planned directly by the impacted LDC and the transmitter through the LP process and that further coordinated regional planning was not required. Hydro One with the impacted LDCs further undertook planning assessments to develop options and recommend a wires only solution(s). Gardiner TS (230/44 kV)

3.1 Gardiner TS (230/44kV)

Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast which takes planned CDM targets and DG contributions into consideration, this issue will be avoided. Nevertheless, the station will still be loaded at 100% of its thermal capacity at that time. The load forecast provided by LDCs and the CDM and DG forecast provided by the IESO are attached in Appendix A.

4 Options Considered

This section describes the options considered to address the local need described in section 3.1.

4.1 Gardiner TS Load Balancing

Prior to the regional planning process, Hydro One Distribution had already planned on re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. This would alleviate the loading concerns at Gardiner TS T1/T2 DESN1 for this study period. The preliminary budgetary cost estimate for this project is about $1.5M.

4.2 Do Nothing

Do nothing is not a viable option since it could result in the violation of transformer ratings at Gardiner TS T1/T2 DESN1, which is not acceptable.

5 Recommendation

The study team agreed that transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 would relieve the thermal loading at Gardiner TS T1/T2 DESN1. This is a cost effective solution that will ensure that any additional load growth during the study period at Gardiner TS can be accommodated without exceeding the station thermal limit. Hydro One Distribution will be proceeding with the development of a plan to transfer the load along with a cost estimate for the work by the end of 2015. The expected in-service date for this feeder load transfer is end of 2018.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

iii) Peterborough to Kingston Region Needs Assessment Report

Appendix A: Load Forecast for Peterborough to Kingston Region

Table A1: Gross Load Forecast (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Battersea DS T1/T2	9.4	9.4	9.4	9.4	9.3	9.2	9.1	9.1	9.0	9.0
Belleville TS T1/T2	141.5	131.7	131.4	131.1	130.8	129.8	128.7	128.6	128.3	128.0
Dobbin DS T1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Dobbin DS T2	6.3	6.2	6.2	6.2	6.2	6.2	6.1	6.1	6.1	6.1
Dobbin TS T3/T4	83.5	83.2	83.0	83.0	82.7	81.6	80.5	80.3	79.9	79.5
Frontenac TS T3/T4	100.8	101.5	102.3	103.3	104.0	103.8	103.6	104.4	105.0	105.5
Gardiner TS T1/T2	125.3	124.9	124.8	125.2	124.8	122.9	121.2	120.9	120.4	119.8
Gardiner TS T3/T4	15.8	15.8	15.9	15.9	16.0	15.8	15.7	15.7	15.7	15.7
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Havelock TS T1/T2	63.5	63.3	63.2	63.2	63.1	62.4	61.8	61.7	61.5	61.3
Hinchinbrooke DS T1	6.5	6.5	6.5	6.5	6.5	6.4	6.4	6.3	6.3	6.3
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3
Lodgeroom DS T2	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1
Napanee TS T1/T2	55.1	52.6	52.5	53.1	53.3	53.0	52.7	53.1	53.4	53.6
Northbrook DS T1	6.8	6.8	6.8	6.8	6.8	6.8	6.7	6.7	6.7	6.6
Otonabee TS T1/T2	43.6	43.4	43.1	43.1	42.9	42.4	41.9	41.7	41.5	41.3
Otonabee TS T1/T2	84.3	83.8	83.4	83.4	83.0	81.8	80.8	80.5	80.0	79.6
Picton TS T1/T2	54.6	46.4	46.6	47.0	47.2	46.8	46.4	46.7	46.8	46.9
Port Hope TS T1/T2	53.1	49.7	49.3	49.4	49.4	48.9	48.5	48.5	48.4	48.3
Port Hope TS T3/T4	64.1	63.4	63.2	63.2	63.0	62.1	61.3	61.1	60.9	60.6
Sharbot DS T1	4.3	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.2
Sidney TS T1/T2	64.1	63.9	63.8	64.0	63.9	63.1	62.4	62.4	62.2	62.1
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A2: Net Load Forecast (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Battersea DS T1/T2	10.0	10.0	10.1	10.1	10.1	10.1	10.2	10.2	10.2	10.2
Belleville TS T1/T2	148.9	149.3	149.6	149.9	150.3	150.6	150.9	151.3	151.6	152.0
Dobbin DS T1	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2
Dobbin DS T2	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.6	6.6	6.6
Dobbin TS T3/T4	84.3	84.6	84.9	85.3	85.6	85.9	86.2	86.5	86.8	87.1
Frontenac TS T3/T4	106.2	107.6	108.9	110.3	111.7	113.0	114.4	115.8	117.2	118.5
Gardiner TS T1/T2	140.5	141.3	142.2	143.1	143.7	144.3	144.9	145.5	146.1	146.7
Gardiner TS T3/T4	16.0	16.1	16.2	16.4	16.5	16.6	16.8	16.9	17.1	17.2
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Havelock TS T1/T2	64.0	64.2	64.4	64.6	64.9	65.1	65.3	65.5	65.7	66.0
Hinchinbrooke DS T1	6.6	6.6	6.6	6.7	6.7	6.7	6.7	6.7	6.8	6.8
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4
Lodgeroom DS T2	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Napanee TS T1/T2	71.1	72.0	72.8	73.6	74.4	75.2	76.0	76.9	77.7	78.5
Northbrook DS T1	6.9	6.9	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.2
Otonabee TS T1/T2	45.5	45.6	45.7	45.8	45.9	46.0	46.1	46.1	46.2	46.3
Otonabee TS T1/T2	88.0	88.2	88.3	88.5	88.6	88.8	88.9	89.0	89.2	89.3
Picton TS T1/T2	55.1	55.7	56.3	56.9	57.5	58.2	58.8	59.4	60.0	60.6
Port Hope TS T1/T2	53.7	54.0	54.3	54.5	54.8	55.1	55.4	55.7	56.0	56.3
Port Hope TS T3/T4	64.7	65.0	65.3	65.5	65.8	66.1	66.4	66.6	66.9	67.2
Sharbot DS T1	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5
Sidney TS T1/T2	77.3	77.7	78.0	78.3	78.7	79.0	79.3	79.7	80.0	80.3
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A3: Conservation Demand Management (Percent of Gross Load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
EE programs	0.5%	0.8%	1.0%	1.1%	1.3%	2.1%	3.1%	3.2%	3.6%	4.2%
Total	1%	1%	2%	2%	3%	4%	5%	6%	6%	7%

Table A4: Distributed Generation (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Battersea DS T1/T2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Belleville TS T1/T2	6.7	16.2	16.2	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Dobbin DS T1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dobbin DS T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Frontenac TS T3/T4	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Gardiner TS T1/T2	13.8	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Lodgeroom DS T1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lodgeroom DS T2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Napanee TS T1/T2	15.5	18.3	18.7	18.7	18.9	18.9	18.9	18.9	18.9	18.9
Otonabee TS T1/T2	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Otonabee TS T1/T2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Picton TS T1/T2	0.0	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Port Hope TS T1/T2	0.2	3.5	3.9	3.7	4.0	4.0	4.0	4.0	4.0	4.0
Port Hope TS T3/T4	0.0	0.46	0.52	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sidney TS T1/T2	12.7	12.	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7

South Georgian Bay/Muskoka

REGIONAL INFRASTRUCTURE PLAN

August 18th, 2017

hydro one

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

With support from:

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

DISCLAIMER

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

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

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

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EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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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.

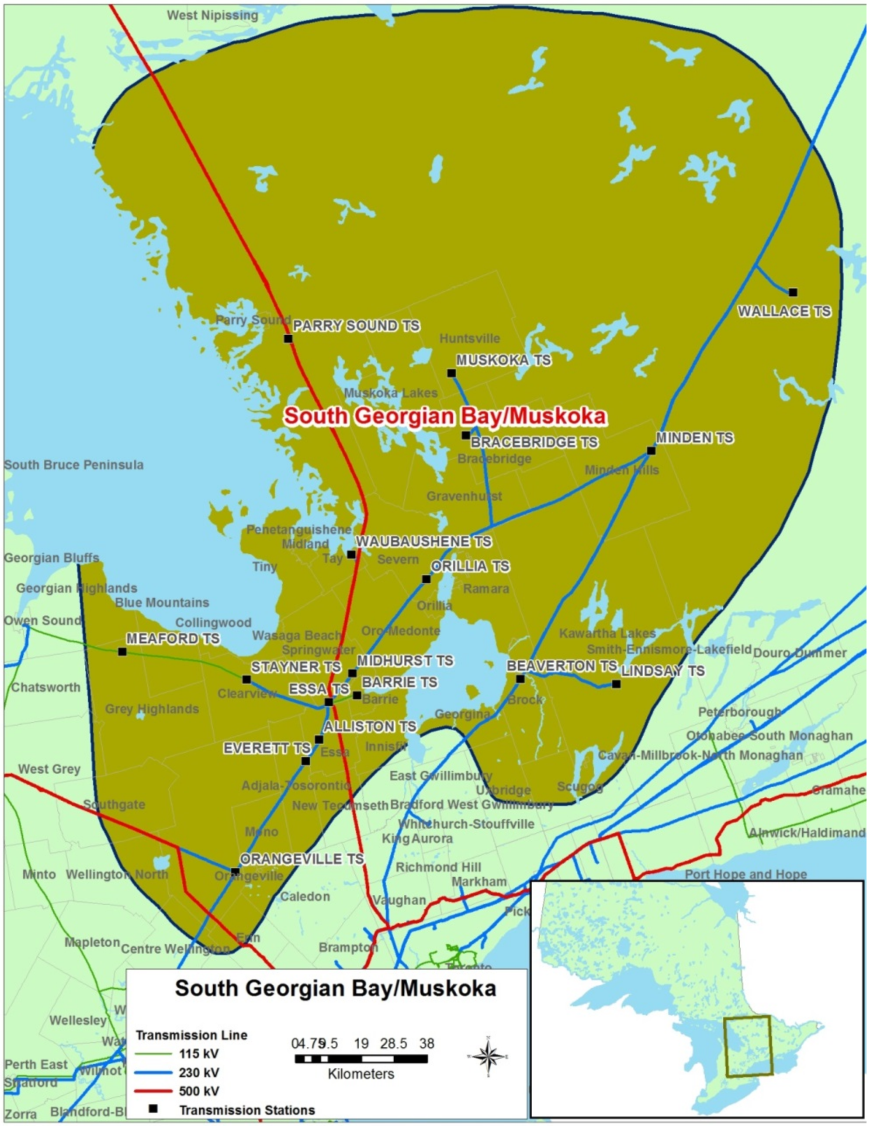

Figure 1-1 South Georgian Bay/Muskoka Region

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.

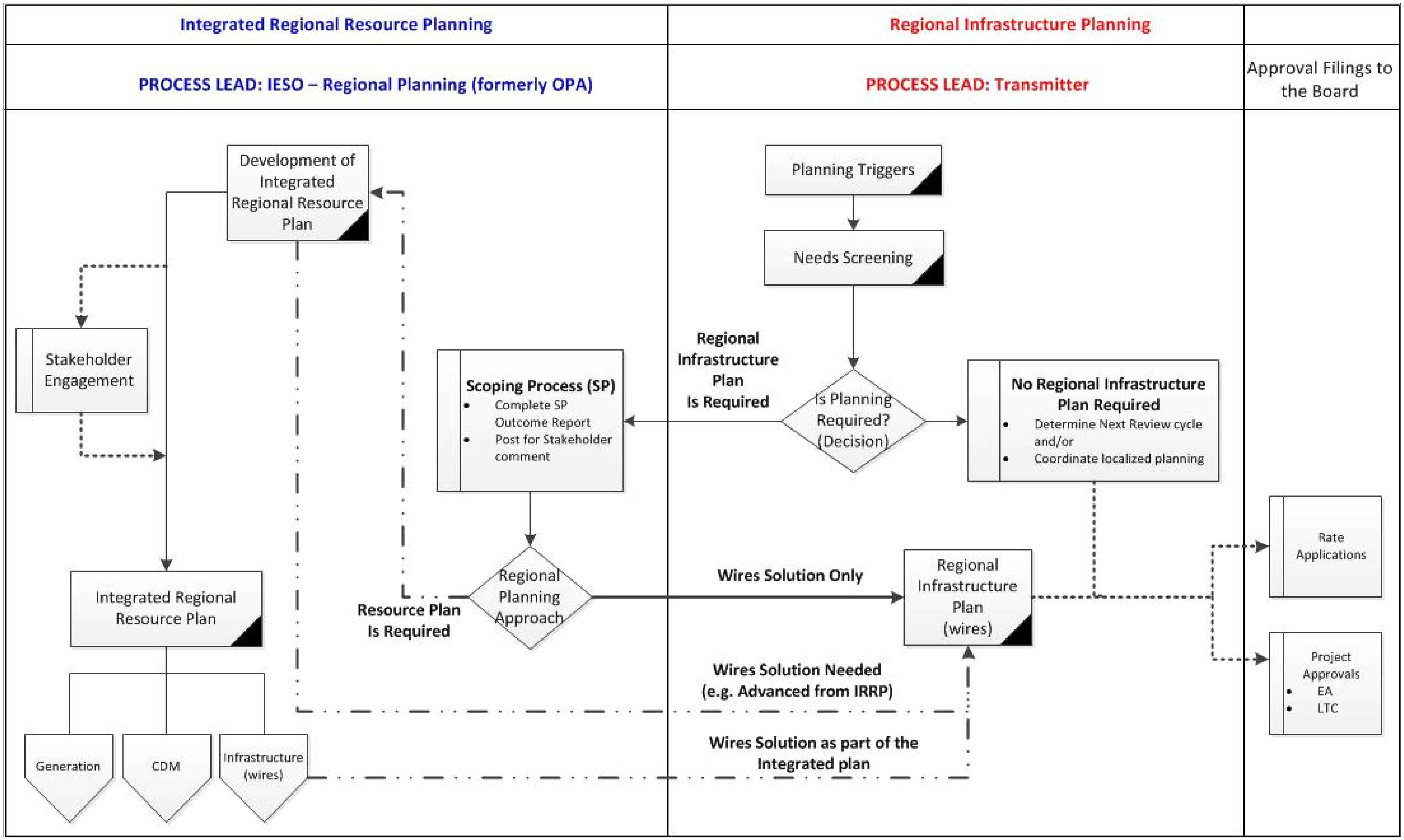

Figure 2-1 Regional Planning Process Flowchart

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 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.

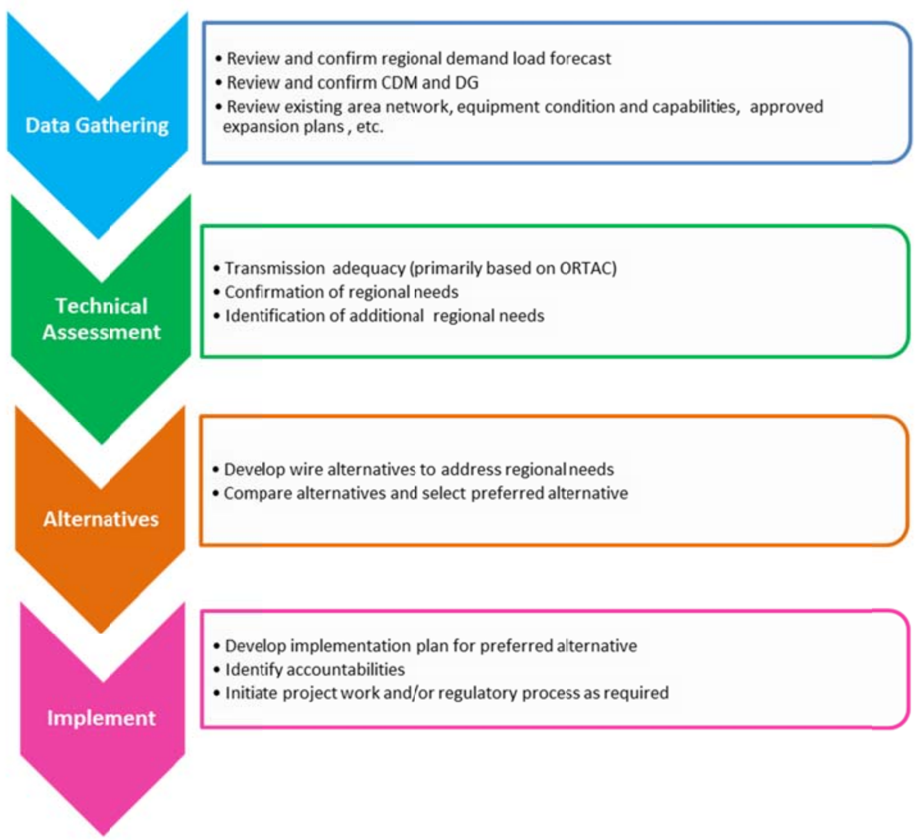

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE 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.

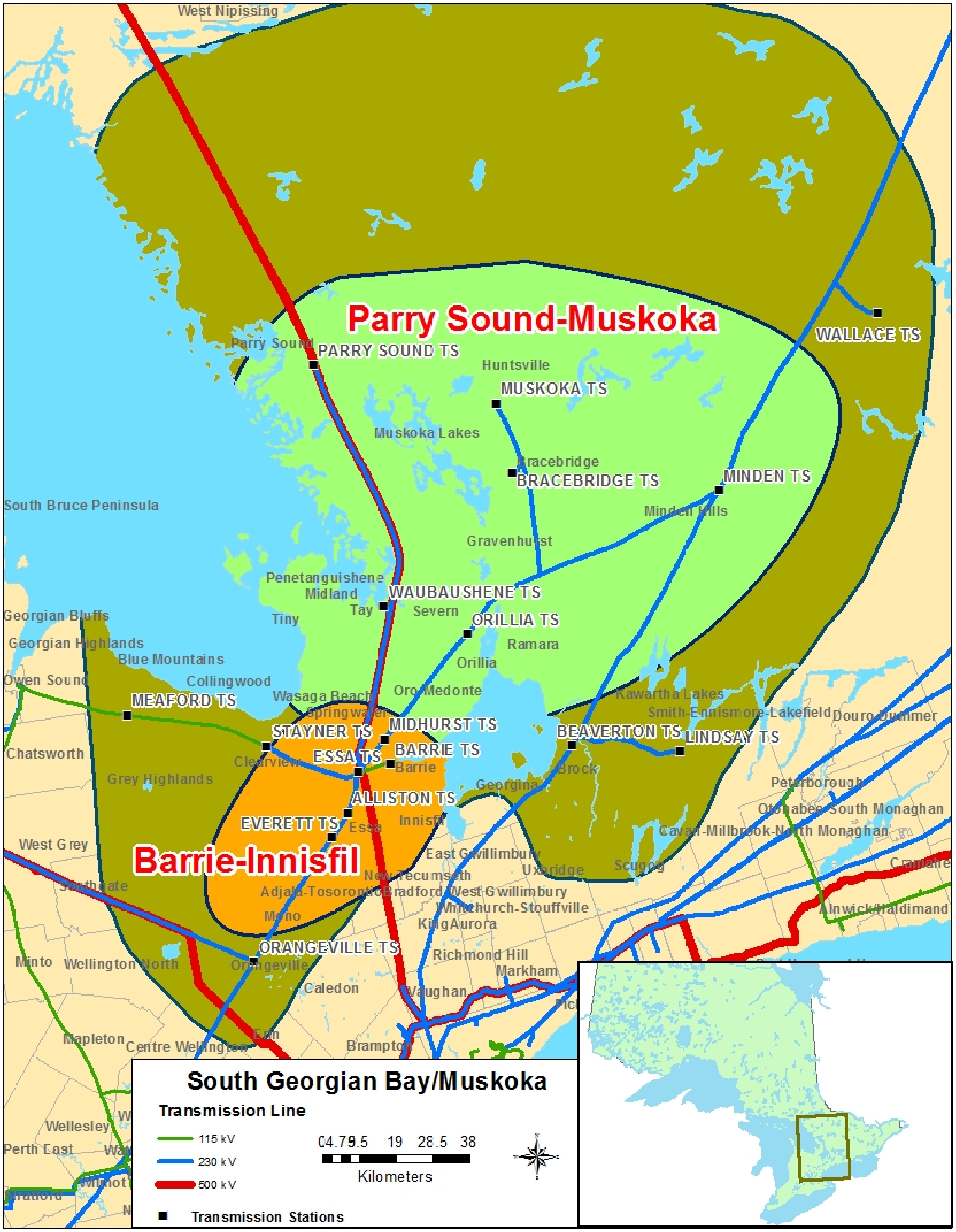

Figure 3-1 South Georgian Bay/Muskoka – Supply Areas

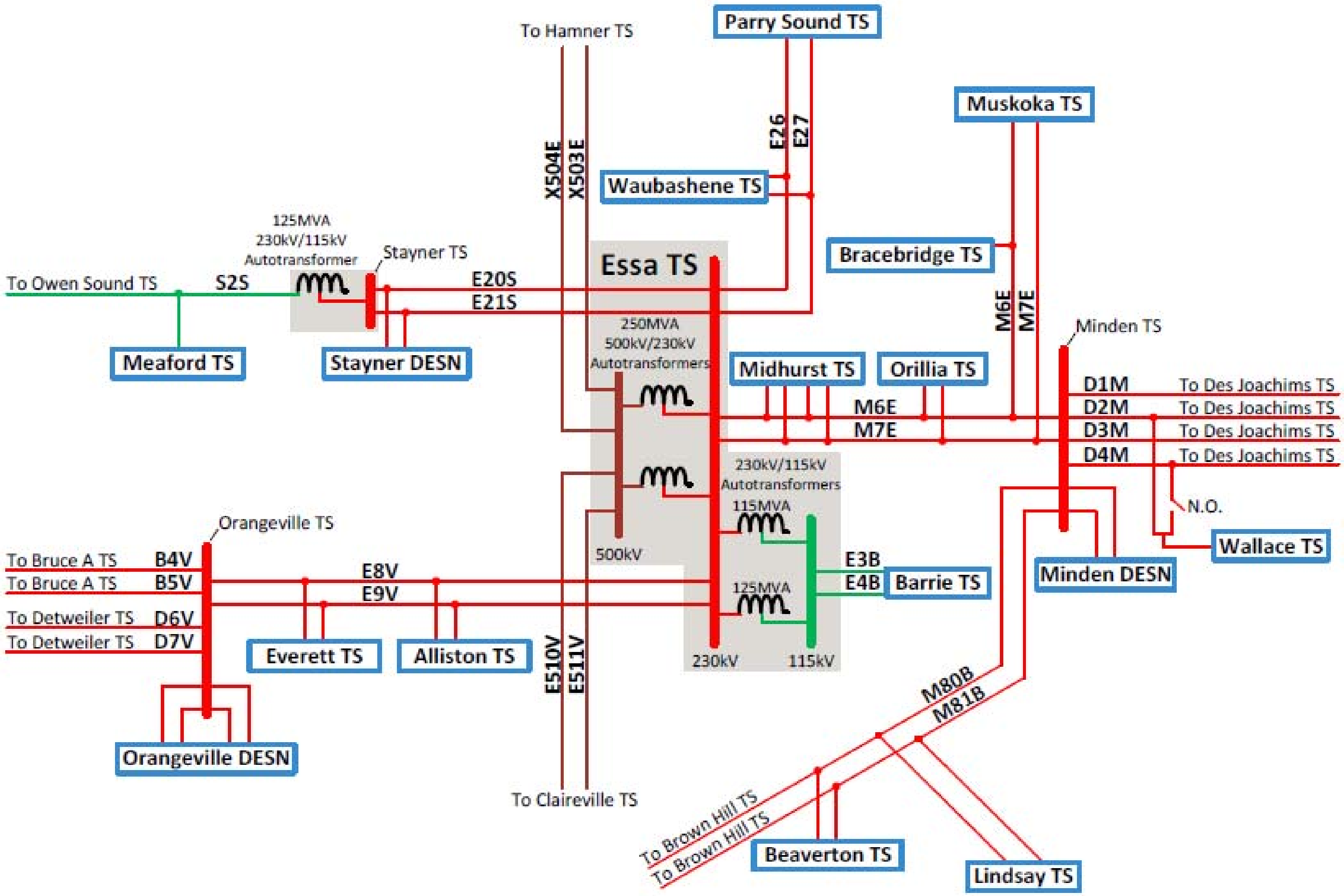

Figure 3-2 South Georgian Bay/Muskoka Region Single Line Diagram (Current)

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.

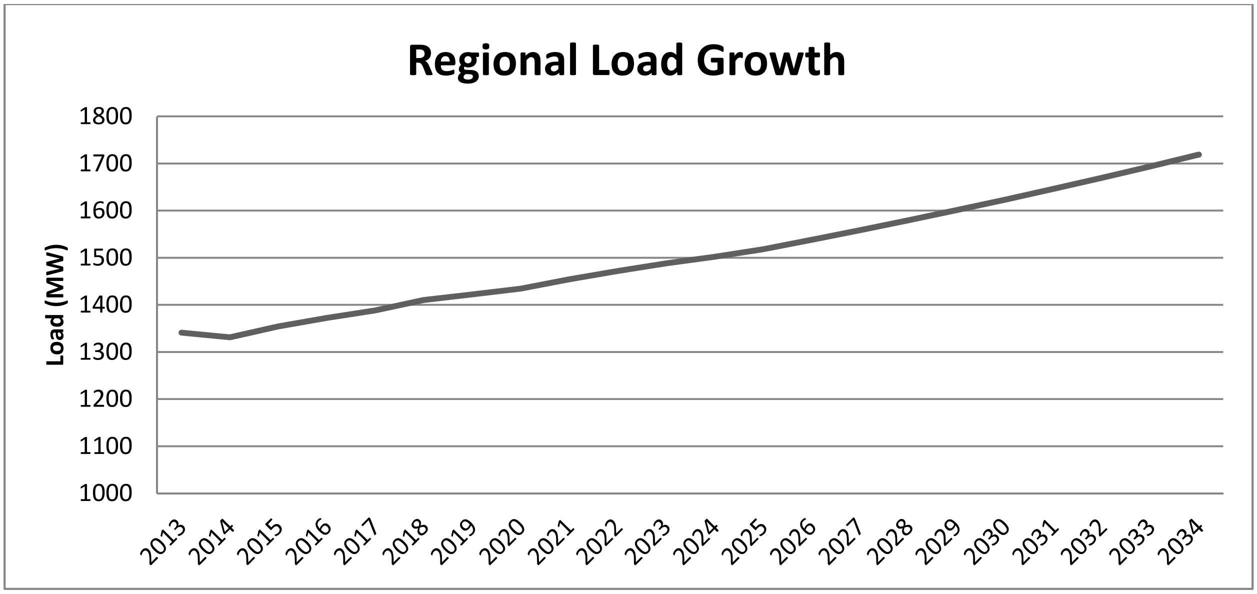

Figure 5-1 South Georgian Bay/Muskoka Region Winter Coincident Net Load Forecast

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.

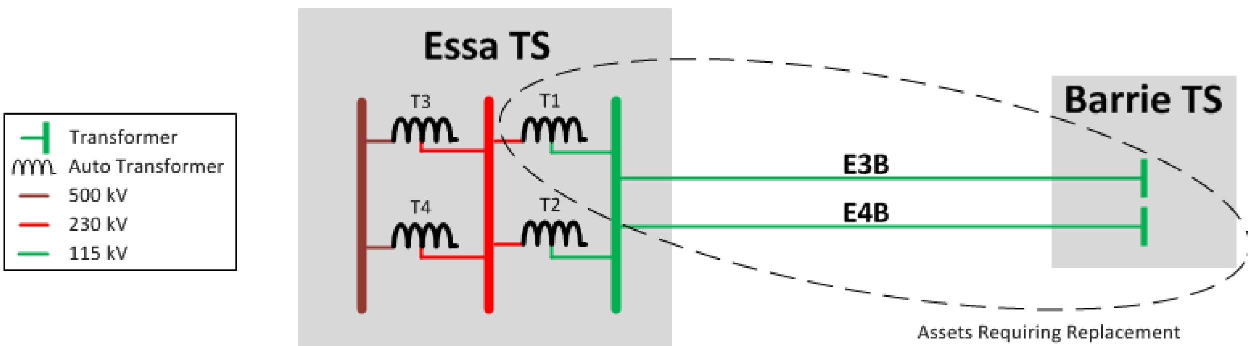

Figure 7-1 Current Arrangement of Essa TS, Barrie TS, and Circuits E3B/E4B

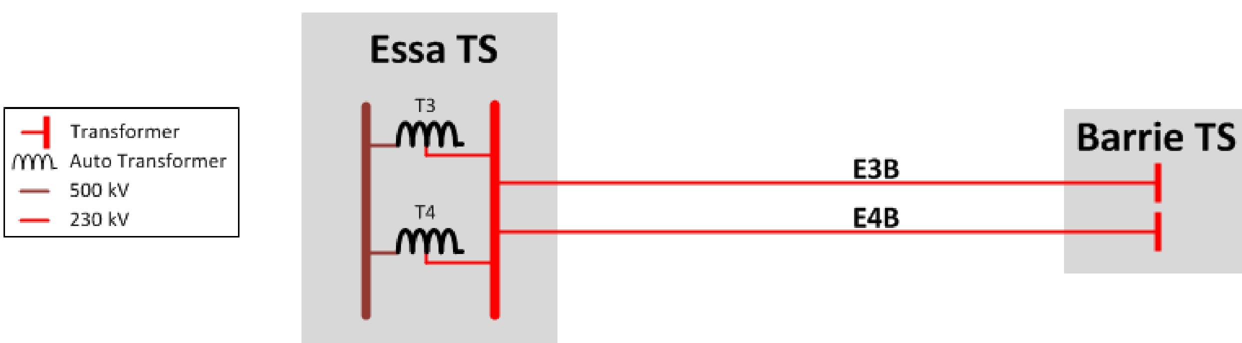

Figure 7-2 New Configuration of Essa/Barrie Supply to Barrie DESN

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

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

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

Note: 2014 values in grey are actuals from IRRP

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

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

Appendix E: List of Acronyms

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

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

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Sudbury/Algoma Region

Regional Infrastructure Plan ("RIP")

June 10th, 2016

Greater Sudbury Hydro Inc.
Hydro One Networks Inc. (Distribution)

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden.

The Needs Assessment ("NA") for the Sudbury/Algoma region was completed in March, 2015 (see attached) and the report recommends that no further coordinated regional planning is required to address needs in the Sudbury-Algoma Region.

To address local needs, local planning was undertaken by Hydro One Networks Inc. (Transmitter) and Hydro One Networks Inc. (Distribution) to address the "Manitoulin TS Low Voltage Regulation" need. A Local Planning ("LP") report was prepared and published by the Working Group for the Sudbury/Algoma region in September, 2015 (also attached).

The only major project planned for the Sudbury/Algoma Region over the near and mid-term is

- New 230/44kV station at Hanmer Ts to replace Coniston Ts (115/22kV). As part of this project, Coniston loads will be converted from 22kV to 44kV (2019). The approximate cost of this work is $25M. This is a pool funded investment.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the ("RIP") for the Sudbury/Algoma Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2013) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at www.ontarioenergyboard.ca

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

Manitoulin TS Low Voltage Regulation
Region: Sudbury-Algoma

Revision: Final
Date: September 30, 2015

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team	
Organization	Name
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra
Hydro One Networks Inc. (Distribution)	Richard Shannon

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Sudbury-Algoma Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning 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 Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning 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 Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Sudbury to Algoma (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 20, 2014	**END DATE**	September 30, 2015

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Sudbury-Algoma Region dated March 12, 2015. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 6 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the Sudbury-Algoma region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Manitoulin TS Voltage Regulation is a local need addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the above need with the following options;

Alternative 0 – Status Quo.
Alternative 1 - Install 44kV Capacitor Bank at Manitoulin TS
Alternative 2 - Install 115kV Capacitor Bank at Manitoulin TS

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time is Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

TABLE OF CONTENTS

1 INTRODUCTION

The Needs Assessment (NA) for the Sudbury/Algoma ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Sudbury-Algoma Region over the next ten years (2014 to 2023) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 Sudbury to Algoma Region Description and Connection Configuration

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

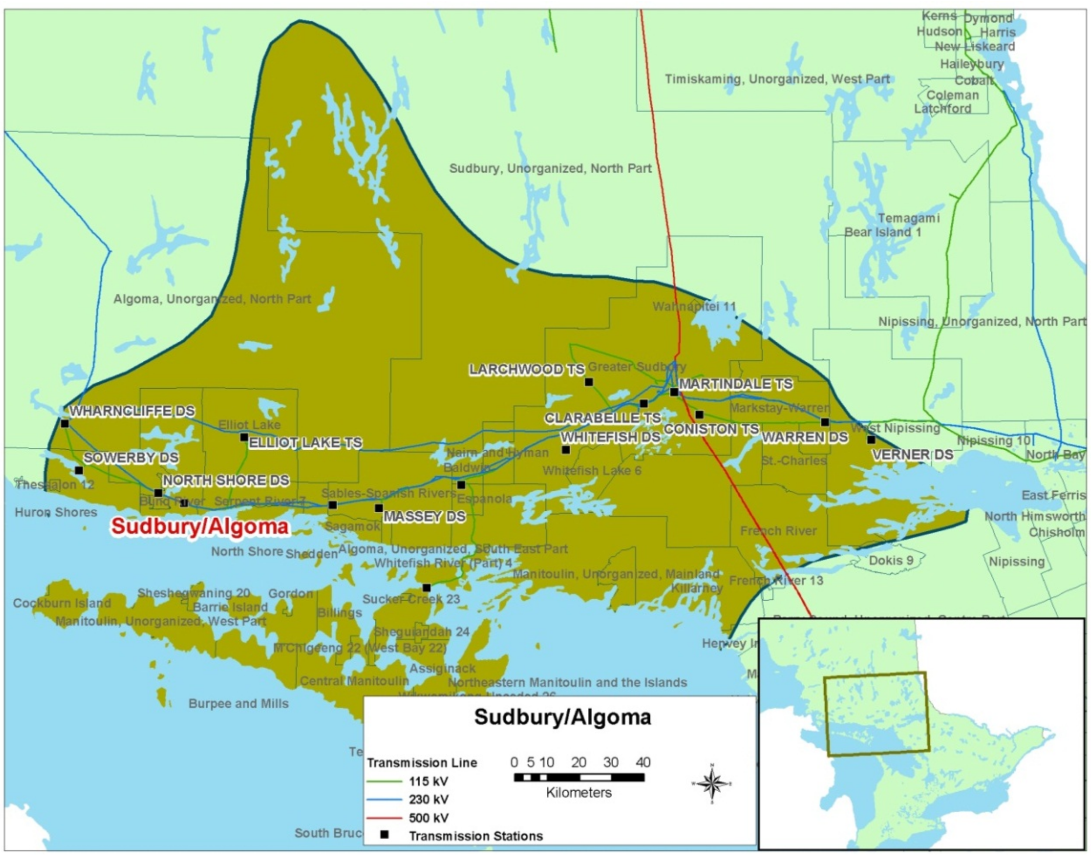

Figure 1: Sudbury to Algoma Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS. Table 2 below lists the major transmission circuits and Hydro One stations in the subject region.

This region has the following two local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

Espanola Regional Hydro Distribution is a third LDC in this region embedded into the Hydro One Distribution system. Although invited, this LDC opted not to participate in the Study Team. However, the interests of this LDC were communicated and considered through Hydro One Distribution as a host LDC.

Transmission connected loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One considered their impact in this analysis.

115kV circuits	230kV circuits	Hydro One Transformer Stations
S6F,S5M	X74P, X27A	ALGOMA TS
S2B,B4B	A23P, A24P	MARTINDALE TS
T1B, B3E	X23N, S21N	HANMER TS
B4E, L1S	X25S, X26S	CONISTON TS
	S22A	CLARABELLE TS
		ELLIOT LAKE TS
		ESPANOLA TS
		LARCHWOOD TS
		MANITOULIN TS

Table 1: Transmission Lines and Stations in Sudbury to Algoma Region

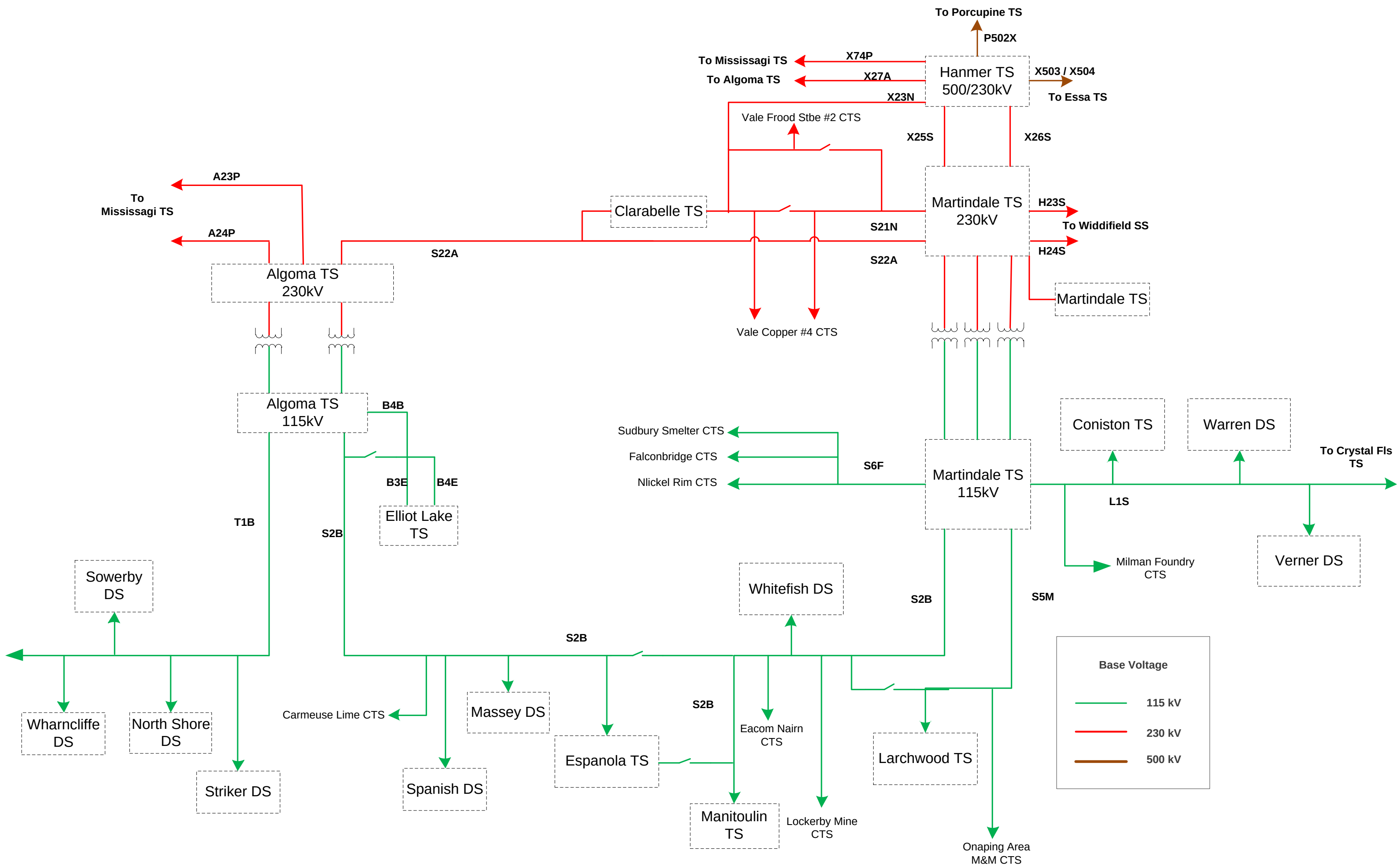

Figure 2: Single Line Diagram – Sudbury to Algoma Region

2 AREA NEEDS

2.1 Sudbury-Algoma Region Needs

As an outcome of the NA process, the study team did not identify any capacity needs based on LDCs load forecast. Only need identified was an issue with potential voltage regulation at Manitoulin TS in the Sudbury-Algoma Region to be addressed by a “localized” wires planning. Where local planning was recommended to address the needs, Hydro One, as transmitter, with the impacted LDC, further undertook planning assessments to address the need.

2.2 Needs Assessed by Hydro One led Local Planning

- Manitoulin TS Voltage Regulation – pre-contingency voltages at Manitoulin TS 115kV can at times fall below the ORTAC criteria of 113kV. Without McLean’s mountain wind farm in service, and under peak load conditions, pre-contingency voltage at Manitoulin TS high voltage bus can be as low as 110kV when supplied from Algoma TS, and 112kV when supplied from Martindale TS.

3 ALTERNATIVES CONSIDERED

Hydro One transmission reviewed the above need and determined that the only LDC impacted by a low voltage at Manitoulin TS is Hydro One distribution which is directly supplied at the stations’ 44kV bus. Following options were considered to address the needs identified in section 2 above.

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the load and voltages over the next three years. Further review will be undertaken in the next planning cycle or earlier if there is any evidence where load cannot be served or system cannot be operated in a safe, secure and reliable manner.

Alternative 2 – Install 44kV Capacitor Bank at Manitoulin TS

A 7MX low voltage capacitor bank can help improve high voltages regulation at Manitoulin TS. Manitoulin TS has a non-standard low voltage switch yard arrangement whereby each of the two feeders is supplied from a dedicated bus and associated transformer. There is currently no tie breaker between the two 44kV buses and thus, two 5.4MX capacitor banks will be required (for each of the busses). See figure 3.

Alternative 3 – Install 115kV Capacitor Bank at Manitoulin TS

A high voltage capacitor bank would also regulate the high voltage bus at Manitoulin TS. This alternative would require two high voltage breakers, and a motorized disconnect switch. See figure 4. Further investigation into this alternative indicated that 96MX capacitor bank is the smallest size available at this voltage. This large capacitor size would cause large voltage changes during switching and would violate operational criteria. Although this aspect would rule out this alternative it is shown illustration purposes in Table 3.

Table 3 below provides a budgetary cost summary of a cost of all options.

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance of 115kV and 44kV bus with no immediate investment.	--
Alternative 2 – Install 44kV Capacitor Bank at Manitoulin TS	$4M
Alternative 3 – Install 115kV Capacitor Bank at Manitoulin TS	$6M

Table 2 – Budgetary Cost for Alternatives

4 PREFERRED SOLUTION AND REASONING

Hydro One Networks and the LDC have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that the Manitoulin TS HV bus may experience voltages below ORTAC requirements only during limited operating scenarios. These scenarios are infrequent and the impacts of a low voltage at this point does not affect system stability or result in low voltages issues beyond the Manitoulin TS and Hydro One Distribution (LDC)

Manitoulin TS power transformers (T3/T4) are presently equipped with under load tap changers which have the ability to maintain 44kV bus voltages for wide array of voltage variations on the 115kV bus. ULTC ratings for both T3 and T4 are 44kV +/- 20% on 115.5kV at 42MVA load. These ratings are sufficient to maintain a customer delivery point performance within the rules of the Transmission System Code. The 44kV bus voltage will be maintained within 1.06 and 0.98pu for a 110kV (or lower) voltage.

Manitoulin TS voltage is constantly monitored by Hydro One's Ontario Grid Control Centre (OGCC) . OGCC's records will be reviewed regularly to ascertain the system conditions during peak load and its ability to operate the system and supply load to Manitoulin TS at acceptable voltage.

Voltage history will be reviewed with the LDC to determine if 44kV supply voltage remains within acceptable range for all distributed connected customers. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

5 NEXT STEPS

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Need	Action / Recommended Solution	Lead Responsibility	Timeframe
Low Voltage at Manitoulin 115kV bus	• Status Quo –standard five year cycle	Hydro One Networks	Maximum five years

Table 3: Solutions and Timeframe

6 DIAGRAMS

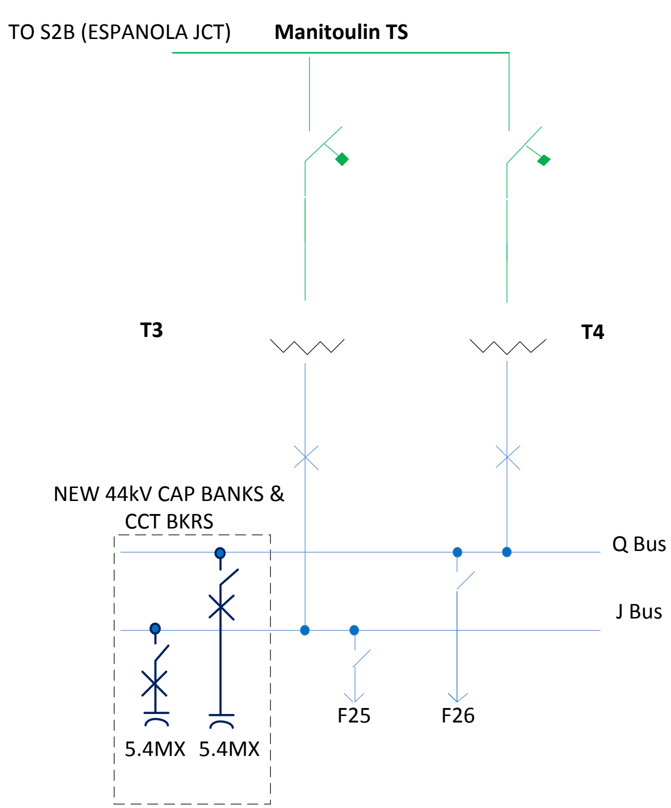

Figure 3 – New 44kV Capacitor Banks

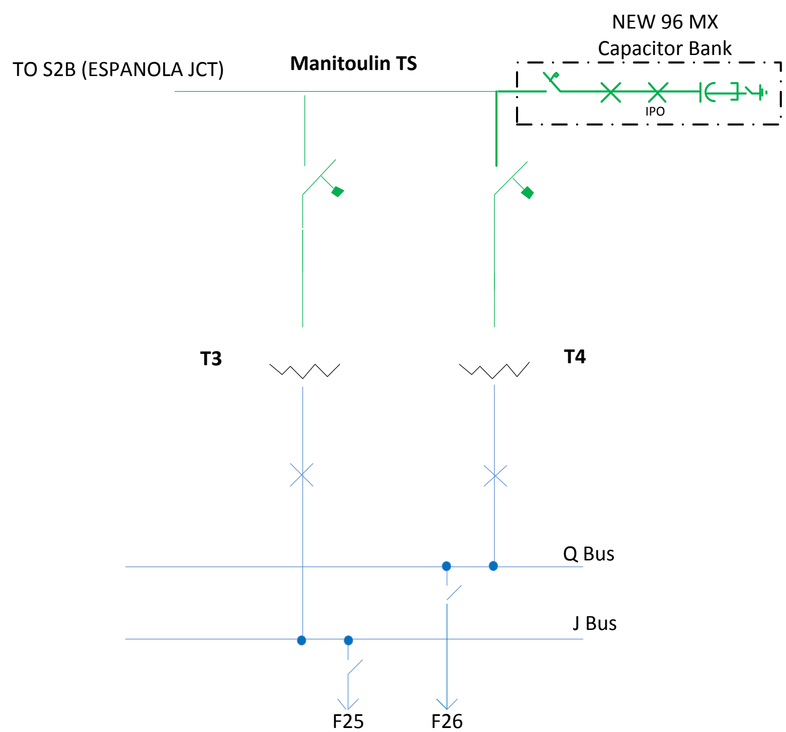

Figure 4 – 115kV Cap bank

7 REFERENCES

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] Sudbury-Algoma Needs Assessment Report

8 ACRONYMS

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A – LOAD FORECAST FOR SUDBURY-ALGOMA STATIONS

Station Name	DESN ID	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2011	2012	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Clarabelle TS	T1/T2	Gross Peak Load				106.7	105.8	104.9	103.9	103.0	102.1	101.3	100.4	99.5	98.6
		Net Load Forecast	87.4	78.7	114.3										
Coniston TS	T2/T3	Gross Peak Load				3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8
		Net Load Forecast	9.0	10.8	7.1										
Elliot Lake TS	T1/T2/T3	Gross Peak Load				20.3	20.4	20.6	20.7	20.7	20.9	21.1	21.2	21.3	21.4
		Net Load Forecast	43.2	39.3	40.3										
Espanola TS	T1/T2/T3	Gross Peak Load				13.9	14.0	14.0	14.1	14.2	14.3	14.5	14.5	14.6	14.6
		Net Load Forecast	26.7	24.0	26.4										
Larchwood TS	T2	Gross Peak Load				13.2	13.3	13.4	13.5	13.6	13.8	13.9	14.0	14.1	14.2
		Net Load Forecast	25.2	27.1	26.2										
Manitoulin TS	T3/T4	Gross Peak Load				37.8	38.2	38.5	38.8	39.0	39.5	40.0	40.3	40.5	40.8
		Net Load Forecast	73.5	63.5	71.0										
Martindale TS	T25/T26	Gross Peak Load				149.5	151.5	152.3	153.0	153.6	154.5	155.3	155.9	156.5	157.9
		Net Load Forecast	97.7	88.3	95.0										
Massey DS	T1	Gross Peak Load				7.5	7.6	7.6	7.7	7.7	7.8	7.9	8.0	8.0	8.1
		Net Load Forecast	11.7	10.7	14.9										
North Shore DS	T1	Gross Peak Load				5.9	6.0	6.1	6.1	6.2	6.3	6.5	6.5	6.6	6.7
		Net Load Forecast	11.3	11.5	11.5										

LOAD FORECAST FOR SUDBURY-ALGOMA REGION (CONTINUED)

Station Name	DESN ID	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2011	2012	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Sowerby DS	T1	Gross Peak Load				4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9	5.0
		Net Load Forecast	10.3	9.7	9.3										
Spanish DS	T1	Gross Peak Load				4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.6	4.6
		Net Load Forecast	7.7	6.7	7.9										
Striker DS	T1/T2	Gross Peak Load				10.0	10.1	10.3	10.4	10.5	10.7	10.8	11.0	11.1	11.2
		Net Load Forecast	16.8	14.0	19.6										
Verner DS	T1/T2	Gross Peak Load				6.3	6.4	6.4	6.5	6.5	6.6	6.7	6.7	6.8	6.8
		Net Load Forecast	12.1	10.8	12.5										
Warren DS	T1/T2	Gross Peak Load				8.0	8.1	8.1	8.2	8.2	8.3	8.4	8.5	8.5	8.6
		Net Load Forecast	14.6	13.0	15.5										
Wharncliffe DS	T1/T2	Gross Peak Load				5.3	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.5	5.6
		Net Load Forecast	9.9	9.1	10.5										
Whitefish DS	T1	Gross Peak Load				6.6	6.7	6.7	6.8	6.8	6.9	7.0	7.0	7.1	7.1
		Net Load Forecast	13.8	12.1	13.1										

1. CDM & DG Not included in this table.
2. Sudbury-Algoma region is winter peaking

DG & CDM FORECAST FOR SUDBURY-ALGOMA STATIONS

Station Name	DESN ID	BUS ID	Customer Data	Existing	Near Term Forecast					Medium Term Forecast				
				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Clarabelle TS	T1/T2	M1/M3/M7	DG (MW)	5.93	6.19	6.20	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21
			CDM	-	-	-	-	-	-	-	-	-	-	-
Coniston TS	T2/T3	M1	DG (MW)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
			CDM	-	-	-	-	-	-	-	-	-	-	-
Elliot Lake TS	T1/T2/T3	M1/M2/M3	DG (MW)	-	0	0	0	0	0	8.46	8.46	8.46	8.46	8.46
			CDM	-	-	-	-	-	-	-	-	-	-	-
Espanola TS	T1/T2/T3	M1	DG (MW)	-	-	-	-	-	-	2.54	2.54	2.54	2.54	2.54
			CDM	-	-	-	-	-	-	-	-	-	-	-
Larchwood TS	T2	M3/M4	DG (MW)	-	-	-	-	-	-	6.28	6.28	6.28	6.28	6.28
			CDM	-	-	-	-	-	-	-	-	-	-	-
Manitoulin TS	T3/T4	M25/M26	DG (MW)	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
			CDM	-	-	-	-	-	-	-	-	-	-	-
Martindale TS	T25/T26	M5/M6/M7	DG (MW)	5.98	5.98	6.40	6.40	6.40	6.40	8.49	8.49	8.49	8.49	8.49
			CDM	-	-	-	-	-	-	-	-	-	-	-
Massey DS	T1	F1/F3	DG (MW)		-	-	-	-	-					
			CDM	-	-	-	-	-	-	-	-	-	-	-
North Shore DS	T1	F1/F2	DG (MW)	1.71	1.71	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
			CDM	-	-	-	-	-	-	-	-	-	-	-

DG & CDM Forecast for Sudbury-Algoma Stations (Continued)

Station Name	DESN ID	BUS ID	Customer Data	Existing	Near Term Forecast					Medium Term Forecast				
				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sowerby DS	T1	F1/F2	DG (MW)	-	-	-	-	-	-	-	-	-	-	-
			CDM	-	-	-	-	-	-	-	-	-	-	-
Spanish DS	T1	F1/F2	DG (MW)	-	-	-	-	-	-	0.78	0.78	0.78	0.78	0.78
			CDM	-	-	-	-	-	-	-	-	-	-	-
Striker DS	T1/T2	F1/F2	DG (MW)	0.01	0.01	0.01	0.01	0.01	0.08	0.08	0.08	0.08	0.08	0.08
			CDM	-	-	-	-	-	-	-	-	-	-	-
Verner DS	T1/T2	F1/F2/F3	DG (MW)											
			CDM	-	-	-	0	0	0	0	0	0	0	0
Warren DS	T1/T2	F1/F2/F3/F4	DG (MW)	-	-	-	0	0	0.02	0.02	0.02	0.02	0.02	0.02
			CDM	-	-	-	-	-	-	-	-	-	-	-
Wharncliffe DS	T1/T2	F1/F2	DG (MW)	-	-	-	-	-	-	-	0.47	0.47	0.47	0.47
			CDM	-	-	-	-	-	-	-	-	-	-	-
Whitefish DS	T1	F1/F2/F3	DG (MW)	-	-	-	-	0.02	0.02	0.02	0.02	0.02	0.02	0.02
			CDM	-	-	-	-	-	-	-	-	-	-	-

1. DG value (MW) is cumulative
2. DG MW Value is for winter peak
3. '-' indicates CDM or DG value not available

Hydro One Networks Inc.
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NEEDS ASSESSMENT REPORT

Region: Sudbury Algoma

Date: March 12, 2015

Prepared by: Sudbury - Algoma Region Study Team

Sudbury to Algoma Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra
Independent Electricity System Operator	Phillip Woo Angelina Tan Kun Xiong
Greater Sudbury Hydro	Brian McMillan
Hydro One Networks Inc. (Distribution)	Richard Shannon

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Sudbury Algoma region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment 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 Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Sudbury to Algoma (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 20, 2014	**END DATE**	March 20, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Sudbury to Algoma Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Sudbury Algoma Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Sudbury Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Sudbury Algoma Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

C. 115kV Transmission Lines

- The 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
-

D. 230 kV and 115 kV Connection Facilities

- The 230k and 115kV connection facilities in this region are adequate over the study period.

E. Pre-contingency voltages at Manitoulin TS

- Under peak load conditions, pre-contingency voltages at Manitoulin TS 115kV bus can be below 113 kV.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period. For the loss of one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. In addition,

- As identified by the IESO, under peak load conditions, the loss of two Martindale TS 230/115kV transformers may result in the overload of the third Martindale transformer.
- As identified by the IESO, With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits.

The above issues will be further assessed as part of bulk system planning outside of the regional planning process.

Aging Infrastructure / Replacement Plan

Replacement of the autotransformers at Martindale is currently in Hydro One's 5yr sustainment business plan. As part of this replacement, T21/T23 autotransformer replacement at Martindale TS may result in higher emergency ratings.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination is required and following needs identified in Section 6 be further assessed as part of Local Planning:

Manitoulin TS Voltage Regulation

- Low pre-contingency voltages at Manitoulin TS 115kV bus.

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Sudbury to Algoma Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Sudbury to Algoma Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the Sudbury to Algoma Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Sudbury to Algoma Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Greater Sudbury Hydro Inc ("Sudbury Hydro")
4.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Sudbury to Algoma Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Sudbury to Algoma Region belongs to Group 2. The NA for this Region was triggered on October 20, 2014 and was completed on March 20, 2015

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Sudbury to Algoma Region over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Sudbury to Algoma Region Description and Connection Configuration

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

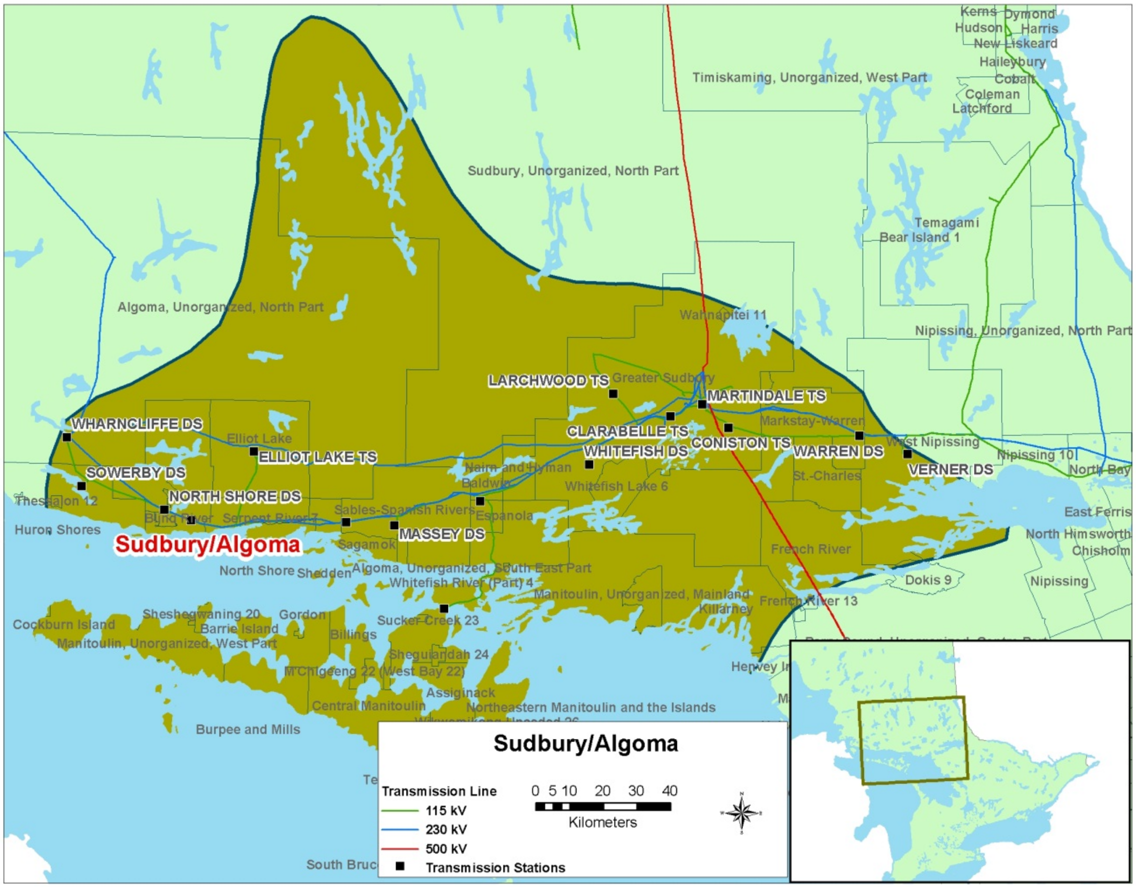

Figure 1: Sudbury to Algoma Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS. Table 2 below lists the major transmission circuits and Hydro One stations in the subject region.

This region has the following two local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

Espanola Regional Hydro Distribution is a third LDC in this region embedded into the Hydro One Disribution system. Although invited to participate in the Study Team, the interests of this LDC was communicated through Hydro One Distribution.

Tranmission connected loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One will consider their impact in the NA of this region.

115kV circuits	230kV circuits	Hydro One Transformer Stations
S6F,S5M	X74P, X27A	ALGOMA TS
S2B,B4B	A23P, A24P	MARTINDALE TS
T1B, B3E	X23N, S21N	HANMER TS
B4E, L1S	X25S, X26S	CONISTON TS
	S22A	CLARABELLE TS
		ELLIOT LAKE TS
		ESPANOLA TS
		LARCHWOOD TS
		MANITOULIN TS

Table 2: Transmission Lines and Stations in Sudbury to Algoma Region

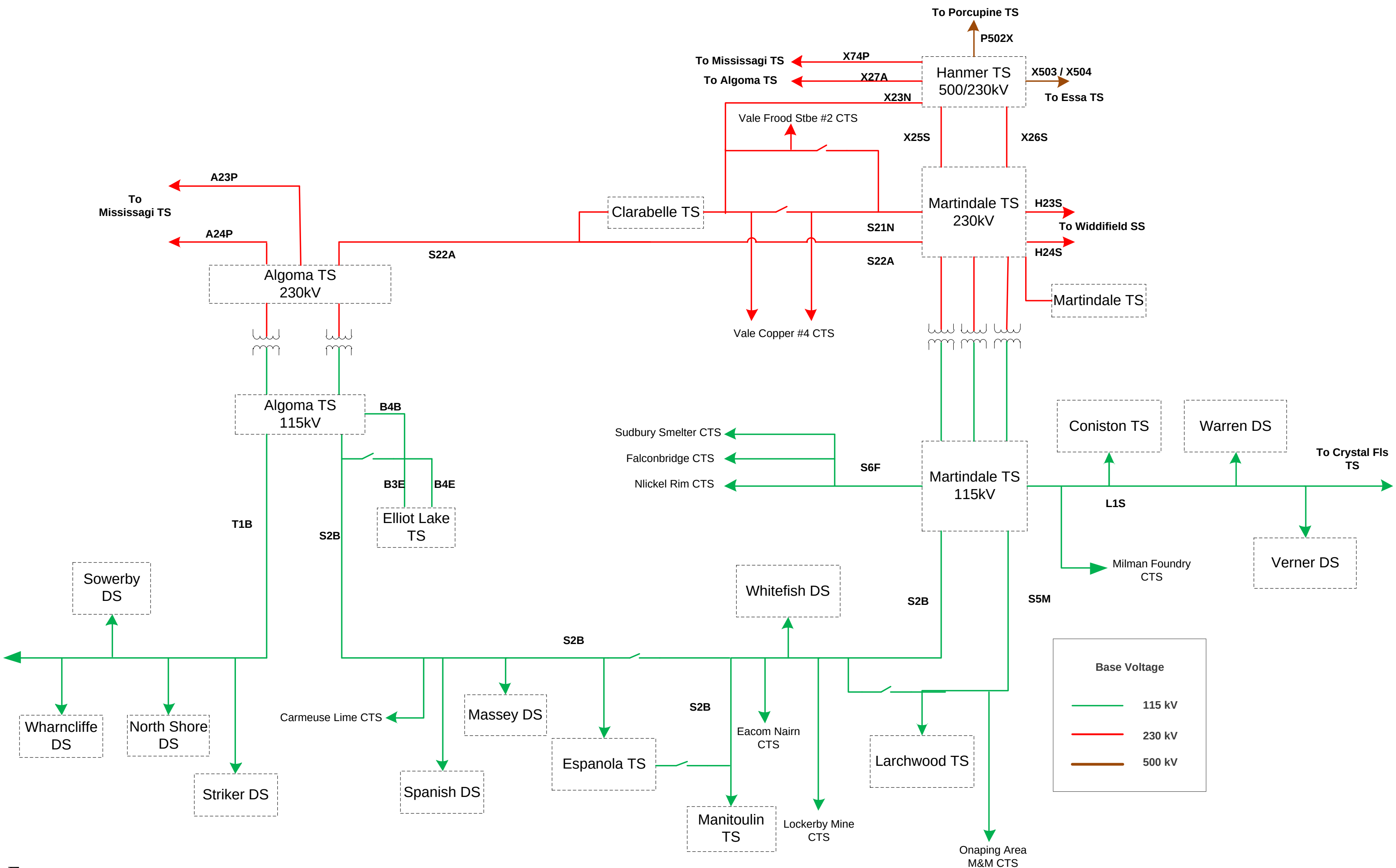

Figure 2: Single Line Diagram – Sudbury to Algoma Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical 2013 regional coincident peak load and station non-coincident peak load
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.3% annually from 2014-2023.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.2% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region’s LDCs (Greater Sudbury Hydro Inc, Hydro One Distribution).
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. The LDC’s load forecast is translated into load growth rates and is applied onto the 2013 winter peak load as a reference point.
5. The 2013 winter peak loads are adjusted for extreme weather conditions according to Hydro One’s methodology.

6. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for Section 6.1.3 of this report.

   A gross and net region-coincident peak load forecast was used to perform the analysis for sections 6.1.1 and 6.1.2.

   Review impact of any on-going and/or planned development projects in the Region during the study period.
7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
8. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer or winter 10-Day Limited Time Rating (LTR), as appropriate.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Sudbury to Algoma Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Algoma TS, Martindale TS, Hanmer TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period.

6.1.3 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period (2014-2023).

6.1.4 Pre-contingency voltages at Manitoulin TS 115kV

Pre-contingency voltages at Manitoulin TS 115kV bus can be below the ORTAC criteria of 113 kV. This issue has been also identified by the IESO as part of their System Impact Assessments.

6.2 System Reliability, Operation and Restoration

Based on the gross coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to The loss of two elements is below the load loss limit of 600MW by the end of the 10-year Study period. For the loss of one or two elements, the load interrupted by configuration does not exceed 150 MW or 250 MW. Review of the power network in the area indicates that all loads in the Sudbury-Algoma area can be restored within the 8 hour requirement.

6.2.1 Post contingency voltage declines at Martindale TS

With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC limits. This issue has been presented in the IESO System Impact Assessment Victoria

Advanced Exploration Project (CAA 2013-512). In this assessment, voltage declines at the Martindale 230kV and 115 kV buses were found to be greater than the 10% limit.

6.2.2 Post Contingency Thermal Overload of Martindale Autotransformers

Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer. This issue has been presented in the IESO System Impact Assessment Process Gas (CAA 2012-488).

The double element contingency presented here occurs on the premise that all 115kV area loads would be supplied from one remaining autotransformer at Martindale TS. The worst case would be with Martindale T23 transformer remaining as it has the lowest STE (Short Term Emergency) rating.

Replacement of the autotransformers is listed in Hydro Ones 5yr sustainment business plan. T21/T23 autotransformers at Martindale TS may result in higher emergency ratings. In addition, loads connected to S2B (from Martindale) can also be transferred to S2B from Algoma, reducing Martindale 115kV load.

The above issues (6.2.1, 6.2.2) will be further assessed as part of bulk system planning outside of the regional planning process.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. During the study period:

- Replace T21/T23 230/115kV autotransformers at Martindale TS
- Build a new 230/44kV station at Hanmer TS to replace Coniston TS (115/22kV). As part of this project, Coniston loads will be converted from 22kV to 44kV
- Replace 115/44kV power transformers at Espanola TS (T1/T2) and Larchwood TS (T2)

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required. It is further recommended that following needs identified be best addressed by wires options thru local planning led by Hydro One:

Manitoulin TS - Pre-contingency voltages

- Low pre-contingency voltages at 115kV Manitoulin TS.

8 NEXT STEPS

Following the Needs Assessment process, the next regional planning steps, based on the evaluation conducted by this assessment is for Hydro One Transmission and impacted LDCs to carry out the local planning studies identified in Section 7

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Chatham-Kent/Lambton/Sarnia

Regional Infrastructure Plan

August 21, 2017

Prepared by Hydro One Networks Inc. (Lead Transmitter)

With support from:

Companies
Independent Electricity System Operator (IESO)
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Regional Infrastructure Plan (“RIP”) was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in the Chatham-Kent/Lambton-Sarnia Region. 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 members in the region.

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, with input from the Region's Local Distribution Companies ("LDCs") and the IESO in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements. It summarizes investments in transmission facilities, distribution facilities, or both, recommended to meet the electricity infrastructure needs within the Chatham-Kent/Lambton/Sarnia Region.

The regional planning process for the Chatham-Kent/Lambton/Sarnia Region was initiated with a Needs Assessment in April 2016, which identified loading at Kent TS would exceed their transformer 10-day Limited Time Rating ("LTR") in 2016 based on the net load forecast. The Needs Assessment Study Team recommended Hydro One and relevant LDCs to develop a Local Plan to address this issue ("Kent TS T3 Capacity Limitation"). This Local Plan was completed in June 2017, and concluded that there is existing distribution transfer capability to ensure that the transformer T3 would not exceed its LTR.

The major sustainment projects planned for the region over the near and medium-term are given as below:

- Refurbishment of existing Wanstead TS is currently underway and is scheduled to be completed in 2018;
- Chatham SS component replacement, including a capacitor and the associated breaker, is planned to be completed by 2023;
- St. Andrews TS T3, T4 & switchyard refurbishment, planned to be completed by 2023;
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

In accordance with the regional planning process as mandated by the TSC and DSC, the next planning cycle will be started no later than 2020. However, should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle may commence earlier to address the need.

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1. INTRODUCTION

This Regional Infrastructure Plan ("RIP") summarizes all the regional planning activities undertaken in the Chatham-Kent/Lambton/Sarnia Region. It was prepared by Hydro One Networks Inc. ("Hydro One") as the lead transmitter in the region, and is supported by the representatives from Bluewater Power Distribution Corporation, Entegrus Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"). This RIP is the final phase of the regional planning process for the region in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

1.1 Background and Scope

In accordance with the TSC and DSC amendments in August 2013, the regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with Needs Assessment in April 2016 and was completed in June 2016.

Based on the findings, the Needs Assessment Study Team agreed that Scoping Assessment was not required for this region at the time. The only need identified, thermal overloading of transformer T3 at Kent TS, was to be addressed between Hydro One (transmitter) and relevant LDCs through Local Planning process which was completed in June 2017.

Being the final phase of the regional planning process, the scope of this RIP includes a comprehensive summary of the needs and relevant wire plans to address near and medium-term needs (2015-2025) identified in previous planning phases.

2. REGIONAL DESCRIPTION

The Chatham-Kent/Lambton/Sarnia Region, as shown in Figure 2-1, includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. The area is bordered by the London area to the east and Windsor-Essex to the southwest. The region's summer coincident peak load was about 710 MW in 2016.

Figure 2-1 Map of Chatham-Kent/Lambton/Sarnia Region

Electricity supply for the region is provided through a network of 230 kV and 115 kV transmission lines. The bulk of the electrical supply is transmitted through 230 kV circuits (N21W/N22W, L24L/L26L, and W44LC/W45LS) towards Buchanan TS. This region also contains a number of interconnections with neighboring Michigan State (B3N, L4D, and L51D). Figure 2-2 shows Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Large gas-fired generators in the region include: Greenfield Energy Centre CGS, TransAlta Sarnia CGS, St. Clair Power CGS, and Greenfield South Power Corporation (GSPC). Lists of transmission lines, stations, and distributors (LDCs) in the region are provided in Appendix A, B, and C, respectively.

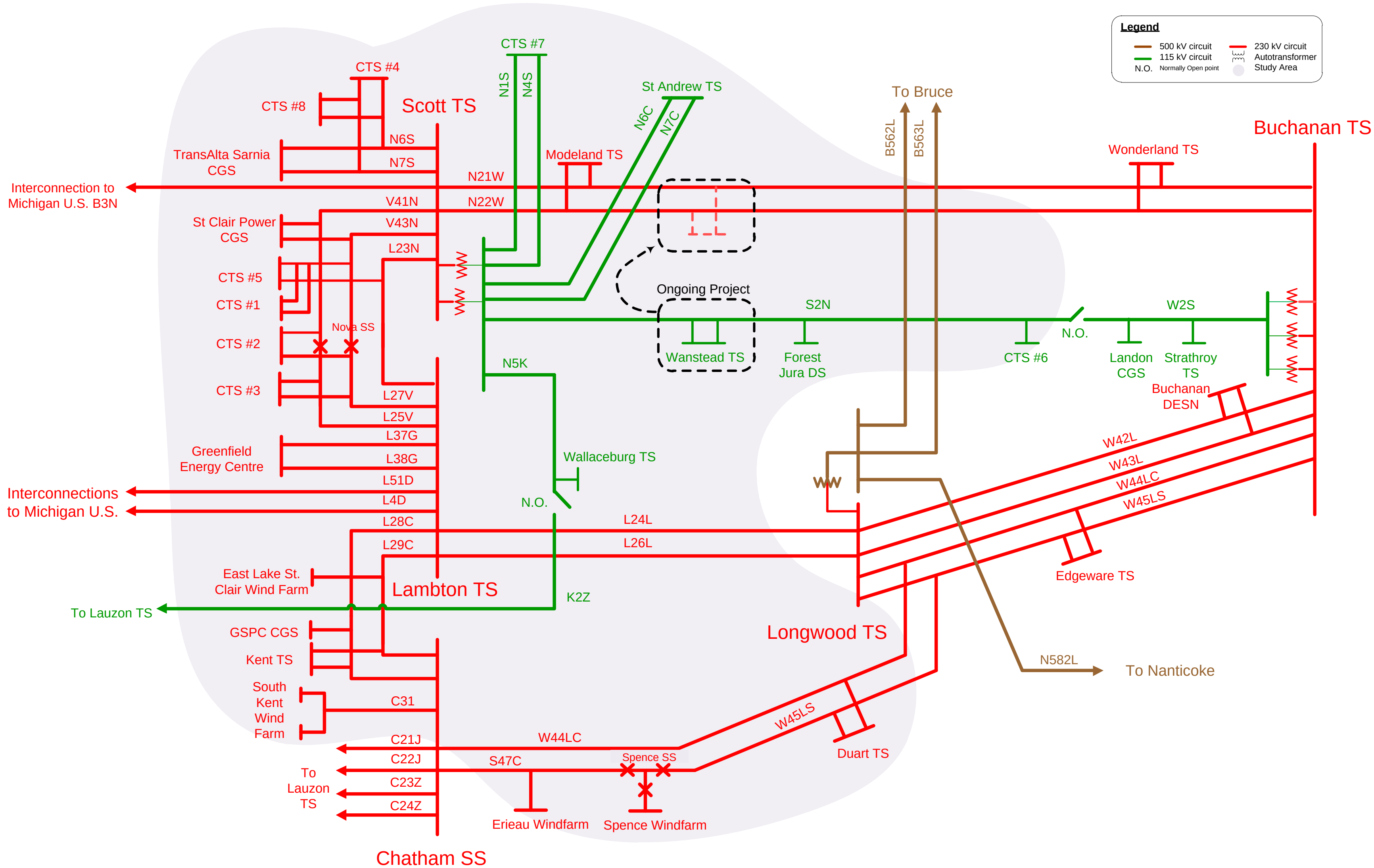


Figure 2-2 Single Line Diagram of Chatham-Kent/Lambton/Sarnia Region

3. NEEDS ASSESSMENT RESULTS

3.1 Load Forecast

During the Needs Assessment phase, LDCs in the region provided gross load forecasts for Hydro One's step-down transformer stations and assumed 2015 historical extreme weather-corrected summer peak loads as reference points. As for transmission connected industrial customers, 2014 historical load levels were assumed throughout the study period.

Based on data provided by the Study Team, the summer gross coincident load in the region is expected to grow at an average rate of approximately 1.3% annually over the next 10 year period. Factoring in the contributions of conservation and demand management and distributed generation, the summer net coincident load in the region is expected to grow at an average rate of approximately 0.2% annually.

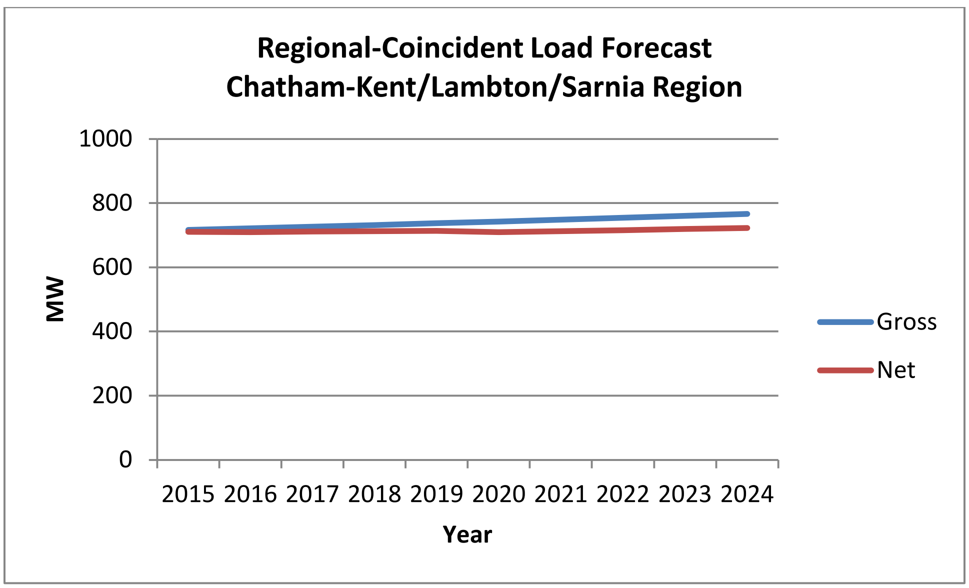


Figure 3-1 Regional load forecast during Needs Assessment

Further load forecast details are provided in Appendix D.

3.2 Major Transmission Projects Completed or Underway

Over the last 10 years, a number of major transmission projects, shown below, have been completed by Hydro One aimed to maintain or improve the reliability and adequacy of supply in the Chatham-Kent/Lambton/Sarnia Region:

- Lambton to Longwood 230kV L24L/L26L Circuit Reconductoring
- New Transformer Station Duart TS

In addition, as part of Hydro One's transmission rates application (EB-2016-0160), existing Wanstead TS has been identified as reaching end-of-life. Effort is underway to convert Wanstead TS from 115 kV to 230 kV and connecting to 230 kV circuits N21W/N22W. The target in-service date is Q4 2018.

3.3 Regional Needs

The results from the Needs Assessment for the region are summarized below:

Table 3-1 Regional Needs

No.	Needs	Description
1	Kent TS Capacity	Loading at Kent TS is expected to exceed the transformer 10-day limited time rating (LTR) in 2016 based on the net load forecast.
2	End-of-Life equipment at St. Andrews TS, Scott TS, and Chatham SS	During the study period, plans to replace end of life equipment at St. Andrews TS, Scott TS, and Chatham SS[1] are identified.

4. RECOMMENDED PLANS

This section provides a consolidated summary of the regional infrastructure plans for addressing needs in the Chatham-Kent/Lambton/Sarnia Region.

4.1 Kent TS Transformation Capacity

Based on the information available at the time of Chatham-Kent/Lambton/Sarnia Region Needs Assessment, it was identified that transformer T3 at Kent TS will be overloaded for the loss of its companion transformer T4. Subsequently, local planning team consists of Hydro One and impacted LDCs had undertaken further investigations and determined there is a sufficient transfer capability on the distribution system to offload Kent TS T3. Therefore, the local planning team agreed no further action is required at this time.

[1] The need to replace end-of-life equipment at Chatham SS was identified post completion of the 2016 Needs Assessment report.

4.2 Sustainment Plans

As part of Hydro One's transmitter license requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Since the conclusion of Needs Assessment, additional sustainment projects have been planned for the region in the medium-term. Below is a list of Hydro One's major transmission sustainment projects in the Chatham-Kent/Lambton/Sarnia Region that are currently planned. Note that the project scopes and timelines are currently under development and may change accordingly.

- Chatham SS Component Replacement, mainly to replace capacitor SC21 and the associated breaker and is planned to be completed by 2023.
- St. Andrews TS T3, T4 & Switchyard Refurbishment, planned to be completed by 2023. The current scope includes both transformers and a breaker replacement.
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

5. CONCLUSION AND NEXT STEPS

This Regional Infrastructure Plan (RIP) report summarizes the regional planning activities for the Chatham-Kent/Lambton/Sarnia Region and concludes the first regional planning cycle for the region.

