1.0 DISTRIBUTION SYSTEM PLAN

On October 18, 2012, the Ontario Energy Board ("Board" or "OEB") released its *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("RRF"), and on March 28, 2013 the Board issued its filing requirements for Consolidated Distribution System Plans pursuant to the RRF. The Board's RRF framework calls for distributors to focus on customer needs and preferences and to demonstrate that their investment plans support cost- effective planning and operation of the distribution network.

The Board expects each distributor to prepare its application to fit its particular circumstances and to measure its performance to ensure the company is delivering on its plan. The RRF emphasizes the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities will better respond to customer needs and preferences, and enhance distributor productivity and promote innovation.

Table of Contents

Witness: Darlene Bradley

Witness: Darlene Bradley

Index of Tables

Witness: Darlene Bradley

MAP TO OEB REQUIREMENTS

Hydro One's Distribution System Plan has been prepared in accordance with Chapter 5 of *Filing Requirements for Electricity Transmission and Distribution Applications* (March 28, 2013) ("DS Plan Filing Requirements"). Table 1 below maps each Chapter 5 requirement to a section in this DSP.

Table 1 Mapping of OEB Requirements to DSP

OEB Chapter 5 Filing Requirement		**Hydro One Reference**
5.2 Distribution System Plans		**1.0 Distribution System Plan**
5.2.1	**Distribution system plan overview**	**1.1 Distribution System Plan Overview**
	5.2.1 a) Key elements	1.1.1 Key Elements of the DSP
	5.2.1 b) Cost savings	1.1.2 Cost Savings
	5.2.1 c) Plan period	1.1.3 Period Covered by the DSP
	5.2.1 d) Information vintage	1.1.4 Vintage of the Information
	5.2.1 e) Changes to asset management process	1.1.5 Changes to Asset Management Process
	5.2.1 f) Work contingent on historic/future activities	1.1.6 Work Contingent on Historic/Future Activities
5.2.2	**Coordinated planning with 3rd parties**	**1.2 Coordinated Planning with Third Parties - Regional Planning**
	5.2.2 a) 5.4.2 d) Consultation description	1.2.1 Overview of the Regional Planning Process
		1.2.2 Regional Planning Consultation Description

OEB Chapter 5 Filing Requirement		Hydro One Reference
		1.2.3 Status of Regional Planning Activities
		1.2.4 How the Plan Reflects Regional Planning
	5.2.2 b) Final deliverables *5.2.2 c) IESO comment letter*	1.2.5 Attachments: IESO Comment Letter and Regional Planning Reports
5.2.2	**Coordinated planning with 3rd parties**	**1.3 Coordinated Planning with Third Parties - Customer Engagement**
	5.2.2 a) Consultation description	1.3.1 How Customer Needs are Determined
		1.3.2 Customer Engagement Process
		1.3.3 Summary of Customer Needs and Preferences
	5.4.1 f) Impact of customer engagement on plan	1.3.4 How the Plan Reflects Customer Needs and Preferences
		1.3.5 Attachments: Customer Engagement
5.2.3	**Performance Measurement for Continuous Improvement**	**1.4 Performance Measurement and Outcome Measures**
	5.2.3 a) Methods and measures	1.4.1 Methods and Measures
	5.2.3 b) Performance trends	1.4.2 Performance Trends / Update
	5.2.3 c) Impact on DSP	1.4.3 How the Plan Reflects Performance Measurement and Outcome Measures
	Performance Measurement for Continuous Improvement	**1.5 Productivity and Continuous Improvement**
		1.5.1 Productivity Savings in the Plan

Witness: Darlene Bradley

OEB Chapter 5 Filing Requirement		Hydro One Reference
	Performance Measurement for Continuous Improvement	**1.6 Benchmarking**
	5.2.3 a) Methods and measures	1.6.1. Benchmarking Study Overview
		1.6.2. Summary of Benchmarking Findings and Recommendations
	5.2.3 c) Impact on DSP	1.6.3 How the Plan Reflects the Benchmarking Findings and Recommendations
		1.6.4 Attachments: Benchmarking Studies
5.3 Asset Management Process		**2.0 Asset Management Process**
5.3.1	**Asset management process overview**	**2.1 Investment Planning Process**
	5.3.1 a) Asset management objectives	2.1.1 Strategic Context
	5.3.1 b) Asset management process	2.1.2 Planning Assumptions
		2.1.3 Needs Assessment
		2.1.4 Investment Development
		2.1.5 Investment Optimization
		2.1.6 Investment Approval and Implementation
		2.1.7 Performance Reporting
		2.1.8 Investment Planning Summary
5.3.2	**Overview of Assets Managed**	**2.2 Overview of Assets Managed**
	5.3.2 a) Description of service area	2.2.1 Description of the Distribution Service Area
	5.3.2 b) Description of system configuration	2.2.2 Description of System Configuration and Capacity

Witness: Darlene Bradley

OEB Chapter 5 Filing Requirement		Hydro One Reference
	5.3.2 c) Asset type information	
	5.3.2 d) Capacity of system	
5.3.3	**Asset lifecycle optimization policies and practices**	**2.3 Asset Component Information and Life Cycle Strategies**
	5.3.3 a) Life cycle optimization policies *5.3.3 b) Lifecycle risk management policies*	2.3.1 Key Component Summaries – Distribution Stations
		2.3.2 Key Component Summaries – Distribution Lines
		2.3.3 Key Component Summaries – Other Assets
		2.4 How the Plan Reflects Investment Planning and Asset Management
5.4 Capital Expenditure Plan		**3.0 Capital Expenditure Plan**
5.4.1	**Summary**	3.1 Capital Expenditure Summary
	5.4.1 a) Capability to connect new load	3.3.1 Capability to Connect New Load or Generation Customers
	5.4.1 b) Total annual capital expenditure forecast	3.2 Capital Expenditure Forecast
	5.4.1 c) Impact of asset management and capital planning on investment level	3.3.2 Impacts of Investment Planning Process 2.4 How the Plan Reflects Investment Planning and Asset Management
	5.4.1 d) List of material investments	3.7 List of Material Capital Investments Proposed
	5.4.1 e) Impact of regional planning on plan	3.3.3 Impacts of Regional Plans

Witness: Darlene Bradley

OEB Chapter 5 Filing Requirement		Hydro One Reference
	5.4.1 f) Impact of customer engagement on plan	3.3.4 Impacts of Customer Engagement Feedback 3.3.5 Impact of Benchmarking
	5.4.1 g) System development over the planning period	3.3.6 System Development Forecast over the Planning Period
	5.4.1 h) List of projects planned to address: customer, technology, and innovation	3.3.7 List of Projects Planned to Address Customer, Technology, and Innovation
5.4.2	**Capital expenditure planning**	3.4 Capital Expenditure Planning Process Overview
	5.4.2 a) Capital planning objectives, criteria	Discussed within 2.1 Investment Planning Process
	5.4.2 b) Policies	Discussed within 2.1.1 Strategic Context
	5.4.2 c) Process for identifying investments	Discussed within 2.1.3 Needs Assessment
	5.4.2 d) Customer engagement process	Discussed within 1.3.2 Customer Engagement Process
	5.4.2 e) Process for prioritizing renewables	Discussed within 2.1.5 Investment Optimization
5.4.3	**System capability assessment for renewables**	3.5 Distributed Generation Connections
	5.4.3 a) Renewable applications	3.5.1 Renewable Applications
	5.4.3 b) Number/capacity of connections	3.5.2 Connection Forecast - Distributed Generation
	5.4.3 c) Capacity of system	3.5.3 Capacity and Constraints – Distributed Generation
	5.4.3 d) System constraints for renewables	

OEB Chapter 5 Filing Requirement		Hydro One Reference
	5.4.3 e) System constraints for embedded LDC	
5.4.4	**Capital expenditure summary**	**3.6 Capital Expenditure Summary**
	Table 2	Discussed within the following: • 3.6.1 Shifts in Forecast vs. Historical Budgets by Category • 3.6.2 Plan vs. Actual Variance Trends by Category • 3.6.3 Impact of Capital Investment on Operations, Maintenance and Administration Spending
5.4.5	**Justifying Capital Expenditures**	**3.6 Capital Expenditure Summary**
	5.4.5.1 Overall Plan	3.6 Capital Expenditure Forecast
	5.4.5.2 Material Investments *A) General information on investment* *B) Evaluation criteria* *C) Category specific requirements*	3.7 List of Material Capital Investments Proposed 3.8 Attachments: Investment Summary Documents – Material Capital Investments

THIRD PARTY REVIEW OF DSP

To ensure that the Hydro One DSP was complete and constructed in accordance with industry practice, Hydro One sought counsel from an independent third party. AESI Inc. ("AESI") is an international firm that has consulted with several local distributors in Ontario and has significant experience in preparing system plans at many utilities across the province. AESI was asked to review the Hydro One DSP and provide advice with respect to suitability and compliance. Hydro One relied upon that advice in preparing the DSP.

Exhibit B1, Schedule 1, Tab 2 includes the attestation of AESI that this DSP satisfies the *OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements*. Included, as well, is a final report outlining the findings and recommendations from their review.

INFORMATION FOR ACQUIRED UTILITIES

Hydro One, since its last rebasing of rates for 2015-2017, has acquired three local distribution companies – Haldimand County Hydro Inc. ("HCHI"), Norfolk Power Distribution Inc. ("NPDI"), and Woodstock Hydro Services Inc. ("WHSI") (collectively the "Acquired Utilities"). Operationally, all three of the Acquired Utilities have been integrated into normal Hydro One operations. The investment planning for these areas follows the process described in Section 2.1 of the DSP. The Asset registry information and the Asset Strategies employed to monitor and maintain the Acquired Utilities' assets are included in Sections 2.2 and 2.3 of the DSP.

For rate making purposes the Acquired Utilities have been kept separate from Hydro One. The financial information presented in the DSP excludes the financial information for the Acquired Utilities until January 1, 2021. Details regarding the financial integration of the Acquired Utilities are included in Exhibit A, Tab 7, Schedule 1.

Separate DSPs were not prepared for each of the Acquired Utilities. Details regarding the characteristics of the assets of the Utilities are included as Appendix A attached to the Hydro One DSP at Exhibit B1, Tab 1, Schedule 1.

1.1 (5.2.1) DISTRIBUTION SYSTEM PLAN OVERVIEW

Hydro One's Distribution System Plan (DSP) is the product of an investment planning process in which Hydro One engaged directly with customers to learn their needs and preferences. Customers want their rates to be kept as low as possible. To specifically address these rate sensitivities, Hydro One has right-sized its 2018 capital plan by increasing its efficiency and reducing its OM&A costs before asking customers to pay higher rates. The DSP reflects Hydro One's plan to appropriately prioritize and pace its capital investments over the 2018 to 2022 period which will align: (a) customer needs to keep rates as low as possible and a preference to maintain current service levels; (b) asset needs driven by condition and compliance requirements; and (c) rate impacts.

The process to prepare a Distribution System Plan is long, complex and iterative. The process involves accumulating and assessing a significant amount of information that supports decisions related to a system with assets worth $7.7 billion (2018 distribution rate base) that serves approximately 1.3 million residential customers and a network of unique commercial and industrial customers with varying needs and preferences.

For this Application, Hydro One is very aware that customers are experiencing increasing and, in some cases, unmanageable electricity bills. These increases have been driven by many factors, including investments by generators, the need to invest in the end-of-life wires infrastructure and material changes in generation mix, from lower-cost coal to a higher reliance on cleaner and more efficient natural gas, nuclear and renewable generation. In addition, conservation and demand management initiatives have increased costs, on a per kWh basis, as the predominantly fixed system investment is now being recovered over lower total Ontario demand.

Hydro One's approach has been shaped by: (i) a thorough investigation of opportunities to reduce its costs and increase efficiencies; (ii) ensuring investments support specific customer feedback on needs and preferences; and (iii) reducing or deferring investment levels to align customer rate impacts and potential impacts on reliability.

Hydro One cares about all of its customers. It is very concerned about the effect of electricity costs on its most vulnerable customers. In some cases, bills for a low-density customer, even after the upcoming provincial rebates and existing support programs, can represent 18% of household net income. Studies presented to the OEB in the past have drawn the affordability line at 4-6% of household net income. About 71,000 Hydro One customers exceed the Statistics Canada Low-Income Cut-offs, with 3,500 of those experiencing electricity costs greater than 10% of net income. Hydro One's customer service representatives manage these customer impacts with as much empathy as possible and encourage these customers to fully avail themselves of existing support programs. Hydro One is also participating in OEB initiatives and studies, such as the First Nations rate recommendations, and is sharing and communicating specific support programs and ways to reduce consumption within First Nations communities.

Initially, Hydro One prepared an asset investment plan, known as Plan A, which focused on maintaining or improving reliability for customers, and responded to specific feedback received from a wide variety of customers. It included significant efficiency improvements and focused on reducing backlog of deteriorated assets over the five-year period. Plan A resulted in a 7.1%[1] Hydro One rate increase in 2018 (average of 3.8% over the five years), and forecasted improvement of approximately 6% in SAIDI and 4%

---

[1] The rate impacts and reliability projections included in Section 1.1 are equal to the numbers used during the business plan review period ending November 2016 described in this section. Current rate impacts using revised data have subsequently been calculated and a complete list of the rate impacts are included in Exhibit H, Tab 4, Schedule 1.

in SAIFI[2] related to the company's most significant areas of reliability risk over the five-year period. Plan A was supported by detailed analysis, iteration and assessment of investment candidates and asset sustainment plans, and reductions of certain candidate investments.

Hydro One then prepared a detailed plan using lower levels of investment than in the Plan A recommendation. Based on these inputs and feedback from executive management, an alternative investment "Plan B" was produced that reduces the rate impact in 2018 by 1%, to 6.2% (average of 3.5% over the five years), and also delivers a reliability improvement (approximately 3% SAIDI, 2% SAIFI).

The Plan A and Plan B alternatives were further discussed with the Executive Leadership Team and, subsequently, the Board of Directors. These discussions explored further options to mitigate rate effects and, in particular, options to reduce the effect on customer rates in 2018 while maintaining responsible system investments, acceptable reliability and other outcomes.

Hydro One also considered what would be required to achieve the lowest 2018 rate increase without material disruption to its operations. Presented as the "Plan C" scenario, Hydro One's conclusion was that this option as a whole was not viable due to the estimated degradation of approximately 2% in both SAIDI and SAIFI that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition.

---

[2] Detailed, updated SAIDI and SAIFI projections by component are included in Section 2.4.

However, Hydro One also considered an option known as "Plan B – Modified." This option reduces the immediate impact on rates in 2018 to 5.4% while holding reliability performance constant over the planning period. The remainder of the DSP details the process followed to arrive at Hydro One's final investment plan, Plan B – Modified.

Section 1 of the DSP provides information on critical inputs into the formation of Hydro One's investment plan, specifically, customer engagement results, regional plans, internal productivity analyses and external benchmarking analyses.

Section 2 discusses the Investment and Asset strategies followed by Hydro One with respect to its asset base. The planning and optimization processes undertaken to determine the appropriate portfolio of investments and a detailed description of the system and its components are included here.

Section 3 describes the specifics about the selected investments including a set of Investment Summary Documents ("ISD") describing all investments over $1 million.

1.1.1 (5.2.1 A) KEY ELEMENTS OF THE DSP

Alignment of Business Objectives

The Business Objectives for Hydro One's Distribution System Plan reflect its assessment of customer needs and preferences. Other drivers of investment planning include public and worker safety, productivity and efficiency improvements, compliance with regulations, codes and rules and environmental sustainability.

Hydro One has appropriately prioritized and paced the elements of its proposed plan to align customers' needs regarding service levels with rate impacts and system reliability. Complete details on Hydro One's customer engagement activities are in Section 1.3.

Hydro One's DSP is the result of applying its planning process to produce an investment plan that meets Hydro One's Business Objectives. These Objectives align with the OEB's Renewed Regulatory Framework Performance Outcomes. The Business Objectives and processes are explained in detail in Section 2.1. The alignment of Hydro One Business Objectives and RRF Outcomes is listed in the table below for convenience.

Table 1: OEB Performance Outcomes and Hydro One Business Objectives

OEB RRF Performance Outcomes	**Hydro One Business Objectives**
Customer Focus Services are provided in a manner that responds to identified customer preferences	**Customer** • Improve current levels of customer satisfaction • Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	**Safety** • Drive towards achieving an injury-free workplace for employees and the public
	Reliability • Provide reliability consistent with customer expectations
	Productivity • Actively control and lower costs through OM&A and capital efficiencies
	Employees • Achieve and maintain employee engagement
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Shareholder Value** • Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment • Sustainably manage our environmental footprint

OEB RRF Performance Outcomes	Hydro One Business Objectives
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Benefit** • Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts

Hydro One's planning process produced a sustainable and prudent five-year plan that will allow the company to deliver on the Business Objectives listed above from 2018 to 2022. This plan seeks to achieve the desired Business Objectives over the long term by managing foreseeable changes and requirements on its distribution system.

Regional Planning

Based on the results of regional planning activities described in Section 1.2, a number of investments are included in the DSP which are related to regional infrastructure needs. This is aligned with customer preferences to ensure adequate capacity is available and to connect new customers to the system. These consist of capital contributions to the transmitter, for new or upgraded connection facilities and construction of new feeders to utilize such transmission connection capacity.

Customer Engagement

The DSP is designed to show how Hydro One understands customers' needs and preferences and that this understanding is reflected in its investment plan. Some of the specific measures being taken to address the customer engagement information are listed below.

Through customer engagement activities, customers indicated that keeping rates low was their top priority and many customers, especially residential customers, ranked reliability performance second to rate impacts. In alignment with customer needs and preferences, Hydro One has deliberately deferred some early year capital spending in order to pace investments in such a way as to minimize rate impacts and offset the effects of a reduced load forecast. This includes managing rate of replacement and, where appropriate, accepting short-term, small scale reliability impacts to reduce or defer capital spending requirements and minimize rate impacts.

A top priority for Large Customers is to improve power quality. To address this, Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue they are experiencing. Furthermore, a capital power quality program has been incorporated into the plan. Hydro One has also increased the funding for reliability enhancement projects to specifically target Large Distribution Account ("LDA") and mid-size industrial customers.

Residential and Small Business customers requested that Hydro One maintain its existing level of reliability. In an effort that shows an understanding of its customers, Hydro One has assessed the condition of its key assets and has developed an investment plan that properly paces renewal investments to sustain reliability performance across the province. By responding to customer preferences, Hydro One has created a distribution outcome that is valued by its customers. Supporting this are System Renewal projects and programs such as the Pole Replacement Program, Distribution Station Refurbishment Projects, and Line Renewal Projects.

The pole replacement program will be replacing 77,400 poles over the planning period to manage the volume of poles in poor condition. Similarly, the number of distribution stations that are refurbished has been established to sustain the condition of the fleet. Reliability performance of specific feeders that have outlier performance will be addressed by correcting the root cause of reliability on a case by case basis. Some feeder performance improvements will be accomplished through remote monitoring and control of switches and breakers as well as fault locating technology and additional protective devices.

Further details regarding customer engagement are included in Section 1.3.

Outcome Measures

Productivity and outcome measures are used to drive continuous improvement in asset management planning, work execution, and in customer-oriented performance. The measures are driven by the alignment of Hydro One's performance measures with its Business Objectives and the corresponding RRF Outcomes described in Table 1 above. Furthermore, Section 1.4 details the outcome measures that will demonstrate performance in:

- Customer Focus;
- OM&A and Capital Efficiencies;
- Managing Public Safety Risk;
- Providing Reliability Consistent with Customer Expectations; and
- Public Policy Responsiveness.

Productivity

To support the accomplishment of its Business Objectives, Hydro One has reaffirmed its commitment to continuous improvement and providing outcomes which are valued by customers, including cost efficiency. This renewed focus on productivity has become central to the planning and execution of work programs across the Company.

Hydro One has undertaken a number of initiatives to reduce costs while maintaining service quality and work outputs. These initiatives are the result of an internal evaluation of the Company to determine where productivity improvements could be made. Recommendations were made and evaluated to determine feasibility and to ensure that sustainable improvement would be the result. These quantifiable cost improvements were then embedded in the business plan with respective managers accountable for delivering the expected savings.

The following items summarize the planned productivity initiatives.

- More effective procurement programs, including investments in new processes and tools;
- Reductions in administrative expenditures through improved processes and optimization of internal staff skills;
- Rationalization of IT spending;
- Improved field efficiency through improved work planning; and
- Development of analytical measures, including more linkages for projects and programs to reliability performance to enable tracking of outcomes and better leverage of existing spending.

More details on these items and the specific initiatives planned are included in Section 1.5.

Benchmarking

Benchmarking is increasingly being referenced as a means of monitoring company performance. With the vision of excellence in execution, Hydro One has conducted the following studies:

- Total Factor Productivity;
- Pole Replacement and Station Refurbishment;
- Vegetation Management;
- IT Budget Assessment;

- Total Compensation; and
- Total Cost.