As mandated by the OEB, next planning cycle will begin no later than 2020. Should there be a need that emerges due to change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

6. REFERENCES

[1] Needs Assessment Report, Chatham-Kent/Lambton/Sarnia Region. June 12, 2016. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf

[2] Local Planning Report – Kent TS Transformation Capacity, Chatham-Kent/Lambton/Sarnia Region. June, 2017. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Kent%20TS%20Transformation%20Capacity%20Local%20Planning%20Report%20(Final).pdf

APPENDIX A: TRANSMISSION LINES IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No	Circuit Designation	Location	Voltage (kV)
1	N6S, N7S	Scott TS to TransAlta Sarnia CGS	230
2	V41N, V43N	Scott TS to Nova SS	230
3	L23N	Scott TS to Lambton TS	230
4	L25V, L27V	Lambton TS to Nova SS	230
5	L37G, L38G	Lambton TS to Greenfield Energy Centre CGS	230
6	L28C, L29C	Lambton TS to Chatham SS	230
7	C31	Chatham SS to South Kent Wind Farm CGS	230
8	W44LC	Buchanan TS to Longwood TS to Chatham SS	230
9	W45LS	Buchanan TS to Longwood TS to Spence SS	230
10	S47C	Spence SS to Chatham SS	230
11	L24L, L26L	Lambton TS to Longwood TS	230
12	N21W, N22W	Scott TS to Buchanan TS	230
13	N1S, N4S	Scott TS to CTS	115
14	N6C, N7C	Scott TS to St. Andrews TS	115
15	S2N	Scott TS to CTS	115
16	N5K	Scott TS to Wallaceburg TS	115
17	K2Z	Kent TS (115kV) to Lauzon TS	115

APPENDIX B: STATIONS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Scott TS	230/115	N/A
2	Lambton TS	230	N/A
3	Kent TS	115	L28C/L29C
4	Duart TS	230	W44LC, W45LS
5	Modeland TS	230	N21W, N22W
6	Wanstead TS	115 (existing) 230 (future)	S2N (existing) N21W/N22W (future)
7	St. Andrews TS	115	N6C, N7C
8	Wallaceburg TS	115	N5K
9	Forest Jura HVDS	115	S2N

Note: Customer-owned transformer stations are excluded

APPENDIX C: DISTRIBUTORS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

Distributor Name	Station Name	Connection Type
Bluewater Power Distribution Corporation	Modeland TS	Tx
	St. Andrews TS	Tx
	Wanstead TS	Dx
Entegrus Inc.	Kent TS	Tx, Dx
	Wallaceburg TS	Dx
Hydro One Networks Inc. (Distribution)	Duart TS	Tx
	Forest Jura HVDS	Tx
	Kent TS	Tx
	Lambton TS	Tx
	Wallaceburg TS	Tx
	Wanstead TS	Tx

APPENDIX D: REGIONAL-COINCIDENT LOAD FORECAST (MW)

Coincidental Net Load (MW)

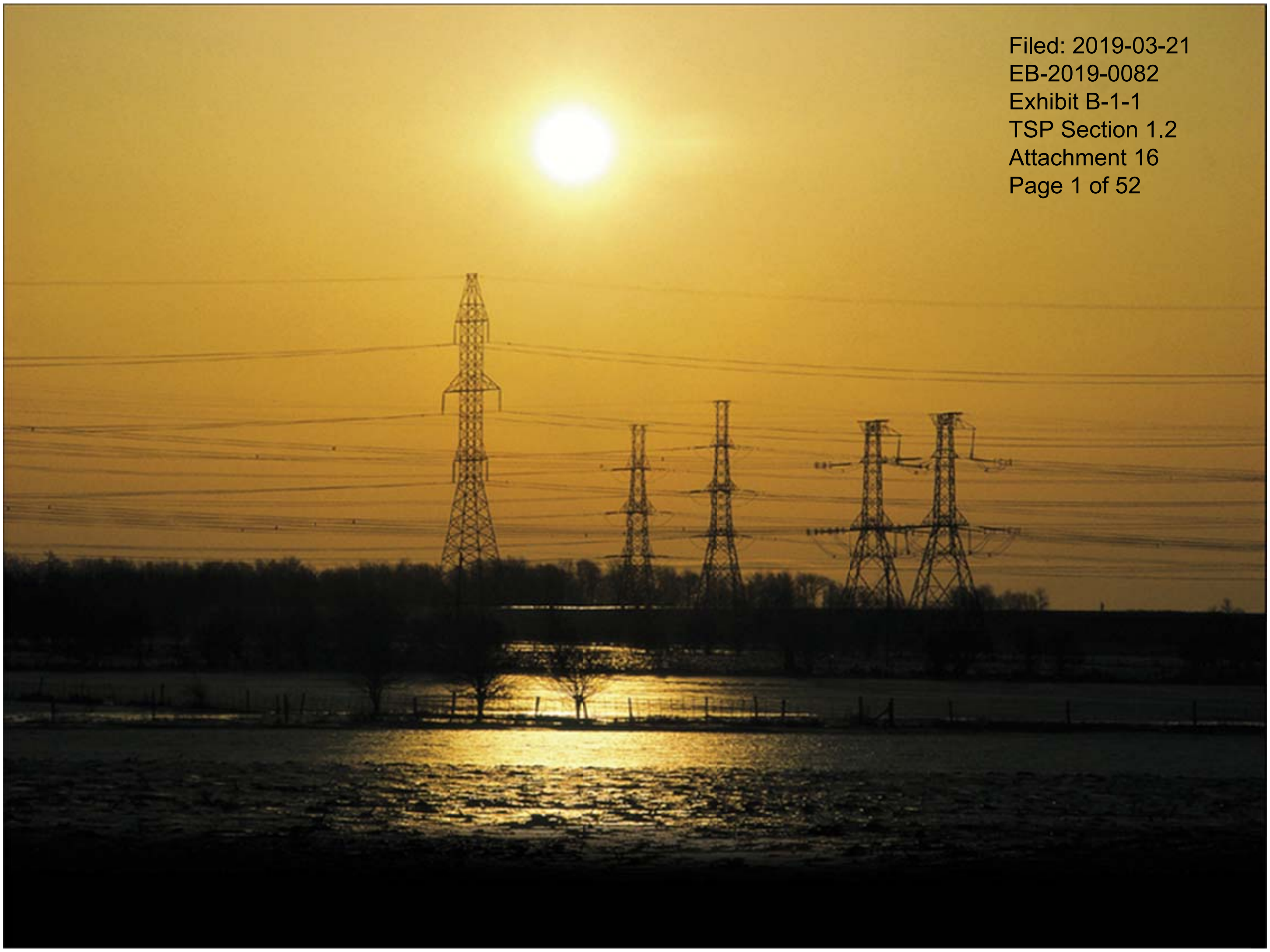
	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.5	14.5	14.4	14.5	14.5	14.6	14.7	14.8	15.0	15.1
Forest Jura DS	19.5	19.6	19.8	19.9	20.0	20.2	20.4	20.6	20.9	21.1
Kent TS T1/T2	69.8	70.0	71.1	72.0	72.9	74.0	75.3	76.6	78.1	79.5
Kent TS T3/T4	40.3	40.7	41.3	41.8	42.2	42.8	43.5	44.2	45.0	45.8
Lambton TS	61.7	61.6	61.8	61.7	61.6	61.7	61.9	62.2	62.5	62.8
Modeland TS	82.1	81.4	81.2	80.6	80.1	79.7	79.5	79.4	79.4	79.2
St. Andrews TS	63.0	62.3	61.8	61.1	60.5	60.0	59.6	59.3	59.0	58.7
Wallaceburg TS	27.0	26.8	27.2	27.6	27.9	23.2	23.7	24.2	24.8	25.3
Wanstead TS	28.1	28.2	28.5	28.6	28.8	29.0	29.3	29.6	30.0	30.3
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

Coincidental Gross Load (MW)

	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.7	14.9	15.1	15.3	15.5	15.7	16.0	16.2	16.4	16.7
Forest Jura DS	19.7	20.0	20.4	20.7	21.1	21.4	21.8	22.2	22.6	22.9
Kent TS T1/T2	71.1	72.7	74.4	76.1	77.9	79.7	81.6	83.5	85.4	87.4
Kent TS T3/T4	40.8	41.7	42.6	43.6	44.6	45.5	46.6	47.6	48.7	49.8
Lambton TS	62.3	62.9	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.0
Modeland TS	82.9	83.3	83.6	84.0	84.3	84.7	85.0	85.3	85.7	86.0
St. Andrews TS	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
Wallaceburg TS	27.7	28.3	29.0	29.7	30.3	31.0	31.8	32.5	33.3	34.0
Wanstead TS	28.7	29.2	29.7	30.1	30.6	31.1	31.6	32.2	32.7	33.2
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

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
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
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
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
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code



Greater Bruce - Huron

REGIONAL INFRASTRUCTURE PLAN

August 18, 2017

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Power Lines Inc.
Erie Thames Powerlines Corporation
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

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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 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 PLANNED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER BRUCE-HURON REGION.

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

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

This RIP is the final phase of the regional planning process for the Greater Bruce-Huron Region and provides a consolidated summary of needs and recommended plans for the Greater Bruce-Huron 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.

Investments planned for the Greater Bruce-Huron 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	Improve L7S Customer Delivery Point Performance	Staged Plan 2017-2023	$154k - TBD
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	TBD (customer dependent)	TBD

In accordance with the Regional Planning process, the RIP 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 earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started 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 BRUCE-HURON 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, Entegrus Power Lines Inc., Erie Thames Powerlines Corporation, Festival Hydro Inc., Hydro One Distribution, the Independent Electricity System Operator ("IESO"), Wellington North Power Inc., Goderich Hydro - West Coast Huron Energy Inc. and Westario Power Inc. in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

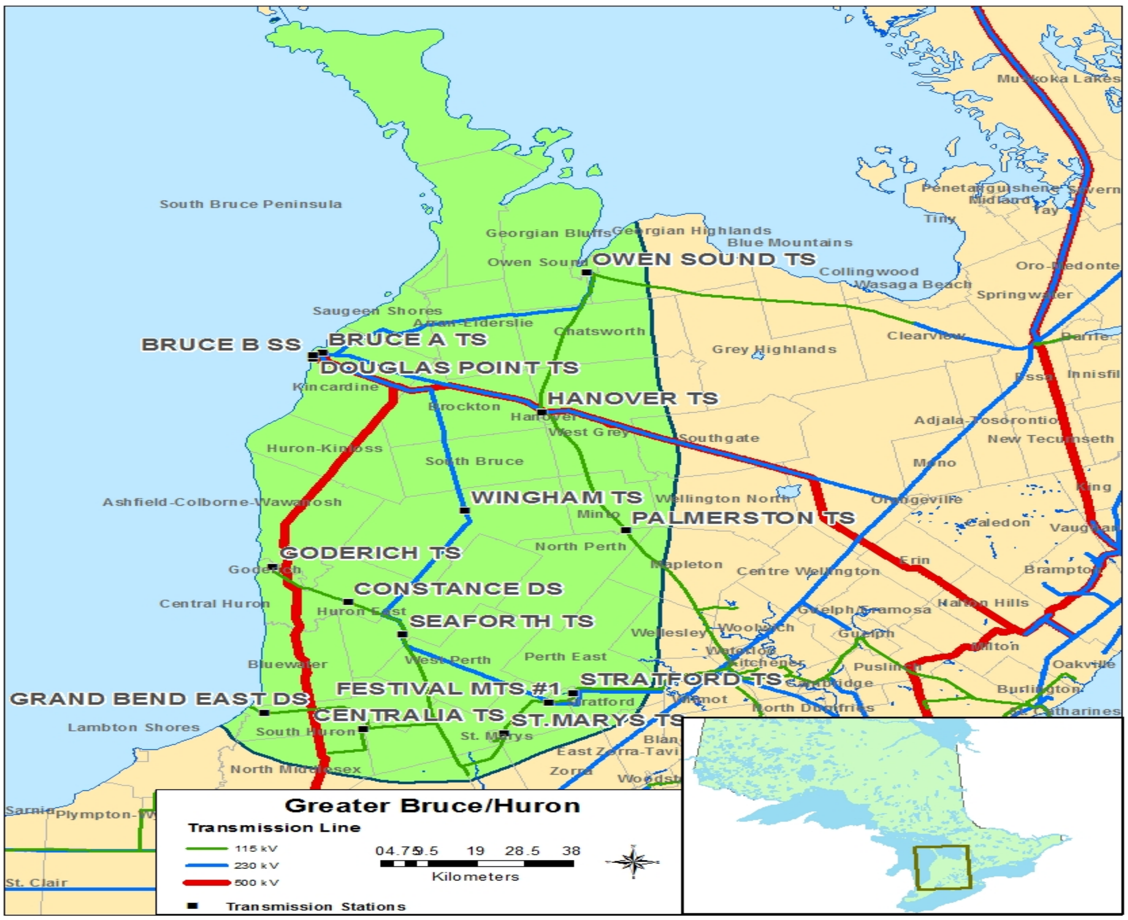

Figure 1-1 Greater Bruce-Huron Region

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. Electrical supply to the Region is provided from six 230 kV and twelve 115 kV step-down transformer stations. The boundaries of the Region are highlighted in Figure 1-1 above.

1.1 Objective and Scope

This RIP report examines the needs in the Greater Bruce-Huron Region. Its objectives are:

- To develop a wires plan to address needs identified in previous planning phases for which a wires only alternative was recommended by the Working Group
- 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 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 reviewed factors such as the load forecast, major high voltage sustainment work, 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 (2016-2025) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2016-2025 period
- 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 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 summarizes the Regional Plan to address the needs
- 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 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 options (e.g. CDM, generation and Distributed Energy Resources ("DER")) 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

[1] Also referred to a Needs Screening

specific wires alternatives and recommend the 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 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 was determined to 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/or LDCs for the Greater Bruce-Huron 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 and LP phases of regional planning.
- 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.

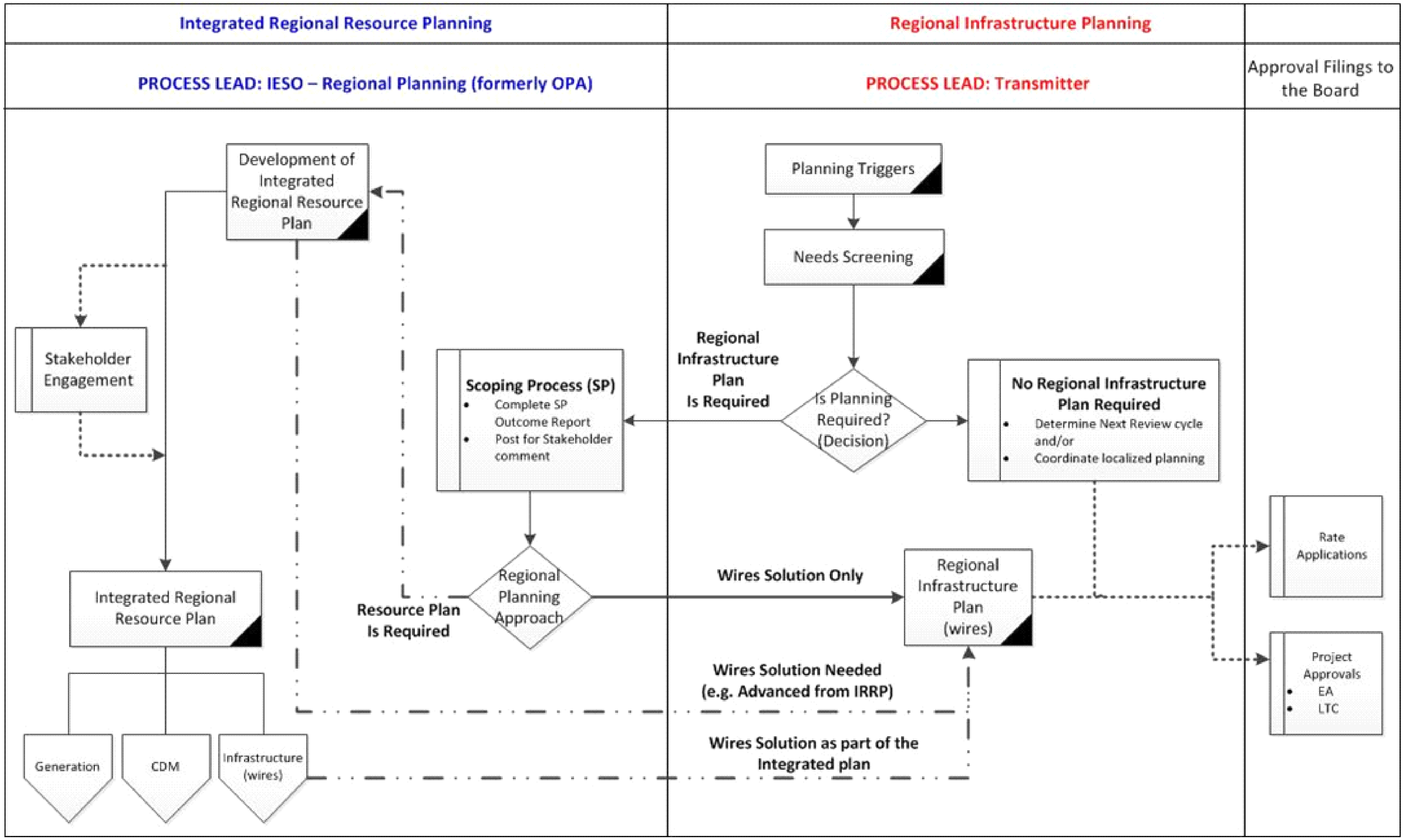

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of 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:
   - Gross and net peak demand forecast at the transformer station level. This includes the effect of any distributed generation and/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.

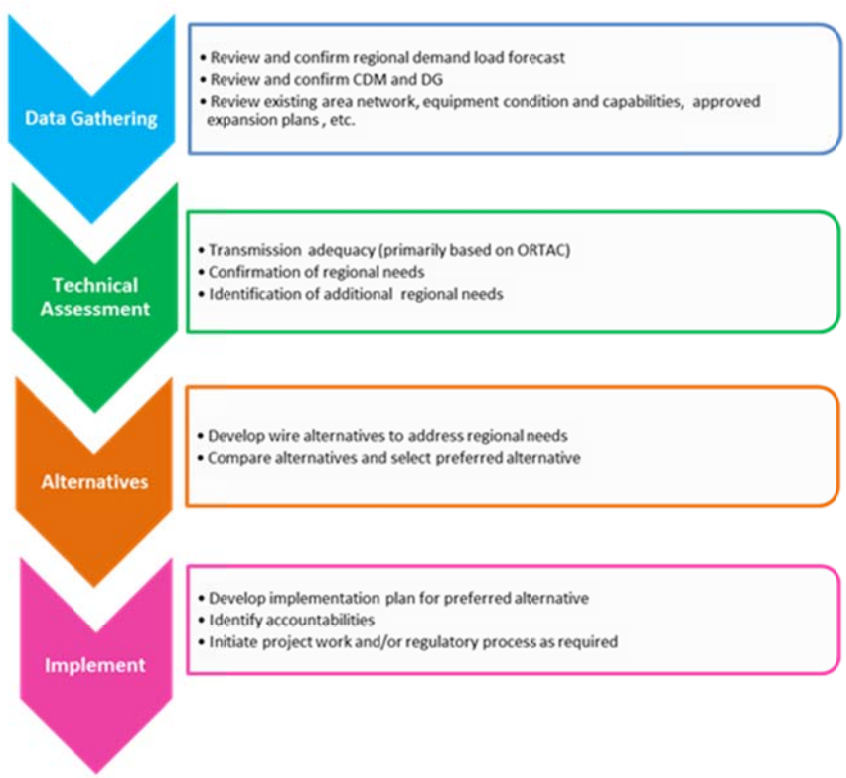

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER BRUCE-HURON REGION COMPRISES OF THE COUNTIES OF BRUCE, HURON, AND PERTH, AS WELL AS PORTIONS OF GREY, WELLINGTON, WATERLOO, OXFORD, AND MIDDLESEX COUNTIES AS SHOWN IN FIGURE 3-1.

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The majority of the electrical supply in the region is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Within the Region, electricity is delivered to the end users of LDCs and directly-connected industrial customers by eleven Hydro One step-down transformation stations, as well as seven customer-owned transformer or distribution stations supplied directly from the transmission system. Appendix A lists all step-down transformer stations in the Region. Appendix B lists all transmission circuits and Appendix C lists LDCs in the Region. The Single Line Diagram for the Greater Bruce-Huron Region transmission system facilities is shown below in Figure 3-2.

Figure 3-1 Geographical Area of the Greater Bruce-Huron Region with Electrical Layout

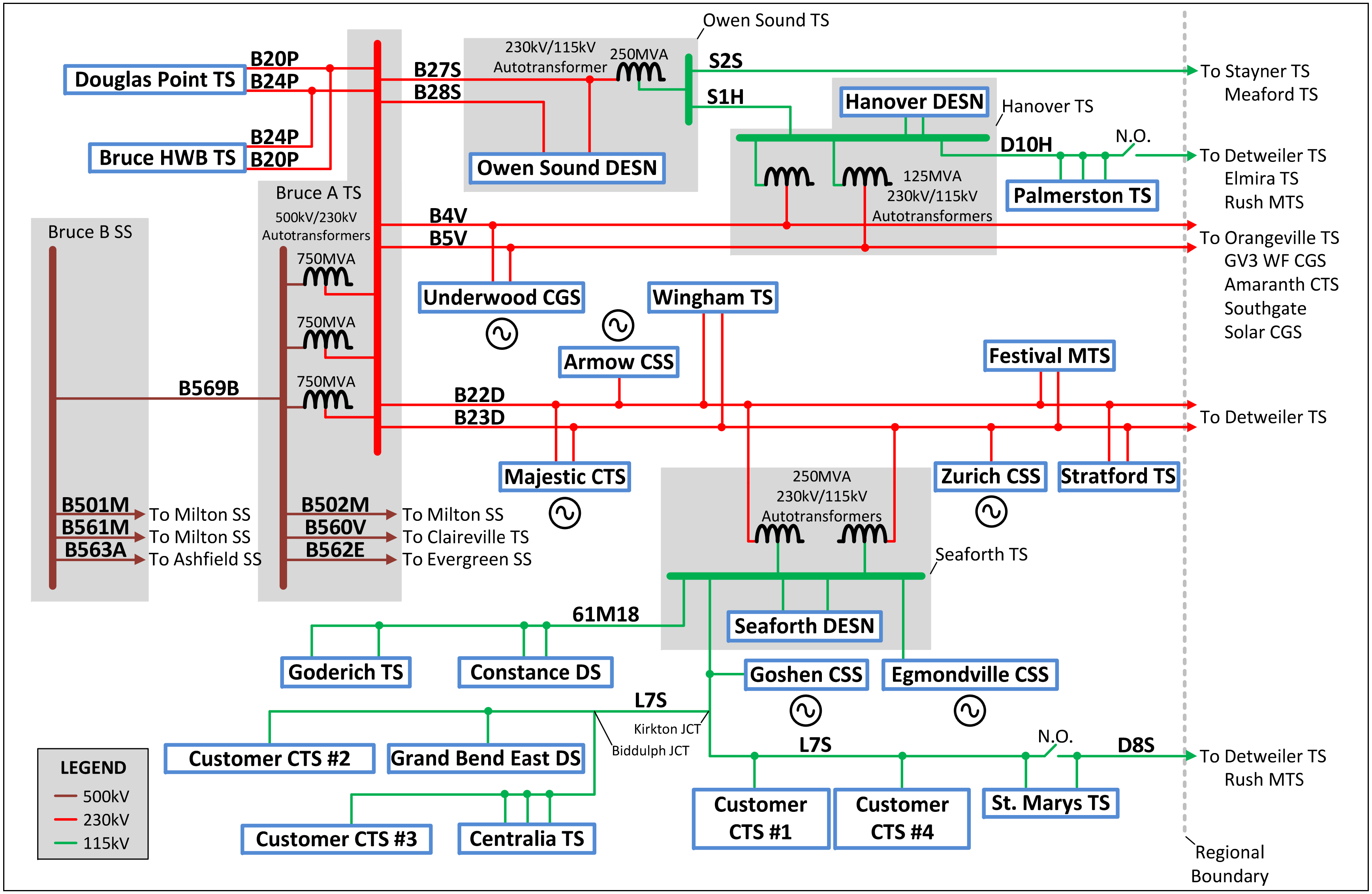

Figure 3-2 Greater Bruce-Huron Region Single Line Diagram

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

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 GREATER BRUCE-HURON REGION.

In addition to Hydro One's ongoing transmission station and line sustainment programs, specific 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 reactive and voltage support needs:

- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008

For bulk power system transfer needs:

- 500 kV double circuit line from the Bruce Nuclear Complex to Milton SS in 2011
- 230 kV Static Var Compensator (SVC) at Detweiler TS in 2011

For major station refurbishment needs based on asset condition assessment:

- Goderich TS in 2016

For renewable generation connection needs:

- 230 kV Melancthon Grey Wind Farm onto circuits B4V/B5V in 2006/2008
- 230 kV Ripley Wind Farm onto circuits B22D/B23D in 2007
- 230 kV Underwood Wind Farm onto circuits B4V/ B5V in 2008
- 230 kV Dufferin Wind Farm into Orangeville TS in 2014
- 500 kV Jericho/Adelaide/Bornish Wind Farms into Evergreen SS in 2014
- 230 kV Grand Valley 3 Wind Farm onto circuit B4V in 2015
- 115 kV Bluewater Wind Farm into Seaforth TS in 2015
- 115 kV Goshen Wind Farm onto circuit L7S in 2015
- 500 kV K2 Wind Farm into Ashfield SS in 2015
- 230 kV Grand Bend Wind Farm onto circuit B23D in 2016
- 230 kV Armow Wind Farm onto circuit B22D in 2016
- 230 kV Southgate Solar Farm onto circuit B4V in 2016

The following projects are underway:

- Centralia TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Palmerston TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Bruce A TS 230 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by 2019.
- Replacement of the Bruce Special Projection Scheme (BSPS) is currently underway with a projected in-service of 2018.
- Modification to the Bruce Reactor Switching Scheme (RSS) is currently underway with a projected in-service of 2018.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Bruce-Huron Region is forecast to increase annually between 2016 and 2025. The growth rate varies across the Region with most of the growth concentrated in the County of Bruce and more specifically in the Kincardine area. The Region's 2017 RIP load forecasts are provided in Appendix D and were prepared by the Working Group upon initiation of the RIP phase. The RIP forecasts are identical to the Needs Assessment forecast except as otherwise noted in Appendix D.

As per the load forecasts in Appendix D, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.4% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.3% from 2016-2025.

As per the load forecasts in Appendix D, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 0.8% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.6% from 2016-2025.

Figure 5-1 shows the Region's gross and net *winter* coincident forecasts while Figure 5.2 shows the Region's gross and net *summer* coincident forecasts. The regional-coincident (at the same time) forecast represents the total peak load of all 18 step-down transformer stations in the Region.

Based on historical load and on the coincident load forecasts, the Region's winter coincident peak load is larger than its summer coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors assessment for this Region was conducted for both summer and winter peak load.

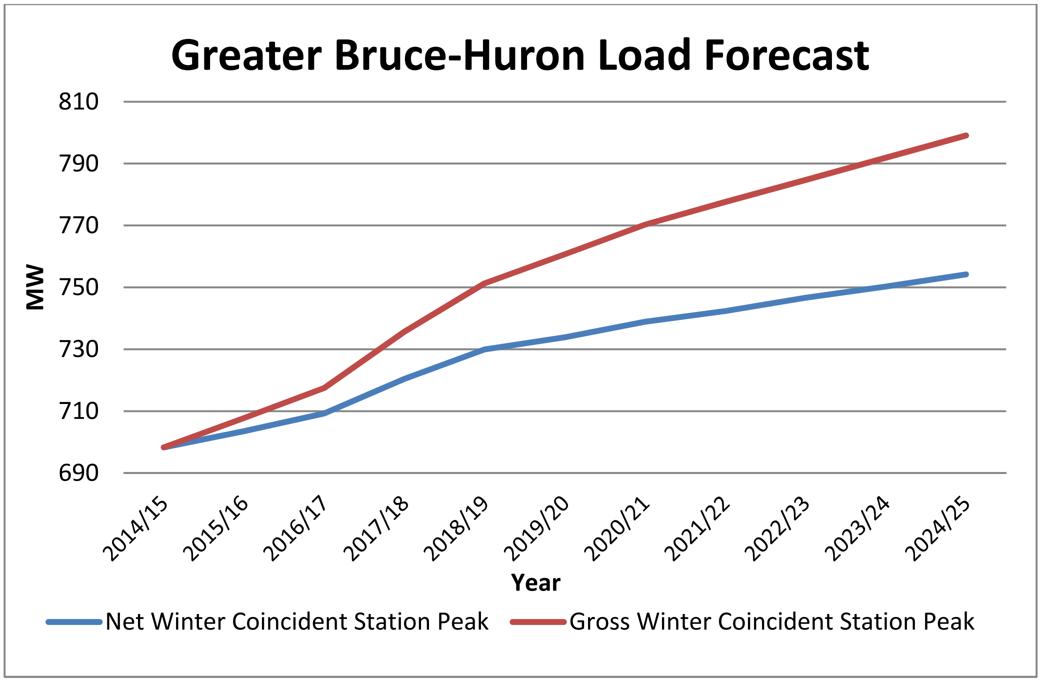

Figure 5-1 Greater Bruce-Huron Region Winter Extreme Weather Peak Forecast

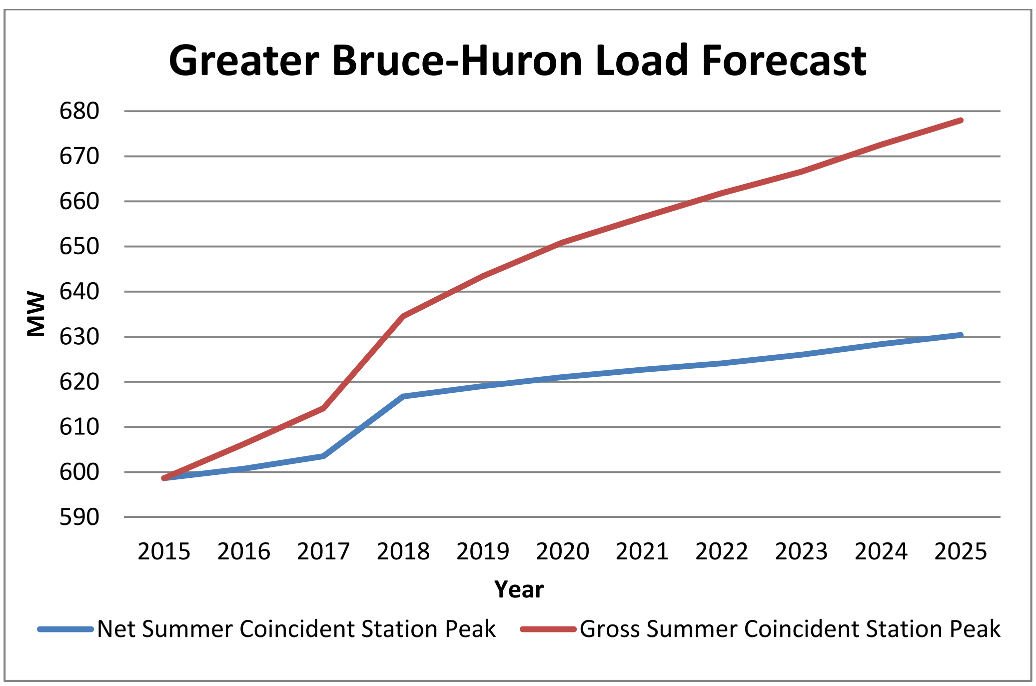

Figure 5-2 Greater Bruce-Huron Region Summer Extreme Weather Peak Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2016-2025.

2) All planned facilities listed in Section 4 are assumed to be in-service.

3) The Region contains some stations that are summer peaking and others that are winter peaking. The assessment is therefore based on both summer and winter peak loads.

4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.

5) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2016-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE GREATER BRUCE-HURON REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, five regional assessments have been conducted for the Greater Bruce-Huron Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report - Greater Bruce-Huron Region, May 2016
2) Local Planning Report - Low Power Factor at Wingham TS, October 2016
3) Local Planning Report - Circuit L7S Thermal Overload, November 2016
4) Local Planning Report - Low Power Factor at Bruce HWP B TS, May 2017
5) Customer Delivery Point Performance Review, 2016-2017

This RIP reviewed the loading on transmission lines and stations in the Greater Bruce-Huron Region based on the RIP load forecast. Sections 6.1-6.6 presents the results of this review and Table 6-1 lists the Region's needs identified in both the Needs Assessment and the RIP phases.

In addition, this RIP reviewed an updated list of Hydro One transmission lines and station major sustainment work over the next several years to determine if there are opportunities to consolidate with any emerging development needs within the Region. Section 7.5 presents the results of this review.

Table 6-1: Near and Mid-term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the Needs Assessment Report [1]			
Transmission Circuit Capacity	6.3	Overload on sections of 115 kV single circuit line, L7S	2019 (based on gross load forecast) 2025 (based on net load forecast)
Power Factor Review	6.5.2	Low power factor at Wingham TS	Immediate
		Low power factor at Bruce HWP B TS	Immediate
Customer Delivery Point Performance Review	6.5.1	Delivery points supplied from 115 kV circuits 61M18, L7S and D10H	Immediate
Additional Needs identified in RIP Phase			
Step-down Transformation Capacity	6.4	Hydro One Distribution (Kincardine area)	2019/2020

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the Greater Bruce-Huron Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the KWCG, Georgian Bay 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) Bruce A TS to Orangeville TS 230kV transmission circuits B4V/B5V – supplies Hanover TS
2) Bruce A TS to Detweiler TS 230kV transmission circuits B22D/ B23D – supplies Wingham TS, Seaforth TS, Festival MTS #1, and Stratford TS
3) Bruce A TS to Owen Sound TS 230kV transmission circuits B27S/B28S – supplies Owen Sound TS
4) Bruce A TS to Douglas Point TS 230kV transmission circuits B20P/B24P – supplies Douglas Point TS and Bruce HWP B TS

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.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the Greater Bruce-Huron 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) Three (3) 500/230kV autotransformers at Bruce A TS
2) Two (2) 230/115kV autotransformers at Seaforth TS
3) Two (2) 230/115kV autotransformers at Hanover TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the autotransformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The Greater Bruce-Huron Region contains four (4) single circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Hanover TS to Detweiler TS 115 kV transmission circuit D10H with Normally Open (N/O) point at Palmerston TS – supplies Palmerston TS & Elmira TS
2) Seaforth TS to Goderich TS 115 kV transmission circuit 61M18 – supplies Constance DS and Goderich TS
3) Seaforth TS to St. Marys TS 115 kV transmission circuit L7S – supplies Grand bend East DS, Lake Huron WTP CTS, Centralia TS, McGillivray R&BP CTS, Enbridge Bryanston CTS and St. Marys Cement CTS
4) Hanover TS to Owen Sound TS 115 kV transmission circuit S1H

The RIP review shows that based on current forecast station loadings, the supply capacity of the 115 kV network is adequate over the study period, except circuit L7S. Circuit L7S will exceed its thermal rating in 2019 based on gross load forecast, and in 2025 based on net load forecast.

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the Greater Bruce-Huron Region. Fourteen supply electricity to LDCs and four are transmission-connected industrial customer stations. These stations are listed in Appendix C. Of the 18 stations, 3 of them are owned and operated by LDCs.

As part of both the Needs Assessment as well as this RIP, step-down transformation station capacity was reviewed. Since the May 2016 Needs Assessment, the load forecasts at Seaforth TS, Stratford TS and Douglas Point TS have been modified; refer to Appendix E for the analysis of these modifications. The analysis showed that the load forecasts at Seaforth TS and Stratford TS can still be accommodated. However, the load forecast modification at Douglas Point TS will result in its transformation capacity limit being exceeded towards the end of the study period, winter 2023/2024. This is due to a 15 MW request for capacity made since the May 2016 Needs Assessment.

Furthermore, since updating the RIP forecast there has been additional connection requests for 2.2 MW, 0.5 MW and 20 MW of capacity by 2019/2020 at Douglas Point TS. The 2.2 MW and 0.5 MW requests can be accommodated within the station’s transformation capacity limits; however the 20 MW request would result in Douglas Point TS exceeding its transformation capacity within the near term (2019/2020) and cannot be fully accommodated at this time. Therefore additional step-down transformation capacity at/near Douglas Point TS is needed.

Based on the requirements of the customer requesting the 20 MW of connection capacity, three “need” scenarios have been developed:

Scenario 1 – If the customer requires all 20 MW of capacity immediately, the need for additional step-down transformation capacity is required in 2019/2020. Hydro One Transmission will work with Hydro One Distribution and the customer to develop a plan to meet the increased capacity requirement. All costs for the additional capacity will be allocated to the benefitting customer(s) as per the Transmission System Code.

Scenario 2 – If the customer accepts an offering to connect a portion of its load, the need for additional step-down transformation capacity is required in 2021 due to the inherent “organic” growth of load. In order to meet the need timeline, an expedited coordinated regional planning process will be undertaken by the IESO, Hydro One Transmission and Hydro One Distribution. Cost allocation for additional investment will depend on the solution to address the need.

Scenario 3 – If the customer elects not to proceed with its connection request, the need for additional step-down transformation capacity is require by 2023/2024. CDM would help to defer the need and therefore it is recommended to monitor load growth and re-evaluate the need in the next regional planning cycle.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Delivery Point Performance

The Needs Assessment section 6.2.5 identified that a performance review of several 115 kV customer delivery points be undertaken. A summary of the review is provided in Appendix F.

6.5.2 Low Power Factor Concerns

The Needs Assessment sections 6.2.3 identified two stations which historically have low power factor: Wingham TS and Bruce HWB TS.

6.6 Long-Term Regional Needs

A long-term, beyond 10 year, analysis was not deemed necessary by the Working Group for the Region at this time and therefore no long-term studies have been undertaken. 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 SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS LISTED IN TABLE 6-1.

7.1 Transmission Circuit Capacity

7.1.1 Circuit L7S

L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Marys TS. As per section 6.1.3 of the Needs Assessment, the circuit will reach its Load Meeting Capability ("LMC") in 2019 based on the gross load forecast and 2025 based on the net load forecast.

Recommended Plan and Current Status

To address the transmission circuit capacity needs for L7S, the Local Planning working group created a Development Plan which recommended monitoring load growth at stations supplied from circuit L7S. The Development Plan is detailed in the Local Planning report [3]. The Development Plan specified that when loading on L7S is expected to exceed its limits within a 3 year period, Hydro One Transmission will increase the thermal rating of the limiting spans of circuit L7S. The cost to increase the rating is currently estimated to be approximately $550 k. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period. Loading beyond the study period's forecast may then require additional voltage support. Capacity cost allocation will be as per the Transmission System Code.

Current Status of the Loading on Circuit L7S

The past winter (2016/2017) loading on circuit L7S was reviewed in accordance with the Development Plan. Winter peak coincident loading on the circuit was approximately 65% of the circuit capacity and did not trigger the need to increase the rating. Monitoring will continue after each peak load season, winter and summer.

7.2 Power Factor Review

7.2.1 Wingham TS

Power factor at Wingham TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Wingham TS is to be managed by the transmitter and affected LDCs.

Recommended Plan and Current Status

The power factor review conducted by the Local Planning working group, showed that the power factor of the load itself remains within Market Rule requirements. Further investigation revealed that the low power factor is due to the connected Distributed Generation (DG). The investigation is detailed in the Local Planning report [2]. The Local Plan recommends no mitigation is required at this time and to seek IESO's direction on power factor requirements with respect to DG.

<u>Current Status of Power Factor with Respect to Distributed Generation</u>

At this time, IESO does not recommend a Market Rule power factor amendment as the measured power factor is due to the connected DG and asks that a case by case review be conducted when the power factor consistently does not meet the Market Rule requirement.

7.2.2 Bruce HWP B TS

Power factor at Bruce HWP B TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Bruce HWP B TS is to be managed by the transmitter and the affected customer.

Recommended Plan

The power factor review conducted by the Local Planning working group, showed that while the power factor of the load occasionally (rather than often as previously identified) does not meet Market Rule requirements there is no negative effect at this time. The investigation is detailed in the Local Planning report [4]. The Local Plan recommends no mitigation is required at this time.

7.3 Customer Delivery Point Performance

7.3.1 Customers Supplied from Circuit 61M18

The performance of delivery points supplied from circuit 61M18, specifically Constance DS and Goderich TS were reviewed. The review is summarized in Appendix F, section F.1.

Recommended Plan and Current Status

To address delivery point performance to Constance DS and Goderich TS, it is recommended that Hydro One Transmission continue to rely on its line and station maintenance programs, as well as capital sustainment projects listed in section 4.0 and in Table 7-1 to improve the overall reliability.

<u>Current Status of Sustainment Work associated 61M18 Delivery Points</u>

The 17 remaining original 1959 structures on circuit 61M18 along with 11 other structures are schedule to be tested over the next 2 years. Those that are determined to be End-Of-Life (in poor condition), will then be replaced in the next 5 years. These replacements will occur under Hydro One's Line Sustainment programs.

7.3.2 Customers Supplied from Circuit L7S

The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Marys TS and the 4 industrial customer connections, were reviewed. The review is summarized in Appendix F, section F.2.

Recommended Plan

To address delivery point performance, it is recommended that Hydro One Transmission undertake a staged approach. Stage 1 will entail a detailed field screening of the line for approximately $154 thousand in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches on circuit L7S to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution from customers is not anticipated at this time. If, however, capital contribution is required from customers such financial obligation will be determined using methodology set out in the Transmission System Code.

7.3.3 Customers Supplied from Circuit D10H

The performance of delivery points supplied solely from circuit D10H, specifically Palmerston TS and Elmira TS were reviewed. The review is summarized in Appendix F, section F.3.

Current Status

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution might be required from customers and such financial obligation will be determined using methodology set out in the Transmission System Code.

7.4 Step-Down Transformation Capacity

7.4.1 Hydro One Distribution

The RIP load forecast in conjunction with more recent requests for step-down transformation capacity by Hydro One Distribution at Douglas Point TS indicates that additional step-down transformation capacity is needed.

Current Status

Hydro One Distribution is currently working with its customer to determine their connection capacity requirements, size and timeline. Once the customer's requirements are firm, one of the three "need" scenarios outlined in section 6.4 of this report will be undertaken.

7.5 Transmission Sustainment Plans

As part of Hydro One's transmitter requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Table 7.1 lists Hydro One's major transmission sustainment *projects* in the Region that are currently planned or underway. There is currently no major line sustainment *projects* planned within the next 5 years. Maintenance *programs* such as insulator, shield wire, structure replacements will continue to be carried out in the Region as required based on equipment/asset condition assessments.

Table 7-1: Hydro One Transmission Major Sustainment Initiatives[2]

Station	General Description of Work	Planning In Service Date
Bruce A TS	• Replacement of 230 kV circuit breakers • Uprating of the station strain buses • Replacement of Protections and Control relay building	2019
	• Replacement of 500 kV circuit breakers and switches • Replacement of 2 autotransformers 500/230 kV • Upgrading of Protection and Control equipment	2025
Bruce B SS	• Replacement of 500 kV circuit breakers and switches	2021

[2] Scope and dates as of July 2017 and are subject to change

Centralia TS	• Replace existing 3 transformers with a typical 25/42 MVA 2 transformer arrangement • Replacement of 27.6 kV switchyard • Installation of new PCT Facilities	2019
Detweiler TS	• Replacement of AC and DC station service	2018
	• Replacement of T2 and T4 autotransformers and upgrade to spill containment • Replacement Protection and Control equipment	2021
Hanover TS	• Replacement of T1/T2 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems and CVT's *Additional scope of work currently under development*	2023
Palmerston TS	• Replace existing 3 transformers with a typical 50/83 MVA 2 transformer arrangement. • Replacement of low voltage switches • Replacement of Protection and Control systems with new PCT facilities • Upgrade to AC & DC station services	2019
Seaforth TS	• Replacement of 2 autotransformers 230/115 kV • Replacement of 2 step-down transformers 115/27.6 kV • Replacement of 230kV switches • Upgrade Protection and Control systems • Updated AC & DC station service	2023
Wingham TS	• Complete station refurbishment *Additional scope of work currently under development*	2022

Based on the needs identified in the region thus far and the transmission sustainment plans listed in Table 7-1, consolidation of sustainment and development needs is not necessary at this time.

8. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER BRUCE-HURON REGION.

Five near and mid-term needs were identified for the Greater Bruce-Huron Region. They are:

I. Transmission Circuit Capacity on L7S

II. Low power factor at Wingham TS

III. Low power factor at Bruce HWB TS

IV. Customer delivery point performance review on the 115 kV system

V. Step-down transformation capacity at Douglas Point TS

This RIP report addresses all five of these needs and has concluded that no regional plans for needs I, II and III are required at this time. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans needs IV and V 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	In-Service Date	Cost	Needs Mitigated
1	Improve 3L7S Delivery Point Performance	2 Stage Plan	Hydro One Transmission	2017-2023	$154k - TBD	IV
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	Await Customer Direction	Hydro One Distribution	TBD	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] Hydro One, "Needs Assessment Report, Greater Bruce-Huron Region", 6 May 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf

[2] Hydro One, "Local Planning Report – Low Power Factor at Wingham TS Assessment", 18 October 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20Wingham%20TS%20Power%20Factor%20Assessment.pdf

[3] Hydro One, "Local Planning Report – L7S Thermal Overload", 14 November 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20L7S%20Thermal%20Overload.pdf

[4] Hydro One, "Local Planning Report – Low TS Power Factor at Bruce heavy Water B TS Assessment", 12 May 2017. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Bruce%20HWB%20TS%20Power%20Factor%20Assessment%20-%20FINAL.PDF

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE GREATER BRUCE-HURON REGION

Station	Voltage (kV)	Supply Circuits
Bruce HWP B TS	230 kV	B20P/B24P
Douglas Point TS	230 kV	B20P/B24P
Hanover TS	115 kV	B4V/B5V
Owen Sound TS	230 kV	B27S/B28S
Seaforth TS	115 kV	B22D/B23D
Stratford TS	230 kV	B22D/B23D
Wingham TS	230 kV	B22D/B23D
Festival MTS #1	230 kV	B22D/B23D
Palmerston TS	115 kV	D10H
Goderich TS	115 kV	61M18
Constance DS	115 kV	61M18
St. Marys TS	115 kV	L7S
Customer CTS #1	115 kV	L7S
Centralia TS	115 kV	L7S
Grand Bend East DS	115 kV	L7S
Customer CTS #2	115 kV	L7S
Customer CTS #3	115 kV	L7S
Customer CTS #4	115 kV	L7S

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE GREATER BRUCE-HURON REGION

Location	Circuit Designation	Voltage (kV)
Bruce A TS - Orangeville TS	B4V/B5V	230 kV
Bruce A TS - Detweiler TS	B22D/ B23D	230 kV
Bruce A TS - Owen Sound TS	B27S/B28S	230 kV
Bruce A TS - Douglas Point TS	B20P/B24P	230 kV
Hanover TS – Palmerston TS	D10H-North	115 kV
Seaforth TS - Goderich TS	61M18	115 kV
Seaforth TS - St. Marys TS	L7S	115 kV
Owen Sound TS – Hanover TS	S1H	115 kV

APPENDIX C: DISTRIBUTORS IN THE GREATER BRUCE-HURON REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Constance	Tx
	Centralia TS	Dx
	Grand Bend East DS	Tx
	Douglas Point TS	Dx
	Goderich TS	Dx
	Hanover TS	Dx
	Owen Sound TS	Dx
	Palmerston TS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Wingham TS	Dx
Erie Thames Power Lines Corporation	Constance DS	Dx
Festival Hydro Inc.	Grand Bend East DS	Dx
	Seaforth TS	Dx
	Stratford TS	Dx
	Festival MTS #1	Tx
Lake Huron Primary Water Supply System	Lake Huron WTP CTS	Tx
Lake Huron Primary Water Supply System	McGillivray R&BP CTS	Tx
West Coast Huron Energy Inc.	Goderich TS	Tx
Enbridge Pipeline Inc.	Enbridge Bryanston CTS	Tx
St. Marys Cement Inc.	St. Marys Cement CTS	Tx

APPENDIX D: REGIONAL LOAD FORECAST (2016-2025)

Table D-1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS*	33.44	33.65	37.25	33.62	33.87	34.12	34.28	34.44	34.59	34.74
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS*	80.14	80.81	81.39	85.46	86.20	86.93	87.56	88.18	88.79	89.41
Wingham TS	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS*	47.40	47.40	63.29	63.76	64.26	64.64	65.03	65.41	65.78	66.18
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.71	76.94	77.62	78.60	79.25	79.71	80.12	80.53	80.93	81.32
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS*	30.68	34.34	30.56	30.78	30.99	31.14	31.27	30.78	31.54	31.67
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS*	78.09	78.59	82.38	83.14	83.91	84.52	85.11	85.70	86.29	86.88
Wingham TS	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

*Updated March 2017 for RIP

Table D-3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	96.65**	97.40	98.12	99.09	100.07	101.06	101.71	102.33	102.97	103.58
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	68.03**	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS*	34.75	34.96	38.70	34.92	35.19	35.44	35.62	35.78	35.93	36.09
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS*	84.52	85.23	85.84	90.13	90.91	91.69	92.36	93.00	93.65	94.30
Wingham TS	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS*	48.06	48.06	64.17	64.65	65.15	65.54	65.93	66.32	66.69	67.10
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	75.61**	75.84	76.50	77.47	78.12	78.57	78.97	79.37	79.77	80.15
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	54.71**	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS*	31.00	34.70	30.87	31.10	31.31	31.46	31.59	31.10	31.86	31.99
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS*	88.42	88.99	93.28	94.15	95.01	95.70	96.38	97.05	97.71	98.37
Wingham TS	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS*	33.24	33.26	36.45	32.63	32.64	32.68	32.68	32.72	32.71	32.72
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS*	79.65	79.87	79.65	82.97	83.08	83.29	83.48	83.78	83.99	84.23
Wingham TS	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS*	47.00	46.67	61.64	61.45	61.39	61.39	61.38	61.49	61.50	61.58
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.70	38.50	38.18	37.98	37.84	37.74	37.63	37.59	37.50	37.43
Grand Bend East DS	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS*	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS*	77.42	77.37	80.20	80.09	80.13	80.23	80.31	80.53	80.65	80.80
Wingham TS	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

*Updated March 2017 for RIP

Table D-7: Net – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.77*	102.99	102.75	102.81	103.07	103.48	103.63	103.90	104.09	104.30
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS*	33.66	33.68	36.92	33.05	33.05	33.10	33.09	33.13	33.13	33.14
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS*	83.99	84.23	84.00	87.49	87.61	87.83	88.03	88.34	88.57	88.83
Wingham TS	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

Table D-8: Net – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	47.66	47.32	62.49	62.30	62.24	62.24	62.23	62.35	62.36	62.44
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.41	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.73	86.68	89.84	89.72	89.77	89.88	89.97	90.21	90.35	90.52
Wingham TS	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Updated March 2017 for RIP

APPENDIX E: RIP TRANSMISSION ADEQUACY ASSESSMENT

This table assesses the impact of the updated March 2017 RIP load forecast based on the original findings of the May 2016 Needs Assessment.

Change in Load Forecast	Seaforth TS			Stratford TS			Douglas Point TS		
		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW
Red font indicates an increase in forecasted load from the Needs Assessment.	summer: 2025 Gross	31.67	31.67	summer: 2025 Gross	86.88	98.37	summer: new 2025 Gross	66.18	67.1
	summer: 2025 Net	29.42	29.42	summer: 2025 Net	80.8	90.52	summer: new 2025 Net	61.58	62.44
	summer 10 Day LTR	39.3 MW		summer 10 Day LTR	104.4 MW		summer 10 Day LTR	87.5 MVA	
Green font indicates a reduction in forecasted load from the Needs Assessment.	winter: new 2025 Gross	34.74	36.09	winter: new 2025 Gross	89.41	94.3	winter: new 2025 Gross	99.39	99.39
	winter: new 2025 Net	32.72	33.14	winter: new 2025 Net	84.23	88.83	winter: new 2025 Net	93.64	93.64
	winter 10 Day LTR	49.9 MW		winter 10 Day LTR	115.7 MW		winter 10 Day LTR	98.8 MW	

	Seaforth TS	Stratford TS	Douglas Point TS
Historical Power Factor	N/A	N/A	N/A
Load Security	no negative impact	no negative impact	no negative impact
Load Restoration	no negative impact	no negative impact	no negative impact
Voltage Performance	no negative impact	no negative impact	no negative impact
CDPP	N/A	N/A	N/A
230/115 kV Autos	no negative impact	no negative impact	no negative impact
230 kV Lines	no negative impact	no negative impact	no negative impact
115 kV Lines	no negative impact	no negative impact	no negative impact
Step down Transformation Capacity	no negative impact	Study shows that there is a slight impact but loading remains within LTR and at least one LV cap must be in-service during summer loading by the end of the study period. This is similar to the Needs Assessment results.	Study shows that the gross winter forecast loading is at the LTR in winter 2023/2024. All summer forecasts show loading is within LTR for the study period.
Bulk System Performance	no negative impact	no negative impact	no negative impact

APPENDIX F: CUSTOMER DELIVERY POINT PERFORMANCE REVIEW

Based on the recommendations from the May 2016 Needs Assessment, 15 customer delivery points were reviewed in detail to assess their reliability performance. Reliability performance of a delivery point is a measure of the frequency of interruption and duration of interruption. The yearly frequency and yearly total duration of interruptions are compared against Hydro One performance standards filed with the OEB, [EB-2002-0424, updated February 7, 2008].

All 15 delivery points are supplied solely from single circuit 115 kV transmission lines and are grouped as follows:

Table F-1 - Customer Delivery Points

Single circuit 115 kV Transmission Line	Station	# of Customer Delivery Points
61M18	Goderich TS	2
	Constance DS	1
L7S	Centralia TS	2
	Grand Bend East DS	1
	St. Mary TS	1
	Industrial Customer # 1	1
	Industrial Customer # 2	1
	Industrial Customer # 3	1
	Industrial Customer # 4	1
D10H -North	Palmerston TS	2
D10H - South	Elmira TS	2

The reliability performance of the delivery points were studied in groups based on their connection point to the transmission system, specifically their 115 kV transmission line supply as shown in Table F-1.

The review of each delivery point included a 10 year review of interruptions between years 2006 and 2015. The interruptions were compared against each delivery points "Group" metrics as defined in the OEB filing as well as each delivery points "Individual Historical Performance" as defined in the OEB filing. Where the yearly performance did not meet either the Group or Individual standards for either frequency or duration of interruptions, Hydro One Transmission classified the delivery point as an "Outlier". Based on a delivery point's Outlier status, their reliability performance is reviewed. The summary of review is given below.

F.1 Delivery Points Supplied by Transmission Line 61M18

In the past, 2006-2010, Goderich TS was classified as a Group Outlier for both frequency and duration of interruption. Recently it is classified as a Group Outlier for duration only. These classifications are mainly due to past equipment failures at Seaforth TS and recently as a consequence of line 61M18 tied to line L7S while L7S experienced interruptions.

Constance DS is not classified as a Group Outlier; however it is occasionally classified as an Individual Outlier for duration of interruption. Although Constance DS is subject to the same line 61M18 interruptions as Goderich TS, it is typically not classified as a Group Outlier because it has less stringent performance metrics due to the smaller amount of load (MW) supplied from it.

The review showed that the root cause of interruptions is due to the performance of the transmission line 61M18 during adverse weather. When 61M18 is interrupted, all load connected to Constance DS and Goderich TS is left unsupplied. As line 61M18 is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Overall, customers supplied from Constance DS and Goderich TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line’s susceptibility to faults caused by external forces such as lightning and storms.

As upgrading the transmission supply to these stations is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it is recommended for Hydro One Transmission to continue to rely on its Line and Station maintenance and capital sustainment projects to improve the overall reliability performance to delivery points. Based on customer consultations, Goderich Hydro - West Coast Huron Energy Inc., Erie Thames Power and Hydro One Distribution have agreed to this approach and will continue to monitor performance.

F.2 Delivery Points Supplied by Transmission Line L7S

Centralia TS is classified as a Group Outlier for both frequency and duration of interruption. Recently in 2013 and 2014 is has also been classified as an Individual Outlier for duration of interruption.

Grand Bend East DS is classified as a Group Outlier for both frequency (occasionally) and duration (consistently) of interruption, as well as an Individual Outlier for duration.

All four industrial customer delivery points are occasionally classified at a Group Outlier for frequency of interruption; while one of them often is classified as a Group Outlier for duration of interruption. Over the past 3 years, the industrial customer delivery points have often been classified as Individual Outliers for duration.

The review showed that the root cause of interruptions is due to the performance of the transmission line L7S during adverse weather. When L7S is interrupted, all load connected to it is left unsupplied. As line L7S is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Depending on prevailing system conditions, manual switching on the transmission system can be performed to resupply some L7S load from Detweiler TS via 115 kV circuit D8S. Overall, customers supplied from L7S have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line's susceptibility to faults caused by external forces such as lightning and storms.

Due to the Individual Outlier classification of delivery points supplied from L7S it is recommended that a focused line assessment is undertaken. Although major upgrades to the transmission supply is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it remains the recommendation for Hydro One Transmission to improve the reliability of transmission line L7S. A two stage approach is prudent. Stage 1 will entail a detailed field screening of the line for approximately $154 k in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. It is expected that reduction to the frequency of interruptions will reduce the total duration of interruptions. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location.

Based on customer consultations, Festival Hydro, Hydro One Distribution and the industrial customers have agreed to this approach.

F.3 Delivery Points Supplied by Transmission Line D10H

115 kV circuit D10H between Detweiler TS and Hanover TS is operated normally-open at Palmerston TS whereby Palmerston TS is normally supplied from Hanover TS (D10H-North) while Elmira TS is normally supplied from Detweiler TS (D01H – South).

Over the past 3 years, Palmerston TS has been classified as a Group Outlier for both frequency and duration of interruption. It has not been classified as an Individual Outlier over the 10 year review period.

Over the past 3 years, Elmira TS has been classified as a Group Outlier for both frequency and duration of interruption. It has been classified as an Individual Outlier once in the 10 year review period; specifically in 2013 for frequency of interruption.

The review showed that the root cause of interruptions is due to the performance of the transmission lines D10H-North and D10H-South during adverse weather. When D10H-North is interrupted, all load connected to Palmerston TS is left unsupplied. When D10H-South is interrupted, all load connected to Elmira TS is left unsupplied. Since there are several 115 kV in-line switches along D10H and depending on prevailing system conditions, circuit D10H can be reconfigured to supply Palmerston TS and Elmira TS from either the Hanover TS or Detweiler TS ends. 115 kV in-line switches at Palmerston TS have the capability to be operated remotely. There are two other manual-operated switches surrounding the tap to Elmira TS.

Overall, customers supplied from Palmerston TS and Elmira TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance comparable to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line’s susceptibility to faults caused by external forces such as lightning and storms.

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M.

APPENDIX G: 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

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Niagara
Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Alectra Utilities
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham.

The Needs Assessment ("NA") report for the Niagara Region was completed on April 30th, 2016 (see attached). The report concluded that there were only two needs in the Region and that they should be addressed as follows:

- Thermal overloading of 115kV circuit Q4N: Addressed in a Local Plan ("LP") report.

The loading constraints on 115kV circuit Q4N was addressed in a LP report led by Hydro One Networks Inc. and published on November 11th, 2016. The report concluded that Hydro One already has plans to replace the existing section of conductor between Sir Adam Beck SS #1 and Portal JCT with a 910A continuous rating conductor at 93°C as part of their Beck #1 SS Refurbishment project. The expected in-service date for this conduction section upgrade is December 2019.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the Niagara Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
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Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment 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 Needs Assessment Report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the Needs Assessment Report (“the Other Third Parties”), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region Description and Connection Configuration

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

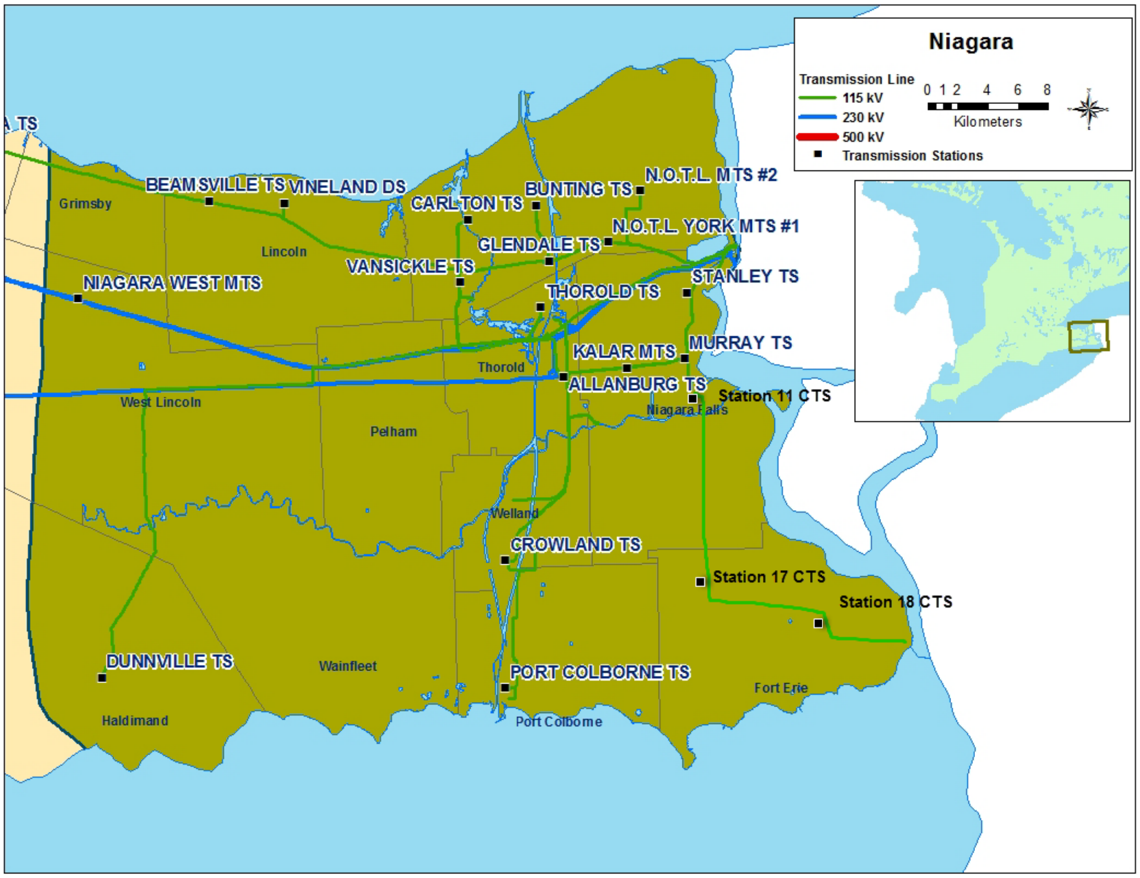

Figure 1: Niagara Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

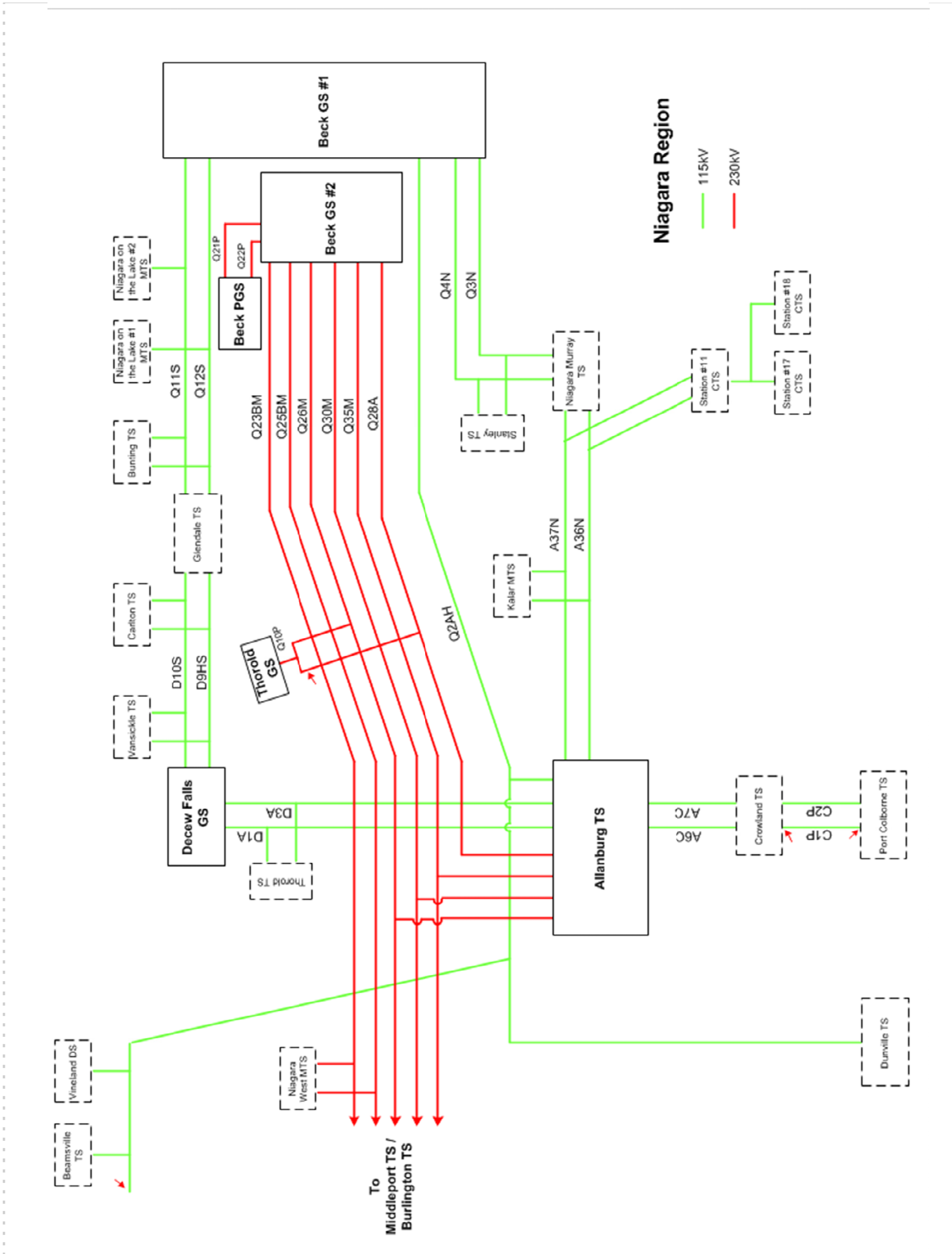

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

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

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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LOCAL PLANNING REPORT

Q4N THERMAL OVERLOAD

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

TABLE OF CONTENTS

LIST OF FIGURES

1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

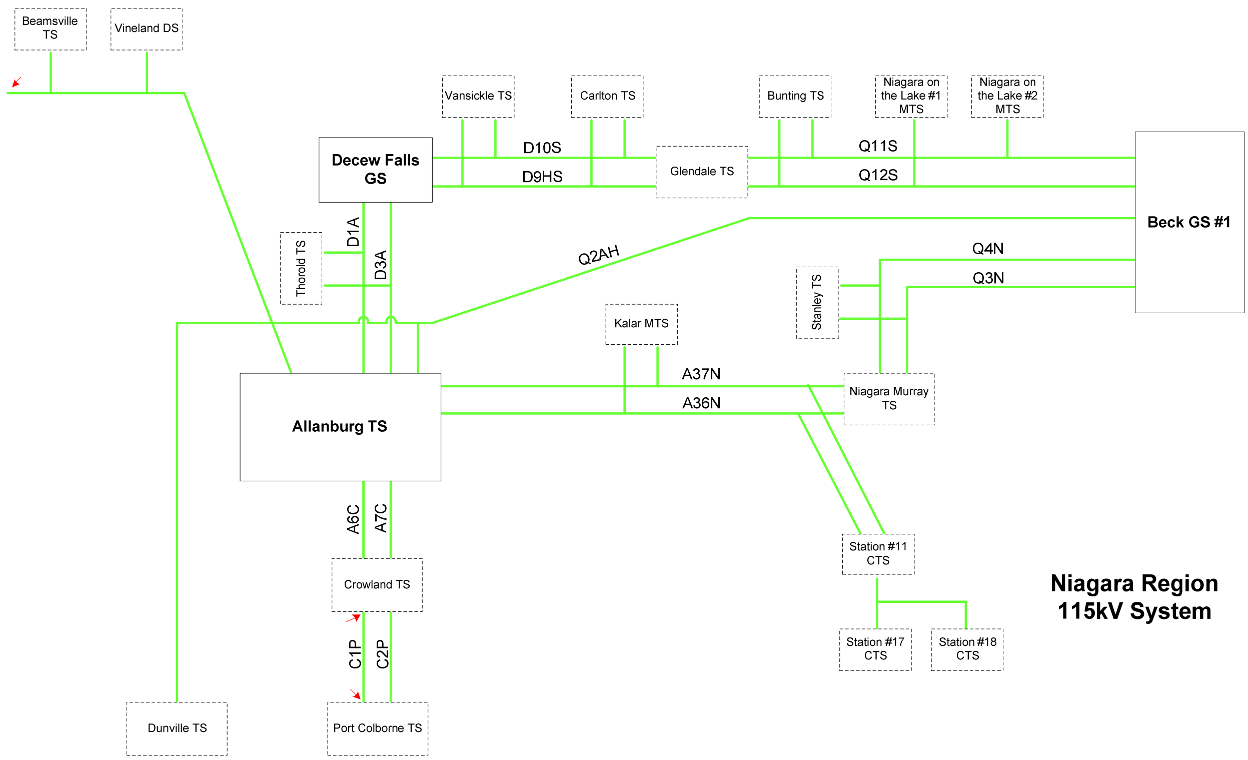

Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

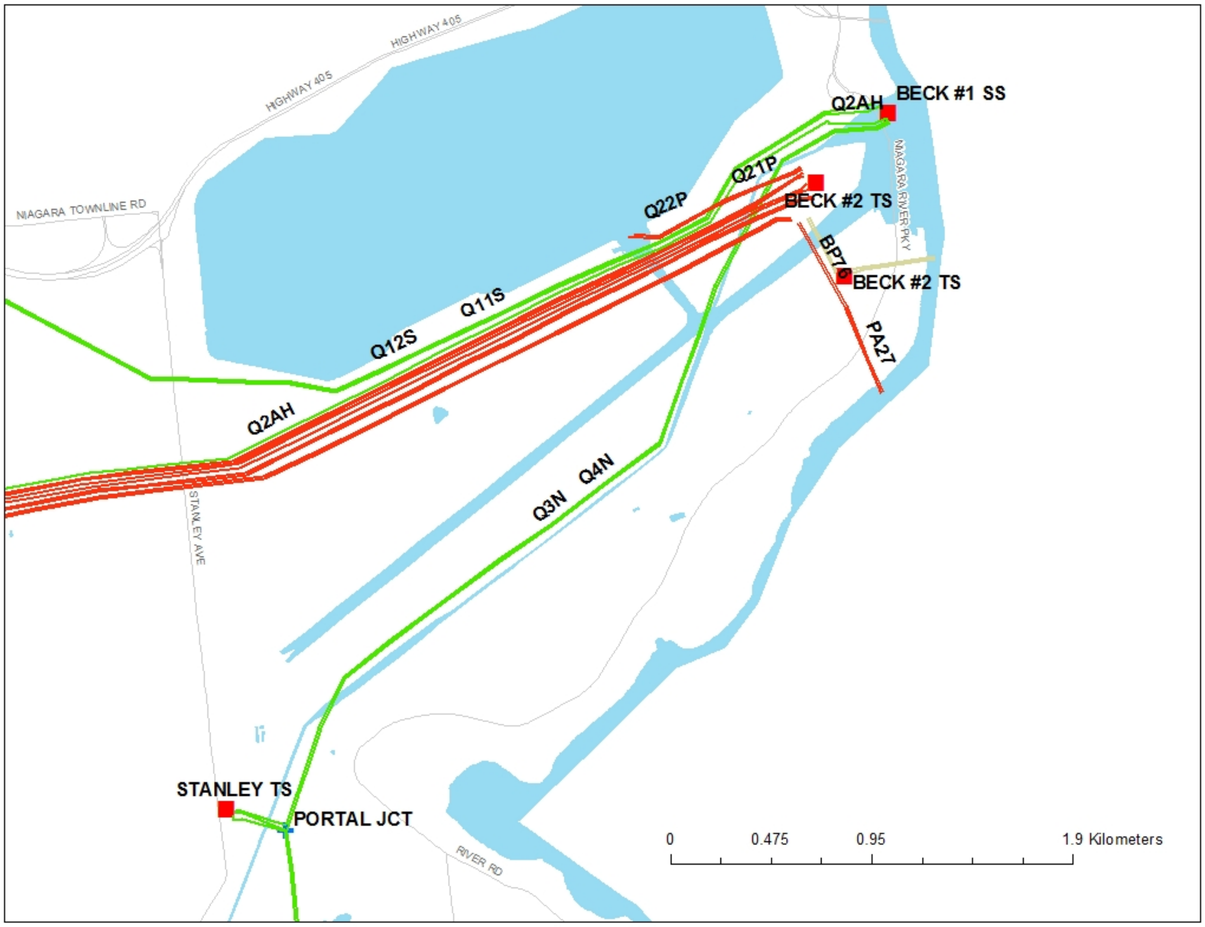

Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for "Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz" it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93°C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93°C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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North/East of Sudbury

Regional Infrastructure Plan ("RIP")

April 13, 2017

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

North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

The Local Planning ("LP") report for the North/East of Sudbury Region was completed on August 8, 2016 (see attached), and identified the following needs in the region:

- Timmins TS/Kirkland Lake TS – Voltage Regulation Issues:

In the LP report, the study team acknowledged that the Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. Operating measures are established to control the voltage decline post contingency, and the study team concluded no action is currently required. Hydro One will continue to monitor Timmins area load growth to ensure operating measures outlined in the LP report continue to be effective for voltage regulations.

The LP also report concluded that corrective actions to control voltage violations on the system may be required for any new loads in the Kirkland Lake or Dymond area.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the North/East of Sudbury Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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

LOCAL PLANNING REPORT

Timmins / Kirkland Lake Voltage Regulation
Region: North & East of Sudbury

Revision: FINAL
Date: August 8, 2016

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning 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 Local Planning Report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the Local Planning 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 Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 9, 2016	**END DATE**	November 30, 2016

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only option and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region dated April 15, 2016. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 7 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the North & East of Sudbury region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Timmins and Kirkland Lake area voltage regulation are local needs addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the Timmins TS voltage regulation need with the following options;

Alternative 0 – Status Quo.

Alternative 1 - Implement a Load Rejection Scheme on T61S and P7G

Hydro One (Transmitter) and Hydro One Distribution (LDC) have agreed that Alternative 0 – Status Quo is the only option to be considered for Kirkland Lake TS voltage regulation need.

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time for both the Timmins TS and Kirkland Lake TS voltage regulation needs are Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

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1 Introduction

The Needs Assessment (NA) for the North & East of Sudbury ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the North & East of Sudbury Region over the next ten years (2016-2026) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

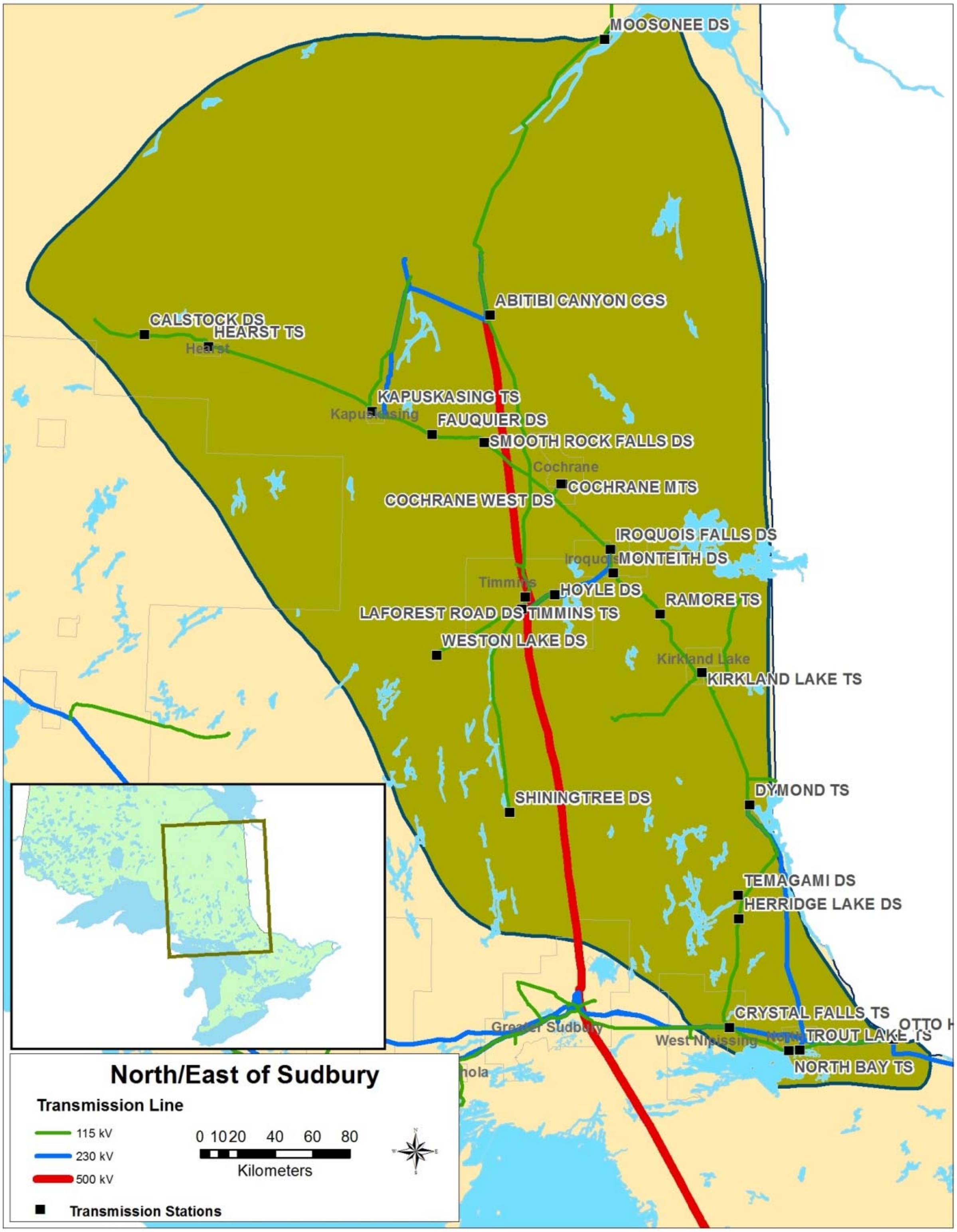

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS. This region has the following four local distribution companies (LDC):

Hydro One Networks (distribution)
Northern Ontario Wires Inc
Hearst Power Ltd
North Bay Hydro Distribution Ltd.

Table 1: Transmission Lines and Stations in North & East of Sudbury Region

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS* Timmins TS Trout Lake TS Widdifield SS

*Stations with Autotransformers installed

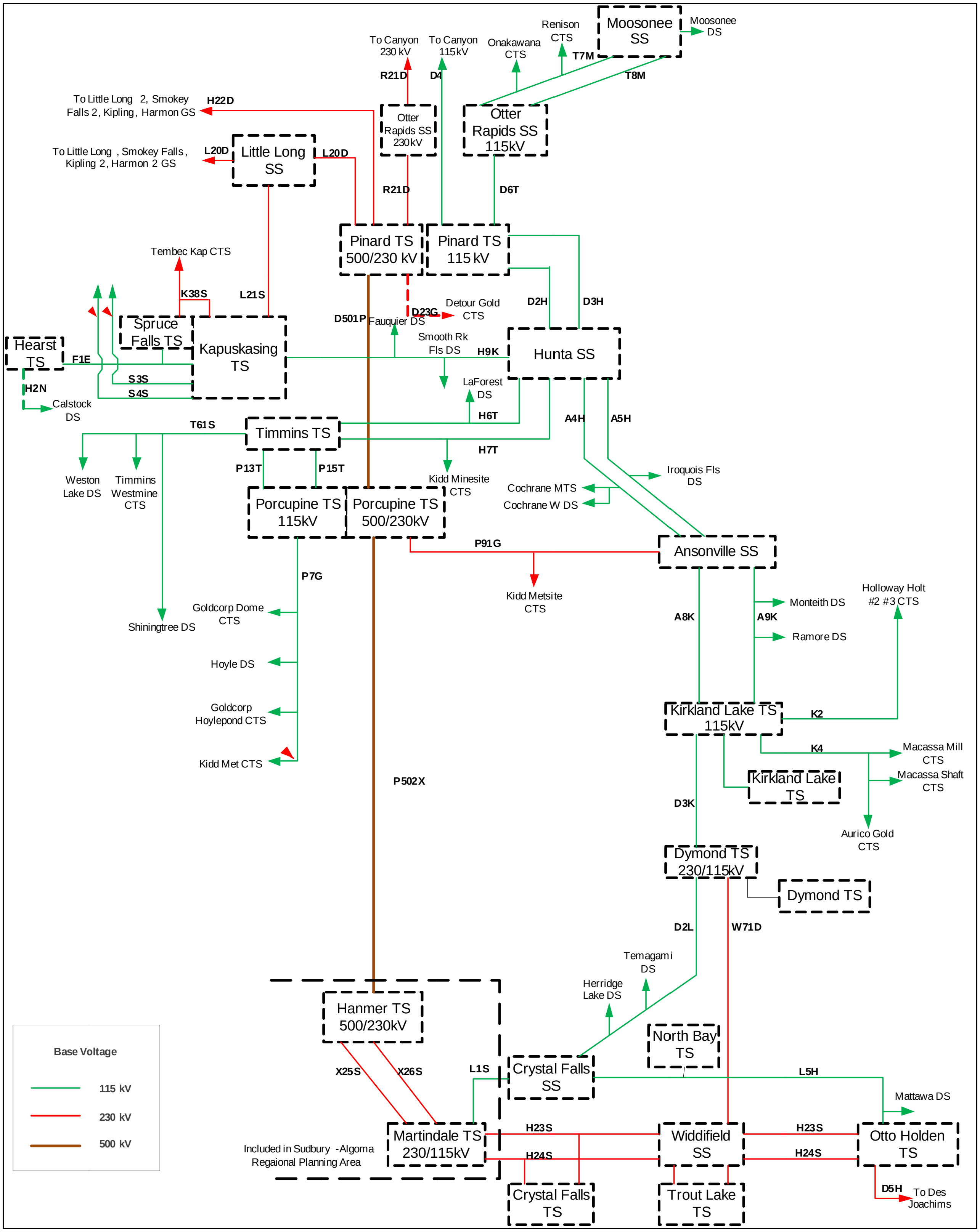

Figure 2: North and East of Sudbury Regional Planning Electrical Diagram

2 Area Needs

2.1 North & East of Sudbury Region Needs

As an outcome of the NA process, the study team identified voltage regulation issues at Timmins TS and Kirkland Lake TS which are addressed in this report. Local planning was recommended, and Hydro One as the transmitter, with the impacted LDC further undertook planning assessments to address the following needs;

- Timmins TS voltage regulation - The loss of Porcupine TS 115kV circuit breakers (K1K4 and K1K2) may result in voltage declines at Timmins TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and load rejection following the loss of the second element was proposed by IESO to improve post contingency voltage performance. See Figure 3 – Timmins area connection diagram for reference.