In summary, Hydro One is addressing the following key recommendations:

- Institute productivity initiatives to lower cost (see Section 1.5 for details on those initiatives);
- More comprehensive but less frequent pole inspections;
- Investigate the feasibility of pole refurbishment;
- Increase pole replacement rate;
- Implementing a formal data governance process for equipment data;
- Enhance cost and work completion reporting;
- Develop a more comprehensive set of key performance indicators on reliability, cost and asset health;
- Continue expansion of Hydro One's station-centric approach to refurbishment; and
- Maintain the current condition profile and reliability for stations.

The findings and recommendations from the studies are described in detail in Section 1.6.

Asset Management Process

Infrastructure Asset Management is the combination of management, financial, economic, engineering, and other practices applied to physical assets, with the objective of providing a level of service that is consistent with customer needs and preferences, consistent with asset needs and responsive to rate impacts. Hydro One's asset management goal is to monitor system assets and determine the optimal timing of asset maintenance and capital investments throughout the asset life cycle. This is done to manage risks and to support the achievement of Hydro One's Business Objectives, while managing total cost and customer rate impacts.

For the planning of capital investments, Hydro One utilizes a comprehensive investment planning process for identification, prioritization and optimization of asset and capital investments. An overview of the investment planning process is included in Section 2.1.

On the asset maintenance side, strategies are developed based on the condition and requirements of the various assets themselves. A high level summary of Hydro One's distribution system and associated key distribution assets outlining the specific maintenance and replacement strategies for each of these various assets is contained in Section 2.2.

As described in Section 2.3, a large number of Hydro One's assets require significant investment to maintain supply reliability and to mitigate the associated risks to Hydro One's Business Objectives.

Hydro One has a number of proactive investment programs that aim to pre-emptively address critical assets where a failure would impact a large number of customers. Hydro One has maintenance programs to address less pervasive assets and to quickly respond to events such as asset failures on a reactive basis. Finally, Hydro One has comprehensive demand-driven programs that react to unforeseen incidents that affect the entire system, such as storms or other external factors.

Capital Expenditure Plan

The investments reflected in the DSP are grouped into four categories: System Access, System Renewal, System Service, and General Plant. Nearly half of Hydro One's distribution capital plan is focused on System Renewal investments where an asset's condition warrants replacement. A summary of Hydro One's capital expenditure plan by these four categories is provided in Tables 2 and 3 below.

Table 2: 2018 – 2022 Capital Spending Forecast ($ Million)

Category	**2018**	**2019**	**2020**	**2021**	**2022**
System Access	154.6	157.6	160.9	165.9	170.0
System Renewal	248.6	318.7	336.7	362.5	451.1
System Service	81.8	93.4	85.6	78.8	69.5
General Plant	149.0	187.1	135.8	133.4	136.6
Total	**633.9**	**756.8**	**719.0**	**740.7**	**827.2**

Table 3: 2018 – 2022 Capital Spending Forecast (% by Category)

Category	**2018**	**2019**	**2020**	**2021**	**2022**
System Access	24%	21%	22%	22%	21%
System Renewal	39%	42%	47%	49%	55%
System Service	13%	12%	12%	11%	8%
General Plant	23%	25%	19%	18%	17%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Investment Summary Documents ("ISD") detailing the specifics for each material investment with spending greater than $1 million in any one year are listed in Section 3.7 and included in Section 3.8. An overview of the main factors driving the investments in each of these categories is included below.

System Access

New connections, line relocations, and service upgrades make up the bulk of activities in this category. Most of this spending is non-discretionary in nature and is dominated by the New Load Connections program (ISD SA-04) as it relates to providing customers with access to the system. Average spending is expected to increase less than 0.2% over the forecast period.

System Renewal

System Renewal investment costs are projected to increase by an average of 12.3% annually during the forecast period. Storm damage restoration and trouble calls, pole replacements, and distribution station refurbishments (ISD SR-07, ISD SR-09, and ISD SR-06, respectively) make up the bulk of activities in this category. Storm damage restoration and trouble call costs have been forecast based on multi-year historical experience and are expected to remain stable and consistent over the period of the DSP with normal year over year volatility due to weather patterns.

The pole replacement program (ISD SR-09) is planned to be lower in 2018, to address customer rate sensitivities. The program will then increase until 2020 and level off in 2021 and 2022. There is a low reliability impact associated with this plan. Hydro One's goal is to sustain or modestly improve the condition of the pole fleet through the investment planning period.

In order to align customer rate sensitivities with rate impacts, the station refurbishment program (ISD SR-06) is expected to decrease in 2018 and then continue to increase until 2020. This also will have limited reliability impacts over the short term and the increase towards the end of the plan reflects the growing number of assets forecast to be in deteriorated condition and requiring refurbishment to avoid negative reliability performance impacts.

A significant increase in projected spending for 2022 reflects the required replacement of smart meters that begin reaching the end of their useful life (ISD SR-14).

System Service

After 2018, System Service investment costs are projected to trend downward over the forecast period. Hydro One expects variability from year to year based on specific investment needs but spending over the 5 year period is expected to increase by an average of 0.8% annually. The bulk of these investments address the system constraints caused primarily by increases in load and ensure that customers continue to receive consistent service. To alleviate constraints, a multitude of investments throughout the province are planned to upgrade the capacity of Hydro One's distribution assets. Material investments designed to upgrade capacity include System Upgrades Driven by Load Growth (ISD SS-02). Hydro One has selected and is targeting the feeder performance outliers on the system for improvement (ISD SS-06). Hydro One will expand this program throughout the forecast period. This investment will improve system reliability for feeder performance outliers.

General Plant

The largest single portion of General Plant spending supports transport and work equipment investments (ISD GP-01). The next largest portion funds general facility improvements (ISD GP-02). General Plant investment costs are generally expected to decline modestly until the end of the forecast period in 2022 except for the spending associated with the planned new Integrated System Operations Centre (ISD GP-18). This will replace the existing backup power system control and telecommunications management centres and accommodate a new security operations centre to meet business and regulatory requirements.

Overall, General Plant investments are expected to decline over the period by an average of 1.4% per year.

Further Details on the Capital Expenditure Plan are included in Section 3.0.

1.1.2 (5.2.1 B) COST SAVINGS

To support the accomplishment of its Business Objectives, Hydro One has reaffirmed its commitment to continuous improvement and providing outcomes which are valued by customers, including cost efficiency. This renewed focus on productivity has become central to the planning and execution of work programs across the company.

Hydro One has undertaken a number of initiatives to reduce costs while maintaining service quality and work outputs. These initiatives are the result of an internal evaluation of the company to determine where productivity improvements could be made. Recommendations were made and evaluated to determine feasibility and to ensure that sustainable improvement would result, leading to reduced customer rates. These quantifiable improvements were then embedded in the business plan with respective managers accountable for delivering the expected savings. The planned savings are summarized in the table below. Details of the major productivity initiatives and forecast savings are included in Section 1.5.

Table 4 - Productivity Savings Forecast Summary

$ Millions	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	25.5	26.8	32.2	33.7	34.6
OM&A	34.5	40.5	43.2	45.5	49.8
Corporate Common	3.2	3.3	3.3	3.3	3.3
Total Savings	**63.2**	**70.5**	**78.7**	**82.5**	**87.6**

Witness: Darlene Bradley

1.1.3 (5.2.1 C) PERIOD COVERED BY THE DSP

The DSP covers the historical period from 2013 to 2016, the Bridge period of 2017, where the financial information is based on the first quarter forecast for the year end totals, and the test years from 2018 to 2022.

1.1.4 (5.2.1 D) VINTAGE OF THE INFORMATION

Information contained in this DSP is considered current as of the end of 2016. The asset assessment information utilized in the report (e.g., condition data and performance data) is based on data as of August 2016 to allow time to process and analyze the information to facilitate preparation of the DSP for this rate filing. The asset registry information is current as of October 2016 to allow adequate time for incorporation into the DSP.

1.1.5 (5.2.1 E) CHANGES TO ASSET MANAGEMENT PROCESS

Since Hydro One's last distribution application, it has implemented several improvements to its asset management process, such as restructuring the training process and content, improving data quality assurance and enhancing the enterprise engagement experience.

Investment Planning Training

Investment planning training was restructured into major components of the overall process to assist planners and management in the development of investment plans.

The first training segment outlines key influences on the investment planning process, such as regulatory requirements and details various aspects, requirements and deliverables during the process cycle. This segment is to help ensure planners and managers understand the expectations and conditions in which to develop plans.

The second segment was developed to assist planners in developing appropriate risk assessments for candidate investments. Illustrative examples are used to help planners understand the alignment of investments to the overall corporate business objectives and foster consideration of alternative approaches to articulate investment risk.

The third segment details the elements of the Asset Investment Planning ("AIP") tool to ensure planner awareness of optimization criteria that would affect investment candidates during the optimization process.

In the interest of operating as one company, Hydro One structured training sessions for each of the key asset management business units involved in the planning process to create a focused environment and ensure consistency across the planning groups. Further review of the investment planning process resulted in an initiative for management training on optimization. This detailed overview provides management insight into the optimization process and its effect on their candidate investments within Hydro One's overall investment portfolio.

Data Quality Assurance

The quality assurance process within the investment planning process was further developed to ensure the investment plan is successful in meeting customer expectations and corporate business objectives. Enhancements to the quality assurance process include weekly reporting to planners and management of investment data quality issues, a checklist for management review and a dedicated risk calibration session prior to optimization to promote risk assessment consistency across planning groups. Mitigation of potential issues in advance of optimization sets the appropriate criteria for investment candidates during optimization and warrants a more effective investment plan as a result.

A risk to corporate project prioritization is related to consistency of the risk assessments across planning groups. Hydro One continues to employ quality assurance to harmonize these assessments and build a more standardized planning process across the various planning groups.

Enterprise Engagement

Enterprise engagement is used to describe the collaboration of stakeholders, planning and operations, during the investment planning process. Previously, this was a specific dedicated segment held during post-optimization. However, the concept has now been further developed in order to foster communication between stakeholders throughout the investment planning process. Stakeholder sessions were implemented prior to the start of the investment planning process to set expectations, gather feedback of any future concerns and ensure fundamentals, such as unit cost updates, are in place as a foundation to success. Collaboration during the development of an investment candidate promotes consideration of appropriate unit costs, execution strategies and historical results leading to a more robust investment definition and strategy. The dedicated post-optimization enterprise engagement segment, which is described in Section 2.1.5.2, was lengthened to support a thorough review of resource capabilities, execution risks and assurance of outcome measures.

1.1.6 (5.2.1 F) WORK CONTINGENT ON HISTORIC/FUTURE ACTIVITIES

Some investments in the General Plant and System Service categories are contingent on the outcome of ongoing activities. The level of System Access investment related to connecting new customers, distributed generation connections or third party infrastructure projects is dependent on externally-driven requests.

Hydro One Distribution is commonly required to make a capital contribution to support required capital investments on the transmission system. These transmission assets are needed in order to accommodate Hydro One Distribution load increases. These investments are categorized as General Plant investments. General Plant investments related to Hydro One Distribution's capital contribution for investments on the transmission system are contingent on the approval and schedule of the associated transmission projects. A list of the investments to which Hydro One Distribution is forecast to make capital contributions during the period of the DSP are:

- Leamington TS, (ISD GP-25);
- Hanmer TS, (ISD GP-26); and
- Enfield TS, (ISD GP-27).

System Service investments to fund the new Leamington TS and Enfield TS feeder development projects are contingent on the approval and schedule for Hydro One's Leamington TS and Enfield TS transmission investments.

Several General Plant investments are common to both Hydro One's transmission and distribution businesses. These common investments are contingent on the approval of Hydro One's transmission portion of the investment.

1.2 (5.2.2) COORDINATED PLANNING WITH THIRD PARTIES - REGIONAL PLANNING

Planning transmission and distribution infrastructure on a regional basis helps promote the cost effective development of the electricity infrastructure in Ontario. This is one of the key guiding principles in the Board's Renewed Regulatory Framework[1] requirements which states that infrastructure planning on a regional basis, between licensed transmitters and distributors, is to be undertaken to ensure that regional issues and requirements are integrated into the utility's planning processes.

Hydro One Distribution is actively involved in the regional planning process. This is consistent with Hydro One's business objectives of addressing customer needs and responding to public policy initiatives as well as contributing to the continued economic success of the province.

The following sections outline: (a) the regional planning process as outlined in the "The Process for Regional Infrastructure Planning in Ontario" report[2] endorsed by the Board; (b) Hydro One Distribution's participation in the consultation process; and (c) the status of regional planning activities and how these are reflected in the distribution system plan.

[1] http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf - Page 39
[2] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

1.2.1 (5.2.2 A) OVERVIEW OF THE REGIONAL PLANNING PROCESS

Regional planning addresses supply and reliability issues at a localized level. The regional planning process focuses on coordinating the planning of transmission-level investments that provide supply to more than one distributor. Distribution-level investments are considered when such investments address a regional need more effectively than other transmission options.

Figure 1 illustrates the various phases of the regional planning process and the trigger, process lead, and outcome for each respective phase, as documented in the "The Process for Regional Infrastructure Planning in Ontario" report endorsed by the Board. It is intended that this process be repeated for each of the 21 regions in the province every five years. The process may be more frequent, depending upon the emergence of new needs.

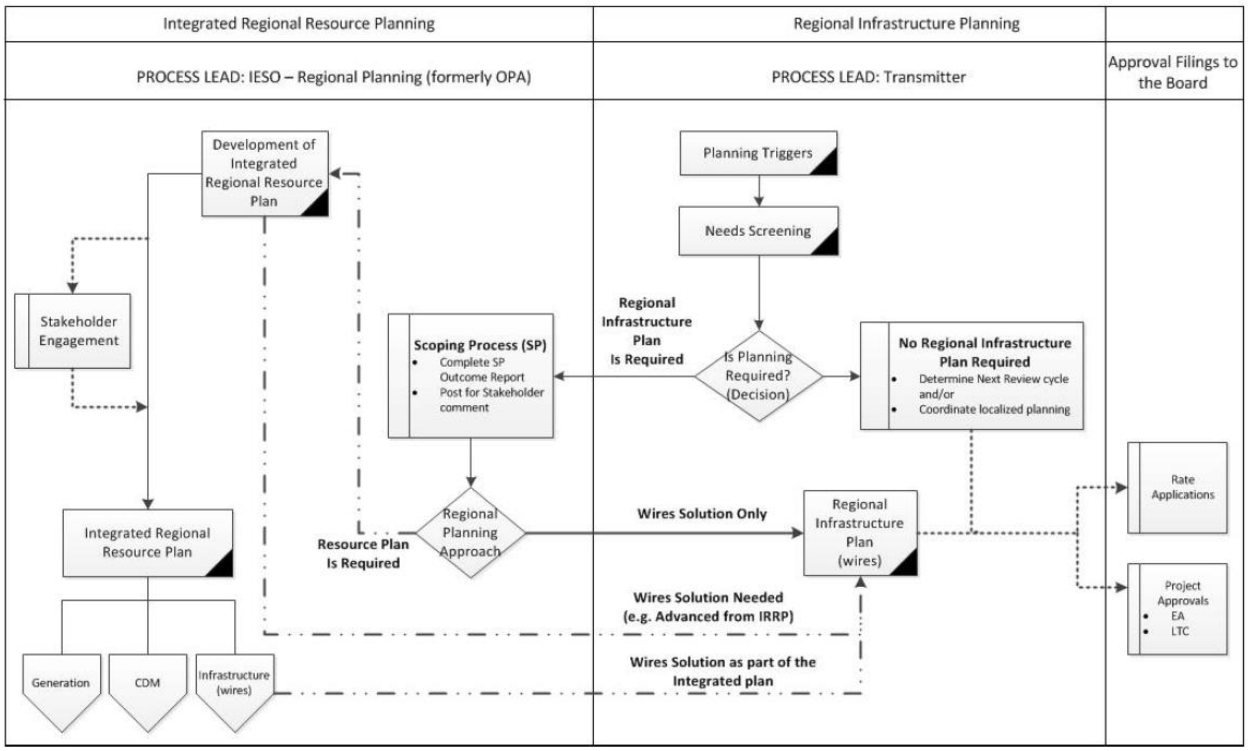


Figure 1 - Regional Planning Process

In general, the process consists of the following phases:

- Needs Screening (or Needs Assessment ("NA"));
- Scoping Process (or Scoping Assessment ("SA"));
- Integrated Regional Resource Plan ("IRRP"); and
- Regional Infrastructure Plan ("RIP").

The regional planning process begins with planning triggers. Planning triggers include:

- a regularly scheduled Needs Assessment by the transmitter (every five years);
- a scheduled review specified in an existing RIP;
- a Government directive;
- a significant change to codes and standards; or

Witness: Darlene Bradley / Lyla Garzouzi

- an emergent need brought forward by the transmitter, distributors, customers, or the Independent Electricity System Operator ("IESO") that cannot wait until the next scheduled review.

The initial phase of the regional planning process is the Needs Assessment phase which is led by the transmitter. In this phase, needs are identified in consultation with distributors and the IESO, and a high level assessment is undertaken to determine potential alternatives or solutions to address the needs.

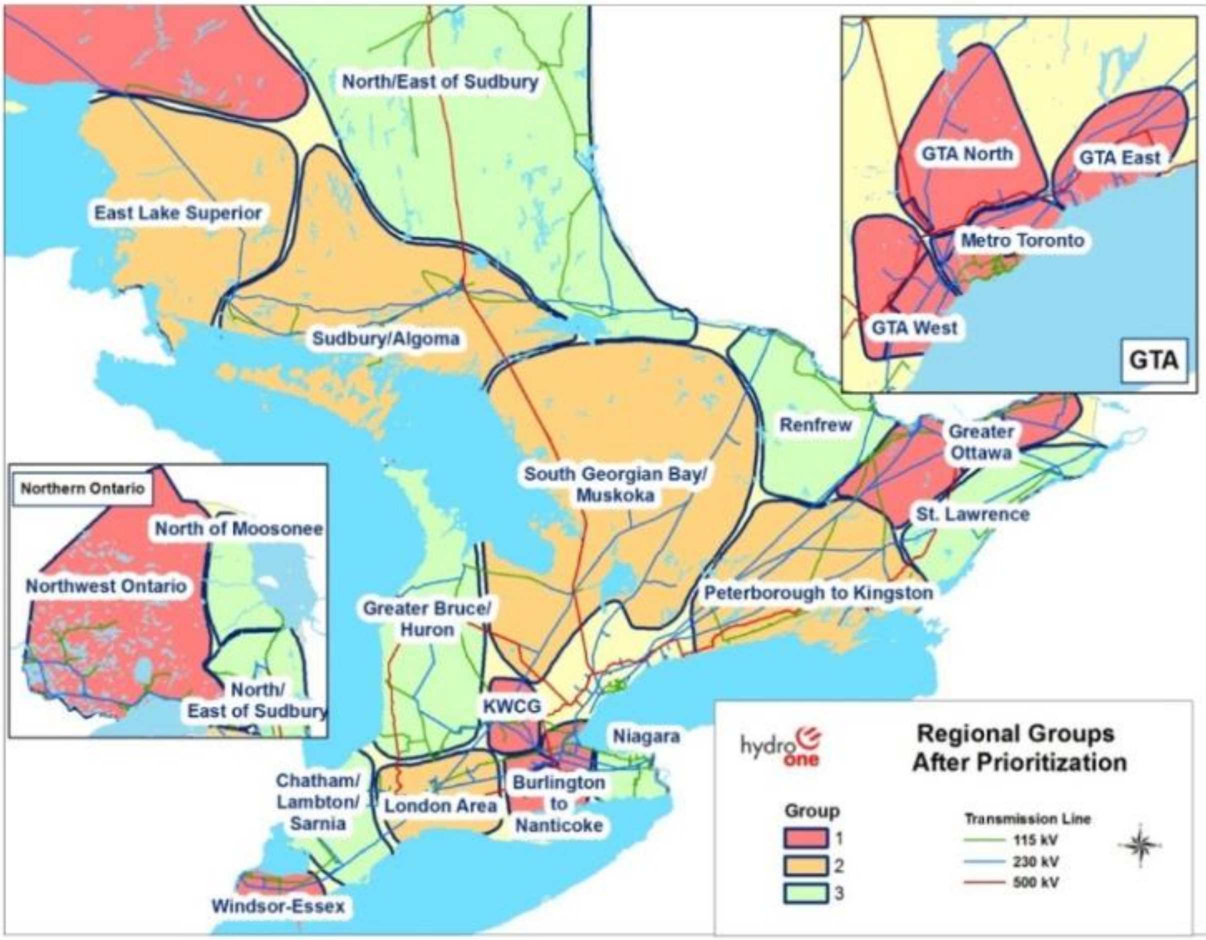
In cases where: (a) the needs are local or limited in nature; (b) further regional coordination is not required; and (c) the needs can be addressed directly by the transmitter and distributor(s) or other transmission connected customer(s) through transmission and/or distribution facilities ("wires") solution(s), then a local plan is developed. The local plan(s) ultimately becomes part of the RIP for the region.

In other cases where further planning studies and coordination are necessary, the IESO initiates the Scoping Assessment phase. The IESO, in collaboration with the transmitter and impacted distributors, reviews the information collected during the Needs Assessment phase. The IESO also considers information relating to potential non-wires alternatives (e.g. conservation, generation). Based on these analyses, the IESO determines the most appropriate regional planning approach, (i.e. whether an IRRP or an RIP or both are required), to address the needs in the region or sub-region.

The IRRP process involves the identification, evaluation and integration of potential wires and non-wires solutions at the regional or sub-regional level. The IRRP phase generally assesses resource versus wires infrastructure options at a higher level, but with sufficient detail to allow for a comparison of options. If the IRRP determines that resource options are best suited to meet a need, then those options are further planned by the IESO. However, if wires options are the more appropriate alternative, then those options are further assessed as part of the RIP process.

The RIP process is the final phase of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs. This phase is led and coordinated by the transmitter, and the deliverable of this phase is a comprehensive report of a wires plan for the region.

To undertake the regional planning process, the province was divided into 21 electrical regions for the purposes of conducting assessments and developing regional plans. Each of these 21 regions have been assigned to one of the three regional planning groups in order to prioritize and manage the regional planning process, as noted in Figure 2 below. Hydro One Distribution is a participant in all regions, except East Lake Superior and North of Moosonee.



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

Figure 2 - Regional Planning Groups

Note: (1) "KWCG" stands for Kitchener-Waterloo-Cambridge-Guelph
(2) Hydro One Distribution is not a participant in this region

1.2.2 (5.2.2 A) REGIONAL PLANNING CONSULTATION DESCRIPTION

As part of the regional planning process, the lead transmitter undertakes consultation with stakeholders to identify needs and develop plans as envisioned by the Board in its Renewed Regulatory Framework. Hydro One, one of the LDC stakeholders, delivers its planning needs through this process and collaborates with the other LDC stakeholders as necessary. The customers of Hydro One benefit from this process in two key ways. First, the capacity needs of the system are addressed to ensure that expansion requirements to address load growth and new connections are undertaken in advance of customer in-service requirements. Second, any cost effective opportunities to collaboratively address capacity requirements with another LDC(s) are discussed and executed where feasible.

Over the last three years, working groups comprising representatives from the IESO, LDCs, Hydro One Distribution and Hydro One Transmission were established in all of the 19 regions across the province in which Hydro One Distribution manages assets. Hydro One Distribution's participation in the regional planning consultation for each of the regions includes:

1. **Pre-meeting Conference Calls / Webinars:** At the beginning of each phase, Hydro One Distribution, regional LDCs and the IESO are notified in advance of upcoming regional planning activities and are provided an overview of the process by the lead transmitter.
2. **Kick-Off Meeting: A** kick-off meeting with the working group takes place to initiate each of the phases of the regional planning process and provide templates for the collection of information/data.
3. **Additional Face to Face Meetings / Conference Calls / Webinars:** The working group meets on a regular basis to discuss planning matters such as assessment methodology, customer needs, and regional needs and timing before recommending a preferred solution.

Hydro One Distribution has been and continues to be an active participant in the regional planning process providing input into the Needs Assessment, Community Engagement, Scoping Assessment, Local Planning Reports, IRRP and RIP Reports. Specific input that has been provided by Hydro One Distribution includes:

- Providing short-term and long-term load forecasts to the transmitter and the IESO - both Gross and Net (with Conservation Demand Management & Distributed Generation) load forecasts are provided;
- Providing background on the distribution system including information on past system performance;
- Identifying local supply needs or constraints from the LDC perspective;
- Participating in community engagement sessions with local municipalities and other stakeholders;
- Participating in meetings of Local Advisory Councils;
- Participating in local planning led by the transmitter to address local supply needs as determined through the Needs Assessment stage;
- Identifying and evaluating of potential distribution based wires solutions to meet regional or local infrastructure needs;
- Attending regularly scheduled IRRP and RIP Working Group meetings at the regional and sub-regional level as required;
- Providing input and comments to proposed wires and non-wires solutions to address identified system needs; and
- Reviewing and providing comments on draft planning reports/documents prepared by the IESO and the transmitter.

For specific details at the regional level on all the participants involved, please refer to the reports filed as Attachments to this exhibit or to Hydro One's Regional Planning website:

http://www.hydroone.com/RegionalPlanning/Pages/home.aspx

These consultations ensure transparency of regional activities that may influence stakeholders' future planning strategies. The nature and prospective timing of the final deliverables that resulted from the consultations and their effect on distributor's Distribution System Plan are provided in the following sections.

1.2.3 STATUS OF REGIONAL PLANNING ACTIVITIES

As a province wide distributor, Hydro One Distribution's assets are located in 19 of the 21 regions that have been identified for the purpose of regional planning. These regions correspond to the same 19 regions where Hydro One Transmission is the lead transmitter. A copy of the latest Regional Planning Status Letter provided by Hydro One Transmission, as required under Section 3C.2.2 of the Transmission System Code, is provided in Attachment 2.

The initial cycle of regional planning has been completed, or deemed completed, for 12 out of the 19 regions that Hydro One belongs to, and the regional planning activities are in progress on the remaining 7 regions. A summary of the status of these regional planning activities for each region involving Hydro One Distribution, showing sub-regions where applicable, is provided in Table 5 below. The subsequent sections provide details on the regional planning activities that were completed or are underway for each region. For regions or sub-regions where planning has been completed, a description of the recommendations is provided as well as an indication of whether Hydro One Distribution is impacted by the recommendations.

Table 5: Regional Planning Status Summary

STATUS:		Completed		Not Required		In Progress		Not Started Yet

Region	Sub-Region	NA	SA	IRRP	RIP
Burlington to Nanticoke	Brant				
	Bronte				
	Greater Hamilton				
	Caledonia-Norfolk				
Greater Ottawa	Ottawa				
	Outer Ottawa				
GTA East	Oshawa-Clarington				
	Pickering-Ajax-Whitby				
GTA North	York				
	Western				
GTA West	Northwestern				
	Southern				
Kitchener-Waterloo Cambridge-Guelph (KWCG)					
Metro Toronto	Central Downtown				
	Northern				
Northwest Ontario	North of Dryden				
	Greenstone-Marathon				
	City of Thunder Bay				
	West of Thunder Bay				

Witness: Darlene Bradley / Lyla Garzouzi

STATUS:		Completed		Not Required		In Progress		Not Started Yet

Region	Sub-Region	NA	SA	IRRP	RIP
	Remote Communities				
Windsor-Essex					
London Area	Greater London				
	Aylmer-Tillsonburg				*
	Strathroy				*
	Woodstock				*
	St. Thomas				*
Peterborough to Kingston					
South Georgian Bay/Muskoka	Barrie/Innisfil				
	Parry Sound/Muskoka				
Sudbury/Algoma					
Chatham/Lambton/Sarnia					*
Greater Bruce/Huron					*
Niagara					
North/East of Sudbury					
Renfrew					
St. Lawrence					

Note: The asterisk (*) represents that a Local Planning Report is In Progress

NA=Needs Assessment; SA=Scoping Assessment; IRRP=Integrated Regional Resource Plan; RIP=Regional Infrastructure Plan

Burlington to Nanticoke Region

The Burlington to Nanticoke Region comprises four sub-regions: (i) **Brant,** (ii) **Bronte,** (iii) **Greater Hamilton**, and (iv) **Caledonia-Norfolk**. An IRRP for the Brant and Bronte sub-regions was completed and these reports are presented in Attachments 3 and 4 to this Exhibit.

The IRRP for the Brant and Bronte sub-regions did not identify any actions for Hydro One Distribution, as the recommended plans involve actions by the transmitter and other LDCs of the region. For the other two sub-regions, it was determined that the needs were local in nature. A Local Planning Report developed by Hydro One Distribution and impacted LDCs is presented in Attachment 5 of this Exhibit.

Consistent with the Local Planning Report, there are two local needs in the Burlington to Nanticoke Region which will require action by Hydro One Distribution, the Dundas TS Station Capacity (Project LG-28) and Reactive Support in Norfolk Area.

The RIP for the region is currently underway and is scheduled for completion in Q1 2017.

Greater Ottawa Region

The Greater Ottawa Region comprises of two sub-regions: (i) **Ottawa Area**; and (ii) **Outer Ottawa**. An RIP for this region was completed and is presented in Attachment 6 to this Exhibit.

The RIP for the Greater Ottawa Region did not identify any actions for Hydro One Distribution. All recommended plans will be implemented by Hydro One Transmission and/or another LDC from this region.

GTA East Region

The GTA East Region comprises two sub-regions: (i) **Pickering-Ajax-Whitby**; and (ii) **Oshawa-Clarington**. An IRRP for the Pickering-Ajax-Whitby sub-region was completed and is presented in Attachment 7 to this Exhibit. The recommended plan for this sub-region does not require any action by Hydro One Distribution.

For the Oshawa-Clarington sub-region, it was determined that the needs were local in nature. A Local Planning Report for Wilson TS and Thornton TS was developed by Hydro One and the impacted LDCs and is presented in Attachment 8 to this Exhibit. Consistent with the Local Planning Report, a new load station, "Enfield TS," to relieve Wilson TS and Thornton TS, is to be constructed. Hydro One Distribution is required to make a capital contribution to Enfield TS as per Section 6.3.1 of the TSC, (ISD GP-27). In addition, a coordinated review of feeder load transfer capabilities by Hydro One Distribution and Oshawa PUC was conducted in order to optimize the utilization of existing capacity at Wilson TS and Thornton TS.

The RIP for the region was completed in January 2017 and is presented in Attachment 28.

GTA North

The GTA North Region comprises two sub-regions: (i) **York**; and (ii) **Western**, with the York sub-region further defined into the Southern York Area and Northern York Area for planning purposes. An RIP for this region was completed and is presented in Attachment 9 to this Exhibit.

The RIP for the GTA North Region identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in the Northern York Area. Despite the non-wires solutions proposed in the RIP, there continues to be a need to address both the transformation capacity and transmission capacity limits in the Northern York Area as early as 2023. The working group expects to finalize a plan to address these needs in an IRRP update currently scheduled for completion in 2017. Hydro One Distribution is affected by the Northern York Area and as such will continue to be an active member of the working group as plans to address the medium and long-term needs in this area are developed.

GTA West

The GTA West Region comprises two sub-regions: (i) **Northwestern**; and (ii) **Southern**. An RIP for this region was completed and is presented in Attachment 10 to this Exhibit.

The RIP for the GTA West Region identified several needs and recommended actions to address the short and medium term needs in the region. The majority of these actions will be implemented by Hydro One Transmission and/or other LDCs within this region.

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

An RIP for the KWCG Region was completed and is presented in Attachment 11 to this Exhibit. The RIP for the KWCG Region did not identify any actions for Hydro One Distribution. All recommended plans will be implemented by Hydro One Transmission and/or other LDCs from this region.

Metro Toronto

The Metro Toronto Region comprises of two sub-regions: (i) **Central Downtown**; and (ii) **Northern**. An RIP for this region was completed and is presented in Attachment 12 to this exhibit.

Hydro One Distribution has no customers in the Metro Toronto Region, however it is a member of the region since it owns distribution assets that are used to transfer power from stations located within Toronto Hydro service territory to other LDC's outside the region. The RIP for the Metro Toronto Region identified plans to address needs in the Central Downtown sub-region which do not impact Hydro One Distribution. The RIP also concluded that there were no needs in the Northern sub-region.

Northwest Ontario

Northwest Ontario Region comprises of five sub-regions: (i) **North of Dryden**; (ii) **Greenstone-Marathon**; (iii) **City of Thunder Bay**; (iv) **West of Thunder Bay**; and (v) **Remote Communities**. The IRRP's for the North of Dryden, Greenstone-Marathon and West of Thunder Bay sub-regions were completed and are presented in Attachments 13, 14 and 15 to this Exhibit. The IRRP for the City of Thunder Bay sub-region was completed in December 2016.

Several needs and recommended actions were identified for the four sub-regions with completed IRRP's. Consistent with the IRRP, one of the recommendations involves transmission upgrades that impact load connection assets to which Hydro One Distribution is required to make a capital contribution as per Section 6.3.1 of the TSC.

The region's RIP will be initiated in Q1 2017. Other plans identified for the Northwest Ontario Region are not expected to impact Hydro One Distribution.

Windsor-Essex Region

The RIP for the Windsor-Essex Region was completed and is presented in Attachment 16 to this Exhibit. The RIP for the Windsor-Essex Region identified several needs and recommended actions. Consistent with the RIP, the Supply to Essex County Transmission Reinforcement ("SECTR") project is being undertaken to address the need for new transmission facilities to which Hydro One Distribution is required to make a capital contribution as per Section 6.3.1 of the TSC, (ISD GP-25).

London Area

The London Area Region comprises of five sub-regions: (i) **Greater London**; (ii) **Aylmer-Tillsonburg**; (iii) **Strathroy**; (iv) **Woodstock**; and (v) **St. Thomas**.

The IRRP for the Greater London sub-region is currently underway and is scheduled for completion in Q1 2017. The Needs Assessment for the London Area Region determined that, for the other four sub-regions, the needs were local in nature. The Needs Assessment report is presented in Attachment 17 to this Exhibit.

The RIP for the region will be initiated after the IRRP and sub-region RIP are completed.

Peterborough to Kingston

The RIP for the Peterborough to Kingston Region was completed and the report is presented in Attachment 18 to this Exhibit. The assessment determined that the needs in this region were local in nature. Consistent with the RIP, transformation capacity relief is required for Gardiner TS.

South Georgian Bay/Muskoka

The South Georgian Bay/Muskoka Region comprises two sub-regions: (i) **Parry Sound/Muskoka**; and (ii) **Barrie/Innisfil.** A Needs Assessment Report was completed for this Region and is presented in Attachment 19 to this Exhibit. The NA identified a requirement to complete IRRPs for both sub-regions which were completed in December 2016. These are presented in Attachments 29 and 30. The NA for this region also identified a local need concerning end-of-life assets at Orangeville TS. A Local Need Report for this is presented as Attachment 20.

For the Parry Sound/Muskoka IRRP, a near-term need to provide load relief to Parry Sound TS and Waubaushene TS was identified. The report recommended that Hydro One Distribution undertake distribution load transfers to mitigate overloading of these stations. The cost for Hydro One Distribution to construct these new distribution facilities is expected to be approximately $5M – $6M (LG-24 ISD SS-02).

The IRRP for Barrie/Innisfil identified an urgent need to upgrade Barrie TS and the existing E3/4B 115 kV transmission line with new 230 kV infrastructure as soon as possible. Hydro One Distribution has no distribution customers fed from Barrie TS but is a transmission connected customer at the station providing embedded LDC supply to InnPower via an idle 115 kV transmission line operating at 44 kV. The report recommends that Hydro One Distribution and InnPower develop a plan to build a new two-circuit 44 kV distribution line outside of the transmission corridor to meet future load needs in the area (LG-26).

The RIP for the region is scheduled for completion in 2017.

Sudbury/Algoma

The RIP for the Sudbury/Algoma Region was completed and the report is presented in Attachment 21 to this Exhibit. The assessment determined that the needs in this region were local in nature. A Local Planning Report was developed by Hydro One Distribution and impacted LDCs to address low incoming 115 kV supply voltage at Manitoulin TS.

The Needs Assessment report also references the construction of a new 230/44kV transformer station at Hanmer TS to replace the existing 115/22kV Coniston TS to which Hydro One Distribution is required to make a capital contribution, as per Section 6.3.1 of the TSC (ISD GP 26).

Chatham/Lambton/Sarnia

A Needs Assessment for the Chatham/Lambton/Sarnia Region was completed and the report is presented in Attachment 22 to this Exhibit. The assessment determined that the needs in this region were local in nature. A Local Planning Report is currently underway involving Hydro One Transmission and the affected LDC's, including Hydro One Distribution, to address these needs. The Local Planning Report is scheduled for completion by Q1 2017. The RIP will be finalized once the Local Planning report is completed.

Greater Bruce/Huron

A Needs Assessment for the Greater Bruce/Huron Region was completed and the report is presented in Attachment 23 to this Exhibit. The assessment determined that the needs in this region were local in nature. A Local Planning Report is currently underway involving Hydro One Transmission and the affected LDCs, including Hydro One Distribution, as well as the affected transmission connected customers, to address these needs. The Local Planning Report is scheduled for completion by Q2 2017. The RIP will be finalized once the Local Planning report is completed.

Niagara

A Needs Assessment for the Niagara Region was completed and the report is presented in Attachment 24 to this Exhibit. The assessment concluded that no regional infrastructure needs exist and no further planning is required at this point.

North/East of Sudbury

The Needs Assessment for the North/East of Sudbury Region was completed and the report is presented in Attachment 25 to this Exhibit. The assessment determined that the needs in this region were local in nature and that there are existing operating procedures in place to deal with potential low voltage conditions in the Timmins and Kirkland Lake areas. Hydro One Distribution will continue to monitor loading and voltage conditions in these areas and implement further planning as required.

Renfrew

The RIP for the Renfrew Region was completed and the report is presented in Attachment 26 to this Exhibit. The assessment concluded that no regional infrastructure needs and no further planning is required at this point.

St. Lawrence

The RIP for the St. Lawrence Region was completed and the report is presented in Attachment 27 to this Exhibit. The assessment concluded that no regional infrastructure needs exist and no further planning is required at this point.

1.2.4 (5.4.1 E) HOW THE PLAN REFLECTS REGIONAL PLANNING

Based on the results of regional planning activities described in the previous section, a number of investments are included in the DSP which are related to regional infrastructure needs. These consist of capital contributions to the transmitter for new connection facilities and construction of new feeders to incorporate new or existing transmission connection capacity. The table below summarizes the investments that are informed by the regional planning activities described in the previous section. The table contains the regional planning group, project description reference, timeline and expected costs where available.

Table 6 - Regional Planning Project Summary

Project ID	Project Name	In-Service Date	Project Plan	Project Cost	Region
ISD SS-02 Project LG-28	Dundas TS #2 Feeders	10/2020	Construct 2 x 44 kV feeder positions & 10 km of new line	$6.7M	Burlington to Nanticoke
ISD GP-27	Enfield TS - capital contribution	05/2019	C Build a new 230/44 kV 170 MVA TS shared between Hydro One and Oshawa PUC	$5.0M	GTA East
ISD SS-02 Project LG-11	Enfield TS Feeder Development	05/2019	Construct 20km of new 44 kV feeder lines	$8.0M	GTA East
ISD GP-25	Leamington TS Capital Contribution	04/2018	Build a new 230 kV – 27.6 kV DESN TS	$6.7M	Windsor-Essex
ISD SS-02 Project LG-14	Leamington TS Feeder Development	06/2019	Construct 20 km of new 27.6 kV lines	$10.5M	Windsor-Essex

Project ID	Project Name	In-Service Date	Project Plan	Project Cost	Region
	Kingston Gardiner TS M26 Feeder Development	10/2018	Develop 1 new 44 kV Feeder	$0.9M	Peterborough to Kingston
ISD GP-26	Hanmer TS Capital Contribution	02/2019	Add two new 50/83 MVA step-down transformers and associated switchgear at Hanmer TS	$16M	Sudbury/Algoma
ISD SR-11 Project LC-10	Hanmer TS Feeder Development	02/2019	Build 2.4 km new 44 kV line	$1.4M	Sudbury/Algoma
ISD SS-02 Project LG-24	Muskoka TS M5 x M1 Feeder Tie	12/2019	Build 14 km new 44 kV line	$5.3M	Southern Georgian Bay/Muskoka
ISD SS-02 Project LG-26	Barrie TS – Construct new Feeders	12/2020	Build 8km new 2-circuit 44 kV line	$2.6M	Southern Georgian Bay/Muskoka

Note: In all cases, the Project Costs included above refer to the amount that Hydro One Distribution will pay towards completion of the overall project. This may represent the net amount contributed toward a project to be completed by Hydro One Transmission or the amount net of contributions from other parties such as LDCs and Large Customers.

1.2.5 (5.2.2 B, C) ATTACHMENTS: IESO COMMENT LETTER AND REGIONAL PLANNING REPORTS

Attachment	Name
1	IESO Letter of Comment on Hydro One's DSP Renewable Energy Investments
2	Regional Planning Status Letter from Hydro One Transmission
3	Integrated Regional Resource Plan - Brant Sub-Region
4	Integrated Regional Resource Plan – Bronte Sub-Region
5	Local Planning Report – Burlington to Nanticoke Region
6	Regional Infrastructure Plan – Greater Ottawa
7	Integrated Regional Resource Plan – Pickering - Ajax-Whitby Sub-Region
8	Local Planning Report – Wilson-Thornton
9	Regional Infrastructure Plan – GTA North
10	Regional Infrastructure Plan – GTA West
11	Regional Infrastructure Plan – KWCG
12	Regional Infrastructure Plan – Metro Toronto
13	Integrated Regional Resource Plan – North of Dryden Sub-Region
14	Integrated Regional Resource Plan Greenstone-Marathon Sub-Region

Attachment	Name
15	Integrated Regional Resource Plan - West of Thunder Bay Sub-Region
16	Regional Infrastructure Plan – Windsor-Essex
17	Needs Assessment – London Area
18	Regional Infrastructure Plan – Peterborough to Kingston
19	Needs Assessment – South Georgian Bay/Muskoka
20	Local Planning Report – Orangeville TS
21	Regional Infrastructure Plan – Sudbury/Algoma
22	Needs Assessment – Chatham/Lambton/Sarnia
23	Needs Assessment – Greater Bruce/Huron
24	Needs Assessment – Niagara
25	Needs Assessment – North/East of Sudbury
26	Regional Infrastructure Plan – Renfrew
27	Regional Infrastructure Plan – St. Lawrence
28	Regional Infrastructure Plan – GTA East
29	Integrated Regional Resource Plan – Parry Sound/Muskoka Sub-Region
30	Integrated Regional Resource Plan – Barrie/Innisfil Sub-Region

IESO Letter of Comment

Hydro One Networks Inc.