- Kirkland Lake TS voltage regulation - The loss of Ansonville T2 and D3K may result in voltage declines at Kirkland Lake TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and all new loads in the area will be required to participate in a local load rejection scheme to help improve post contingency voltage performance.

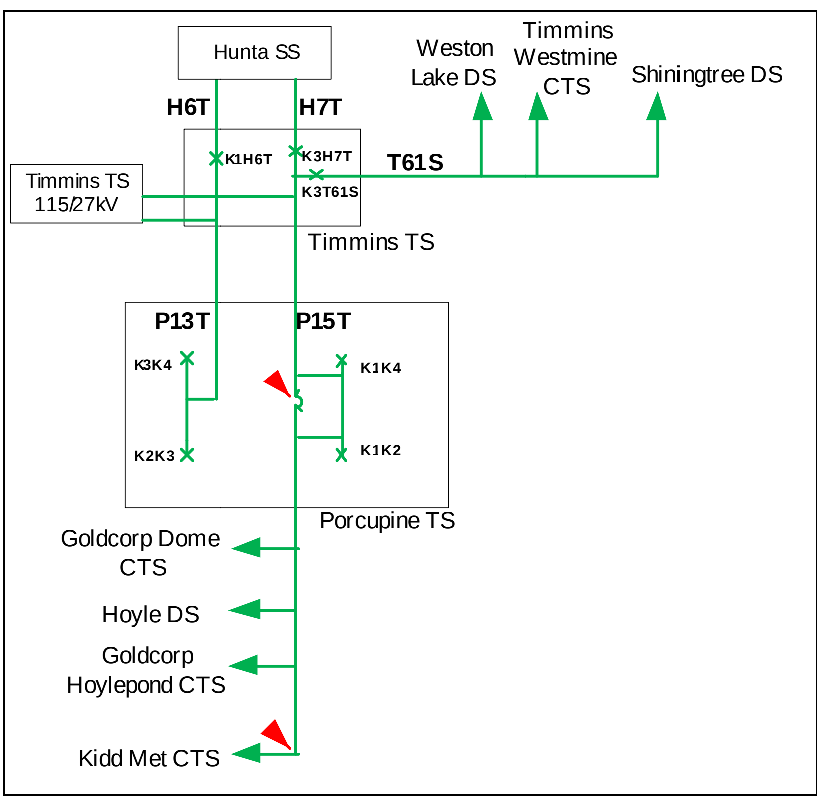

Figure 3: Timmins area connection diagram

3 Alternatives Considered

3.1 Timmins TS Voltage regulation

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the loads and voltages in the area in the upcoming years. Further review of this issue will be undertaken in the next planning cycle or earlier if there is evidence that load cannot be served or system cannot be operated in a safe, secure and reliable manner. Voltage issues can be addressed with operating procedures which are presently in place without any use of load rejection.

Alternative 2 – Implement Load Rejection on T61S, P7G, P15T to control Timmins TS voltages

This option will require expansion of the Northeast LR/GR scheme to include tripping of the Hydro One 115kV T61S, P7G, and P15T circuits upon contingency of both Porcupine TS K1K4 and K1K2 circuit breakers. This will allow for automatic load rejection of approximately 40MW of load.

Table 2: Budgetary Cost for Alternatives

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance with no immediate investment.	--
Alternative 2 – Expand Northeast Special Protection Scheme (SPS) to include P15T, P7G, T61S circuits	$2M

3.2 Kirkland Lake TS Voltage regulation

Alternative 1 – Status Quo. See details in section 4 below.

4 Preferred Solution and Reasoning

4.1 Timmins TS Voltage regulation

Hydro One Networks and Hydro One Distribution have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. The possibility of this scenario is remote and there are established operating measures in place should the first Porcupine TS breaker (either K1K4 or K1K2) be placed out of service. The following control measures are taken which help alleviate the voltage decline post contingency.

- Open Timmins TS LV breaker to offload Timmins TS from P15T
- Transfer P7G load to P91G by closing breaker B5L2 at Kidd Creek Metsite and open Porcupine TS switch 30-P7G
- Place one Abitibi Canyon 115kV unit on condenser mode.

Hydro One Networks and Hydro One Distribution have agreed that these operating measures are a preferred alternative to load rejection. In addition, implementing the load rejection scheme will expose the customers in the area to unnecessary interruption due to misoperation of the load rejection scheme.

Hydro One will continue to monitor Timmins area load growth from both LDCs and industrial customers to ensure load growth (if any) does not make voltage situation worse whereby the above operating measures are no longer effective. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

4.2 Kirkland Lake TS Voltage Regulation

Hydro One Networks and Hydro One Distribution agree that new loads in the Kirkland Lake or Dymond area may be subject to participate in an under voltage load rejection scheme as part to help control voltages in the area post contingency. Presently there is no load growth in the area over the study period. Investments are not required at this time for existing LDC loads and Hydro One will monitor load growth in the area and take corrective action as required or when instructed to do so by the IESO as proponent connection requirements. These will be identified during the load connection process after the connection applications and will be implemented by Hydro One.

5 Next Steps

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 3: Solutions and Timeframe

Need	Action / Recommended Solution	Lead Responsibility	Timeframe
Timmins TS Voltage Regulation	• No Immediate action required • Hydro One and LDC to monitor area load growth	Hydro One Networks	Five years
Kirkland Lake TS Voltage Regulation	• No Immediate action required • Connection requirements for new transmission or distribution connections to be implemented as identified during system studies.	Hydro One Networks	N/A

6 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] North & East of Sudbury Needs Assessment Report

Appendix A: Load Forecast for North & East of Sudbury Stations

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kapuskasing TS	Gross Peak Load				13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.0	14.0
	Net Load Forecast	26.1	16.1	13.5	13.4	13.3	13.2	13.2	13.1	13.1	13.1	13.0	13.0	13.0	13.0
Trout Lake TS	Gross Peak Load				121.9	122.2	122.7	123.3	123.9	125.3	126.7	127.1	128.4	129.8	131.2
	Net Load Forecast	147.5	124.1	119.4	120.6	120.0	119.1	118.5	118.1	118.7	119.2	119.1	119.7	120.5	121.1
Dymond TS	Gross Peak Load				32.7	32.9	33.1	33.6	34.0	34.2	34.4	34.6	34.8	35.0	35.2
	Net Load Forecast	37.7	34.6	32.4	32.4	32.3	32.2	32.2	32.4	32.4	32.4	32.4	32.4	32.5	32.5
Kirkland Lake TS	Gross Peak Load				32.2	32.3	32.6	32.9	33.3	33.5	33.7	33.8	34.0	34.1	34.3
	Net Load Forecast	43.8	35.7	31.9	31.9	31.7	31.6	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.6
Timmins TS	Gross Peak Load				53.4	53.7	54.2	54.9	55.6	56.0	56.4	56.7	57.0	57.4	57.7
	Net Load Forecast	51.0	51.1	52.9	52.8	52.7	52.6	52.7	53.0	53.0	53.0	53.1	53.2	53.2	53.3
Hearst TS	Gross Peak Load				27.5	27.6	28.8	29.1	29.3	29.5	29.7	29.9	30.0	30.2	30.4
	Net Load Forecast	27.8	27.3	27.2	27.2	27.1	28.0	27.9	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Herridge Lake DS	Gross Peak Load				3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5
	Net Load Forecast	3.5	3.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Temagami DS	Gross Peak Load				2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6
	Net Load Forecast	2.5	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
LaForest Rd TS	Gross Peak Load				10.4	10.4	10.5	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
	Net Load Forecast	12.8	9.7	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Hoyle TS	Gross Peak Load				8.9	8.9	9.0	9.2	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Net Load Forecast	9.3	10.4	8.8	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	9.0	9.0
Monteith DS	Gross Peak Load				2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
	Net Load Forecast	3.1	2.9	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Ramore TS	Gross Peak Load				9.1	9.2	9.3	9.5	9.7	9.8	9.9	10.1	10.2	10.3	10.4
	Net Load Forecast	8.2	9.1	8.9	9.0	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.6
Cochrane West DS	Gross Peak Load				3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1
	Net Load Forecast	4.1	4.1	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Smooth Rock Falls DS	Gross Peak Load				2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
	Net Load Forecast	2.4	2.4	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Fauquier DS	Gross Peak Load				2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4
	Net Load Forecast	2.3	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Moosonee DS	Gross Peak Load				14.2	14.3	14.4	14.6	14.8	14.9	15.0	15.0	15.1	15.2	15.3
	Net Load Forecast	18.0	13.5	14.1	14.1	14.0	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Calstock DS	Gross Peak Load				5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5
	Net Load Forecast	5.1	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1
Mattawa DS	Gross Peak Load				5.5	5.5	5.6	5.7	5.7	5.8	5.8	5.8	5.9	5.9	5.9
	Net Load Forecast				5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Iroquois Falls DS	Gross Peak Load				10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3
	Net Load Forecast	5.1	4.9	4.9	10.7	10.7	10.6	10.6	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Crystal Falls TS	Gross Peak Load				9.9	10.0	10.0	10.2	10.3	10.4	10.4	10.5	10.5	10.6	10.6
	Net Load Forecast	18.7	11.1	9.8	9.8	9.8	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Cochrane MTS	Gross Peak Load				11.3	11.4	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
	Net Load Forecast	10.3	10.9	11.1	11.1	11.2	11.2	11.1	11.0	11.0	10.9	10.8	10.8	10.7	10.7
North Bay	Gross Peak Load				39.0	39.0	39.0	39.0	39.0	39.4	39.8	40.2	40.6	41.0	41.4
	Net Load Forecast	29.0	39.0	25.0	38.6	38.3	37.9	37.5	37.2	37.3	37.4	37.7	37.8	38.0	38.2

Load Forecast for North & East of Sudbury Stations (Continued)

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weston Lake DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.1	4.3	4.1	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2
Shiningtree DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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CTS	Customer Transformer Station
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kV	Kilovolt
LDC	Local Distribution Company
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NA	Needs Assessment
NERC	North American Electric Reliability Corporation
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OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
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NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
Organization	**Name**
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Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the North & East of Sudbury region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by Working Group participants.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2026. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers
The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.

B. 500/115kV Autotransfomers
The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit

C. 230/115 kV Autotransformers
The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit

D. Transmission Lines & Ratings
The 500kV, 230kV transmission lines are adequate over the study period.

Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.

E. 230 kV and 115 kV Connection Facilities
The 230kV and 115kV connection facilities in this region are adequate over the study period.

F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS
The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus

G. Ansonville T2 or D3K Outages
With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

System Reliability, Operation and Restoration Review

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan
Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the North & East of Sudbury Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The North & East of Sudbury Region belongs to Group 3.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

North & East of Sudbury Region Description and Connection Configuration
The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

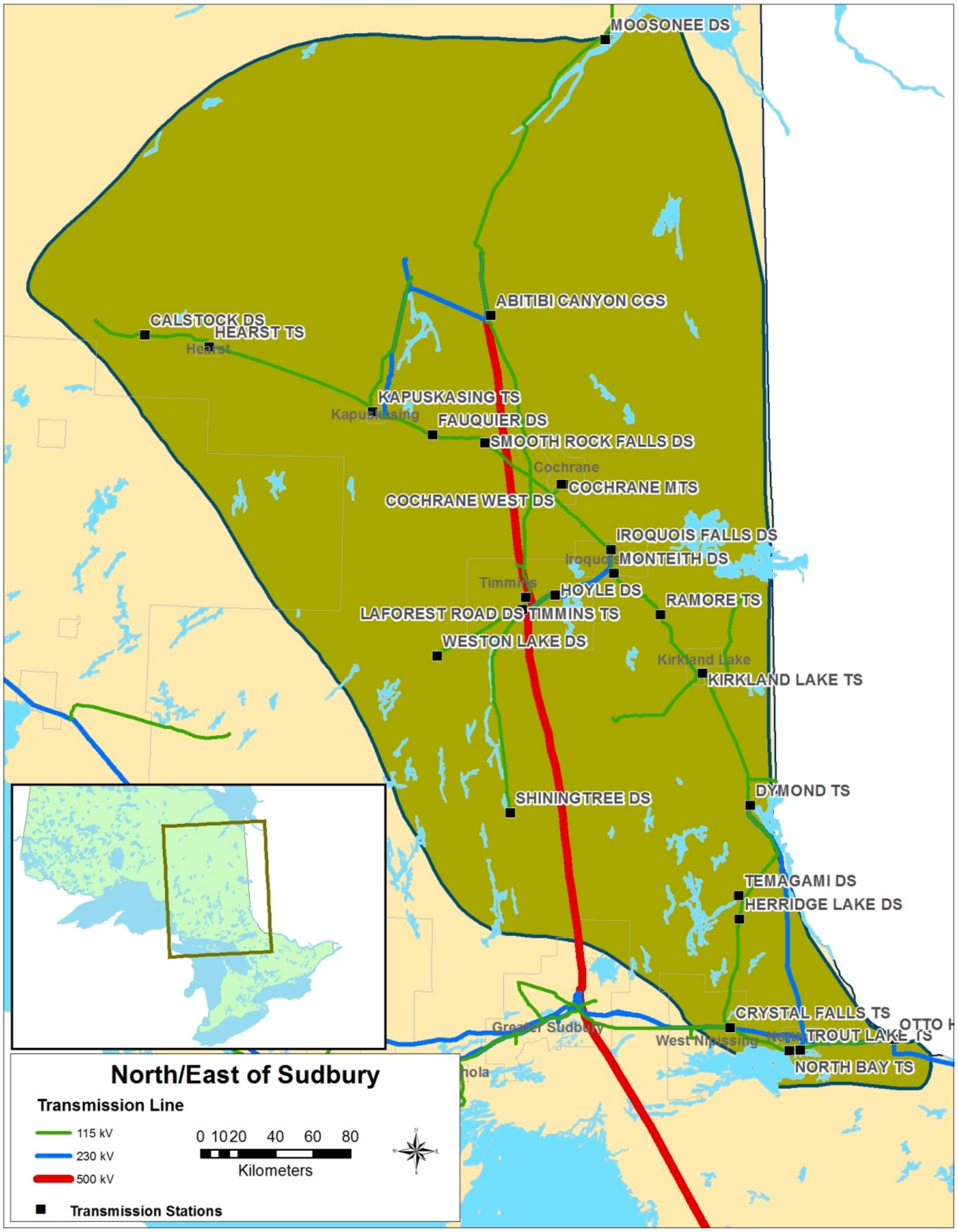

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS.

This region has the following four local distribution companies (LDC):

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

115kV circuits	**230kV circuits**	**500kV circuits**	**Hydro One Transformer Stations**
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

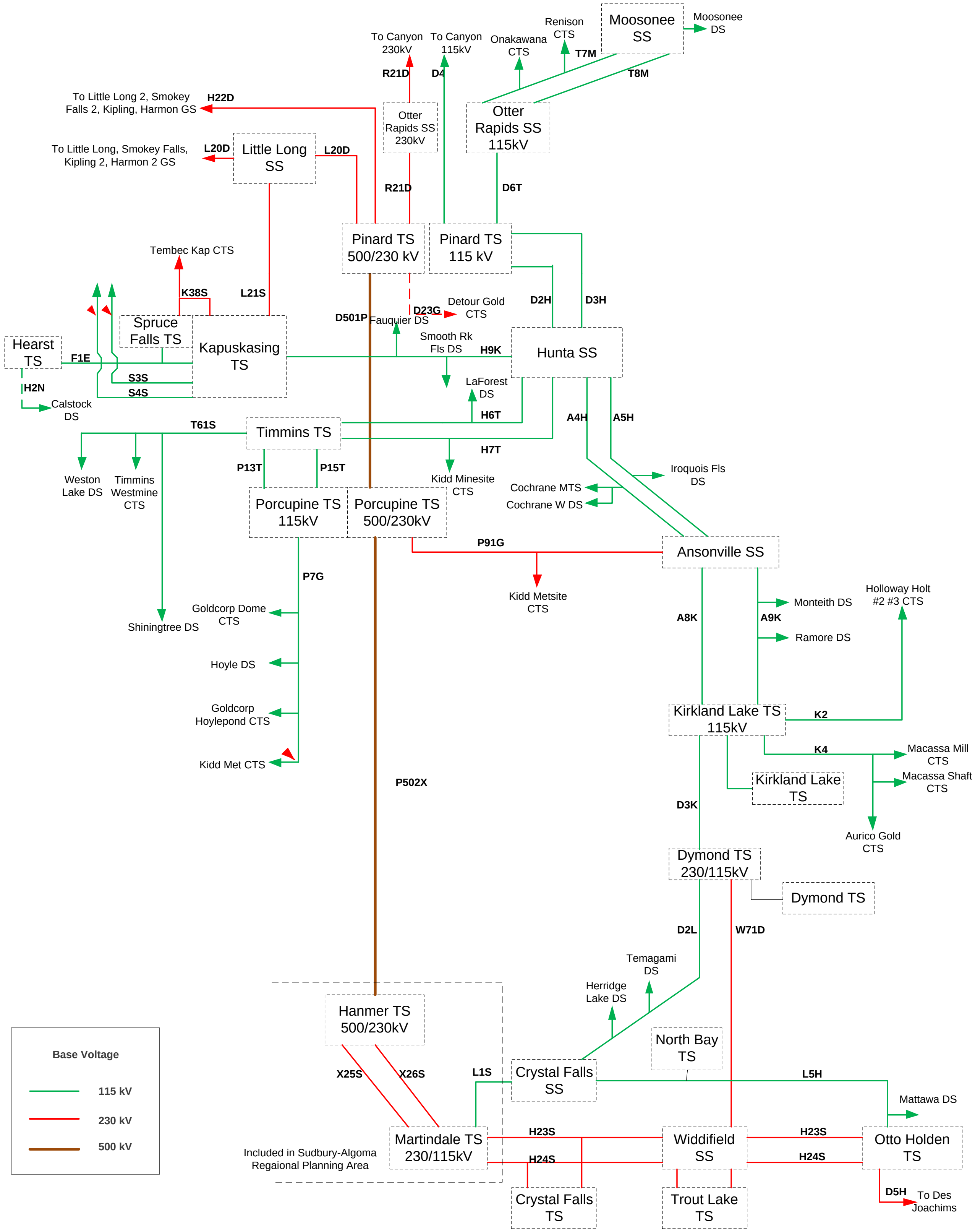

Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 INPUTS AND DATA

In order to conduct this Needs Assessment, Working Group participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
    - With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

6.1 500/230kV Autotransfomers

The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers

The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings

The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

7.1 Performance

The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration

Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 Aging Infrastructure and Replacement of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

<u>Timmins TS / Kirkland Lake TS – Voltage Regulation Issues</u>

11 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

12 Acronyms

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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Renfrew Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

The Renfrew Region consists of Renfrew County and it is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast.

The Needs Assessment ("NA") report for the Renfrew region was completed in March, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time although circuit X1P is nearing its capacity and will be monitored on a regular basis over the next three to five years.

There are no other major development projects planned for the Renfrew Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB, the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the Renfrew Region.

The next regional planning cycle for the region is expected to be undertaken in five years from the start of this planning cycle (2015) or earlier if there is a new need emerging in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
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Toronto, Ontario
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NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment 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 Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, and assets approaching end-of--life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows:

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). The 115kV circuits are supplied by 230/115 kV autotransformers at Chenaux Transformer Station (TS) from the East and Des Joachims TS from the West. A normally opened 115kV switch at Pembroke TS isolates the East and the West sides of the region.

The Renfrew Region is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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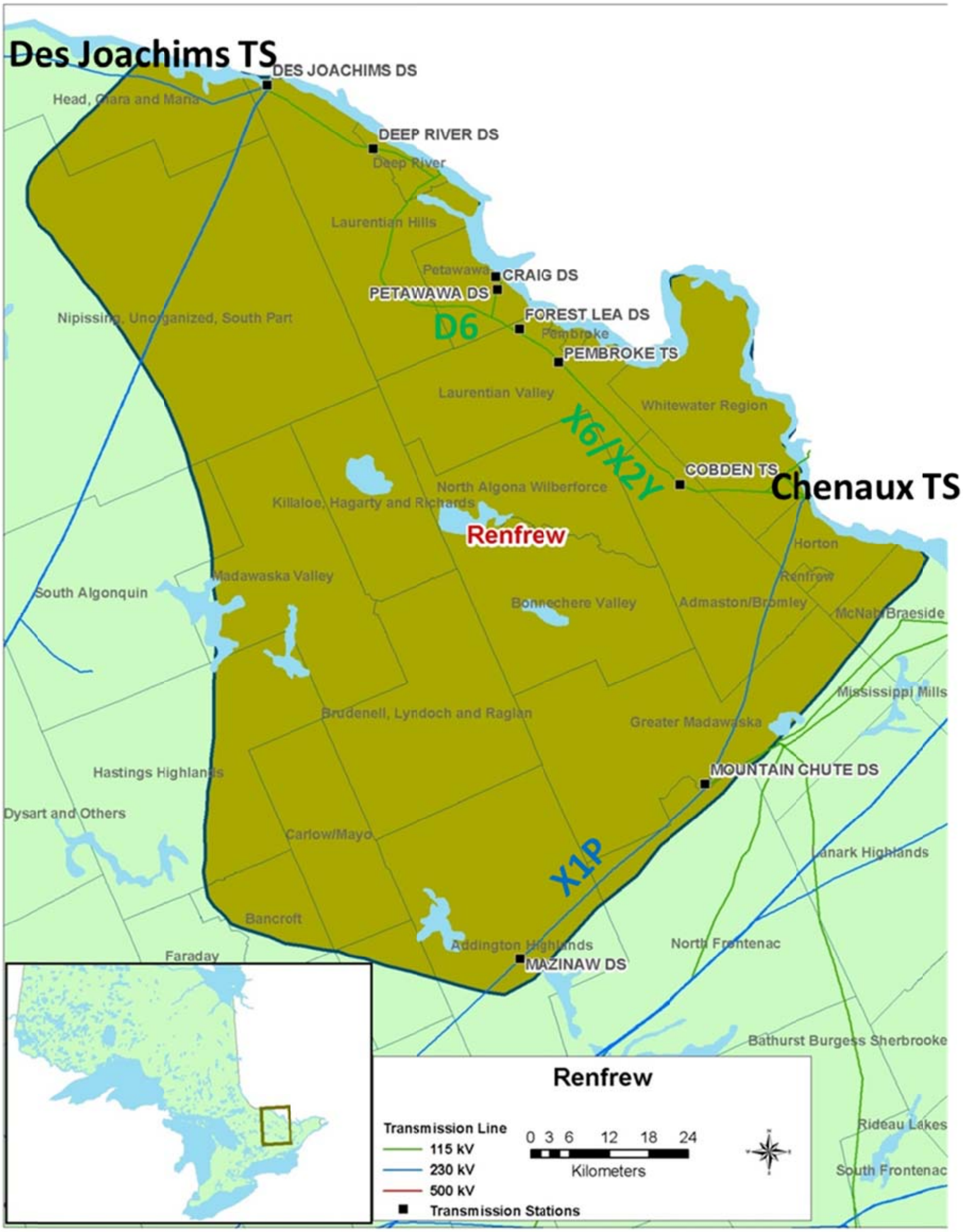

Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y.

- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.

- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew Region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region. The DS typically has load less than 1MW.

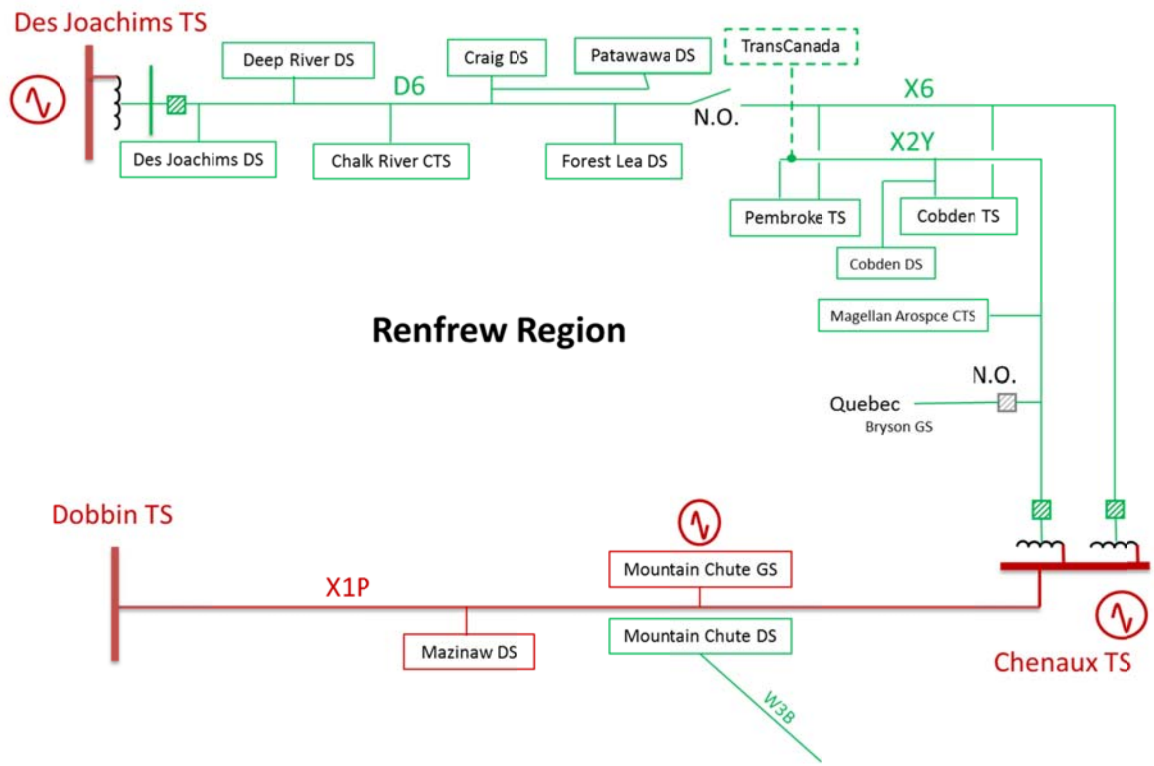

Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
    i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

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

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

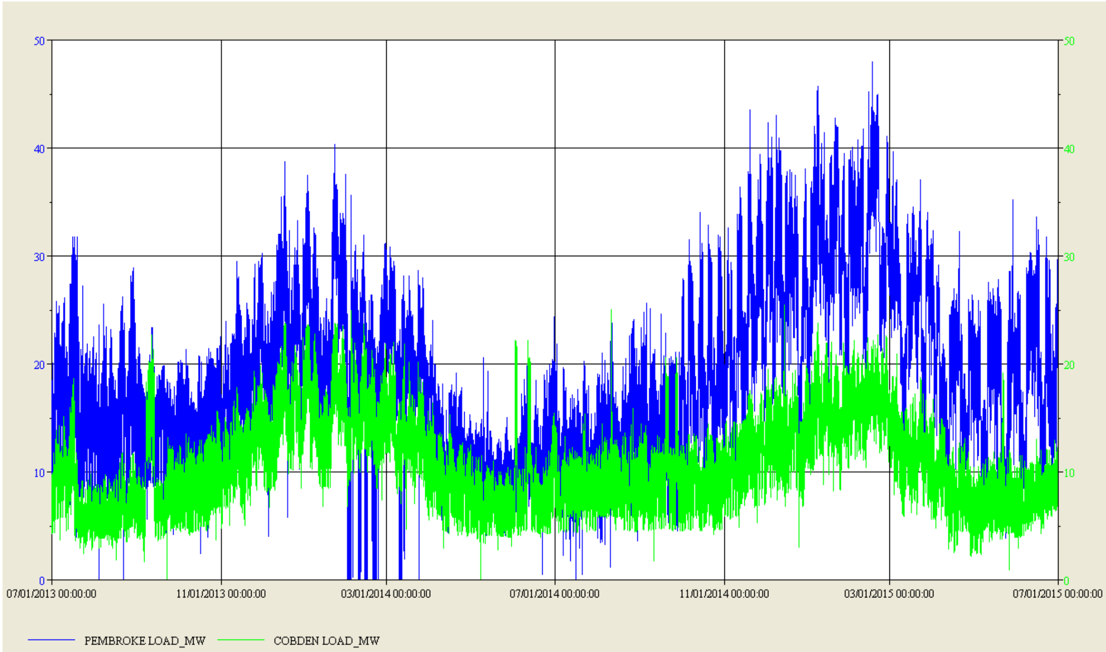

Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region's total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

> No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A. LOAD FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

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St. Lawrence Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East..

The Needs Assessment ("NA") report for the St. Lawrence region was completed in April, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time.

There are no other major development projects planned for the ST. Lawrence Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the St. Lawrence Region.

The next regional planning cycle for the region is expected to be undertaken in five years form the start of this planning cycle (2015) or earlier if new needs emerge in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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

NEEDS ASSESSMENT REPORT

Region: St Lawrence

Date: April 29, 2016

Prepared by St Lawrence Region Study Team

St Lawrence Region Study Team

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the St Lawrence region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment 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 Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	St Lawrence (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	March 1, 2016	**END DATE**	April 29, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the St Lawrence Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3. The St Lawrence Region belongs to Group 3. The NA for this Region was triggered on March 1, 2016 and was completed on April 29, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO) and Hydro One transmission provided information for the St Lawrence Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2025). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. 230/115 kV Autotransformers

The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

B. Transmission Lines & Ratings

The 230kV lines are adequate over the study period. A Special Protection Scheme is in place to reject generation at Beauharnois GS and/or Saunders GS under post contingency conditions to ensure the loading on the St Lawrence to Hinchinbrooke TS 230KV circuits are within ratings.

The 115kV lines are adequate over the study period to supply the forecasted load. The section of the 115kV lines L2M/L1MB between St Lawrence TS and Lunenberg Jct may be overloaded under light load conditions and high DG and Cardinal Power generation, for the loss of the companion circuit. Since 2012, Morrisburg TS has been restricted and no additional generation is accepted. At the same time, this situation is also mitigated using the Cardinal Power CGS run back scheme or by limiting generation dispatch during these light load conditions. No further action is required.

C. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

Inadvertent breaker operation (IBO) at Cardinal Power on either L1MB or L2M can result in Morrisburg TS transformers exceeding their reverse flow limits and/or cause a transformer to be loaded beyond ratings at Dyno Nobel CTS. Morrisburg TS has been restricted and no additional generation is accepted since 2012. This situation is also mitigated by using Cardinal Power runback scheme. No further action is required.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element does not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period. No action is required.

Chesterville TS missed its delivery point performance standard in recent years due to momentary outages resulting from severe weather patterns. The delivery point performance at Chesterville TS will be assessed and monitored to determine if corrective actions are required. No further action is required as part of regional planning.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- Morrisburg TS: components replacement (2019 in service)
- Smiths Falls TS: components replacement (2021 in service)
- St Lawrence TS: components replacement (2024 in service)

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the St Lawrence Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the St Lawrence Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the St Lawrence Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1 Study Team Participants for St Lawrence Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The St Lawrence Region belongs to Group 3.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the St Lawrence Region over an assessment period of 2016 to 2025. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

St Lawrence Region Description and Connection Configuration

The St Lawrence Region covers the southeastern part of Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East.

The western part of the region is supplied from Hydro One owned stations connected to the 230kV network. The reminder of the region is supplied from Hydro One stations connected to the 115kV network except for St Lawrence TS which is supplied from 230kV.

The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region. A map of the region is shown below in Figure 1.

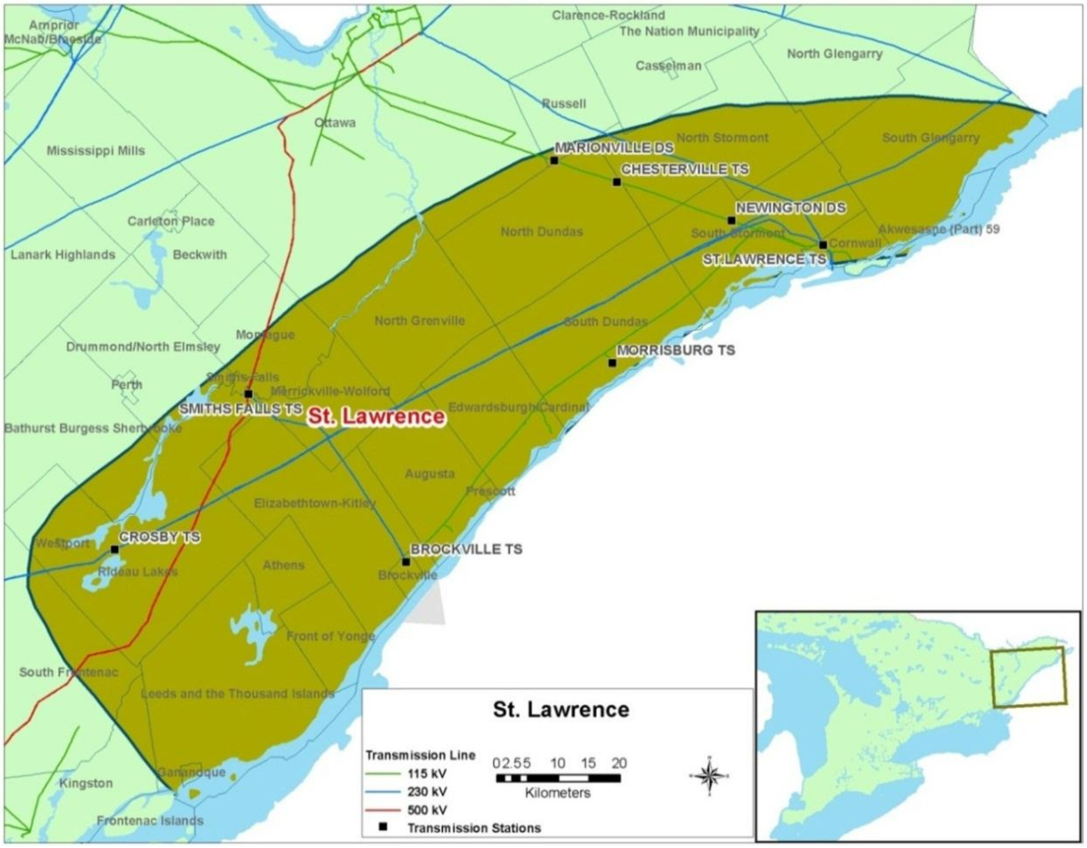

Figure 1   Map of St Lawrence Regional Planning Area

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. The major source of supply for this region is OPG's Saunder Hydro Electric station which connects to St Lawrence TS 230kV yard.

This region has the following three local distribution companies (LDC):

- Hydro One Networks (Distribution)
- Cooperative Hydro Embrun Inc. (embedded in Hydro One Distribution)
- Rideau St Lawrence Distribution Inc. (embedded in Hydro One Distribution)

Table 2 Transmission Lines in the St Lawrence Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
L1MB, L2M, L5C[1]	L20H, L21H, L22H, L24A[2], B31L[2]	Brockville TS, Chesterville TS, Crosby TS Morrisburg TS, Newington DS, Smith Falls TS St Lawrence TS*

*Stations with Autotransformers installed

[1] L5C is normally o/s, and used as a backup supply for the City of Cornwall.

[2] L24A and B31L connect to St Lawrence TS but do not have load customers connection.

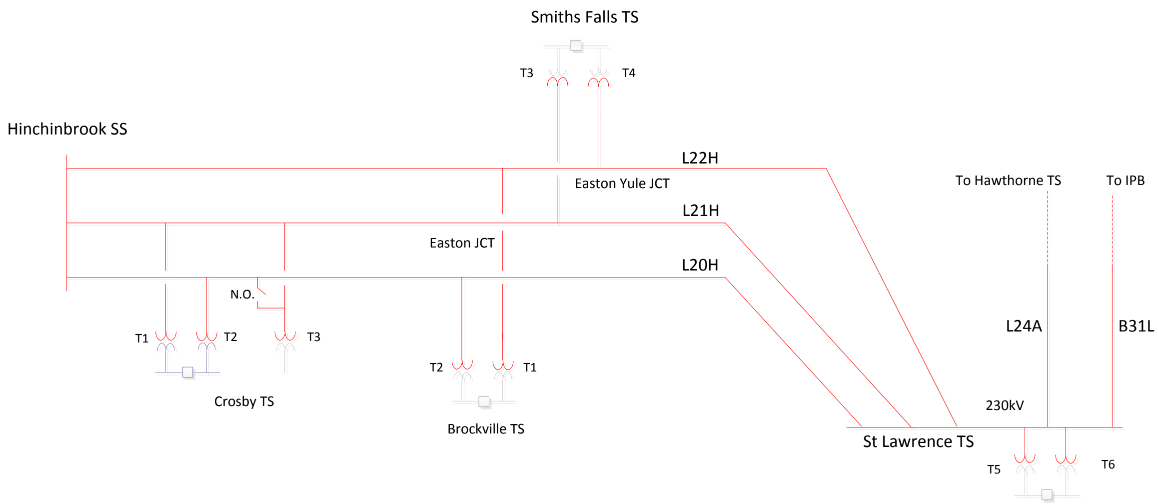

Figure 2 Single Line Diagram 230 kV St Lawrence Regional Planning Area

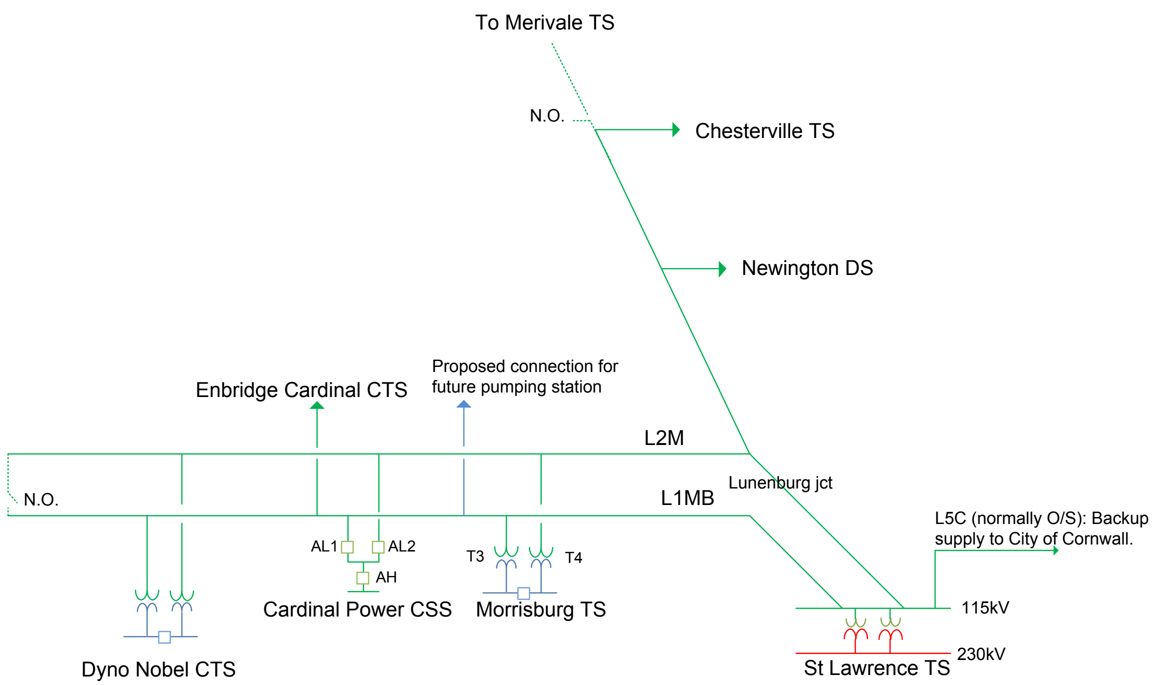

Figure 3 Single Line Diagram 115 kV St Lawrence Regional Planning Area

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2025).
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.8% annually from 2016-2025.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.2% annually from 2016-2025.

Future Project
As shown in Figure 3, there is a proposal to connect a pumping station for the TransCanada Energy East project that will add 18MW of load to the area. The pumping station is planned to be connected to circuit L1MB close to Morrisburg TS. The current in-service date is 2021.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Saunders GS was assumed to generate at its average 98% of time dependable hydro generation level which is 542MW.
3. Forecast loads are provided by the Region's LDCs

4. Load data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
5. Accounting for (3), (4), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to verify each station is within its rating to supply the forecasted load. The net forecast was used for system study.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Winter LTR ratings were reviewed.
8. Extreme weather scenario factor at 1.0582 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

230/115 kV Autotransformers
The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

Transmission Lines & Ratings

230kV Lines
The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

There is a generation rejection scheme in place that can runback Saunders GS and/or Beauharnois GS under post-contingency conditions. This scheme ensures that the St Lawrence to Hinchinbrooke TS lines are not overloaded under peak summer conditions.

115kV Lines
Under the assumptions made for regional planning, the 115kV lines are adequate over the study period for the loss of a single circuit in the Region.

The following operating issues have been previously in the SIA/CIA done for Cardinal Power G3 Expansion [4, 5]:

Under light load condition and with all distributed generation in the area and the Cardinal Power generation at maximum output the section of the L1MB/L2M line between St Lawrence to Lunenburg JCT can be loaded beyond its short time emergency (STE) rating for loss of either circuit.

To manage the situation, Morrisburg TS has been restricted to accept new generation connection since 2012. In addition, there is Cardinal Power's runback scheme will reduce the plant output following the loss of either circuit and hence reduce the post-contingency loading on either of the L1MB/L2M lines. However since the lines could be loaded beyond their STE, measures such generation re-dispatch is implemented by the IESO as per the Cardinal Power G3 Expansion studies [4, 5].

230 kV and 115 kV Connection Facilities
A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

Reverse Power Flow

At Morrisburg TS, under light load condition and high distributed and directly connected generation, a reverse power flow issue was identified in the Cardinal Power G3 Expansion SIA/CIA [4, 5]. This situation occurs if one of the line breakers at Cardinal Power has an inadvertent opening (IBO). This IBO results in all of Cardinal Power's generation being sent to one line, which causes reverse power at Morrisburg TS beyond its maximum limit. As noted previously, since 2012, additional generation connection has been restricted at Morrisburg TS to manage the reverse power flow at the station.

Dyno Nobel CTS

Under the same conditions mentioned above, an IBO at Cardinal Power can also result in power flow through the Dyno Nobel CTS to exceed their rating [4, 5].

For Morrisburg TS and Dyno Nobel CTS transformer loading issues, Cardinal Power run back scheme is triggered to reduce the flows to within equipment ratings as it was outlined in the SIA and CIA [4,5]. No further action is recommended within the scope of this regional planning.

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

Based on the gross coincident load forecast, the loss of one element does not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW for the duration of the 10-year study period.

Chesterville TS and Newington DS are on single supply from L2M for a combined gross load of 50MW in 2025. If the supply from St Lawrence TS becomes unavailable, these two stations can be supplied from Merivale TS.

All loads in the St Lawrence area can be restored within the 8 hour requirement.

IESO indicated in their unsupplied energy report that the 115kV area did not meet its target in the past. Chesterville TS missed its customer delivery point target (frequency of interruption) in recent years due to momentary outages seen as a result of severe weather patterns. Hydro One will review and monitor its supply point performance at Chesterville TS to determine if corrective measures are required. No further actions required as part of regional planning.

8 AGING INFRASTRUCTURE AND REPLACEMENT PLAN OF MAJOR EQUIPMENT

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables during the study period. At this time the following sustainment work is planned for the stations in the area:

Morrisburg TS: Protection upgrade, 44kV breakers (2019 in service)

Smiths Falls TS: Protection replacement, battery and charger, switches (2021 in service)

St Lawrence TS: Replacement of oil breakers at 230kV, 115k, and 44kV; replacement of AC/DC station service supplies; and protection upgrade work. (2024 in service)

The facilities at these stations are adequate and there is no need to increase the equipment rating.

9 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

10 NEXT STEPS

No further Regional Planning is required at this time. The St Lawrence Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

11 REFERENCES

1. Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
2. IESO 18-Month Outlook: March 2014 – August 2015
3. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
4. Cardinal Power 15MW Plant Expansion SIA (2011-432)
5. Cardinal Power 15MW Plant Expansion CIA

APPENDIX A: Load Forecast

Winter Load: Normal Weather Condition.

Station		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Brockville	Non Coincidental Gross		135.8	136.7	137.9	139.7	141.4	142.5	143.6	144.6	145.6	146.5
	CDM (MW)		1.1	1.9	3.2	4.3	5.4	6.3	7.0	7.5	8.2	8.8
	DG (MW)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Non Coincidental Net	134.3	132.9	132.8	132.8	133.5	134.2	134.4	134.6	135.2	135.5	135.8
	Coincidental Net	115.6	115.9	115.9	115.9	116.4	117.0	117.2	117.4	117.9	118.2	118.5
Chesterville	Non Coincidental Gross		42.0	42.5	43.2	44.1	45.0	45.7	46.3	46.9	47.6	48.2
	CDM (MW)		0.3	0.6	1.0	1.4	1.7	2.0	2.3	2.4	2.7	2.9
	DG (MW)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Non Coincidental Net	41.2	40.6	40.9	41.2	41.7	42.3	42.7	43.0	43.5	43.9	44.3
	Coincidental Net	41.2	41.6	41.9	42.2	42.8	43.3	43.7	44.1	44.5	44.9	45.3
Crosby	Non Coincidental Gross		28.8	29.0	29.2	29.6	30.0	30.2	30.4	30.6	30.8	31.0
	CDM (MW)		0.2	0.4	0.7	0.9	1.1	1.3	1.5	1.6	1.7	1.9
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	28.5	25.9	25.9	25.9	26.1	26.2	26.2	26.3	26.4	26.5	26.5
	Coincidental Net	18.9	18.9	18.9	18.9	19.0	19.1	19.1	19.2	19.2	19.3	19.3
Morrisburg	Non Coincidental Gross		61.5	61.7	62.1	62.7	63.3	63.7	64.0	64.3	64.6	64.9
	CDM (MW)		0.5	0.9	1.4	1.9	2.4	2.8	3.1	3.3	3.6	3.9
	DG (MW)	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
	Non Coincidental Net	60.0	52.6	52.4	52.3	52.3	52.5	52.4	52.4	52.5	52.5	52.5
	Coincidental Net	53.9	53.9	53.8	53.6	53.7	53.8	53.8	53.8	53.9	53.9	53.9
Newington	Non Coincidental Gross		1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1
	CDM (MW)		0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	DG (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Smiths Falls	Non Coincidental Gross		124.2	125.1	126.6	128.1	128.8	129.5	130.2	130.8	131.4	132.1
	CDM (MW)		1.0	1.8	2.9	4.0	4.9	5.7	6.4	6.8	7.4	7.9
	DG (MW)	3.9	4.0	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
	Non Coincidental Net	122.5	119.2	118.8	119.2	119.5	119.4	119.3	119.3	119.5	119.5	119.6
	Coincidental Net	112.7	112.8	112.4	112.7	113.1	113.0	112.9	112.8	113.0	113.1	113.2
St Lawrence	Non Coincidental Gross		44.5	44.7	45.1	45.5	45.6	45.7	45.8	45.9	46.0	46.0
	CDM (MW)		0.4	0.6	1.0	1.4	1.7	2.0	2.2	2.4	2.6	2.8
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	44.2	41.6	41.5	41.5	41.5	41.3	41.1	41.0	40.9	40.8	40.7
	Coincidental Net	43.0	42.9	42.8	42.8	42.8	42.6	42.4	42.3	42.2	42.1	42.0

APPENDIX B: Acronyms

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

1.3 (5.2.2) CUSTOMER ENGAGEMENT – HOW HYDRO ONE'S INVESTMENT PLAN INCORPORATES THE NEEDS OF CUSTOMERS

Hydro One's transmission system serves a diverse customer base made up of: (i) electricity generators who deliver power to the transmission system; (ii) distributors who deliver power to direct customers; and (iii) end-users such as mining and industrial enterprises that use the power themselves at transmission level voltage.

Hydro One's customers are located throughout the province. Serving customers in northern and rural areas presents different challenges due to sparse populations, remote location of assets and often, single-phase circuits. Conversely, customers in non-rural, more populated areas often share multi-circuit lines with other transmission customers. Indeed, the three customer groups described above often have needs and preferences unique to their segement. Engaging with these different customer segments requires a number of channels for customer engagement.

Through its broad range of customer engagement activities, Hydro One has developed a clear and specific understanding of the outcomes that its transmission customers care most about, as well as the level of spending and mix of investments that customers would most like to see included in Hydro One's investment plan. The feedback received from customers through these engagement activities is an important and direct input into Hydro One's investment planning process. Consequently, Hydro One's capital expenditure plan, as set out in Section 3 of this Transmission System Plan ("TSP"), is closely aligned with and highly responsive to the customer needs and preferences that Hydro One has identified.

This section describes the various initiatives through which Hydro One has developed an understanding of the specific needs and preferences of customers, including a customer engagement survey that was carried out specifically to inform this TSP. The feedback received from these processes has contributed to Hydro One's understanding of the outcomes that are of the greatest value to its transmission customers. This feedback has been inputted directly into Hydro One's investment planning process. The results of the customer engagement survey have been re-affirmed by feedback received from subsequent ongoing customer engagement activities.

1.3.1 (5.2.2 A) IDENTIFICATION OF CUSTOMER NEEDS AND PREFERENCES

Hydro One collects feedback from transmission customers through the following initiatives:

- Customer Engagement Surveys;
- Large Customer Account Management;
- Ontario Grid Control Centre's ("OGCC") Customer Operating Support Group;
- Large Customer Conferences;
- Oversight Committees and Working Groups;
- Customer Satisfaction Surveys and Research; and
- Focussed Planning Meetings with Customers.

These initiatives are firmly integrated into Hydro One's business practices and are fundamental to the way Hydro One interacts with its customers and carries out its transmission business. The Customer Engagement Survey has been a valuable process for supplementing, formalizing and validating the feedback Hydro One collects through ongoing engagement activities, and for formalizing the manner in which this feedback is integrated into investment planning.

Figure 1 below is a summary of key priorities for customers based on customer engagement and specific steps taken to incorporate customer considerations into the investment planning methodology and overall investment strategy.

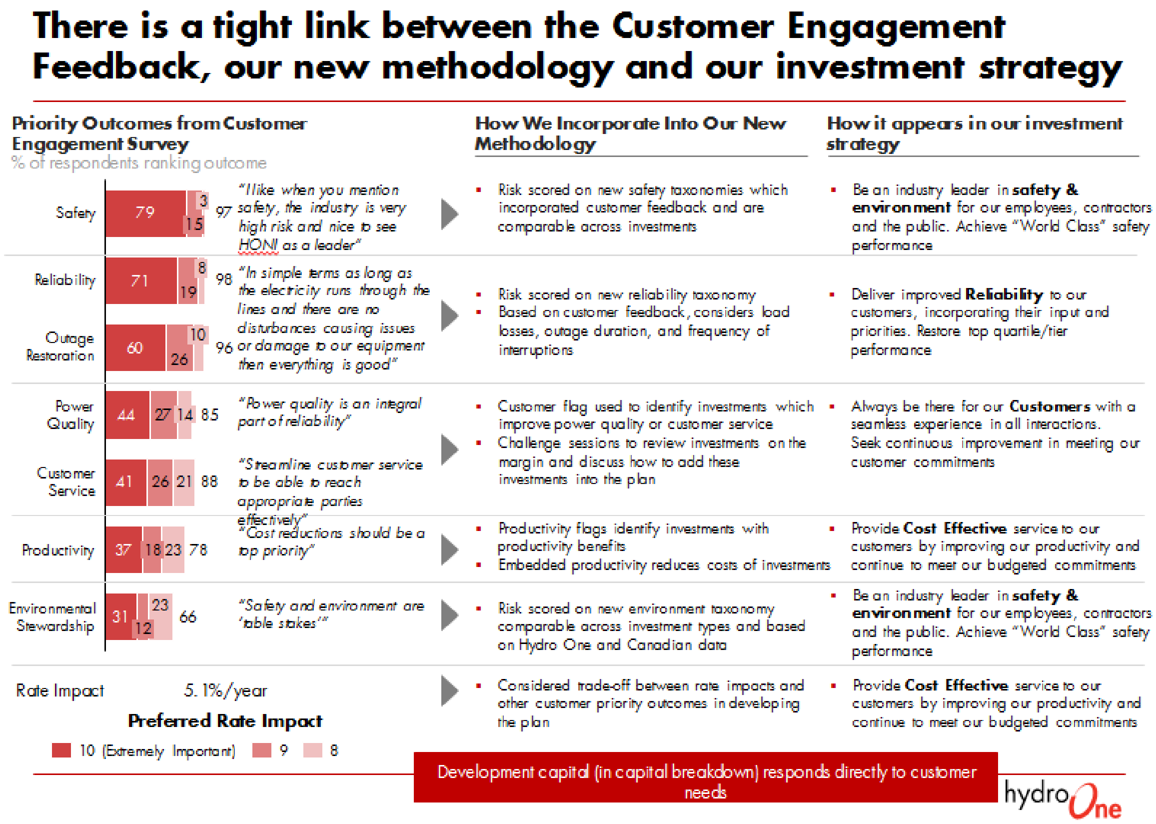

Figure 1 - Incorporation of Customer Considerations Into the Investment Strategy

Section 2.1 of the TSP explains how customer feedback is considered in Hydro One's investment planning process. Section 3.2 of the TSP explains how the proposed capital expenditure plan reflects the outcomes valued by customers.

1.3.2 (5.2.2 A) CUSTOMER ENGAGEMENT SURVEY

The Transmission Customer Engagement Survey process enables Hydro One to engage in formal discussion with its transmission customers for the purpose of obtaining feedback to inform Hydro One's investment planning process. This process aligns with Hydro One's vision to be a customer-focused commercial entity with a transmission investment plan that will drive the outcomes that customers value by demonstrating responsiveness to identified customer needs and preferences, including how to make trade-offs between outcomes and costs.

1.3.2.1 BACKGROUND AND OBJECTIVES

In 2016, Hydro One introduced a Transmission Customer Engagement Survey process. The approach taken by Hydro One in its 2017 survey was improved by incorporating lessons learned and addressing comments made about the 2016 survey.

In 2017, Hydro One engaged Innovative Research Group ("IRG"), an experienced third party research and consultation firm, to develop and implement a second iteration of the Transmission Customer Engagement Survey process (as outlined in Appendix 1). Content for the 2017 Transmission Customer Engagement Survey incorporated lessons learned from the 2016 Survey process, including feedback received from the OEB and interveners in the last transmission rate proceeding (as outlined in Appendix 2). This content established a framework for Hydro One to obtain useful, credible and unbiased information to guide the investment and business planning efforts that underpin this TSP.

The scope of the 2017 survey was also expanded beyond the level of investments. In 2016, customers were mostly asked what funding level was appropriate. In 2017, the survey sought customer feedback regarding which investments should be prioritized by evaluating what outcomes customers valued.

Through the 2017 Transmission Customer Engagement Survey process, Hydro One further developed its understanding of the needs and preferences of its transmission customers that were considered at various points in Hydro One's investment planning process. Hydro One carried out this customer engagement process early in the planning process to allow sufficient time for customer needs and preferences to be considered and integrated into the transmission investment planning and business planning processes.

Detailed results of the 2017 process are set out in the IRG Customer Engagement Report provided in Attachment 1. Appendix 1 outlines the process and timing of the engagement survey, and Appendix 2 outlines the feedback heard from OEB staff and interveners regarding the 2016 process and the specific steps taken to address that feedback as part of the 2017 process.

1.3.2.2 (5.2.2 B) SUMMARY OF CUSTOMER NEEDS AND PREFERENCES

All transmission-connected customers were invited to participate in Hydro One's customer engagement survey. Over 100 Hydro One transmission-connected customers participated in the 2017 Transmission Customer Engagement Survey, reflecting a participation rate of 66%. This improved level of participation reflected the involvement of 103 out of Hydro One's 156 transmission-connected customers including a large number of LDCs. These 2017 participation rates were 51% higher than those of the 2016 customer engagement.

Hydro One's Transmission Customer Engagement Survey process yielded valuable feedback concerning the specific needs and preferences of its transmission-connected customers to shape Hydro One's investment plans. The prioritized list of outcomes valued by Hydro One's transmission customers is presented in the figure below (reproduced from Attachment 1):

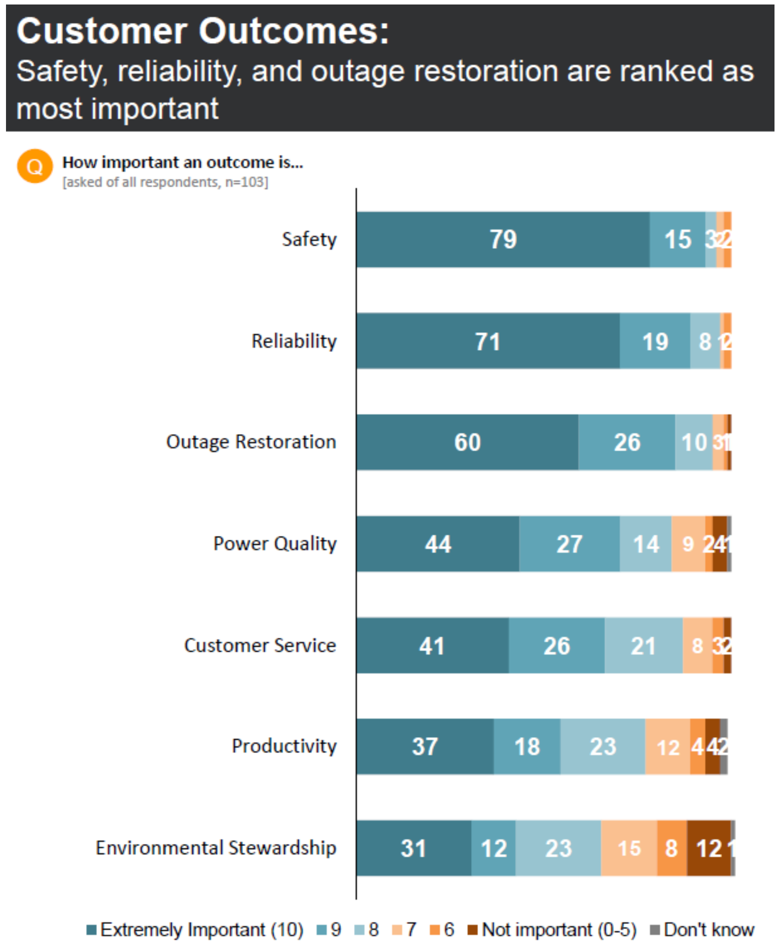

Figure 2 - Customer Outcomes

The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:

- Safety, reliability, and outage restoration are customers' top prioritized outcomes;
- All customer segments prefer to see investments spread out over time versus investing now with higher rates in the 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 of outages. 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 Prior Proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option; and
- About half of end-user participants (19 of 38) rate power quality as an "extremely important" outcome.

Despite different perspectives, most customers agreed that improvements in both frequency and duration of outages are among their top needs. Power quality and transmission capacity were also raised as major issues facing customers, particularly in northern Ontario. Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

1.3.3 (5.2.2 A) CUSTOMER SATISFACTION SURVEYS AND RESEARCH

In addition to Hydro One's customer engagement surveys, Hydro One regularly solicits feedback from customers through a variety of channels to be leveraged throughout Hydro One's planning process.

1.3.3.1 CUSTOMER SATISFACTION SURVEYS

Since 1999, Hydro One has been collecting feedback from transmission customers through an annual customer satisfaction research process. The customers surveyed are critical to the success of Hydro One's business, and are also critical to the communities in which they operate. The trending of results over time assists Hydro One in identifying areas to improve transmission customer satisfaction. Hydro One uses this data to inform and improve business practices and stay informed about the trends that matter most to transmission customers. Customer Satisfaction scores are also included in Hydro One's Corporate Team Scorecard (Exhibit F, Tab 4, Schedule 1, Attachment 4) and Hydro One's proposed Transmission Scorecard (as described in Section 1.5 of the TSP).

This research is conducted by independent expert customer research firms. The most recent iteration of this research was carried out and reported on by Innovative Research Group in 2018 and is described in Section 1.5 of the TSP.

The objectives of the Large Transmission Customer survey are to measure the level of customer satisfaction, and to monitor Hydro One's performance in four dimensions of satisfaction among customers: Price, Customer Service, Product Quality/Reliability and Relationship. The survey measures customer perceptions of the Company (whether they have interacted with Hydro One recently or not), with a specific focus on how well the Company meets expectations and delivers on critical success factors. The survey is administered to transmission-connected Generators, End Users and all LDCs. The customer survey research is used to evaluate the overall satisfaction levels of these customers groups, and to better understand their perceptions of Hydro One.

Figure 3 illustrates the trend of the overall satisfaction results. In 2018, Overall Satisfaction was at the highest point in the past seven years at 90%, which is a 12% increase since 2016. The increase in overall satisfaction can be attributed to LDCs and generation customers. The main driver identified through analysis for higher customer satisfaction was customer communication and key account managers. The identified driver correlated with lower satisfaction was the ability to recall a planned outage. Additional information can be found in TSP Section 1.5 and the complete 2018 survey results can be found in Attachment 5 to this exhibit. The greatest dimension of high customer satisfaction was customer service, with 93% satisfaction with communications methods, 93% satisfaction with customer service overall and 90% satisfaction with key account services from account executives. A majority, 60%, are satisfied with Hydro One’s product. Some dimensions with lower product satisfaction include number of unplanned outages, a dimension 50% of customers are dissatisfied with.

Figure 3 from Exhibit B1, Tab 1, Schedule 1, Section 1.5 – Overall Customer Satisfaction, Corporate Survey (% satisfied)

1.3.3.2 (5.2.2 B) ONTARIO GRID CONTROL CENTRE TRANSMISSION CUSTOMER SURVEY

Hydro One's Ontario Grid Control Centre ("OGCC") has surveyed satisfaction among its medium and large business customer satisfaction since 2013. The main objective of the survey is to determine key dimensions of satisfaction, strengths, and opportunities and to improve customer service policies, service delivery processes and communications in the areas of accountability of the OGCC such as outage planning and interruption restoration information. Overall satisfaction with OGCC has improved over the past year (98% in 2018 vs. 94% in 2017). The greatest driver of OGCC customer satisfaction was communications and responsiveness. Hydro One's average performance over the past five years was 90 per cent, and the overall trend indicates that satisfaction with outage planning procedures is improving. Over the rate period, Hydro One plans to maintain its historical average, targeting 90 per cent satisfaction with outage planning procedures.

Additional information can be found in TSP Section 1.5. The complete 2018 OGCC customer survey results are provided as Attachment 6 to this exhibit.

1.3.4 (5.2.2 A) ONGOING CUSTOMER ENGAGEMENT

Hydro One believes that understanding customers, and their needs, is critical to a successful business. Hydro One engages with customers regularly and through different mechanisms. Customer needs can be categorized as either (i) initial connection needs, or (ii) needs of connected customers.

Initial connection needs are generally identified either through the Hydro One customer connection process or by need assessments and customer consultations under the regional planning process, as described in TSP Section 1.2. The regional planning process ensures that needs are assessed and identified by Hydro One in conjunction with customers, the IESO and LDCs.

Once connected, customer needs are identified by continuous monitoring of the power system. Hydro One planners continuously engage with customers (e.g. LDCs, industrial and commercial transmission-connected customers) to discuss and solicit feedback on investments to address end of life asset replacements. Open dialogue with customers during the planning stages of candidate investments ensures customers' needs and preferences are addressed in a collaborative manner, and it allows customers to have a voice regarding technical system requirements such as improved station configuration to enable greater operational flexibility, and changes in work execution practices and processes that impact customers. Customer feedback also provides valuable information that planners incorporate into the Investment Planning Process during the Asset Risk Assessment ("ARA") process (discussed further in TSP Section 2.1) to inform the development of investment candidates.

1.3.4.1 ONGOING CUSTOMER ENGAGEMENT SURVEY (RRFE)

Hydro One is implementing an Ongoing Customer Engagement Questionnaire that will quantify transmission customers' satisfaction regarding a variety 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.

Although the questionnaire asks customers to rank satisfaction of key indicators on a scale of 1-5, the survey also addresses specific preferences, asking customers if they would prefer shorter and more frequent outages or longer and less frequent outages, for example. Results of these questions will be inputted into Hydro One's Customer Relationship Management system, which keeps records of customer agreements, issues complaints, feedback and CSAT results. These questionnaire results will directly inform Investment Planning on problem areas that need to be mitigated, as well as broader customer preference trends to apply across the system. The questionnaire will be done on an annual basis to give planners a continuous source of customer information beyond CSAT scores, beginning in 2019.

Directly connected transmission customers currently receive an annual reliability report which summarizes historical and annual performance at transmission and distribution delivery points, describes investments recently made in the customer's area, investments planned in the customer's area and upcoming maintenance in the customer's area. The reliability report allows customers to provide informed input into customer engagement touch points, such as Hydro One's new Ongoing Customer Engagement Questionnaire.

1.3.4.2 LARGE CUSTOMER ACCOUNT MANAGEMENT

The Large Customer Account Management Group (formerly, "Customer Business Relations") provides customers with a single point of contact at Hydro One for all types of interactions. In particular, this group communicates with customers on matters that include customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality.

Account Executives from Hydro One's Large Customer Account Management Group meet with transmission customers on a regular basis to ensure that the needs of customers are identified and discussed, and action plans are developed to address these needs. If an action plan results in new or modified connection facilities and/or asset needs, then the Account Executive will directly communicate with the affected customer(s) to ensure a common understanding of the related connection process and contractual requirements, such as connection cost estimates and capital cost recovery agreements. Examples of investments included in this TSP that have resulted from direct communication by Account Executives in Hydro One's Large Customer Account Management Group with customers, are Enfield TS and the Seaton MTS Connection. Hydro One's transmission system planners developed candidate projects to address the customer needs identified in action plans. Risks associated with each of these candidate projects were considered throughout Hydro One's investment planning process and resulted in the inclusion of the Enfield TS and Seaton MTS Connection projects in Hydro One's capital expenditure plan.

Hydro One's Account Executives proactively engage with transmission customers to review and coordinate planned outage activities to minimize impacts on customers and to optimize opportunities for both Hydro One and customers to plan and execute work on their respective facilities. The outcomes of these discussions are used as inputs to the OGCC's Transmission System Outage ("TSO") process to coordinate multiple work activities on the same equipment during a single outage, as discussed further below. Account Executives also participate in the OGCC's meetings with customers to discuss planned outages and work as part of the regional planning process, discussed in TSP Section 1.2.

In 2018, Hydro One addressed the OEB's finding that: "Hydro One should improve its internal institutional processes to better inform the transmission performance management system of distribution customers' satisfaction level for the purpose of gauging what, if any, elements of transmission operation are the cause of any dissatisfaction”.[1] In response, among other things, the Company began consolidating the service delivery model for its largest customers having a 2 MW demand or more including Hydro One’s distribution-connected end use consumers. This change will introduce a similar level of customer service for Hydro One’s Large Distribution Accounts (“LDA”) that Hydro One’s transmission-connected customers currently receive, including the assignment of Account Executives to LDA customers, tracking of customer information and interactions, and identifying opportunities for advocacy for these large customers across the company.

In particular, this approach will facilitate the consistent and more complete reporting of customer needs and preferences for use by planners, operators and customer service teams to consider when making transmission planning and investment decisions. Further details in respect of how Hydro One addressed the OEB’s findings quoted above are set out in Appendices 1, 2 and TSP Section 1.5.2.

1.3.4.3 OGCC’S CUSTOMER OPERATING SUPPORT AND OUTAGE PLANNING GROUP

The OGCC’s Customer Operating Support Group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages so Hydro One or the customer can complete required work, to respond quickly to unexpected outages, and to coordinate switching activities.

The Outage Planning Group organizes bi-annual customer meetings throughout the province to coordinate outage planning activities. These meetings are a key activity in Hydro One’s TSO process. The OGCC sends reports, customized for individual customers that provide a rolling, one-year window of the planned outages that will affect

[1] EB-2016-0160, Decision and Order (November 1, 2017), pp. 38-39

the customer's delivery point. These reports contain information on outage start and end dates, the equipment involved, purpose, recall time and schedule profile. The reports provide an opportunity for customers to provide feedback. The Outage Planning Group also provides information on Hydro One's plans, particularly with respect to outages, for the balance of the year and/or the next scheduling year. During these meetings, customers may bring forward their own maintenance plans for their facilities, with a view to scheduling or bundling outages in a manner that minimizes the frequency and duration of outages for both the utility and the customer.

1.3.4.4 LARGE CUSTOMER CONFERENCE

Each year, Hydro One organizes and hosts a Large Customer Conference for all large transmission and large distribution (2 MW+) customers. The focus of the conference is to provide an opportunity for large customers to hear about Hydro One's plans and initiatives, ask questions, discuss their interests, and raise concerns with representatives and executives from several Hydro One lines of business. To ensure that the conference addresses the specific areas of interest for these customers, Hydro One seeks customer input prior to the conference to inform the conference agenda. This provides initial insights into the issues that are top of mind to Hydro One's large customers. At the conference, customers who are directly connected to the transmission system are presented with information about significant upcoming Hydro One initiatives that may affect them, including any technological changes they would need to be aware of or other potentially impactful initiatives.

In recent years, Hydro One has used these conferences as an opportunity to provide large customers with presentations about Hydro One's planned investments and activities. In addition, large customers are given an opportunity during each Large Customer Conference to meet with Hydro One staff, including Planning staff, to share information and raise concerns. In addition to Planning staff learning about customer needs and preferences through these informal conversations, feedback received during the conference, and through post-conference customer surveys, is subsequently provided to Planning for further consideration. Recent feedback suggests that customers would like to hear more about reliability, maintenance procedures and lowering recall time in outages.

1.3.5 (5.2.2 A) OVERSIGHT COMMITTEES AND WORKING GROUPS

Hydro One has established a number of oversight committees (and in the case of Metrolinx, a working group) to engage and obtain feedback from customers on topics with a high level of customer interest. Ongoing coordination with other entities is particularly valuable where there is a need for coordinated health and safety oversight. The purpose and value of the oversight committees is to ensure that the ongoing operational needs and preferences of these customer groups are accounted for in a timely and tactical fashion. The purpose of these oversight committee meetings is not expressly to direct investment plans, although the oversight committees can give an early insight as to future investment needs more generally. To date, Hydro One has established and maintains a number of oversight committees as follows.

1.3.5.1 SARNIA AREA RELIABILITY OVERSIGHT COMMITTEE

The Sarnia Area Reliability Oversight Committee consists of Hydro One staff and industrial and generation-connected customers and LDCs in the Sarnia Chemical Valley area. Chemical Valley customers include a large number of facilities and refineries with very sensitive manufacturing processes. The industry in the Sarnia area is particularly concerned with reliability and power quality such as loss of supply, loss of redundancy, and voltage fluctuations that can result in possible wide spread health and safety issues such as gas flares and cause very costly damage to customer manufacturing equipment and halt their processes. This committee meets twice a year to identify issues regarding reliability in the Sarnia Area and to review proposed annual work plans to ensure that issues will be addressed appropriately, having regard for the environmental and safety concerns of these customers.

1.3.5.2 LDC WORKING GROUP

Hydro One facilitates an LDC working group, which serves as a forum to update and communicate with LDCs on Hydro One's transmission-related policies and practices, identify emerging issues, as well as solicit input to enhance customer experience. This group meets three to five times annually.

1.3.5.3 TORONTO HYDRO OVERSIGHT COMMITTEE

Hydro One holds quarterly Oversight Committee meetings with Toronto Hydro-Electric System Limited to identify and resolve issues and to coordinate efforts on capital projects and other matters. This forum allows the two utilities to coordinate their operations in a safe and efficient manner.

1.3.5.4 SWITCHYARD OVERSIGHT COMMITTEES

Hydro One facilitates and participates in switchyard oversight committees with Bruce Power Inc. and Ontario Power Generation Inc. These committees assist the parties in overseeing and coordinating matters of mutual interest, such as interface equipment, procedures and policies that pertain to Hydro One equipment at nuclear generation facilities. These committees ensure the safe and efficient operation of switchyards at Ontario’s nuclear generation facilities, help maintain compliance with legal requirements, and allow for the efficient coordination of capital projects and other matters. These committees each meet approximately three times each year.

1.3.5.5 METROLINX WORKING GROUP

Hydro One’s Metrolinx Working Group provides a forum to reviews issues arising during the large scale transportation infrastructure work that Metrolinx is undertaking in Ontario. This working group is made up of staff from Hydro One’s Large Account Management, Real Estate, and Transmission Planning groups and staff from Metrolinx. The working group reviews and addresses customer escalations arising from the Metrolinx work program and ensures that issues are addressed in a timely manner.

1.3.5.6 HYDRO OTTAWA OVERSIGHT COMMITTEE

The Hydro Ottawa Oversight Committee was established in 2018 and provides a forum for Hydro Ottawa and Hydro One to meet twice a year to identify and resolve any issues and to ensure safe and efficient operations between Hydro One and Hydro Ottawa. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

1.3.6 (5.2.2 A) INCORPORATING CUSTOMER NEEDS INTO THE PLAN

Insights from recent surveys reveal customers are seeking improvements in the following areas:

- Safety, reliability, and outage restoration are customers' top prioritized outcomes;
- All customer segments prefer to see investments evenly spread out over the long term;
- Reducing the frequency of outages is more important that reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions;
- The majority of customers prefer to maintain levels of investment in line with the proposal filed in Hydro One's last transmission rate application (EB-2016-0160), rather than to increase or decrease investment levels;[2]
- End user participants rate power quality as an "extremely important" outcome;
- Reliability metrics used by Hydro One do not adequately capture events on the network that may actually be associated with power quality;
- Customers would like to have more assistance investigating power quality events;
- Customers would like reduced timelines for connection estimates;
- Customers would like lower connection costs;
- Customers desire improved communication and transparency; and
- Customers believe Hydro One should be easier to do business with.

Hydro One's full spectrum of customer engagement initiatives is leveraged to increase its understanding of customers' needs and preferences; enhance Hydro One's ability to provide the expected level of service; produce outcomes that are valued by customers;

[2] Customer preferences are set out in Attachment 1 of Section 1.3 of the TSP.

and result in an improvement to customers' overall satisfaction with Hydro One's Transmission business.

As part of the multi-step investment planning process described in TSP Section 2.1, planners develop a set of candidate investments that are designed to address the relevant asset needs and risks, and incorporate transmission customers' needs, preferences and feedback to inform the capital expenditure plan.

1.3.6.1 IDENTIFYING TRENDS

Cross functional sessions are held to review all customer engagement results, identify broad trends and specific customer needs and preferences. This review provides a basis to capture customer needs and preferences in the investment planning process and improve alignment between individual candidate investments identified by planners and the outcomes of the customer engagement activities.

1.3.6.2 INVESTMENT ASSESSMENT

Since the last transmission rate application, Hydro One has introduced investment planning process improvements, including a revised scoring process and a formalized flagging framework as described in TSP Section 2.1.4. The feedback provided through the customer engagement process informed the enhanced risk and scoring framework. In particular, the revised scoring process focuses on assessing risk related to safety, reliability and environmental considerations. These three outcomes are among the top customer priorities identified and validated through Hydro One's customer engagement. As risk scoring is the dominant evaluation method for candidate investments, customer needs and preference are reflected in all risk-scored investments.

In addition to investment scoring for safety, reliability and environmental risk, investments are flagged for factors including customer needs and preferences identified through the engagement process. A full list of flags is included in TSP Section 2.1.4.2.

Examples of customer needs and preferences that were identified through customer engagement and flagged include:

- Concerns expressed with delivery point performance as a result of nuisance wildlife or equipment configuration;
- Coordination of asset maintenance and replacement activities with generator customers during planned outages to minimize disruptions to operations;
- Concerns expressed with power quality; and
- Addressing worst performing delivery points (outliers).

1.3.6.3 CALIBRATION SESSIONS

Following the development of investment candidates and risk scoring, structured calibration sessions are held to ensure that scoring and the application of flags is consistently applied across the organization. Based upon business knowledge gathered through customer-facing efforts described earlier and results obtained through the Transmission Customer Engagement Survey, management validates that the investments are responsive to customer needs and preferences by comparing the description of the need/preference with the high level themes identified through the customer engagement results.

1.3.6.4 OVERALL FUNDING ENVELOPE

The feedback received through the customer engagement process influenced the company's decisions around the overall funding envelope. As part of the customer engagement survey, respondents were provided with descriptions of four illustrative investment scenarios. They were then provided with a line of data points that started at zero and extended beyond all four of the illustrative investment scenarios. Customers were asked to select any point along that continuum that reflected what they believed to be the best and most appropriate balance between rates impacts and outcomes:

- Scenario A was based on limited investment;
- Scenario B involved a decrease in the current level of investment;

- Scenario C would maintain the current level of investment; and
- Scenario D would increase beyond the current level of investment.

Scenario C, which maintains the current level of investment proposed in EB-2016-0160, reduces reliability risk, improves long-term reliability performance and offers level future rate increases, was strongly favored over the other three scenarios with 24% of respondents selecting this scenario. Respondents indicated their preference through the selection of a point along a line showing the spectrum of scenarios; 21% chose a point between Scenario B and Scenario C and 17% chose a point between Scenario C and Scenario D. This clustering informed the initial funding envelope.

1.3.6.5 PRIORITIZATION, OPTIMIZATION, ENTERPRISE ENGAGEMENT AND MANAGEMENT REVIEW AND APPROVAL

Following review and calibration, all candidate investments were aggregated into a consolidated portfolio for prioritization with a view to reflecting the level of investment most preferred by customers in the customer engagement exercise. While the initial prioritization and optimization is risk based, subsequent structured and facilitated trade-off discussions identify projects on the margin and determine allocation of funding based on consideration of investment merits from both risk and non-risk perspectives, such as the appropriate incorporation of customer needs and preferences.

Ultimately, Hydro One determines a funding envelope that balances identified transmission customer needs and preferences with rate impacts and asset/system needs. These considerations are integral in the review and final approval of the Business Plan by the Executive Leadership Team and Board of Directors.

The manner in which the proposed capital expenditure plan reflects the aforementioned transmission customer engagement initiatives, including in particular the 2017 Transmission Customer Engagement Survey process, is discussed in TSP Section 3.2.2.

1.3.7 ATTACHMENTS: CUSTOMER ENGAGEMENT

Attachment #1 - Customer Engagement Survey

Attachment #2 - Stakeholder Engagement Session Presentation Slides

Attachment #3 - Stakeholder Session Notes

Attachment #4 - Reliability Risk Summary

Attachment #5 – Large Tx Customer Satisfaction Survey Report

Attachment #6 – OGCC Customer Satisfaction Survey – 2018 Results

APPENDIX 1: CUSTOMER ENGAGEMENT PROCESS AND TIMING

Managers and Executives from Hydro One's Customer Service, Planning and Regulatory groups met in February 2017 to plan and prepare for the 2017 Transmission Customer Engagement Survey process, with a view to using the results of this initiative to guide and inform the investment planning process as part of this Application.