Distribution System Plan

March 9, 2017

Connecting Today.
Powering Tomorrow.

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Hydro One Networks Inc. – Distribution System Plan

On February 27, 2017, Hydro One Networks Inc. ("Hydro One") provided its Renewable Energy Generation Investments Information ("Plan") to the Independent Electricity System Operator ("IESO") covering a 5-year forecast planning period. The IESO has reviewed Hydro One's Plan and provides the following comments.

OPA FIT/microFIT Applications Received

On Table 1 of its Plan, Hydro One indicates that they have connected and/or committed to connect the following renewable generation projects:

- 247 Capacity Allocation Required (CAR) projects with a total capacity of 1746.7 MW
- 729 Capacity Allocation Exempt (CAE) projects with a total capacity of 136.2 MW
- 13,885 MicroFIT projects with a total capacity of 125.9 MW.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

The IESO records as of January 31, 2017 indicate that the following REG projects have connected or approached Hydro One for connection based on IESO (and former OPA) contracts:

- 253 Capacity Allocation Required (CAR) projects with a total capacity of 1849 MW
- 816 Capacity Allocation Exempt (CAE) projects with a total capacity of 161 MW
- 13,114 MicroFIT projects with a total capacity of 122 MW.

The information provided by Hydro One is therefore reasonably consistent with that of the IESO.

The IESO also has 379 REG contracts under FIT 4 procurement program that will be connecting to Hydro One's distribution system. Hydro One's Plan refers to these 379 REG projects showing consistency with the IESO's records, however, the contract holders have not yet approached Hydro One for connection.

The renewable generation procurement program under FIT 5 is underway and the final outcome of this process will not be available until early summer. Hydro One's Plan estimates 200 CAE projects under the FIT 5 program to be connecting to its distribution system. The IESO believes this estimate is reasonable based on the information available to date.

In accordance with the September 27, 2016 direction from the Ministry of Energy, the IESO has ceased the Large Renewable Procurement program. Also, the Minister's December 16, 2016 direction amended the FIT 5 procurement target and directed the IESO to cease accepting applications under the FIT program by December 31, 2016. Therefore, future renewable generation projects will not be based on IESO contracts until further direction is given to the IESO. Hydro One has provided a forecast of distribution connection generation connection for the 2017-2022 period. However because of government direction to cease procurements under the noted REG programs, the IESO provides no comment on Hydro One's forecast.

With respect to REG investments, Hydro One's Plan indicates that for the planning period it has not forecast any investments for the purposes of enabling renewable energy generation connection. This fact eliminates the necessity of the IESO to comment on whether there is a potential need for coordination with others on implementing elements of the REG investments, and whether the REG investments proposed in the Plan are consistent with any Regional Infrastructure Plan.

The responsibilities of both Hydro One and the IESO are outlined in the OEB Transmission System Code, and the IESO's licence with respect to the province's regional planning process, and because of this there is, and will be, ongoing collaboration in developing and implementing regional plans.

The IESO looks forward to its continued work with Hydro One on regional planning and appreciates the opportunity to comment on the REG information provided as part of its distribution system plan.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

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

January 26th, 2017

Mr. Paul Brown
Director, Distribution Asset Management
Hydro One Distribution
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. Brown,

Subject: Regional Planning Status – Hydro One Distribution

This letter is in response to your request for a Planning Status letter for your cost of service application. The province has been divided into 21 Regions for the purpose of regional planning, which are assigned to one of the 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively. Hydro One Distribution belongs to 19 Regions, as listed below, in which Hydro One Networks Inc. (HONI) is the lead transmitter:

Group 1 Regions	**Group 2 Regions**	**Group 3 Regions**
Burlington to Nanticoke	London Area	Chatham/Lambton/Sarnia
Greater Ottawa	Peterborough to Kingston	Greater Bruce/Huron
GTA East	South Georgian Bay/Muskoka	Niagara
GTA North	Sudbury/Algoma	North/East of Sudbury
GTA West		Renfrew
KWCG		St. Lawrence
Metro Toronto		
Northwest Ontario		
Windsor-Essex		

This letter confirms that Needs Assessment (NA) for all of the 19 Regions have been completed or deemed to be completed for the first cycle of regional planning process. In addition, Regional Infrastructure Plans (RIP) for 12 Regions have been completed and remaining 7 are expected to be completed by August 2017. An overview of Ontario's regional planning process is available on Hydro One's Regional Planning homepage. Each region's current status and corresponding reports are also published online and can be accessed using the links above. The planning status for the 19 Regions is briefly discussed below.

Group 1 Regions

Burlington to Nanticoke

The Scoping Assessment (SA) recommended to undertake Integrated Regional Resource Plan (IRRP) for Brant and Bronte Sub-Regions which were completed in April 2015 and June 2016, respectively. In addition, for other local needs, a Local Planning (LP) report, led by Hydro One, was published in October 2015 to address the transformation capacity need for Dundas TS T1/T2, Nebo TS T3/T4, and Mohawk TS. The report recommended that LDCs undertake distribution load transfers to mitigate overloading of respective stations.

A RIP report for the region is underway and is expected to be completed by Q1 2017. Currently, reconfiguration and installation of breakers at Brant TS is the major investment stemming from regional planning process. In addition, there are several end of life asset refurbishments in the region underway and/or planned over the next few years. It is expected that there will be little or no cost implications for Hydro One Distribution in the region.

Greater Ottawa

The first Regional Planning cycle for Greater Ottawa Region is now complete and the RIP report was published in December 2015. It is expected that there will be no cost implications for Hydro One Distribution in the region as a result of recommendations stemming from regional planning process. The next planning cycle for this region will be initiated in Q4 2017 or Q1 2018.

GTA East

The first Regional Planning cycle for GTA East is now complete and the RIP report was published in January 2017. GTA East has been divided into Pickering-Ajax-Whitby and Oshawa-Clarington Sub-Regions and the NA report for the region was completed in August 2014. The IRRP report for the Pickering-Ajax-Whitby Sub-Region was completed in June 2016 and it identified transformation capacity need at 27.6kV voltage level due to development of new community of Seaton in northern Pickering. A new transformer station, called Seaton MTS, is planned to be built by Veridian Connections Inc. and commissioned in 2019 to address the capacity need.

Also, as recommended in the SA, a wires plan was developed to address the transformation capacity at Wilson TS and Thornton TS as part of the LP report in May 2015. The Working Group recommended a new DESN, Enfield TS, at Clarington TS site. Currently it is expected to be in-service by 2019 with an approximate budgetary cost of $34M. Consistent with the TSC, it is currently estimated that Hydro One Distribution will have to make a capital contribution of approximately $5M.

GTA North

The first Regional Planning cycle for the GTA North Region is now complete and the RIP report was published in February 2016.

The GTA North Region consists of the York and Western Sub-Regions. The following needs were identified for the York Sub-Region during the regional planning process:

- Transformation capacity in Vaughan, Markham and Northern York Area
- Load Security and Load Restoration capability on the lines from Claireville to Parkway (V71P/V75P) and Claireville to Brown Hill (B82V/B83V)
- Transmission Capacity on the Claireville to Brown Hill line (B82V/B83V)

Work on a new transformer station, Vaughan MTS #4, is underway by PowerStream to address the near-term transformation capacity need in Vaughan. The expected in-service date is May 2017. There are no cost implications for Hydro One Distribution.

The construction of inline breakers and switches at Holland TS along with a Special Protection Scheme is underway to address the near term needs for the Claireville to Brown Hill line (B82V/B83V). The expected in-service date is October 2017 and there are no cost implications for Hydro One Distribution.

Work on inline switches on the Claireville to Parkway line (V71P/V75P) is underway to address the load restoration need and the expected in-service date is May 2018. There are no cost implications for Hydro One Distribution.

A load restoration need for the loss of the Claireville to Kleinburg line (V43/V44) was identified in the Western Sub-Region. The study team recommended that this need be addressed as part of the IESO led GTA West Bulk System Planning initiative.

GTA West

GTA West was divided into Northwestern and Southern Sub-Regions for regional planning purpose. The first Regional Planning cycle for GTA West Region is now complete and RIP report was published in January 2016.

The following major needs were identified during the regional planning process:

- Station capacity for Halton TS and Erindale TS T1/T2
- Transmission circuit capacity for R14T/R17T, R19TH/R21TH, H29/H30, T38B/T39B
- Load restoration/security capability for above circuits plus V41H/V42H and B15C/B16C

Two new transformer stations, Halton Hills Hydro MTS and Halton TS #2, have been proposed to relieve Halton TS capacity by 2018 and 2020, respectively. A new DS has also been proposed to relieve Erindale TS T1/T2 capacity. However, there is no cost implications for Hydro One Distribution. A need to upgrade 230kV line H29/H30 conductor is also identified, and will be finalized in the next regional planning cycle.

KWCG

The first Regional Planning cycle for KWCG Region is complete and RIP report was published in December 2015.

The following needs were identified as part of the regional planning process:

- Transmission circuit capacity for B5G/B6G, D7F/D9F, and F11C/F12C
- Load restoration capability for Waterloo-Guelph and Cambridge-Kitchener 230kV subsystems

As part of the Guelph Area Transmission Reinforcement (GATR) project, 115kV transmission systemwas reinforced in 2016 by introducing a new 230/115kV injection point at Cedar TS using two new 230kV/115kV autotransformers. Also, two new 230kV in-line switches were installed in 2016 to address the load restoration need near Guelph North Junction on D6V/D7V to isolate faulted elements in Waterloo-Guelph subsystem. The cost of GATR project is estimated to be about $95 million and will be a transmission pool investment.

To address the load restoration need in Cambridge-Kitchener subsystem, two new 230kV in-line switches on M20D/M21D are recommended near Galt Junction to isolate faulted elements. This project is estimated to cost $6 million and will be a transmission pool investment.

As a result of above investments, there will be no cost implications for Hydro One Distribution.

Metro Toronto

The first Regional Planning cycle for Metro Toronto Region is complete and RIP report was published in January 2016.

The following needs were identified during the regional planning process:

- Transformation station capacity in the West Toronto, Southwest Toronto and Downtown Core areas
- Transmission line capacity for the 115kV Manby x Wiltshire corridor, and the 230kV Richview x Manby corridor

The transformation capacity needs will be addressed by adding 115/27.6kV, 230/27.6kV, or 115/13.8kV DESNs in low capacity areas. The transmission line capacity need in the West Toronto area will be addressed by upgrading the 115kV circuits between Manby TS and Wiltshire TS, with an estimated cost of $30 million approximately to be recovered in accordance with the TSC. The 230kV Richview x Manby transmission corridor will also be reinforced while different alternatives are being evaluated and estimated currently. The investment cost will be in the range of $20-30 million, to be recovered in accordance with the TSC.

It is expected that the next planning cycle for this region will be initiated over the next 2 years.

Northwest Ontario

In March 2014, Working Group members from the LDCs, IESO, and Hydro One collected the LDC load forecast and concluded that the primary objective of the Needs Assessment (NA) to identify needs in the region had been already established in the region. As a result, Working Group decided that a NA report was not required and IESO should initiate the SA process for this region.

Northwest Ontario Region was divided into 4 Sub-Regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, and Greenstone-Marathon. SA report for this region was completed in January 2015. Planning for Remote Communities was already underway and a draft plan referred to as "Remote Communities Plan" has been developed. IRRPs for the four regions were also completed as discussed below -

The North of Dryden IRRP report, published in January 2015, has following recommendations:

- New 230kV transmission line from Dryden/Ignace area to Pickle Lake plus a 230/115kV autotransformer with related infrastructure
- Upgrading 115kV transmission lines; Dryden to Ear Falls (E4D) and Ear Falls to Red Lake (E2R)

It is expected that there will be some cost implications for Hydro One Distribution resulting from upgrade of E4D. However, currently this project is on hold awating customer confirmation.

The Greenstone-Marathon IRRP, published in June 2016, has following recommendations:

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, and a new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac Transformer Station ("TS") to be in-service coincident with the pumping stations loads.
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the incorporation of the pumping stations as part of the major pipeline conversion project.
- Mine developers in Greenstone have the option of upgrading circuit A4L from Alexander Switching Station ("SS") to Beardmore TS as an economic alternative for supplying the Beardmore mine and additional mining in Greenstone.

It is expected that there will be no cost implications for Hydro One Distribution as a result of the above recommendations.

The West of Thunder Bay and Thunder Bay IRRPs were published in July and December 2016, respectively, where no needs were identified in the Sub-Region.

The planning for Remote Communities Sub-Region is being led by the IESO and a draft Connection Plan has been developed. The plan has not yet been fully reviewed by the stakeholders and awaiting community engagement to be finalized. It is expected that there will be limited, if any, cost implications for Hydro One Distribution.

The IRRPs for all Sub-Regions are now complete by the IESO and Hydro One is expected to initiate the RIP process by end of January 2017. It is expected that the RIP for the region will be completed by August 2017.

Windsor-Essex

Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be completed and the planning status for the region was considered to be in the IRRP phase of the regional planning process. The IRRP and RIP reports for the region were completed in April 2015 and December 2015, respectively. During the regional planning process, the following needs were identified that are being addressed by wires solution in the region:

- Supply Interruptions in the J3E-J4E Subsystem
- Additional Supply Capacity requirement in the Kingsville-Leamington Area

The above needs will be addressed by the new Supply to Essex County Transmission Reinforcement ("SECTR") project as an integrated solution for both needs. The SECTR project consists of:

- A new 230/27.6 kV Leamington TS in the Municipality of Leamington
- Distribution investment for Leamington TS; includes additional feeder positions and protection upgrades for in-service Kingsville DG transferred to Leamington TS.
- Construction of a 13 km double-circuit 230 kV line to connect the existing C21J/C22J circuits to the new transformer station.

Sufficient load is also planned to be transferred to the new TS from Kingsville TS to provide relief to the station. The estimated completion date for the SECTR project, as per the RIP report, is June 2018. As per the latest estimates, the SECTR project is estimated to cost about $78M for building transmission infrastructure. In addition, Hydro One Distribution is expected to invest in building distribution

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

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

January 26th, 2017

Mr. Paul Brown
Director, Distribution Asset Management
Hydro One Distribution
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. Brown,

Subject: Regional Planning Status – Hydro One Distribution

This letter is in response to your request for a Planning Status letter for your cost of service application. The province has been divided into 21 Regions for the purpose of regional planning, which are assigned to one of the 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively. Hydro One Distribution belongs to 19 Regions, as listed below, in which Hydro One Networks Inc. (HONI) is the lead transmitter:

Group 1 Regions	**Group 2 Regions**	**Group 3 Regions**
Burlington to Nanticoke	London Area	Chatham/Lambton/Sarnia
Greater Ottawa	Peterborough to Kingston	Greater Bruce/Huron
GTA East	South Georgian Bay/Muskoka	Niagara
GTA North	Sudbury/Algoma	North/East of Sudbury
GTA West		Renfrew
KWCG		St. Lawrence
Metro Toronto		
Northwest Ontario		
Windsor-Essex		

This letter confirms that Needs Assessment (NA) for all of the 19 Regions have been completed or deemed to be completed for the first cycle of regional planning process. In addition, Regional Infrastructure Plans (RIP) for 12 Regions have been completed and remaining 7 are expected to be completed by August 2017. An overview of Ontario's regional planning process is available on Hydro One's Regional Planning homepage. Each region's current status and corresponding reports are also published online and can be accessed using the links above. The planning status for the 19 Regions is briefly discussed below.

The above needs will be congregated and addressed further in a RIP report for South Georgian Bay/Muskoka Region, expected to be completed by August 2017.

Sudbury/Algoma
The NA and LP Reports for Sudbury/Algoma Region were completed in March and September 2015. Considering that no further regional coordination was required, the NA and LP reports were deemed to form the RIP report for the region, and published in June 2016.

A new 230/44kV DESN at Hanmer TS is proposed to replace the 115/22kV Coniston TS at a total cost of approximately $30M. The project has not yet been released for estimating and current cost estimates are budgetary only. Consistent with the TSC, it is expected that LDC contribution will be approximately $16 million subject to change based on final estimates. All loads will be transferred to the new DESN and supplied at 44kV voltage level by 2019.

The voltage regulation issue at Manitoulin TS was further assessed by the Working Group and it was determined that this can be dealt with Under Load Tap Changers (ULTC) on the power transformers to regulate voltages within the range outlined in the TSC. No further action is required at this time.

Group 3 Regions

Chatham/Lambton/Sarnia
Regional Planning for the Chatham/Lambton/Sarnia Region started with the Information Gathering in December 2015 and the NA report was completed in June 2016.

The study team's recommendation was that no further regional coordination is required. Based on the net load forecast, Kent TS T3/T4 is forecasted to exceed its 10 – Day LTR in 2016. A wires' solution, led by Hydro One and in collaboration with relevant distributors, has been recommended to address this need in a LP report, to be completed in Q1 2017.

The NA and LP reports for the Region will be deemed to form the RIP report because no further regional coordination was required. The RIP report for Chatham/Lambton/Sarnia Region is expected to be completed in Q2 2017.

Greater Bruce/Huron
The NA for the Greater Bruce-Huron Region was completed in May 2016. The following needs were identified:

- Poor power factor at Wingham TS (and resulting voltage deficiency) and Bruce HWP B TS
- Transmission circuit capacity for L7S
- Customer Delivery Point Performance

The Working Group concluded no further regional coordination was required via an Integrated Regional Resource Plan. As a result plans to mitigate the needs are currently being pursued via the Local Planning process and Hydro One's OEB-approved process for addressing poor performance.

LP reports were developed for needs at Wingham TS and L7S circuit capacity and there will be no cost implications for Hydro One Distribution. Another LP is currently being developed for the Bruce HWP B

TS need and as Hydro One Distribution is not a customer at this station, there will not be cost implications for them.

Hydro One Transmission is currently investigating poor customer delivery point performance in the Region and will work with Hydro One Distribution as well as the other LDC's in the Region and transmission customers to develop a plan. Any cost implications for Hydro One Distribution will be incorporated into the Region's RIP report.

The NA report and all LP reports for the Region will be deemed to form the RIP report because no further regional coordination was required. The RIP report for Greater Bruce/Huron Region is expected to be completed in Q2 2017.

Niagara

Regional Planning for the Niagara Region started with the Information Gathering in November 2015 and the NA report was completed in April 2016.

The study team addressed the thermal overloading of 115kV circuit Q4N as part of a LP report completed in November 2016. As part of the Beck #1 Refurbishment project, the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal JCT is to be uprated from 680A to 910A ampacity. The expected in-service date is December 2019. There will be no cost implications for Hydro One Distribution.

The NA and LP reports for the Region will be deemed to form the RIP report for the Niagara Region because no further regional coordination was required. It is expected that the RIP report will be issued in Q1 2017.

North/East of Sudbury

Based on the findings of the NA, completed in April 2016, the Working Group recommends that no further regional coordination is required.

Voltage regulation needs at Timmins TS and Kirkland Lake TS were identified and addressed in the LP report completed in August 2016. Existing operating measure exists to address these issues, and the working group members agreed these methods continue to be acceptable ways of managing system voltages in the area. Hydro One Networks investments are not required at this time and Hydro One will monitor load growth in the area and take corrective actions as required. There will be no cost implications for Hydro One Distribution.

The NA and LP reports for the Region will be deemed to form the RIP report for the North/East of Sudbury Region because no further regional coordination was required. The RIP report for the Region is expected to be completed by Q1 2017.

Renfrew

The first Regional Planning cycle for Renfrew Region is now complete. The NA report was completed in March 2016 and no needs were identified in the Region. The NA report was deemed to form the RIP report for the Renfrew Region because no regional coordination was required. There will be no cost implications for Hydro One Distribution.

St. Lawrence
The first Regional Planning cycle for St .Lawrence Region is now complete. The NA report was completed in April 2016 and no needs were identified in the Region. The NA report was deemed to form the RIP report for the St. Lawrence Region because no regional coordination was required. There will be no cost implications for Hydro One Distribution.