Hydro One determined that all of its transmission-connected customers would be invited to participate in this process and that, given the discrete number of transmission customers (in comparison to the number of customers that need to be engaged with to support preparation of a Distribution System Plan), this effort would be qualitative rather than quantitative (i.e., it would provide guidance directionally, but not statistically, due to the limited population size of the transmission customer base). The survey was also developed based on the engagement sessions with stakeholders from the 2017/2018 application.

The 2017 Transmission Customer Engagement Survey process was implemented based on the following schedule.

Description	Date
Final Survey Submitted	03-May-17
Survey In Field	11-May-17 – 15-Jun-17
Interim Report	31-May-17
Survey Concluded	09-Jun-17
Final Report	02-Jul-17

Findings were used to inform the plan as it was iteratively developed through the planning and feedback process.

Detailed results of the 2017 process are set out in the IRG Customer Engagement Report provided in Attachment 1.

APPENDIX 2: INCORPORATING FEEDBACK INTO THE CUSTOMER ENGAGEMENT SURVEY

Hydro One's approach to engaging transmission customers has evolved, and continues to evolve, in response to the OEB's recommended areas for improvement as set out in its September 28, 2017 Decision and Order in proceeding EB-2016-0160. In particular, the OEB found that Hydro One should (i) begin its customer engagement process sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance; (ii) include LDCs so as to determine practical ways to seek some input from their end users; (iii) incorporate timely and meaningful input from First Nations representatives; (iv) ensure that information presented to customers is unambiguous and easy to understand.[3]

The 2017 Transmission Customer Engagement Survey was designed to be responsive to feedback heard from OEB staff and intervenors in the EB-2016-0160 proceeding and is consistent with the Board's findings in its Decision and Order. Hydro One made a number of improvements that address the Board's findings.

FINDING 1: TIMING OF CUSTOMER ENGAGEMENT SURVEY

The 2017 engagement survey was completed prior to the Investment Planning Context phase of the Investment Planning Process outlined in Section 2.1 of Transmission System Plan.

FINDING 2: INCLUDE FEEDBACK FROM LDC END-USERS

Hydro One's transmission system is the upstream supplier of electricity to LDCs across the Province of Ontario. Electricity is transmitted over the Hydro One transmission system to Delivery Points ("DPs") with the LDCs. DPs are boundaries between the electricity systems of Hydro One and the LDCs. Each LDC has significant power

[3] See OEB, Decision and Order in EB-2016-0160, September 28, 2017, pp. 24 and 117.

requirements, unique needs, a diverse group of end-use customers, and most importantly, distribution systems designed to meet their requirements and needs, to service their end-use customers. There is no direct link between the Hydro One transmission system and the LDC's end-use customers.

In Hydro One's 2017 Transmission Customer Engagement Survey, Hydro One asked LDCs to identify whether their responses to the survey were informed by their own customer engagement activities for the purposes of their own rate applications, or by any other customer research. Of the 28 respondents, 11 answered "yes" to this question. Additionally, Hydro One's Account Executives interact with the LDCs, and engage the LDCs in discussion regarding the needs of their ultimate end-use customers, as described above. Results from these inputs were considered by Hydro One during its investment planning process. In addition, Hydro One noted that in customer surveys conducted by other LDCs, residential customers, small business customers (general service<50 kW), and mid-market customers (general service>50 kW) consider price their number one priority and reliability their number two priority whereas larger demand key accounts prioritize reliability over price. These results demonstrate the importance of keeping costs as low as possible while maintaining system integrity to ensure reliable service to businesses in the province.

Subsequent to the issuance of the OEB's decision, Hydro One contacted some LDCs to solicit further approaches it could use to solicit feedback from LDC end-users, in the future. The feedback from LDCs included: (i) suggestions to continue using the account executive model to serve the needs of LDC customers, a program Hydro One has expanded as described above; (ii) that Hydro One meet with the large industrial customers of other LDCs, with Hydro One executives responding to customer concerns. Hydro One executed this suggestion and will facilitate future meetings as requested by LDCs; and (iii) that Hydro One may review LDC survey information. As indicated above, Hydro One considered the results of other LDCs customer surveys during its investment planning process.

FINDING 3: INCORPORATE INPUT FROM FIRST NATION REPRESENTATIVES

As noted, one message that Hydro One heard in the last transmission rate proceeding was that First Nations customers were not effectively represented in Hydro One's transmission customer engagement process, nor was any particular process in place to specifically engage with these customers. To respond to this concern, Hydro One asked LDC customers who serve First Nations communities whether there was anything in particular they felt Hydro One could do to better serve the specific needs of First Nations and Métis communities. Hydro One also leveraged its ongoing engagement activities with First Nations and Metis communities to identify customer needs and preferences for these customers. Details of Hydro One's ongoing initiatives can be found in Exhibit A, Tab 7, Schedule 2.

FINDING 4: ENSURE INFORMATION PRESENTED TO CUSTOMERS IS EASY TO UNDERSTAND

Finally, the design of the 2017 engagement survey included information that was purposefully written to ensure the content was unambiguous, sufficiently informative for customers to respond to, and easy for customers to understand. To gauge the quality and clarity of the information, the survey included a post-survey question asking "Did Hydro One provide too much information, not enough or just the right amount?" The result was that 76% of respondents believed the survey contained just the right amount of information.

Stakeholder Session

A stakeholder session, which included OEB staff and interveners who participated in prior Hydro One transmission rate proceedings, was held on March 22, 2017. The session aimed at gathering thoughts and insights from stakeholders on Hydro One's prior customer engagement activities. The feedback provided during this session was addressed as part of the 2017 Transmission Customer Engagement Survey process, as summarized in Table 1 below.

Table 1 - Summary of Feedback Received by OEB Staff and Interveners and Hydro One's Actions Taken

Feedback Received	Action Taken
Consultation did not take place early enough to have impacted business decisions.	The 2017 Transmission Customer Engagement report was released to Hydro One planners in 2017 and was incorporated into the iterative planning process undertaking in 2018.
Participation rates were low in the 2016 Transmission Customer Engagement effort, and did not represent the ones who will feel the impact of an increase (i.e., end-users of LDCs).	Hydro One invited all transmission customers to participate in the survey via a variety of channels. For the 2017 survey, 103 of 153 customers, or 66% of Hydro One transmission-connected customers, participated in the survey including a large number of LDCs.
A subset of the majority of attendees does not pay transmission rates directly and, therefore, Hydro One addressed the wrong audience.	A section for LDCs was added to the survey to address this concern, asking for the LDC's feedback to be provided on behalf of their customer base.
The costs of improved reliability and top quartile status were not fully explained to participants, impacting customer perception and whether they were willing to approve increased spending approvals.	A broader spectrum of options and enhanced details about each option were provided as part of investment outcomes.
There was a perceived endorsement of the middle investment scenario option and survey participants did not have enough options with 3 scenarios presented.	Customers were provided 4 detailed scenarios (as referenced in Attachment 1) and, when indicating their preference, were not constrained to choose one of the four scenarios, but rather respondents were asked to choose a point on a continuum (a total of 17 possible responses).
There was a perception that risks were exaggerated impacting customer perception to approve increased spending	IRG was asked to correct any wording used as part of the survey that could be perceived as 'leading' and additional information was provided in supplementary

Feedback Received	Action Taken
approvals, and that the risk model was not mature or predictive.	materials to better explain how and when the Hydro One Reliability Risk Model[4] is used. A broader spectrum of outcomes beyond reliability risk was provided to customers for each investment scenario to allow for more informed selections.
First Nations Customers were not represented and no consultation process was in place.	Hydro One engages with First Nation customers on a regular basis through a variety of channels (as outlined in Exhibit A, Tab 7, Schedule 2). Although Hydro One has no First Nation transmission customers, LDCs who serve First Nations and Métis Nation customers were asked specifically to provide feedback on how Hydro One could improve service to these customer segments. Of the LDC customers served by Hydro One who self-identified as serving First Nations and Métis communities, two provided a response. One indicated that Hydro One did not need to do anything else. The other stated that, "The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response." This feedback was considered when assessing the overall pool of investments addressing lower performing sections of the transmission system. Hydro One actively monitors all customer delivery point performance and invests in the system to address customer power quality concerns. Significant investment is planned in wood pole replacements, where the majority of the asset population is located in northern Ontario, along with transmission line refurbishments to address poor condition assets that pose a high risk to customer reliability.
Customers may not have fully understood what was being asked of them.	Links were included in the survey that took customers to a second document with more contextual information and definitions of terms used in support of the survey.
Confusing terms were used by Hydro One as part of the survey with terms used interchangeably, confusing customers (outage, interruption, end of useful life, expected service life, etc.).	The survey was carefully developed to be consistent with the use of terms throughout the survey process. Clarity on terms was provided in the supporting materials described above.

[4] Further details regarding the reliability risk model are provided in Attachment 4.

An additional discussion on end-user customers is presented in TSP Section 1.5.2, *Responses to OEB Directions from EB-2016-0160, LCD End-User Satisfaction.*

The presentation slides and summary notes from this stakeholder session are provided as Attachments 2 and 3 to this section of the TSP.

INNOVATIVE RESEARCH GROUP

Hydro One

Transmission Customer Engagement

hydro one

JULY 2017 | REPORT

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Survey Methodology

Overview:
Innovative Research Group (INNOVATIVE) was commissioned by Hydro One to conduct a customer engagement survey with its 156 transmission customers. INNOVATIVE worked closely with Hydro One to ensure that the survey structure and all questions were methodologically sound and that all data was collected in a private and secure manner. The results of the survey will be used as input for Hydro One's 2019 to 2023 business plan.

Sample Frame:
Hydro One and INNOVATIVE made efforts to contact all 156 Hydro One transmission customers to participate in this engagement (see details below). From a list of 156 customers, a total of 103 completed the survey.

Methodology:
In order to meet the needs of senior executives, customers were given the option of participating online on a custom site created and hosted by INNOVATIVE, or through an in-person or telephone interview with a senior INNOVATIVE consultant. While most customers chose to use the online tools, one customer requested an in-person interview and three opted for a telephone interview.

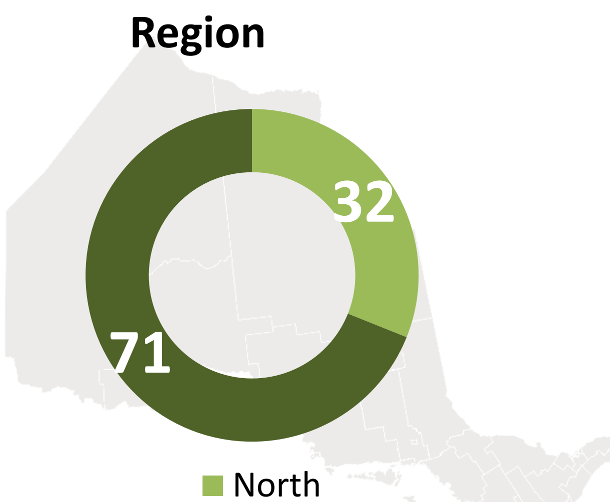
The survey design kept the amount of background information to a minimum in recognition of the high level of electricity system knowledge of many participants. To assist customers who are less engaged in the system, additional information (see Appendix 1.3) was made available to all survey participants, either with "click to access" buttons throughout the online survey, or in a standalone document for those who completed an in-person or telephone interview.

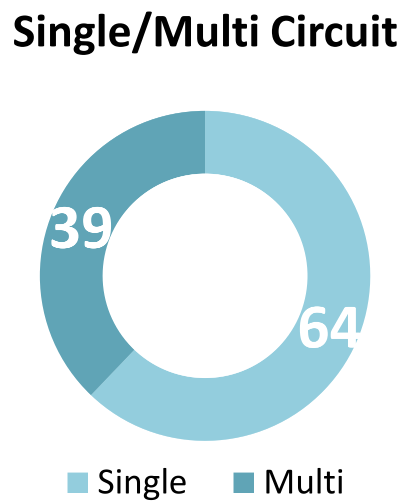
Where possible, invitations were initially extended through a phone call from Hydro One account executives and INNOVATIVE researchers. Most (n=142) customers were successfully contacted by phone and all but nine of this group (who stated they were not interested) were subsequently sent an email from INNOVATIVE which contained an individual URL for the survey site. Twelve customers who were not reached by phone were sent an email invitation which included a direct link to the online survey, along with contact details for an INNOVATIVE consultant should they wish to do an in-person or telephone interview. There were only two customers who could not be reached by email or by telephone.

Field Dates:
May 11th to June 15th, 2017

Participant Segmentation

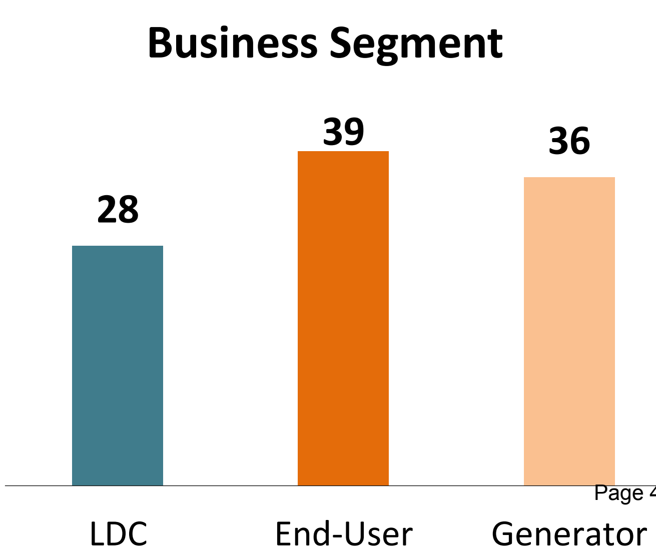
Hydro One understands that its customers have differing needs and preferences. To understand these differences, Hydro One asked that the results be presented in certain segments, as described below.





Northern customers commonly use a large percentage of the power delivered by their respective lines. Lines in the North tend also to be relatively long in length. Southern customers are generally more tightly integrated into a larger grid and more frequently share lines with many other transmission customers.

Multi-circuit customers have relatively low frequency of outages given the inherent redundancy. Single circuit customer do not benefit from redundancy and have a much higher risk of outage when an interruption in the system occurs.



Local Distribution Companies (LDCs) take power and distribute it to other customers within their franchise area. End Users take power directly and use the power for their own purposes. Generators deliver power to the transmission system, often in very large quantities.

Executive Summary (1)

Response to the Customer Engagement

Of Hydro One's 156 transmission customers, a total of 103 participated in this customer engagement – a response rate of 66%. Every customer who started the survey reached the end of the survey, where they were asked to provide feedback on the engagement itself. Participant response was overall positive and most felt that "just the right amount" of information was provided for the engagement.

Current Performance

In preparation for an open-ended probe designed to address their overall needs, customers were asked how satisfied they are with Hydro One's overall performance. As in other research, most transmission customers are satisfied in this regard.

In response to an open-ended question to identify any needs that Hydro One may not be meeting, many customers did not provide any suggestions. However, those who did suggested Hydro One could improve in the areas of customer service, reliability and infrastructure. All suggested areas for improvement are included in Appendix 1.1.

Customer Outcomes

Hydro One and INNOVATIVE reviewed previously available documents and talked to customer-facing Hydro One staff in order to develop a list of customer outcomes that was included in the survey. Prior to being exposed to this list, an open-ended question designed to elicit outcomes in customers' own words was asked. In response to this open-ended question, transmission customers said they know Hydro One is doing a good job for their business based on reliability, and customer service/communication (both of which were included in the list of outcomes developed for the survey). All outcomes suggested by transmission customers are included in Appendix 1.1.

Rating the provided list of seven customer outcomes on a scale of importance from 0 to 10 revealed that safety and reliability are top outcomes in terms of importance. When ranking in terms of what should be Hydro One's first priority, safety and reliability once again appear at the top of the list. However, through the lens of a combined ranking (first, second, and third), reliability becomes the top priority followed by safety and outage restoration.

Pace of Investment

All business segments, particularly LDCs, prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for ratepayers and the ability to plan ahead.

Executive Summary (2)

Reliability

In their own words, transmission customers define reliability using phrases like “lack of outages”, “stable power supply”, and “quality of power”. They also note that outages are not only a safety hazard, but also a financial concern affecting their business/production.

Reducing the frequency of power interruptions is more important than reducing the duration. Most important is reducing the number of day-to-day interruptions.

Illustrative Investment Scenarios

By a wide margin, maintaining the current level of investment (Scenario C) is the most popular choice over the other three scenarios. It is seen as reflective of the current approach which has the advantage of familiarity, and a less risky option. Second choice falls somewhere in between a decrease in investment (Scenario B) and maintaining the current level.

Differences Across Business Segments

Local Distribution Company (LDC) participants are less likely than End Users or Generators to consider reliability “extremely important”. Environmental stewardship is also less important among LDC customers than it is among the other Business Segments. On pace of investment, LDC customers show the strongest preference for spread-out investments and stable increases. Seventeen of 28 LDC customers prefer illustrative investment Scenario C (n=6) or an option one (n=6) or two (n=5) points lower along the spectrum (towards Scenario B).

About half of **End User** participants (19 of 38) rate power quality an “extremely important” outcome – a higher proportion than either LDC or Generator customers. End Users also consider productivity more important than the other business segments. While most (n=11) End Users selected illustrative investment Scenario C, they are also more likely than other business segments to have selected Scenario B (n=5).

Generator participants are most likely to consider safety an important outcome, with 30 of 35 rating it “extremely important”. This business segment also considers customer service to be more important than the other two business segments with about half rating it “extremely important”. Only among Generators does the level of support for illustrative investment Scenario D (n=6) approach the level of support for Scenario C (n=8).

Current Performance

Current Performance: Summary

Most transmission customers are satisfied with the overall performance of Hydro One in providing their business with electricity, suggesting that customer expectations are being met. That being said there are some End Users who report being "very dissatisfied" with Hydro One's provision of electricity.

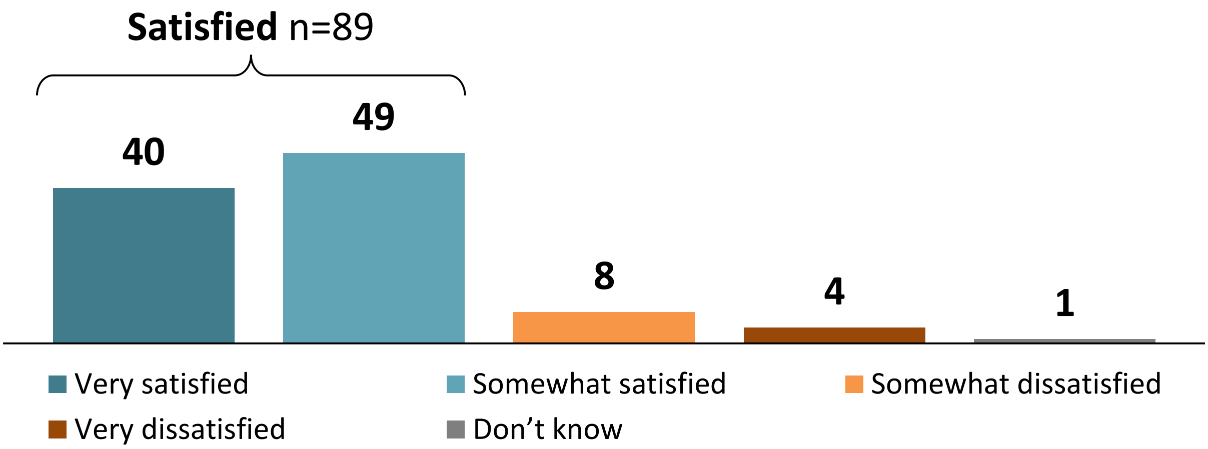
In response to an open-ended question, customers cite reliability and infrastructure concerns most frequently as outstanding needs. Reliability is mentioned most frequently by Generators and customers in the North. LDC customers are more likely than other business segments to mention infrastructure. Customers in the North and End Users do not mention improved communication in terms of outages, but LDCs and Generators in the rest of the province do. LDCs and those served by a Multi-Circuit connection are more likely than other segments to be looking for improved communication in general.

Overall Performance:

Across the board, most are satisfied with Hydro One's performance in providing their business with electricity

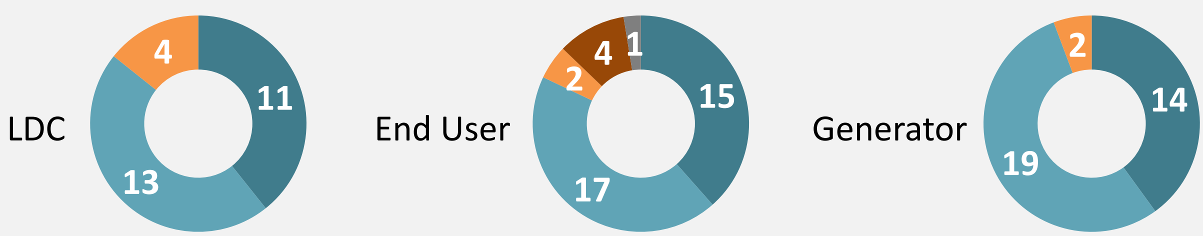
Q **How satisfied are you with the overall performance of Hydro One in providing your business with electricity?**

[asked of all respondents, n=103]

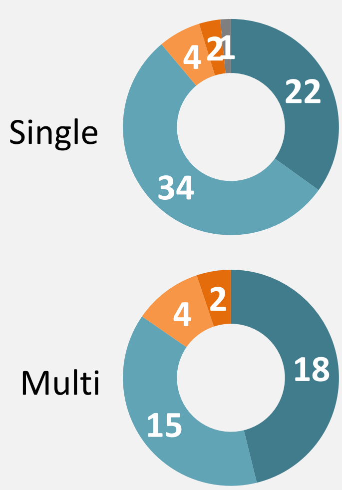


NOTE: No response (n=1) not shown

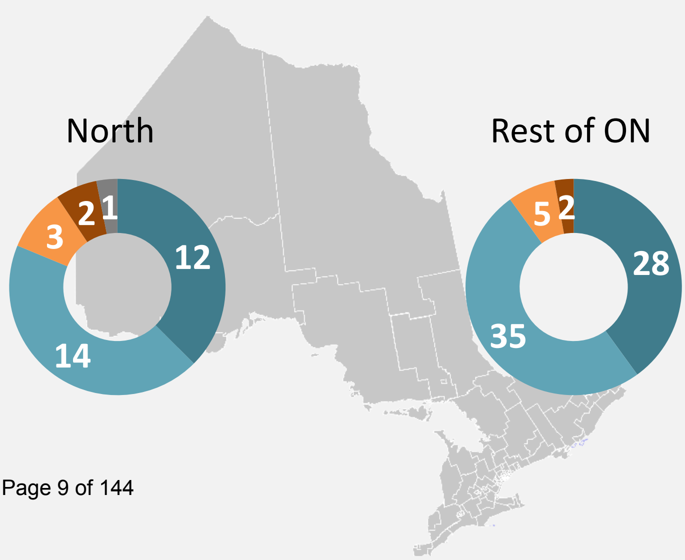
Business Segment



Single vs. Multi Circuit

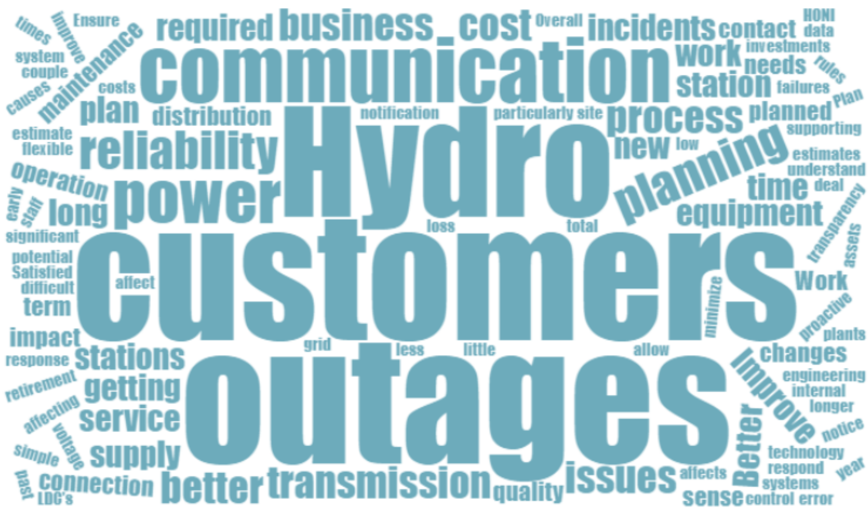


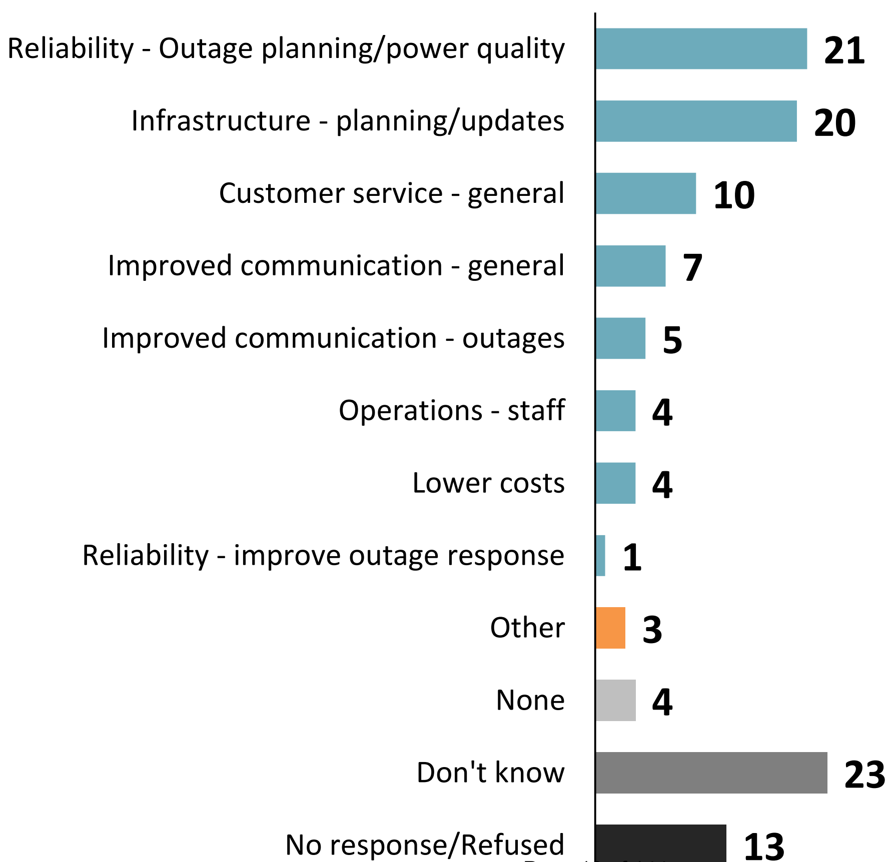
Region



Suggestions for Improvement:
Reliability and *infrastructure* are top mentions

Q **Is there anything in particular you feel Hydro One can do better?**
[asked of all respondents, n=103]





INNOVATIVE RESEARCH GROUP

NOTE: Total is greater than 103 due to responses being coded into multiple categories

Suggestions for Improvement:
Verbatim for the top two responses

Reliability – Outage planning/power quality

- Address "power quality"
- be more reliable
- Better coordination of outages and associated changes to same which might affect generating stations on the same network.
- Coordinate planned maintenance outages - proper lengthy notice
- Decrease the number of outages
- More assistance with power quality investigations, especially where HONI customers are affecting our customers (i.e. HONI arc furnace customers causing voltage flicker issues for our customers)
- Plan HO outages during our low production times to limit the loss of revenue to our business
- Plan outages better and work in better with clients to minimize impact on their business
- Timely contact with Account Rep to review transmission system reliability and incidents affecting WNH
- Understanding the true meaning of reliability and the impacts this has not only on HO customers but the impacts this has on its neighbours.

Infrastructure – planning/updates

- Add capacitance on S2B line?
- Continue to maintain the distribution equipment.
- Earlier engagement with impacted LDC's for station asset renewal projects.
- Ensure reliability of supply by ensuring equipment supporting our plants is maintained to highest standard. Ensure management and training of staff supports safe and error free operation of equipment supporting our plants particularly the nuclear fleet.
- Estimation, planning and engineering could be more proactive with generators. A lot of delay in getting cost estimate and work planning are having huge impact on our business.
- I would like to see the long term plan for Hydro One transmission investments to see how it fits with our business requirements. I feel Transmission Station investments should be pooled to avoid duplication
- Improve Hydro One's procurement process to minimize delays in resolving equipment issues.
- Interaction between technical/engineering groups and customers early in the connection process needs to improve. Improved sense of accountability required at Hydro One. Actual connection costs coming in well outside acceptable industry variance ranges. Paying significant amounts for connection estimates that provide little value (+/-50% estimate is unacceptable from any engineering firm). No sense of urgency, unless the lights are out.
- Line Maintenance needs improvement due to two recent Sky wire failures.
- our response is transmission based only and does not include distribution supplied locations. Better notification and planning with regards to maintenance activities would allow us to better plan and respond to our down stream customers.
- Overall satisfied, however, some H1 assets are getting aged and maintenance times to return transformers back to service appear to be getting longer. Potential for future issues.
- Share long term plan and how it affects my site
- there have been some concerns expressed over voltage regulation and insulators failures at the ts.
- Timeliness of transmission station upgrades and renewal.
- Upgrade facilities to allow for simple transfer to alternate circuit in the event of work required on our circuit.

See Appendix 1.1 for all verbatim responses

Customer Outcomes

Customer Outcomes:
Developing the List of Outcomes

The Hydro One transmission customer engagement survey presented customers with a list of seven customer outcomes, which they were then asked to rate in terms of importance, and rank in terms of priority.

To develop this list of outcomes, we first conducted a review of existing research and other documentation, which included a study conducted by INNOVATIVE for the Canadian Electricity Association (Hydro One was a subscribing member for this research), Hydro One's strategic planning documents, a Transmission Customer Satisfaction Report written by Northstar in February of 2017, and a Transmission Customer Consultation Report prepared by Ipsos in April of 2016.

In addition to these materials, Hydro One senior representatives walked INNOVATIVE consultants through their internal planning process in order to explore how investment areas correspond to customer outcomes.

In order to ensure customer input was included in the development of the list of customer outcomes for the survey, a Hydro One senior executive conducted one-on-one interviews with customer-facing Hydro One staff. A summary of these interviews was shared with INNOVATIVE during the survey development phase.

Customer Outcomes: Summary

At the start of the survey, respondents were asked an open-ended question designed to elicit customer outcomes. Reliability - reduction of interruptions and good communication top the list of mentions. Looking at respondent segments, there are few differences, however, LDCs and those in the North are more likely to mention customer service in terms of availability than other customer segments.

Respondents were asked to rate seven customer outcomes on a scale of 0 (not at all important) to 10 (extremely important), and then to rank them in order of priority. The first exercise gives an idea of perceived importance of each individual outcome, while the ranking shows how customers perceive the outcomes in relation to each other. When asked to rate the *importance* of an outcome, safety and reliability receive the highest ratings. When asked to rank in order of *priority*, two stories emerge. Through the lens of first priority ranking, safety and reliability come out on top. When looking at the first, second, and third rank combined, a slightly different story appears. Reliability is ranked highest, followed by safety, and outage restoration becomes the third highest ranked outcome. Power quality and customer service land in the middle, and productivity and environmental stewardship are the bottom two.

At the overall level, 79 out of 103 survey participants rate safety "extremely important". In fact, across all customer segments, most consider safety to be "extremely important". Among Generators, there is not a single respondent who rates safety lower than a nine.

Reliability is second only to safety, with 71 of 103 rating it "extremely important". Looking at the various customer segments, while there are some who rate reliability as low as a six, at least half consider reliability to be "extremely important".

With 60 of 103 rating it "extremely important", outage restoration rounds out the top three customer outcomes. In the North, no one rated outage restoration any lower than an eight, but in the rest of the province, a handful rated it seven or lower.

Fewer than half (44 of 103) rate power quality as "extremely important". LDC customers do not give power quality a rating lower than a six, but there are customers in all other segments who consider power quality to rate somewhere between a zero and five on importance.

Looking at the bottom three, customer service is considered "extremely important" by 41 out of 103. Proportionately, Generators and transmission customers in the North are most likely to rate customer service a 10.

About a third (37 of 103) rate productivity at a 10. Generators do not rate productivity any lower than a six, but there is at least one customer in all other segments who rates it somewhere between a zero and five.

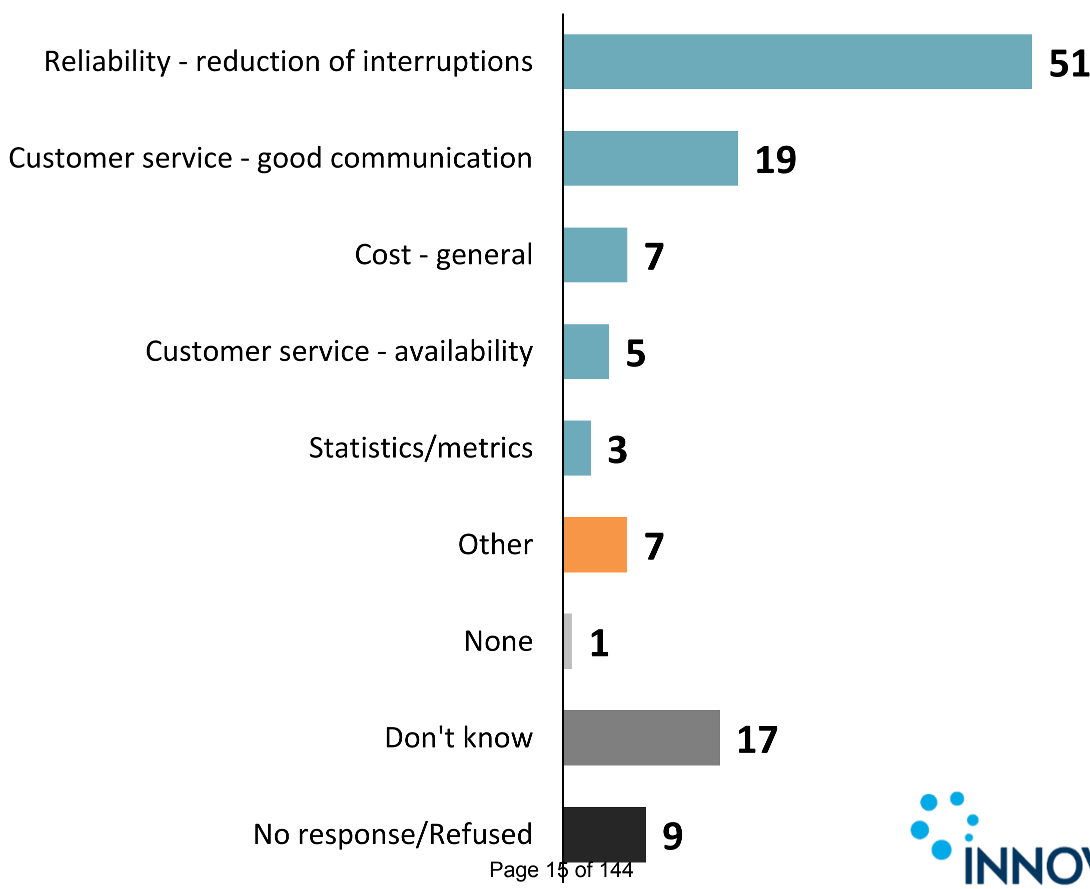
Rounding out the bottom three with 31 of 103 rating it "extremely important" is environmental stewardship. LDC customers tend to rate this outcome lower then End Users or Generators. Customers with a single-circuit connection consider it more important that those with a multi-circuit connection.

Asked if any customer outcomes were missing from the list of seven included in the survey, some customers were able to suggest additional customer outcomes, using phrases like "system capacity", "value for money", "response" and "customer service". None of the suggested outcomes were ranked as being more of a priority than the original seven.

Performance Criteria:

Reduction in outages and interruptions, power supply, and customer service in terms of communication are top mentions for performance metrics

Q **How do you know if Hydro One is doing a good job for your business?**
[asked of all respondents, n=103]



INNOVATIVE RESEARCH GROUP

NOTE: Total is greater than 103 due to responses being coded into multiple categories

Performance Criteria:
Verbatim for the top response

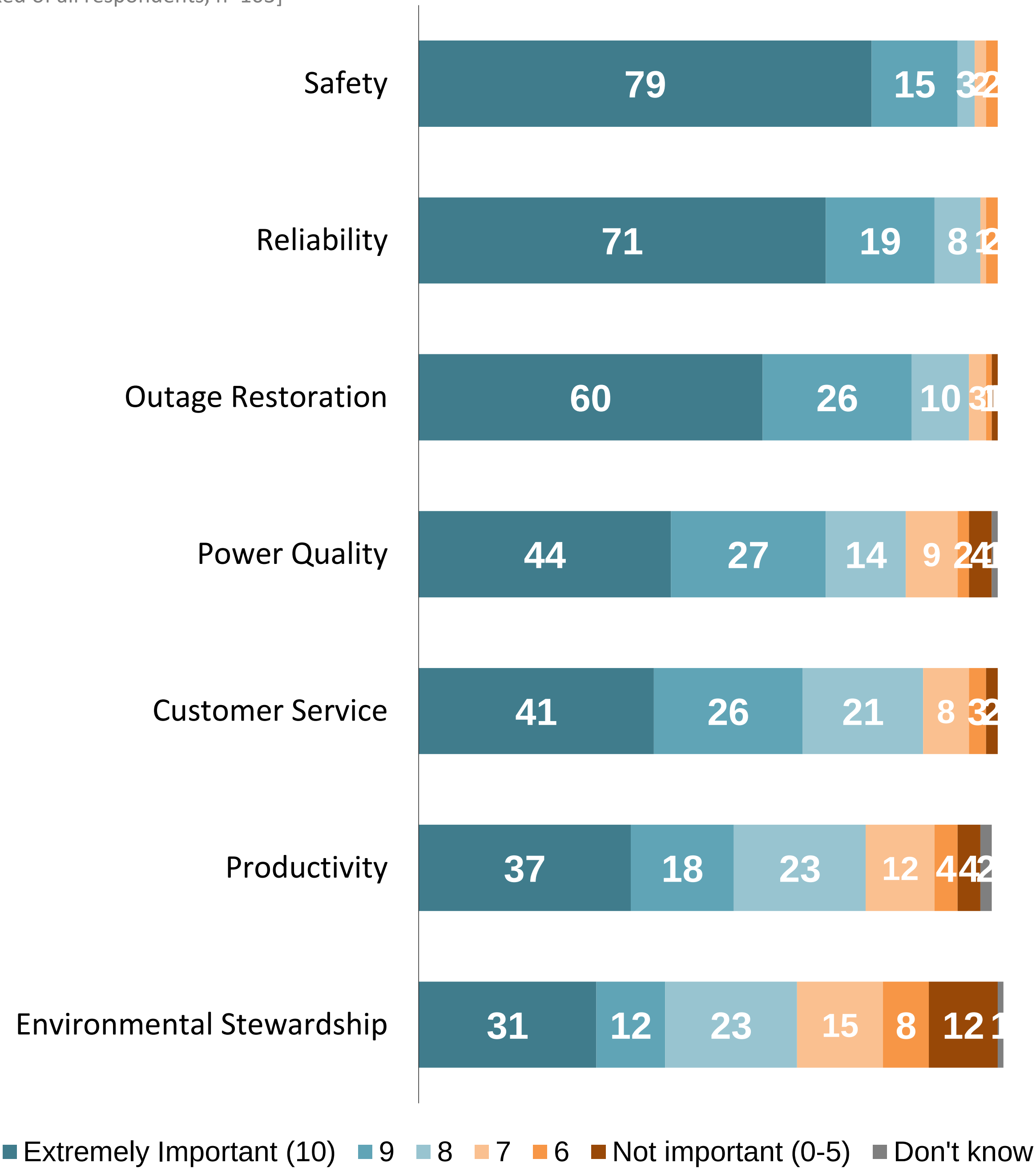
Reliability – reduction of interruptions

- if I do not have to call them
- Keeping the supply of power on
- My power is still on
- No surprises
- On rates, no idea...on work around transmission doing fine, meeting with us generators every 6 months to try and best facilitate outages/repairs/upgrades
- Performance is based on Hydro One's ability to provide its service reliably and implications to our operations.
- Power Supply reliability
- provides reliable supply and responsive service
- Reliability is important but at a cost that makes us uncompetitive and sends jobs abroad is not sustainable and will hurt all citizens of Ontario
- Reliability of supply.
- Reliable electrical power supply.
- reliable supply of electricity at a reasonable cost
- stable grid system, less impact on the customer side are all we need.
- that the delivery of Hydro is reliable
- They work with us in outage management
- Timely and accurate billing and reconciliation. Reliable power.
- We look at overall reliability as well as Hydro One's understanding and explanations of the incidents that have occurred.
- We measure reliability based on Loss of Supply. Quality and timeliness of responses from Distributed Generation and Engineering groups.
- When100% availability is achieved
- 1) No unplanned outages and consistent power quality. Score 8 out of 10. 2) Supportive in planning and outage response. Score 9 out of 10.
- By the way that Hydro One coordinates planned equipment outages with the customer needs.
- Effectively communicating and ensuring to work with customers to minimize impact of business interruption
- Electrical outages are rare and when there is an outage they are quick to respond and communicate the outage
- Few outages, either planned or unplanned
- Fewer outages
- Forced outages are reduced and power quality is improved.
- If the lines remain open for business and interruptions are held to a minimum
- If they are doing good then we won't have any surprise outages and/or time we can't inject into the grid.
- in simple terms as long as the electricity runs through the lines and there are no disturbances causing issues or damage to our equipment then everything is good
- Interruptions are at an absolute minimum and wherever possible with as much advance notice as possible.
- No interruptions in supply and no voltage issues.
- no issues with unplanned outages, invoices are accurate
- Number of outages my business experiences or individual equipment trips due to voltage sag
- Number of power interruptions that occur.
- Power reliability and quality issues reduce to once per year.
- Reliability and costs are the primary drivers in the measurement of performance.
- Reliability to date has been good, however, increasing frequency/duration of reduced redundancy due to extended maintenance periods. Resulting in higher potential risk exposure for customers.
- Reliability, costs, general customer service, responsiveness, operations service and interfaces, ease of doing business with, relationships. Enable the LDC to forward their objectives.
- Reliability, responsiveness
- Reliable service.
- Sustained, reliable electricity delivered to our door. Our joint work - when the actuals are more in line with the plan, be it outages or length of outages, and cost.
- Unplanned outages are minimal, good communication on maintenance being completed
- We are provided with the reliability information from our Network Management Officer.
- We can gage the performance of the HONI system via the number of outages due to loss of supply
- We seldom loose production because of hydro outages
- When I don't hear about any business interruptions or scheduling conflicts.

See Appendix 1.1 for all verbatim responses

Customer Outcomes:
Safety, reliability, and outage restoration are ranked as most important

Q **How important an outcome is…**
[asked of all respondents, n=103]

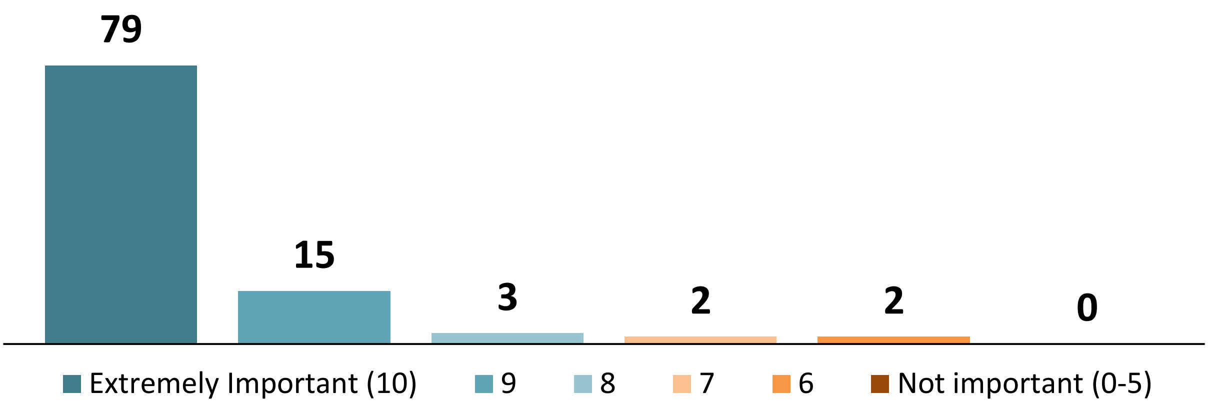


NOTE: No response (n-size varies from 1 to 3) not shown

Safety:

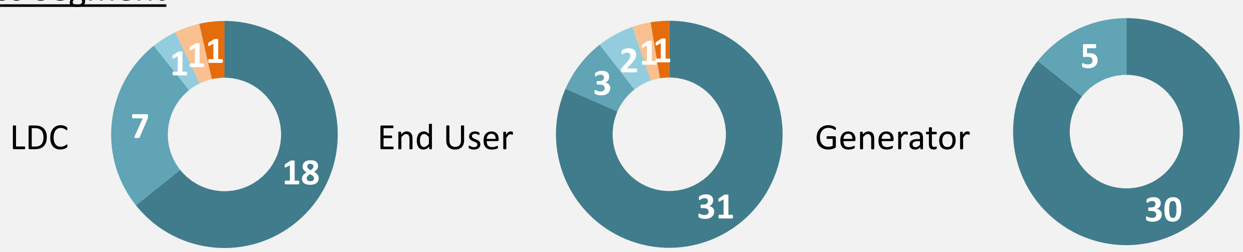
Across all segments, most (n=79) consider safety to be extremely important

Q Eliminating and mitigating risk to public and employee safety in the operation of the transmission system. **How important an outcome is safety?**
[asked of all respondents, n=103]

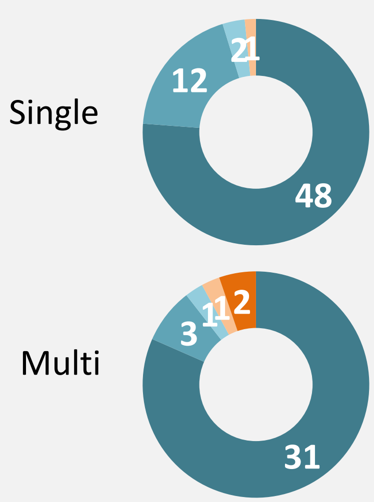


NOTE: No response (n=2) not shown

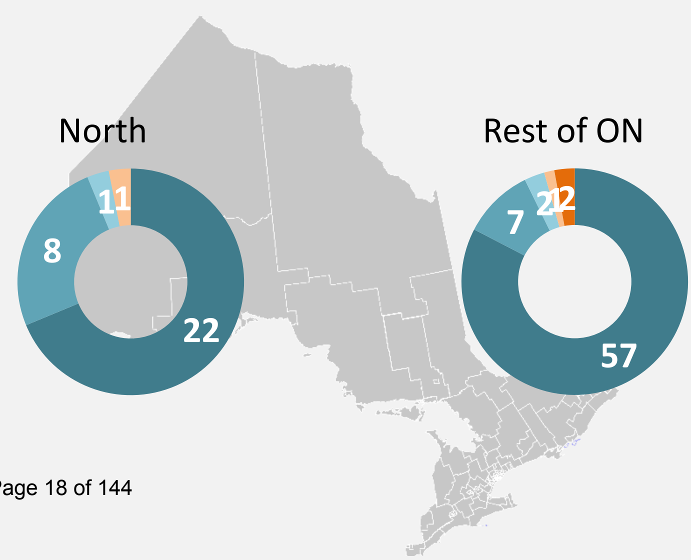
Business Segment



Single vs. Multi Circuit

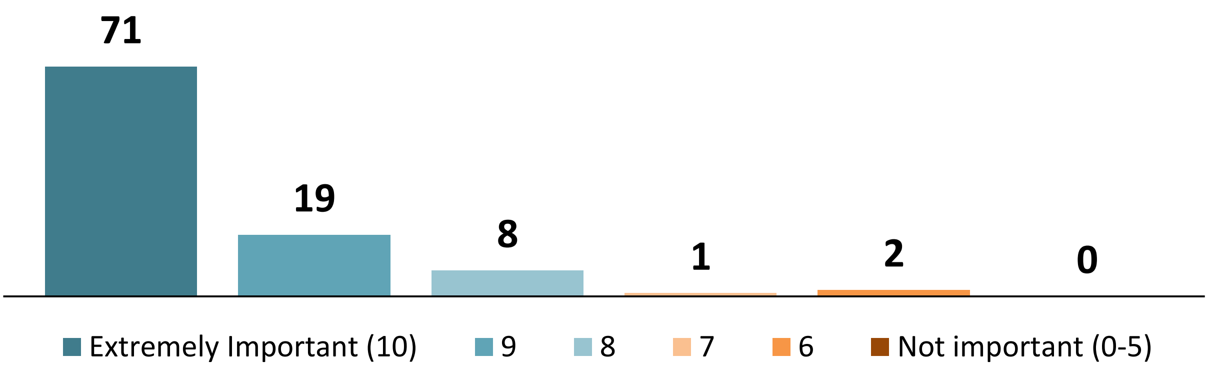


Region



Reliability:
Most (n=71) consider reliability to be extremely important; LDCs are less likely than other business segment cohorts to consider reliability extremely important

Q Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers. **How important an outcome is reliability?**
[asked of all respondents, n=103]



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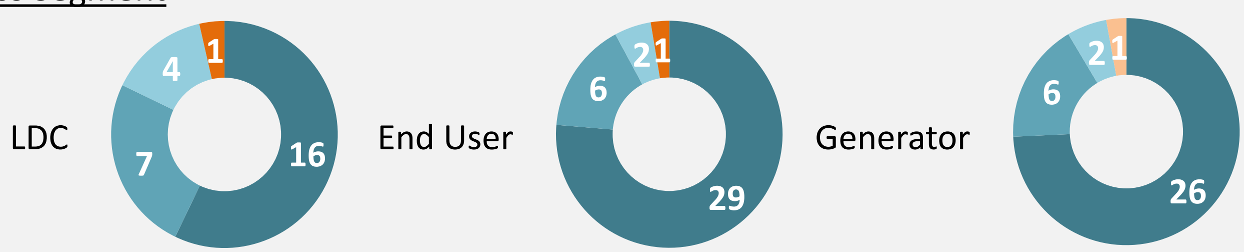
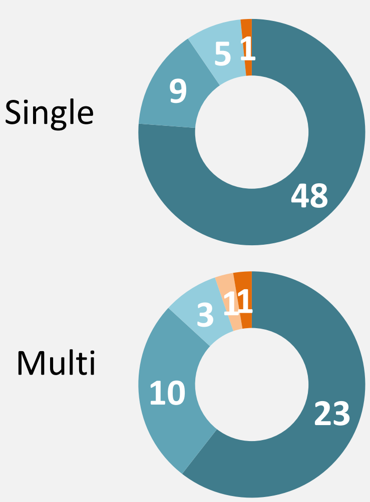
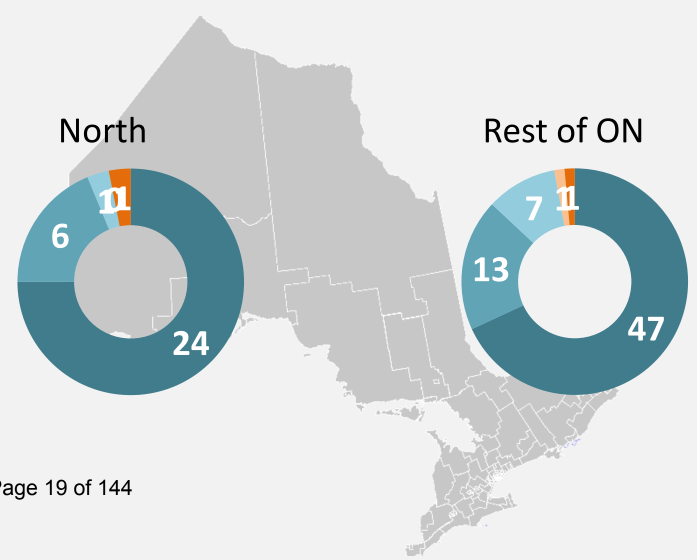
Business Segment



Single vs. Multi Circuit



Region

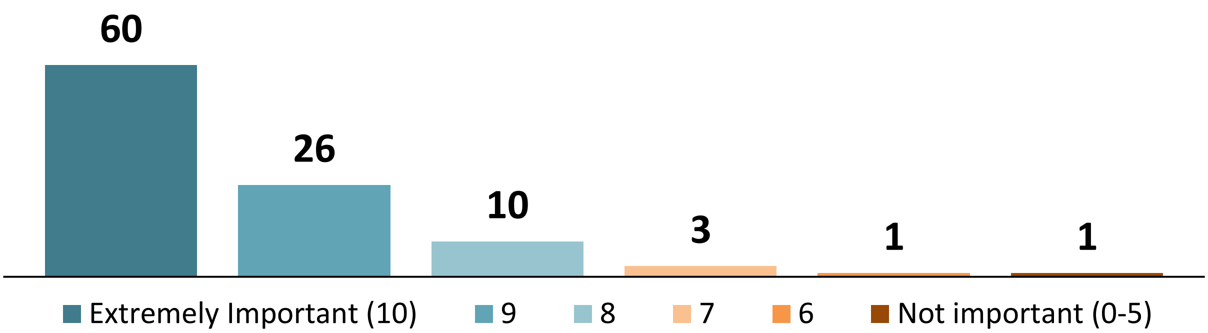


Outage Restoration:

Most (n=60) consider outage restoration extremely important; this opinion is strongest among Single Circuit transmission customers

Q Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions. **How important an outcome is outage restoration?**

[asked of all respondents, n=103]



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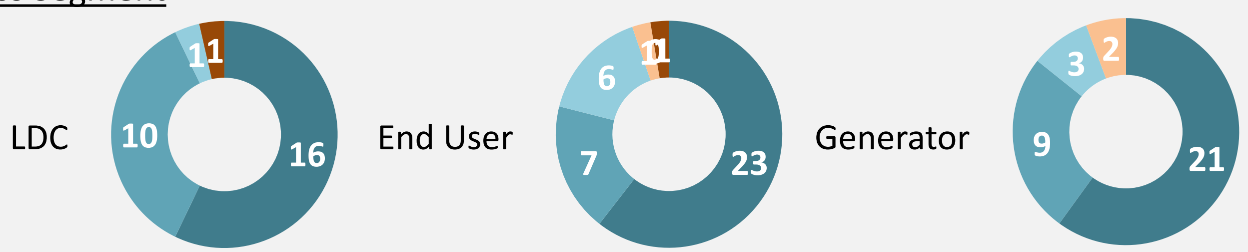
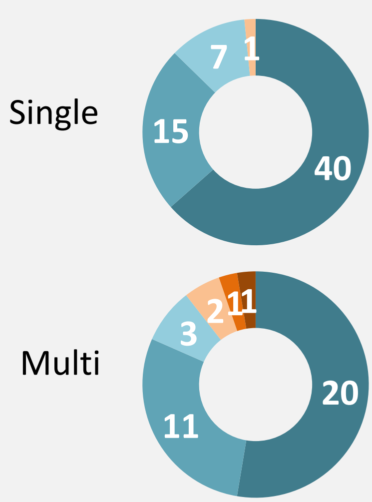
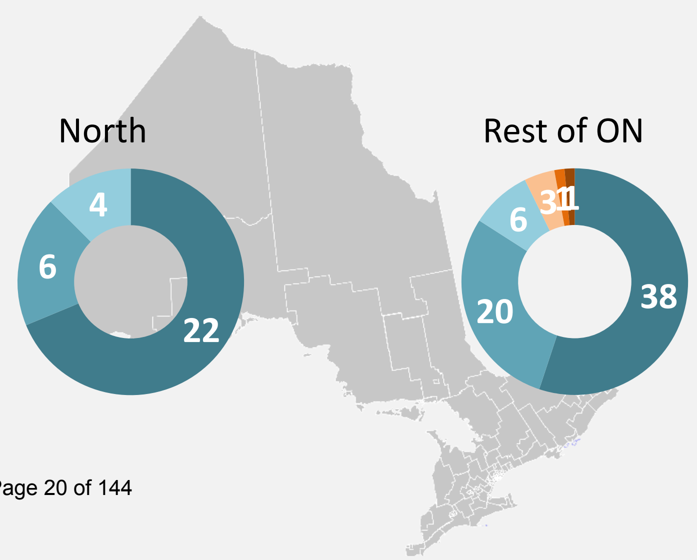
Business Segment



Single vs. Multi Circuit



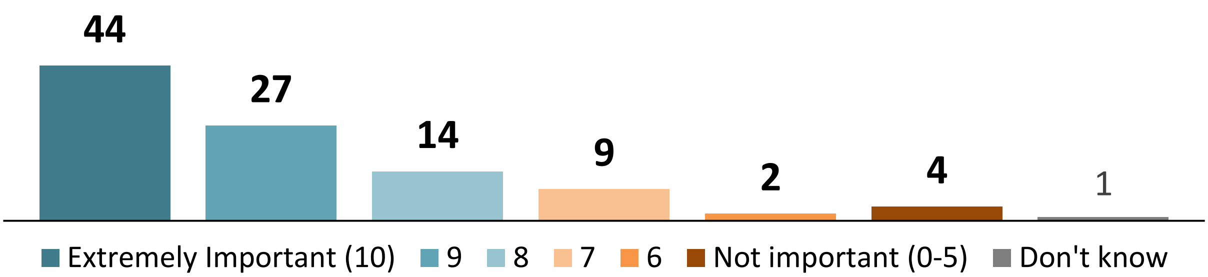
Region



Power Quality:

A plurality perceive power quality as extremely important; this opinion is strongest among Single Circuit and End-User customers

Q Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers. **How important an outcome is power quality?**
[asked of all respondents, n=103]



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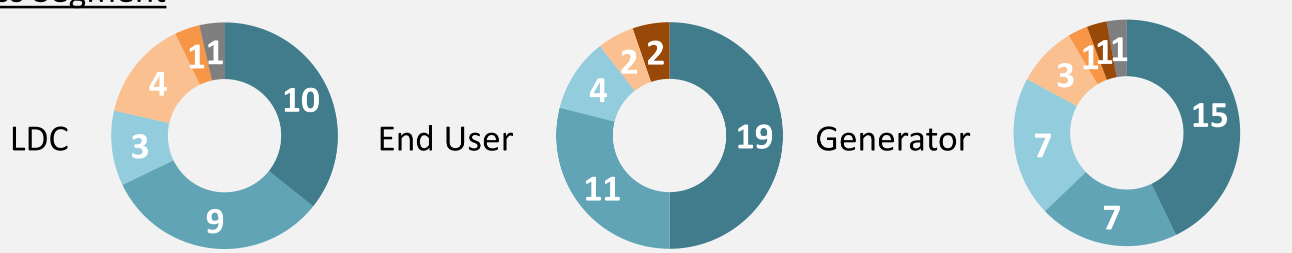
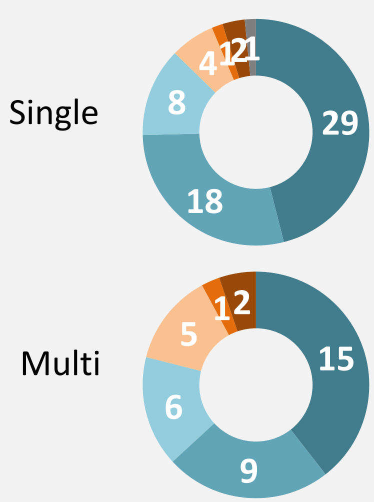
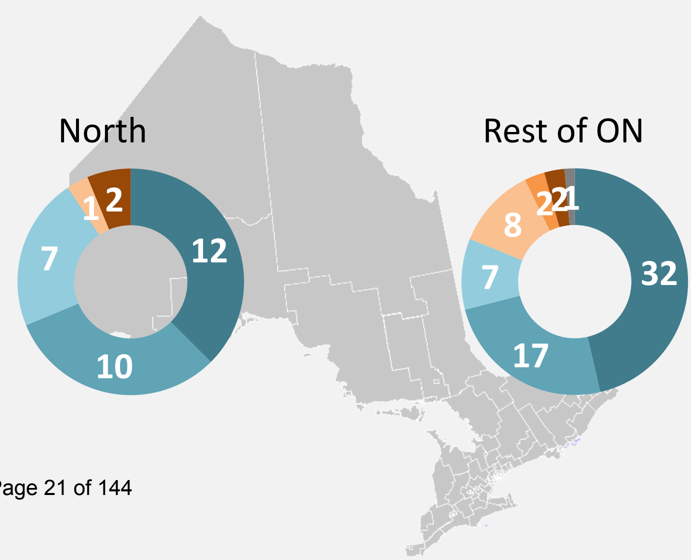
Business Segment



Single vs. Multi Circuit



Region

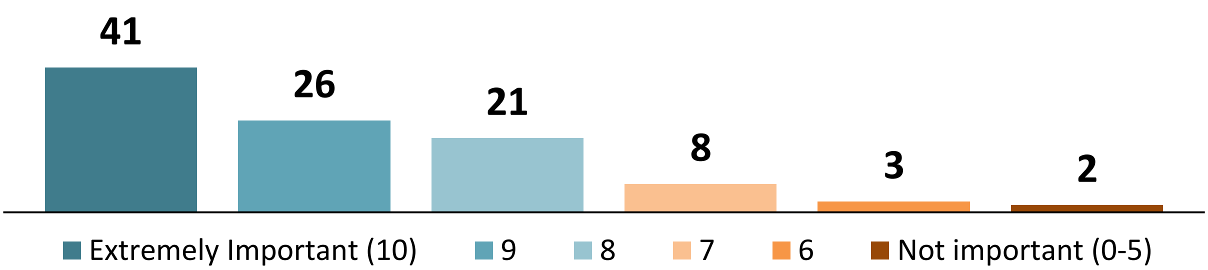


Customer Service:

A plurality (n=41) perceive customer service to be extremely important; this outcome is more likely to be of higher importance to those in the North region

Q Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers. **How important an outcome is customer service?**

[asked of all respondents, n=103]



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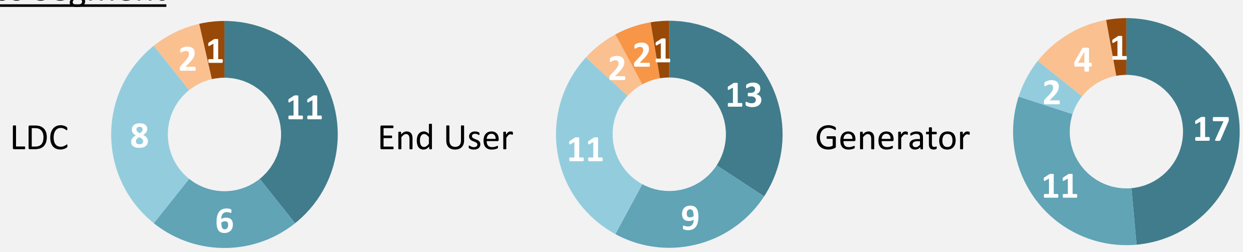
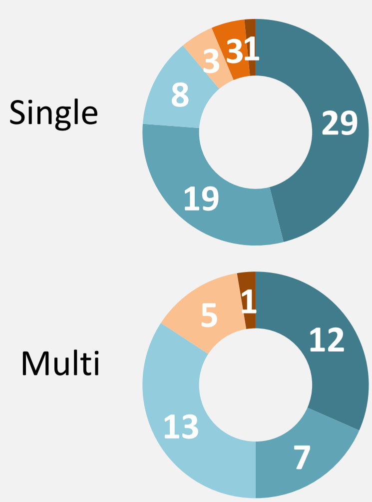
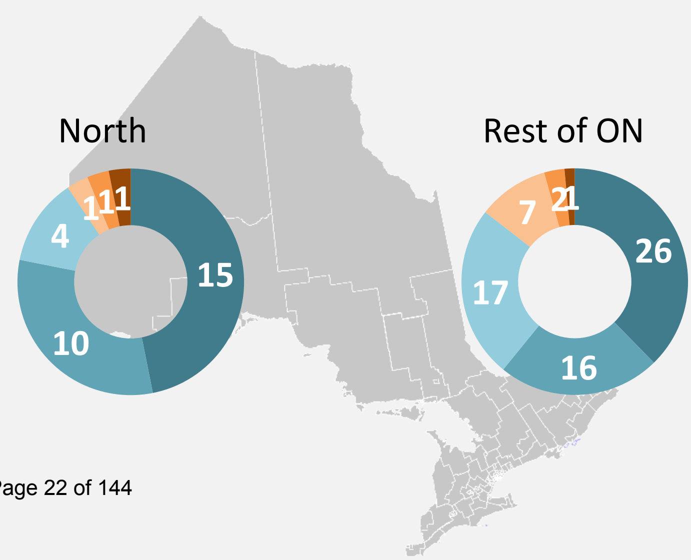
Business Segment



Single vs. Multi Circuit

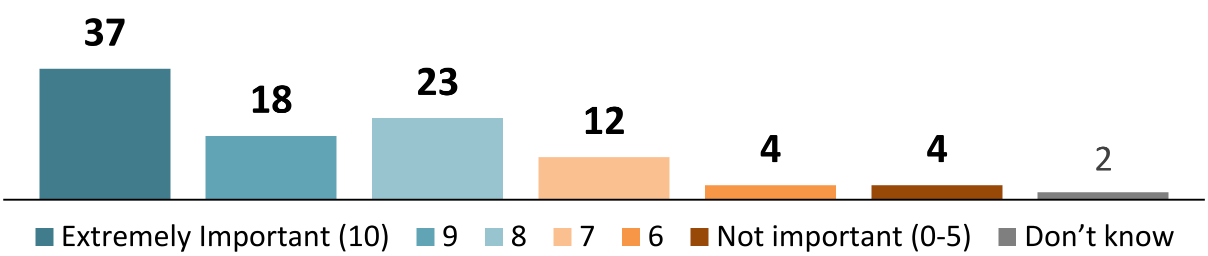


Region



Productivity:
About half of End-Users say productivity is extremely important; importance of productivity is higher for the Single Circuit segment than Multi Circuit

Q Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources. Hydro One understands that customers expect it to look first for internal savings before asking for any additional rates. **How important an outcome is productivity?**
[asked of all respondents, n=103]



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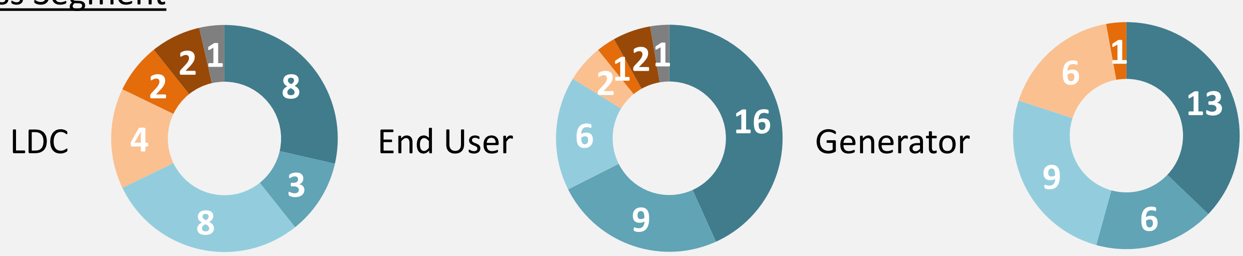
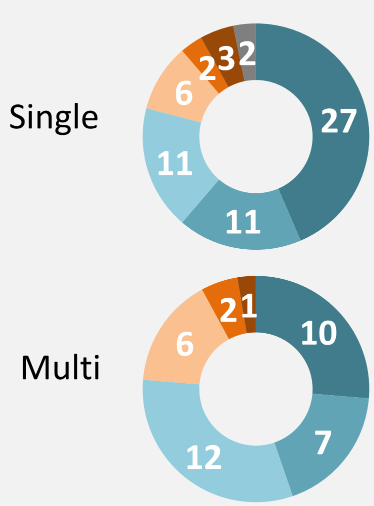
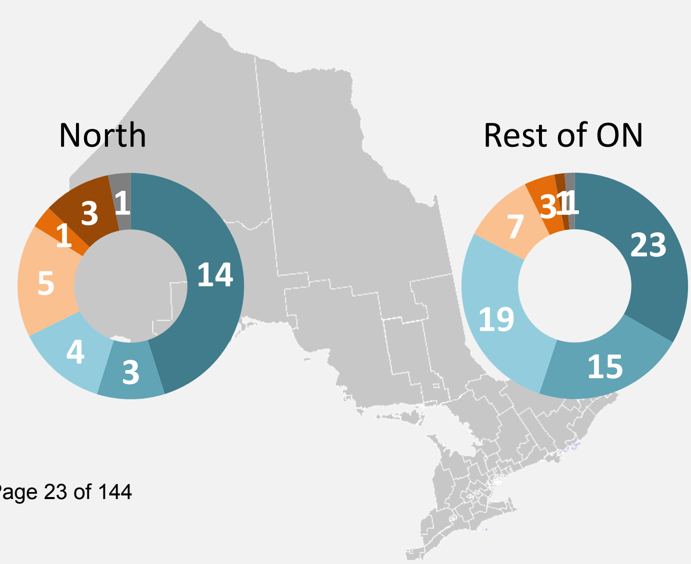
Business Segment



Single vs. Multi Circuit



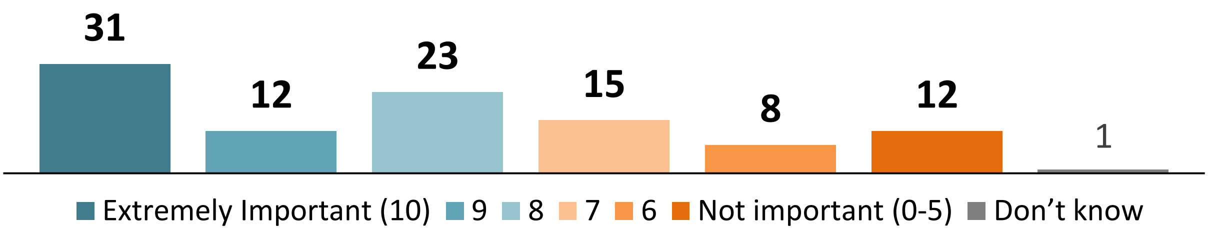
Region



Environmental Stewardship:

Importance of environmental stewardship is highest among the Single Circuit segment; least important among LDCs

Q Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada. **How important an outcome is environmental stewardship?**
[asked of all respondents, n=103]



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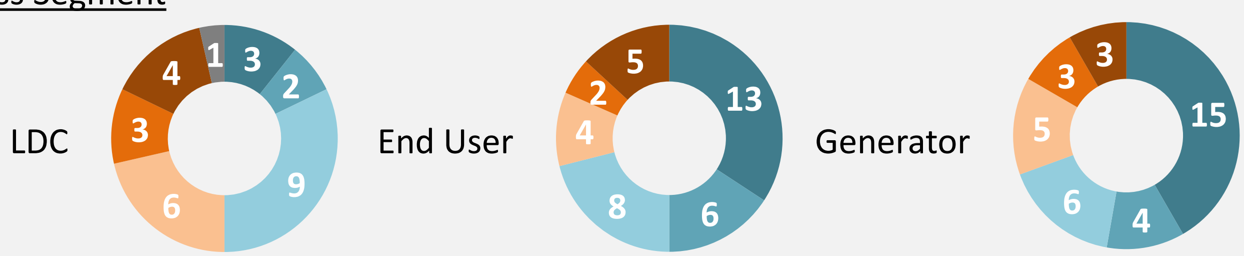
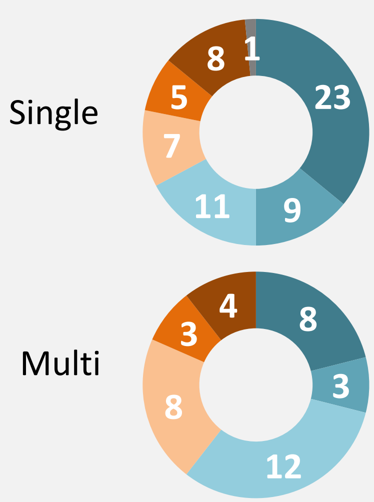
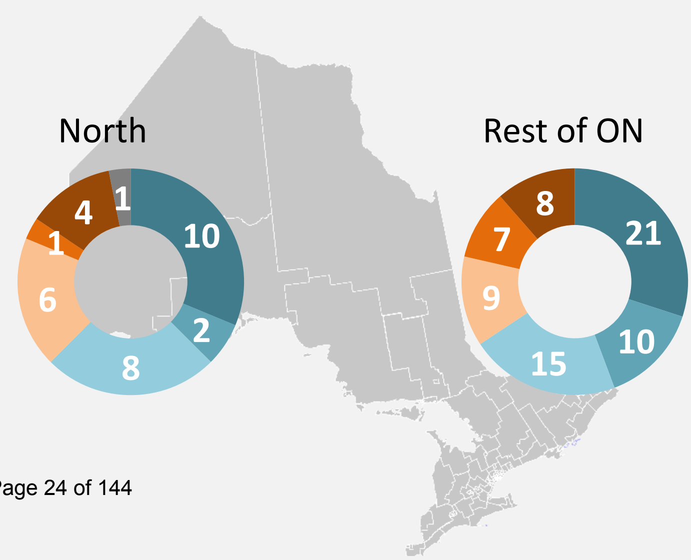
Business Segment



Single vs. Multi Circuit



Region

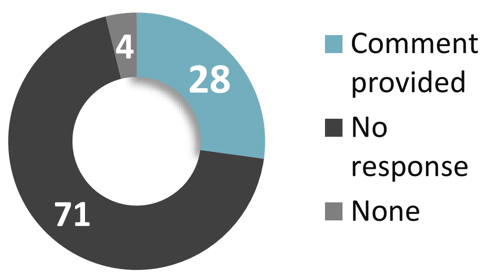


Additional Outcomes (1):

Majority of respondents had nothing to offer on missed outcomes; among those who did, cost and capacity/expansion are top mentions

Q Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.

[asked of all respondents, n=103]



System capacity - Have a transmission system with the capacity to meet the needs of our customers.

New connections and upgrades built and energized on a timely basis.

Price or cost - what is the value for money.

Costs; You will say its inferred in productivity and others. This is the reason we are in a mess.

Reduction on cost of GA.

Grid Capacity Expansion.

Response from local Hydro One team to respond to emergencies related to un-expected site power outage.

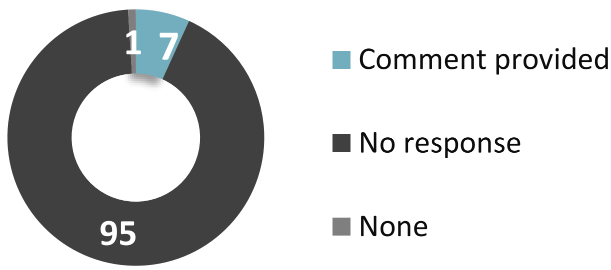
General communication about direction of HONI certainly helps me as a customer understand ramifications.

Responsiveness and personal assignment of a customer service representative for major customers.

Streamline the customer service experience to be able to reach appreciate parties efficiently.

Additional Outcomes (2):
Very few were able to suggest a second additional outcome

Q Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.
[asked of all respondents, n=103]



Reasonable cost and timeliness to provide services such as connections, transfer trips, CIAs.

Power Distribution costs go down.

Accountability and transparency - Most people can't understand their bills and costs are fixed.

Drive for Delivery - accountable to deliver and action oriented.

Communication.

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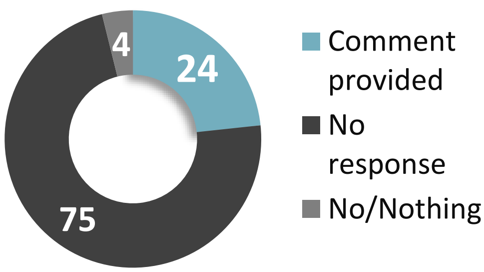
Comments:
Comments regarding customer outcomes touch on a wide variety of topics including safety, reliability, and cost

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?
Please fill in your response below.
[asked of all respondents, n=103]



Cost reductions should be a top priority and given serious consideration and not just lip service.

Cost estimates for work to be performed by Hydro One are extremely high. While part of the issue is the class C estimate contingency, those costs cause a lot of concern for customers considering connections for generators.

All outcomes are equally important. It is hard to have one and not the other. Ultimately we do not see the environmental stewardship piece directly at the mill site.

I like when you mention safety, the industry is very high risk and nice to see HONI as a leader.

The main outcome should be to provide reliable power at the best possible cost which should be benchmarked to a world standard to remain competitive and to make it so people don't have to choose between eating and having access to power.

As a generator it also extremely important that HONI is available to take the power and transmit it reliably.

Power Quality is an integral part of Reliability.

Ensure that there is regular communications and dialogue.

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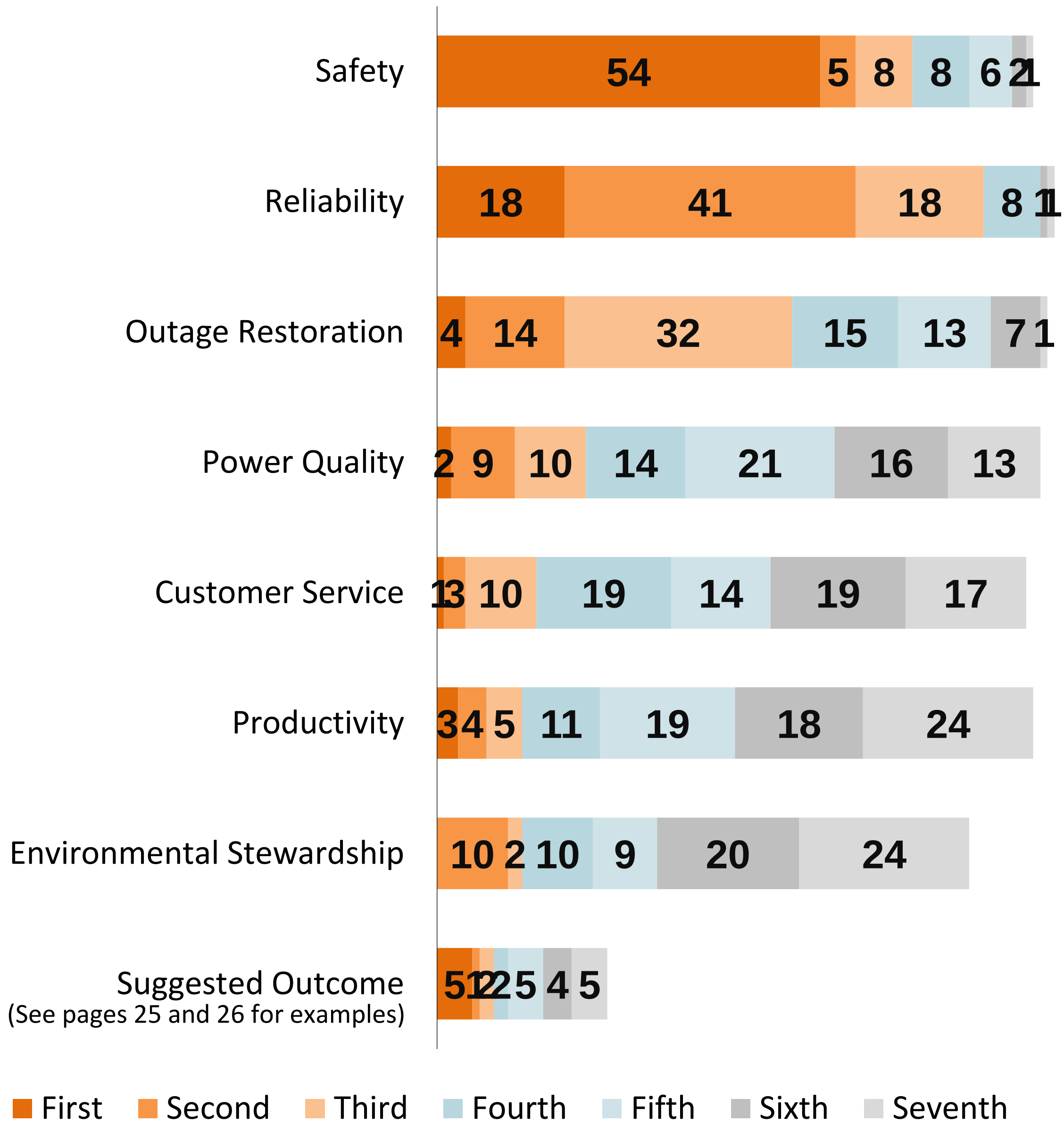
Top Priorities:

More than half rank safety as *first* priority. Rolling top 3 priorities together, reliability and outage restoration increase as priorities

Q While all the outcomes listed are important to many customers, planners set priorities among different outcomes. The purpose of this section is to help Hydro One set priorities as it prepares its business plan. Which priorities should they focus on first?