Acquisition of Local Distribution Companies by Hydro One

Norfolk Power Inc.
In July 2014, the OEB issued a decision and order that approved the acquisition of Norfolk Power Inc. by Hydro One. Norfolk Power Inc. served approximately 18,000 customers in Port Dover, Simcoe, Waterford, and the urban areas of Delhi and Port Rowan in the Norfolk County, mainly supplied by Norfolk TS and Tillsonburg TS, located in southern Ontario. Norfolk Power Inc. was part of Burlington to Nanticoke and London Area Regions. RIP report for Burlington to Nanticoke region is currently underway while RIP report for London Area will be initiated following the completion of the IRRP, expected to be completed by end of January 2017. Based on the previous regional planning assessments no needs were identified in the area that may have any cost implications for the LDC.

Haldimand County Hydro
In March 2015, the OEB approved the acquisition of Haldimand County Hydro by Hydro One. Haldimand County Hydro served approximately 21,200 customers in the Haldimand County spanning across Caledonia, Cayuga, and other southern rural areas along Lake Ontario which is part of the Burlington to Nanticoke and Niagara Regions. Caledonia TS, Nanticoke TS, and Dunnville TS are the main transmission facilities supplying the electrical demand in the area. RIPs for both of these regions are currently underway and expected to be completed in Q1 and Q2 2017, respectively. However, based on the previous regional planning assessments no needs were identifued in the area that may have any cost implications for the LDC.

Woodstock Hydro Services Inc.
In September 2015, the OEB approved the acquisition of Woodstock Hydro Services Inc. by Hydro One. Woodstock Hydro served approximately 15,800 customers in the city of Woodstock, mainly through Woodstock TS and Karn TS, located in London Area Region. RIP for London Area will be initiated following the completion of the IRRP, expected to be completed by end of January 2017.

Further details will be discussed with the Working Group and communicated as they become available. Hydro One looks forward to working with Hydro One Distribution in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,

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

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

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

<u>Appendix B: List of LDCs for Each Region</u>

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.

9. East Lake Superior	N/A → This region is not within Hydro One's territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.

13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc. Please refer to the letter for a brief description on the acquisition approved by the Ontario Energy Board (OEB).

BRANT AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the Burlington-Nanticoke Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Brant Area

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Brant Area Working Group, which included the following members:

- Independent Electricity System Operator
- Brant County Power Inc.
- Brantford Power Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Brant Area Working Group assessed the adequacy of electricity supply to customers in the Brant Area over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Brant Area; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Brant Area Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Brant Area Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
C&S	Codes and Standards
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EV	Electric Vehicle
FIT	Feed-in Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
LMC	Load Meeting Capability
MCOD	Maximum Commercial Operation Date
MW	Megawatt
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTS	Municipal Transformer Station
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority

Abbreviation	Description
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SCGT	Simple-Cycle Gas Turbine
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for Brant Area IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Brant Area ("Area") over the next 20 years from 2014 to 2033. This report was prepared by the IESO on behalf of a Technical Working Group composed of the IESO, Brant County Power Inc., Brantford Power Inc., Hydro One Distribution, and Hydro One Transmission ("the Working Group").

The Brant Area encompasses the County of Brant, City of Brantford and surrounding areas. It has an estimated population of over 136,000 people. The electricity demand mix is comprised of residential, commercial and industrial uses. The Brant Area is supplied by the Brant TS, Powerline MTS and Brantford TS.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the twenty-one electricity planning regions at least once every five years.

Under the Province's Growth Plan for the Greater Golden Horseshoe,[1] the Brant Area is expected to experience continued population growth in the coming decades. It continues to attract industrial and commercial customers and create opportunities for future development. This IRRP will help to ensure that the electricity system will support the expected development over the long term.

The Brant Area is a sub-region within the Burlington/Nanticoke region established through the OEB regional planning process. This report therefore contributes to fulfilling the requirements for the Burlington/Nanticoke region as mandated by the OEB. A second sub-region of the Burlington/Nanticoke region consists of the Bronte Area of Oakville and Burlington; this sub-region will be studied as a separate IRRP and is not included in the scope of this IRRP.

This IRRP for Brant identifies and coordinates options to meet electricity needs in the Area over the next 20 years ("study period") and is sub-divided into the near term (0-5 years, or 2014 through 2018), medium term (6-10 years, or 2019 through 2023) and longer term (11-20 years, or 2024 through 2033). Specifically, this IRRP identifies investments for immediate

[1] *Growth Plan for the Greater Golden Horseshoe, 2006 under the Places to Grow Act, 2005*

implementation to meet near- and medium-term needs in the Area, respecting expected lead times for development. This IRRP also identifies a number of options to meet longer-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for longer-term options and does not recommend specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork to meet future needs, should they arise. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020, so that the results of these actions can inform a decision should one be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for the Brant Area is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Brant Area and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation assumptions, are described in Section 5;
- Near- medium- and long-term electricity needs in the Brant Area are presented in Section 6;
- Options for meeting near- and medium-term needs are assessed and recommendations for the near-term plan are provided in Section 7;
- Alternatives for meeting long-term needs are discussed and actions to support development of the long-term plan are provided in Section 8;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Brant IRRP provides recommendations to address the Area's forecast electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies forecast electricity needs in the Area over near term (0-5 years, or 2014 through 2018), medium term (6-10 years, or 2019 through 2023) and longer term (11- 20 years, or 2024 through 2033). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost, feasibility, and maximization of the use of the existing electricity system, where it is economic to do so.

This IRRP identifies specific projects for implementation in the near and medium term. This is necessary to ensure that they are in-service in time to address the Area's more urgent needs, respecting the lead time for development of the recommended infrastructure.

This IRRP identifies a number of alternatives to prepare to meet the Area's longer-term electricity needs. However, as these needs are forecast to arise in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to recommend specific projects at this time. Instead, near-term actions are identified to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform a decision at that time.

2.1 Near-Term and Medium-Term Plan (2014 through 2023)

Near-Term Need
• Supply capacity in the Brant-Powerline 115 kV sub-system is inadequate today

The first element of the near-term plan is to account for targeted conservation and contracted distributed generation ("DG"). To address urgent supply capacity needs, two transmission projects are also recommended. The development of one of the transmission projects is currently underway; the former OPA issued a letter[2] to Hydro One Networks Inc.

[2]Letter to Hydro One: http://www.hydroone.com/RegionalPlanning/Burlington/Documents/OPA Letter - Burlington Nanticoke - Brant.pdf

("Hydro One") supporting this near-term project in order to ensure it was initiated and brought into service in time to address an urgent need. The second transmission project is under discussion between Brantford Power Inc., Brant County Power Inc. and Hydro One. These projects are described below and their respective locations are shown in Figure 2-1. The estimated cost of these transmission projects is approximately $13-16 million. Together, these projects can increase the load meeting capability ("LMC") of the 115 kV sub-system from 104 MW to approximately 165 MW. Combined with the other near- and medium-term recommendations, these projects will be sufficient to meet the forecast demand growth until the end of the study period.

Figure 2-1: Brant Area Electricity System

These recommendations meet the near- and medium-term electricity needs of the Brant Area in a timely and cost-effective manner, and were developed with a view to maximizing the use of the existing system.

Recommended Actions

1. Implement conservation and distributed generation and monitor results

The implementation of provincial conservation and DG targets established in the 2013 Long Term Energy Plan ("LTEP") are key components of the near- and medium-term plan for the

Brant Area. In developing the demand forecast, peak-demand impacts associated with the provincial targets were assumed before identifying any residual needs, consistent with the provincial Conservation First policy.[3] Conservation resources account for approximately 40% of the forecast demand growth during the first 10 years of the study.

As the provincial conservation targets are energy[4] based, the IESO with the Area local distribution companies ("LDCs") will monitor the magnitude of the peak demand savings resulting from these targets in the Brant Area. This will be an important element of the near-term plan, and will also lay the foundation for the long-term plan by gauging actual performance of specific conservation measures, and assessing potential in the Area for further conservation efforts.

Provincial programs that encourage the development of distributed generation, such as the Feed-in-Tariff ("FIT"), microFIT, and Combined Heat and Power Standard Offer ("CHPSOP") programs, can also contribute to reducing peak demand in the Region, dependent , in part, on local interest and opportunities for development. Existing and committed distributed generation impacts were also assumed before identifying needs for the Area. It is expected that distributed generation resources will reduce the gross forecast for the Area by approximately 5 % for the study period. The LDCs and the IESO will continue their activities to support DG initiatives where appropriate and monitor their impacts.

2. Install capacitor banks at Powerline MTS

To meet the urgent need to provide capacity relief to the Area's 115 kV supply pocket the Working Group recommended the installation of 30 MVAR of capacitor banks at Powerline MTS. The estimated cost from Brantford Power and Brant County Power for this project is approximately $1-million. These capacitor banks are expected to be in-service for the summer of 2015, and will provide additional capacity of 21 MW to the Brant-Powerline sub-system. Implementation began in 2014 with the former OPA issuing a letter supporting this project so that it could be brought into service in time to address urgent needs.

---

[3] Conservation First policy:
http://www.energy.gov.on.ca/en/conservation-first/http:/www.energy.gov.on.ca/en/conservation-first/
[4] The provincial targets are for energy and have to be converted to capacity to calculate impact on peak demand by conservation.

3. Connect existing 115 kV Circuits B12/13 to B8W

To meet the remaining supply capacity need in the near term, the Working Group recommended the installation of three (3) 115 kV breakers to connect the existing circuits B12/13 from Hamilton to B8W from Woodstock. The budgetary estimate for this project is $12-15 million with an in-service date of 2017. These switching facilities are expected to provide additional capacity of 40 MW to the Brant-Powerline sub-system after the addition of the capacitor banks at Powerline MTS.

4. Demand response Pilot Program for Brant

A pilot demand response ("DR") program will be considered by the IESO in order to identify costs and determine feasibility and potential of DR to meet supply capacity needs in the Area. If DR proves to be feasible and economic, it could play an important role in long-term planning for the Area.

2.2 Near- and Medium-Term Actions in Support of Long-Term Plan (2024 through 2033)

The recommended near- and medium-term solutions are expected to satisfy the forecast demand growth for the expected-growth scenario until the end of the study period. In the long term, the Brant Area electricity system's ability to supply load will be constrained if additional industrial loads arise in the Area or higher demand growth occurs. Thus, the Working Group believes it is prudent to plan to meet a higher-demand scenario for the longer term. This will provide a capacity margin to supply emerging needs, and allow flexibility and time to plan for the next round of growth should a supply gap materialize.

A number of alternatives are possible to meet the Area's longer-term needs under in the high-demand growth scenario, including combinations of conservation, local generation, "wires" (transmission and distribution) and other emerging technologies. While specific solutions do not need to be committed today, it is prudent to begin work now in order to gather information, monitor developments, engage the community, and develop alternatives to meet the needs and to support decision-making in the next iteration of the IRRP. The longer-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. Long-term options will be reviewed in subsequent Burlington-Nanticoke regional planning studies.

Recommended Actions

1. Monitor load growth and conservation achievement and distributed generation performance

On an annual basis, the IESO will coordinate a review of conservation achievement, the uptake of provincial DG projects, and actual demand growth in the Brant Area. This information will be used to track the expected timing of longer-term needs to determine when a decision on the long-term plan is required. Information on conservation and DG performance will also provide useful feedback into the ongoing development of these options as potential long-term solutions. Additionally, the IESO will also monitor results and the incorporation of lessons learned from the DR pilot if it is implemented.

2. Undertake community engagement

Broad community and public engagement is essential to development of a long-term plan. As no long-term needs have been identified for the Brant Area, there is no requirement at this time for engagement on long-term options.

A Local Advisory Committee ("LAC") may be established for the broader Burlington to Nanticoke region once the IRRP process for the one remaining area in the Burlington to Nanticoke region has been completed. A LAC's purpose is to provide input and advice on regional plans and the engagement of those plans for an area or region. It is expected that a LAC will consist of community representatives and stakeholders. Advice from the LAC will be incorporated in developing engagement plans for the Area.

3. Continue ongoing work to develop transmission/generation options

The Working Group will continue to work together to evaluate the transmission and generation alternatives to meet the potential long-term needs.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA license changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

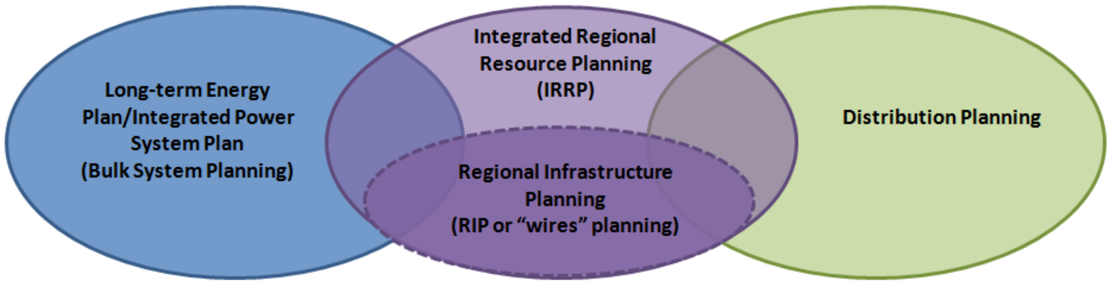
The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a scoping assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. It is typically carried out by the IESO and considers the major transmission facilities and assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

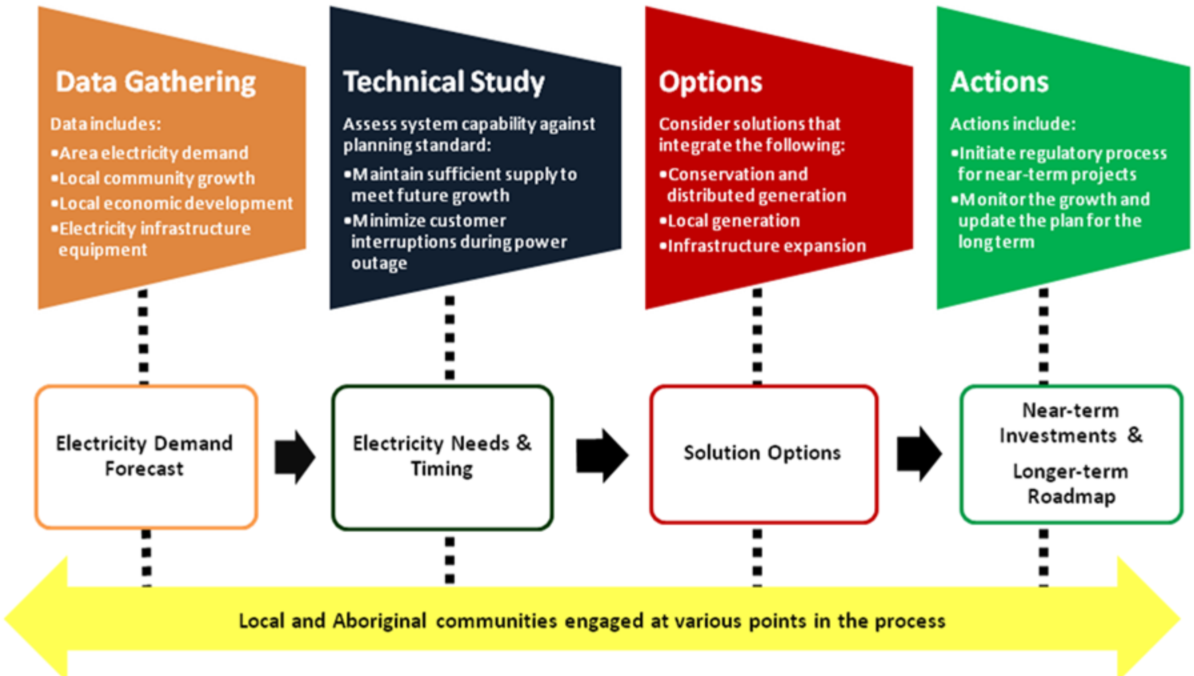
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nations and Métis communities and stakeholders. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Brant Area Working Group and IRRP Development

The Brant IRRP is a "transitional" IRRP in that it began prior to formalization of OEB's regional planning process and some of the study was conducted before the new process and its requirements were known. While much of the work completed in the early days of the study is consistent with the new process, certain aspects of the development of the IRRP have been refined, and the underlying data and assumptions, such as demand forecasts, have been updated to reflect changes since the study began.

In 2013, the Working Group was formed to assess the supply capacity for Brant Area. The Working Group developed a Terms of Reference for the study,[5] gathered data, identified near- to long-term needs in the Area, and recommended the near- and medium-term actions included in this IRRP.

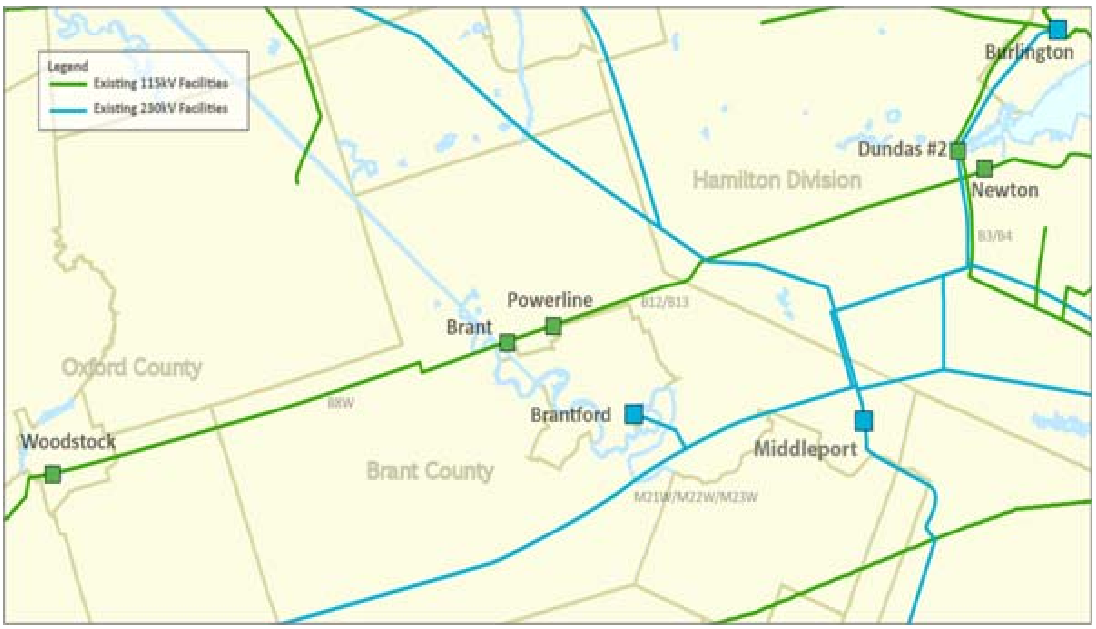
[5] Brant IRRP Terms of Reference: http://powerauthority.on.ca/sites/default/files/planning/Brant-Terms-of-Reference.pdf

4. Background and Study Scope

This report presents an IRRP for the Brant Area over a 20-year period from 2014 to 2033. The Brant Area is a sub-region within the Burlington/Nanticoke region.

The geographic scope of the Brant IRRP includes the County of Brant and the City of Brantford. The electricity supply to the study Area is provided by three step-down stations: Brant TS, Powerline MTS and Brantford TS, as shown in Figure 4-1.

Figure 4-1: Brant Area and Vicinity



Brant TS and Powerline MTS are connected to the double-circuit 115 kV transmission line, B12/13[6] originating from Burlington TS. These stations are also backed up in emergencies by the 115 kV line B8W from Woodstock. Under normal operation, the B8W circuit is not connected to the Brant-Powerline sub-system circuits B12/13. The Brantford TS is supplied at 230 kV from the double-circuit transmission line M32/33W between Middleport TS (Hamilton) and Buchanan TS (London). The coincident peak demand of the three stations in summer 2014

[6] Circuits B12/13 also supply two other DESN stations, Dundas #2 TS and Newton TS in the Hamilton area serving customers of Horizon Utilities Corporation and Hydro One Distribution. As Dundas #2 TS and Newton TS are not directly impacted by the supply issues associated with the Brant Area in this study, a detailed assessment of these two stations is covered in the broader region needs screening of Burlington-Nanticoke.

was approximately 250 MW. Distribution service to customers in the Area is provided by Brant County Power Inc., Brantford Power Inc. and Hydro One Distribution.

For the purposes of this IRRP, the term "Brant Area" is used to more precisely define the Area supplied by the following transformer stations: Brant TS, Powerline MTS and Brantford TS.

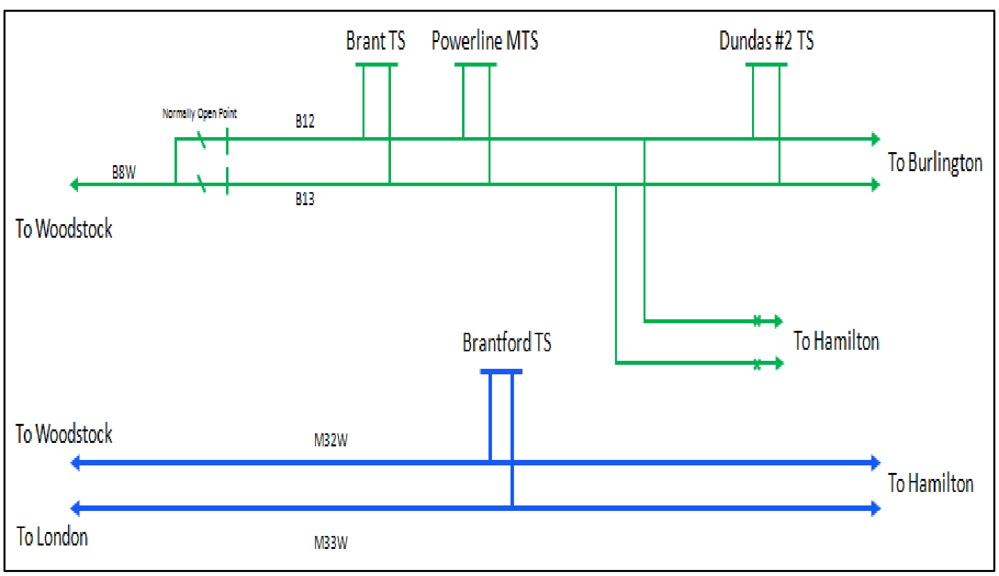
For the purposes of this IRRP, the transmission system in the Brant Area is further divided into two sub-systems:

1. The Brant Powerline sub-system: customers supplied from Brant TS and Powerline MTS via the B12/B13 115 kV transmission line; and
2. The Brantford TS sub-system: customers supplied from Brantford TS via the 230 kV transmission line M32W/M33W.

While there is some emergency transfer capability between the two Brant Area sub-systems, they are normally operated independently.

These two sub-systems are shown in Figure 4-2 below.

Figure 4-2: Brant Area Sub-systems

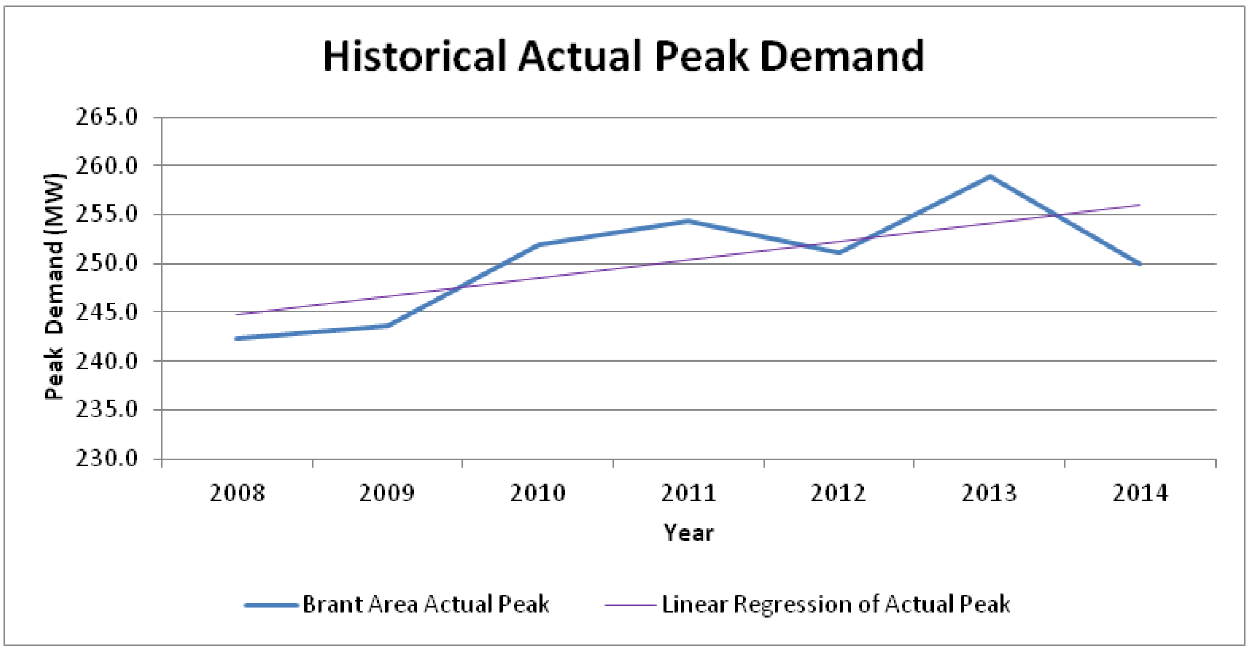


5. Demand Forecast

5.1 Historical Demand

Actual peak electricity demand in the Brant Area has increased moderately from 242 MW in 2008 to 259 MW in 2013, with a modest drop to 250 MW in 2014. This represents a nominal growth rate of 1.9 %, as shown in Figure 5-1. The historical peak demand reflects the weather experienced at the time of the system's coincident peak, and includes the impacts of conservation and DG.

Figure 5-1: Brant Area Historical Electricity Demand



5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements of that area. Therefore, regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

The near- and medium-term aspects of a forecast are closely linked to the historical growth experienced in an area and is usually based on loads expected to be in-service within a few years of growth being planned. Unmet needs forecast to arise during this time frame typically require solutions to be developed and implemented during the current planning cycle. The long-term forecast is typically used to identify emerging issues and to set longer-term priorities, with the goal of ensuring near- and medium-term actions will not be stranded or somehow limited in value by the most likely long-term outcomes.

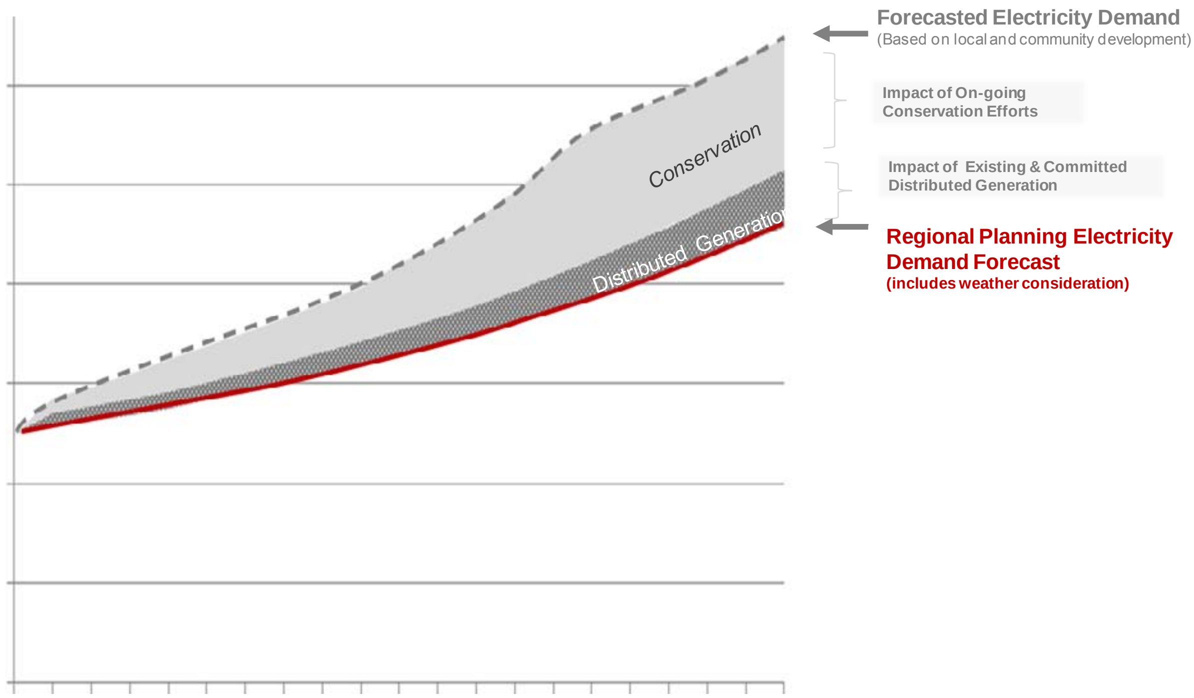
After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced based on the LDCs' gross demand forecasts and reflecting the 2013 LTEP growth assumptions - this is the expected-growth forecast. Additionally, a second net demand forecast was prepared for the longer term to account for added planning uncertainty, based on the provincial Places to Grow Act - this is referred to as the higher-growth forecast.

5.2.1 Near- and Medium-Term (2014 through 2023)

For the near and medium term, a regional peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT, and adjusted to reflect extreme weather conditions, to produce a planning forecast. The planning forecast was then used to assess any growth-related electricity needs in the region.

Using a planning forecast that is net of provincial conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. The planning forecast assumes that these conservation targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

Figure 5-2: Development of Demand Forecasts



5.2.2 Longer Demand Forecast (2024 through 2033)

For the longer-term outlook, two demand forecast scenarios were developed to reflect the inherent uncertainty associated with forecasting this far in the future.

1. **"Expected Growth":** This scenario was developed consistent with the growth assumptions embodied in the government's provincial energy plan. As with the near and medium-term (0-10 years) forecast, the provincial conservation targets up to 2032 are deducted from the gross demand projections to produce a planning forecast net of conservation.
2. **"Higher Growth":** This scenario was developed to reflect continued development in Brant Area consistent with the projections associated with the province's *Places to Grow Act, 2005*. This higher-growth forecast scenario is consistent with the growth assumptions associated with the long-term municipal plan projections. As with the near- and medium-term forecasts, the provincial conservation targets up to 2032 are deducted from the gross demand projections to produce a planning forecast net of conservation.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

The gross demand forecast for the Brant Area was developed by the Area LDCs based on historical growth rates. The forecast population is based on the Ministry of Finance's Spring 2013[7] population projection for the Brant Census Division, which includes the City of Brantford and Brant County. The Brant Census Division forecasts an average annual population growth rate of 0.9% from 2012-2031.

Area LDC forecasts are based on historical growth rates, supported by Municipal and Regional Official Plans as a primary source for input data. Other common considerations included known connection applications, and typical electrical demand intensity for similar customer types.

Additional background on the methodology used by each LDC to prepare their gross demand forecasts are available in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. Conservation is achieved through a mix of program-related activities, including behavioral changes by customers and mandated efficiencies from building codes and equipment standards ("C&S"). These approaches complement each other to maximize conservation results. The conservation savings forecast for Brant Area are applied to the gross peak demand forecast.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP"), which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak demand impacts from the provincial targets in the Brant Area.

---

[7] Ministry of Finance Spring 2013 population projection
http://www.fin.gov.on.ca/en/economy/demographics/projections/table6.html

It is assumed existing DR already in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Brant Area is also applied to offset peak demand requirements. Distributed generation resource development in Ontario has been encouraged by the *Green Energy Act, 2009* and associated procurements such as the Feed-in Tariff ("FIT") program. These procurements have increased the significance of DG in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province. These procurements take into consideration the system need for generation as well as cost.

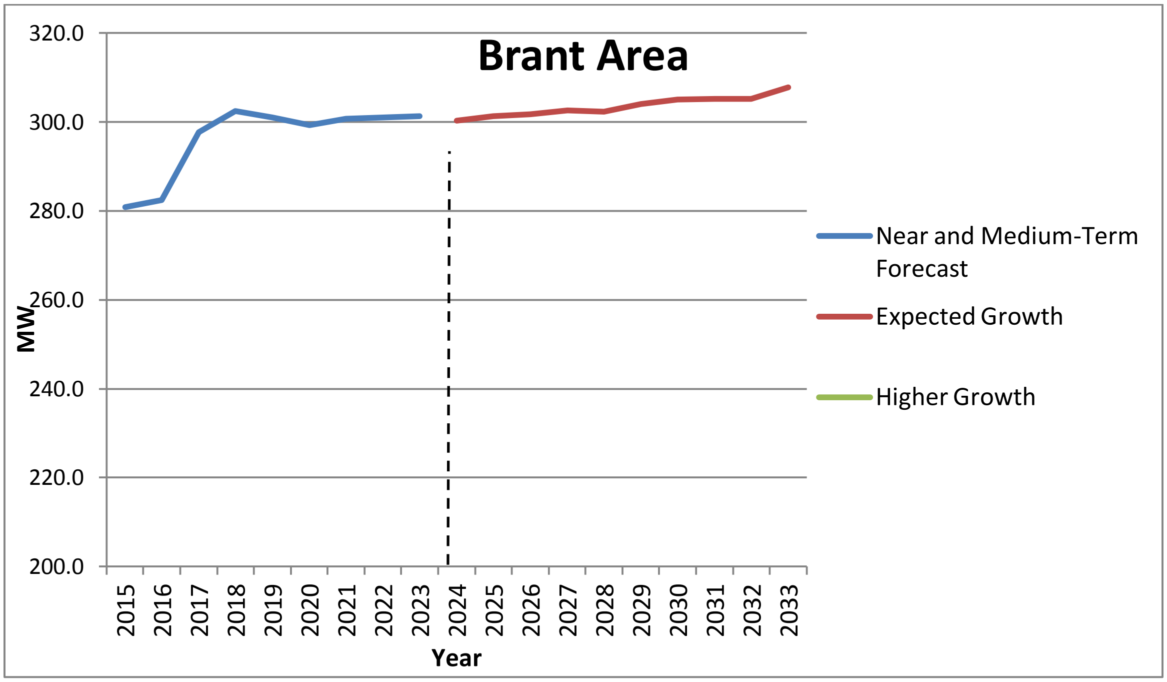
One aspect related to DG that should be noted is that DG resources, such as intermittent renewable generation resources like wind and solar, are not always available at the time of system peak. Therefore, the assumed effective capacity of these facilities (approximately 20 MW), not the full installed capacity, is applied to the Brant Area peak demand.[8] The location, contract capacity, and effective contribution of these resources in the Brant Area can be found in Appendix A.

[8] Effective capacity is the portion of installed capacity that contributes at the time of system peak.

5.6 Planning Forecasts

5.6.1 Total Demand Forecast in Brant Area

Figure 5-3: Brant Area Total Demand Forecast



5.6.1.1 Near- and Medium-Term (2014 through 2023)

The near- and medium-term aspects of a forecast are closely linked to the historical growth experienced in an area and are usually based on loads expected to be in-service within a few years or growth being planned.

The summer peak demand planning forecast of the Brant Area is shown in Figure 5-3 . There is a noticeable step increase in peak demand from the year 2015 to 2018. This is based on customers requesting connection over the next three years. Approximately 37 MW of industrial demand was added to the demand forecast in 2014, which is roughly 15% of the total Area demand. These types of loads often arise on short notice and in large blocks as is evidenced from the in-service dates of 2015 through 2018 and the step changes noticeable in the graph. For example, a forging expansion project will need additional 16 MW supply capacity by 2016.

Table 5-1 below shows the size of the large industrial loads which have been considered in the demand forecast based on LDCs information.

Table 5-1: Near-Term Industrial Load

Proposed Connection Station	LDCs	Estimated Size (MW)
Brantford TS	Brantford Power Inc.	16
Brant TS	Brantford Power Inc.	6
Powerline MTS	Brant County Power Inc.	8
Brantford TS	Brant County Power Inc.	4
Brant TS	Brant County Power Inc.	3
Total Load Added		**37**

The type of block industrial load that has been considered in the near- to medium-term forecast is difficult to forecast for the long term. As seen in Table 5-1, the loads are not concentrated at one station or within one LDC and these types of block loads can also appear with short notice. Consequently, industrial growth incremental to the loads indicated in Table 5-1 were not forecast as part of the medium-term forecast.

5.6.2 Long-Term (2024 through 2033)

For the longer-term outlook, two demand forecast scenarios were developed to reflect the inherent uncertainty associated with forecasting this far in the future.

The "expected-growth scenario" was developed consistent with the growth assumptions embodied in the government's 2013 LTEP. This scenario was a continuation of the forecast used for the near- and medium-term. The expected-growth scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy. The long-term Area forecast under the expected-growth scenario grows 27 MW from 281 MW to 308 MW. This includes the reduction in demand of approximately 49 MW from conservation, and approximately 18 MW from DG.

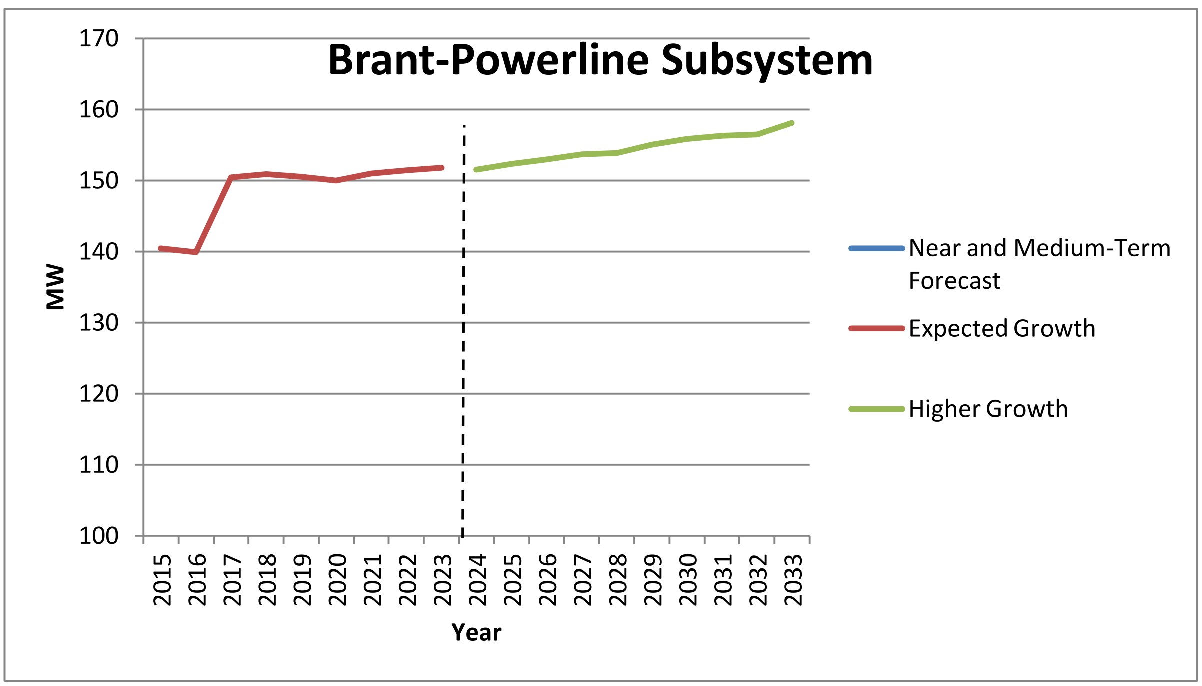
Taking into account the type of load growth the Brant Area has experienced (i.e., fast developing, large block loads), the Working Group examined an additional scenario to consider the possible impact of higher growth on the Area's needs. A higher-growth scenario was developed to reflect continued development in the Brant Area consistent with the projections associated with the province's Places to Grow policy. This forecast scenario is also consistent with growth assumptions associated with the long-term municipal plan projections for the Brant Area.

The higher-growth forecast assumes a total of 57 MW of new savings from conservation targets across the Brant Area over the next 20 years.

5.6.3 Sub-system Forecasts

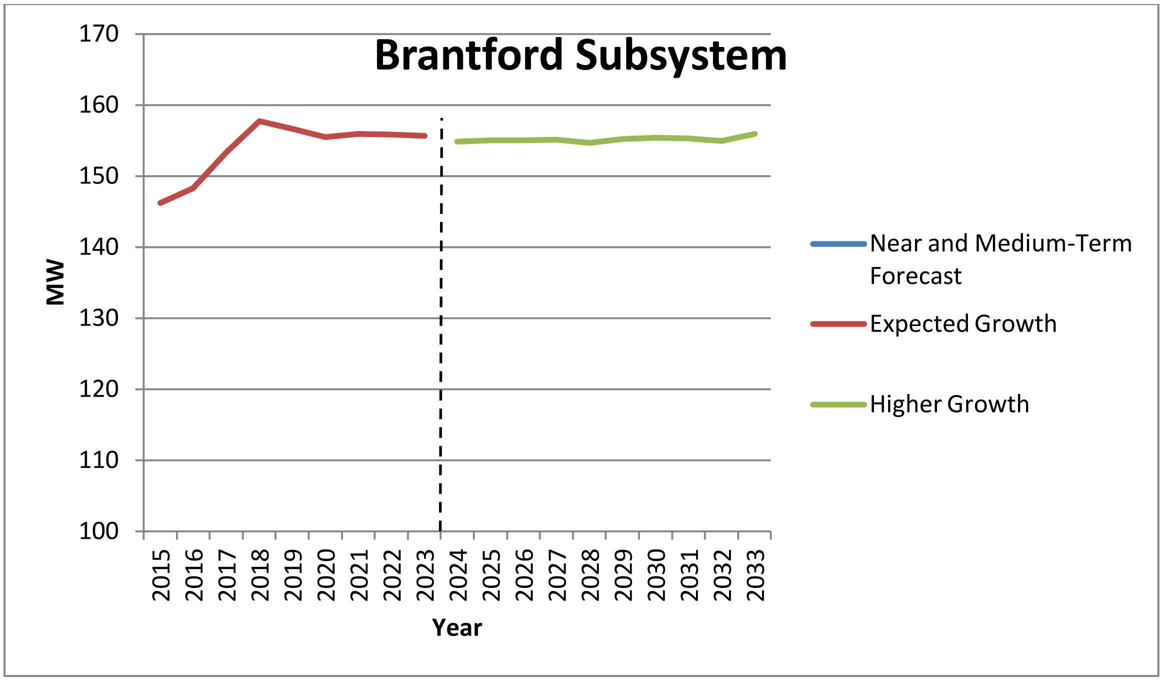
For the Brant-Powerline sub-system, the forecast demand under the expected-growth scenario grows from 140 MW to 158 MW from 2015 to 2033. This includes the reduction of approximately 25 MW from conservation, and approximately 9 MW from DG, with approximately 13 MW of demand reduction through conservation expected in the 2024-2033 timeframe. For the higher-growth scenario, the forecast grows from 157 MW in 2024 to 177 MW in 2033.