Please rank your top priorities from the list below.

[asked of all respondents, n=103]

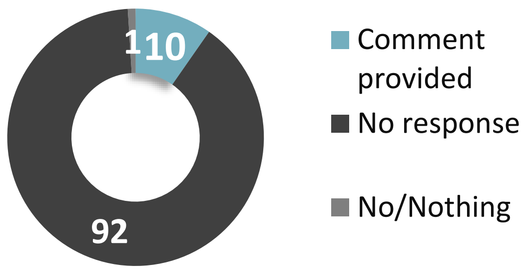


NOTE: No response (n=16) not shown.

Comments:

Most did not provide any additional comments following the customer outcome priority ranking exercise

Q Comments in response to ranking customer outcome priorities:
[asked of all respondents, n=103]



Customer Service is affected by not only the customer service through communications and follow up but it is driven by the quality and reliability of the service of supplying electricity.

The focus on environmental steward ship and the solar and wind ventures it generated where ill conceived and poorly planned and have costs significant hardship on the citizens of Ontario . Although important it was very badly managed.

Note that although power quality is on the bottom it is also extremely important.

Safety and Environmental stewardship are not my interests but your employees and the governments interests respectively - as a customer I need performance improvement in all other areas and results now and need to know and trust that you have it and are going to do something on it.

As a customer, reliability and outage restoration are important outcomes. I should be able to rank those at the top without sacrificing Safety or the Environment. This survey does not give that choice.

Number one for my customers is rates. Productivity is not a direct reflection of that, but is similar.

This ranking is predicated on Hydro 1 executing these priorities - if power quality and reliability are not improved, then customer service becomes much more important.

This is difficult as they are all important.

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Pace of Investment

Pace of Investment: Summary

Customers indicate a strong preference for stable rate increases and investments spread out over time, with 74 out of 103 choosing this option over 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 increases).

LDCs show the strongest preference for spreading out investments, with all but a handful choosing this option.

Asked why they prefer this option over others, customers mention affordability and aligning rate increases with inflation. The perceived affordability of this option is viewed both from the perspective of being a business transmission customer (“Easier to forecast for business plan with stable increases”), as well as the end customer of LDCs (“This is the philosophy we have taken as a distributor ... affordability needs to be considered”).

Ten respondents were not able to make a choice on the pace of investment options presented to them. Some of these customers use phrases like “Show some flexibility” and “revisit and optimize costs” to describe what the decision depends on. Others wanted more detail about the investments and the magnitude of rate increases.

Pace of Investment:
Preamble and Survey Question

Before being asked the question about the pact of investment, respondents were provided with the following preamble:

When Hydro One replaces equipment in declining health, it has some flexibility in its pacing. We would like to understand your general views on the appropriate pacing of Hydro One's investments over the next 15 – 20 years. Hydro One can front load its capital investments, it can spread them evenly over time, or it can delay its investments.

Front-loading investments would provide some benefits in terms of more connection capacity, decreased equipment failures, increased reliability, and improved productivity and quality. This would mean higher rate increases now but lower rate increases in the future. Spreading evenly over time means some benefits are delayed but some long term savings are secured and it is more efficient in terms of staffing. Rate increases would increase at a stable level. Asset deployment costs would likely be lower using this more stable pacing philosophy.

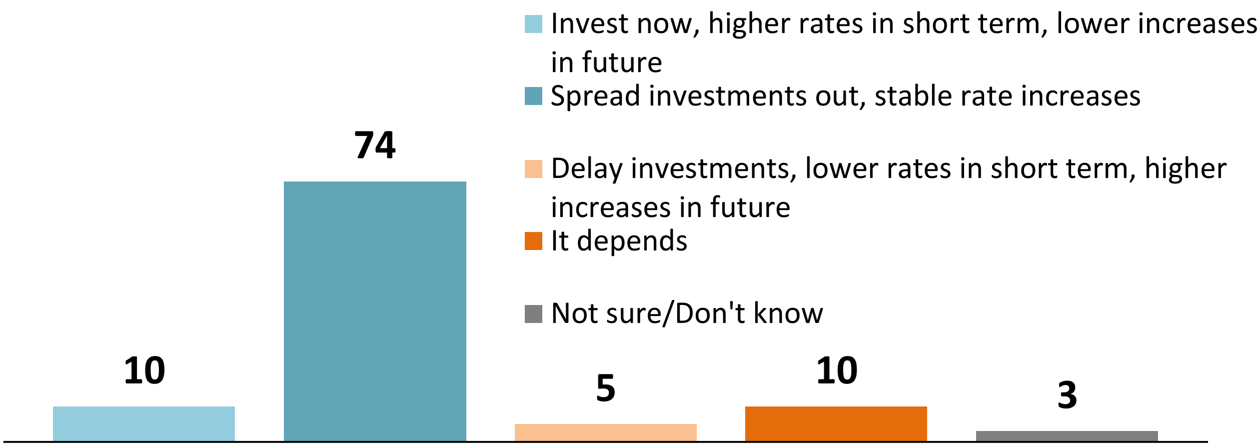
Given the current health and demographics of the system, Hydro One can delay investments further until declining equipment conditions threaten Hydro One's ability to meet power reliability requirements. Reliability would still meet minimum standards but customers would likely experience more interruptions than today. Rates increases would be relatively low for several years but increase at a steeper rate in the future.

Following the preamble, respondents were asked the following question:

Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?

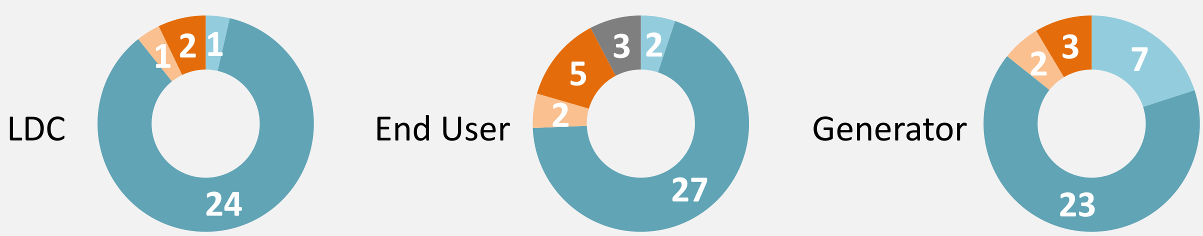
Pace of Investment:
Strong preference for spread-out investments and stable increases; highest in 'Rest of Ontario' region and among Single Circuit customers

Q Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?
[asked of all respondents, n=103]

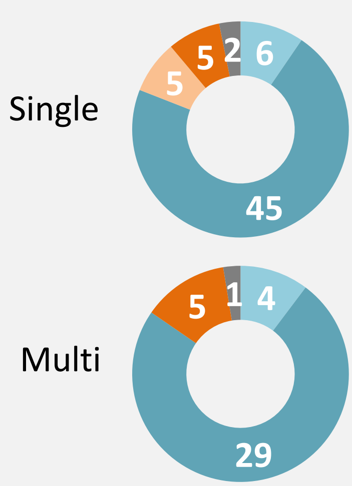


NOTE: No response (n=1) not shown

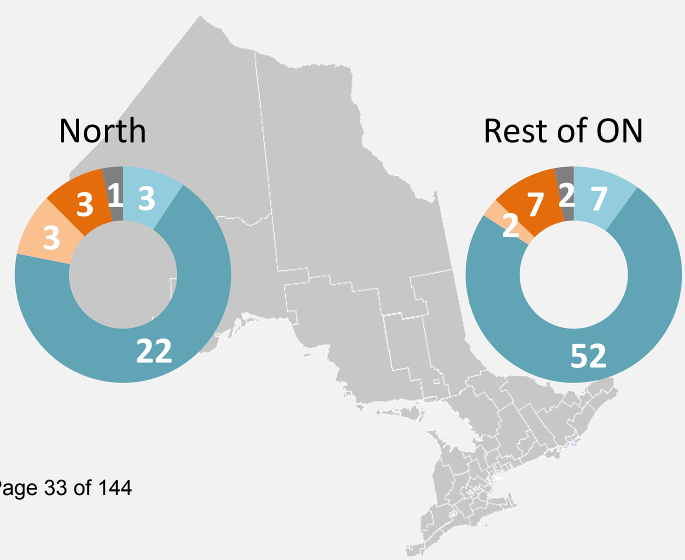
<u>Business Segment</u>



<u>Single vs. Multi Circuit</u>



<u>Region</u>



Invest Now:
Those who prefer to invest now appear to be motivated by the reliability risks associated with aging infrastructure

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Invest now, higher rates in short term, lower increases in future…

Decrease in system reliability or increases in equipment failures negatively impacts our facilities operations and earnings.

Locally many assets are getting aged and reliability is already at risk. Higher capital investment now along with a push for higher productivity and lower internal cost would be the preferred approach to reduce rate impacts.

Infrastructure drives reliability.

Current state of equipment.

To increase capacity in the short term to be able to add more renewable energy to replace fossil and nuclear generation.

I say this but a change is an election away. We need the long term vision and goal the strive for.

Price only will go up if waiting.

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Spread Investments Out:

Preferences for spreading out investments seem to stem from themes of affordability and reducing financial impact for both rate payers and businesses

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Spread investments out, stable rate increases…

Good balance.

Balanced investments so rate increases are aligned with inflation. Electricity in Ontario is extremely expensive and has put Ontario business at a significant disadvantage. While investments are necessary so are ensuring competitive costs.

Most cannot afford higher rates, and delaying will just cause future generations to deal with legacy issues.

This is the philosophy we have taken as a distributor. At some point affordability needs to be considered in capital expenditure levels year over year.

Would prefer option on invest now, but the cost may be too high, so spreading costs may be better.

Manageable to ratepayers while insuring reliability.

A spread of investments avoids putting costs to ratepayers in the future and avoids the risk that future ratepayers may be in a worse position to pay the increased rates. It also avoids the cost of frontloading the costs when there is currently much customer concern over their ability to pay. This middle alternative seems to provide a reasonable cost balance while somewhat increasing reliability risk.

Given that the current electricity rate in Ontario is among the highest in North America.

Financial impact.

Hydro is too expensive.

As a customer ourselves managing the rate increases so infrastructure investments are financed at a reasonable pace i.e. inflation plus 2%.

Less impact on cashflow for companies.

Easier to forecast for business plan with stable rate increases.

Produces more certainty in planning and rate increases.

Stable investments assuming reliability and PQ are held constant.

Over the long-term this provides the best return on investment.

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Spread Investments Out (2):
Spreading out investments can allow for reliability to be maintained while reducing financial impact

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Spread investments out, stable rate increases…

It is unlikely that rates would ever decrease. Good practice would be to manage assets without too much of an impact on the customer and rates.

Spreading out investments allows you to prioritize as needed at a sustainable run rate, in addition to evening out the rate impact as much as possible.

I believe it's the best thing for the ratepayer. No shocks. I understand why Hydro One may see it differently, but the goal is to provide power with as much consistency in price as we can. Quick raises in price is not looked upon favourably.

Ontario residents are already suffering high energy costs.

Over half a century old, it's easier on the elderly population which is increasing to financially handle any smaller increases because of fixed income.

1) Predictability in pricing 2) Not letting the system fail

It is a reasonable approach between responding to excessive failures (by deferring investments) vs the additional cost (spreading the investment).

Preference is to have stable rate increases for financial planning provided that reliability is not compromised.

I believe that Hydro One can find internal efficiencies to help offset rates while continuing to improve reliability.

I don't believe delaying the investment would be prudent and we would feel that in the future with reliability and outage issues. I don't see our business expanding too much in the near future so I would prefer to spread it out evenly.

We cannot defer our costs to make the next generation can pay.

Its unfortunate the state of power in Ontario. Hydro One should reflect on their performance vs other provinces and states. What are we doing wrong when it costs so much to produce power vs other areas?

It's pragmatic.

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Delay Investments:
Finding internal efficiencies first is mentioned as rationale for delaying investments

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Delay investments, lower rates in short term, higher increases in future…

Because I believe that internal productivity increases within Hydro One should be the first priority.

CUT COSTS NOW e.g. salaries by 15% to 30% for sunshine employees.

Hydro One needs to get their internal house in order before it inefficiency spends any more ratepayer dollars.

I don't agree it will mean higher increases in the future . AT least it may eliminate investments that are needed. We have made a lot of investments in the past we don't need. This will prevent that.

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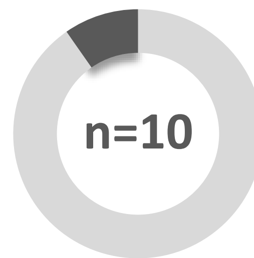
Pace of Investment (3):

Among those who say “It depends”, having flexibility in investment planning is a top concern

Q What does it depend on?

[asked of of those who said “it depends” when asked of about preferred paceof investment, n=10]

It depends



Customer connection requirements and timing of those. Show some flexibility! just because a new customer connection falls a year outside the Hydro One plan should not necessarily require the customer to pay the full advancement cost.

Plan the requirements, allow for the unexpected (which will be minimal if planned properly). Capital programs are inherently lumpy!

Safety, reliability, growth regions, new technology, innovation - it shouldn't just be an all or nothing approach.

It would have been useful if you could have quantified the magnitude of rate increases and not just higher or lower. Are you talking about 1 verses 2% or are you talking about 1 verses 10% It is hard to make a good decision until the impact is known.

Not knowing exactly what the investments are made to achieve/address and their impact/cost this question is difficult to answer in general.

I think you need to do some investments, spread payments over time, but revisit and optimize costs...ALWAYS be more productive, look for economies of scale, look to streamline and cut where people or assets are not productive and a drag on the system, literally and figuratively...have yet to see HONI do this.

A management plan that gets the most out of the team it has - I don't believe you have that yet.

Getting what you really need right (nowhere close to that yet), getting your operating costs in line (lots to do there), what your financing charges are compared to ours (we have to borrow to pay for you guys, and your rates are likely lower than ours), setting priorities that provide a level of priority for economic health of your jurisdiction vs convenience.

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Reliability

Reliability: Summary

Asked what reliability means to their organization, for some customers, reliability is about having a power supply that is consistent and stable. For others, it is a lack of unplanned power interruptions. There are also some who emphasize the impact that power interruptions have on their business, both in terms of productivity and safety.

A consistent and stable power supply is mentioned more often by Generators and LDCs than End Users, and more often by Single-Circuit than Multi-Circuit customers.

Customers in the North mention no/few unplanned interruptions more often than customers elsewhere in the province, and End Users mention this more than LCDs or Generators.

When asked to rank five reliability metrics in terms of which are most important to them, transmission customers put reducing the frequency of day-to-day interruptions at the top of the list most frequently, followed by overall power quality and reducing the frequency of interruptions due to major events. Reducing the duration of interruptions (be they day-to-day or a result of major events) is less important than reducing the number of interruptions, when responses are ranked according to which is selected most often as a “first priority”, but when first, second and third priorities are added together, reducing the duration of day-to-day interruptions is almost on par with reducing the number of interruptions due to major events.

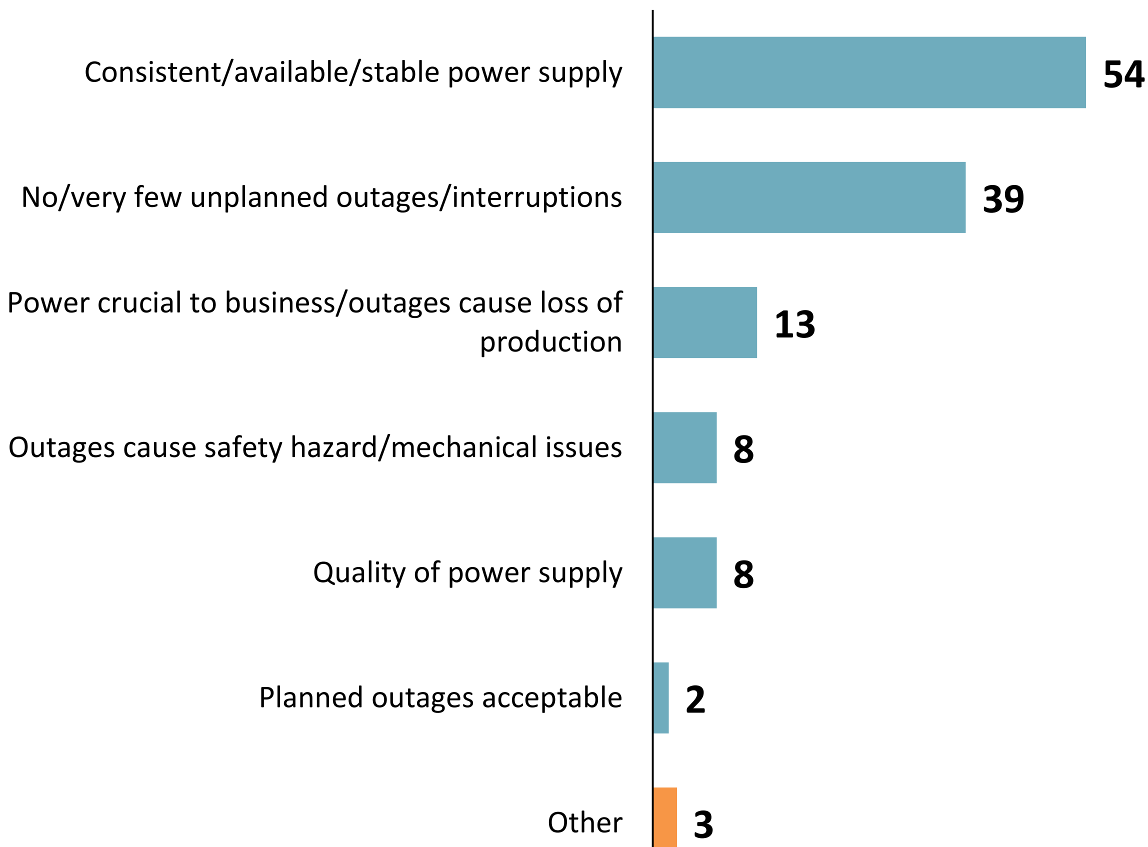
Customers were provided with a comments box in which to record anything they wanted to add on the topic of reliability. Sixteen customers recorded comments, ranging from not being able to control major events to feeling that power quality did not belong on the list as it is not a transmission issue.

Reliability:

Availability, consistent supply, and lack of outages are the phrases used most often by customers to define reliability

Q We are now going to move on to the topic of reliability. The term "reliability" means different things to different people, so before we move on, please describe what reliability means to your organization. When you are talking about transmission reliability, what does that mean to your organization?

[asked of all respondents, n=103]



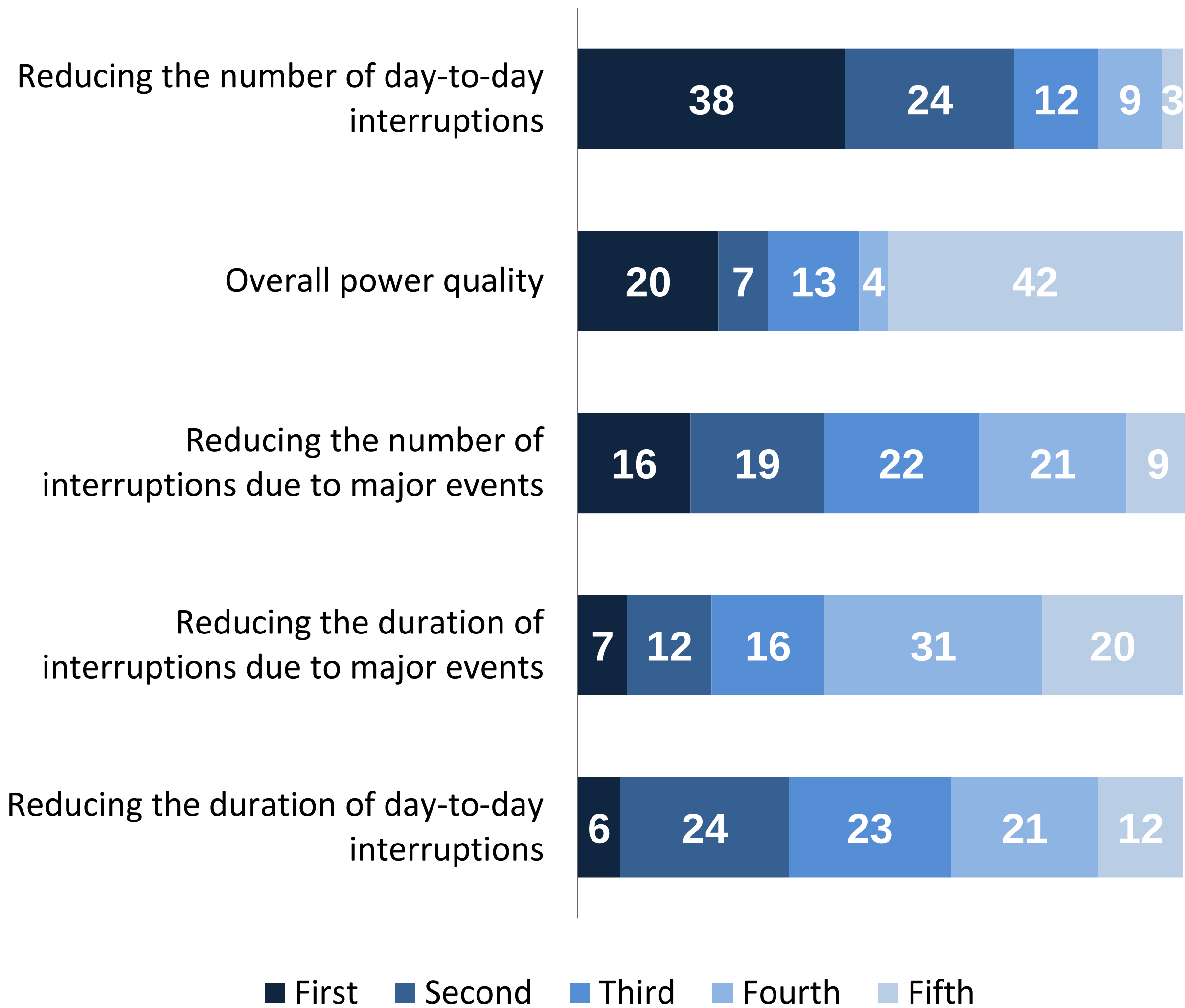
NOTE: Total is greater than 103 due to responses being coded into multiple categories

Reliability Priorities:

Reducing interruption frequency appears to be more important than reducing interruption duration

Q Reliability has a specific meaning in electricity, but often when customers talk about reliability, they are also talking about power quality (defined as delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform). Below is a list of five items that are often included when people talk about reliability. In addition to power quality, when people raise concerns about interruptions they often draw a distinction between interruptions that are experienced during normal day-to-day operations versus interruptions that occur during major events such as severe storms. **Please rank the following reliability items in order of which are most important to your organization.**

[asked of all respondents, n=103]

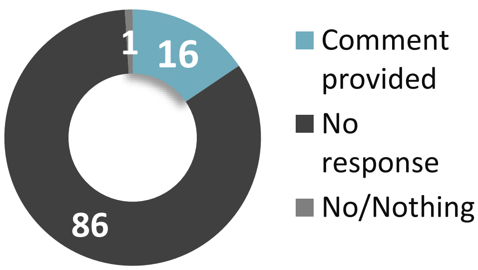


NOTE: No response (n=16 for first priority, n=17 for additional priorities) not shown.

Comments on Reliability:

Focus on reducing day-to-day interruptions over unpredictable major events

Q Is there anything else you would like to add on the topic of reliability?
[asked of all respondents, n=103]



I understand we do not control the weather, goal is to reduce the impact on the utility.

Major events cannot be reasonably predicted especially with global warming trends and more severe weather. The flexibility and the ability to react to the event is more important which will impact duration.

Power quality is most important to large, power quality sensitive customers while small commercial or residential customers are most concerned with the number and duration of day-to-day interruptions. Most customers have the most tolerance for outages due to major events as they can understand the reason behind the outage while the cause of day to day outages is largely invisible to most customers.

Power quality is not a transmission issue and shouldn't be on the list. Frequency and duration of outages are the key. Due planning processes for planned events is critical.

On-peak periods is our main focus and need interruptions reduced or eliminated during the on-peak periods Monday thru Friday.

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Investment Scenarios

Investment Scenarios: Summary

Respondents were provided with detailed descriptions of four illustrative investment scenarios. These scenarios were then plotted as reference points along a line of 17 points, and respondents were asked to choose a point along that line which best represented their preferred approach for Hydro One's investments (see page 22 of Appendix 1.2). Scenario A was based on limited investment, Scenario B involved a decrease in the current level of investment, Scenario C would maintain the current level of investment, and Scenario D would increase beyond the current level of investment. Each scenario impacts reliability risk, long-term reliability and future rates.

Scenario C, which maintains current investment, decreases reliability risk, increases long-term reliability and offers level future rate increases was the single most popular choice with 25 out of 103 survey respondents selecting this option. Having the ability to choose one of 17 points along a line, 22 chose a point between Scenario B and Scenario C, and 18 chose a point between Scenario C and Scenario D. This clustering of points around Scenario C reinforces the earlier stated preference for a pace of investment which would spread investments out over time with stable rate increases.

This pattern of "clustering" on or near the point along the line representing Scenario C was common across all business segments. Generators are the only business segment where the level of support for Scenario D (n=6) approaches the level of support for Scenario C (n=8).

All respondents were asked to describe why they chose the point along the line that they did. Those who chose Scenario C used phrases like "reduces risk", "maintaining status quo would seem appropriate", "balanced and consistent", and "same health level as it is today".

Illustrative Scenarios:
Information for Participants

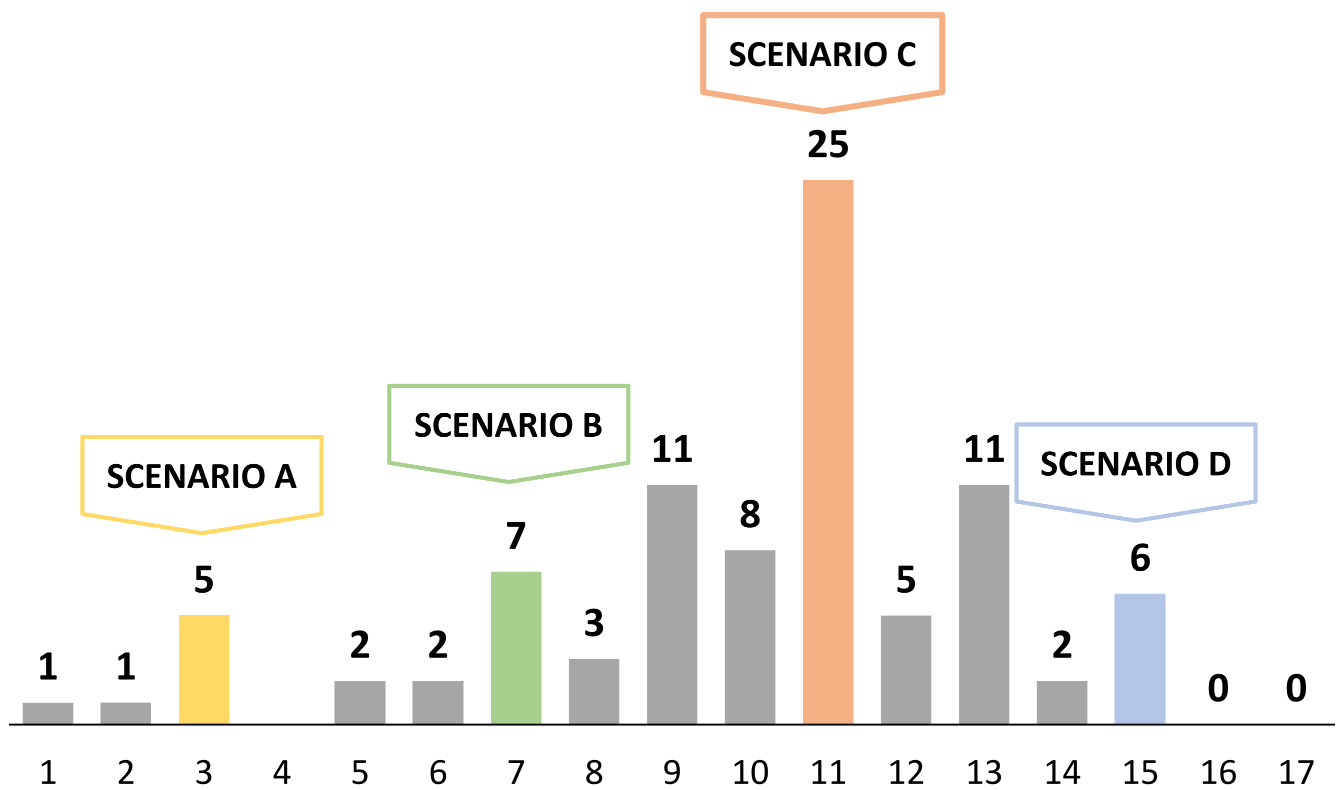
A preamble provided background on four illustrative investment scenarios. Each scenario was then described in detail, and a summary table (below) provided a comparative overview of all four scenarios. The descriptions of the illustrative investment scenarios can be found on pages 18 to 22 of Appendix 1.2, and a slightly more detailed summary table was available to survey participants on page 18 of Appendix 1.3.

	Illustrative Scenarios			
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)	29%	26%	19%	17%
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits.

Illustrative Scenarios:
Maintaining current level of investment (“Scenario C”) is the most popular scenario

Q Thinking of all the considerations outlined, please choose a point along the line below that you believe strikes the right balance between rates and outcomes. (Remember that you can choose a point between scenarios or directly aligned with one of them).
[asked of all respondents, n=103]

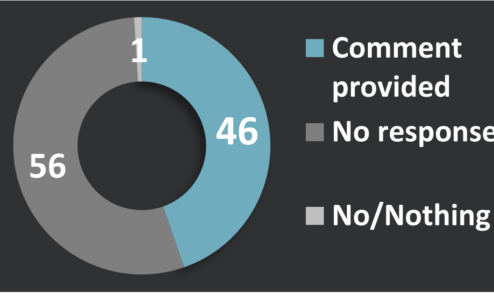


Lower increases now Higher future increases Lower reliability	⟷	Higher increases now Lower future increases Higher reliability

NOTE: “Don’t know” (n=7), No response (n=7) not shown.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
LDC		1	1		1	1			5	6	6	1	3				
End-User			2		1		5	1	3	2	11	2	4				
Generator	1		2			1	2	2	3		8	2	4	2	6		

Comments:
Point 3 - "Scenario A" preferred by those who want to limit rate increases



Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 1

Clever OEB type presentation Ontario in very fragile economic condition   Just focus on cutting cost There is not as you imply direct correlation between cost reduction and reliability.

Point 2

1) Hydro One is inefficient and needs to sort out their internal processes and find greater efficiency. 2) There is nothing in this plan for innovation. Why would they invest in Tx infrastructure without a plan to manage the two-way flow of electricity that distributed generation will bring in 10-15 years. The last thing anyone wants is billions of $ in distressed.

Point 3 – "Scenario A"

I am prepared to take on more risk as we get the cost envelope sorted out and I am not willing to accept that rates would only change from .11% to .46% between scenario's when costs to the public have been going up by double digits per year for many years. In addition I am not prepared to accept that managing the rate of investment now will necessarily result in significantly higher future rates. The whole system has to take responsibility for the costs the public is struggling with NOW!

Scenario A seems the most favourable at this time; companies are very cost focussed and margins are currently very tight.

Low rates a priority and managed risks - information is imperfect and so the best investment is to get better data/information while you have the time to drive better investment outcomes while living within a cost affordability index. Are you getting the right bang for your investment today? That data was not made available - can you assume you will get more for the money you are investing?

Point 4 – No comments

Point 5

Keep increases at inflation.

Point 6

You should manage your business to be at or below the annual Canadian index price increase and still be reliable. Actual rates are already very high. We pay anywhere between $120-150/MW which is too high.

I recognize HONI has very difficult choices to make. However, it is very difficult to support a transmission rate increase that is greater than 1.5 times CPI

Comments (2):
Point 7 – "Scenario B" preferred by those who acknowledge the current state of rates

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 7 – "Scenario B"

Hydro One is unfortunately operating in one of the highest rate markets in North America. Normally higher increases could be tolerated, however with the current state of the electricity market reasonable rate increase are expected, even if it comes at the cost of degraded reliability. This is ultimately due to current and previous provincial governments however Hydro One is forced to take this under consideration.

We're on unreliable lines so we'd like some investment in those lines under any scenario. some is more than what we've seen in recent years. with upward pressure on rates, we'd be hard pressed to call for much more reinvestment than B. I'm wondering about the capital estimates and whether or not there is any room for efficiencies within?

Balance the annual rate increase based on risk.

Point 8

Transmission costs are already too high. More needs to be done to ensure the investment $$ are being spent wisely.

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Comments (3):

Point 9 preferred by those who are looking for a balance between improving reliability and the cost of doing so

Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 9

Best balance of costs vs benefits.

Chose the middle, trying to find a happy medium, so that we try to fix the mess we are in efficiently and cost affective as possible. However the rate increases is to high but we can't keep delaying either creating a bigger problem for future etc.

Reliability needs to improve but rate increases need to be balanced as it effects our operating costs.

We want a decrease in reliability risk and not too much increase in rates.

I do not agree with Hydro One's premise that there should be increases in Hydro rates amongst all the options. Like any other business; Hydro One needs to improve how it runs its business; how it seeks innovative answers; how it can deliver the same or better service for less money. I fundamentally disagree with all the options above; Hydro One has to stop acting in a way that it think it is entitled to more money or else the lights go out; Hydro One needs to start thinking like all other businesses; get lean; lower costs; meet customer expectations. The people and businesses of Ontario shouldn't have to keep paying for Hydro One's excesses. Rates should be kept constant; and the service should improve for that cost moving forward.

Preference would be investment close to scenario C but at lower transmission rate increase. i.e. Hydro One should look into improving its own efficiencies or finding ways to obtain the required funds to achieve scenario D or at minimum Scenario C's goals without significant increases to the transmission rates.

Significant investments have been made over the last five years to allow for DG resources to be connected. My expectation is that the rate of investment can now be curtailed back some.

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Comments (4):

Point 11 - “Scenario C” as a reference point is the most popular choice

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 10

The costs are a major input into these evaluations. A TS decommissioning was quoted at over $10M, transfer trip for a DG a few years ago was $180k is now being quoted at $400k, rebuilding a TS is being quoted at $38M. The choice is really C with an A rate increase.

Internal savings and efficiencies must be considered (salaries) to minimize rate increases. Increases in the 2 to 3% range combined with internal savings should net to Scenario C. This should be the goal.

This rate should still enable you to decrease the risk without a significant short term rate increase.

Maintains the average percentage of key assets beyond expected service life constant.

Point 11 – “Scenario C”

Do not want to see any service supply or reliability deteriorate from the current state.

Increased reliability, levelled rates.

It combines all four scenarios into one with moderate rate increase, high reliability and moderature future increases.

It meets many of the things and it's a substantial capital investment, but it has a lot of things moving in the right way. Decrease in reliability risk, improvement in long-term reliability. Fairly level future rate increase.

Maintaining the current level of investments will provide the planning and necessary funds for equipment is replace/upgrade as required to ensure reliability of power supply

Reduces risk, reduces the number of assets beyond expected life, cost increase is high, moving to Scenario D does not reduce the risks that much more based to cost. Selecting Scenario A or B will put our distribution system at to high a risk.

Decrease on reliability risk while levelling future rate increases.

The current level of reliability is acceptable therefore maintaining the status quo would seem appropriate.

The current situation is in part the result of a deliberate reduction in re-investment in the mid 1990's to mid 2000's which has resulted in equipment beyond service life. If reliability levels are to be maintained or improved, then a balanced and consistent approach is required.

Comments (5):

Point 11 – "Scenario C" preferred by those are focused on reducing reliability risk and improving the long-term health of the system

Q Please use this space to tell us why you chose the point you did.
[asked of all respondents, n=103]

Point 11 – "Scenario C" (Cont'd)

This scenario keeps the transmission system at about the same health level as it is today and while the transmission rate increase is moderate, the overall bill impact is small and likely tolerable by most customers.

To maintain a consistent cost (although increased) with a higher reliability.

There is a lot of old components that need replacing already. reducing spent $'s will not enhance current performance.

Point 12

The system already has a health percentage of aged equipment and with the increasing reliance on the transmission system to achieve the government's environmental goals, reliability will only become more important.

Point 13

Ideally, the rate increase would be inflation plus some nominal percentage. However, if 3.3% results in a material decrease in service capability, this new information suggests that the next highest level of investment is appropriate, thereby putting this somewhere in between Scenarios C and D.

Point 15

Best choice overall from reliability and long term cost perspective

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Questions for LDCs

Questions for LDCs: Summary

Local Distribution Company (LDC) customers (n=28) were asked a series of supplementary questions in order to provide them an opportunity to respond with consideration to the needs of their customers.

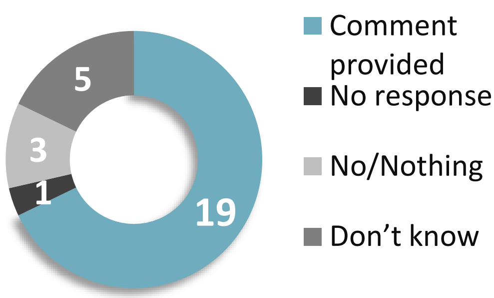
In response to an open-ended question, LDC survey participants identified costs and local support as the primary areas where they feel Hydro One can do more to help them meet the needs of their customers.

One LDC respondent, whose company provides electricity to First Nations and/or Métis communities, expressed their opinion that northern communities deserve more attention as the single-circuit connections result in vulnerabilities regarding power supply and interruption.

Eleven of the 28 LDC survey participants reported that their responses to Hydro One's transmission customer engagement survey were informed by their own customer engagement activities or other customer research.

Questions for LDCs:
Reduced costs and local support are where LDCs would like improvement

Q Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?
[asked of all LDC respondents, n=28]



It would be helpful if Hydro One were able to provide more reasonable cost estimates for their work. In past years, Hydro One was known for high costs of work and had an active program to reduce their costs of doing business. That effort seems to have waned now and costs have gone back to levels that many customers feel are too high.

Improve reliability in smaller rural communities, reduce engineering costs for distributed generation projects. Reduce operating, maintenance and administrative costs as a whole and pass the savings onto the customer base.

Consider both the financial and reliability impact of your actions on our customers.

Increased pre-planning for joint investments with the LDCs. Improve project management to achieve project milestones on time. Better transparency of costs associated to projects requested by the LDC for Hydro One to complete.

Communication and coordination of TS work requires significant improvement.

Better planning of maintenance outage notifications. Costs need to stabilize while at the same time allow for development of new loads in rural areas at costs that are reasonable and not prohibitive. Don't try and push normal maintenance and replacement costs onto new customers.

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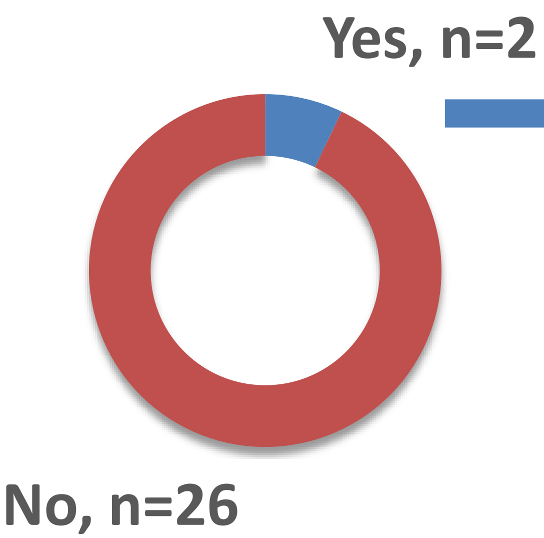
Questions for LDCs (2):
About a third report that their responses were informed by prior research

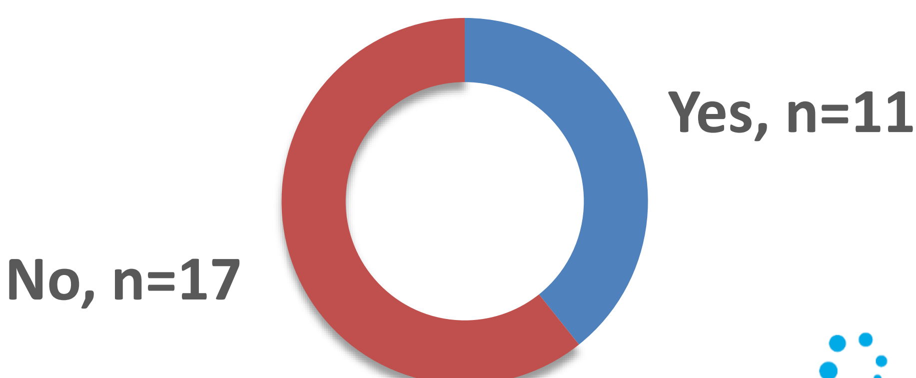
Q Does your company provide electricity to First Nations and/or Métis communities?
[asked of all LDC respondents, n=28]



Q Is there anything in particular you feel Hydro One can do to better serve the specific needs of First Nations and/or Métis communities?
[asked of all LDC respondents who serve First Nations and/or Metis communities, n=2]

> **No.**
>
> **The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response.**

Q Were your responses to this survey informed by your own customer engagement activities for the purposes of a rate application, or by any other customer research?
[asked of all respondents, n=28]



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How Did We Do?

How Did We Do?: Summary

The rate of participation and the fact that all who started the survey went on to complete it suggest that transmission customers are eager for an opportunity to provide Hydro One with their input on future business planning.

Most survey participants (n=81) had either a “very positive” or “somewhat positive” overall impression of Hydro One’s transmission customer engagement. Only three reported a negative impression.

In terms of volume of information, most (n=78) felt that Hydro One provided “just the right amount” of information for the engagement.

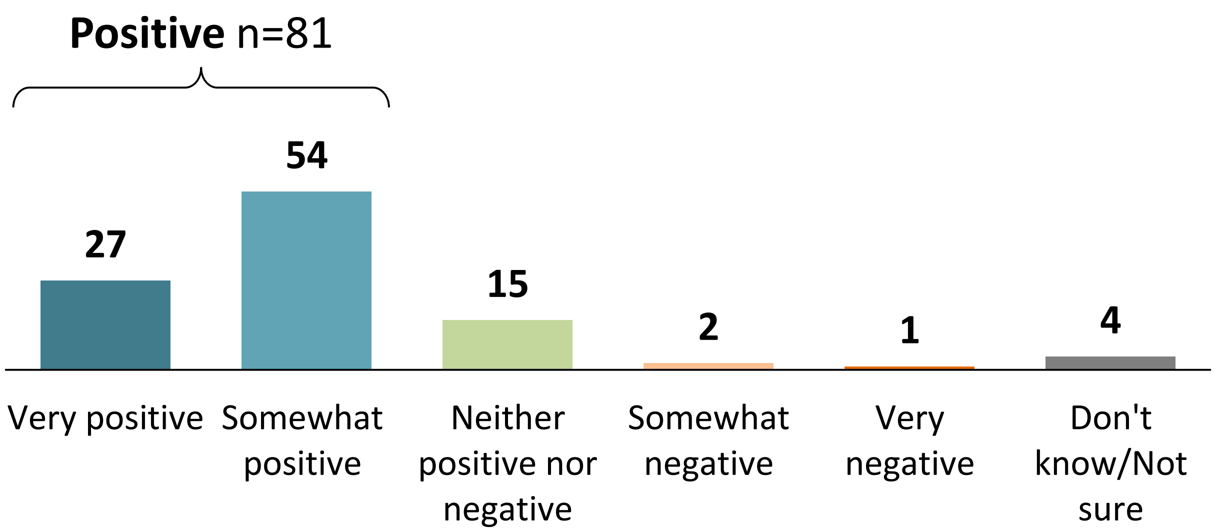
Further, only a handful felt there was any content missing that they would like to have seen included. Mentions included cost of service/efficiency planning, breakdown of necessary investments, and benchmarking information. Two participants referred to “dishonest/skewed conclusions”.

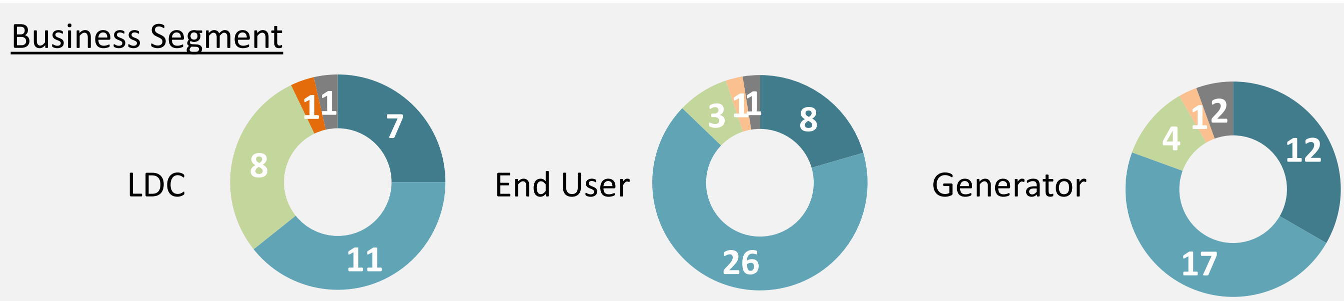
Asked if there is anything they would still like answered, a handful of participants would like details on Hydro One’s plans to improve reliability, to drive cost savings, and to improve customer service.

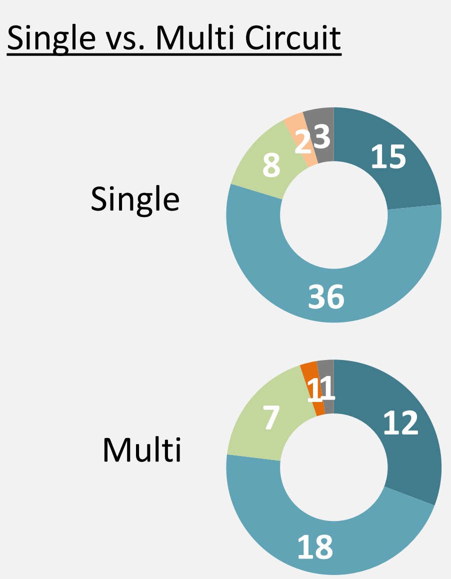
While few offered an opinion on how they would prefer to participate in future customer engagements, most of those who did comment said they would prefer the current format. A few mentioned in-person interviews.

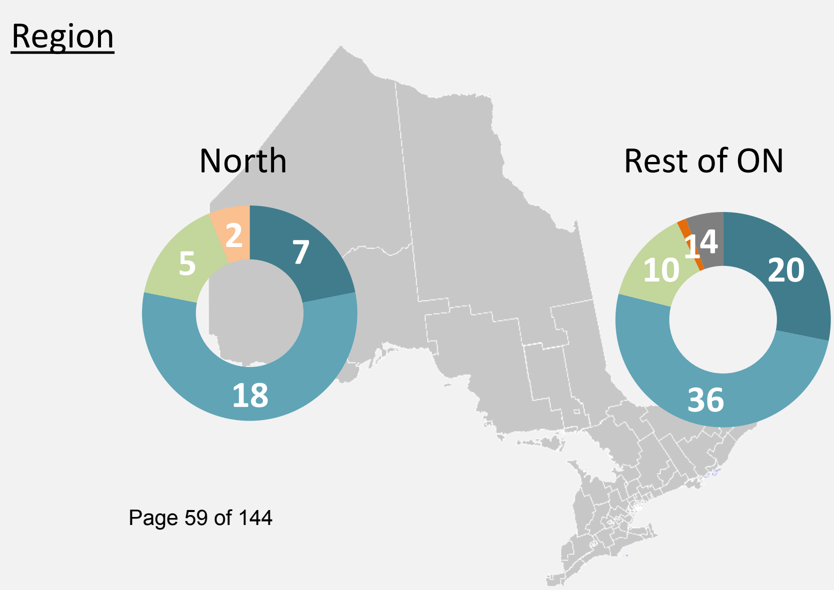
Overall Impression:
Most rated the Transmission Customer Engagement positively

Q What was your overall impression of the Transmission Customer Engagement?
[asked of all respondents, n=103]





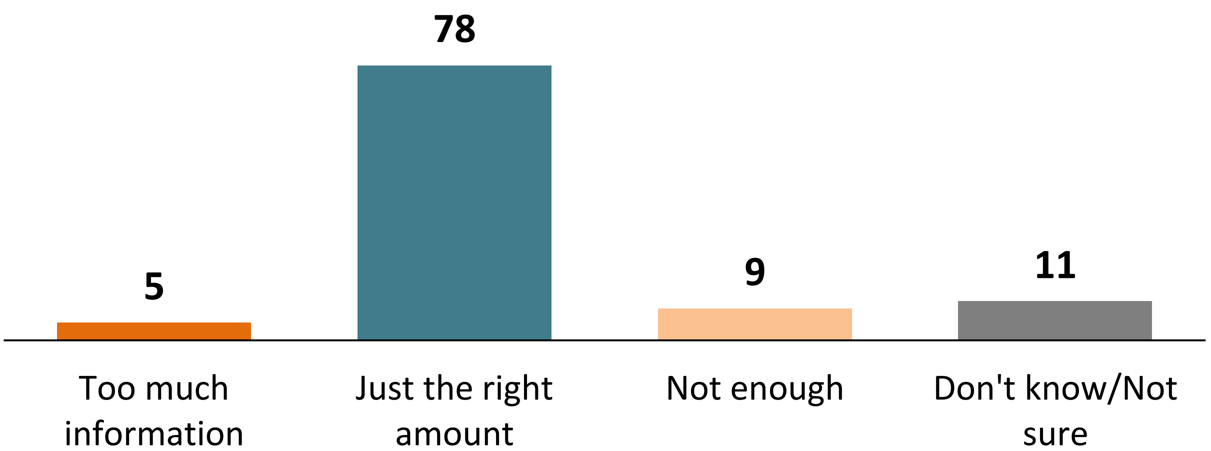




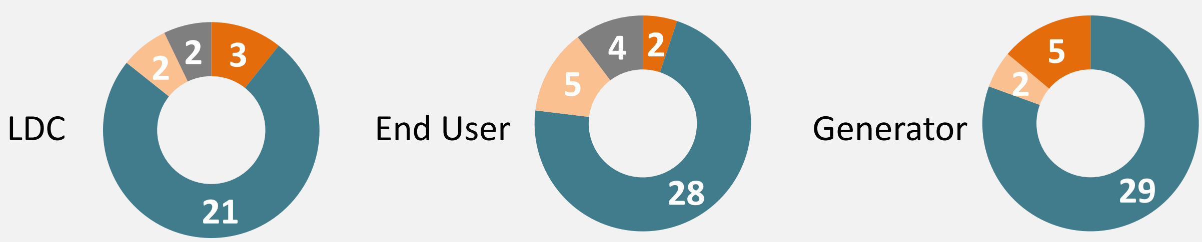
Volume of Information:

Most felt that “just the right amount” of information was provided

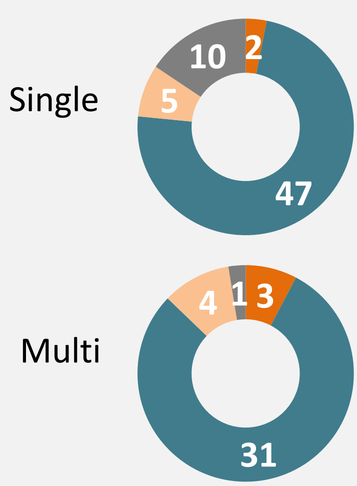
Q Did Hydro One provide too much information, not enough, or just the right amount?
[asked of all respondents, n=103]



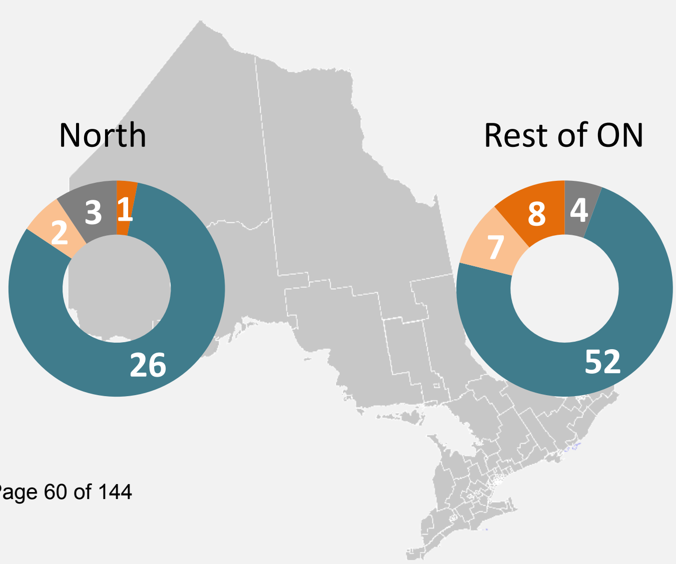
Business Segment



Single vs. Multi Circuit



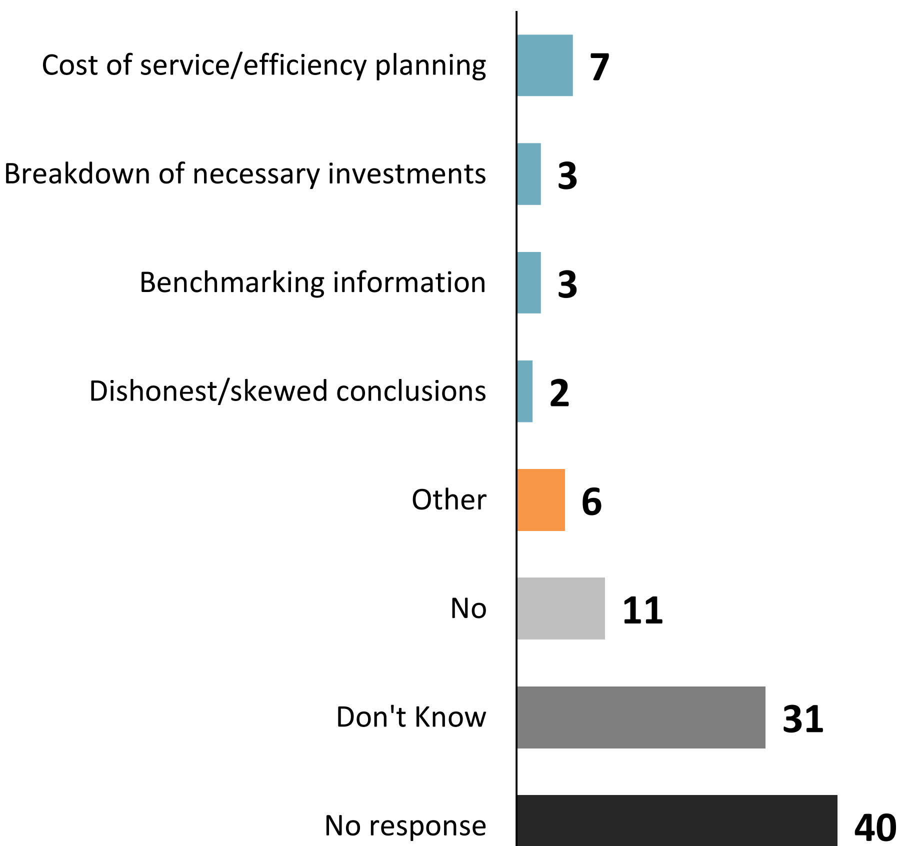
Region



Content Covered:

Very few comments; top comments related to cost of service

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]



Outstanding Questions:
A few comments on reliability, cost savings, and communication

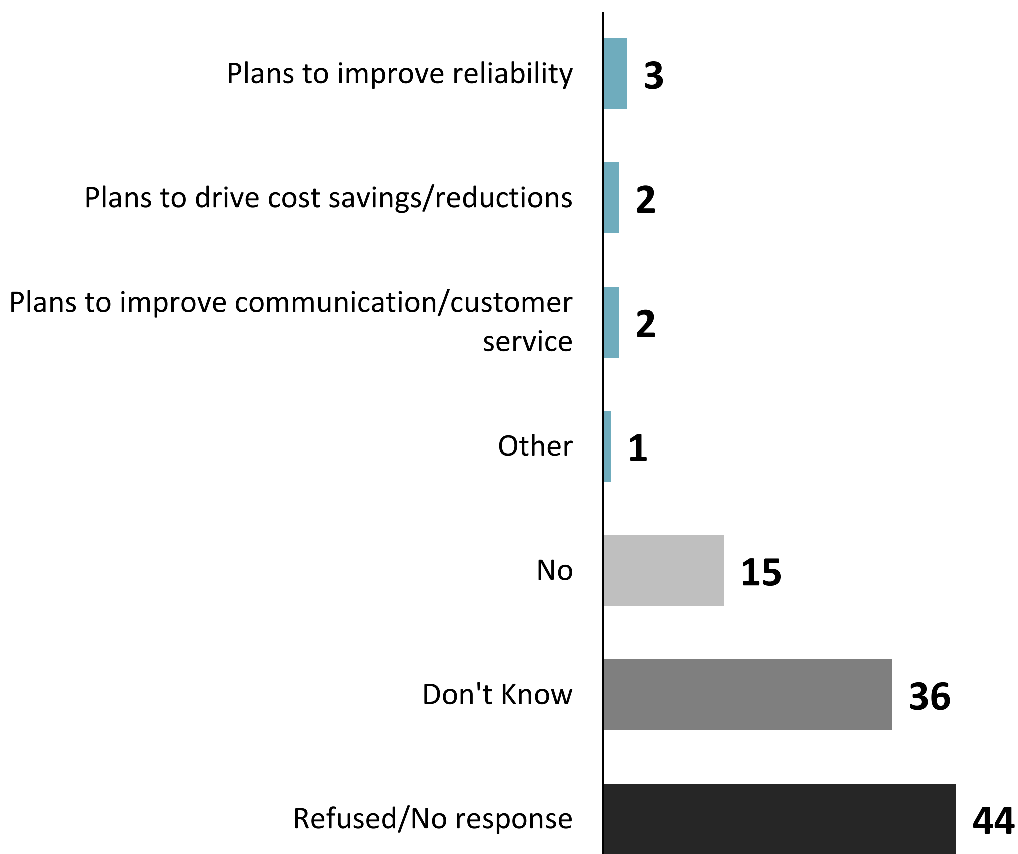
Q Is there anything that you would still like answered?
[asked of all respondents, n=103]

I would like to be able to review and understand the Hydro outage summary. Why is it so cryptic, it should be very transparent and not require an interpreter.

Please ensure to pass on the current level and expectations of customer focus to new employees of HONI; communications is key and appreciation of the cost to customers when the grid is not available.

When are you releasing the plans? Will there be any dialogue on rates and where will we get a chance to review those comments?

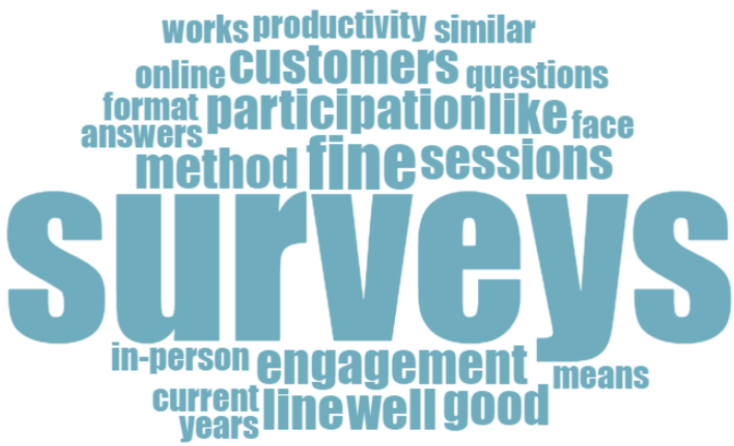
Innovation and lean management of Hydro One to drive cost savings and improve performance.

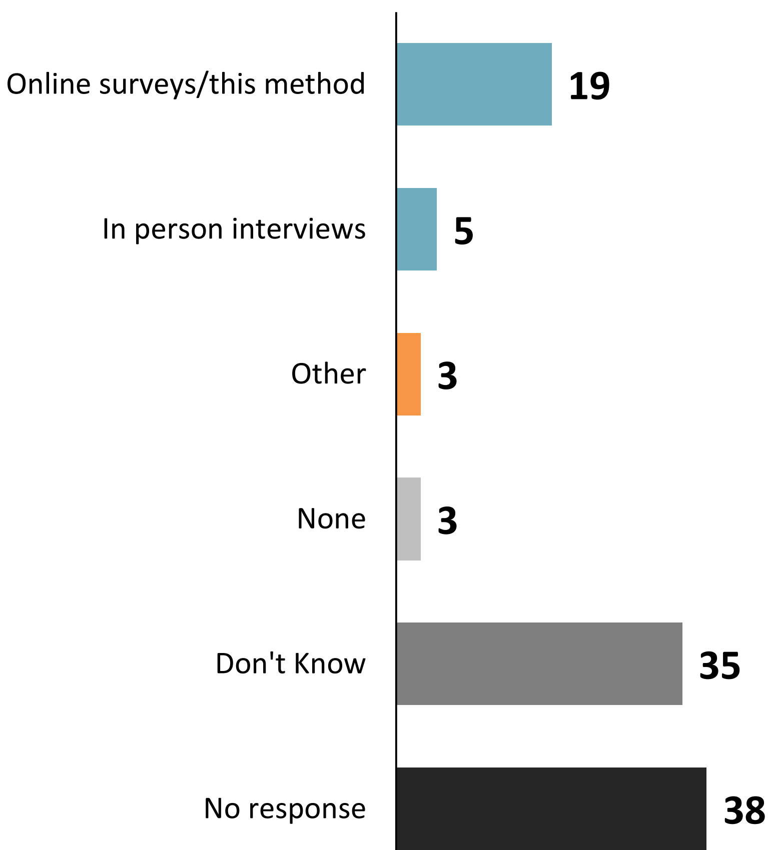


Future Customer Engagements:

Those who commented tended to prefer the current format

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]





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Appendix 1.1
Full Verbatim Responses

Suggested Improvements (1)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

LDCs

- Better Customer communication to LDC's
- communication re longer term plans
- Earlier engagement with impacted LDC's for station asset renewal projects.
- Timely contact with Account Rep to review transmission system reliability and incidents affecting [company]
- Nothing
- No.
- As an LDC, we deal with both staff from Hydro One's distribution and transmission business. We're somewhat satisfied with transmission system; but very dissatisfied with the distribution system.1) Hydro One needs to clean up the management of it's distribution system2) Maintain the existing service/performance of the transmission system3) Simplify ""event notification"": we struggle in decoding the location of circuits that are faulting.4) Demonstrate that they care about their LDC customers -- i.e. why won't Mayo come talk to the EDA? We'd listen and welcome the opportunity to work together.5) Improve their brand. When Hydro One ""screws-up"" the entire industry shares the burden of their poor customer relations. End customers blame our LDC for poor customer relationships that Hydro One has developed over the years. This makes running our LDC more difficult.
- I personally have no issues with Hydro One as the account rep and supervisors that I deal with always deal with our issues in a timely matter
- animal contact outage causes in stations - should be preventable - more can be done information sharing with outage causes and outage post mortem analysis
- More assistance with power quality investigations, especially where HONI customers are affecting our customers (i.e. HONI arc furnace customers causing voltage flicker issues for our customers)
- Upgrade facilities to allow for simple transfer to alternate circuit in the event of work required on our curcuit.
- Communication around job planning that affects our utility has been poor.
- our response is transmission based only and does not include distribution supplied locations. Better notification and planning with regards to maintenance activities would allow us to better plan and respond to our down stream customers.
- In the past year there have been a couple incidents where station supply was lost due to human error during station work. While only a couple incidents there is concern that perhaps the loss of experienced staff through retirement is manifesting as incidents.
- I would like to see the long term plan for Hydro One transmission investments to see how it fits with our business requirements. I feel Transmission Station investments should be pooled to avoid duplication
- Reduce cost of Engineering estimates. Improve reliability to rural areas. Improve communications regarding Distributed Generation projects with Local Distribution Companies. Improve power quality from transformer stations
- Work with the LDC utililities. Hydro One and the utilities are utlimately serving the same end use customer. As power system technology, communciatons, and IT technology advance at a rapid pace Hydro One must be able to be more flexible to enable Smart Grid and not to impede it. For example digital fault data is inherently available in new relays and systems. Make it simple and very low cost for LDC's to access this data. Cost transparency and no barriers. Work together toward solutions.
- Overall satisfied, however, some H1 assets are getting aged and maintenance times to return transformers back to service appear to be getting longer. Potential for future issues.
- Work closer with customers on planned outages. Resolve Middleport issue.
- there have been some concerns expressed over voltage regulation and insulators failures at the ts.
- Power Quality assessment could be streamlined. - Transmission expansion information/assessment could be done more quickly"

Suggested Improvements (2)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

End Users

- Share long term plan and how it affects my site
- Decrease the number of outages
- As a smaller industrial customer, we'd want more help / education in navigating the electricity system - particularly information and guidance on money saving programs that we're eligible to participate in (e.g. ICI)
- More direct communication with Customer
- Streamlining the process for connecting new customers would be beneficial, i.e. using one point of contact for all matters (including dealing with other agencies such as the IESO). It's a complicated process and time consuming.
- Satisfied with overall reliability but the costs make most of our business ventures uncompetitive and the lack of transparency and fixed nature of the billing makes it virtually impossible for us to effect the outcome.
- Timeliness of transmission station upgrades and renewal.
- Line Maintenance needs improvement due to two recent Sky wire failures.
- Continue to maintain the distribution equipment.
- Lower Costs
- be more reliable
- Response time to outages in [town] that require a crew to be dispatched from London is too long.
- Voltage adjustments to the 115kv supply (for province-wide power/demand response) can often have significant implications to our operation.
- Address "power quality"
- Better anlaysis/control of potential impact customers changes to their power systems have on the grid.
- Understanding the true meaning of reliability and the impacts this has not only on HO customers but the impacts this has on its neighbours.
- We would have selected Satisfied if it was provided. Overall, our service and interaction with Hydro One is very good. However, the bureaucratic processes are very slow.
- Keep the power on and clean (power quality, not sourcing), and don't charge us a fortune - I'm getting a 73 Chevy and paying for a 2017 Porsche Cayenne
- Add capacitance on S2B line?
- No we are happy with your service
- Take on a customer centric approach. Recognize that large industrials are important customers. Provide proactive resolution to problems Be more flexible and less driven by an internal set of rules that make very little sense to others.
- Identify, plan and execute any mitigating factors that would improve power reliability to the mill site and [region]

Suggested Improvements (3)

Q Is there anything in particular you feel Hydro One can do better?
[asked of all respondents, n=103]

Generators

- Communication of outages
- early notification for outages (when & duration), understand this can be difficult but the more lead time the better
- Consider more flexibility in internal rules so interests of both Hydro One and their customer are addressed.
- Improve forecasting / Cost estimating capability when partnering with generators.
- The cover process is somewhat ambiguous and the cost and schedules are not particularly accurate
- Customer communication
- Better coordination of outages and associated changes to same which might affect generating stations on the same network.
- Follow up on new employees in OGCC control room
- Improve Hydro One's procurement process to minimize delays in resolving equipment issues.
- Outage planning. sometime last year, there were in total of 4 planned outages were scheduled at different time slots on the same day. which it was quite confusing. later on I contacted the Hydro One officer and go clarification.
- Plan HO outages during our low production times to limit the loss of revenue to our business
- taking into consideration the customers assets and the difficulty seasonal outages can be on the operation.
- Planning & grid control needs to get better at communicating customers. Most likely turnover or retirement has resulted in new personnel with not necessary the same level of customer service.
- "All Hydro One's responses are governed by rules No special cases taken into account Cost of any interface too high"
- Service the Seaforth T/S so we have less outages
- Coordinate planned maintenance outages - proper lengthy notice
- "Interaction between technical/engineering groups and customers early in the connection process needs to improve. Improved sense of accountability required at Hydro One. Actual connection costs coming in well outside acceptable industry variance ranges. Paying significant amounts for connection estimates that provide little value (+/-50% estimate is unacceptable from any engineering firm).No sense of urgency, unless the lights are out."
- Greater communication on outages, It is very difficult to understand what all is required or not required for outages.
- Clearer direction on how potential upcoming outages affect the customers and for how long.
- Outages - unknowns and changes have been issues...last minute they just asked us for an outage to connect another windfarm with <30days notice on a project in the works for the past 3 yrs. Rates for remote power supply are incredible...bringing the total cost to nearly $0.25/kwh for our stations service for our switch station!
- Estimation, planning and engineering could be more proactive with generators. A lot of delay in getting cost estimate and work planning are having huge impact on our business.
- The distribution line running between [location] and [location] seems to have a number of extended outages which does cause us some headaches.
- respond faster to inquiries
- Plan outages better and work in better with clients to minimize impact on their business
- Ensure reliability of supply by ensuring equipment supporting our plants is maintained to highest standard. Ensure management and training of staff supports safe and error free operation of equipment supporting our plants particularly the nuclear fleet.

Performance Metrics (1)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

LDCs

- provides reliable supply and responsive service
- The transmission planning will dovetail into the distribution planning process to drive overall system efficiency.
- Timeliness of response to inquiries. Delivery point reliability improvement year over year.
- We haven't had a total loss of power in the last few years due to material degradation or anything such like that
- Timely responses from inquiries Outage frequency and duration is minimized Generally helpful and courteous staff
- Availability of Executive staff to discuss matters, field staff willingness to assist when needed, open minded, willingness to resolve issues
- good communication and timely responses
- Reliable service.
- Loss of supply statistics
- Win back end-customer confidence and improve its brand.
- same as above the people that I deal with always either answer the phone right away or call me back as soon as they can
- Several points to consider - level of engagement on issues - staying current and open communication, level of effort along prevention - are you really doing the simple things, are you easy to do business with, can you actually get things done when you say your going to do it.
- We can gage the performance of the HONI system via the number of outages due to loss of supply
- Keeping the supply of power on
- Few outages, either planned or unplanned
- Reliability and costs are the primary drivers in the measurement of performance.
- We look at overall reliability as well as Hydro One's understanding and explanations of the incidents that have occurred.
- We measure reliability based on Loss of Supply. Quality and timeliness of responses from Distributed Generation and Engineering groups.
- Reliability, costs, general customer service, responsiveness, operations service and interfaces, ease of doing business with, relationships. Enable the LDC to forward their objectives.
- Reliability to date has been good, however, increasing frequency/duration of reduced redundancy due to extended maintenance periods. Resulting in higher potential risk exposure for customers.
- No interruptions in supply and no voltage issues.
- Reliability of supply.
- - based on reliability (is excellent)- responsiveness to queries

Performance Metrics (2)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

End Users

- Unplanned outages are minimal, good communication on maintenance being completed
- They are very communicative
- Power Supply reliability
- Forced outages are reduced and power quality is improved.
- Reliability is important but at a cost that makes us uncompetitive and sends jobs abroad is not sustainable and will hurt all citizens of Ontario
- When100% availability is achieved
- Great customer service by providing assistance after failure of [company] Power Transformer T5.Greatly improved communication of shutdown work, long term planning needs etc.
- Reliable electrical power supply.
- Costs to businesses are kept in control. Evidence that cost control at Hydro One is in place and effective.
- Power service is reliable and I seldom receive any calls/complaints from our operations groups. Also, our account manager, Jim Perpick does a great job of keeping us informed and following up on any issues we raise with him.
- if I do not have to call them
- We are provided with the reliability information from our Network Management Officer.
- responsiveness to reporting requests, capital projects and market data. Very pleased.
- Electrical outages are rare and when there is an outage they are quick to respond and communicate the outage
- Number of outages my business experiences or individual equipment trips due to voltage sag
- Number of power interruptions that occur.
- Open dialogue and regular face to face visits reassure us HO understands the impacts of safe reliable operations
- 1) No unplanned outages and consistent power quality. Score 8 out of 10.2) Supportive in planning and outage response. Score 9 out of 10.
- The power stays on, your sags, swells, harmonics etc do not destroy my instrumentation, and the cost of distribution is strongly competitive with what is charged by other jurisdictions in North America in which are situated my competitors who are trying to put me out of business
- Willing to meet with us to discuss our problems. Do everything possible to keep us supplied with power. Upgrading the S2B line in the past few years.
- We seldom loose production because of hydro outages
- My power is still on
- Probably if there was very little noise about Hydro, we'd know that Hydro was doing a good job.
- Interruptions are at an absolute minimum and wherever possible with as much advance notice as possible.
- Power reliability and quality issues reduce to once per year.
- reliable supply of electricity at a reasonable cost
- Our electrical department informs us of any issues with Hydro One and how things were handled to resolve
- Good communication, fast response. Good job guys!

Performance Metrics (3)

Q How do you know if Hydro One is doing a good job for your business?
[asked of all respondents, n=103]

Generators

- No surprises
- in simple terms as long as the electricity runs through the lines and there are no disturbances causing issues or damage to our equipment then everything is good
- Regular communication at all level between hydro one steakholders for ongoing projects and maintenance activities on customer site.
- Sustained, reliable electricity delivered to our door. Our joint work - when the actuals are more in line with the plan, be it outages or length of outages, and cost.
- Reliability, responsiveness
- This survey is a small step forward in Hydro One determining the needs of its customers.
- When I don't hear about any business interruptions or scheduling conflicts.
- I think yes. Never had problems so far.
- They work with us in outage management
- Performance is based on Hydro One's ability to provide its service reliably and implications to our operations.
- stable grid system, less impact on the customer side are all we need.
- If the lines remain open for business and interuptions are held to a minimum
- Timely and accurate billing and reconciliation. Reliable power.
- Effectively communicating and ensuring to work with customers to minimize impact of business interruption
- that the delivery of Hydro is reliable
- Fewer outages
- Some communication on outages
- By the way that Hydro One coordinates planned equipment outages with the customer needs.
- No metrics that Hydro One is willing to provide. cant even get a detailed itemized statement for a connection to see how they performed against their estimates.
- no issues with unplanned outages, invoices are accurate
- On rates, no idea...on work around transmission doing fine, meeting with us generators every 6 months to try and best facilitate outages/repairs/upgrades
- We are working with HONI for generator connection since 2008. At that time, HONI were more proactive working with generator. Since 2-3 years it seems like there is no willing in resolving issues.
- If they are doing good then we won't have any surprise outages and/or time we can't inject into the grid.
- The reliability of the M2W transmission line is very good which is essential for our business.
- results
- Communication concerning outages; timely and accurate responses to queries; price
- We work collaboratively with Hydro one and participate in numerous committees overseeing areas of mutual concern

Suggested Additional Outcomes

Q Are there any outcomes we missed?
[asked of all respondents, n=103]

LDCs

- Timely delivery of project milestones.
- no
- Communication - transparency and timliness
- Price or cost- what is the value for money
- Costing allocations should either be socialized on the whole rate base or significant lead time to
- Easy to deal with.
- System capacity - Have a transmission system with the capacity to meet the needs of our customers.
- affordability - lower rates

End Users

- Weather risk mitigation - system hardening
- Flexibility of planned outages schedule to accommodate Customer restrictions
- Costs ; You will say its inferred in productivity and others. This is the reason we are in a mess.
- Inclusion of major customers like Dofasco in communication of future local investments
- Reduction on cost of GA
- So far none
- The slider above does not work in my browsers.
- New connections and upgrades built and energized on a timely basis.
- Responsiveness and personal assignment of a customer service representative for major customers
- Outage co-ordination with plant outages minimizing single line exposure.
- Your wages reflect those in industry, so that we don't keep losing our best people to you
- something about 'managing and accommodating growth and expansion with IESO through SIAs / CIAs'
- Response from local Hydro One team to respond to emergencies related to un-expected site power outage

Generators

- Predictable schedule preparation and execution
- no
- Grid Capacity Expansion
- COST   COST
- Communication within IESO and HONI
- Efficiency of operations - reducing the bureaucracy, having decisions at lowest reasonable level
- general communication about direction of HONI certainly helps me as a customer understand ramification
- Streamline the customer service experience to be able to reach appreciate parties efficiently.
- Technology/Standard requirement
- Respect for other people's property - eg talking with property owners before accessing

Comments on Customer Outcomes (1)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?

[asked of all respondents, n=103]

LDCs

- ensure that there is regular communications and dialogue
- None
- More timely response for communications and delivery of project milestones. Safety has been a concern when Hydro One crews have been working on shared ownership sites without engineered drawings under regulation O.22/04.
- Hydro One needs to fix its business processes and find productivity. I don't believe senior management in Toronto has the tools or workflow processes to manage or monitor projects efficiently in Northern Ontario. Until they sort out their internal workings, they don't deserve any rate increases.
- no
- You can do more with less on all of this - its not a trade off between money and results - we need the results described and we need it at a more affordable rate.
- Only proceeding on productivity projects that will guarantee a financial payback and reduce rates for all customers. Tried to provide feed back in suggested outcome 1 box but was limited to one line of text. Frequency of outages is a higher priority than duration when dealing with the general public
- Cost estimates for work to be performed by Hydro One are extremely high. While part of the issue is the class C estimate contingency, those costs cause a lot of concern for customers considering connections for generators.
- Cost reductions should be a top priority and given serious consideration and not just lip service.

Comments on Customer Outcomes (2)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?

[asked of all respondents, n=103]

End Users

- Safety and Environmental Stewardship are "table stakes". If they can't delivery these 2 outcomes, they have no business operating a transmission system.
- The main outcome should be to provide reliable power at the best possible cost which should be benchmarked to a world standard to remain competitive and to make it so people don't have to choose between eating and having access to power.
- The "extremely important" responses for my organization are related to our activities which are primarily linked to [removed for privacy]. Were we primarily an office accommodation portfolio, the responses would have been less important.
- We have observed improvements in overall customer service.
- Productivity should be a key focus at Hydro One. There is little evidence that this is a consideration at any level in the organization
- Power Quality is an integral part of Reliability.
- Some of these question miss the mark 1.I don't care about productivity; I care about costs going down; 2. If power didn't keep going off, then I would not care about customer service 3. Safety and environment and politically correct questions - don't kill anyone and don't poison the planet; otherwise, get on with the job (do not use these answers as a license for expanding PC topic bureaucracy) 4. Once we are out, restart takes hours anyways; we are more concerned with not going out, then with outage length - based on past performance, we have had to install all kinds of back up generation already (costs are sunk - back to the 73 Chevy)
- Customer service should be accomplished through culture and not cost the rate payer anything. in fact, would mean savings to the rate payer. the rate payer has paid significantly for reduced emissions. outage restoration - we are on the longest radial line at [location] and incur 25 outages / year. this is unacceptable and costs us an estimated $6 M/year.
- All outcomes are equally important. It is hard to have one and not the other. Ultimately we do not see the environmental stewardship piece directly at the mill site.
- We have a good relationship with Hydro One

Comments on Customer Outcomes (3)

Q Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?

[asked of all respondents, n=103]

Generators

- basically each and every item is extremely important, some of these are important to us as end users or generators and others are important to Hydro One as the service provider. Not sure if the questions wanted us to rank them which I thought would be more informative
- no
- Grid Capacity Expansion
- As a generator it also extremely important that HONI is available to take the power and transmit it reliably.
- Customer service & reliability is very important and your area or customer representatives have done an excellent job conveying this message to us.
- YOU MISSED COST OF EVERY ACTIVITY UNDERTAKEN BY HYDRO ONE
- No
- i like when you mention safety, the industry is very high risk and nice to see HONI as a leader
- There are still some old requirement that would need to be updated to reflect the new reallity, mainly in communication media for teleprotection.

Comments on Ranking Customer Outcomes

Q Comments:
[asked of all respondents, n=103]

LDCs

- Safety and Environmental stewardship are not my interests but your employees and the governments interests respectively - as a customer I need performance improvement in all other areas and results now and need to know and trust that you have it and are going to do something on it.
- Customer Service is affected by not only the customer service through communications and follow up but it is driven by the quality and reliability of the service of supplying electricity.
- As a customer, reliability and outage restoration are important outcomes. I should be able to rank those at the top without sacrificing Safety or the Environment. This survey does not give that choice.
- Number one for my customers is rates. Productivity is not a direct reflection of that, but is similar.

End Users

- Safety and Environmental Stewardship are "table stakes". We don't consider them outcomes that should be ranked, but rather core deliverables of a transmission company.
- The focus on environmental steward ship and the solar and wind ventures it generated where ill conceived and poorly planned and have costs significant hardship on the citizens of Ontario . Although important it was very badly managed .
- n/a
- Reduant question although most important is reliablity and productivity
- This is difficult as they are all important.
- This ranking is predicated on Hydro 1 executing these priorities - if power quality and reliability are not improved, then customer service becomes much more important.
- Note that although power quality is no the bottom it is also extremely important

Generators

[NO COMMENTS]

Pace of Investment (1)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

LDCs

- produces more certainty in planning and rate increases
- Spreading out investments allows you to prioritize as needed at a sustainable run rate, in addition to evening out the rate impact as much as possible.
- over half a century old, it's easier on the elderly population which is increasing to financially handle any smaller increases because of fixed income
- As a customer ourselves managing the rate increases so infrastructure investments are financed at a reasonable pace ie. inflation plus 2%
- It is unlikely that rates would ever decrease. Good practice would be to manage assets without too much of an impact on the customer and rates.
- Hydro One needs to get their internal house in order before it inefficiency spends any more ratepayer dollars.
- Why cant you do more with less? Why are you trading off performance for costs - are you doing and getting the most out of the resources you have? I vote that one.
- It is a reasonable approach between responding to excessive failures (by deferring investments) vs the additional cost (spreading the investment).
- Local needs must be considered and vary
- A spread of investments avoids putting costs to ratepayers in the future and avoids the risk that future ratepayers may be in a worse position to pay the increased rates. It also avoids the cost of frontloading the costs when there is currently much customer concern over their ability to pay. This middle alternative seems to provide a reasonable cost balance while somewhat increasing reliability risk.
- I believe that Hydro One can find internal efficiencies to help offset rates while continuing to improve reliability.
- We cannot defer our costs to make the next generation can pay.
- Locally many assets are getting aged and reliability is already at risk. Higher capital investment now along with a push for higher productivity and lower internal cost would be the preferred approach to reduce rate impacts.
- Over the long-term this provides the best return on investment
- This is the philosophy we have taken as a distributor. At some point affordability needs to be considered in capital expenditure levels year over year.
- Stable investments assuming reliability and PQ are held constant.

Q What does it depend on?
[asked of those who answered “it depends” to previous question]

- A management plan that gets the most out of the team it has - I dont believe you have that yet.
- it would have been useful if you could have quantified the magnitude of rate increases and not just higher or lower. Are you talking about 1 verses 2 % or are you talking about 1 verses 10% It is hard to make a good decision until the impact is known

Pace of Investment (3)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

Generators

- Current state of equipment
- I believe it's the best thing for the ratepayer. No shocks. I understand why Hydro One may see it differently, but the goal is to provide power with as much consistency in price as we can. Quick raises in price is not looked upon favourably.
- infrastructure drives reliability
- it's pragmatic
- Ontario residents are already suffering high energy costs.
- Decrease in system reliability or increases in equipment failures negatively impacts our facilities operations and earnings.
- Price only will go up if waiting.
- I dont believe delaying the investment would be prudent and we would feel that in the future with reliability and outage issues. I dont see our business expanding too much in the near future so i would prefer to spread it out evenly,
- less impact on cashflow for companies
- CUT COSTS NOW e.g salaries by 15% to 30% for sunshine employees
- It's real
- Because I believe that internal productivity increases within Hydro One should be the first priority
- Plan the requirements, allow for the unexpected (which will be minimal if planned properly). Capital programs are inherently lumpy!
- i say this but a change is an election away. We need the long term vision and goal the strive for.
- To increase capacity in the short term to be able to add more renwable energy to replace fossil and nuclear generation.
- Easier to forecast for business plan with stable rate increases;
- manageable to ratepayers while insuring reliability
- It isn't as simple as a broad answer above. Some items are more critical and should be completed upfront. Other assets should be sweated and delayed. New technologies and options should be considered for some investments

Q What does it depend on?
[asked of those who answered “it depends” to previous question]

- Customer connection requirements and timing of those. Show some flexibility! just because a new customer connection falls a year outside the Hydro one plan should not necessarily require the customer to pay the full advancement cost.
- I think you need to do some investments, spread payments over time, but revisit and optimize costs...ALWAYS be more productive, look for economies of scale, look to streamline and cut where people or assets are not productive and a drag on the system, literally and figuratively...have yet to see HONI do this
- Safety, reliability, growth regions, new technology, innovation - it shouldn't just be an all or nothing approach.

Pace of Investment (2)

Q Why do you prefer the scenario you chose over the other two scenarios?
[asked of all respondents, n=103]

End Users

- Most can not afford higher rates, and delaying will just cause future generations to deal with legacy issues
- 1) Predictability in pricing2) Not letting the system fail
- Good balance
- I don't agree it will mean higher increases in the future . AT least it may eliminate investments that are needed. We have made a lot of investments in the past we don't need. This will prevent that.
- This scenario depends on the specifics of investments, their value and benefits.
- Hydro is too expensive.
- Given that the current electricity rate in Ontario is among the highest in North America.
- ontario pay more for hydro then anybode around. How we can stay in business and compete
- Financial impact,
- Balanced investments so rate increases are aligned with inflation. Electricity in Ontario is extremely expensive and has put Ontario business at a significant disadvantage. While investments are necessary so are ensuring competitive costs.
- Prioritize, plan and execute.
- HO should look for internal savings/efficiencies before rate increases to fund not only growth but reliability and maintenance projects. This is how industry operates, we would expect the same from HO.
- Preference is to have stable rate increases for financial planning provided that reliability is not compromised.
- Folks - start doing root cause and figure out your problems - you have bought crap breakers and are now replacing them, crap ceramic insulators and are now replacing them, and crap transformers that have fried equipment vital to our operations (I'm assuming that these problems are not caused by poor maintenance done by your very lucratively paid employees). Let's figure out how much money you are wasting, and fix that first. What is your ROI on the vaunted IT system - are you there yet? You need an industry culture and an industry style focus - once we see that and its results, you will find that you don't need anywhere near the stuff you think you do - and this is assuming that you are not trying to pad the asset base to maximize regulatory returns to your new shareholders - big assumption.
- Invest now (in the north!), where there has been no investment in decades. we are at the end of long, inefficient lines at [location] and [location]. we were forced to invest in a transmission line in red lake b/c hydro was reluctant to do so.
- Its unfortunate the state of power in Ontario. Hydro One should reflect on their performance vs other provinces and states. What are we doing wrong when it costs so much to produce power vs other areas?
- Would prefer option on invest now, but the cost may be too high, so spreading costs may be better

Q What does it depend on?
[asked of those who answered “it depends” to previous question]

- Not knowing exactly what the investments are made to achieve/address and their impact/cost this question is difficult to answer in general.
- Rate increases vs internal savings. Demonstrating internal efficiencies and cost cutting (salaries) eases the impact of continuous rate increases.
- Getting what you really need right (nowhere close to that yet), getting your operating costs in line (lot's to do there), what your financing charges are compared to ours (we have to borrow to pay for you guys, and your rates are likely lower than ours), setting priorities that provide a level of priority for economic health of your jurisdiction vs convenience.

Reliability (1)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

LDCs

- Our customers are nearly 100% depended on supply we receive from Hydro One. Therefore reliability has a direct impact on our customers.
- Reliability of service to our delivery points
- have the "clean" transmission supply continually available
- Transparent communication on system operations that create power quality or outage events in the distribution system.
- Sustained outage of transmission circuits resulting in loss of load at WNH delivery points. Recent experience is these events seem to happen more frequently on double circuit transmission lines when one line is already out for planned maintenance.
- We only have the one circuit in our community so the reliabiliyt of that circuit is quite important to our township. For example, winter months where we have lost power for 3 days in the middle of winter.
- Availability of power and or service
- A system that is not down due equipment breakdowns
- adequate and sufficient power. Power available when you need it in a safe manner
- Consistent supply of electricity and fast response to interruptions.
- Keeping the lights on
- Uninterrupted supply. Their Tx reliability is very good!
- this is extremely important as an LDC our customers count on us to deliver a safe a reliable system and we expect the same form our provider
- No loss of supply events greater than x for longer than y - x and y are terms I am certain will mean something different to most. It is also accepting a go forward view as to the level of managed risks we are being exposed to - we should not accept a level of risk of outage greater than Z when planning and operating the system
- Reliability is a measure of how often the system is available for use operating
- Reliability being the dependability of the service and being able to count on the reliability of power to be available without itneruptions. HIghly reliable versus unreliable.
- No outages
- It is presence of in specification voltage levels and adequate current availability.
- Reliability means minimization of incidents where power is interrupted for more than a couple seconds. It is closely related to power quality and is often used interchangeably by customers that are sensitive to power quality issues.
- Reliability is key in providing service to our end customers. Ensuring safe reliable electricity is imperative.
- duration and frequency of loss of supply incidents that affect our customer base.
- Essentially reliability it is the time the power is available. Being a dual element system the reliability is generally excellent. However, since a transmission outage can be a major event, the risk of an outage due to a forced or planned outage of one of the elements is also a consideration.
- For our organization, reliability would refer to the availability of at least one of the two supplies to the station supplying our feeders. For single source stations, the lines are maintained to provide alternate supply routes via switching. Our customers have growing expectations for availability of power and we in turn rely on the Hydro One transmission system to allow us to service our customers.
- Power available 24/7 at the correct voltages and with no curtailments of supply
- Frequency and duration of power interruptions.
- relaibility of supply - availability of power

Reliability (2)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

End Users

- No unplanned extended outages
- no outages and constant electricity quality
- 1) No interruptions2) Having a ""plan B"" - redundancy built into the system
- Continuous, uninterrupted and good quality supply of power to Customer
- Reduction of unplanned outages
- 0% of unplanned downtime with respect to electrical supply. Power is a significant input to the operations, safety, and protection of the environment. Unplanned outages have high consequences.
- Continuation of services, minimizing lost time due to equip./line failures
- I translate it to availability. I don't expect 100 % it can be defined. No outages lasting longer than 8 hours except with one catastrophic outage once every 3 years lasting no longer that 3 days. 95 % of days with no interuptions. That is what I would expect.
- Un-interrupted power supply.
- No unplanned outages...
- Zero interruptions, very low number of unplanned events such as loss of redundancy and power quality incidents (particularly voltage sags).
- 100 % power availability and 100% quality
- Reliability = Uptime or ability to fuction
- No power interruption at all times. Our facility is 24x 7 service industry and continously power is a key to all the safe operation of the plant and to keep the production to meet the customer demand
- No power interuptions means higher productivity.
- Power available to run our pumps on a continuous, uninterrupted basis.
- A reliable transmission is delivering electrify to the distribution point in a form (within reasonable tolerance) that doesn't cause any disruption to our plant production process.
- Mean a lot. Any interruptions and loss of power cost us lot off money and potentially lose a customers
- We are a 24/365 [removed for privacy] operation that is energy intensive and trade exposed. Power outages have a large negative effect on the bottom line.
- Uninterrupted supply of electricity to meet the utilization of our operations.
- Consistency in product and service supply, with minimal interruptions or periods of reduced service quality.
- power outages cause major issues on campus, research experiments are compromised, failure of electronic equipment increases from outages or blips. There is a financial cost to each recovery from an outage, at times in the tens of thousands
- Number of times each year we experience a partial or total plant trip due to the transmission system.

[CONTINUED ON NEXT PAGE]

Reliability (3)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

End Users

- Percent of the time sufficient power is available to operate our facility.
- Consistent power supply, little to no unplanned outages. Planned outages are also part of reliability, so we as the customer can plan as well.
- 115kv power available 365 days 24hrs a year
- zero interruptions which force an unplanned shutdown of our facility.
- No unplanned outages and consistent power quality. (Ie no impact to production).
- Power stays on in such a fashion that it does not kick out and/or burn out instrumentation, VFD's, and other (typically expensive and vital) equipment
- Steady operations, with long MTBF.
- Very few unplanned outages
- That the Light is on when I turn on the switch
- power available around the clock.
- Consistency of supply.
- A measurement of uptime
- Consistent supply of quality electricity with few if any unscheduled interruptions
- No unexpected outages or variance from agreed upon target voltage supplied to site
- Any power outage can cause a loss of production. And due to the limitation of travel can cause issues with men underground

Reliability (4)

Q When you are talking about transmission reliability, what does that mean to your organization?
[asked of all respondents, n=103]

Generators

- Providing stable and consistent energy as promised
- uptime while maintaining excellent power quality
- Minimal power interruptions.
- Power from the grid available when required and no generation interruptions
- Our ability to get power onto the grid. It's knowing of planned outages, reduction of forced outages, limiting time, length and number of outages. I think Hydro One does an excellent job of providing contingency.
- There when needed
- Maintaining the resources required to provide customers with the proper delivery of electricity.
- The ability to generate our production (electricity) and sell our product.
- Having no service interruption or fluctuation.
- The ability to generate and export power.
- Reliability means we can rely on the transmission system to be available at all times to allow our generation facilities to transmit electricity to the grid.
- Stable connection, less outage, long term operation.
- up time vs downtime
- Systems are available and trasmitting our electricity without interuption.
- As a generator it also extremely important that HONI is available to take the power and transmit it. When developing projects cooperation and schedule adherence is very important.
- Continuous supply of quality energy
- The grid is ready and available to deliver our electrons at all times, primarily during on-peak periods.
- Reliability to us is that we are able to transmit power into the H1 owned facility, as our core business is to sell power to the IESO
- Availability, minimize planed and forced outages
- Minimisation of production revenue losses
- Less down time on the grid with stable power. Very important
- No unplanned outages
- The number and duration of transmission line outages
- Proper technical operation, no unintended outages due to equipment malfunction or failure. Planning of outages taking into consideration customer impacts and full up front communications with those customers, not just a select few.
- power is flowing as required with little to no down time.
- uninterrupted power transmission
- Having a stable and reliable grid for which power can be injected as a generator.
- Ability for the grid to stay operating, including managing around foreseeable unforeseeable events for high "availability"
- It mean that the transmission system is always available.
- Electricity flows when needed and no power outages;
- Grid availability as we are a renewable energy generator and rely on the grid to sell our product.
- low outages due to equipment failure
- Reliability means the customer can understand when power will be on, and will be off - they can plan for this and understand that if Hydro One says the power will be on; it will be on. In the event of storms or other disruptions; Hydro One will move swiftly to return power from unexpected events.
- Grid reliability isssues do not impact generation from nuclear and other large generators, low risk of blackouts

Comments on Reliability

Q Is there anything else you would like to add on the topic of reliability?
[asked of all respondents, n=103]

LDCs

- Their Tx reliability is very good. Communications is more important to use the loss of supply (mind you, loss of supply rarely occurs).
- Power quality is most important to large, power quality sensitive customers while small commercial or residential customers are most concerned with the number and duration of day-to-day interruptions. Most customers have the most tolerance for outages due to major events as they can understand the reason behind the outage while the cause of day to day outages is largely invisible to most customers.
- The only choice in this survey is reducing. There is no option to maintain current levels. Being prepared to minimize the duration of an event should it happen is important.

End Users

- Major events cannot be reasonably predicted especially with global warming trends and more severe weather. The flexibility and the ability to react to the event is more important which will impact duration.
- Drag and drop does not work in my browsers.
- Consistent and reasonable Power Quality is a main element any reliable electricity supply.
- no
- Drag and drop does not work. most important reducting the number of day to day interruptions, reducing the durantion of day to day interruptions, reducing the duration of interruptions due to major events, reducing the number of interruptions due to major events, overall power quality.
- At [company] a consistent voltage supply with minimal swing from min to max is critical for our plant. It's fine to quote industry standard expectations, our expectations are higher than this.
- Unplanned outages whether day to day or major events have significant impacts on employee safety, the environment, neighbouring communities and profits. Our licence to operate is compromised.
- A one minute outage or a 30 minute outage will still cause over 2 hours of production loss.
- This question is like asking me do I prefer having my eardrum poked out or my finger nail pulled off - anything that brings our equipment down costs us a lot of lost production, lost material, and often lost instrumentation boards etc. Once we are down, whether the power comes back in 2 seconds or two hours is less important - we are often down for over a shift anyways.
- Not relevant. All equal.

Generators

- As long as we understand this is seen purely from me as a power producer. We don't rely on the grid for our internal stuff.
- On-peak periods is our main focus and need interruptions reduced or eliminated during the on-peak periods Monday thru Friday.
- Power quality is not a transmission issue and shouldn't be on the list. Frequency and duration of outages are the key. Due planning processes for planned events is critical.
- i understand we do not control the weather, goal is to reduce the impact on the utility

Investment Scenarios (1)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

LDCs

- best balance of costs vs benefits
- This rate should still enable you to decrease the risk without a significant short term rate increase.
- I recognize HONI has very difficult choices to make. However, it is very difficult to support a transmission rate increase that is greater than 1.5 times CPI
- It combines all four scenarios into one with moderate rate increase, high reliability and moderature future increases.
- Ideally, the rate increase would be inflation plus some nominal percentage. However, if 3.3% results in a material decrease in service capability, this new information suggests that the next highest level of investment is appropriate, thereby putting this somewhere in between Scenarios C and D.
- decrease on reliability risk while levelling future rate increases.
- 1) Hydro One is inefficient and needs to sort out their internal processes and find greater efficiency.2) There is nothing in this plan for innovation. Why would they invest in Tx infrastructure without a plan to manage the two-way flow of electricity that distributed generation will bring in 10-15 years. The last thing anyone wants is billions of $ in distressed transmission assets.
- Low rates a priority and managed risks - information is imperfect and so the best investment is to get better data/information while you have the time to drive better investment outcomes while living within a cost affordability index. Are you getting the right bang for your investment today? That data was not made available - can you assume you will get more for the money you are investing?
- I would consider a point midway between scenario B and C, the point where risk is neither increasing or decreasing..
- Under your maintain current level you are showing a reduction in average percentage of key assets beyond normal life expectancy. how is this maintain? In addition, you are suggesting that to maintain current levels of expenditures you need a 5.1 % annual increase in rates. Why is it not at or below inflation? These various senerios don't seem to make sense when looking at the rates or risks shown
- This scenario keeps the transmission system at about the same health level as it is today and while the transmission rate increase is moderate, the overall bill impact is small and likely tolerable by most customers.
- Significant investments have been made over the last five years to allow for DG resources to be connected. My expectation is that the rate of investment can now be curtailed back some.
- The costs are a major input into these evaluations. A TS decommisioning was quoted at over $10M, transfer trip for a DG a few years ago was $180k is now being quoted at $400k, rebuilding a TS is being quoted at $38M. The choice is really C with an A rate increase.
- The system already has a health percentage of aged equipment and with the increasing reliance on the transmission system to achieve the government's environmental goals, reliability will only become more important.
- No choice made. Analysis simplistic. Need to look for alternative savings (OM&A) to offset cost of increased asset investments.
- Keep increases at inflation.

Investment Scenarios (2)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

End Users

- Chose the middle, trying to find a happy medium, so that we try to fix the mess we are in efficiently and cost affective as possible. However the rate increases is to high but we can't keep delaying either creating a bigger problem for future etc
- maintaining the current level of investments will provide the planning and necessary funds for equipment is replace/upgrade as required to ensure reliability of power supply
- Good balance
- Reliability needs to improve but rate increases need to be balanced as it effects our operating costs
- To maintain a consistent cost(although increased) with a higher reliability.
- I am prepared to take on more risk as we get the cost envelop sorted out and I am not willing to accept that rates would only change from .11% to .46% between scenario's when costs to the public have been going up by double digits per year for many years. IN addition I am not prepared to accept that managing the rate of investment now will necessarily result in significantly higher future rates. The whole system has to take responsibility for the costs the public is struggling with NOW !
- Maintains the average percentage of key assets beyond expected service life constant.
- Preference would be investment close to scenario C but at lower transmission rate increase. i.e. Hydro One should look into improving its own efficiencies or finding ways to obtain the required funds to achieve scenario D or at minimum Scenario C's goals without significant increases to the transmission rates.
- The current level of reliability is acceptable therefore maintaining the status quo would seem appropriate.
- Reduces risk, reduces the number of assets beyond expected life, cost increase is high, moving to Scenario D does not reduce the risks that much more based to cost. Selecting Scenario A or B will put our distribution system at to high a risk.
- Transmission costs are already too high. More needs to be done to ensure the investment $$ are being spent wisely.
- Hydro One is unfortunately operating in one of the highest rate markets in North America. Normally higher increases could be tolerated, however with the current state of the electricity market reasonable rate increase are expected, even if it comes at the cost of degraded reliability. This is ultimately due to current and previous provincial governments however Hydro One is forced to take this under consideration.
- Internal savings and efficiencies must be considered (salaries) to minimize rate increases. Increases in the 2 to 3% range combined with internal savings should net to Scenario C. This should be the goal.
- It would appear that the infrastructure has not been maintained at the correct pace. A reduction now would jeopardize future reliability.
- Your reliability assessments are not credible - on the single circuit SAIDI you do not even know why the majority of the interruptions occurred - so how can you model accurate reliability assessments? Your question is the equivalent of asking "if I fall out of a boat, should I wait for help or try and swim for shore? Why not just climb back into the boat?" You are missing the third option. Ex: instead of flying helicopters to check lines, why not use drones whose flight controls are tied to a carrier signal on the power line itself - get creative with the regulatory guys and find a way to reduce the costs - this is what industry does ....How big a transformer can you put on a flatbed - can several (already on flat beds) be used for multi circuit reliability and in case of an emergency, pulled out to use elsewhere ..... what about a system (used in Europe) where if one phase goes out, the other two are (downstream) reconfigured to power all three lines - just with a reduced capacity, until repairs are made. etc - etc
- we're on unreliable lines so we'd like some investment in those lines under any scenario. some is more than what we've seen in recent years. with upward pressure on rates, we'd be hard pressed to call for much more reinvestment than B. I'm wondering about the capital estimates and whether or not there is any room for efficiencies within?
- Please lean on successful areas (provinces/states) that face the same pressure and show a marked improvement in Reliability and Quality and use that as a benchmark.
- Do not want to see any service supply or reliability deteriorate from the current state

Investment Scenarios (3)

Q Please use this space to tell us why you placed the slider where you did
[asked of all respondents, n=103]

Generators

- It meets many of the things and it's a subtantial capital investment, but it has a lot of things moving in the right way. Decrease in reliability risk, improvement in long-term reliability. Fairly level future rate increase.
- You should manage your business to be at or below the annual Canadian index price increase and still be reliable. Actual rates are already very high. We pay anywhere between $120-150/MW which is too high.
- Balance the annual rate increase based on risk.
- Scenario A seems the most favourable at this time; companies are very cost focus and margins are currently very tight.
- increased reliability, levelled rates
- Clever OEB type presentation Ontario in very fragile economic condition   Just focus on cutting cost   There is not as you imply direct correlation between cost reduction and reliability
- The reality is we have taken the cheap route and now the system needs to be upgraded and repaired. Best to pay and be done with it.
- The current situation is in part the result of a deliberate reduction in re-investment in the mid 1990's to mid 2000's which has resulted in equipment beyond service life. If reliability levels are to be maintained or improved, then a balanced and consistent approach is required.
- there is a lot of old components that need replacing already. reducing spent $'s will not enhance current performance
- We want a decrease in reliability risk and not too much increase in rates;
- I do not agree with Hydro One's premise that there should be increases in Hydro rates amongst all the options. Like any other business; Hydro One needs to improve how it runs its business; how it seeks innovative answers; how it can deliver the same or better service for less money. I fundamentally disagree with all the options above; Hydro One has to stop acting in a way that it think it is entitled to more money or else the lights go out; Hydro One needs to start thinking like all other businesses; get lean; lower costs; meet customer expectations. The people and businesses of Ontario shouldn't have to keep paying for Hydro One's excesses. Rates should be kept constant; and the service should improve for that cost moving forward.
- Best choice overall from reliability and long term cost perspective

Questions for LDCs (1)

Q Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?
[asked of all LDC respondents, n=28]

LDCs

- Improved Communication to LDC's on reliability issues
- more regular updates
- Mitigate short circuit constraints for generation connections.
- Harden the single circuit 115 kV D10H circuit that supplys Elmira TS. We have lost this supply twice in recent years during ice storm events.
- Nothing. They are doing a fine job at this point with regards to transmission
- Not really
- Invest strategically in infrastructure. Cap top 5 salaries of Hydro One staff (ie: CEO, CFO, etc.) for letting the system deteriorate to the point where it is right now.
- Increased pre-planning for joint investments with the LDCs. Improve project management to achieve project milestones on time. Better transparency of costs associated to projects requested by the LDC for Hydro One to complete.
- Improve its brand/reputation. When Hydro One "screws-up", it bring the reputation of the entire Ontario electricity sector down. This make working with my LDC's customers more difficult.
- no I currently do not have any issues especially with the people that I deal with
- Treat me like a customer - provide me with the level of data needed to manage my customers - often you will react to my customers who are mine and provide better information to them (cause of outage, expected duration, etc) than you do for me. Better collaboration between control centres - I bet you dont treat your Hydro OGCC the same way you treat other utility control centres.
- Assist with Power quality investigations.
- Better support at local level
- communication and coordination of TS work requires significant improvement
- Better planning of maintenance outage notifications. Costs need to stabilize while at the same time allow for development of new loads in rural areas at costs that are reasonable and not prohibitive. Don't try and push normal maintenance and replacement costs onto new customers.
- It would be helpful if Hydro One were able to provide more reasonable cost estimates for their work. In past years, Hydro One was know for high costs of work and had an active program to reduce their costs of doing business. That effort seems to have waned now and costs have gone back to levels that many customers feel are too high.
- LDC's and Hydro One need to be working in partnership not as competitors allowing for further cooperation and to paticipate in early consultation
- improve reliability in smaller rural communities, reduce engineering costs for distributed generation projects. reduce operating, maintenance and administrative costs as a whole and pass the saving onto the customer base.
- See the opening comments.
- Consider both the financial and reliability impact of your actions on our customers.
- regulate voltage better
- lower rates

Questions for LDCs (2)

Q Is there anything in particular you feel Hydro One can do better to serve the specific needs of First Nations and/or Métis communities?

[asked of all LDC respondents who serve First Nations and/or Metis communities, n=2]

LDCs

- No.
- The northern single circuit communities deserve more attention as they are more vulnerable in terms of supply and outage response.

Content Covered (1)

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]

LDCs

- NO
- No mention of removing transmission constraints for distributed generation in our area
- None that can be recalled
- A section focused for the LDC to comment on joint projects.
- Innovation -- how is Hydro One being innovative?
- not at this time
- Yes - already told you your current performance on asset plans was missing, your risk management plans were missing, your productivity improvement plan to show what you get for the $ invested and how much more is expected so that I could "trade" off appropriately
- No.
- No

End Users

- More detailed breakdown of cost
- Cost reduction; show customers what you're doing to save money and find efficiency.
- Although hard to do, a break out of necessary upgrades based on affected areas of distribution, could potentially make justification higher.
- I simply don't agree with some conclusions and feel the analysis was skewed towards the higher investment options.
- It would be good to know what Hydro One is doing to improve its own efficiency in order to free up funds to cover some of the investments
- How to save in GA costs.
- None
- Overall Good Content.
- Results of benchmarking Hydro One with other North American utilities to compare fixed costs, maintenance spend, capital spend and other measures of productivity.
- What is the action plan for internal savings, efficiencies?
- Cost of service - you are an expensive service in an expensive province - if you are having trouble paying for the grid today, then how are you going to pay for it tomorrow when so many more industrial plants leave the province (and we are not investing in Ontario assets - just letting them run down to obsolescence - closures are coming).
- A breakdown of the "key assets" where the major investments are required

Content Covered (2)

Q Was there any content missing that you would have liked to have seen included?
[asked of all respondents, n=103]

Generators

- No
- No
- Some graphics may help. Circuit performance. A map of circuit performance - who is getting the best performance?
- No
- did not attend
- Graphs of last ten year cost and productivity info   Benchmarking
- No
- Some metrics on resourcing required to achieve the goals, efficiency improvements.
- CIA, Connection Cost Estimate and work planning, timeline improvement
- I thought it was quite comprehensive for our purposes, but one aspect to add in for future may be interconnection process feedback.
- plan for increasing the amount renewable energy that can be connected
- I think there is an obvious outcome locked into the questions; whereby all answers involved increased funding. I think this is dishonest and lacks alignment with the people and businesses of Ontario that don't have such a luxury.

Outstanding Questions

Q Is there anything that you would still like answered?
[asked of all respondents, n=103]

LDCs

- No
- Nothing
- Not at this time
- no
- How is Hydro One going to improve productivity? What is process for managing staff / project teams in Northern Ontario?
- no
- When you are releasing the plans? Will there be any dialogue on rates and where will we get a chance to review tha comments?
- No.
- No

End Users

- Cyber security plans.
- Sufficient
- No
- See above
- How do you plan to improve reliability while decreasing costs - and if you are telling me that it can't be done, then in industry parlance "you're fired"!!

Generators

- No
- No
- No
- No
- did not attend
- Please ensure to pass on the current level and expectations of customer focus to new employees of HONI; communications is key and appreciation of the cost to customers when the grid is not available.
- NO   just focus on cost reductions
- No
- i would like to be able to review and understand the Hydro outage summary. Why is it so cryptic, it should be very transparent and not require an interpreter.
- No
- Innovation and lean management of Hydro One to drive cost savings and improve performance.

Future Customer Engagements (1)

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]

LDCs

- If my system would allow me, I would do it over the internet
- in person/email/webinars...but in person is always best
- Survey
- Proper engagement with the LDC community. We want Mayo to reach out to us (and not just to buy us). Come to the EDA and start a dialog with Ontario's LDCs.
- keep it the same as the current method works fine for me
- I would prefer the list of questions and answers fed back and how you respond differently to the critical questions and answers you are recieveing
- similarly with link again
- The survey works well. I have participated in previous in-person group sessions and found them informative as well. Perhaps a balance of alternating in-person with surveys would work.
- On line surveys are good
- I like the format, and the length.

End Users

- "1) Face-to-face feedback sessions.2) Workshops with similar industrial customers."
- Customers direct participation
- None
- Information sessions as well as surveys
- Suggest targets for productivity. H-1 should be looking to improve productivity in an effort to "live within its means" like all other businesses in Ontario - and ALL of H-1's customers - have to.
- None
- Surveys for a couple of years, face to face meetings every 3 years
- Survey is fine.
- Prefer on line surveys to telephone surveys.
- Not sure - maybe an interview would be better - tough to express yourself using words without conveying urgency or emphasis (for which the written word is not amenable - unless you are an accomplished author)
- Too much reading it was making me nod off
- survey was a good vehicle
- Asking to weigh items that are really equal seems like a waste of time.
- Same as this

Future Customer Engagements (2)

Q How would you prefer to participate in these engagements?
[asked of all respondents, n=103]

Generators

- Web based engagement
- We appreciate the opportunity to participate in the engagement and look forward to similar opportunities in the future. We believe the online survey tool is an appropriate means to do so.
- This format is fine.
- did not attend
- AS OEB has mandate over rates my input is of no value
- By on line survey
- I think the online survey is a good method.
- focus more on embedded generation with renewables
- The current method is fine.

INNOVATIVE RESEARCH GROUP

Appendix 1.2
The Survey

hydro one

Welcome to Hydro One's transmission customer engagement survey.

Why are we here?

Hydro One is starting its planning process for the 2019-2023 plan. As you may be aware, Hydro One currently has an application before the Ontario Energy Board to cover the 2017-2018 period. However, transmission systems have long planning horizons and Hydro One needs to start now to prepare the business plan for 2019-2023. For the purpose of getting your views on the outcomes and priorities that matter to you, Hydro One has used this 2017-2018 application as its starting-point. **See the "Additional Information" document for more information about Hydro One's planning process.**

Hydro One engages with its transmission customers through key account mangers, regular surveys, and various planning processes. Now, Hydro One needs to hear from you about the outcomes you care about, as well as the pace and mix of investments that you would like to see included in the plan. Your views are a key input as Hydro One sets priority outcomes in its 2019-2023 business plan and makes choices about the investments that will be included in that plan.

Your privacy will be protected.
Hydro One has engaged an independent research firm, Innovative Research Group, to document your views. All individual responses will be confidential. Your results will be combined with others in any reports. **See the "Additional Information" document to read our privacy policy.**
Throughout this survey, you will see the following: 📖
This is an indication that a word or phrase appears in the glossary at the end of this document.

WE APPRECIATE YOUR PARTICIPATION IN THIS SURVEY, AS THE RESULTS MAY IMPACT YOUR RATES AND THE EXPECTED RELIABILITY OF THE TRANSMISSION SYSTEM.

[LDCs only]
As a distributor, please respond to the questions in this survey with your customers in mind. Your feedback should be made with consideration to your customers' needs.

What we are consulting about?

The Hydro One planning process generates a number of potential capital investments📖. Some of these investments are required to comply with the various standards and regulations that apply to Hydro One's business. But many investments have a discretionary factor, at least in terms of timing.

There are three key questions about Hydro One's potential capital investments at the core of this customer engagement:

- **What outcomes should Hydro One focus on as it decides which investments come first?**
- **How should Hydro One pace its investments in the transmission system over the long run?**
- **What is the preferred balance between reliability and the amount customers are willing to pay?**

When the plan is submitted, Hydro One will share with you both a summary of what customers said in this survey and how Hydro One responded to that input.

SURVEY RESPONSE OPTIONS:
This survey takes about 20 minutes to complete.
You can complete the survey online or, if you prefer, we can schedule a one-on-one interview either in person or by phone. If you prefer a live interview, please contact Susan Oakes at (416) 642-6341 or soakes@innovativeresearch.ca to arrange a time that is convenient for you.

To ensure your comments are considered in the planning process we need your responses by June 9, 2017.

There are *Additional Information* links throughout this workbook.
The questions have been presented with the most important information one might need to make a decision. While many transmission customers are very familiar with the transmission system, there may be specific areas where additional information would help you better answer the questions. As you go through this survey, you will find links to additional information you may find useful. You may need to enable pop-ups on your browser to enable this feature. **You can also see the "Additional Information" document to download the complete background package with all the additional information if you wish.**

The most important part of this workbook is the survey questions.
Utilities are expected to develop a genuine understanding of their customers' needs and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Hydro One to use when making key business decisions. While your view may not always align exactly with the available options, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

You will also find comment boxes throughout the survey. The comment boxes are there to provide you with the opportunity to expand on your answer if needed.

Confidential and Forward Looking Information

CONFIDENTIAL INFORMATION

In this survey, “Hydro One” or “the Company” refers to Hydro One Networks Inc. and its affiliates, taken together as a whole.

Hydro One is providing the information contained in the following survey on a confidential basis in order to solicit your feedback on customer outcomes and potential alternate investment scenarios and their expected impact on the reliability of our transmission system. The feedback from this customer engagement will be considered when making regulatory filings. Any information concerning Hydro One provided as part of this survey should not be disclosed except as necessary within your corporation in order to provide meaningful feedback.

You should not trade in securities of Hydro One Limited or Hydro One Inc. based on any of the information contained within this survey and should not use the information for any other purpose.

In this survey, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this survey demonstrating the historical performance of Hydro One are intended only to illustrate past performance and are not necessarily indicative of future performance.

Forward-Looking Information

This survey contains “forward-looking information” within the meaning of applicable Canadian securities laws. Forward-looking information in this survey is based on current expectations, estimates, forecasts and projections about Hydro One’s business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements regarding expected or projected capital and development expenditures, the timing of these expenditures and the Company’s investment plans; the use of customer feedback from the engagement process and its impact on the Company’s investment plans; the impact of future investments on customer risk, reliability performance and risk, and service interruptions; statements about asset condition, the average ages of critical assets, and their future expected condition; statements about types of asset replacements and their expected associated costs; and statements about illustrative scenarios and their impact on capital spend, expected outcomes, rates, changes in risk profile according to asset class, and increased or decreased system risk impact.

Words such as “aim”, “could”, “would”, “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “target”, “project” and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this survey is based on a variety of factors and assumptions. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One’s business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are: the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned; the risk of public opposition to and delays or denials of requisite approvals and accommodations for the Company’s planned projects; the risk that the Company is not able to arrange sufficient cost-effective financing to fund capital expenditures; the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company’s assets or to carry out projects in a timely manner; the risk that the Company’s Board of Directors may not approve the projected expenditures; and the risk that the regulator may alter or deny approval for requested investments and recoverability in rates.

How well is Hydro One meeting your needs?

Hydro One Inc. owns and operates a 30,000 circuit 🕮 km high-voltage 🕮 transmission network that includes 306 transmission stations and transmits 98 percent of Ontario's electric capacity.

For more information about Hydro One's transmission system, the standards it must meet, its activities, and reliability statistics, See the "Additional Information" document.

Questions

1. **How satisfied are you with the overall performance of Hydro One in providing your business with electricity?**
   - ❍ Very satisfied
   - ❍ Somewhat satisfied
   - ❍ Somewhat dissatisfied
   - ❍ Very dissatisfied
   - ❍ Not sure / Don't know

2. **Is there anything in particular you feel Hydro One can do better?**
   Please fill in your response below

   - ❍ Not sure / Don't know

3. **How do you know if Hydro One is doing a good job for your business?**
   Please fill in your response below

   - ❍ Not sure / Don't know

Customer Outcomes

Hydro One has to make choices in its planning, and it needs to know what is most important to you. Hydro One is responsible to the Ontario Energy Board to show how its plans provide the cost effective delivery of outcomes that customers value. **To learn more about the customer engagement process and the Ontario Energy Board's requirements, See the "Additional Information" document.**

In reviewing its previous customer engagement research and in discussions with customer-facing Hydro One staff including its Key Account Managers, Hydro One has developed a tentative list of outcomes for your review. This survey is going to ask you if anything is missing from that list, how important each outcome is to you, and which outcomes are most important compared to the others.

This section will ask you to rate how important the outcomes are to you and to share your thoughts on how Hydro One could do better. You will also have an opportunity to add any outcomes you feel are missing.

We will be asking you about the following seven outcomes:

- Customer Service
- Environmental Stewardship
- Outage Restoration
- Power Quality
- Productivity
- Reliability
- Safety

To rate the importance of an outcome, please select a point on the slider below each description. If there are areas that you don't have an opinion on, please select the "don't know" option.

Safety

Eliminating and mitigating risk to public and employee safety in the operation of the transmission system. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

4. How important an outcome is safety?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Productivity

Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources. Hydro One understands that customers expect it to look first for internal savings before asking for any additional rates.

5. How important an outcome is productivity?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Reliability

Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers 🕮. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

6. How important an outcome is reliability?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Outage Restoration

Provisions to ensure timely and efficient response to failures, unplanned outages 📖, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

7. How important an outcome is outage restoration?

Not at all important Extremely important

0 10

❍ Not sure / Don't know

Power Quality

Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform 📖. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

8. How important an outcome is power quality?

Not at all important Extremely important

0 10

❍ Not sure / Don't know

Customer Service

Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers. **For additional information on Hydro One's performance to date, See the "Additional Information" document.**

9. How important an outcome is customer service?

Not at all important Extremely important

0 10

❍ Not sure / Don't know

Environmental Stewardship

Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada.

10. How important an outcome is environmental stewardship?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Additional Outcomes

Are there any outcomes we missed? Please use the boxes below to add them, and then the slider to rate their importance.

11a. Suggested Outcome 1:

11b. How important is this outcome to you?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

12a. Suggested Outcome 2:

12b. How important is this outcome to you?

Not at all important — Extremely important

0 — 10

❍ Not sure / Don't know

Comments

13. Do you have any specific comments or suggestions regarding any of the seven outcomes that you just rated or any additional outcomes you added?

- Customer Service
- Environmental Stewardship
- Outage Restoration
- Power Quality
- Productivity
- Reliability
- Safety

Please fill in your response below:

Customer Outcomes

Top Priorities

While all the outcomes listed are important to many customers, planners set priorities among different outcomes. The purpose of this section is to help Hydro One set priorities as it prepares its business plan. Which priorities should they focus on first?

For a list of outcome definitions, See the "Additional Information" document

Please rank your top priorities from the list below.

Drag and drop the priorities in order, starting with the priority most important to you, followed by the second most important, then the third most important, and so on. Please try to rank all listed priorities:

Priorities	Top Priorities
Safety	
Productivity	
Reliability	
Outage Restoration	
Power Quality	
Customer Service	
Environmental Stewardship	

Comments:

Making Choices: Pace of Investment

When Hydro One replaces equipment in declining health, it has some flexibility in its pacing. **For more information on the health of Hydro One's assets, See the "Additional Information" document**

We would like to understand your general views on the appropriate pacing of Hydro One's investments over the next 15 – 20 years. Hydro One can front load its capital investments, it can spread them evenly over time, or it can delay its investments.

Front-loading investments would provide some benefits in terms of more connection capacity 🕮, decreased equipment failures, increased reliability, and improved productivity and quality. This would mean higher rate increases now but lower rate increases in the future.

Spreading evenly over time means some benefits are delayed but some long term savings are secured and it is more efficient in terms of staffing. Rate increases would increase at a stable level. Asset deployment costs would likely be lower using this more stable pacing philosophy.

Given the current health and demographics of the system, Hydro One can delay investments further until declining equipment conditions threaten Hydro One's ability to meet power reliability requirements. Reliability would still meet minimum standards but customers would likely experience more interruptions 🕮 than today. Rates increases would be relatively low for several years but increase at a steeper rate in the future.

Bearing in mind the trade off between immediate rate impact, long term rate impacts and system benefits, which approach best reflects how you feel Hydro One should pace the work required to renew the system over the next 15-20 years?

- ❍ Invest now, higher rates in short term, lower increases in future
- ❍ Spread investments out, stable rate increases
- ❍ Delay investments, lower rates in short term, higher increases in future
- ❍ It depends
- ❍ Not sure / Don’t know

Why do you prefer the scenario you chose over the other two scenarios?

What does it depend on?

Reliability

We are now going to move on to the topic of reliability. The term "reliability" means different things to different people, so before we move on, please describe what reliability means to your organization.

When you are talking about transmission reliability, what does that mean to your organization?

Making Choices: Reliability

Reliability has a specific meaning in electricity, but often when customers talk about reliability, they are also talking about power quality (defined as delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform). Below is a list of five items that are often included when people talk about reliability. In addition to power quality, when people raise concerns about interruptions they often draw a distinction between interruptions that are experienced during normal day-to-day operations versus interruptions that occur during major events such as severe storms.

Please rank the following reliability items in order of which are most important to your organization.
Drag and drop the items in order, starting with the item most important to you, followed by the second most important, then the third most important, and so on. Please try to rank all items:

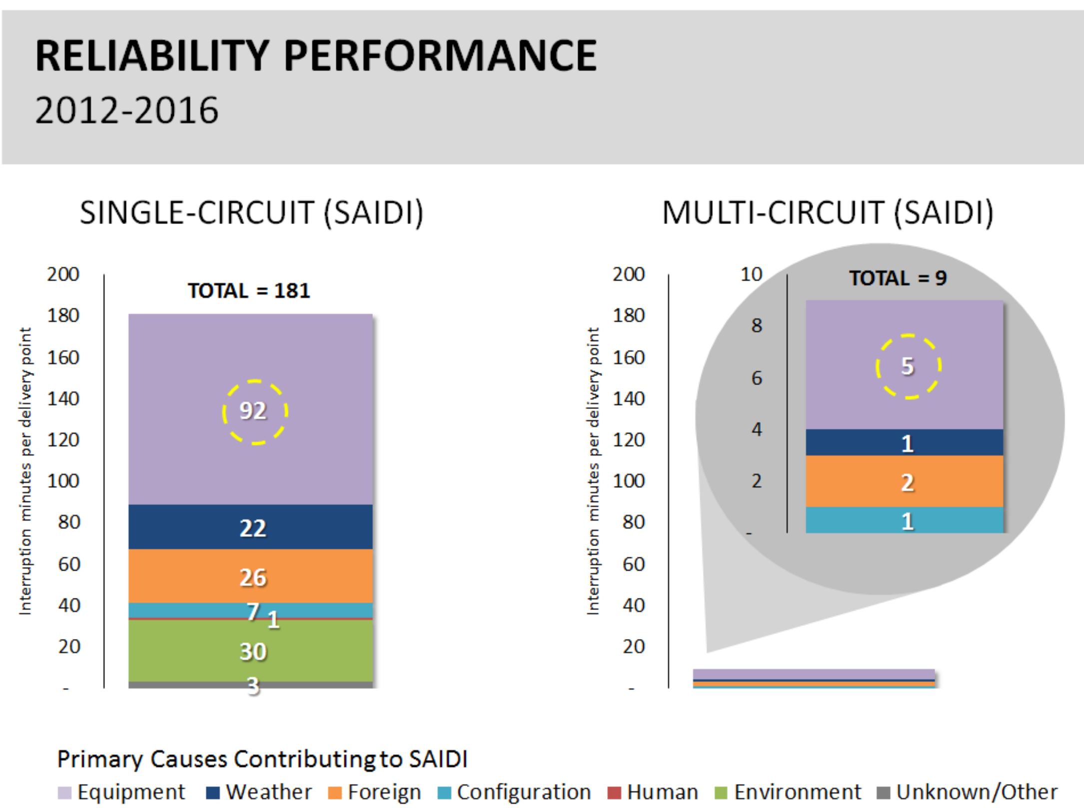
Reliability Items	Importance
Reducing the number of day-to-day interruptions	
Reducing the number of interruptions due to major events	
Reducing the duration of day-to-day interruptions	
Reducing the duration of interruptions due to major events	
Overall power quality	

Comments: Is there anything else you would like to add on the topic of reliability?

Making Choices: Reliability Trade-Offs

Understanding reliability is important when assessing the trade-offs facing Hydro One. To help understand the impact of investment decisions on reliability, Hydro One as developed a metric called "reliability risk". No one knows for sure when a specific piece of equipment will fail, but we do know how likely asset failure is for groups of equipment in specific conditions. This means we can project a likely risk of failure for a given pool of assets.

When it comes to transmission reliability, Hydro One has performed well compared to Canadian peers. The key strategy employed to avoid customer interruption in the transmission system is redundancy 🕮. Most of the transmission system has been built with at least one redundant circuit for every operating circuit. The chart below shows the benefit of redundancy as customers on single circuit 🕮 systems experience much more time (shown below as System Average Interruption Duration Index or SAIDI) 🕮 without power than customers on multi-circuit systems 🕮.



See the "Additional Information" document to read the definitions of these categories

Transmission Customer Engagement

Delaying capital spending will, in time, result in more and more equipment failures. While redundancy often prevents these failures from leading to customer interruptions, equipment failures will leave multi-circuit customers at risk of the single-circuit reliability experience. Reliability risk provides a leading indicator of the expected impact of allowing the condition of equipment in the transmission system to decline.

Making Choices: Illustrative Scenarios

Now we would like to take one last look at the core trade-offs Hydro One must make as it begins its business planning for 2019 to 2023:

- the balance between the level of investment and system reliability, and
- the timing of those investments.

To help understand your priorities, Hydro One has developed four illustrative scenarios. The specific priority of investment items in these scenarios is based on the priorities used in Hydro One's proposal currently before the Ontario Energy Board. While those priorities may change based on your earlier feedback, these scenarios are illustrative of the impacts of various spending levels.

In considering these scenarios, please be advised that all figures are intended as approximate, and are not intended to be relied upon as exact.

These scenarios focus on the trade-offs between the pace of investment, reliability, and future rate increases. The higher the level of investment, the lower the reliability risk 🕮, and vice-versa. As you consider these illustrative scenarios, please bear in mind that your rates can also be impacted by changes in load forecast and electricity prices. All scenarios assume an Operations, Maintenance, and Administration (OM&A) expense percentage increase that is held to less than inflation.

By preparing and providing these illustrations, Hydro One makes no representation that it will select one as its plan before the Ontario Energy Board.

Transmission Customer Engagement

Please read each scenario to understand how different investment levels impact key outcomes. You can choose one of these scenarios, a point between these scenarios or a point above or below these scenarios. There is a follow-up question that allows you to discuss the factors that you considered in making your choice. Your comments will help us better understand the outcomes you value.

These descriptions refer to "key assets" 🕮 which are conductors 🕮, circuit breakers 🕮 and transformers 🕮, as their failure is most likely to impact system reliability.

Scenario A: Limited investment

- Capital investment 🕮 focused on regulatory requirements and customer demand projects, such as new connections
- Sustainment capital 🕮 limited to replacing assets subject to imminent failure; no proactive sustainment investment
- The percentage of key assets beyond Expected Service Life 🕮 will increase from 21% in 2019 to 29% in 2023, increasing expected future investment requirements
- Total 5 year Capital Investment Plan: $1.8 B
- Average Annual Transmission Rate Increase: 1.3%

Scenario B: Decrease in current level of investment

- Capital investment 🕮 reduced compared to plan filed with the Ontario Energy Board in May 2016
- Spending on sustainment 🕮 of key assets deferred to future years
- Contains lower levels of investment in productivity and fewer strategic investments designed to mitigate future rate impacts (e.g., tower coating)
- The percentage of key assets beyond Expected Service Life 🕮 increases from 21% in 2019 to 26% in 2023, increasing expected future investment requirements and expenses
- Additional capital in Scenario B as compared to Scenario A focuses on replacing assets in poorest condition, resulting in a significant reduction in reliability risk 🕮
- Total 5 year Capital Investment Plan: $4.3 B
- Average Annual Transmission Rate Increase: 3.3%

Transmission Customer Engagement

Scenario C: Maintain current level of investment

- Extends investment plan in rate application currently before the Ontario Energy Board to 2023
- Maintains current level of sustainment capital 🕮 investments affecting key assets
- Percentage of key assets beyond Expected Service Life 🕮 decreases from 21% in 2019 to 19% in 2023, decreasing expected future investment requirements
- Incorporates strategic investments that mitigate future rate impacts, such as tower coating
- Total 5 year Capital Investment 🕮 Plan: $6.6 B
- Average Annual Transmission Rate Increase: 5.1%

Scenario D: Increase beyond the current level of investment

This plan contains all investments in Scenario C, with addition of:

- Additional sustainment capital 🕮 focused on key assets
- As a result, the percentage of key assets beyond Expected Service Life 🕮 decreases from 21% in 2019 to 17% in 2023, decreasing expected future investment requirements
- While the above investments benefit all customers to some degree, this scenario also increases capital to add redundancy 🕮 to worst performing single circuits 🕮 in system, benefiting a very small portion of customers in a significant way
- Total 5 year Capital Investment 🕮 Plan: $7.4 B
- Average Annual Transmission Rate Increase: 5.6%

Exploring Trade-offs Using Illustrative Scenarios

Below is a chart summarizing all the scenarios from the previous page and their implications. As we mentioned these examples are meant to illustrate the impacts of different levels of investment on current and future rate increases and system reliability.

You will note that the two middle scenarios, B and C, offer a relatively small change in reliability risk, but moving from B to C offers significant improvements in long-term reliability. The key difference between B and C is that B has larger future increases, while C has level future rate increases. The big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers.

As noted earlier, by offering these illustrative scenarios, Hydro One is not committing to any of them; their purpose is to help Hydro One understand what you as a customer value. When Hydro One makes its Ontario Energy Board filing, Hydro One will incorporate feedback received through this process, but does not commit to pursuing any one of these illustrative scenarios.

Below the chart is a slider which represents the range of potential approaches Hydro One can take. On the far left is lower investment, lower short-term rates, lower reliability, and higher anticipated future increases. On the far right is higher investment, higher short-term rates, higher reliability, and lower anticipated future increases. Please use the slider to indicate what approach you think Hydro One should take. Hydro One will use the results of this exercise as a directional indicator of the route customers want to go.

NB: The location on the slider does not correlate directly with potential rate increases. (For example, while the physical distance between scenarios B and C is the same as between C and D, the impact on reliability, rates and other outcomes is very different).

See the "Additional Information" document to view a larger and more detailed version of this table.

	Illustrative Scenarios			
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)	29%	26%	19%	17%
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits.

Thinking of all the considerations outlined, please choose a point along the line below that you believe strikes the right balance between rates and outcomes. (Remember you can choose a point located between scenarios or directly aligned with them).

Scenario A **Scenario B** **Scenario C** **Scenario D**

Lower increases now
Higher future increases
Lower reliability

Higher increases now
Lower future increases
Higher reliability

❍ Not sure / Don't know

Comments: Please use this space to tell us why you placed the slider where you did.

Questions for LDCs

Local distribution companies have unique needs that often differ from other transmission customers. On this page we'll explore:

Is there anything in particular you feel Hydro One can do better to help you meet your customers' needs?

- ❍ Don't know / Not sure

Does your company provide electricity to First Nations and/or Métis communities?

- ❍ Yes
- ❍ No
- ❍ Don't know / Not sure

Is there anything in particular you feel Hydro One can do better to serve the specific needs of First Nations and/or Métis communities?

- ❍ Don't know / Not sure

Were your responses to this survey informed by your own customer engagement activities for the purposes of a rate application, or by any other customer research?

- ❍ Yes
- ❍ No
- ❍ Don't know / Not sure

How did we do?

Overall Impression: What was your overall impression of the Transmission Customer Engagement?

- ❍ Very positive
- ❍ Somewhat positive
- ❍ Neither positive nor negative
- ❍ Somewhat negative
- ❍ Very negative
- ❍ Don't know / Not sure

Volume of Information: Did Hydro One provide too much information, not enough, or just the right amount?

- ❍ Too much information
- ❍ Not enough
- ❍ Just the right amount
- ❍ Don't know / Not sure

Content Covered: Was there any content missing that you would have liked to have seen included?

- ❍ Don't know / Not sure

Outstanding Questions: Is there anything that you would still like answered?

- ❍ Don't know / Not sure

Suggestions for Future Customer Engagements: How would you prefer to participate in these engagements?

- ❍ Don't know / Not sure

If you have any additional questions or comments about Hydro One's business plan or customer engagement, email: **Spencer.Gill@HydroOne.com.**

Next Steps

Thank you for completing the Transmission Customer Engagement. Your responses have been recorded.

Upon the conclusion of the survey, INNOVATIVE Research Group will compile the results and provide a report to Hydro One.

Hydro One will review the report as it reviews its priority-setting processes and determines the recommended level and pace of investment in its updated Transmission System Plan.

When Hydro One files the Plan in its next Ontario Energy Board application, it will share with you both a summary of what customers said in this survey, and how Hydro One responded to that input.

Thank you for your time.

Glossary

Capital Investment: Money used by a business to purchase fixed assets, such as land, machinery, or buildings.

Circuit: An electrical connection involving metallic conductors that transmits electricity between 2 points.

Circuit Breaker: A switching device for that stops or allows the flow of electricity between electrical equipment.

Conductors: A metallic wire that conducts electricity.

Connection Capacity: Hydro One's ability to add new customers and/or additional load to the transmission system.

Customer Service: Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Delivery Point: The point of supply where the energy from the system is transferred to customers. This point is generally taken as the interface between utility-owned equipment and the customer-owned equipment.

Expected Service Life: The average time in years that an asset can be expected to operate under normal system conditions.

End of Life: the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.

Frequency Deviations: Fluctuations beyond the normal operating frequency range.

High-Voltage Transmission Network: Interconnected circuits that operate at 115kV and higher voltage.

Interruption: A stop in the flow of electricity to a customer.

Key Assets: Major types of transmission assets defined as transformers, circuit breakers and conductors.

Long-Term Reliability: Reliability performance beyond the 5 year rate filing period.

Multi-Circuit Systems: Systems where power delivery points are supplied by more than one circuit.

Outage: Unavailability of electrical equipment due to disturbances, equipment maintenance, or equipment malfunction. Outages do not necessarily lead to interruptions for customers if there are backup or redundant facilities to maintain electrical supply.

Outage Restoration: Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Power Quality: Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity: Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and enabling more efficient use of resources.

Redundancy: The inclusion of duplicate components to the system so that delivery points have multiple simultaneous connections. The purpose is to reduce the possibility of interruption in case of component failure.

Reliability: Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Reliability Risk: An index that provides leading directional indication of overall system reliability performance based on probabilistic risk of asset failures.

Safety: Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Short-Term Reliability: Reliability performance within the 5 year rate filing period.

Single Circuit Systems: Delivery points that rely upon one circuit for the delivery of power. If that circuit fails then power is interrupted.

Sustainment Capital: Capital Investments made in order to maintain the current expected level of functionality and capability of system.

System Average Interruption Duration Index (SAIDI): The average outage duration for each customer served.

Transformer: An electric power equipment that changes the electricity voltage level. In Ontario, the transmission level voltage are typically transformed from 500kV to 230kV and 230kV to 115kV. To supply customers, 115kV and 230kV transmission voltages are transformed to distribution level voltages.

Transmission Stations: An electrical facility that connects a number or transmission circuits and transformers and performs a “hub” function for the flow of electricity across a region.

Transmission System Performance Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Voltage Waveform: The shape of the 60Hz voltage curve observed at the supply point.

Appendix 1.3 Additional Information

Table of Contents

The Customer Engagement Process

Hydro One's investment plan for 2019-2023 will identify, prioritize and schedule the investments made in its system. The customer engagement process will ensure that the investment plan considers and reflects the needs and preferences of Hydro One transmission customers by achieving a balance between managing reliability risk, service and cost. This investment plan will be a key component of Hydro One's transmission rate application to the OEB in the spring of 2018. As a part of its submission to the OEB, Hydro One must demonstrate that its investment plan considers the needs and preferences of its transmission customers with regard to trade-offs between outcomes, costs and pace of investment. This approach is consistent with the OEBs Renewed Regulatory Framework.

The OEB's "**consumer-centric**" *Renewed Regulatory Framework for Electricity* (RRFE) shifts the focus from utility cost to value to customers. A key requirement the rate application process includes documenting the **active engagement** between utilities and their customers. Utilities are now required to demonstrate services are provided in a manner that responds to identified customer **preferences** and **needs**.

Below are quotes taken from the OEB's Rate Handbook outlining expectations for utilities:

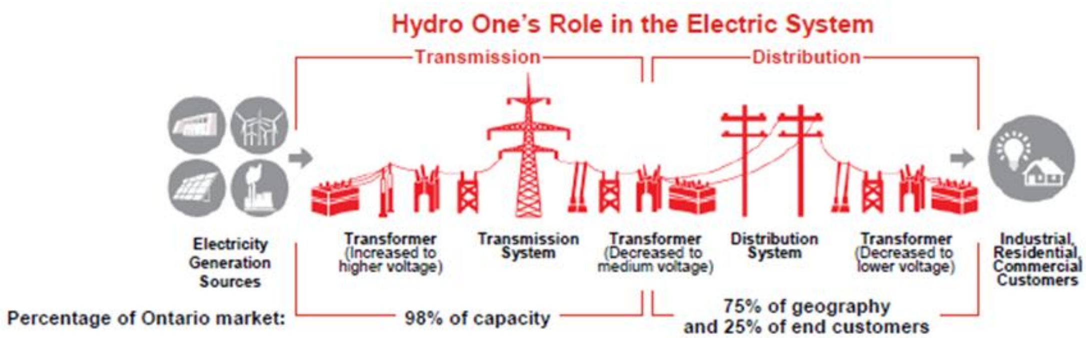
- "A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes."
- "Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives."
- "The outcomes should demonstrate the value proposition for customers and/or public policy goals."
- "Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers."
- "The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance. Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing."

All transmission-connected customers will have an opportunity to provide input that will support the development of the investment plan. Customers can provide their input by completing this online survey, or they may request an interview to be conducted in-person or by telephone.

Hydro One System Overview

Hydro One owns and operates an over 30,000 circuit km high-voltage transmission network, including 306 transmission stations, transmitting 98 percent of Ontario's electric capacity based upon revenue approved by the OEB, and an approximately 123,000 circuit km low voltage distribution network. It serves 75 percent of the geography of the province and more than 1.3 million residential and business customers.

Hydro One transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar generation sources to local distribution companies and to directly connected industrial customers across Ontario.



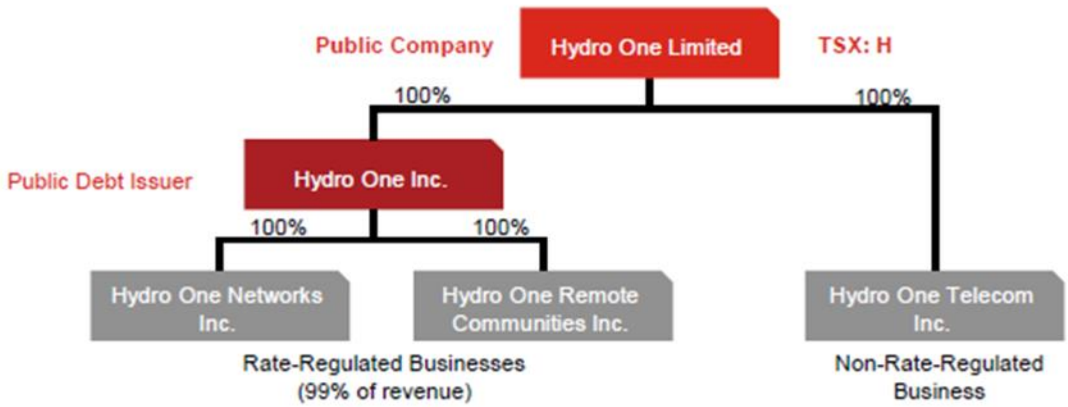
Hydro One's transmission assets can be divided into three main categories:

- Transmission stations: Used for the delivery of power, voltage transformation and switching, the stations serve as connection points for both customers and generators.
- Transmission lines: Bulk transmission lines deliver power from generating stations or connections to receiving terminal stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres.
- Network operations: The Ontario Grid Control Centre manages all of Hydro One's transmission and sub-transmission operations through a network of control, monitoring and communications equipment.

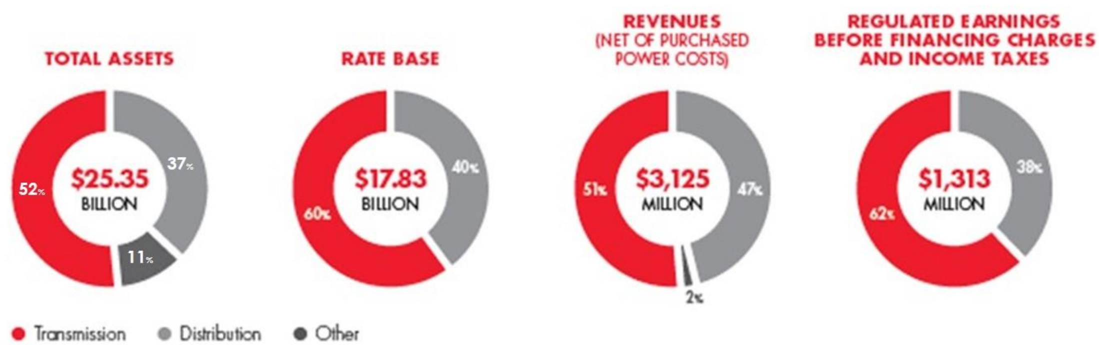
Hydro One's transmission business serves 44 Local Distribution Company (LDC) customer accounts, 87 large directly connected industrial customer accounts, and 126 generator customer accounts.

The assets in the Hydro One transmission system alone represent about $13 billion in net book value. Hydro One Limited became a public company coincident with its initial public offering in November 2015, and its common shares are listed on the Toronto Stock Exchange (TSX: H).

Hydro One's ownership structure:



Hydro One Limited's Financial Details:



Regulatory Stakeholders

Hydro One must meet the compliance requirements of six regulatory stakeholders: the Ontario Ministry of Energy, the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO), the National Energy Board, the North American Electric Reliability Corporation (NERC), and the Northeast Power Coordinating Council.

Who:	Provincial Government, Ministry of Energy
What:	Policy, legislation, regulations
Who:	Ontario Energy Board (OEB)
What:	Independent electric utility price and service quality regulation
Who:	Independent Electricity System Operator
What:	Wholesale power market rules, intermediary, North American reliability standards
Who:	National Energy Board
What:	Federal regulator, international power lines and substations
Who:	North American Electric Reliability Corporation
What:	Continent-wide bulk power reliability standards, certification, monitoring
Who:	Northeast Power Coordinating Council
What:	Northeastern North American grid reliability, standards, compliance

Hydro One's Investment Planning Process

Hydro One must decide what comes first among specific investments. While Hydro One operates within standards that are dictated by various regulators, including the Ontario Energy Board and the North American Electric Reliability Corporation (NERC), Hydro One still has a range of choices in setting priorities among investments.

During Hydro One's planning process, candidate investments are identified by Hydro One's engineers and business planners. They take a variety of factors into account including asset needs, compliance, customer requests, regional needs, productivity and safety.

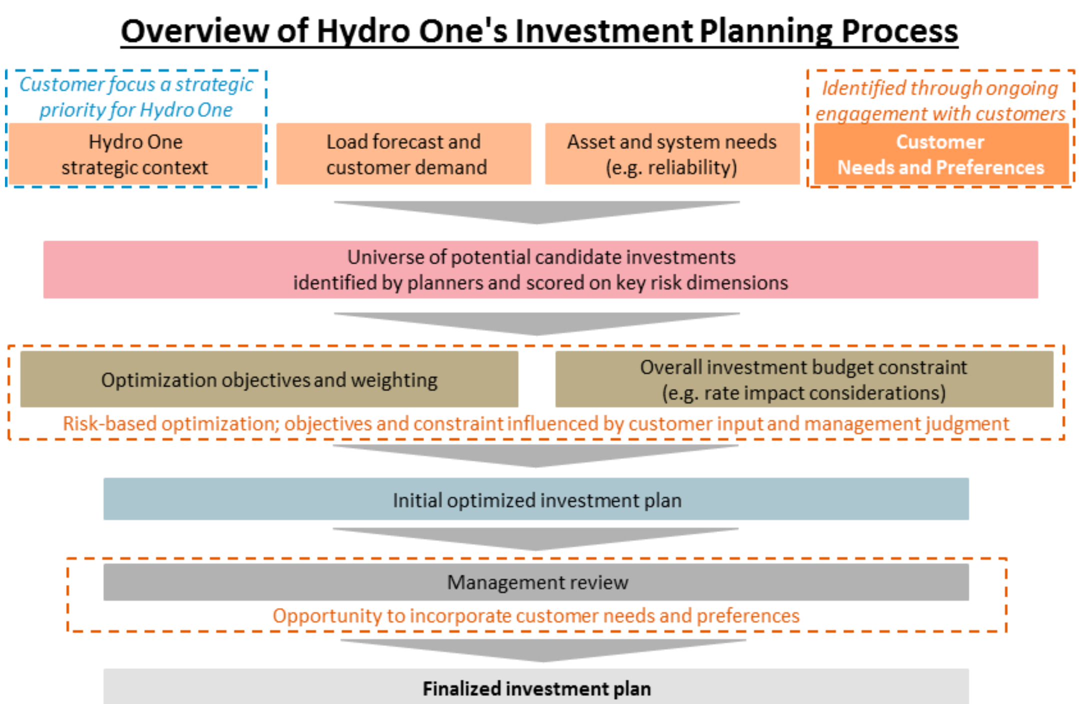
When submitted, each potential investment is scored according to a number of key criteria including the outcomes reviewed with you in this survey.

The total pool of candidate investments is then prioritized using an optimization tool that evaluates the scores assigned to all investments and compiled in to an initial investment plan.

This initial plan is then reviewed by management who evaluate the outcome of the optimization tool to ensure the plan is appropriately addressing the needs of Hydro One's assets along with the needs and preferences identified by Hydro One's customers, including the impact on rates.

Any concerns identified by this review are then incorporated in to the final plan that is approved for execution. The investment planning process is illustrated below.

Hydro One's has invested \$4.3B in capital for its transmission system over the past 5 years (2012-2016).



How Hydro One's Rates Are Set

Hydro One is a rate-regulated company. Hydro One must apply to the Ontario Energy Board (OEB) for approval of its revenue requirement and the rates it charges customers. Rates are designed such that Hydro One recovers the costs allowed by the OEB and also allow Hydro One to earn a formula-based annual rate of return on its equity invested in the regulated businesses. This allowed Return on Equity is set by the OEB by applying a specified equity risk premium to forecasted interest rates on long-term bonds.

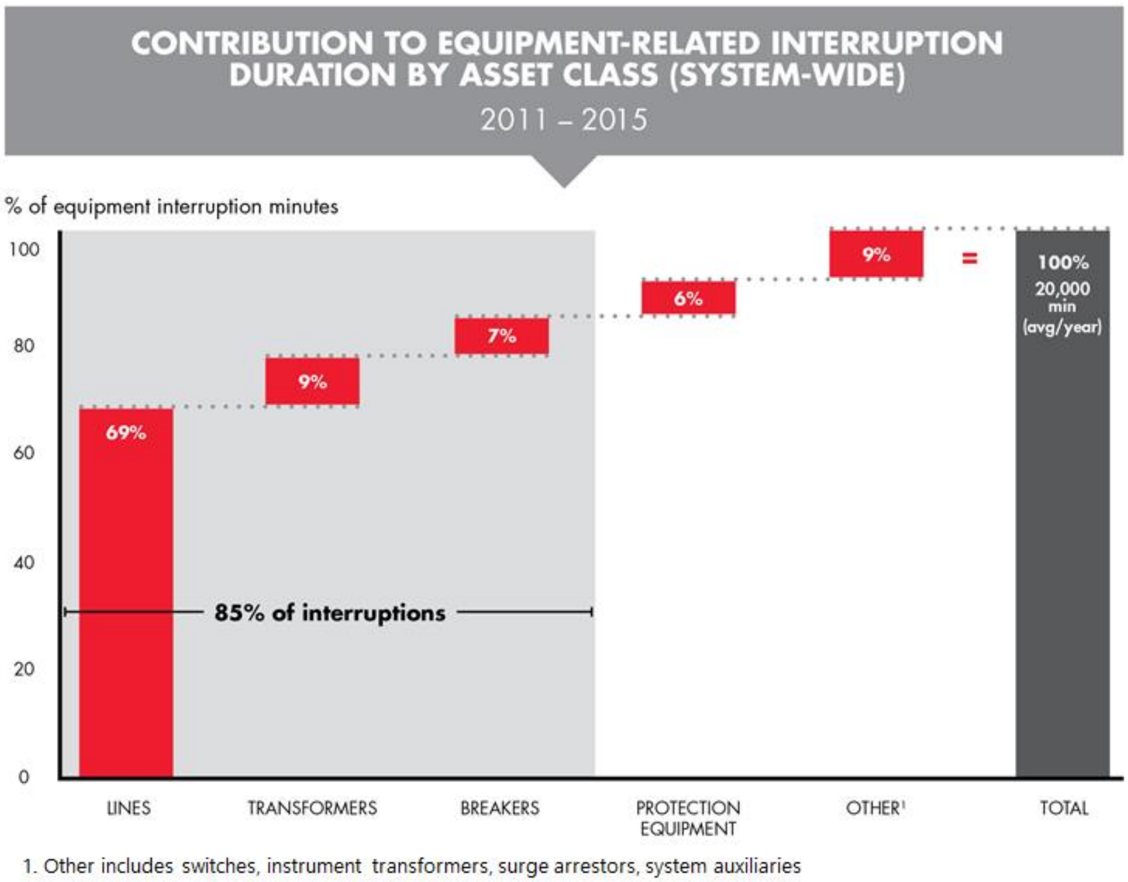
The table below summarizes the OEB-approved Transmission revenue requirement and the associated change over the prior year's revenue requirement for the 2012-2016 period.

	2012	2013	2014	2015	2016	5 Year Average
Revenue Requirement	1,418.4	1,437.7	1,535.3	1,527.2	1,567.6	
Change YoY (%)	5.1%	1.3%	6.4%	-0.5%	2.6%	3.0%

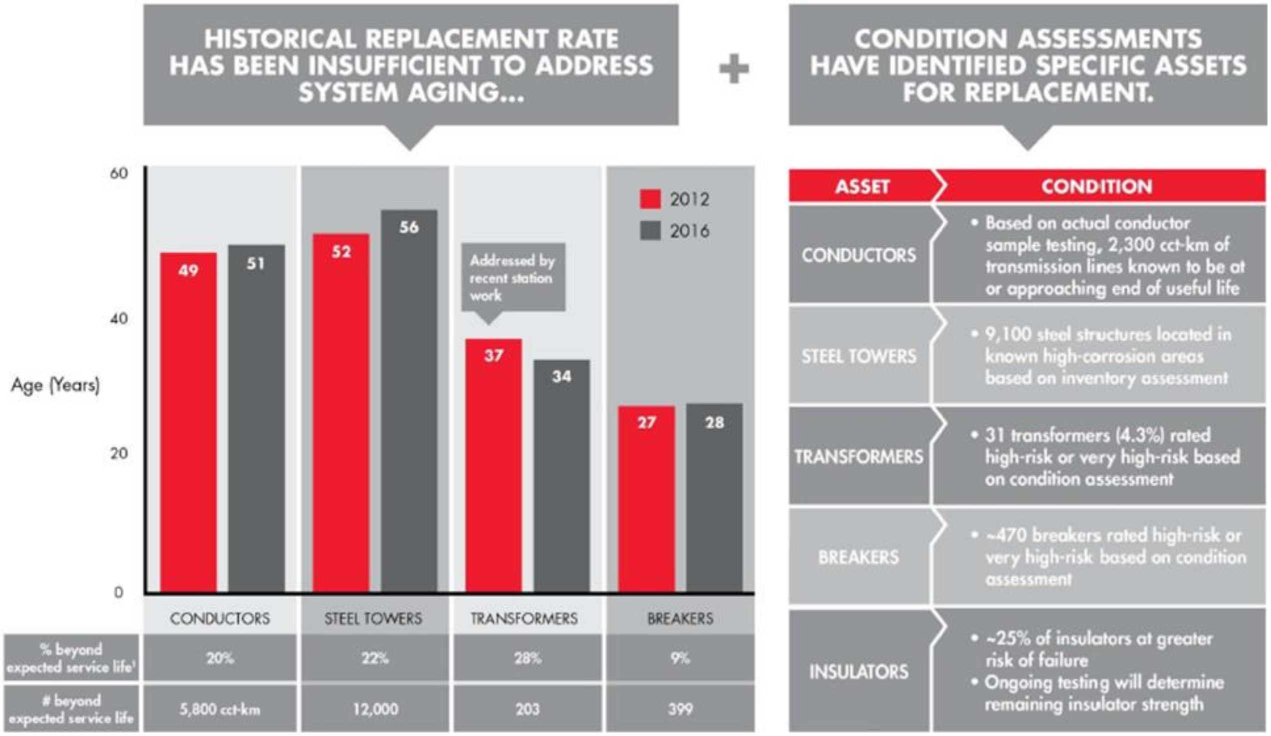
Hydro One System's Asset Health

As the system ages, so do critical assets, resulting in equipment failures and sometimes in power interruptions.

While transmission lines are the primary cause of equipment-related interruptions, transmission lines, transformers and breakers combined accounted for 85% of system interruptions between 2011 and 2015.



As of 2016, at least one-in-five conductors (19%), steel towers (22%) and transformers (28%) are beyond their expected service life. This translates into 5,800 circuit-kilometers of lines, 12,000 steel towers and 203 transformers. Many of these assets are already planned for replacement, but other assets continue to age beyond their expected service life.



1. The average time in years that an asset can be expected to operate under normal system conditions.

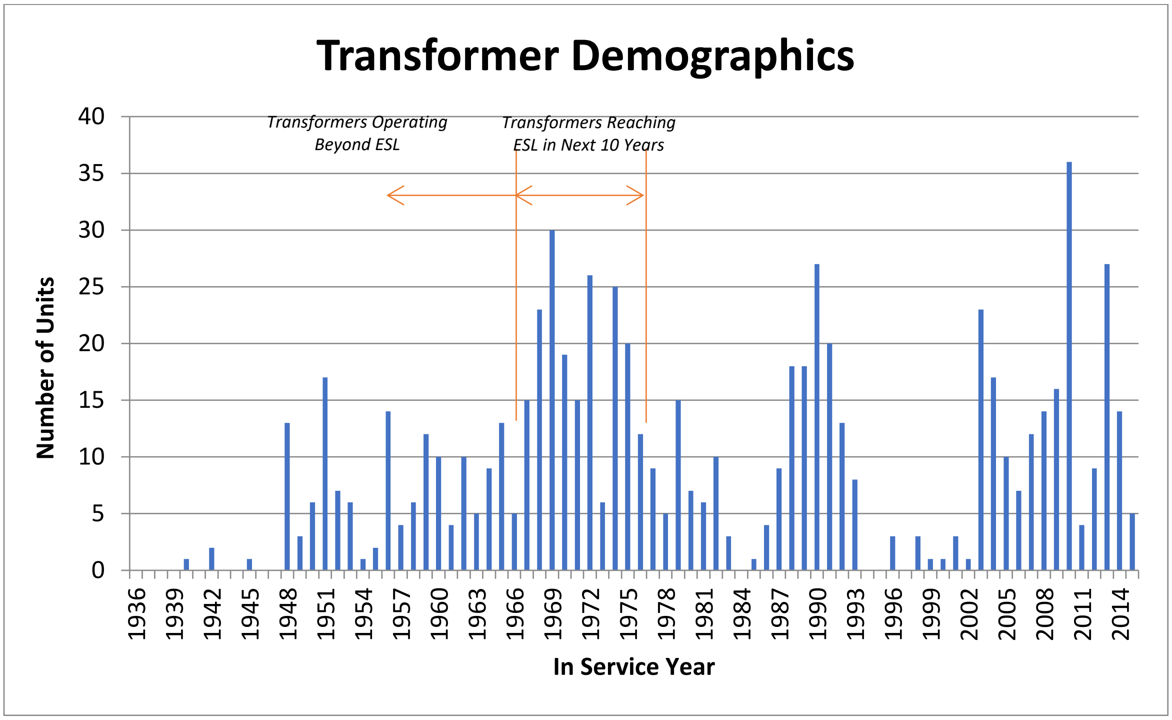
Asset Demographics

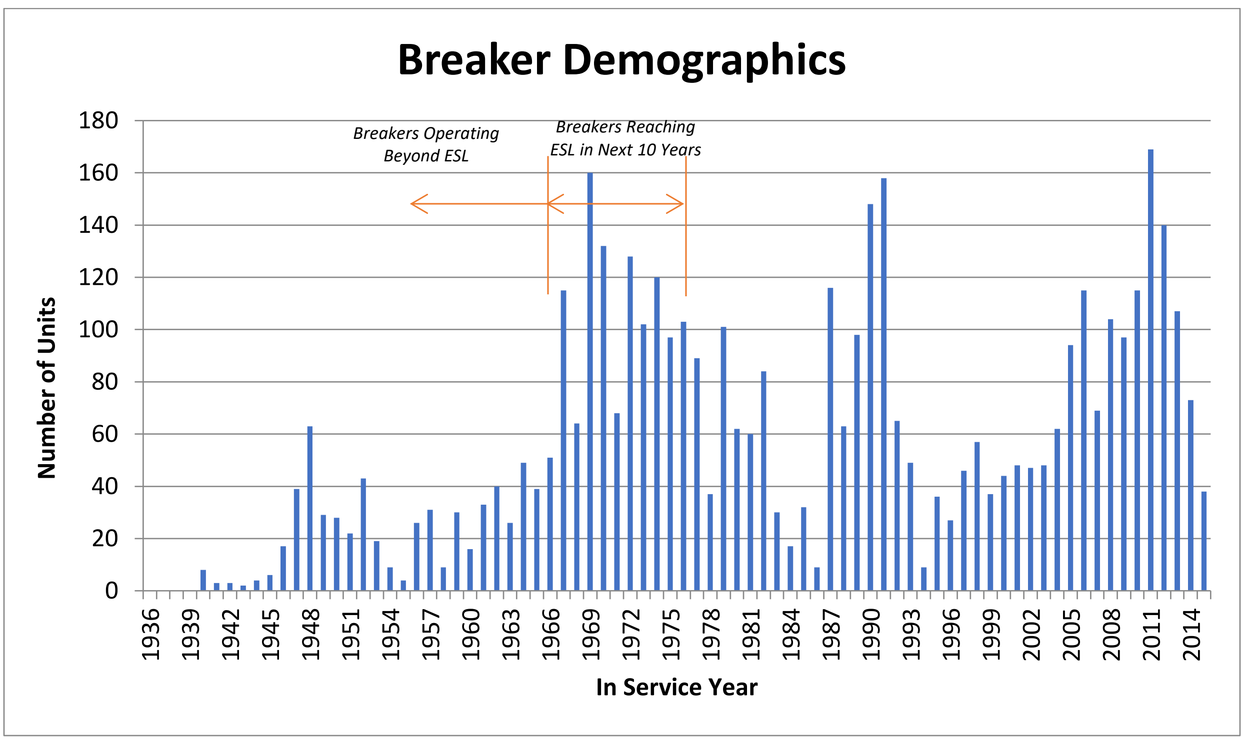
Hydro One only replaces assets that are in poor condition. The condition is determined through inspection and testing. However, a driving factor of equipment condition is age and equipment is more likely to require replacement as it ages.