Figure 5-4: Brant TS and Powerline MTS Forecast



For the Brantford TS pocket, the forecast demand under the expected-growth scenario grows from 146 MW to 156 MW from 2015 to 2033. This includes the reduction of approximately 25 MW from conservation, and approximately 10 MW from DG. For the higher-growth scenario, the forecast grows from 165 MW in 2024 to 182 MW in 2033.

Figure 5-5: Brantford TS Planning Forecast



6. Electricity System Needs

Based on the demand forecasts, system capability, and the Ontario Resource and Transmission Assessment Criteria ("ORTAC")[9] criteria, the Working Group identified electricity needs in the near-to-medium term (0-10 years), and in the long term (11-20 years). This section describes the identified needs for the Brant Area.

6.1 Needs Assessment Methodology

Provincial assessment criteria and standards (ORTAC) were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in the Brant Area over the next 20 years (refer to Section 5). These criteria were applied to assess three broad categories of needs.

- Supply capacity requirements were assessed using PSS/E, a power flow simulation tool, to analyze the capability of the existing system, including transmission and local generation infrastructure, to supply load growth. Technical study is provided in Appendix B.
- ORTAC standards were applied to identify areas with needs to address the impacts of potential major supply interruptions. The amount of customer load supplied from specific circuits before and after potential contingencies, and the capability to restore interrupted loads following a contingency, either through transmission system switching or transfers on the distribution system, were assessed in accordance with these criteria.
- Step-down station capacity needs were identified by comparing forecast demand growth to the 10-day Limited Time Rating ("LTR"), or thermal capacity, of the existing stations in the Area, to determine the net incremental requirement for transformation capacity in the Area.

6.2 Ontario Resource and Transmission Assessment Criteria

The ORTAC the provincial standard for assessing the reliability of the transmission system, were applied to assess supply capacity and reliability needs.

The ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are relevant to this study and guided the technical studies performed in assessing the electricity system needs

[9] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

in Brant Area. The needs can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions. Further details on the application of these criteria are provided in Appendix B.

6.3 Near- and Medium-Term Needs

Near- to medium-term needs often require action immediately to ensure that a solution is in place to address the need by the time it arises.

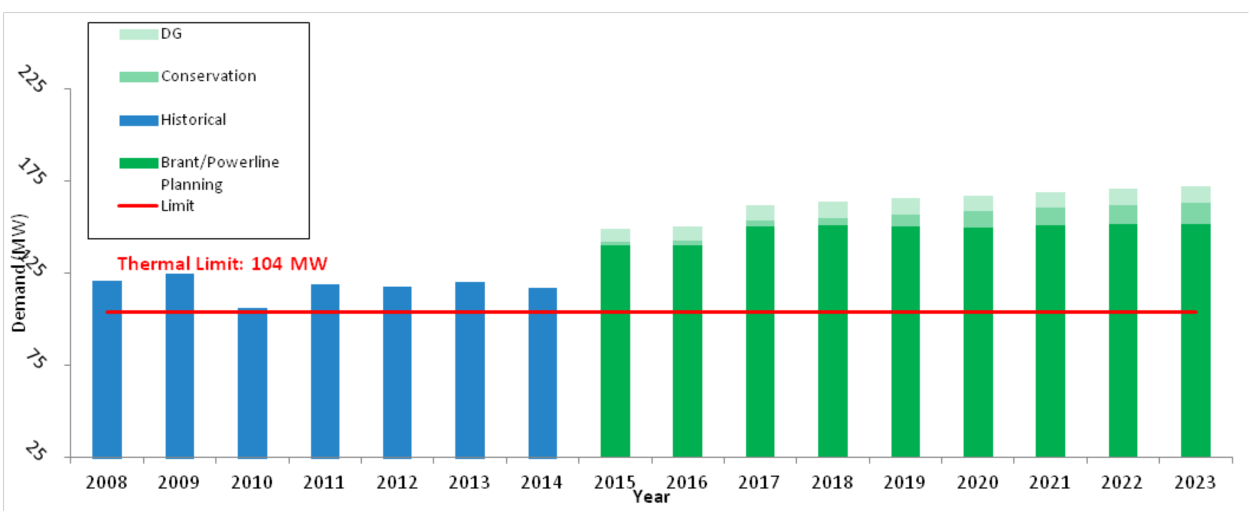
6.3.1 Need for Additional Supply Capacity

Brant-Powerline Sub-system

Today, the B12/B13 115 kV transmission line serving the Brant-Powerline sub-system has a LMC of approximately 104 MW. This limit is based on the violation of the voltage criteria following the loss of one of the B12/13 circuits.

As shown in Figure 6-1 below, peak demand for this sub-system has already exceeded the LMC, and is forecast to continue to exceed this limit throughout the study period.

Figure 6-1: Historical and Forecast Electricity Demand and Supply Capability in the Brant-Powerline Sub-system



Based on the forecast, additional capacity is required to meet current and future electricity demand in the Brant-Powerline sub-system. Until additional capacity is provided, operating measures such as temporary load transfers or interruption of load following a single contingency will be required. The existing system does not meet the ORTAC criteria for supply capacity in the near and medium term.

Brantford TS Sub-system

The Brantford TS sub-system meets the ORTAC criteria for supply capacity for the reference forecast throughout the study period.

6.3.2 Load Restoration Needs

Brant -Powerline Sub-system

Brant TS and Powerline MTS sub-system meets the ORTAC restoration criteria until the end of the study period.

Brantford TS Sub-system

The Brantford TS sub-system meets the ORTAC restoration criteria until the end of the study period.

6.3.3 Conclusion Near- and Medium-Term Electricity Needs

The Brant-Powerline sub-system has already exceeded the LMC of the supply circuits and there is further significant step load growth identified by the LDCs forecast over the next five years. Therefore, an urgent need has been identified to provide additional capacity to the Brant-Powerline 115 kV sub-system.

6.4 Long-Term Needs

To assess needs in the long term, two demand forecast scenarios were considered: expected-growth and high-growth (see Section 5.2). As described in Section 7, the near- and medium-term plan is expected to meet the needs of the Area until the end of the study period.

However, if Area demand is consistent with the higher-growth scenario, additional electricity capacity needs may arise before the end of the study period. Thus, the analysis in this section is to address a scenario where there is a potential need for additional long-term Area supply.

Higher Growth Scenario

The Brant Area peak demand is forecast to grow to 352 MW by 2033 under the higher-growth scenario. At the sub-system level, the Brant-Powerline sub-system is forecast to grow to 177 MW and the Brantford TS sub-system to 182 MW under this scenario by 2033.

Table 6-1: Capacity Gap in 2033 under Higher-Growth Scenario

	Limit after Near- and Medium-Term Solutions (MW)	Higher Growth Forecast demand in 2033 (MW)	Higher Growth Capacity Gap in 2033 (MW)
Brant-Powerline sub-system	165	177	12
Brantford TS sub-system	178	182	4
Brant Area	343	352	9

In the long term, the Brant Area electricity system's ability to supply load will be constrained if additional industrial block loads arise in the Area, or higher demand growth is experienced consistent with the higher-growth scenario (Section 5.6.2). Supply constraints will leave the LDCs unable to connect new customers without additional supply in the Area. Consequently, the Working Group agreed to develop a strategic plan to consider higher demand growth based on the Places to Grow assumptions or additional industrial block loads.

7. Near- and Medium-Term Plan

The plan to address the near- and medium-term electricity needs of the Brant Area consists of specific actions and projects for immediate implementation, reflecting the urgency of the needs and the load time for developing solutions (refer to Section 6.3).

This section describes the alternatives considered in developing the near-term plan for the Brant Area and provides details and rationale for the recommended plan.

7.1 Alternatives for Meeting Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the Brant Area.

7.1.1 Conservation

Conservation was considered as the first alternative to meet the electricity needs through the development of a planning forecast that includes the peak-demand effects of the provincial conservation targets,[10] along with contracted DG (see Sections 5.4 and 5.5). These conservation resources account for approximately 30 MW, or approximately 40% of the forecast demand growth during the first 10 years of the study period (through 2024).

Additional conservation beyond the targeted amounts included in the demand forecast may assist in meeting growth-related needs, such as the need to provide additional LMC in the Brant-Powerline sub-system. To meet these needs with conservation, an additional 50 MW of peak-demand reductions (i.e., 45% of sub-system load), incremental to the forecast of 12 MW from the LTEP conservation target would be required by 2023. This 50 MW plus the 12 MW targeted conservation amounts to approximately 45% of sub-system load. Given the immediate need and magnitude of the needs relative to the LTEP conservation target, the Working Group agreed that additional conservation beyond the targeted amounts is not a feasible option to meet the needs of the Area. However, efforts in the near- and medium-term should be focused on ensuring that the provincial conservation targets are met and monitoring the associated

[10] The provincial targets are for energy and have to be converted to capacity to calculate impact on peak demand by conservation

peak-demand savings that were assumed for the Brant Area. Therefore, conservation efforts to meet this goal are included as a recommendation in the near-term plan.

A provincial DR pilot is expected to roll out in the 2015-2016 time period. The Working Group believes it is prudent to consider this pilot program for the Brant Area to investigate opportunities, costs and feasibility in order to better understand its potential to address the Area's long-term supply capacity needs. A pilot can provide insights into the existence of willing DR participants in the Area. Knowledge and experience gained by way of a pilot will be useful when DR capacity markets are implemented by the IESO in the future and will help to address system as well as regional needs in the Brant Area and other areas of the province. At this time large scale use of DR has not been used as a solution to address local area's needs. Thus, a DR pilot program for the Brant Area could demonstrate its potential to be a technically feasible and cost-effective solution to provide a capacity buffer for the Area and defer larger and more costly infrastructure alternatives.

7.1.2 Local Generation

While in general local generation has the potential to meet both supply capacity and load restoration needs, this alternative was ruled out by the Working Group for meeting the near- to medium-term needs.

For the Brant Area, a natural gas plant for peak supply could meet the capacity needs at a cost of approximately $700-1000/kW with a 2-3 year in-service lead time.

It is the Working Group's view that local generation is not a cost effective option when compared to the recommended transmission options discussed below. Local generation is also not able to maximize the use of the existing Brant-Powerline sub-system infrastructure.

7.1.3 Transmission

Since the LMC of circuits B12/13 is primarily voltage limited, a number of voltage support options were considered to meet the near- and medium-term capacity needs of the Brant Area.

Capacitor Banks at Powerline MTS

Capacitor banks provide reactive support, boosting the voltage in an area. In doing so, they increase the voltage limit which is the first limiting factor in the 115 kV Brant-Powerline sub-system. The IESO and Hydro One studies have shown that 30 MVAR of reactive support at

Powerline TS can raise the LMC of the Brant-Powerline sub-system to 125 MW from 104 MW, thus increasing the useable capacity in the 115 kV Brant-Powerline sub-system. Capacitor banks also have relatively short 1-2 year in-service lead times. This option would cost approximately $1.0 million or $48/kW based on preliminary cost estimates by the LDC's and Hydro One.

Switching Facilities at Brant TS

This option connects the B8W and B12/13 circuits by installing three 115 kV breakers to close the existing normally open points. This option by itself can provide approximately 40 MW of additional supply to the limiting B12/13 circuits. Combined with the capacitor banks option as described above, the LMC of the Brant-Powerline sub-system can be further increased to approximately 165 MW.

It is estimated that the breakers can be in-service by 2017 and the budgetary estimate is $12-15 million based on Hydro One's preliminary cost estimates or $300-$375/kW. Hydro One and LDCs can together develop an implementation plan.

7.1.4 Distribution Options

Load transfers move load from one station to another and are currently used in the Brant Area on a temporary basis to maintain the loading on the 115 kV radial pocket within its LMC during peak demand conditions.

Depending on system conditions, Brantford Power has indicated that it has the ability to transfer up to 10 MW on a temporary, short-term basis from Powerline MTS and/or Brant TS to the Brantford TS. However, due to existing demand and future load growth, Brantford Power does not have the capacity at Brantford TS for permanent load transfers from the 115 kV sub-system. The incremental load at Brant Powerline sub-system in 2015 that is over the current 104 MW limit is expected to be 36 MW; this amount of load would be enough to exceed the limit at the Brantford TS. Therefore, load transfers are not a solution for the Area's capacity needs, as the surplus capacity that exists in the Area will be used up immediately.

7.2 Recommended Near- and Medium-Term Plan

The Brant Area Working Group assessed these alternatives in Section 7.1 as the basis for the following recommendations. Successful implementation of this plan will address the Area's electricity needs until the end of the study period.

To ensure the reliability of the Brant-Powerline sub-system before any permanent solutions are put in place, temporary load transfers will continue to be used in the near and medium term as required by the LDCs to address operational requirements.

Conservation

Meeting the conservation targets is assumed before identifying residual needs for the Area. The Working Group recommends that LDCs' conservation efforts be focused on measures that balance the needs for energy savings to meet the Conservation First targets while maximizing peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near- and medium-term plan, and will also lay the foundation for the long-term plan by reviewing the performance of specific conservation measures in the Brant Area, and assessing potential in the Area for further conservation efforts.

Capacitor Banks at Powerline MTS

The Working Group recommended the installation of capacitor banks at Powerline MTS to raise the LMC of the circuits to 125 MW. The implementation of the capacitor bank solution was assigned to Hydro One by way of a letter[11] from the former OPA in February 2014. The capacitor banks are expected to be in-service for summer 2015 and the implementation is being undertaken by Brantford Power Inc. and Brant County Power Inc.

Switching Facilities at Brant TS

The Working Group recommends utilizing the existing B8W circuit by adding three breakers on circuits B12/13 and B8W. Combined with the capacitor banks, the LMC of the Brant-Powerline sub-system can be further increased to approximately 165 MW. As shown in Figure 7-1, the supply capacity needs under the expected-growth forecast will be addressed by implementing these two stages of transmission reinforcement.

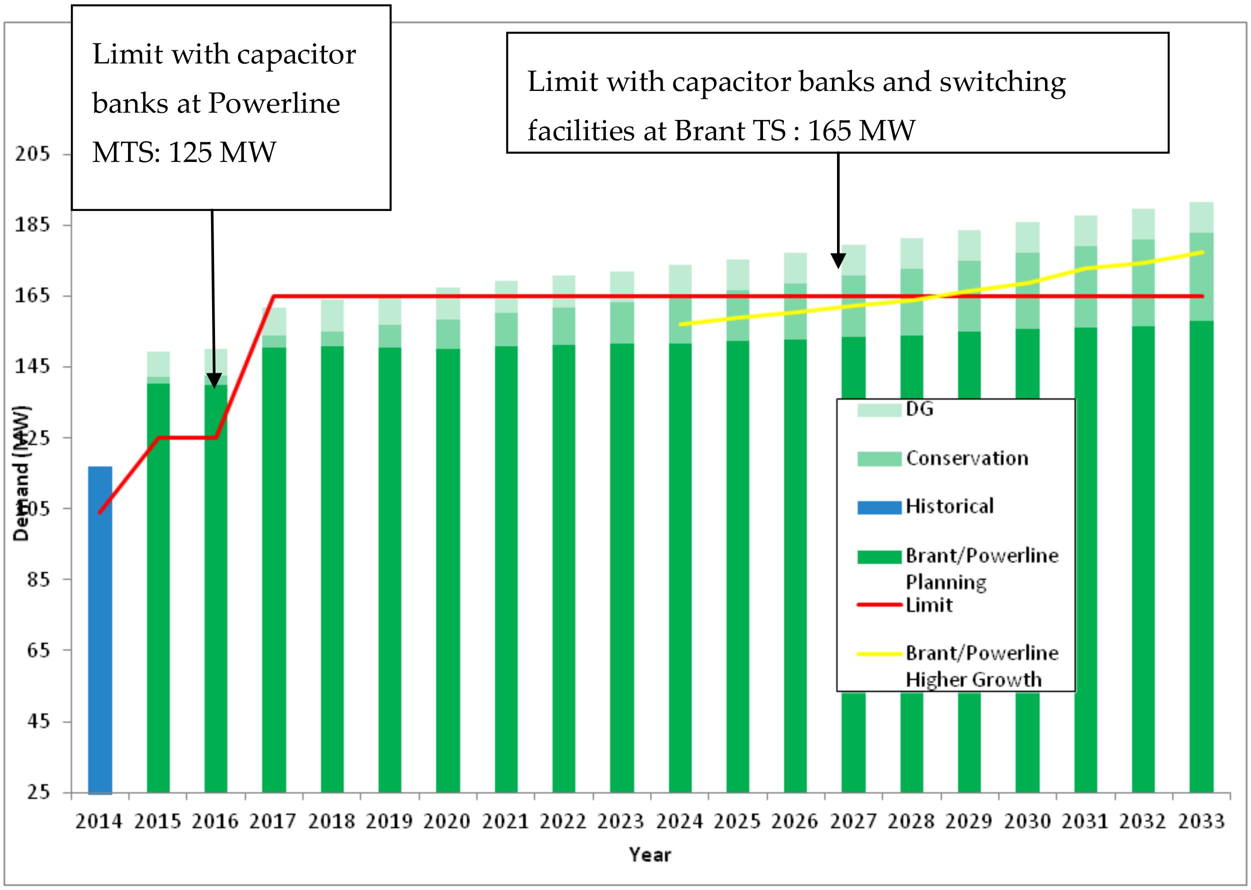
Demand Response

The Working Group has also considered investigating DR opportunities in the Brant Area by way of a DR pilot. The pilot program would be undertaken by the IESO in conjunction with

[11] http://www.hydroone.com/RegionalPlanning/Burlington/Documents/OPA Letter - Burlington Nanticoke - Brant.pdf

Area LDCs to investigate opportunities, costs and quantity of DR available in the Brant Area. Knowledge and experience gained by way of a pilot will be useful to provide options for addressing potential future capacity needs under a high-growth scenario.

Figure 7-1: Brant-Powerline Sub-system Planning Forecast and LMC



As shown in Figure 7-1, the recommended near- and medium-term solutions meet the needs of the Area until the end of the study period for the expected-growth scenario. These solutions are foundational for any longer-term considerations should electricity demand growth correspond with the higher-growth scenario or the Area experiences greater industrial load growth than is forecast.

7.3 Implementation of Near- and Medium-Term Plan

To ensure that the near-term electricity needs of Brant Area are addressed, it is important that the near- and medium-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near- and medium-term plan are outlined in Table 7-1 below, along with their recommended timing, and the parties with lead responsibility for implementation.

Table 7-1: Implementation of Near- and Medium-Term Plan for the Brant Area

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and DG	Develop CDM plans	LDCs	May 2015
	Implement LDC CDM programs	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification (EM&V) of programs, including peak-demand impacts, and provide results to Working Group	IESO	annually
	Continue to support provincial DG programs	LDCs/IESO	ongoing
2. Add capacitor banks at Powerline MTS	Design, develop and construct capacitor banks at Powerline MTS	Brantford Power Inc. and Brant County Power Inc.	ongoing and expected to be in-service summer 2015
3. Add switching facilities at Brant TS	Design, develop and construct new switching facilities at Brant TS	Hydro One, Brantford Power Inc. and Brant County Power Inc.	in-service summer 2017
4. Consider DR pilot for the Area	Continue to investigate opportunities for a DR pilot in the Brant Area	IESO	ongoing

8. Long-Term Plan (2024 through 2033)

The approach to developing long-term electricity plans is somewhat different than for near- or medium-term plans. There is inherently greater certainty in assessment of near- and medium-term electricity needs. For these needs, specific projects may need to be committed to ensure they are available to meet the forecast need. For longer-term electricity needs, there is an opportunity to develop and explore a broader set of options, as specific projects typically do not need to be committed urgently. Instead, the focus is on identifying potential need and on exploring alternatives to meet these needs. There is flexibility to assess alternatives that are not in widespread use but which show promise for the future. There is also opportunity to engage with stakeholders and communities to identify alternatives, to set out preliminary actions, and to monitor actual load growth and the underlying drivers. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to gauge the success and future potential of conservation measures; test out emerging technologies; engage with communities and stakeholders; coordinate with municipal or community energy planning ("MEP/CEP") activities; to lay the foundation for well-informed decisions in the future; and support decision-making in the next iteration of the IRRP.