The figures below show the number of units of each key asset (transformers, breakers and conductors) that has been put in to service since the 1930s. The figures show that a large number of key assets were put in to service between the mid-60s through to the mid-70s. In the next 10 years, those assets, representing a significant portion of Hydro One's total assets, will likely require replacement.

A sizable portion of each critical asset class is operating beyond expected service life.

Specifically, 28% of transformers, 9% of breakers and 19% of conductors are currently operating beyond their normal expected service lives.


Transformer Demographics
Transformers Operating Beyond ESL
Transformers Reaching ESL in Next 10 Years
Number of Units
In Service Year
40
35
30
25
20
15
10
5
0
1936
1939
1942
1945
1948
1951
1954
1957
1960
1963
1966
1969
1972
1975
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014


Breaker Demographics
Breakers Operating Beyond ESL
Breakers Reaching ESL in Next 10 Years
Number of Units
In Service Year
180
160
140
120
100
80
60
40
20
0
1936
1939
1942
1945
1948
1951
1954
1957
1960
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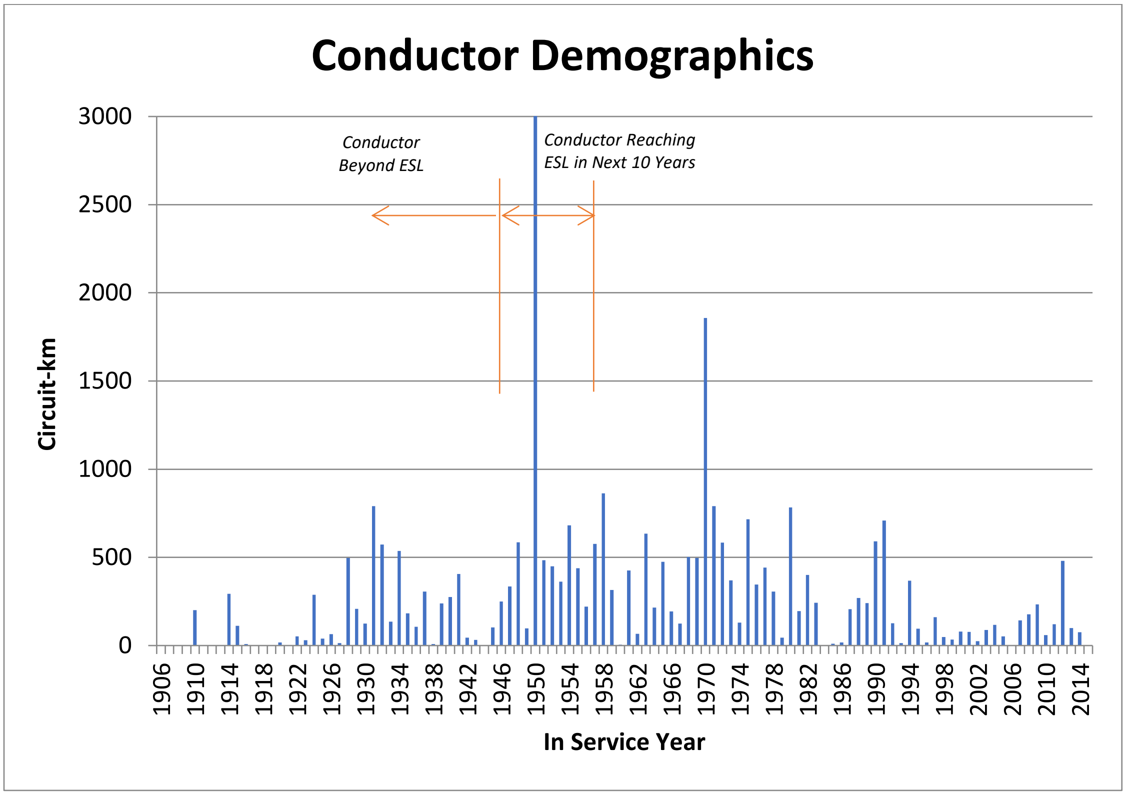
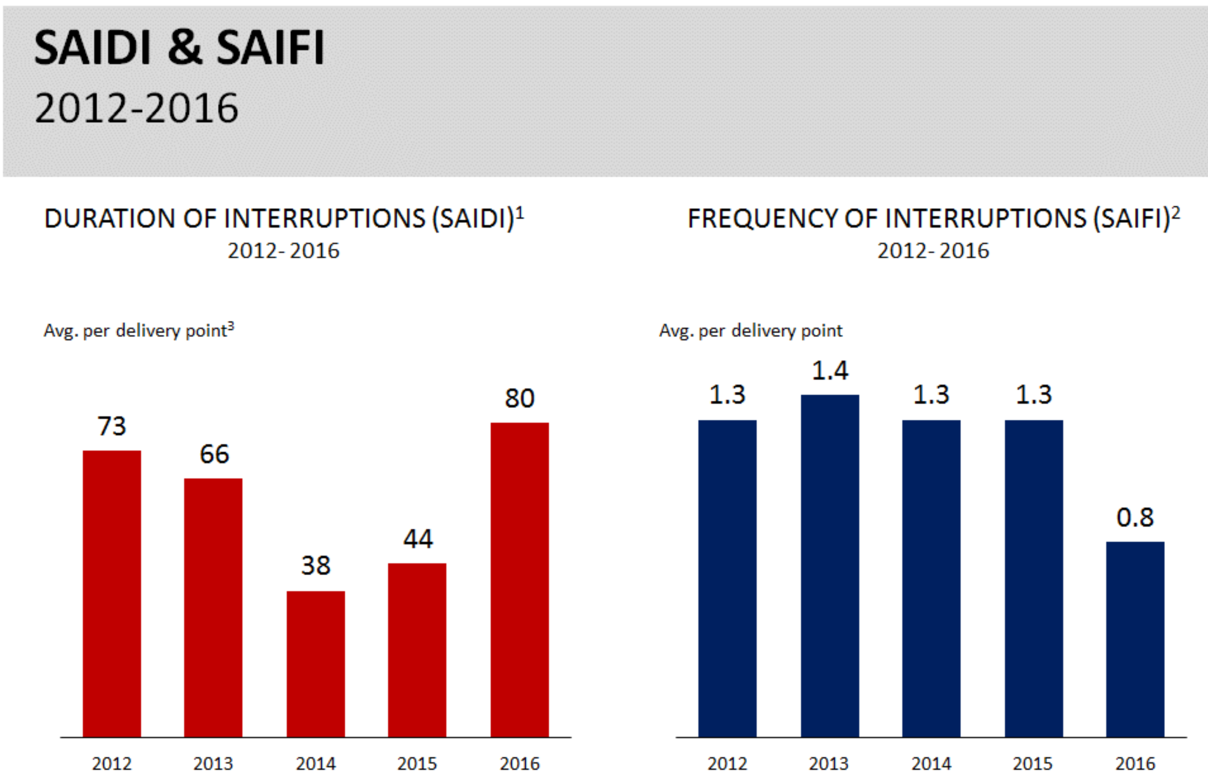
2014


Conductor Demographics
Conductor Beyond ESL
Conductor Reaching ESL in Next 10 Years
Circuit-km
3000
2500
2000
1500
1000
500
0
1906
1910
1914
1918
1922
1926
1930
1934
1938
1942
1946
1950
1954
1958
1962
1966
1970
1974
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014
In Service Year

Reliability

Service reliability is typically measured by the average number, or frequency, of interruptions (SAIFI) and by the average duration of interruptions (SAIFI). The figures below show Hydro One's reliability performance from 2012-2016. The number of interruptions (SAIDI) was relatively stable over that period, with an improvement in 2016. The average length of interruptions showed some variability over the last five years but appears to be trending upwards in recent years.

When it comes to Transmission reliability, Hydro One has performed well compared to its Canadian peers.



Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes 2013 GTA flood (extreme Force Majeure event - a natural consequence of external forces that are beyond reasonable control).
1. System Average Interruption Duration Index
2. System Average Interruption Frequency Index
3. Interface between the Hydro One transmission system and its load customers. Delivery points consist of: (a) all Hydro One owned step-down transformer stations' low-voltage buses, and (b) stations owned by end-use transmission customers, including LDCs and other transmitters operating at 115kV or higher.

Reliability: Issues Driving Performance

A significant driver of the reliability performance experienced by a customer is whether or not that customer is connected to a circuit with redundancy. Customers on a circuit without redundancy experience 10x the average length of outages as those that are connected to delivery point with redundancy. About 30% of Hydro One's delivery points do not have redundancy.

Aside from redundancy, equipment performance is the largest controllable factor when it comes to system reliability, contributing 42% of system *interruption*[1] minutes. Asset continue to age (e.g., 19% of conductors are now beyond *expected service life*[2] of 70 years) increasing the number of equipment related reliability issues.

Condition assessments have identified critical replacement needs, for example:

• 2,300 cct-km of conductors identified for priority replacement due to being at or near end of useful life[3].

• 9,100 steel towers at heightened failure risk due to depletion of their corrosion protection layer.

Hydro One continues to take action to mitigate reliability risk by:

• Managing equipment performance through robust, condition-based asset replacement programs.

• Reducing customer exposure to single-supply through improved planning and work processes.

1. Outages on the transmission system that interrupt the supply of energy to transmission customers.
2. The average time in years that an asset can be expected to operate under normal system conditions.
3. As asset-specific determination based on an asset's condition, criticality, performance, demographics, utilization and economics.

Reliability Risk Model

System reliability is often measured by the frequency and duration of power interruptions. These are historical measures or lagging indicators of performance because they are indicators of past asset investment decisions. While we can measure the historical contribution of equipment failures to system reliability, not every equipment failure leads to an interruption due to the redundancy of Hydro One's system. As a result, Hydro One cannot predict the impact of investments in equipment on SAIFI and SAIDI for the parts of its system that benefit from redundancy.

Reliability risk is a forward looking or leading indicator of system reliability performance. It is calculated using a model which forecasts the risk or probability of asset failure (or needed replacement), based on the historical relationship between asset age and retirement.

It is an outcome measure used to indicate the potential improvement or decline in system reliability as the result of an investment plan. This measure also serves as a directional indicator to inform the appropriate level of pacing of sustainment investments to avoid future decline in reliability. The reliability model is not used to identify specific asset needs and investments. Hydro One chooses the assets it replaces based on detailed assessments of their actual condition.

Delaying capital spending will, in time, result in more and more equipment outages. While redundancy ensures these outages do not immediately lead to customer interruptions, the outages will leave multi-circuit customers at risk of experiencing single-circuit reliability. Reliability risk helps to capture the expected risk customers face under these conditions.

Primary Causes Contributing to SAIDI

Configuration: Interruptions due to system configuration issues where there may have been no direct transmission system equipment outage involved. This includes, loss of system issues originating in adjoining systems including other utilities and customers.

Environment: Interruptions due to adverse environment condition that existed at the time of the outage including pollution, humidity, flooding, and smoke.

Equipment: Interruptions due to defective equipment that has suffered deterioration, faulty design or materials, or lack of maintenance.

Foreign: Interruptions caused by incursions by articles or events that would not normally part of the electricity system. These include such things as vandalism, animals, solar induction, and aircraft.

Human: Interruptions caused by human error including incorrect use of equipment, incorrect documentation or labelling leading to misoperation, faulty settings, damage caused by employees or contractors during a work activity.

Weather: Interruptions caused by adverse weather conditions such as lightning, freezing rain or hail, high winds, and extreme temperature.

Outcome Definitions

Customer Service

Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Environmental Stewardship

Identifying potential risks to the environment as a result of emissions from Hydro One's own operations, and investing in mitigation strategies to ensure compliance with all applicable environmental regulations consistent with the Government of Ontario and the Government of Canada.

Outage Restoration

Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Power Quality

Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and working together to implement mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity

Hydro One understands that customers expect it to look first for internal savings before asking customers to pay through increased rates. Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources.

Reliability

Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Safety

Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Customer Outcomes: Performance

Reliability

Reliability performance is typically measured by the average number of outages experienced by its customers (SAIFI) and the average length of outages (SAIDI). Hydro One's SAIDI and SAIFI performance has been relatively steady of the 2012-2016 period, as shown in the Reliability section of this background material.

Safety

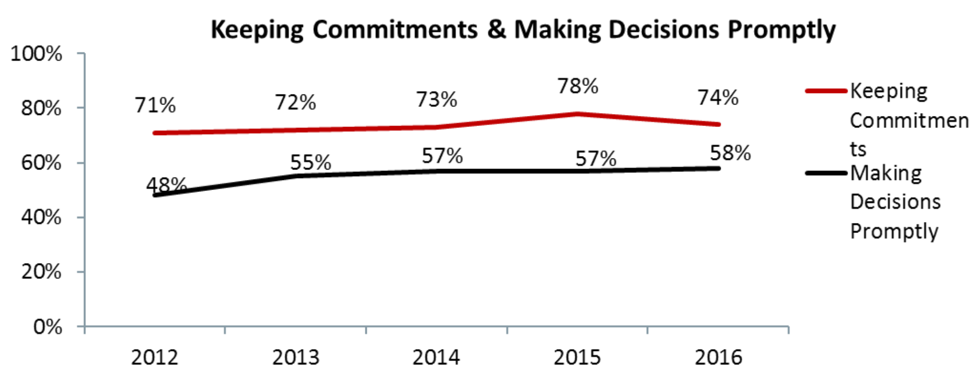
Public and employee safety are one of Hydro One's key strategic objectives. Hydro One's ultimate goal is strive towards zero safety-related incidents. The table below shows the number of serious work-related injuries/illnesses per 200,000 hours worked that have occurred from 2012-2016 along with the targets set by Hydro One. As shown in the table Hydro One has been outperforming its targets over the last five years.

Year	2012	2013	2014	2015	2016
Actual	2.3	2.5	1.8	1.7	1.1
Target	2.2	1.9	1.9	1.7	1.6

Customer Service

Every year, Hydro One conducts a survey of its large transmission customers. Among other things, Hydro One asks it's customers whether they feel Hydro One keeps its commitments to them and whether they feel Hydro One's staff makes decision promptly.

Results from 2012-2016 are shown below. The number of customers that believe Hydro One staff makes decisions promptly has increased by 10% over that period. The number of customers that believe Hydro One staff keeps its commitments has been consistent over that same period. Hydro One is committed to being more customer-focused and improving its customer service.



Detailed Scenario Summary

Illustrative Scenarios				
	A: Limited investment	**B: Decrease in current level of investment**	**C: Maintain current level of investment**	**D: Increase beyond the current level of investment**
5 Year Capital Investment	$1.8 B	$4.3 B	$6.6 B	$7.4 B
Reliability Risk	Increase in risk ~30%	Increase in risk ~10%	Decrease in risk ~10%	Decrease in risk ~15%
Long-term Reliability Impact	↓	↓	↑	↑*
Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)	29%	26%	19%	17%
Number of Key Assets With a High Probability of Failure by end 2023 †				
Transformers (12 in 2019)	14	12	9	9
Breakers (121 in 2019)	174	144	125	121
Conductors (329 circuit-km in 2019)	419 circuit-km	362 circuit-km	285 circuit-km	273 circuit-km
Impact on Future rates	Significantly higher future rate increases	Higher future rate increases	Level future rate increases.	Slightly lower future rate increases.
Average Annual Total Bill Impact – Distribution Connected Customer	0.09%	0.23%	0.35%	0.38%
Average Annual Total Bill Impact – Transmission Connected Customer	0.11%	0.27%	0.42%	0.46%
Average Annual Transmission Rate Increase	1.30%	3.30%	5.10%	5.60%

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits

† As predicted by the reliability risk model. Hydro One only replaces assets in end of life condition, as determined by detailed asset condition assessments.

NOTE: Transmission charges assumed to represent 8.3% of total bill for Transmission connected customers and 6.8% for Distribution Connected customers.

Glossary

Capital Investment: Money used by a business to purchase fixed assets, such as land, machinery, or buildings.

Circuit: An electrical connection involving metallic conductors that transmits electricity between 2 points.

Circuit Breaker: A switching device for that stops or allows the flow of electricity between electrical equipment.

Conductors: A metallic wire that conducts electricity.

Connection Capacity: Hydro One's ability to add new customers and/or additional load to the transmission system.

Customer Service: Enhancements to the transmission customer experience such as outage planning and operational communications, timely estimates and project execution for transmission connected customers.

Delivery Point: The point of supply where the energy from the system is transferred to customers. This point is generally taken as the interface between utility-owned equipment and the customer-owned equipment.

Expected Service Life: The average time in years that an asset can be expected to operate under normal system conditions.

End of Life: the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences.

Frequency Deviations: Fluctuations beyond the normal operating frequency range.

High-Voltage Transmission Network: Interconnected circuits that operate at 115kV and higher voltage.

Interruption: A stop in the flow of electricity to a customer.

Key Assets: Major types of transmission assets defined as transformers, circuit breakers and conductors.

Long-Term Reliability: Reliability performance beyond the 5 year rate filing period.

Multi-Circuit Systems: Systems where power delivery points are supplied by more than one circuit.

Outage: Unavailability of electrical equipment due to disturbances, equipment maintenance, or equipment malfunction. Outages do not necessarily lead to interruptions for customers if there are backup or redundant facilities to maintain electrical supply.

Outage Restoration: Provisions to ensure timely and efficient response to failures, unplanned outages, or imminent risks to the transmission system to minimize customer interruption and prompt restoration to normal operating conditions.

Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Power Quality: Delivering electricity within established voltage and frequency tolerances with a smooth voltage curve waveform. Assessing customer concerns and implementing mitigation plans to address and rectify power quality issues for transmission connected customers.

Productivity: Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and enabling more efficient use of resources.

Redundancy: The inclusion of duplicate components to the system so that delivery points have multiple simultaneous connections. The purpose is to reduce the possibility of interruption in case of component failure.

Reliability: Maintaining the uninterrupted operation of the transmission system for all customers by sustaining the existing assets, replacing assets that are in poor condition and addressing transmission system performance outliers.

Reliability Risk: An index that provides leading directional indication of overall system reliability performance based on probabilistic risk of asset failures.

Safety: Eliminating and mitigating risk to public and employee safety in the operation of the transmission system.

Short-Term Reliability: Reliability performance within the 5 year rate filing period.

Single Circuit Systems: Delivery points that rely upon one circuit for the delivery of power. If that circuit fails then power is interrupted.

Sustainment Capital: Capital Investments made in order to maintain the current expected level of functionality and capability of system.

System Average Interruption Duration Index (SAIDI): The average outage duration for each customer served.

Transformer: An electric power equipment that changes the electricity voltage level. In Ontario, the transmission level voltage are typically transformed from 500kV to 230kV and 230kV to 115kV. To supply customers, 115kV and 230kV transmission voltages are transformed to distribution level voltages.

Transmission Stations: An electrical facility that connects a number or transmission circuits and transformers and performs a “hub” function for the flow of electricity across a region.

Transmission System Performance Outliers: Individual assets or sets of assets whose performance is significantly different than the average performance of the system as a whole.

Voltage Waveform: The shape of the 60Hz voltage curve observed at the supply point.

Stakeholder Session

Transmission Customer Engagement

In preparation for Hydro One's 2019-2023 Tx Application

March 29, 2017

Purpose of Stakeholder Session

Obtain input from Stakeholders as to the form and substance of Hydro One's upcoming Transmission Customer Engagement Process.

Why Customer Engagement

- Consistent with Hydro One's evolution to becoming a commercial entity: focus on customers, greater accountability for performance outcomes, and driving continuous improvements in efficiency and productivity company-wide.

- Inform the development of Hydro One's Transmission System Plan and Transmission Rates Application for 2019-2023 (to be filed Spring 2018)

- Meet or exceed the OEB's expectations pursuant to the Renewed Regulatory Framework (RRF) and meet the filing requirements relating to customer engagement from Chapters 2 and 5 of the Filing Requirements and the Handbook to Utility Rate Applications.

OEB Customer Engagement Filing Requirements

- Chapters 2 and Chapter 5 of the Filing Requirements and the Handbook require:
  - Engagement process be **designed** to identify customer needs and preferences;
  - Customer needs and preferences be **identified** as a result of the engagement process; and
  - Outcomes of the engagement process **inform** the asset planning process; specifically, how customer needs and preferences are **integrated** into an investment plan and how the **trade-off** between outcomes and costs has been made.

Customer Engagement – Hydro One Experience

- Hydro One has conducted two full customer engagement processes to support its
  - 2017 - 2018 Transmission Revenue Requirement Application, and
  - 2018 - 2022 Custom Incentive Distribution Rates Application.
- In both applications, the customer engagement process informed Hydro One's judgment on where customer needs and preferences, customer rates, and asset needs are aligned in the respective TSP and DSP.

Transmission: What We Heard

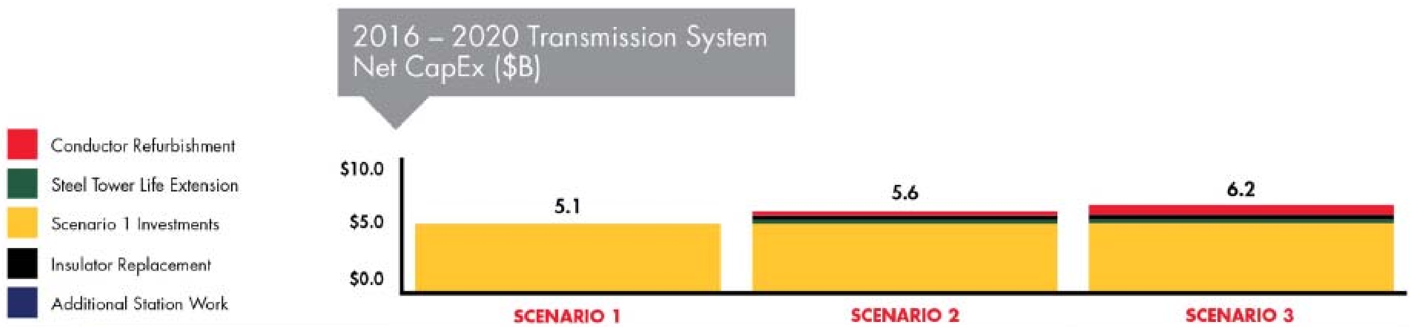
- Timing: engagement did not take place early enough to have impacted business decisions;
- Participation Rates were low
- Did not engage with all customers who will be impacted by the proposed rate increases (i.e., end-users of LDCs);
- Reliability Performance: top quartile status not adequately communicated;
- Information confusion;
- Investment Scenarios: not enough options, no zero rate option;
- Outcomes: reliability risk model not accepted as sole outcome measure; risks exaggerated;
- First Nations and Métis not represented; and
- Purpose of Engagement: customers may not have understood what was being asked of them.

Your Thoughts and Input

- Number of scenarios and how scenarios should be differentiated: rate impact, outcomes valued by customers, or size of 5-year capital envelope;
- Identification of outcome measures;
- How to capture needs and preferences of Distribution-connected end-use customers (i.e. end users of transmission services who are not transmission-connected customers per the Transmission System Code);
- How to capture needs and preferences of First Nations and Métis customers;
- Minimizing information Confusion;
- Timing;
- Participation Rates; and
- Clarity of Purpose
- What other issues should we be aware of?

Recall the "scenarios" we previously used?

OVERVIEW OF THREE POTENTIAL SCENARIOS



		SCENARIO 1	SCENARIO 2	SCENARIO 3
Capital Spend	Sustainment ($B)	3.5	4.0	4.6
	Development ($B)	1.1	1.1	1.1
	Other ($B)	0.5	0.5	0.5
Expected Outcomes	Frequency and duration of interruptions	▲ Expected increase in line-related interruptions	▶ Some increase in lines risk offset by limiting unplanned outages and improved station performance	▼ Reduce risk from lines and continue to limit exposure to unplanned outages
	Reliability risk[1]	▲ Risk is expected to increase	▶ Current risk expected to remain essentially unchanged	▼ Risk is expected to decrease
Rates	Transmission rate impact (Compound Annual Growth Rate for 2017 – 2020)[2]	▲ ~5.8%	▲ ~6.3%	▲ ~6.8%

1. Reliability risk is a probabilistic calculation based on asset demographics and the historical relationship between its age and its failure or replacement.
2. Excludes impacts of potential changes in load forecast and any potential change to operations and maintenance spending.

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Scenarios

Issue: Number of scenarios and how scenarios are differentiated.

Straw Dog: Four scenarios – Differentiated by size of Rate Increase (%) and resultant Outcomes

Scenario #1: Investment plan resulting in zero percent rate increase

Scenario #2:
Scenario #3:
Moderate rate increases with different investment plans and outcomes

Scenario #4: Investment plan resulting in a higher rate increase.

As in previous engagements – the scenarios are intended to represent a range of alternatives, and are not suggested as discrete choices

Scenario Issues

- Is it appropriate to differentiate based on rate increase or should other differentiators be used?
- Are 4 scenarios the right number to go with?
- Is a 0% rate increase an appropriate starting point for scenarios?

Outcome Measures

Issue: Which outcome measures are appropriate?

Options:
Reliability Risk
T-SAIDI
T-SAIFI
Outlier Performance
Safety
Environmental Impact

- Other outcome measures?
- How many measures should be discussed?

Customers Engaged

Issue: How to capture needs and preferences of Distribution-connected end-use customers (i.e. not -transmission-connected)

Straw Dog:

Since LDCs serve these customers, rely on LDCs to represent their customers' needs and preferences to the Transmitter, based on

- their own customer engagement work (including Hydro as well as other LDCs)
- Results of LDC conducted surveys

Alternatives:

- Survey LDC customers directly (potential confusion?)
- Review LDC customer engagement evidence filed with the OEB
- Separately survey LDCs as representatives of their customers

Other approaches?

First Nations and Métis

Issue: First Nations and Métis Engagement

Straw Dog: Rely on the customer engagement work of Hydro One Distribution and other LDCs

» Results of LDC conducted surveys
» LDC customer engagement evidence filed with the OEB
» Survey of LDCs as customer representatives, focusing on First Nations and Metis customers specifically

Alternative: Engage directly with First Nations and Métis

Other approaches?

Information Confusion

Issue: Information Confusion

Specific information to clarify with customers:

– End of Life
– Expected Service Life
– Role of age vs condition
– Reliability
– Reliability Risk
– Service Interruption vs Outage
– Hydro One's historical reliability performance

Other Issues

Timing: Hydro One plans to conduct its Tx Customer Engagement in April- May 2017, and complete the engagement by the end of May 2017, to allow it to commence development of the investment plan

Participation Rates:

Recognizing customers' time constraints, instead of 3 discrete waves (one-on-one meetings, workshops, and an on-line survey), offer customers a choice of channels to provide their needs and preferences

Purpose: Spend more time explaining the purpose of the engagement, its role in the process, the need to balance competing priorities, and any planning constraints facing Hydro One in preparing an investment plan

What other issues should we be mindful of?

What other input or advice can you offer?

Hydro One Networks Inc.
2019-2023 Transmission Rate Application

Transmission Customer Engagement Stakeholder Session

Summary Report

Delta Chelsea Hotel
Toronto, Ontario

March 29, 2017

Session Overview

The session began with an introduction provided by Jody McEachran, Regulatory Affairs, Hydro One. Mr. McEachran highlighted that the purpose of the session is to engage stakeholders in an interactive discussion about the upcoming Transmission Customer Engagement Process being planned in preparation for the 2019-2013 Transmission Rate Application.

An overview of the agenda was then provided by the session facilitator Tracey Ehl, Ehl Harrison Consulting Inc. All stakeholders introduced themselves, including their names, organization and position. Introductions were followed by a presentation by Oded Hubert, Vice President, Regulatory Affairs, Hydro One Networks.

Participants were encouraged to ask questions and provide feedback throughout the delivery of Mr. Hubert's presentation. This report is a synthesis of the discussion from the session, organized by key question. In each section, stakeholder comments are numbered, with the responses, by either participants or staff, directly following. Comments and questions received after the session are not reflected in this report.

A list of participants can be found in Appendix A.

Stakeholder Discussions

A. **Transmission Customer Engagement** (Oded Hubert)

Summary: Mr. Hubert highlighted the importance of the customer engagement component of the upcoming Transmission Rate Application and emphasized that the session was aimed at gathering the thoughts and insights of stakeholders on the form and substance of the engagement activities. Mr. Hubert recapped that Hydro One has conducted two full customer engagement processes to support recent applications. He reviewed key process-related challenges from these two processes and sought input and discussion about approaches to addressing them. Key topics included scenarios, outcome measures, engagement with distribution-connected end-use customers, First Nation and Métis engagement, information confusion, and other issues.

There were a number of key discussion themes that arose from the conversation, as follows.

- *It is important to identify the purpose of the engagement (build plan or tweak plan) and then identify the approach.*
- *Stakeholders felt strongly that the OEB's decision regarding the current (2017-2018 Transmission) application that is before the Board would be important context to this engagement process, and proceeding prior to the decision is not ideal.*
- *The scenarios may not be the most effective starting point for the engagement, because this quickly narrows stakeholder focus, away from system considerations of the application.*
- *The schedule, as presented, is very aggressive. There may be some benefit to continuing the engagement process while the application preparation is ongoing.*
- *Additional (local/granular) information and context (including about past spending and performance trends) should be provided to customers in order to engage in more meaningful feedback/dialogue. The story has to be linked to customer experience outcomes.*

- *There would be great benefit for this and future applications if focus was given to educating/explaining key terms and business practices.*
- *Any engagement approach has to be balanced with the potential for consultation fatigue.*
- *With respect to understanding the needs and preferences of LDC customers, while it is possible to learn from engagement done by LDCs (through data mining), it is still important that Hydro One conduct an engagement processes to hear from end users.*
- *Industry best practices are not readily available. To overcome this, one approach may be to seek the input of a small sample of customers about the engagement process. This may provide valuable input to how process design could support their engagement and more effectively meet Hydro One's application needs.*

General discussion:

1. Is proposed Rate Application expected to be aligned with the Transmission System Plan that was filed with the 2017-2018 Application?
    - Yes.

2. What was the participation rate of LDCs in the last Tx Engagement? The reason for this question is to discern whether the LDCs represent the interests of their customers.
    - Participation rates are not available at this time.

3. Customers need to understand how reliability is affected by Transmission and Distribution. Where (in which system) should the investment be?
    - This was not explored in the previous engagement efforts.

4. Slide 6, what we heard, should include mention of the feedback related to the difference between multi circuit and single circuit systems.

5. Hydro One should wait for the OEB decision before talking to customers again.
    - This will assist in defining parameters and scenario building.
    - Results from Board decision will provide direction that may point you in a different direction.

6. "I'm not sure how you can go to your customers until the decision is known."

7. It is premature to start working on scenarios at this point. Hydro One should focus on designing the process and this will inform how the scenarios are developed.

8. Hydro One should also seek feedback on the incentive regime.

9. Providing customers with an understanding the historic investment strategy and spending will help to inform a good discussion about the future.
    - An educational component will be very important.

How many scenarios should be utilized? Is this the right approach?

1. While scenarios are important, Hydro One may want to consider a more organic process.

2. I have an issue with scenarios. Customers pick the scenario that will benefit them.

- (Hydro One staff) When we talk to customers, they all bring their own issues and preferences which are focused on the individual customer.
- Responses are diverse among customers.
- Scenarios outcomes should be refined by customer.

3. During the previous engagement, was data presented on different types of circuits?
    - (Hydro One staff) Data was presented at a network level. Greater granularity may be of assistance. We have 10 geographic areas across the province. This will provide information relevant to specific groups. This information base could help inform the engagement process

4. Momentary interruptions are a big issue for some industrial customers.
    - (Hydro One staff) Power quality is a 'fuzzy' issue but we had great feedback from our customers on this. As a result, we are focusing more on this in our business plan.

5. People (customers) want to better understand what investment is being done on 'my network' on 'my supply'.

6. Scenarios should show customers what the outcome is for different levels of spending and for spending the same amount (i.e. the middle scenarios). For the middle scenarios, there are different outcomes depending on where the spending is done. Outcomes need to be refined to demonstrate impact and delineated by region.

7. It is not clear to me how Hydro One incorporates a five-year plan (into two-year scenario) and is able to incorporate the outliers? My sense is that there should be more latitude to respond to outliers. Scenarios are 'grab-bags' with a certain amount of latitude for the opportunity to discuss the trade-offs

8. Customers need to understand the base scenarios (and performance trends over time). Under Scenario 1, customers need to see why a continued level of spending is not adequate given past performance. Why is a further increase needed? Under Scenarios 2 and 3, understanding performance trends historically and the impact moving forward with the spending is important for customers to understand. Consider what a rate reduction scenario (and the associated performance trends) looks like.

9. More clarity on outcomes is needed. Information should be provided about what is needed for a local area vs. system wide needs.
    - Take it to a level that we can see reliability risk.
    - Scenarios 2 and 3 will quickly become the focus.

10. The way that the issue is framed will change the feedback/outcome from stakeholders.
    - Reliability risk is not well understood.

11. Hydro One should start with consideration of who the customers are and what are the outputs that are important to them. This should inform the design of a survey that is most appropriate for them.

12. It is important to start with scenario 1 and to include explanation of the details that are contained within it, such as whether it is based on last five year system wide performance or whether it is disaggregated.

- What are you going to project for end of life assets? This is an important part of the baseline.
- More clarity is needed about where we are starting from.

13. There is concern about providing customer with end of life metrics, which can be misleading or misunderstood.

14. Are you still continuing with reliability risk model?
    - Yes, Hydro One is continuing to develop the tool, along with exploring its role. It was developed as an outcome measure.

15. Hydro One should still be using a reliability risk model.

16. What I heard about the last engagement process was that there is a need to understand performance in the past, what spending has been done, and why you need the extra funding. This data/information will help get support.
    - Why don't you demonstrate to customers what a reduction in rate would result in? Customers could then understand outcome.

What outcome measures are appropriate?

1. How can we differentiate reliability? How can we better understand the customer perspective?
    - During consultations, it was suggested more granular information was preferred.
    - Aren't there meetings throughout the year with large customers to discuss the key issues? Do customers want to get additional details?
    - (Hydro One staff) When meetings happen on a monthly basis or ad hoc, the focus of meetings is often about specific events at the customer level, with less focus (if any) at the system level. Customers appreciate understanding the network but then close in on their specific context.

2. Outcome measures that speak to equipment performance, number of customer interruptions, number of customer interruption hours are important and understandable.
    - T-SAIDI and T-SAIFI are not necessarily the most accessible measures to understand in a meaningful way.

3. There were outcome measures discussed (at hearing) that are worth considering, including: Power quality; Number of customer interruption hours/year; Equipment unavailability, failures; Outage versus interruption.

4. The measure should be T-SAIDI and T-SAIFI, but explained in a different way.

5. With respect to geography, what do you do with this information? Will it be used to direct funding? Data on reliability in each geographic area would be very good data to have.
    - (Hydro One Staff) It is a good idea to provide detailed, localized data.

6. Equipment unavailability is an important metric to convey information about equipment failure, how long it is unavailable for and why.

7. When I think of (engagement) slides from last time, slides on T-SAIDI and T-SAIFI showed an average over the last five years. It would have been interesting for customers to see the historic trends, along with looking at five years into the future. This is how you can build up the story for the scenarios.

8. Concern was expressed about showing percentage of outages. There should be an absolute number.

9. If the reliability risk model is not being used to make decisions, it is not that valuable to customers.
    - (Hydro One staff) Hydro One still views Reliability Risk as a meaningful outcome metric.

10. What are the metrics that Hydro One is watching when developing programs? These should be the ones that are also the focus of customer engagement.

11. Hydro One should start by looking at the experience with its own LDC and share this information.

12. It would be very helpful to ask customers to identify meaningful metrics to them. They will ultimately want to understand what they will experience.

How can Hydro One capture needs and preferences of Distribution-connected end-use customers?

1. First, the purpose has to be well understood. Is it to drive the plan development, or to tweak it after the plan has been developed? (Hydro One staff explained that it is the former.) Engage customers where there is material consideration.

2. Concern was expressed about LDCs representing their end-use customers in this type of engagement scenario.
    - They have their own incentives, so care has to be exercised.
    - Mining data from LDCs is challenging, and may not yield useful information for the purpose.
    - Surveying customers directly may be a better approach, however it may lead to confusion.

3. There is a large information gap related to Hydro One business terms and concepts. For example, what is a major event?
    - It is important to get higher level information from customers.
    - You do need to talk to end users but don’t ask how money should be spent.
    - Need to think about what we want to know from end users.

4. If you talk to customers about reliability and rates, input will be contextualized by local inputs/outcomes. This could assist to get sense of the level of satisfaction and then this can inform planning.

5. The customer data collection by LDCs has been fairly rudimentary and self-serving.
    - It is important to understand what the LDCs are saying and their perceptions of inputs.
    - As we move forward, discussion should be more organic.

6. Depending on who you talk to you, there will be different perspectives.

7. What do you want to do with the customer data? If it is to drive the plan we have an issue because we are not talking to the right people. If it is to tweak then maybe it is not as big of an issue
   - Not sure where the Board is going with engagement, as they seem to want engagement but it doesn't seem to impact decisions.
   - (Hydro One staff) For clarification, the purpose of engagement is to inform the plan prior to its development.
8. What is the different between informing and tweaking
   - (Hydro One staff) "Tweaking" is presenting the plan to customers and gathering feedback. Informing is to get input into the development of the Plan

How can Hydro One effectively engage First Nation and Métis?

1. Why does Hydro One not use process defined in the 2007/2008 hearing? That was a robust process and should be utilized again.
   - (Hydro One staff) Hydro One did engage with First Nation and Metis at that time. That was a very large development plan for the entire province with impact on both t on and off-reserve land, but now we are in a sustainment' approach, so a different engagement approach was taken.

2. What do you think would be different in this customer group?
   - (Hydro One staff) Issues are wide ranging. Reliability is important, as are land rights, arrears, affordability, the proposed First Nation rate, past grievances, and past issues with Hydro One.
   - Other than these issues, what would inform a transmission plan in particular for this customer group?
   - (Hydro One staff) Hydro One would need to be clear on what the scope is of a Transmission-focused First Nations and Metis engagement.
   - Certain types of spending already involve engagement with these communities (i.e. Section 92).
   - (Hydro One staff) If we included First Nations in the Customer Engagement, this would not be the only forum, but we would be adding another level of discussion with First Nations.
   - How are First Nations and Métis engaged in regional planning? The IESO has set up local advisory committees for regional planning.
   -
3. This customer group should be engaged differently, through a lens of developing economic and social opportunity through the power system.

4. Best practices have been previously shared at a hearing and should be implemented here as well.

How can information confusion be addressed?

1. There needs to be an information/educational component to this engagement process, if the discussion is to be meaningful. For example, people don't understand the difference between end of life and expected service life.

2. The difference between service interruption and outage is confusing. Hydro One may not even need to speak about outages. Customers are most interested in service interruptions.
    - (Hydro One staff) When we talked to transmission customers, they do seem to understand this difference, as they interact with Hydro One on both equipment outages and interruptions.

3. Whatever information you convey to tell the story should include outcomes. The story has to flow into the outcomes.
    - (Hydro One staff) We are planning on informing the customer engagement process with new data but not any new concepts, such as reliability risk, which was introduced in the last engagement process.

Timing

1. Participants emphasized the importance of waiting for the (Board) decision before starting this engagement process, as one will inform the other.

2. Has the engagement consultant already been chosen?
    - (Hydro One staff) A vendor has not been chosen. It is anticipated that the engagement will include a number of channels, giving choice to customers on how they can provide their input.

3. A market research approach is more appropriate than opinion polling for this process.

4. How does the information that is collected get blended together?
    - (Hydro One staff) This is a real challenge. Education/framing is a huge undertaking, requiring time spent with customers. How much time can we actually get people to spend with us?
    - (Hydro One staff) We will be thinking about how can we segment our customers and provide the information that they need so they can provide input to better inform our plan.

5. Won't the anticipated decision impact plan going forward?
    - (Hydro One staff) Definitely. Customer Engagement is to inform the plan but we will also be informed by the Board Decision. There is a risk both to engaging early and to waiting.

6. (Hydro One staff) Should we continue engagement process into plan development phase?
    - An iterative process would be great, as long as all of the information gathered is incorporated back into the plan. An end date will be needed in this regard. Consider June timing or after the changes from the Fair Hydro Plan.

Participation Rates

1. The consultant hired will be able to assist with identifying and achieving good participation rates.

Purpose

1. Whatever you do will be more meaningful if you are able to provide them more information.

2. How are you framing the purpose? Inform plan or define spending?
   - (Hydro One staff) This engagement will inform the development of the plan.

What other issues should we be mindful of? What other advice do you have?

1. Is it Hydro One's position that you have to do a five-year application?
   - (OEB staff) Yes, this is the minimum period for a Custom IR.

2. Does anyone in North America do Transmission Customer Engagement? Can we look at best practices?
   - Staff and participants were not aware of current best practices. It was indicated by a participant that a lot of research was carried out in the past prior to the break-up of Ontario Hydro.

3. Make sure the engagement is meaningful to Hydro One and to customers.

4. What future Stakeholder engagement activities do you anticipate for this Application?
   - (Hydro One staff) This is still in planning stages, but information will be sent to you once it is known.

5. Is there an opportunity for Hydro One to meet with a small number of large industrial customers, LDCs and explore what approach to engagement might be meaningful to them?
   - (Hydro One staff) Yes. Also, LDCs were included in the invitation to participate in today's discussion, but due to schedule conflicts, none were able to attend.

Session Wrap-up

All stakeholders were thanked for their participation. Additional questions and/or comments were invited following the session.

Appendix A: List of Participants

Andrew Blair – Power Workers' Union
Bill Harper – VECC
Bohdan Dumka – SEP
Cary Ferguson – Anwaatin Inc.
Chris Codd – OEB Staff
Frederick Belanger – HQEM
Hanna Smith – IESO
Harold Thiessen – OEB Staff
Julie Girvan - CCC
Marion Fraser - BOMA
Mark Rubenstien - SEC
Megan Lunh - IESO
Roger Higgin – Energy Probe
Shelley Grice – AMPCO
Vicki Power – SEP

Hydro One
CK Ng – (Planning) Hydro One Networks
Erin Henderson – (Regulatory Affairs) Hydro One Networks
Jeffrey Smith – (Planning) Hydro One Networks
Jody McEachran – (Regulatory Affairs) Hydro One Networks
Oded Hubert – (Regulatory Affairs) Hydro One Networks
Scott McLachlan – (Planning) Hydro One Networks
Spencer Gill – (Customer Service) Hydro One Networks
Steven Vetsis – (Regulatory Affairs) Hydro One Networks
Warren Lister – (Customer Service) Hydro One Networks

Tracey Ehl – Facilitator
Jodi Ball – Note taker

ATTACHMENT 4: RELIABILITY RISK SUMMARY

The reliability risk model was introduced by Hydro One in 2016 to provide a method for demonstrating the value of sustaining investments to customers and to provide a directional indicator to assess the effect of an investment portfolio on reliability.

It is a simplified method to communicate risk to customers and stakeholders. It is not used to identify specific asset needs or justify investments. Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized in accordance with Hydro One's investment planning approach described in TSP Section 2.1, Investment Planning Process.

In order to solicit impact from customers the reliability risk model was one of several measures used in the 2017 Customer Engagement Survey to quantify and communicate the outcomes associated with various investment scenarios. Customer input was a key factor that informed Hydro One's overall investment plan, which underpins this rate application. During customer engagement, there was no preferred investment plan. The risk prioritization investment planning methodology which was used to prioritize the investments underpinning the TSP[1] was under development and not available as an alternative communication tool. As such, the reliability risk model was the method used to communicate risk to customers.

In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco

[1] Detailed in TSP Section 2.1.

Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

Hydro One is aware of reliability forecasting models however comprehensive assessment and testing of these models are not complete. Hydro One has completed substantial work in developing and refining hazard functions of its assets as discussed in TSP Section 1.4 which form a good baseline for forecasting investment requirements. Hydro One will continue to explore and assess other reliability forecasting models to quantify the outcome of its investment plan in the future.

INNOVATIVE RESEARCH GROUP

2018 Large Tx Customer Satisfaction

Understanding Dimensions of Satisfaction and Dissatisfaction

Hydro One
483 Bay Street
Toronto, ON M5G 2P5

hydro one

October 2018 :: Review Draft

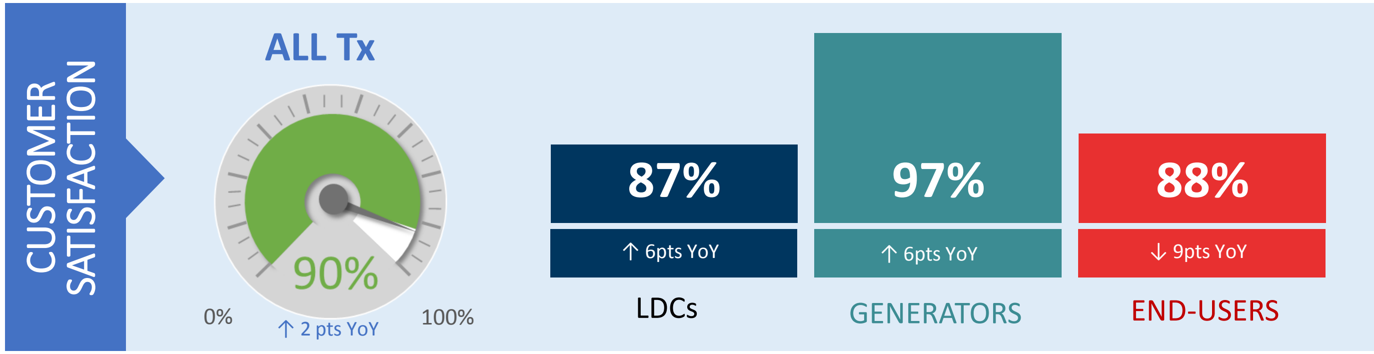
Summary: *2018 LTX Report*

1. **Hydro One's CSAT continues its upward trend and reaches an all-time high, with marginal improvement among Generators and LDCs effectively neutralizing a significant decrease among End-Users.**

2. ***Customer Service* is the dimension on which Hydro One has the highest levels of satisfaction.**

3. ***Product Quality & Reliability* shows room for improvement, particularly on customers' experience of unplanned outages.**

4. **Environmental controls were introduced in 2018 to gauge the impact of economic and political factors that are outside of Hydro One's influence.**



HIGHEST PERFORMING ATTRIBUTES

- Overall customer service (93%)
- Communication methods (93%)
- Service received from account executive (90%)
- Accessibility (87%)
- Understanding business needs (85%)

OPPORTUNITIES FOR IMPROVEMENT

- Duration of unplanned outages (48%)
- Number of unplanned outages (50%)
- Good value for money (58%)
- Communication during outages (62%)
- Time to restore power (66%)

Insights: Drivers of CSAT

- *Customer Service* is the strongest driver of CSAT. This factor has an emphasis on communication:
  - communication methods
  - overall communication
  - service from Key Account Executive
- Being able to recall an unplanned outage has a negative effect on CSAT, which highlights the need to improve customers' experience of unplanned events.

Key Metrics of Satisfaction

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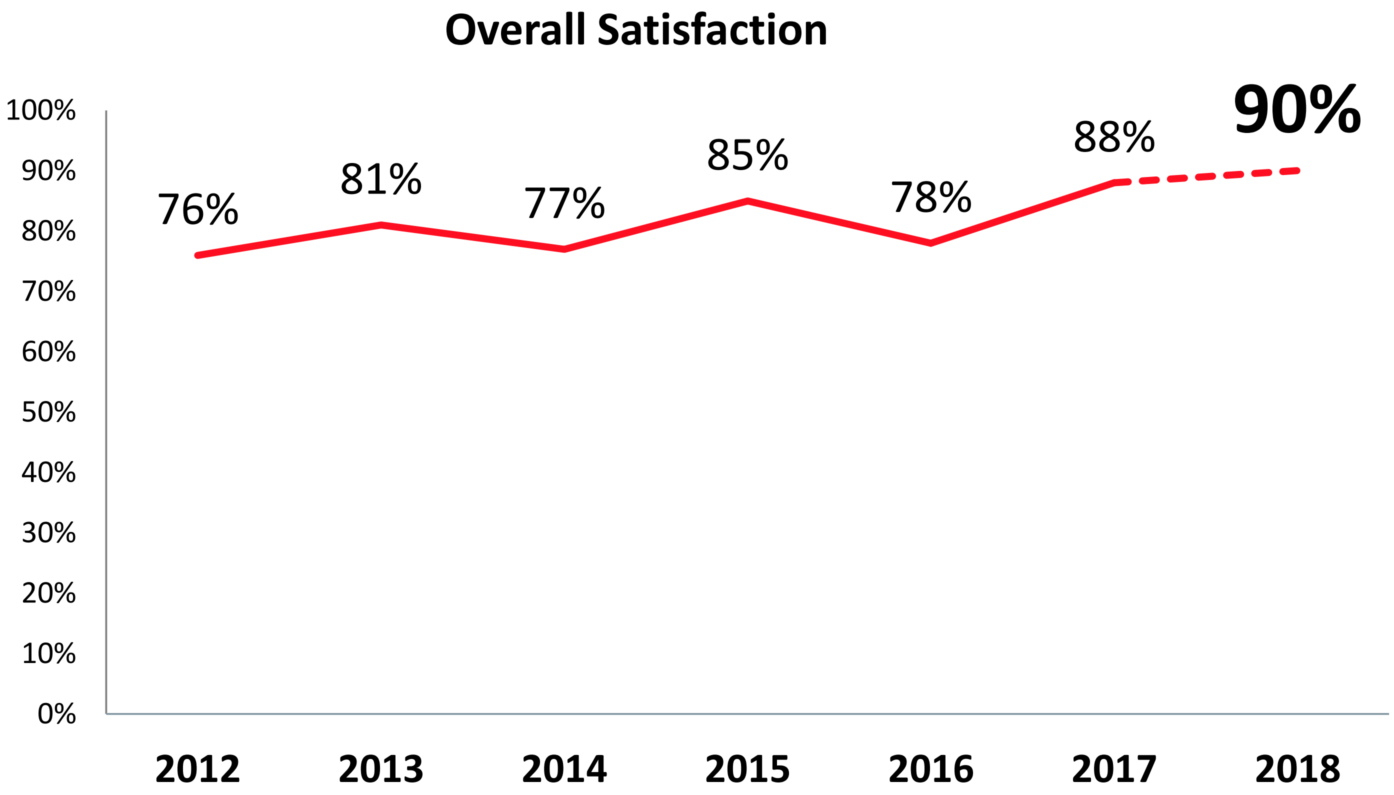
Overall Satisfaction (All Tx): Overall satisfaction continues to trend upwards from 2016, landing at an all-time high of 90%

Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112; valid responses n=112]



Key Insights

- Overall satisfaction continues to trend upwards from 2016, landing at an all-time high of 90%.
- Because there were no respondents who said “don’t know” to this question in 2017 and 2018, the results are reliably trackable. Therefore, we know that there has not been a significant change since 2017.

NOTE: Response "Don't know" (0% in 2017 & 2018) was excluded from this analysis. Statistically significant changes compared to the results from 2017 are indicated by ↑↓.

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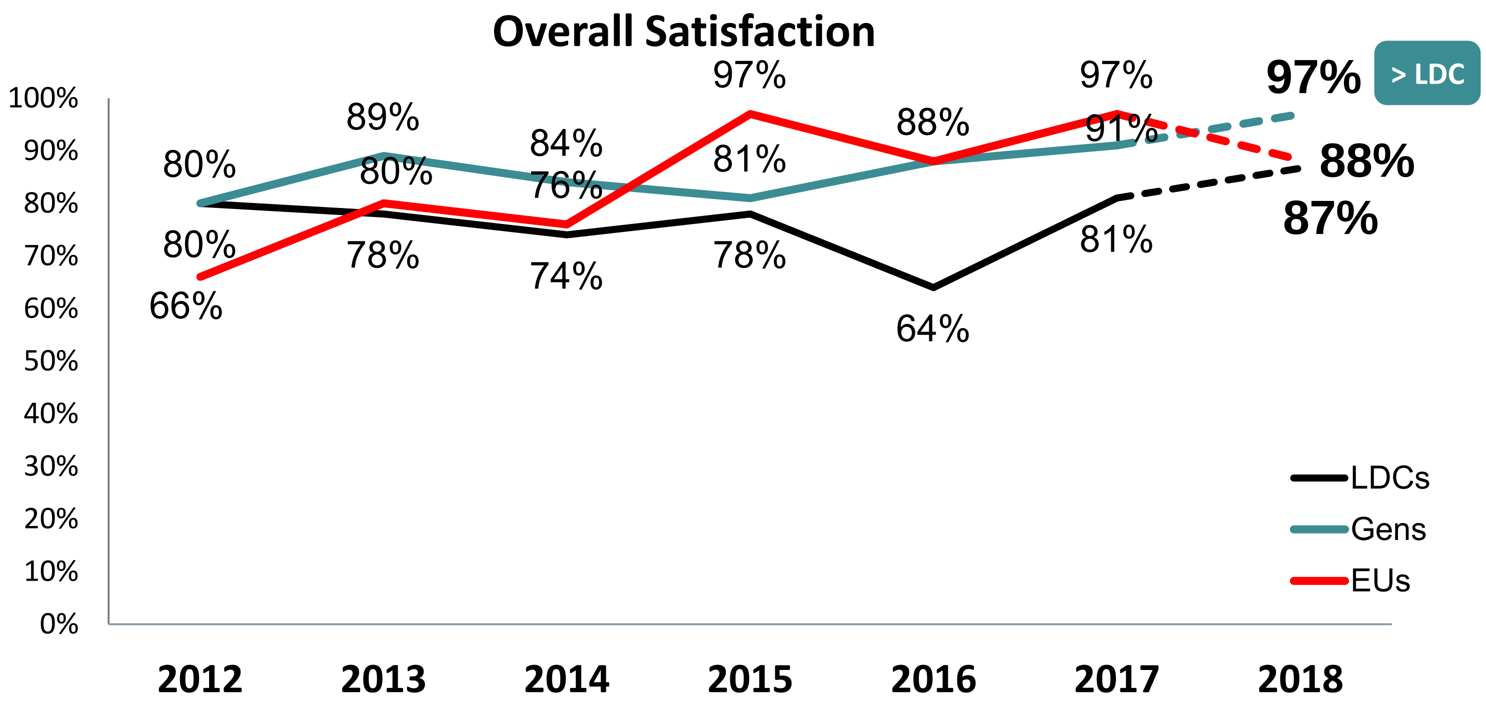
Overall Satisfaction (By Customer Type): Satisfaction among Generators and LDCs hits all-time high in 2018; End-Users down 9pts from 2017

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



	2012	2013	2014	2015	2016	2017	2018
LDCs	80%	78%	74%	78%	64%	81%	87%
Gens	80%	89%	84%	81%	88%	91%	97%
EUs	66%	80%	76%	97%	88%	97%	88%

Key Insights

- Upwards trend of Generator satisfaction continues from 2015, surpassing both other customer groups in 2018.
- LDCs continue to increase from their record low in 2016, albeit less sharply than in 2017.
- End-Users down 9 points from 2017. Due to the small sample size (n=34), this is not a statistically significant change.
- The increase among LDCs and decrease among End-Users has closed the gap between those two groups.

LTX Customer Type	Total Population	Sample Size
LDCs	66	45
Generators	63	33
End-Users	72	34

NOTE: Response "Don't know" (0% in 2017 & 2018) was excluded from this analysis. Statistically significant changes compared to the results from 2017 are indicated by ↑↓. Differences between customer type that are statistically significant at a 95% confidence interval are indicated.

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A Closer Look:
Overall Customer Satisfaction

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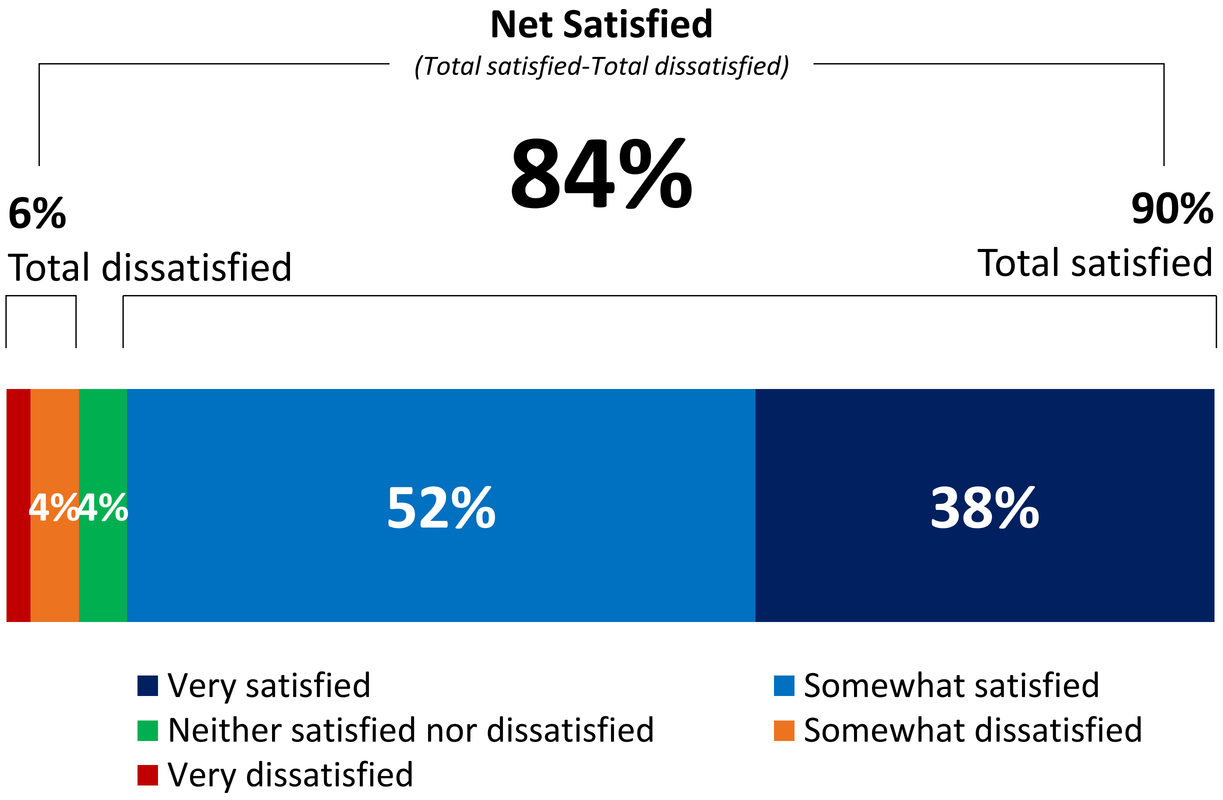
Overall Satisfaction: 9-in-10 (90%) LTX customers are satisfied with the service they receive from Hydro One

Q

C2. Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112]



Key Insights

- Overall satisfaction with Hydro One among LTX customers is verging on universal, but there is room for improvement on intensity. Currently, half (52%) are *somewhat* satisfied, while 38% are *very* satisfied.

NOTE: Response "Don't know" (0%) was included in this analysis

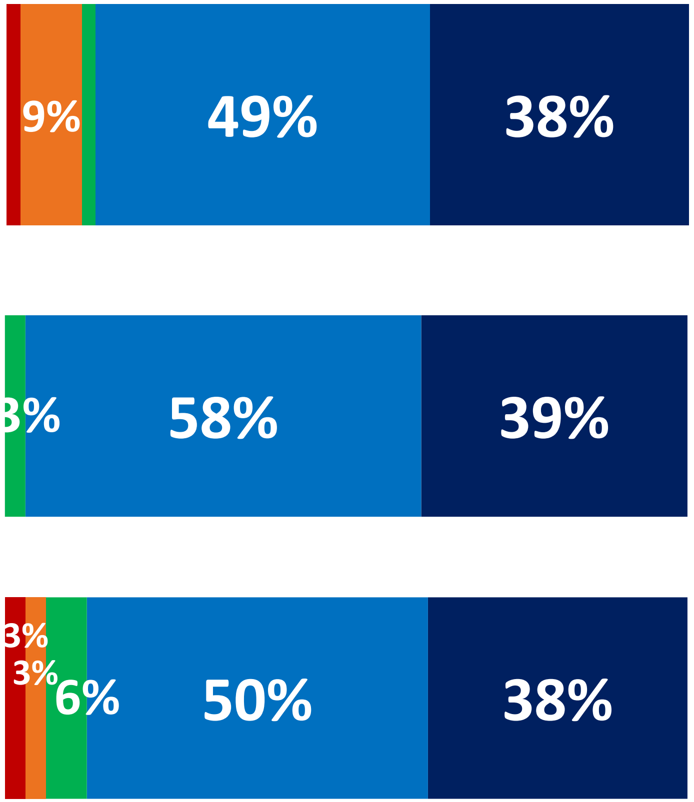
Overall Satisfaction (By Customer Type): Nearly 9-in-10 customers are satisfied across all customer groups; satisfaction highest among Generators

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents]

LDCs
[n=45; valid responses n=45]

Generators
[n=33; valid responses n=33]

End-Users
[n=34; valid responses n=34]



	Total Dissatisfied	Total Satisfied	Net Satisfaction
LDCs	11%	87%	+76%
Generators	-	97% > LDC	+97%
End-Users	6%	88%	+82%

■ Very satisfied
■ Somewhat satisfied
■ Neither satisfied nor dissatisfied
■ Somewhat dissatisfied
■ Very dissatisfied

Key Insights

- The level of intense satisfaction is virtually identical across all three customer segments.
- The higher proportion of somewhat satisfied and complete absence of dissatisfied Generators results in universal satisfaction among that customer group.
- The proportions are small, but there are some dissatisfied LDC (11%) and End-User (6%) customers.

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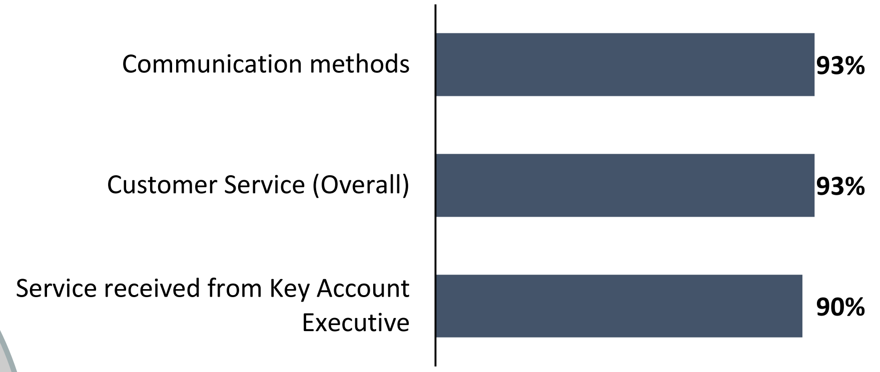
NOTE: Response "Don't know“ (0%) was included in this analysis
Differences between customer type that are statistically significant at a 95% confidence interval are indicated

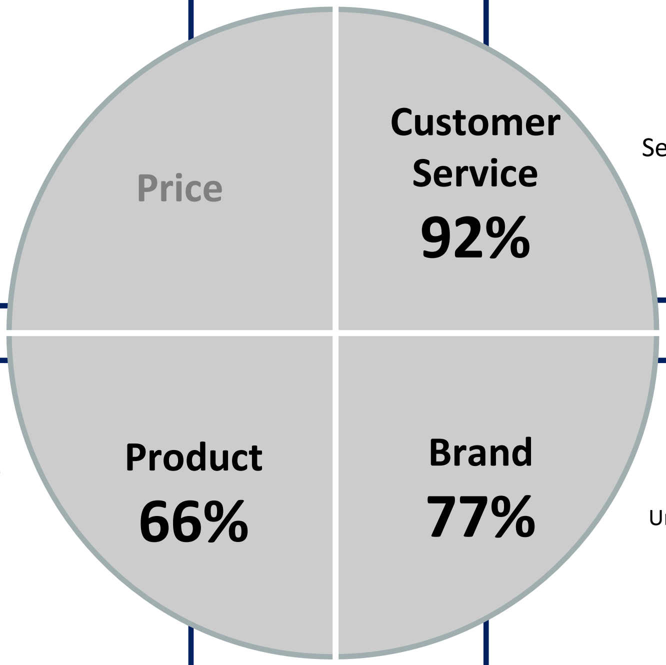
Survey Findings: Dimensions of Satisfaction (LTX – All Segments)

Price/Billing

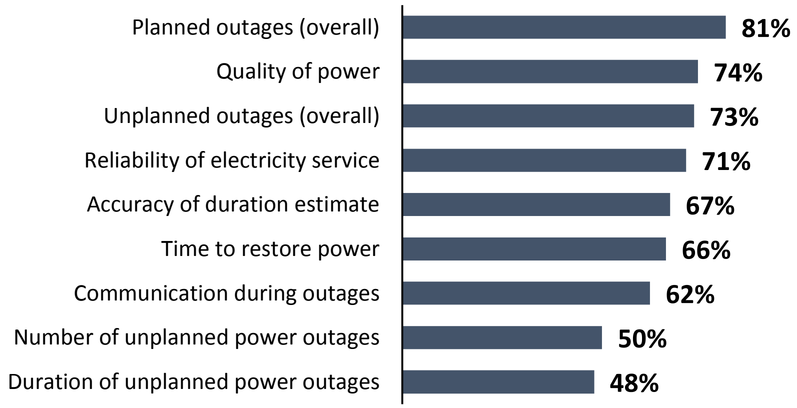
No price/billing questions pertaining to experience with Hydro One were asked of LTX customers

Customer Service





Product Quality/Reliability



Brand

NOTE: Percentages represent total satisfied (very and somewhat satisfied)
Response "Don't know" was included in this analysis.

Survey Findings: Dimensions of Satisfaction (LTX Segments)

Key Insights

- Generators are the most satisfied customer group across all dimensions.
- LDCs are the least satisfied, but just marginally.
- Customer service is the highest-scoring dimension across all LTX customer groups, whereas Product Quality/Reliability is the lowest,

Customer Service – 92%

LDCs	Generators	End-Users
2018	2018	2018
90%	96%	92%

Product Quality/Reliability = 66%

LDCs	Generators	End-Users
2018	2018	2018
62%	77%	64%

Brand – 77%

LDCs	Generators	End-Users
2018	2018	2018
73%	88%	73%

NOTE: Percentages represent total satisfied (very and somewhat satisfied).
No pricing questions were asked of LTX customers.
Response "Don't know" was included in this analysis.

Survey Findings: Dimensions of Dissatisfaction (LTX Segments)

Key Insights

- Dissatisfaction with customer service is nearly non-existent within these customer groups.
- Overall, Generators seem less dissatisfied than other customer groups, which aligns with their overall increase in overall customer satisfaction.
- 1-in-5 LDC and End-Users are dissatisfied with product quality and reliability in 2018. This is five times higher than dissatisfaction among Generators.

Customer Service – 1%

	LDCs	Generators	End-Users
2018	1%	1%	1%

Product Quality/Reliability – 15%

	LDCs	Generators	End-Users
2018	19%	4%	19%

Brand – 9%

	LDCs	Generators	End-Users
2018	10%	4%	11%

NOTE: Percentages represent total dissatisfied (very and somewhat dissatisfied) or total disagreement (strongly and somewhat disagree).
No Price/Billing dimension exists for LTX customers.
Response "Don't know" was included in this analysis.

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Combined LTX and LDA Results

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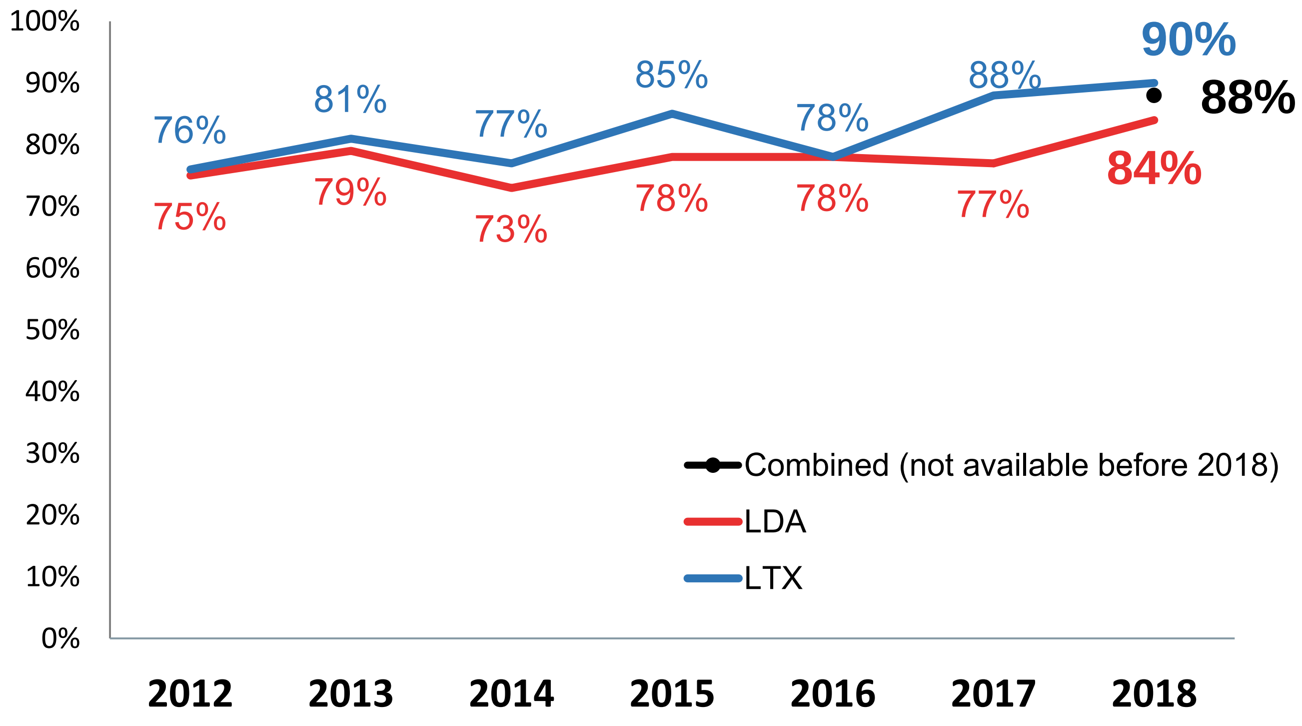
Overall Satisfaction: LTX customers give a marginally higher satisfaction rating than LDA customers

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?

Overall Satisfaction



Key Insight

- Combining LTX and LDA customer results does not have a significant impact on overall satisfaction, but there are marginal differences across the three dimensions.

	Average **Customer Service** Satisfaction Scores	Average **Product** Satisfaction Scores	Average **Brand** Satisfaction Scores
Combined	90%	67%	76%
LDA	86%	70%	72%
LTX	92%	66%	77%

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Regression Analysis: Identifying Drivers

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Using Regression Analysis: Identifying drivers of customer satisfaction

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain a key question we are interested in and see which of these is the most important.
- Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).
- In this study, we use regression to understand **why some respondents rate their satisfaction with or likelihood to recommend Hydro One higher than others.**

We use ***Factor Analysis*** to explore underlying dimensions and structure the regression analysis.

- A factor analysis finds the true underlying dimensions of customer satisfaction that explain the pattern of responses to the larger set of attributes.
- Factor analysis allows us to find which attributes mean similar things to customers. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.

Identifying drivers of CSAT

CSAT
*"Overall, how **satisfied** are you with Hydro One?"*
Measures **overall attitude** towards Hydro One.

What drives each of these measures?

The Regression Model: Identifying drivers of customer satisfaction

Price/Billing

Fairness of the Global Adjustment (GA)
Fairness of the Hourly Ontario Energy Price

Customer Service

Communication methods
Customer service (overall)
Service received from Key Account Executive

Participation in CDM programs
Provision of information on CDM tools and programs by the IESO

Product Quality/Reliability

Planned outages (overall)
Quality of power
Unplanned outages (overall)
Reliability of the electricity service
~~Accuracy of duration estimate~~
Time to restore power
~~Communication during outages~~
~~Number of unplanned power outages~~
~~Duration of unplanned outages~~
Recall of planned outage
Recall of unplanned outage

Brand

Accessibility
Understanding of business needs
Quality advice and guidance
Responds to needs
Ability to keep commitments
Ease of doing business
Trusted business partner
Good value for money

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Price/Billing

Price/Billing

Fairness of the Global Adjustment (GA)

Fairness of the Hourly Ontario Energy Price

Standalones:

- Fairness of the Global Adjustment (GA)
- Fairness of the Hourly Ontario Energy Price

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Customer Service

Customer Service

Communication methods
Customer service (overall)
Service received from Key Account Executive

Participation in CDM programs
Provision of information on CDM tools and programs by the IESO

Factors

Customer Service

Standalone:
- Participation in CDM programs
- Provision of information on CDM tools and programs by the IESO

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Product Quality/Reliability

Product Quality/Reliability

Quality of power
Reliability of the electricity service
Time to restore power

~~Accuracy of duration estimate~~
~~Communication during outages~~
~~Number of unplanned power outages~~
~~Duration of unplanned outages~~

Recall of planned outage
Recall of unplanned outage

Factors

Quality & Reliability

Standalones:

- Recall of planned outage
- Recall of unplanned outage
- Planned outages (overall)
- Unplanned outages (overall)

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

Step 1 – Factor Analysis: Brand

Brand

Ease of doing business
Ability to keep commitments
Understanding of business needs

Quality advice and guidance
Trusted business partner
Good value for money

Accessibility
Responds to needs

Factors

Help & Commitment

Valued Partner

Accessibility & Responsiveness

NOTE: Bolding denotes questions that were asked in the survey but not included in the summary score for the respective dimension.

New to LTX :: *Environmental Controls*
Potential drivers of CSAT outside of Hydro One's control

It is important to distinguish between what is within, and what is outside of Hydro One's influence or control when it comes to drivers of customer satisfaction.

Perceptions of electric companies often tend to move with general perceptions of ***provincial government management in the sector*** rather than in response to the local utility.

In addition, perceptions of utilities are also strongly correlated with **financial circumstances**. In tough times perception and preference can change because customers are struggling with their bills, not because of anything the company has, or has not, done.

Control questions help distributors distinguish between:

a) utility driven programs that impact CSAT; and

b) uncontrollable external drivers that impact CSAT.

When conducting **brand research** in the energy sector, INNOVATIVE often tests multiple environmental control to assess what role predispositions (customer values and beliefs – which can be difficult and costly to change) play in the formation of a utility's brand health and reputation.

However, in **CSAT research**, we usually limit our environmental controls to two key questions to help capture external phenomena:

Government Management of the Electricity System: *Businesses are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.*

Financial Circumstances: *The cost of my organization's electricity bill has a major impact on our bottom line and results in some important spending priorities and investments being put off.*

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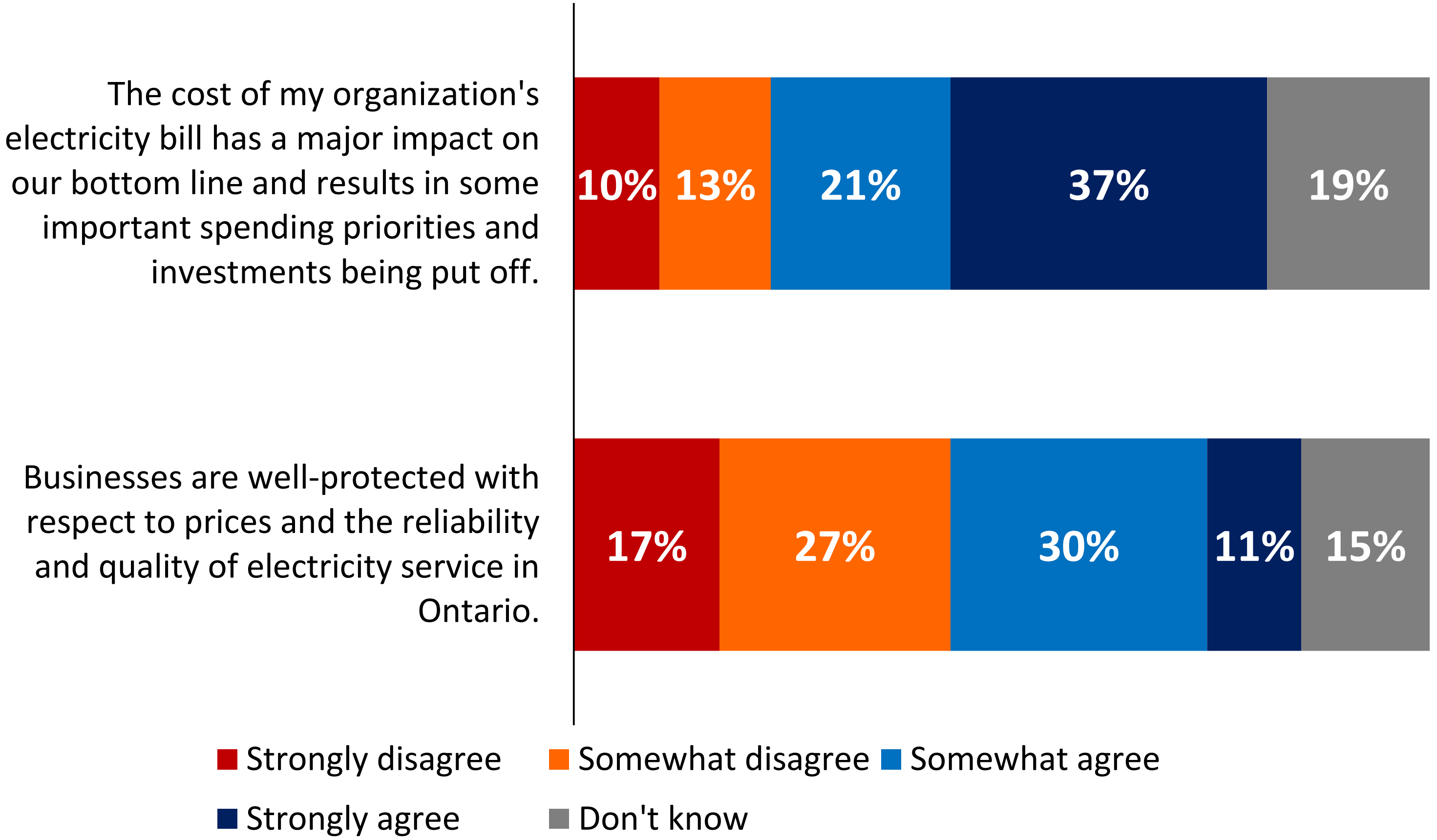
Environmental Controls: Most (58%) LTX customers say their electricity bill is impacting their bottom line; opinion is divided on government protection

Q **H55 & H56.** For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[Asked of all respondents, n=112]



Key Insights

- A majority (58%) of LTX customers say their bottom line is being impacted by their electricity bill. Almost two-in-five (37%) *strongly* agree that this is the case.
  - LDCs: 36% agree
  - Generators: 55% agree **LDC**
  - End-Users: 91% agree **LDC, GEN**
- Opinion on whether or not businesses are protected in terms of prices, reliability ad quality of electricity service in Ontario is divided: 41% agree, and 44% disagree. However, the level of *strong* disagreement (17%) is marginally higher than the level of *strong* agreement (11%).
  - LDCs: 40% agree
  - Generators: 52% agree **EU**
  - End-Users: 32% agree

NOTE: Response "Don't know" was included in this analysis
Differences between customer type that are statistically significant at a 95% confidence interval are indicated.

The Regression Model: Identifying Drivers

Factors

- **Customer Service**
- **Reliability**
- **Help & Commitment**
- **Valued Partner**
- **Accessibility & Responsiveness**

Standalones

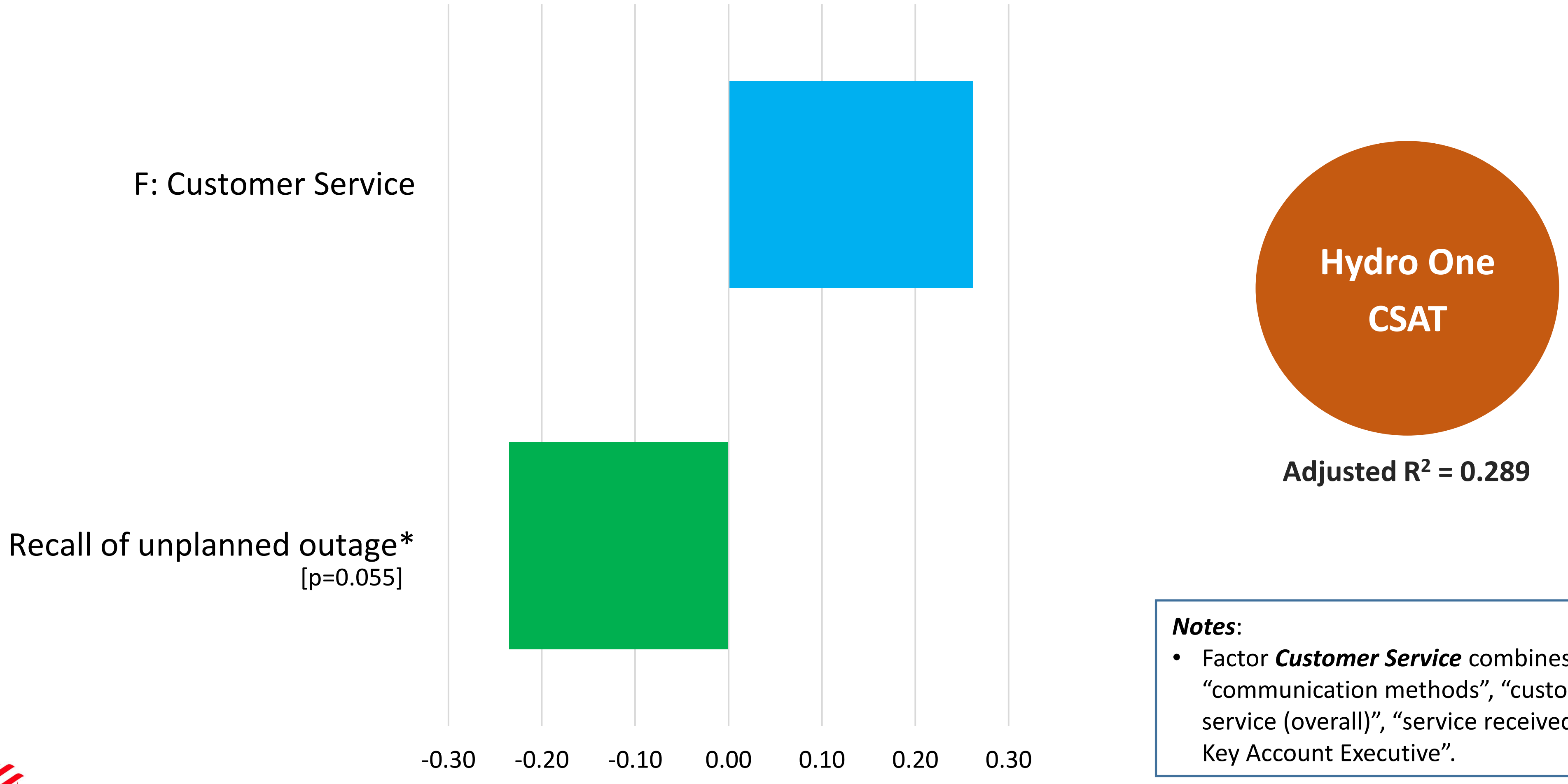
- Fairness of GA
- Fairness of HOEP
- Participation in CDM programs
- Provision of information on CDM tools and programs by the IESO
- Recall of planned outage
- Recall of unplanned outage
- Planned outages (overall)
- Unplanned outages (overall)

Controls

- Customer type
- Environmental controls

Regression Analysis: Identifying drivers of customer satisfaction

Customer service is the only factor that has a positive and statistically significant impact on customer satisfaction. Recall of an unplanned outage has a negative effect.



Adjusted R^2 = 0.289

Notes:
- Factor ***Customer Service*** combines "communication methods", "customer service (overall)", "service received from Key Account Executive".

NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

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INNOVATIVE RESEARCH GROUP

2018 OGCC Customer Satisfaction

Understanding Dimensions of Satisfaction and Dissatisfaction

Hydro One
483 Bay Street
Toronto, ON M5G 2P5

hydro one

December 2018 :: Review Draft

Methodology

The findings presented in this report are based on an online survey carried out by Innovative Research Group (INNOVATIVE) for Hydro One.

The online survey was conducted from October 17th to November 2nd, 2018 among Hydro One LTX customers who had contacted the Ontario Grid Control Centre (OGCC) within the past year. A breakdown of LTX customer segments is included in the table below. In total, 107 participants completed the survey.

The below table shows the surveyed customer segments and their sample sizes:

Segment Size	TOTAL	LDC	Generator	End-User
Total Population Size	218	65	78	74
Surveyed	107	42	31	34
% Captured	49%	65%	40%	46%

Analysis Notation:

Throughout this report "Don't know" was **included** as a valid response.

NOTE: *Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

Executive Summary

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Summary: *2018 OGCC Report*

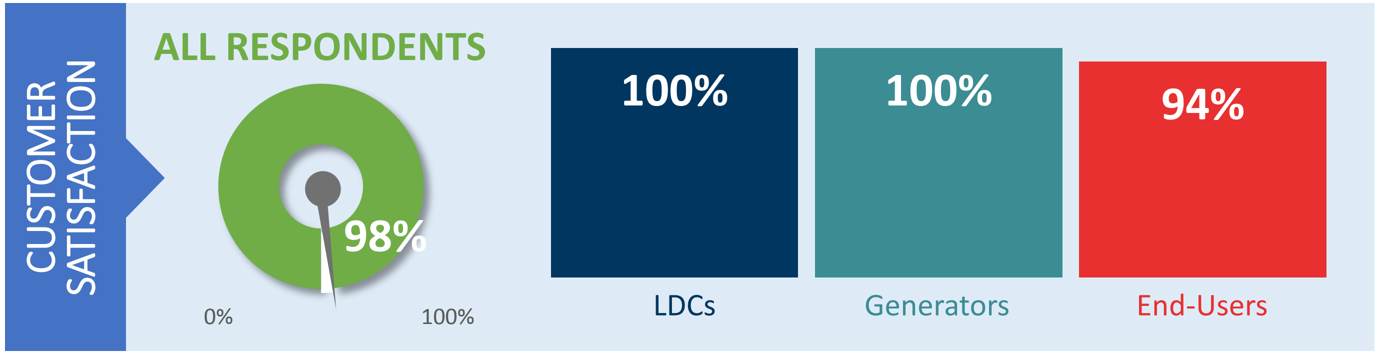
1. **At 98%, customer satisfaction with the OGCC overall is almost universal.**

2. **With the exception of the number of outages and management of <u>unplanned</u> outages, at least half are *"very satisfied"* with every performance metric they were asked about in the survey.**

3. **On a departmental basis, the intensity of satisfaction is highest for the Customer & Operating Support Department (74% *"very satisfied"*).**

4. **Intensity of satisfaction is lowest for the Operating Planning Department (60% *"very satisfied"*).**

5. **The number of <u>unplanned</u> outages has the highest level of dissatisfaction at 31%.**



HIGHEST PERFORMING ATTRIBUTES *("very satisfied")*

- **OGCC**: Relationship with OGCC (96%)
- **Outages**: Planned outage management (57%)
- **Operating Planning**: Proactive communication (65%)
- **Control Room**: Responsiveness (61%)
- **Customer & Operating Support**: Relationship with Network Management Representative (76%)

OPPORTUNITIES FOR IMPROVEMENT *(total dissatisfied)*

- **OGCC**: Sensitivity to operational impact of outages (8%)
- **Outages**: Number of unplanned outages (31%)
- **Operating Planning**: Handling of impactful outages (8%)
- **Control Room**: Prompt updates (3%)
- **Customer & Operating Support**: Effective communication (2%)

Insights: *Drivers of CSAT*

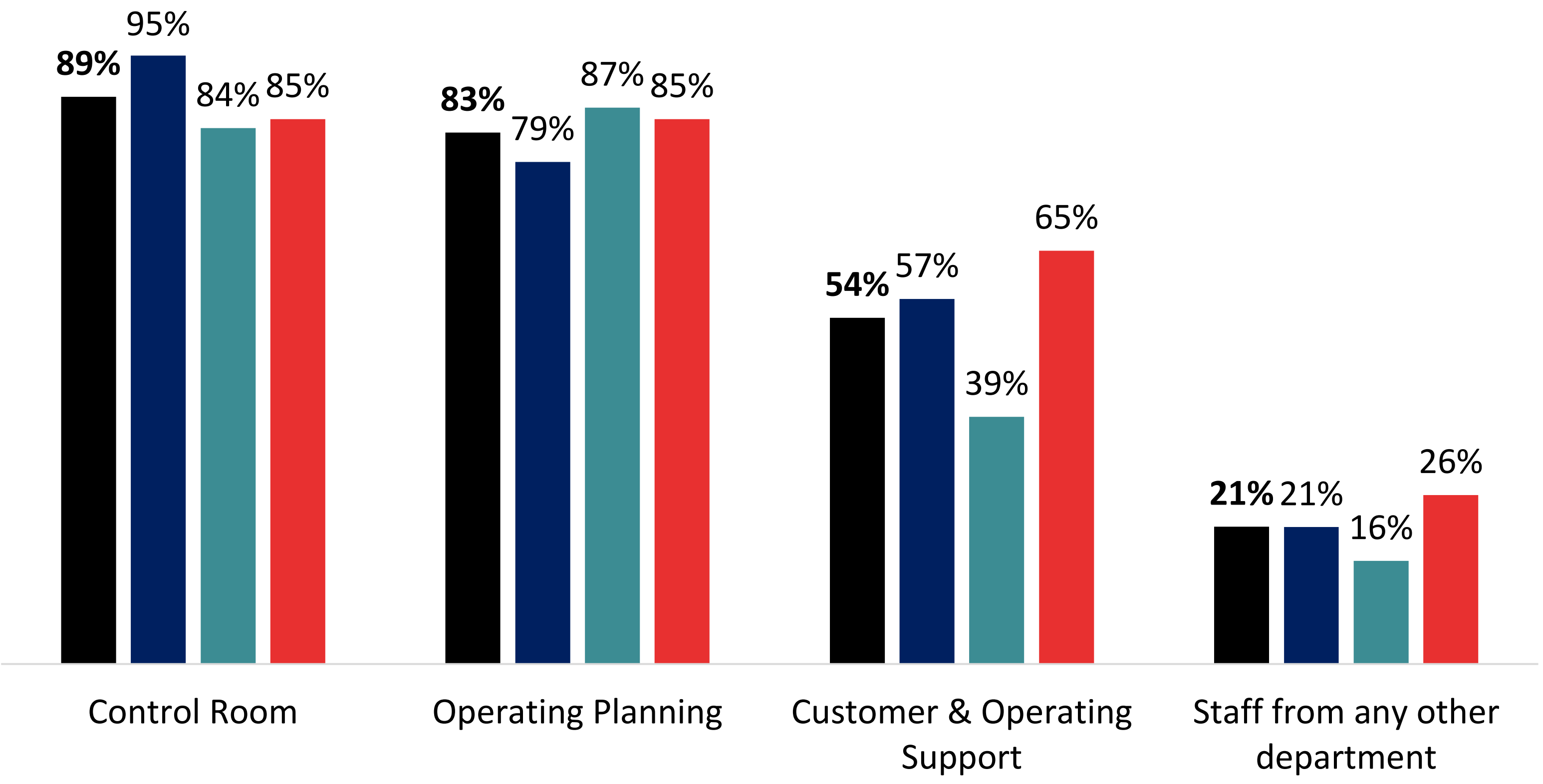
CSAT

- *Communication and Responsiveness* is the strongest driver of overall satisfaction with the service of the OGCC. This factor is a combination of day-to-day communications and responding in a timely manner.
- The level of knowledge of OGCC staff is almost as strong a driver as *Communication and Responsiveness*.
- The third driver is how easy it is to reach the correct contact at the OGCC.
- Being an End-User has a negative impact on overall satisfaction with the OGCC.

OGCC: Department Contact

Q

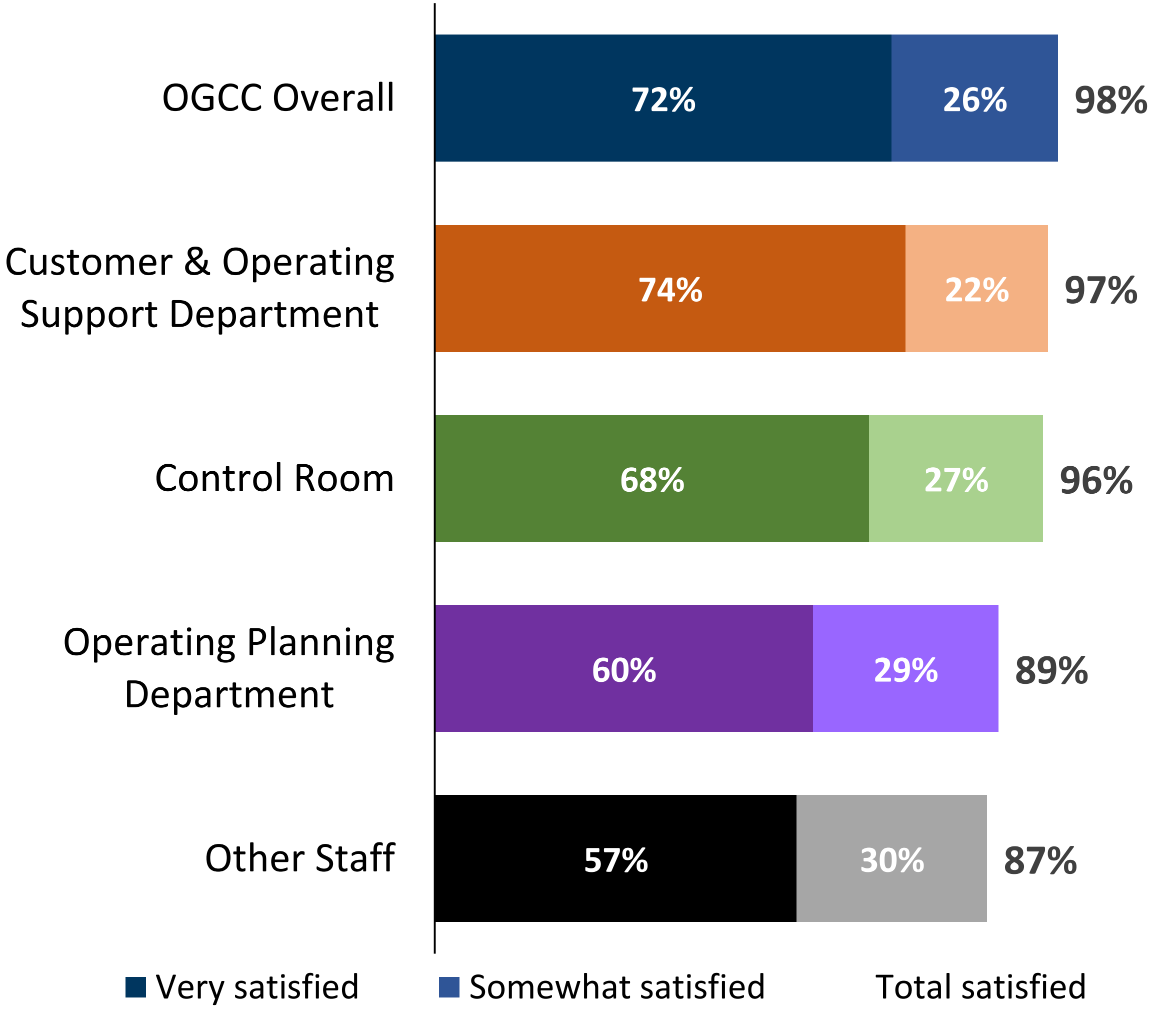
B1. Thinking about the past year, please indicate which of the following Departments at Hydro One's Ontario Grid Control Centre (OGCC) you have had contact with. This contact may have been initiated either by you or by someone at the OGCC.
[Asked of all respondents, multiple-mention, n=107]

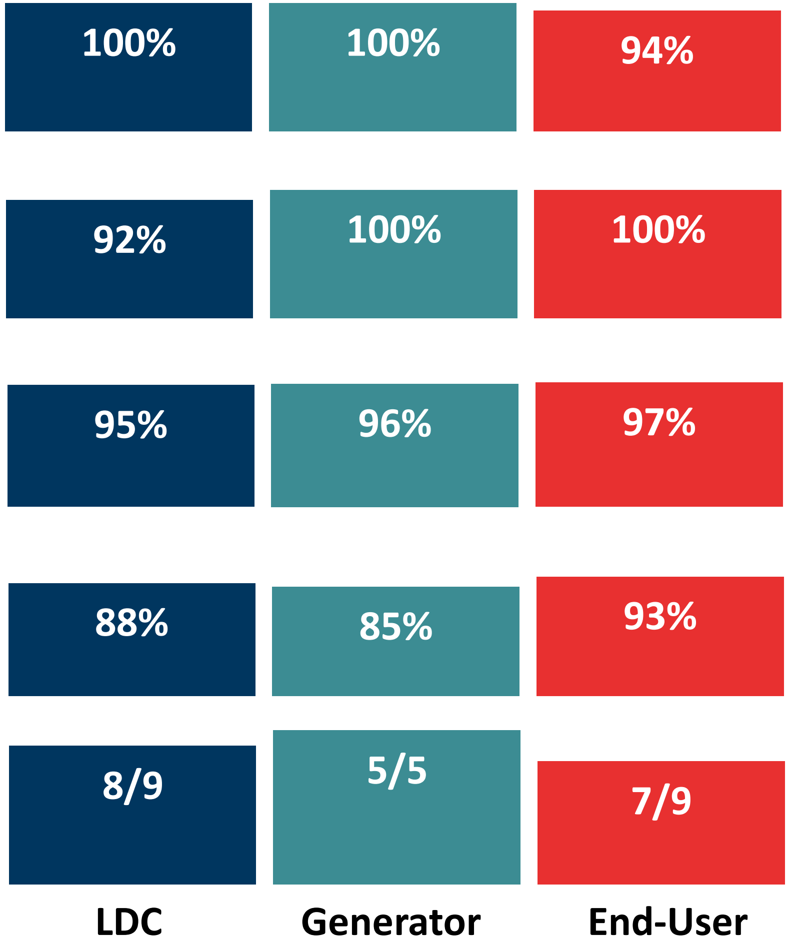


Key Insights

- Over 8-in-10 interacted with the Control Room (89%) and/or the Operating Planning Department (83%) in the past year.
- While this is consistent across Generators and End-Users, LDCs are more likely to have interacted with the Control Room (95%) than the Operating Planning Department (79%).
- Just over half (54%) interacted with the Customer & Operating Support Department in the past year. Generators (39%) are least likely to have interacted with them.

Satisfaction: Overall satisfaction is highest for the OGCC overall and the Customer & Operating Support Department





Overall OGCC Customer Satisfaction

INNOVATIVE RESEARCH GROUP

OGCC Summary

Overall Satisfaction

Metrics Included:

Relationship with OGCC (96%)
Day-to-Day Communications (91%)
Knowledge of Staff (91%)
Responds in Timely Manner (89%)
Ease of Reaching Correct Contact (87%)
Understanding Business Needs (85%)
Sensitivity to Outage Impact (82%)

Overall Satisfaction	Overall Dissatisfaction
98%	1%

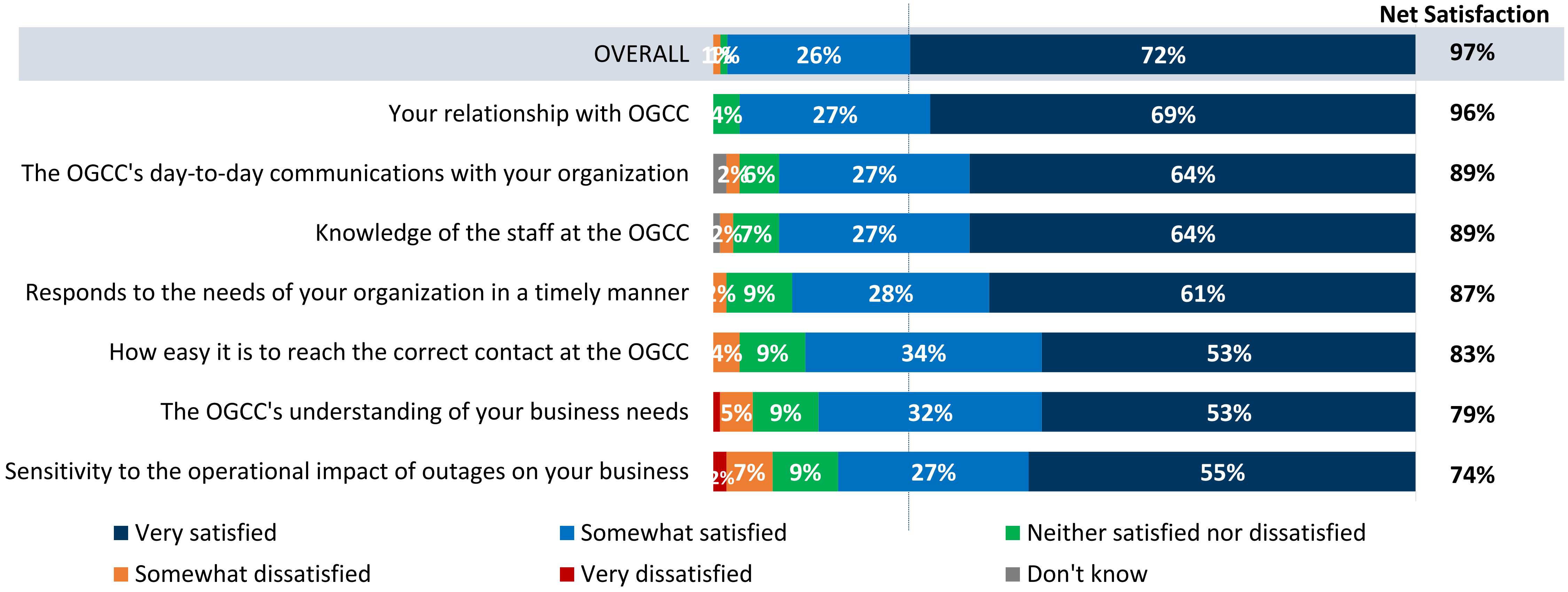
The following questions were asked of all respondents. [n=107]

Key Insights

- Almost all customers who have had contact in the past year are satisfied with the OGCC overall.
- More than three-in-five are *"very satisfied"* with their relationship with OGCC, day-to-day communications, staff knowledge and timeliness of response.
- End-Users are the only group to report being anything less than satisfied with the OGCC overall, but they are at least marginally satisfied than the other two customer groups on most of the individual metrics.
- There is some variation on which metric each customer type reports their lowest level of satisfaction:
    - LDCs: sensitivity to outage impact (81%)
    - Generators: understanding business needs and sensitivity to outage impact (both 77%)
    - End-Users: ease of reaching the correct contact (82%)

OGCC Performance Metrics: A majority are *"very satisfied"* with the OGCC's performance on all aspects

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?
[Asked of all respondents, n=107]



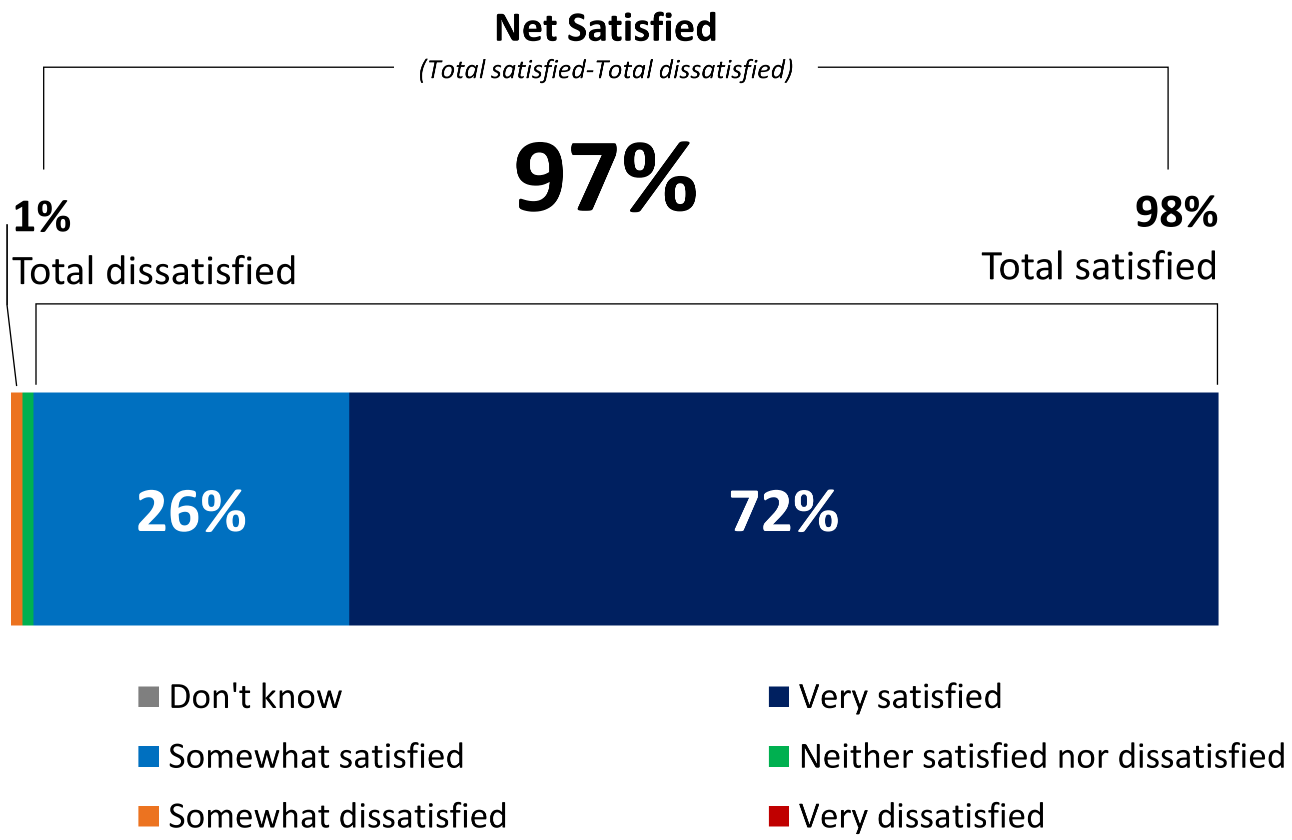
Key Insights

- All performance metrics have strong levels of satisfaction.
- Relationship with OGCC and day-to-day communications have highest net satisfaction.

Overall OGCC Satisfaction: Nearly three quarters (72%) are *"very satisfied"* with the OGCC; only 1% are *"somewhat dissatisfied"*

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?

[Asked of all respondents, n=107]



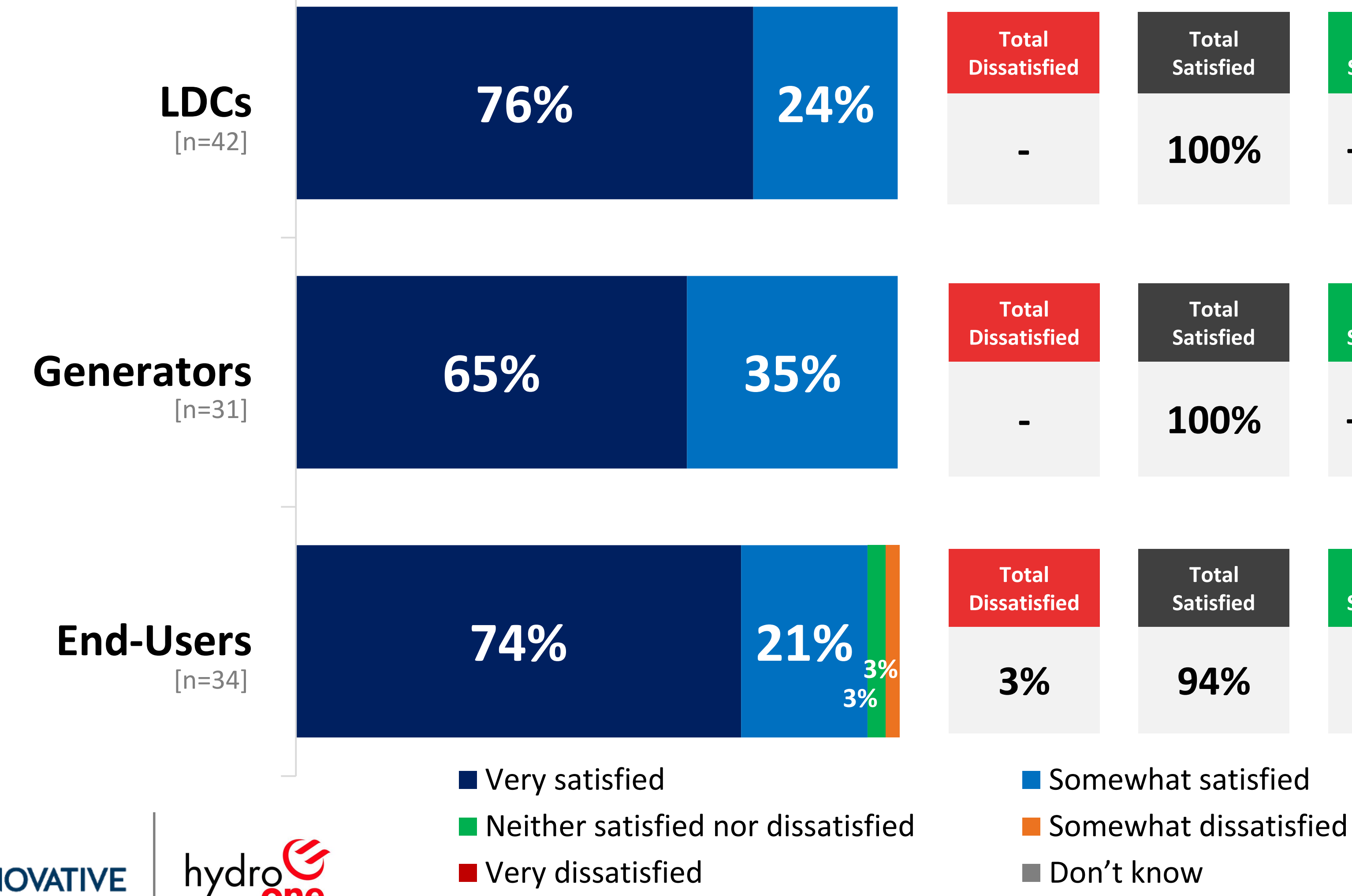
Key Insights

- The level of satisfaction with OGCC is overwhelmingly positive, with three quarters (72%) saying they are "very satisfied".

Overall Satisfaction | By Customer Type: 3-in-4 LDCs and End-Users are "*very satisfied*" with OGCC, about 10 points higher than Generators

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?

[Asked of all respondents, n=107]



	Total Dissatisfied	Total Satisfied	Net Satisfaction
LDCs	-	100%	+100%
Generators	-	100%	+100%
End-Users	3%	94%	+91%

Key Insights

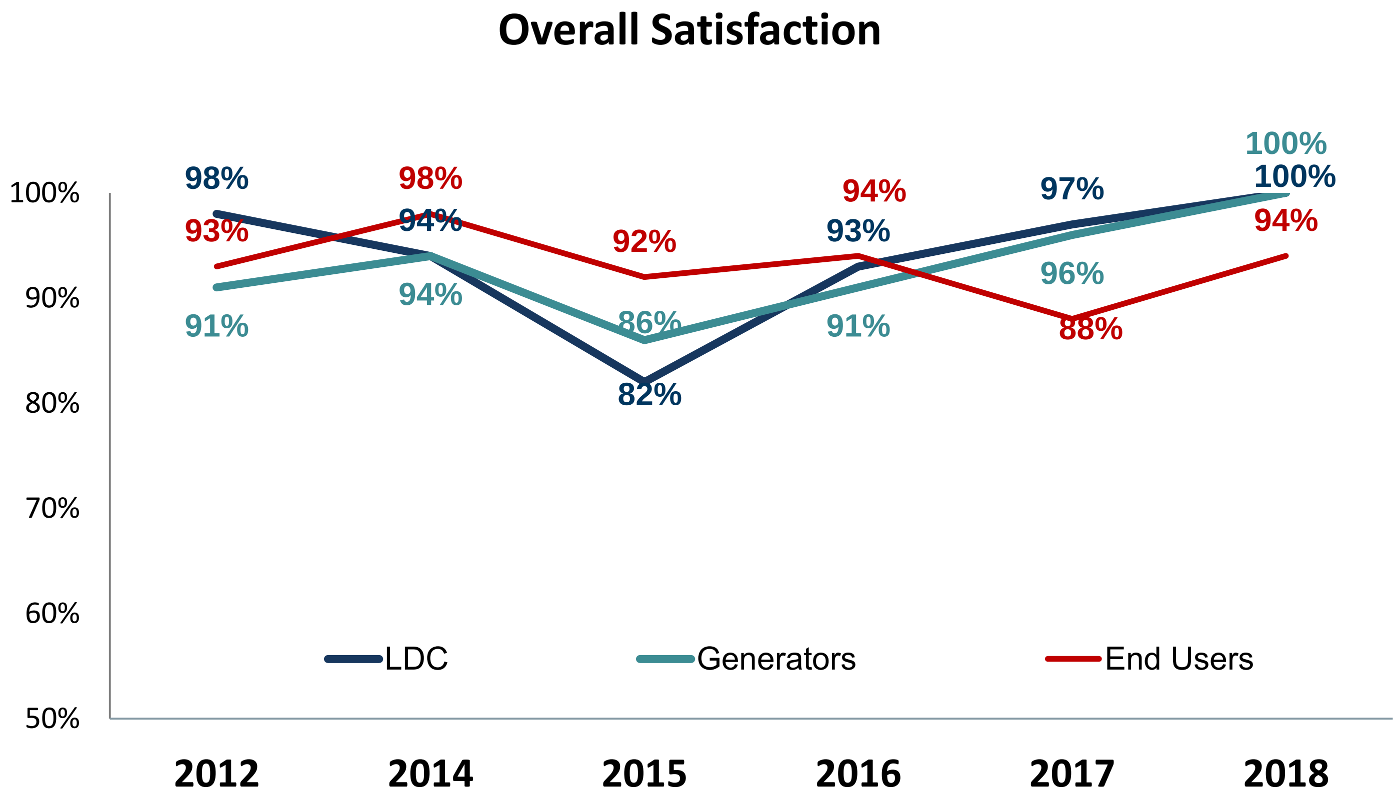
- LDCs and End-Users are more intensely satisfied with OGCC overall than Generators, but there is a little bit (3%) of dissatisfaction among End-Users.

OGCC OVERALL

Overall Satisfaction | Tracking by Customer Type: At least marginal gains in overall satisfaction with OGCC across all customer types

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?

[Asked of all respondents, n=107]



Key Insights

- LDCs and Generators hit universal satisfaction for the first time since tracking began in 2012.
- The customer types have both been trending upward since 2015.
- End-Users have recovered from dip in satisfaction last year.

LTX Customer Type	Total Population	2018 Sample Size
LDCs	65	42
Generators	78	31
End-Users	74	34

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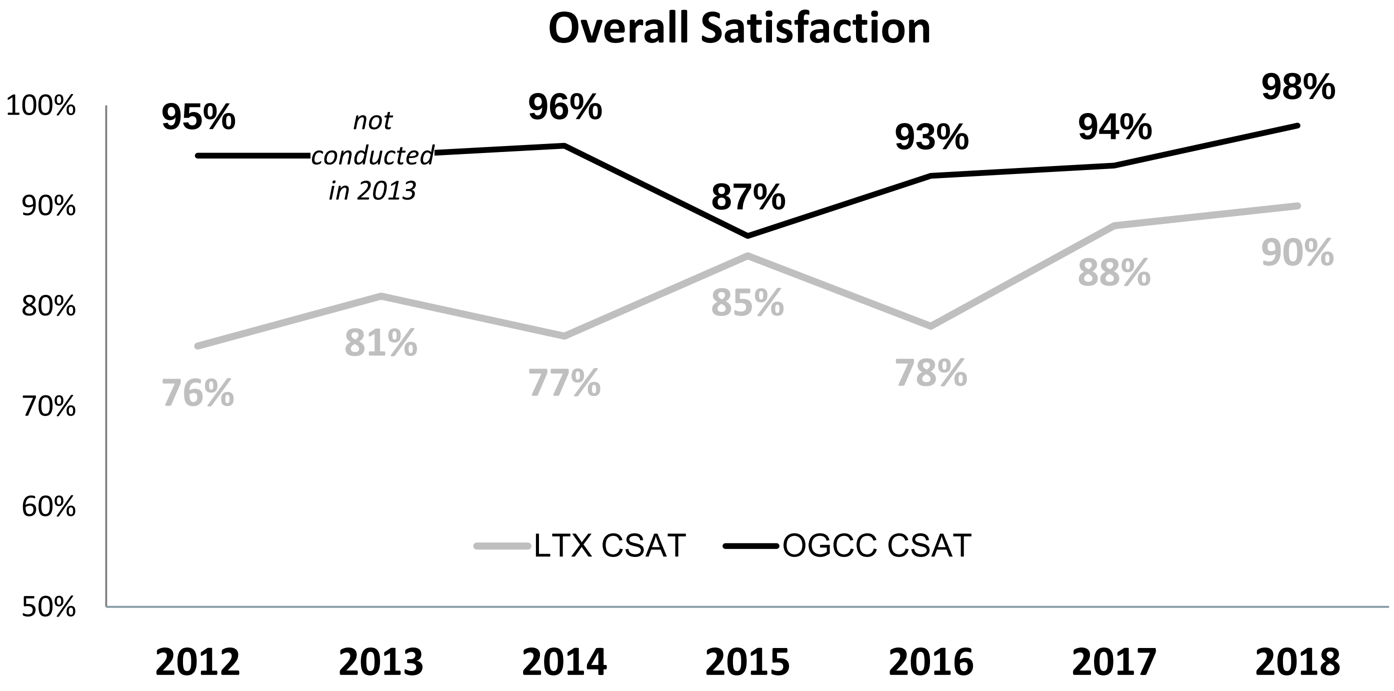
NOTE: Response "Don't know" (0% 2018) was excluded from this analysis in order to be consistent with previous methodology.
Survey not conducted in 2013.

Overall Satisfaction | LTX CSAT vs OGCC CSAT: Marginal widening of the gap between utility and OGCC satisfaction levels

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?
[Asked of all respondents, n=107]

Q **C2.** Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?
[Asked of all respondents, n=112; valid responses n=112]



Key Insights

- After narrowing the gap in 2015, satisfaction with the utility increased and has continued to trend upward since 2016.
- OGCC satisfaction dropped in 2016, bounced back in 2017 and improved marginally in 2018.

NOTE: Response "Don't know" (0% in 2018) was excluded from this analysis in order to be consistent with previous methodology.

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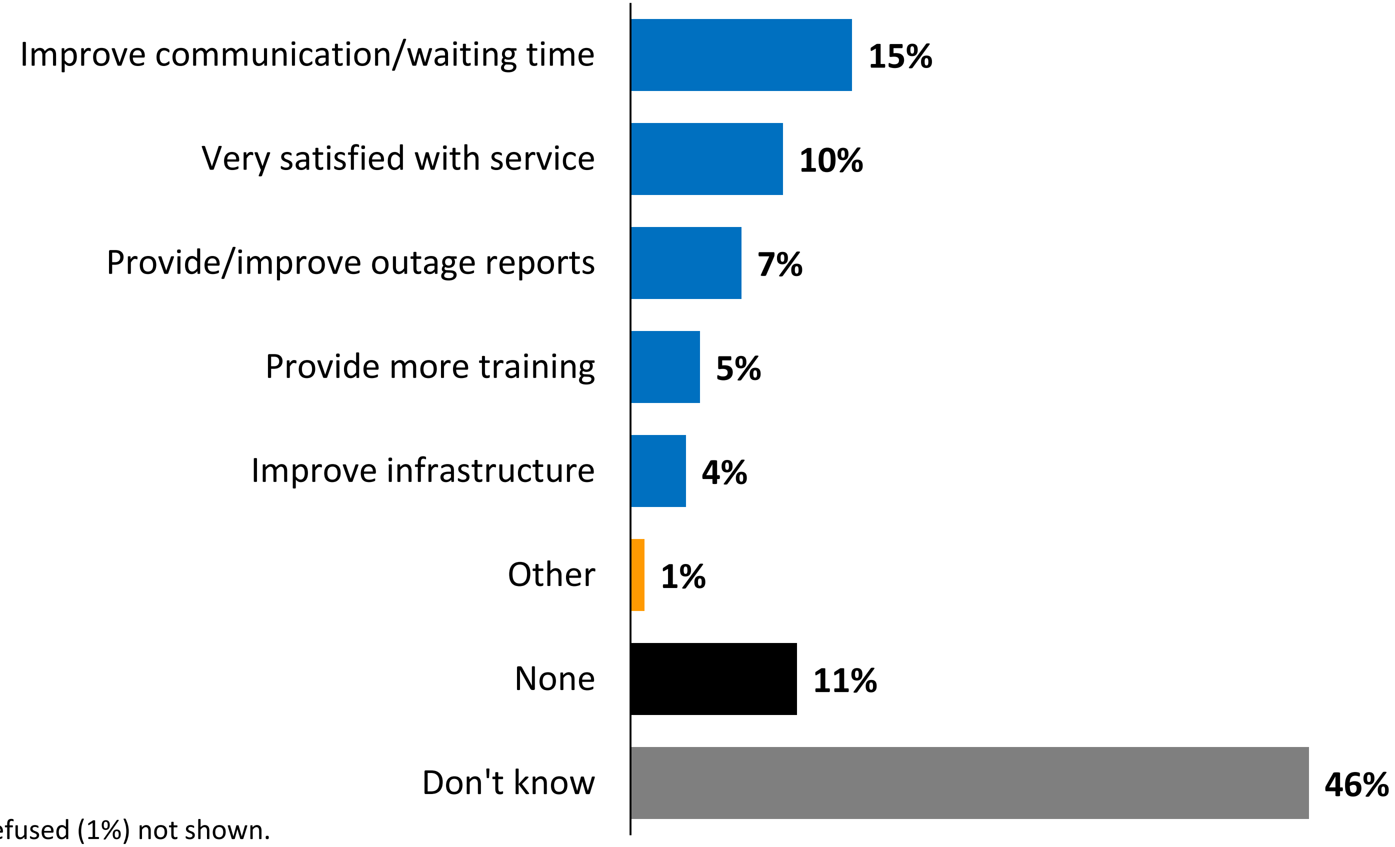
Overall Areas of Improvement: Communication and waiting time lead suggested improvements; over half (57%) say nothing or don't know

Q

C3. Is there anything in particular that Hydro One's Ontario Grid Control Centre (OGCC) can do to improve its services to your organization?

[Asked of all respondents, open-ended, n=107]



NOTE: Refused (1%) not shown.

Key Insights

- More than half do not have any specific suggestions for improvements at OGCC.
- The most common suggestions are to improve communication/waiting time. Others would like improvements on outage reports, and for more training.

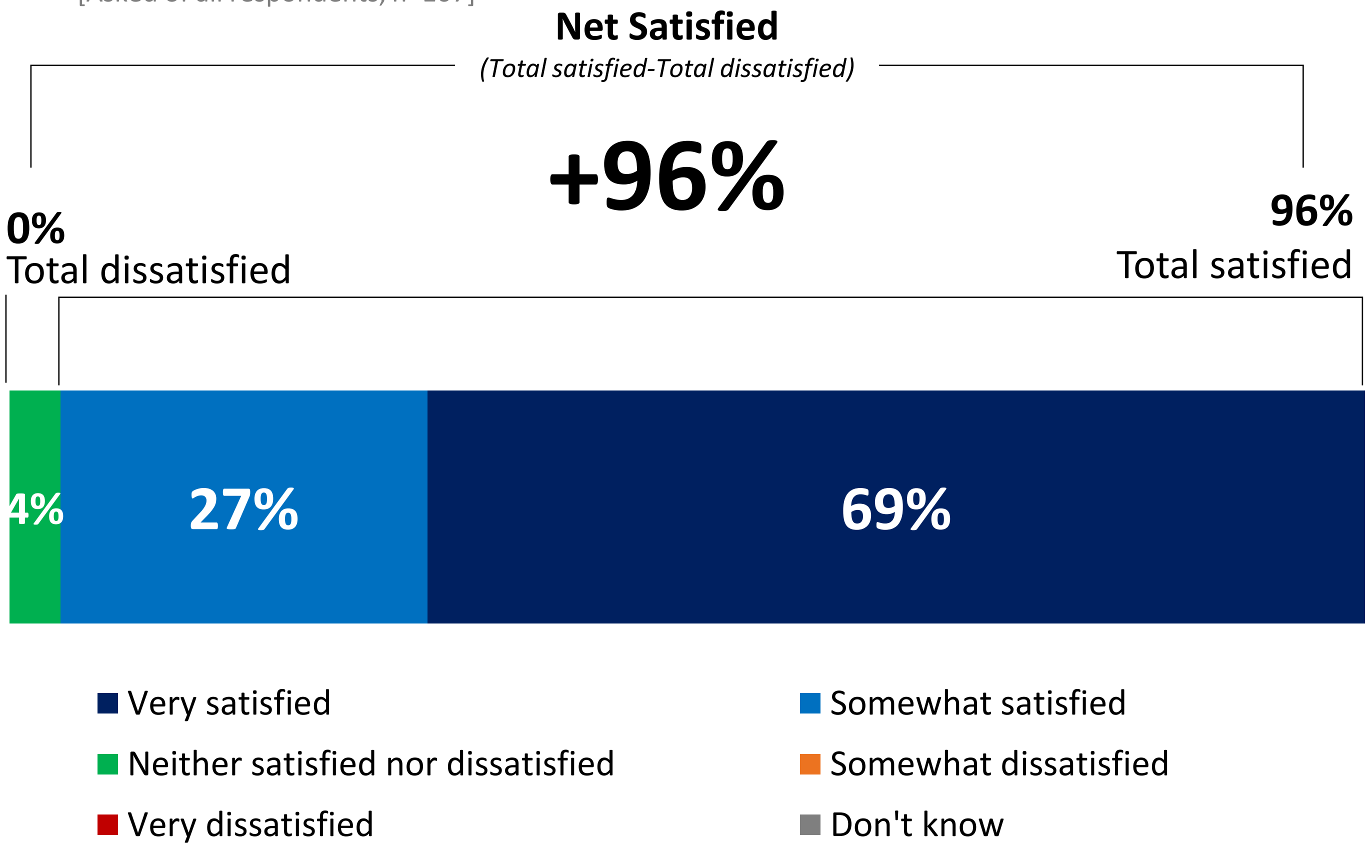
Relationship With OGCC: 7-in-10 (69%) are "*very satisfied*" with relationship; Generators (65%) are marginally less intensely satisfied

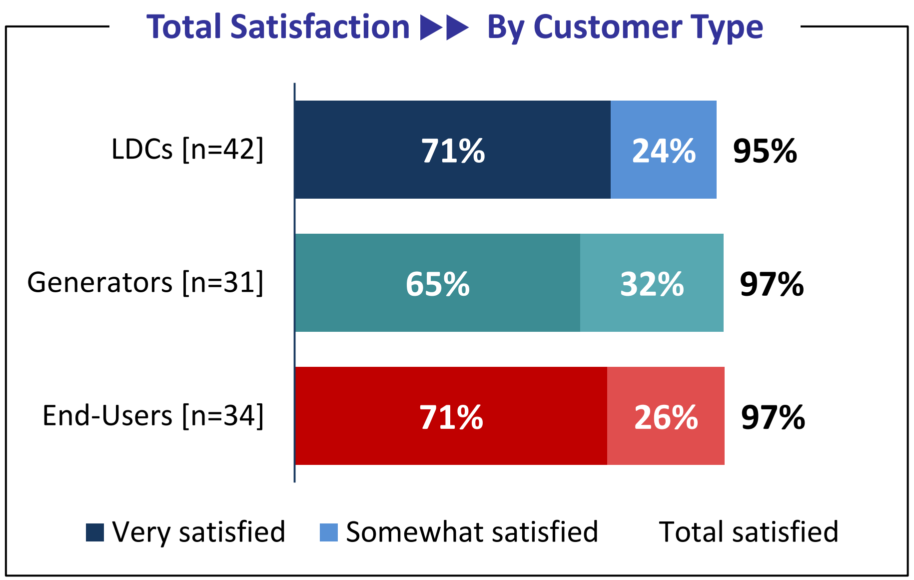
Q

In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C4. Your relationship with OGCC

[Asked of all respondents, n=107]





Key Insights

- While the total satisfaction levels with their relationship with OGCC are consistent across the customer segments, LDCs (71%) and End-Users (71%) are 6 points more likely to say they "very satisfied" than Generators (65%).

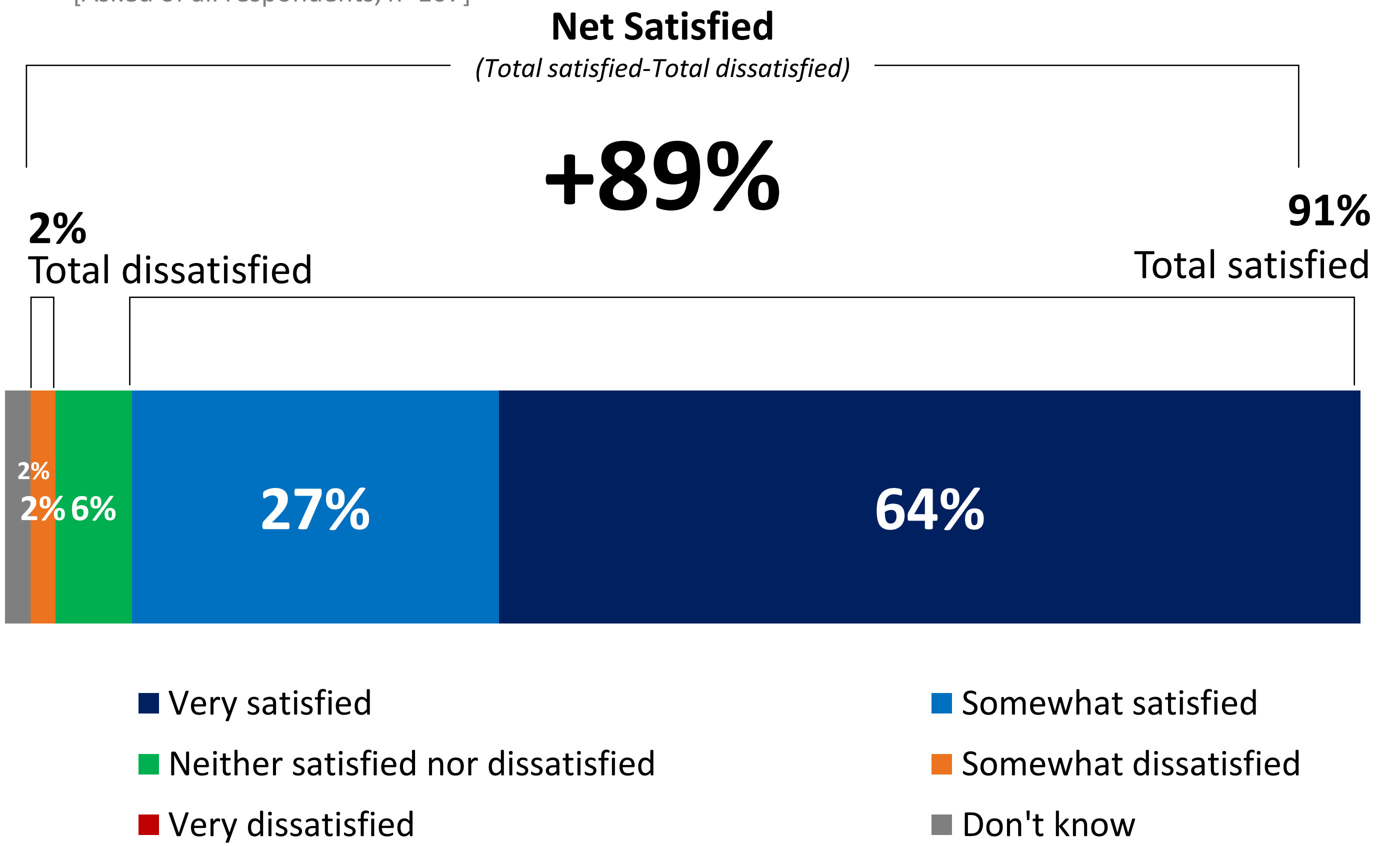
OGCC OVERALL

Day-to-Day Communications: Two-thirds (64%) are "*very satisfied*" with communications; higher among End-Users (71%)

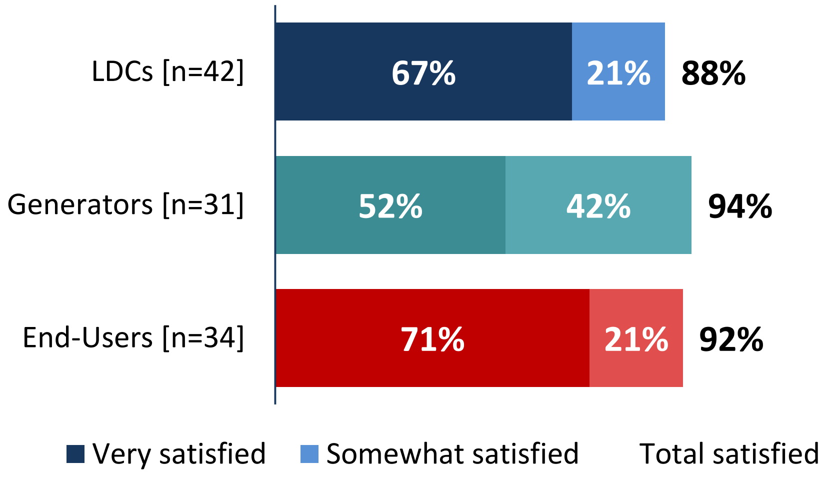
Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C5. The OGCC's day-to-day communications with your organization

[Asked of all respondents, n=107]



Total Satisfaction ▶▶ By Customer Type



Key Insights

- The proportion of LDCs (67%) and End-Users (71%) saying they are "very satisfied" with OGCC's day-to-day communications is 15+ points higher than among Generators (52%).

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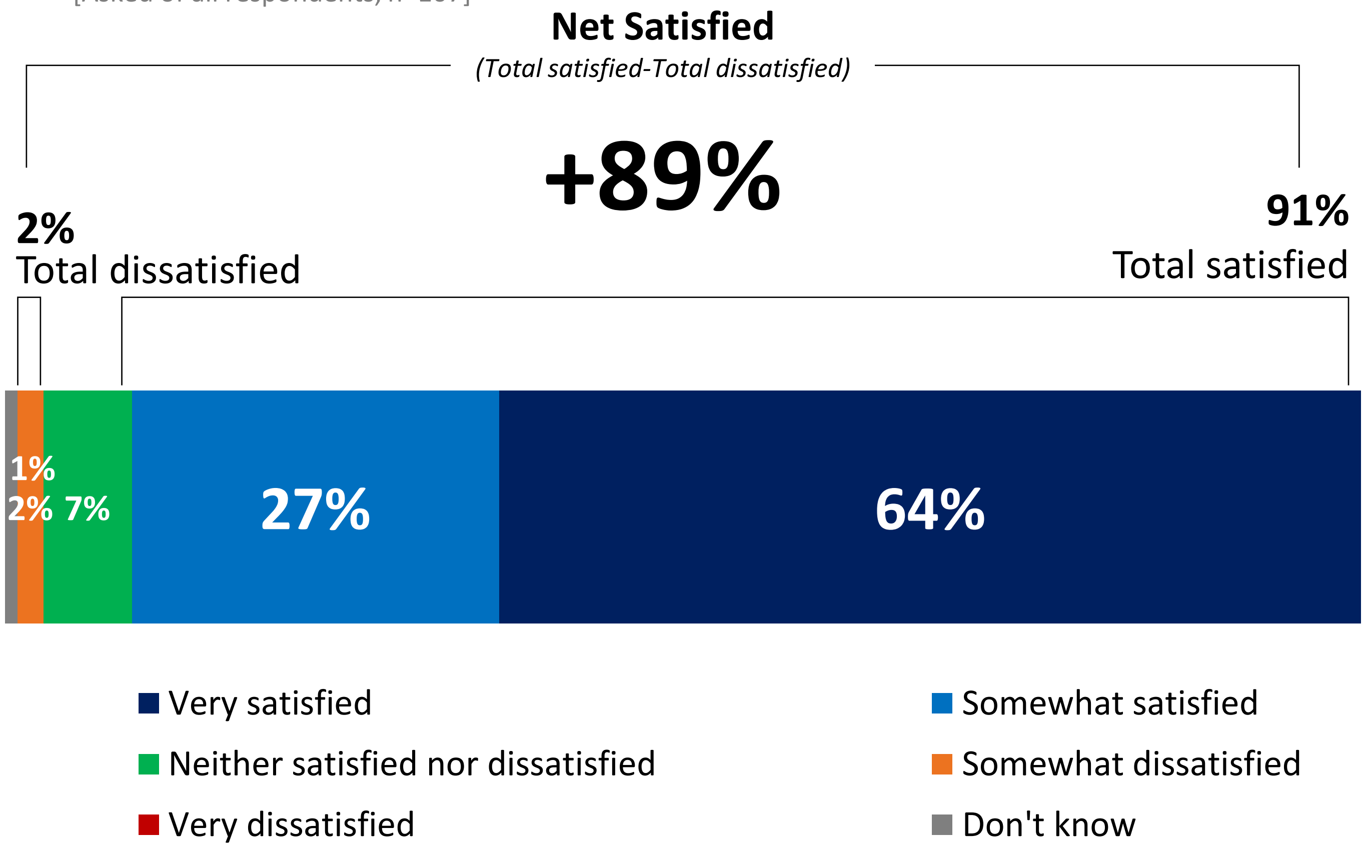
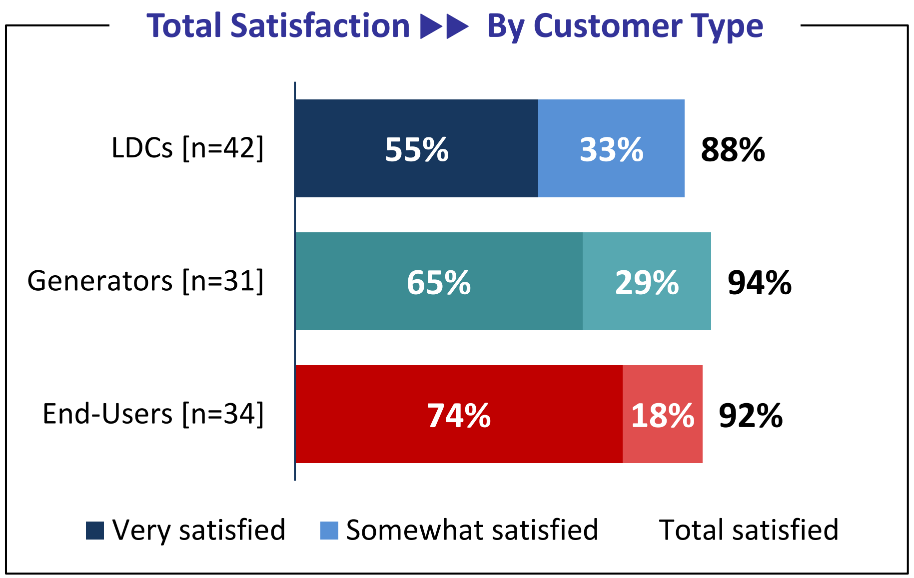
Staff Knowledge: Two-thirds (64%) respondents are "*very satisfied*" with knowledge of staff at the OGCC; highest among End-Users (74%)

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C6. Knowledge of staff at the OGCC

[Asked of all respondents, n=107]





Key Insights

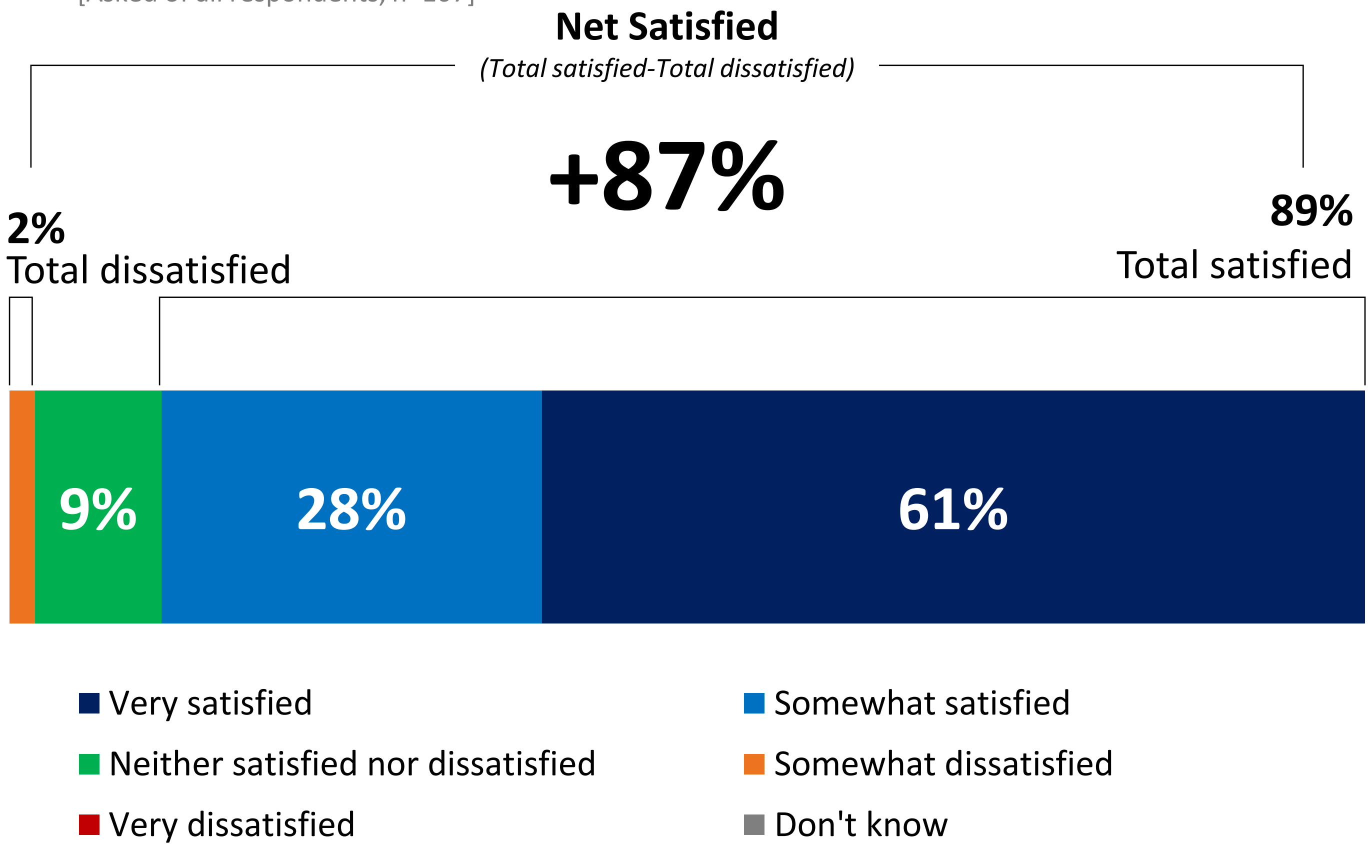
- The proportion of End-Users (74%) saying they are "very satisfied" with the knowledge of OGCC's staff is nearly 20 points higher than among LDCs (55%).
- The total level of satisfaction is marginally higher among Generators and End-Users than among LDCs.

Timely Response to Needs: 3-in-5 (61%) are "*very satisfied*" with the timeliness of response; Generators (58%) marginally lower than average

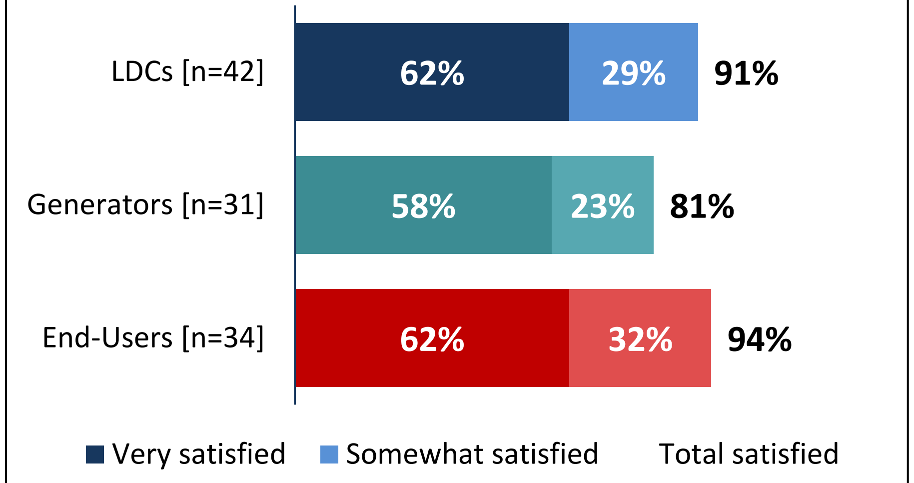
Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C10. The OGCC responds to the needs of your organization in a timely manner

[Asked of all respondents, n=107]



Total Satisfaction ▶▶ By Customer Type



Key Insights

- About 3-in-5 are "very satisfied" with OGCC's timely responses to their needs. This is largely consistent across the three customer types.

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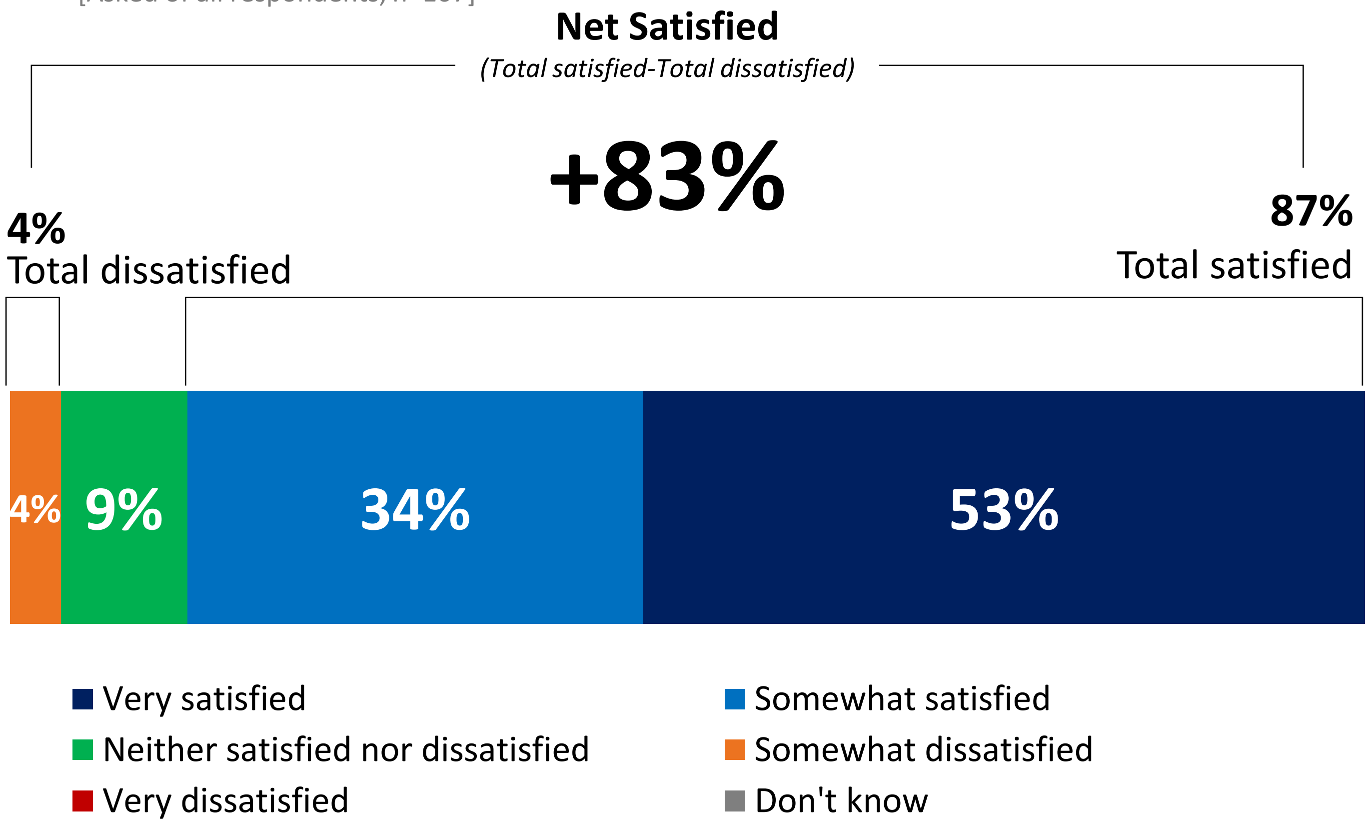
Reaching the Correct Contact: Over half (53%) are "*very satisfied*"; highest among LDCs (62%) and lowest among Generators (45%)

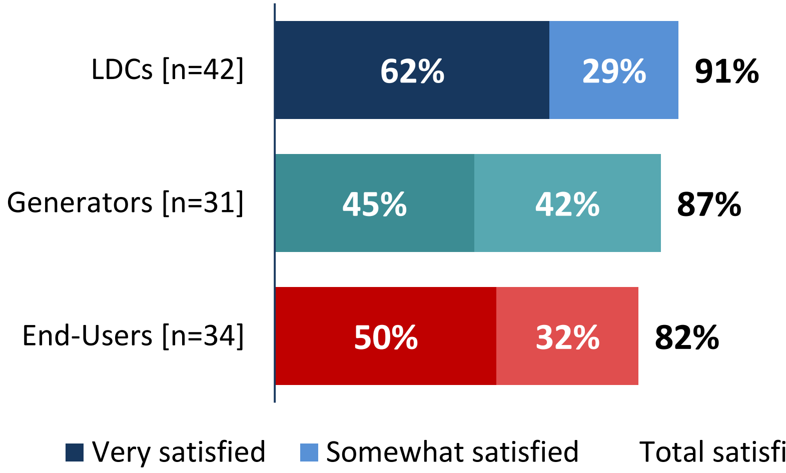
Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C8. How easy it is to reach the correct contact at the OGCC

[Asked of all respondents, n=107]



Total Satisfaction ▶▶ By Customer Type



Key Insights

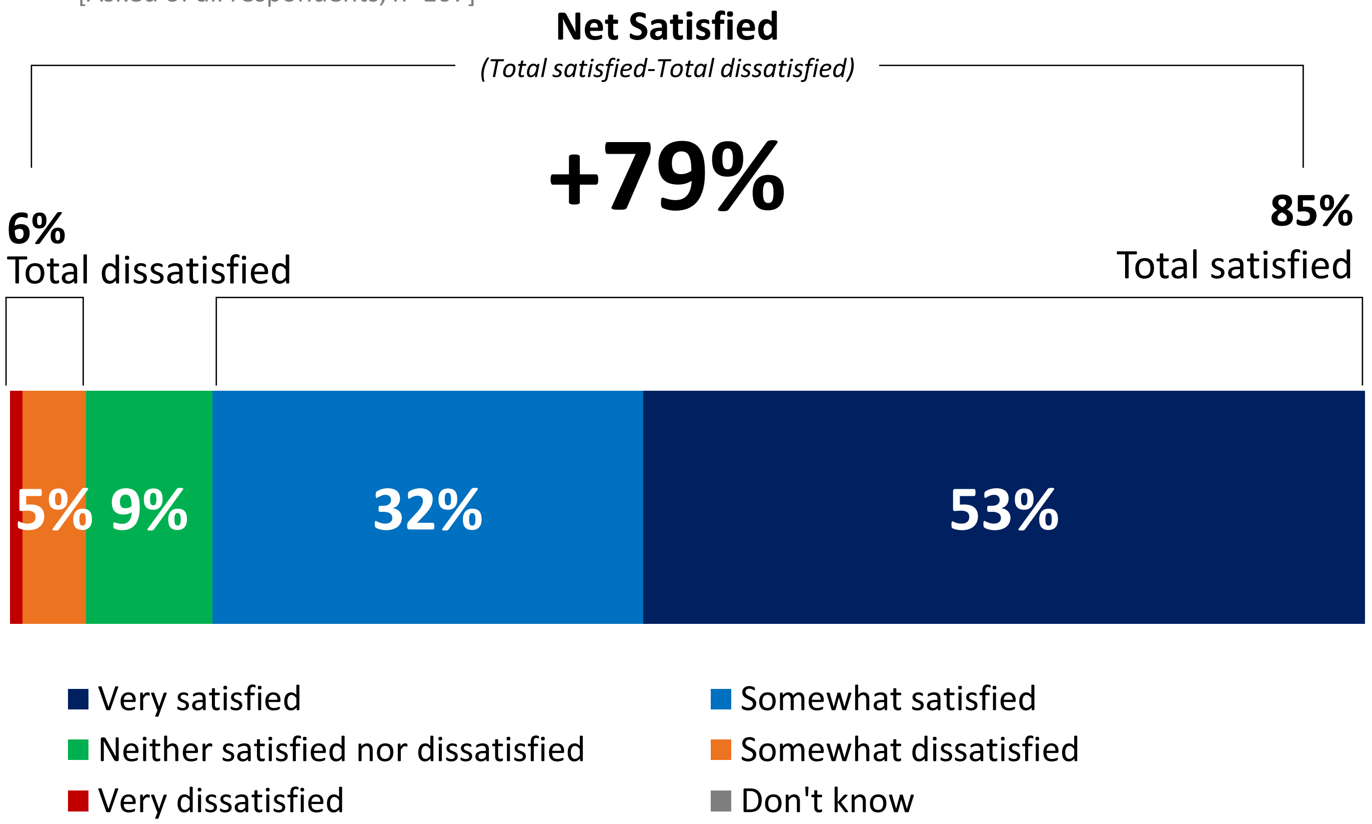
- The proportion of LDCs (62%) saying they are "very satisfied" with the ease of reaching the correct contact is 17 points higher than among Generators (45%).
- The level of intense satisfaction among End-Users (50%) on par with the average (53%).

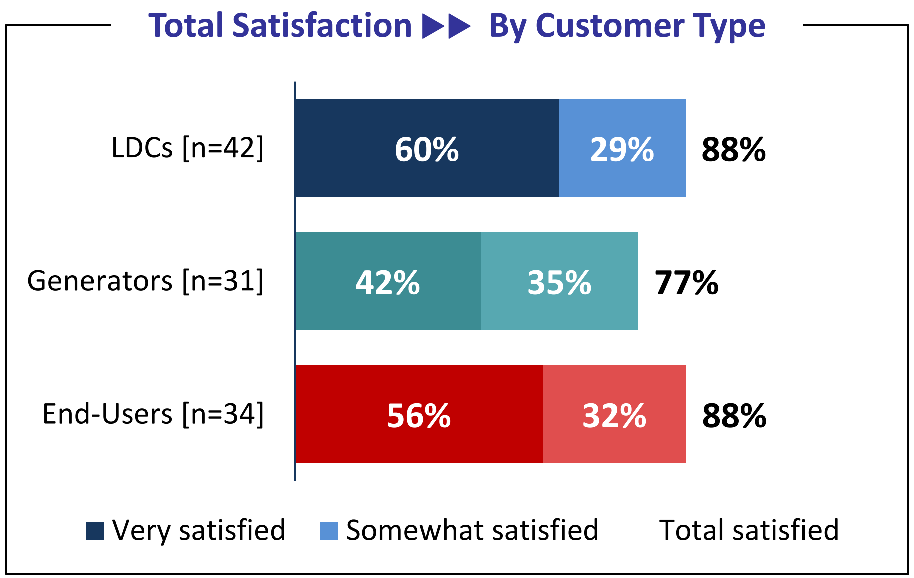
Understanding Business Needs: Over half (53%) are "*very satisfied*" with OGCC's understanding of their needs; lowest among Generators (42%)

Q In general, how satisfied or dissatisfied are you with the following aspects of Hydro One's OGCC?

C9. The OGCC's understanding of your business needs

[Asked of all respondents, n=107]





Key Insights

- Intense satisfaction among End-Users (56%) and LDCs (60%) is 14 or more points higher than among Generators (31%).

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Regression Analysis

Using Regression Analysis: *Identifying drivers of customer satisfaction*

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain a key question we are interested in and see which of these is the most important.
- Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).
- In this study, we use regression to understand **why some respondents rate their satisfaction with Hydro One's OGCC higher than others.**

We use ***Factor Analysis*** to explore underlying dimensions and structure the regression analysis.

- A factor analysis finds the true underlying dimensions of customer satisfaction that explain the pattern of responses to the larger set of attributes.
- Factor analysis allows us to find which attributes mean similar things to customers. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.

Key Question (Dependent Variable): *OGCC Customer Satisfaction (CSAT)*

	OGCC CSAT
Key Question (Dependent Variable)	*"Overall, how **satisfied or dissatisfied** are you with the service your organization receives from Hydro One's Ontario Grid Control Centre (OGCC)?"*
Purpose of the question	Measures **overall satisfaction** towards the OGCC.

What drives overall satisfaction?

The Regression Model and Factor Analysis: *Identifying drivers of customer satisfaction*

We have identified two factors – “Business needs” and “Communications and Responsiveness”. All other drivers are standalone explanatory variables.

Controls

- Customer Type

Interactions with OGCC

- Operating Planning Department
- Control Room
- Customer & Operating Support Department
- Staff from any other department

Unplanned Outage Experience

- Satisfaction with the management
- Satisfaction with the number of unplanned power outages

Planned Outage Experience

- Satisfaction with the management
- Satisfaction with the number of planned power outages

Satisfaction with Various Aspects of OGCC

- Their relationship with OGCC
- The OGCC’s sensitivity to the operational impact of outages on their business
- The OGCC’s understanding of their business needs

Factor: Business needs

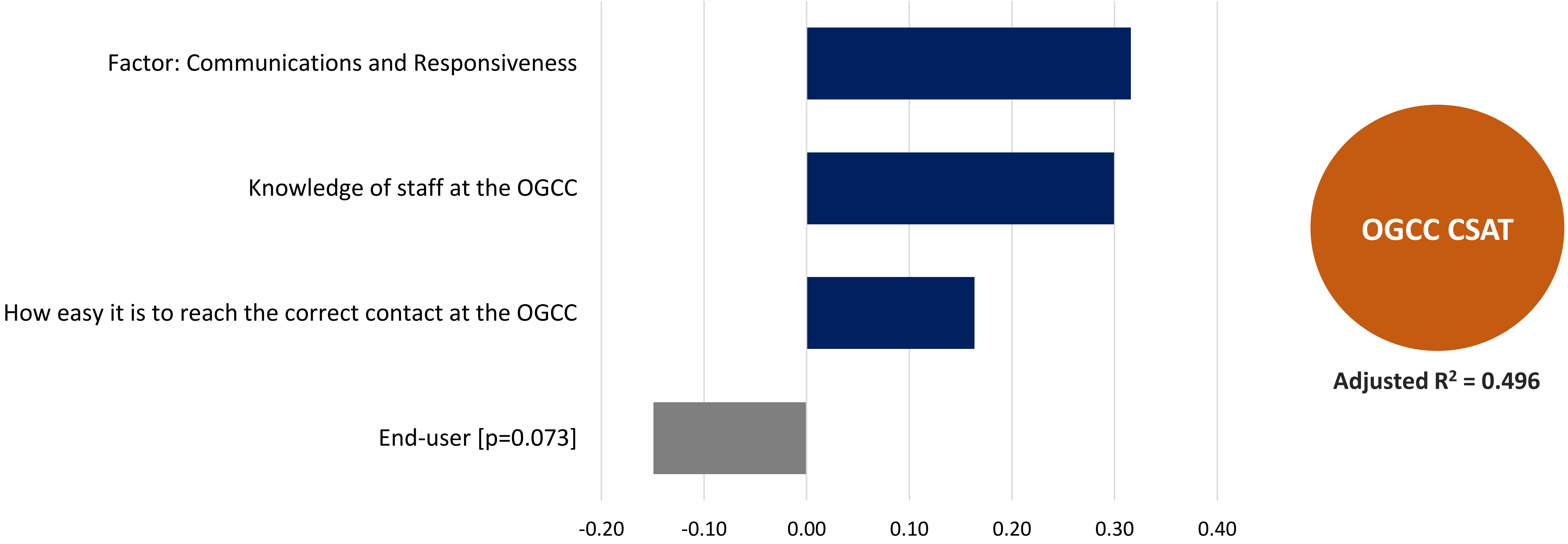
- The OGCC’s day-to-day communications with their organization
- The OGCC responds to the needs of their organization in a timely manner

Factor: Communications and Responsiveness

- Knowledge of staff at the OGCC
- How easy it is to reach the correct contact at the OGCC

Regression Analysis: *Identifying drivers of customer satisfaction*

The strongest driver of customer satisfaction is *Communications and Responsiveness*. Many aspects of OGCC, such as knowledge of staff and the ease of reaching the correct contact, also have statistically significant impacts on customer satisfaction.



NOTES: Factor ***Communications and Responsiveness*** combines “the OGCC’s day-to-day communications with their organization” and “the OGCC responds to the needs of their organization in a timely manner”.
Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

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