An important consideration in developing a long-term plan is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected in-service lead times when identifying and considering alternatives. The longest lead time among all the possible alternatives is usually associated with new major transmission infrastructure, which typically requires 5-7 years to bring into service (including conducting development work, gaining regulatory and other approvals, construction and commissioning).

Based on the expected timing of the long-term needs in the Brant Area and the 5-7-year lead time for major infrastructure alternatives, the Working Group expects that a decision on the long-term plan will likely be required around 2028. Therefore, it is recommended that demand growth be monitored regularly as part of the implementation of this IRRP and, if necessary, that the IRRP be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

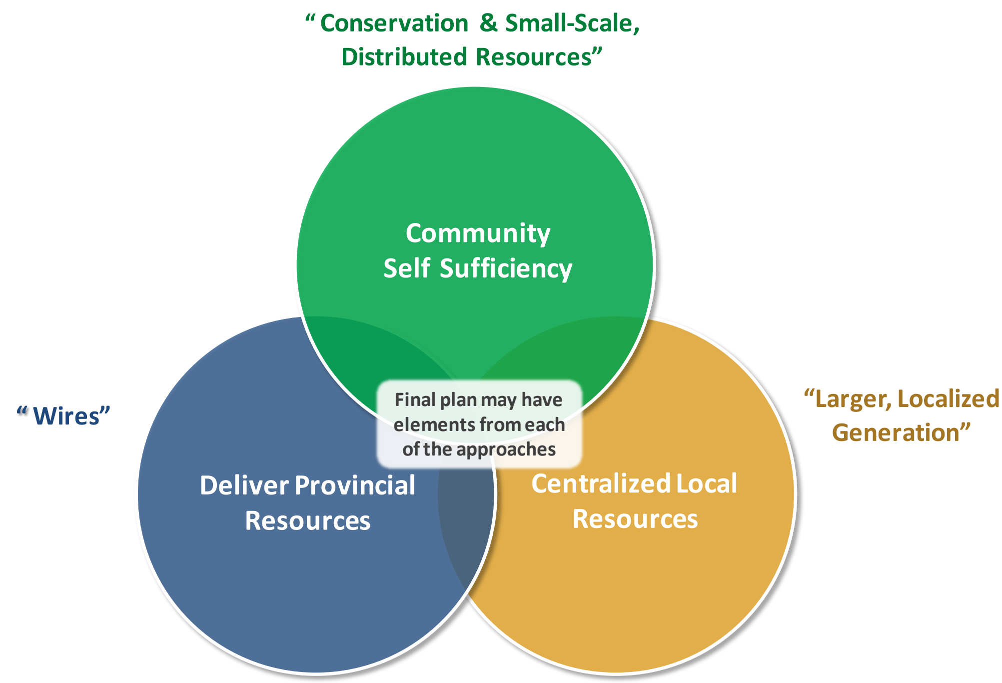
The following sections describe various approaches for meeting the long-term electricity needs of the Brant Area, and lay out recommended actions to develop the longer-term plan, and their implementation.

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increasing community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning, while still technically feasible, may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 8-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 8-1: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use to address regional capacity needs, for regions with

long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options to provide firm capacity resources at the local level before long-term plan commitment decisions are required. The success of this approach depends on early action to explore potential and develop options, and on the local community taking a lead role. This could be through a MEP/CEP process, or an LDC or other local entity taking initiative to pursue and develop options.

The intent of this framework is to identify which approach is to be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation targets will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. In fact, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the decision on the basic approach is made, the plan is developed around that approach, which affects the relative balance of conservation, generation, and "wires" in the plan.

8.1.1 Delivering Provincial Resources

Under a "wires" based approach, the long-term needs of Brant Area would be met primarily through transmission and distribution system enhancements. If the substantial needs forecast under the higher-growth scenario or additional industrial load arise, this could involve major new transmission development to deliver power from the major sources supplying the Area to where the power is needed.

Transmission options typically provide large capacity additions and can take 3-5 years to come into service from time of initiation. Such options could also require approval of leave to construct to the OEB as well as environmental assessments.

8.1.2 Large, Localized Generation

Addressing the Brant Area's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs of the Area. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a simple-cycle gas turbine ("SCGT") technology, would be more cost-effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Based on the long-term demand forecast, a local generation source could be helpful if it is located at Brant TS or Powerline MTS to further relieve the 115 kV sub-system. The cost of this option would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Brant Area through a Community Self-Sufficiency approach requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on emerging technologies, there will be a need to develop and test out solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In the Brant Area, this approach will be led by municipalities, the LDCs and First Nations communities if desired in identifying and developing opportunities.

8.2 Recommended Actions in Support of Long-Term Plan

At this time, while the Working Group does not recommend any specific commitment of investment and facilities to addresses potential longer-term needs (beyond 2025). To prepare for potential longer-term electricity load growth in this Area, the Working Group will investigate opportunities and potential for further cost-effective conservation and generation, as well as any relevant transmission investments.

Monitoring of growth in electricity demand and the achievement of conservation and DG targets in the Brant Area, will also be key components of ongoing electricity planning in the region and the needs and the options in the longer term will be reviewed in subsequent Burlington-Nanticoke regional planning studies.

1. Monitor Load Growth and Conservation Achievement and DG Performance

On an annual basis, the IESO will coordinate a review of conservation achievement, the uptake of provincial DG projects, and actual demand growth in the Brant Area. This information will be used to track the expected timing of long-term needs to determine when a decision on the long-term plan is required. Information on conservation and DG performance will also provide useful feedback into the ongoing development of these options as potential long-term solutions.

Additionally, the IESO will monitor results and incorporate lessons learned from the DR pilot, if it is implemented.

As the long-term needs for the Brant Area becomes more certain, additional measures to meet these needs, including but not limited to, large infrastructure investments, can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

2. Undertake community engagement

Broad community and public engagement is essential to development of a long-term plan. As no long-term needs have been identified for the Brant Area, there is no requirement at this time for engagement on long-term options.

However, a LAC may be established for the broader Burlington to Nanticoke region when the regional planning process is complete for the whole region.

A LAC's purpose is to provide input and advice on engagement plans for an area or region. It is expected that a LAC will consist of community, First Nations and Métis representatives and stakeholders. Advice from the LAC will be incorporated in developing engagement plans for an area/region.

3. Continue ongoing work to develop transmission/generation options

The IESO and Hydro One will continue working with the working group to evaluate the transmission or generation options to meet the potential long-term needs.

8.3 Recommended Actions and Implementation

A number of alternatives are possible to meet the region's long-term needs if they arise. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

The recommended actions and deliverables for the long-term plan are outlined in Table 8-1, along with their recommended timing, and the parties with lead responsibility for implementation are assigned.

Table 8-1: Implementation of Near-Term Actions in Support of the Long-Term Plan for the Brant Area

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Undertake engagement	Undertake public/community engagement as required	LDCs	2015-2017
	Engage with First Nations communities and the Métis Nation of Ontario	IESO	2015-2017
2. Monitor load growth, CDM achievement, and DG uptake	Prepare annual update to the Working Group on demand, conservation and DG trends in the Area, based on information provided by Working Group	IESO	Annually
	Identify long-term CDM potential	IESO	2016
3. Continue ongoing work to develop transmission / generation options	The IESO and Hydro One will continue working with the working group to evaluate the transmission or generation options to meet the potential long-term needs.	IESO/Hydro One	As required based on monitoring of growth
4. Initiate the next regional planning cycle early, if needed	Based on results of monitoring (see recommendation 4), commence the next regional planning cycle in advance of the OEB-mandated schedule, if needed, to enable sufficient time to develop options	IESO	As required

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles. It also addresses activities undertaken to date for the Brant Area IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the Brant IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table (see Figure 9-1). These principles were articulated as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process and they are now guiding the IRRP outreach with communities.

Figure 9-1: Summary of Brant IRRP Community Engagement Process

Creating Transparency: ***Creation of Brant IRRP Information Resources***	• Dedicated Brant IRRP web page created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page added to Hydro One website, and information posted on LDC websites • Self-subscription service established for Brant IRRP for subscribers to receive regional specific updates • Status: complete
Engaging Early and Often: ***Municipal, First Nation & Métis Outreach***	• Presentation and discussion at four group meetings with municipal planners from across the planning region • Information provided to First Nation communities with known interest in the planning area with an invitation to meet • Presentation and discussion with First Nation communities as requested • Information provided to Métis Nation of Ontario • Status: initial outreach complete; dialogue to continue
Bringing Communities to the Table: ***Broader Community Outreach***	• Presentations for Municipal Councils, First Nation communities and the Métis Nation of Ontario as requested • Webinar to discuss electricity needs and near-term solutions • Outreach with the broader community and formation of a Local Advisory Committee to be determined following the launch of the Burlington sub-region IRRP also within the Burlington - Nanticoke planning region • Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the Brant IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide a map of the regional planning Area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the Brant IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the Brant IRRP was meeting with representatives from the municipalities and First Nations communities in the region. For the municipal meetings, presentations were made to the Brant Area municipal planners at two group meetings held in Brant and Brantford in 2013, and again in 2015 after Area load forecasts were updated due to expected increases in near-term demand. The IESO held a separate meeting with representatives of the Six Nations Elected Council.

During these meetings, key topics of discussion involved confirmation of increased growth projections for the Area, which included addressing the near- and medium-terms needs through the installation of capacitor banks at the Powerline MTS and switching facilities at Brant TS, and continued CDM efforts, with the possibility of a DR pilot program in the Area, and potential actions to prepare for the long-term need if it materializes. Invitations to meet to discuss the Brant IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council. The IESO remains committed to responding to any questions or concerns from other communities who may have an interest in the planning Area.

Information on these project-level engagements, if required, will be provided on Hydro One's website and will also be listed on the IESO's Brant IRRP main webpage.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the working group to discuss the plan and potential approaches of possible long-term options. Presentations on the Brant IRRP will also be made to Municipal Councils, First Nations communities and the Métis Nation of Ontario on request.

Decision on broader community outreach activities, including whether to form a LAC will be made after the launch of the Bronte sub-region IRRP that is also within the Burlington – Nanticoke planning region. As LACs are generally formed at the regional planning level, not the sub-region level, additional work is required on the Bronte sub-region IRRP prior to initiating the formation of the LAC. In general, LACs are established as a forum for members to be informed of the regional planning processes. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement, and planning processes. Local Advisory Committee meetings are open to the public and meeting information is posted on the IESO website.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[12] available on the IESO website.

Information on outreach activities for the Brant IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Burlington to Nanticoke IRRP.

[12] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

10. Conclusion

This report documents an IRRP that has been carried out for the Brant Area, a sub-region of the Burlington to Nanticoke planning region.[13] The IRRP identifies electricity needs in the Area over the 20-year study period from 2014 to 2033, recommends a plan to address near- and medium-term needs, and identifies actions to develop broad options for the long term.

Implementation of the near-term plan is already underway, with the LDCs developing conservation plans consistent with the Conservation First policy and infrastructure projects being developed by the LDCs and Hydro One.

To support development of the long-term plan, a number of actions have been identified to monitor growth, engage with the community, and develop alternatives in the Area, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the Brant Area IRRP. A RIP is not required because transmission infrastructure planning to address the needs identified are already at the project level.

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the long term. In addition, the Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the Area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the long term under the higher-growth scenario or arrival of additional industrial load. If demand growth follows the expected-growth scenario or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

[13] The Brant and Bronte area of Oakville and Burlington form part of the larger Burlington to Nanticoke region.

BRONTE SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN

Part of the Burlington-Nanticoke Planning Region | June 30, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Bronte Sub-region

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Bronte Sub-Region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- Oakville Hydro Electricity Distribution Inc.
- Burlington Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Bronte Sub-region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Bronte Sub-region and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions, subject to obtaining all necessary regulatory and other approvals.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviations	Descriptions
A	Amp
ACSR	Aluminum Conductor, Steel Reinforced
Burlington Hydro or BHI	Burlington Hydro Inc.
CCRA	Connection Cost Recovery Agreement
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
CHP	Combined Heat and Power
DG	Distributed Generation
DR	Demand Response
Enersource	Enersource Hydro Mississauga Inc.
FIT	Feed-in Tariff
GTA	Greater Toronto Area
Haldimand Power	Haldimand County Power Inc.
HHH	Halton Hills Hydro Inc.
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MCOD	Maximum Commercial Operation Date

Abbreviations	Descriptions
MTS	Municipal Transformer Station
MW	Megawatt
Norfolk Power	Norfolk Power Distribution Inc.
NWGTA	North West Greater Toronto Area
Oakville Hydro	Oakville Hydro Electricity Distribution Inc.
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
Pickering NGS	Pickering Nuclear Generation Station
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
QEW	Queen Elizabeth Way
RIP	Regional Infrastructure Plan
SS	Switching Station
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt-Hours
Working Group	Technical Working Group for Bronte Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Bronte Sub-region over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group composed of the IESO, Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro"), Burlington Hydro Inc. ("Burlington Hydro"), Hydro One Distribution and Hydro One Transmission [1] (the "Working Group").

The Bronte Sub-region is within the Burlington-Nanticoke planning region. In municipal terms, it roughly encompasses the cities of Burlington and Oakville. The study is focused on the area served by Bronte Transformer Station ("TS"), but the scope will also include consideration of the broader Burlington Hydro and Oakville Hydro service territories, which include portions of the Greater Toronto Area ("GTA") West planning region. Bronte TS is radially supplied from the double-circuit 115 kV transmission line B7/B8 originating from Burlington TS. The study area, including all area transformer stations, is shown in Figure 1-1.

Figure 1-1: Map of Bronte Sub-region

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for 21 electricity planning regions at least once every five years.

This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies investments for immediate implementation necessary to meet near- and medium-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for long-term options and does not recommend specific projects at this time. Instead, the long-term plan identifies near-term actions to consider and develop alternatives, engage with the community and gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results can inform decisions should any decisions need to be made at that time.

This report is organized as follows:

- A summary of the recommended plan for the Bronte Sub-region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Bronte Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions, are described in Section 5;
- Electricity needs in the Bronte Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Sections 7 and 8;
- A summary of engagement to date and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Bronte Sub-region IRRP provides recommendations to address the sub-region's forecast electricity needs over the next 20 years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies forecast electricity needs in the sub-region over the near term (0-5 years, or 2015 through 2019), medium term (6-10 years, or 2020 through 2024) and longer term (11- 20 years, or 2025 through 2034). These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development and planning commitment required over these time horizons. The IRRP was developed based on consideration of planning criteria, including reliability, cost, feasibility, and maximization of the use of the existing electricity system, where it is economic to do so.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the shorter lead time for development of the recommended projects or actions. This IRRP also identifies possible longer-term electricity needs. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change to recommend specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time.

2.1 Near-Term and Medium-Term Plan (2015 through 2024)

Near/Medium-Term Needs and Plan

- Thermal loading of B7/B8 exceeds capacity following loss of companion circuit – 2018
- Post contingency voltage drop exceeds 10% at Bronte TS – 2021
- Address both needs by transferring one feeder (approximately 15 MW) of load from Bronte TS to Tremaine TS - 2018
- Details of implementation to be developed as part of RIP process.

By 2018, peak summer electrical demand on Bronte TS is expected to exceed 135 MW, triggering overloads on the supplying B7/B8 circuits following the loss of the companion circuit. By 2021, forecast station loading is expected to exceed the maximum 10% post contingency voltage drop criteria; although it may be possible to delay this occurrence by as much as 10 years by better distributing load between buses. Since both of these needs are the direct result of loading on Bronte TS, the near-term plan considered options to immediately lower peak electrical demand and the longer-term plan considered ways to maintain total load below 135 MW.

Two near-term options were identified, each capable of meeting near- and medium-term needs:

1. Upgrade transmission line supplying Bronte TS, and redistribute loads between buses
2. Transfer one feeder of load from Bronte TS to Tremaine TS

Recommended Actions

1. Transfer one feeder of load from Bronte TS to Tremaine TS

The shortest lead-time option for reducing load at Bronte TS is to transfer load to an adjacent station. This can be accomplished by constructing additional distribution infrastructure to enable either temporary or permanent connections between the service areas of Bronte TS and a nearby station (Tremaine TS). If a transfer can be accomplished for $9.7 million or less (the alternate cost of a transmission solution), then it is the most economic course of action.

Burlington Hydro has indicated that it would be possible to construct additional transfer capability between Bronte TS and Tremaine TS by 2019 for an approximate cost of $4.5 million. This is significantly less expensive than the alternative of upgrading the limiting section of B7/B8 supply circuits, at an estimated cost of $9.7 million. Oakville Hydro has indicated that it is not technically feasible to transfer loads from the Bronte TS service territory to other stations serving its franchise territory.

Transferring one feeder worth of load will reduce peak electrical demand at Bronte TS by approximately 15 MW, reducing total station load to approximately 120 MW in the near term, and permitting up to 15 MW of continued growth at the station in the mid and long term. Based on the planning forecast, this new capacity would primarily support Oakville Hydro customers, particularly those located in the Bronte village and midtown regions.

Burlington Hydro has indicated that it is concerned about longer-term growth in the Bronte service area impacting future costs. As a result, Burlington Hydro is concerned with relinquishing capacity at Bronte TS on a permanent basis. As part of the implementation Burlington Hydro has proposed a long-term (i.e., 10 years) lease arrangement. Details related to implementation will be developed as part of the Regional Infrastructure Plan ("RIP").

The IESO has committed to working with affected parties to ensure that costs borne by LDCs for the construction and operation of distribution infrastructure are appropriately allocated between the benefiting parties. The specific cost allocation challenges for this option are further discussed in Section 7.3.1.

2.2 Longer-Term Plan (2025-2034)

In the event that long-term load growth within the Burlington service territory requires a return of the 15 MW of capacity to Bronte TS, an alternative infrastructure solution will be required to serve the anticipated 15 MW of incremental Oakville Hydro growth. Oakville Hydro has indicated that distribution transfers from Bronte TS are not feasible at this time, but this assumption should be revisited in the future as changes to system configurations may occur. Assuming distribution transfers are not feasible, the alternative would be to upgrade the transmission line supplying Bronte TS.

If higher than anticipated load growth materializes in the long term, other measures, such as incremental DG or demand response ("DR") programs may become effective options to defer future infrastructure investment. These options will be considered during future regional planning studies when the nature of the long-term needs, alternatives, and associated costs become clearer. In the meantime, Working Group members will continue to engage with local planning bodies to coordinate community planning initiatives and identify cost effective opportunities for supplying local energy needs.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[2] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation,

---

[2] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment determines what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

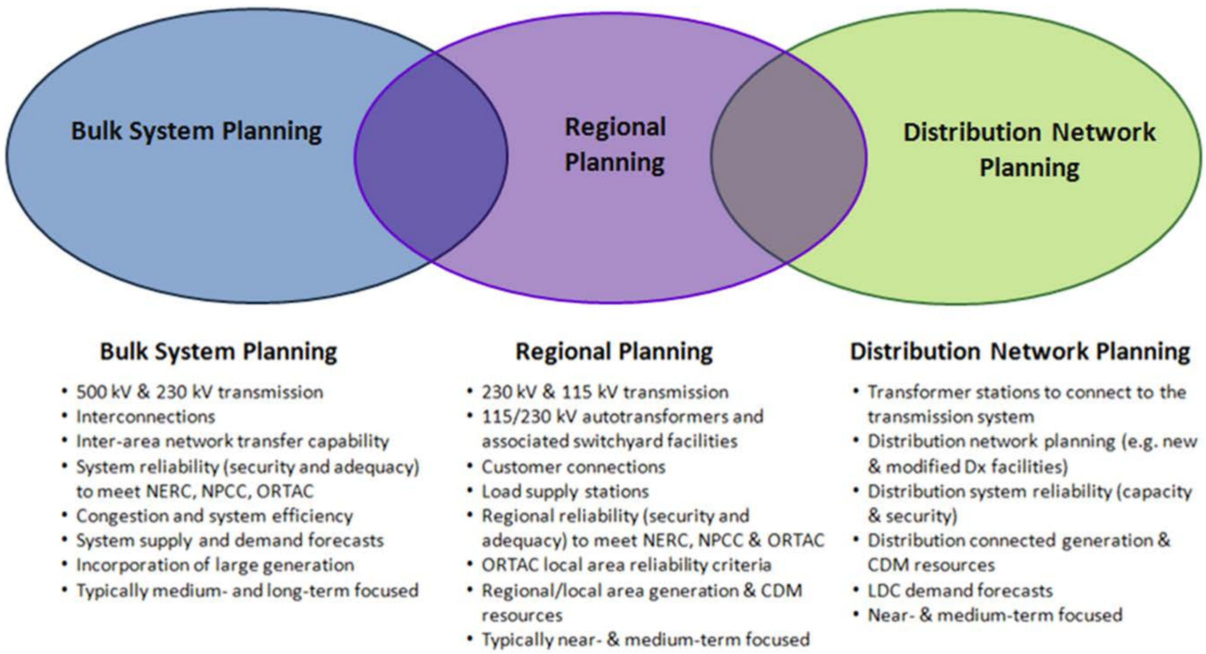
- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue.

Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

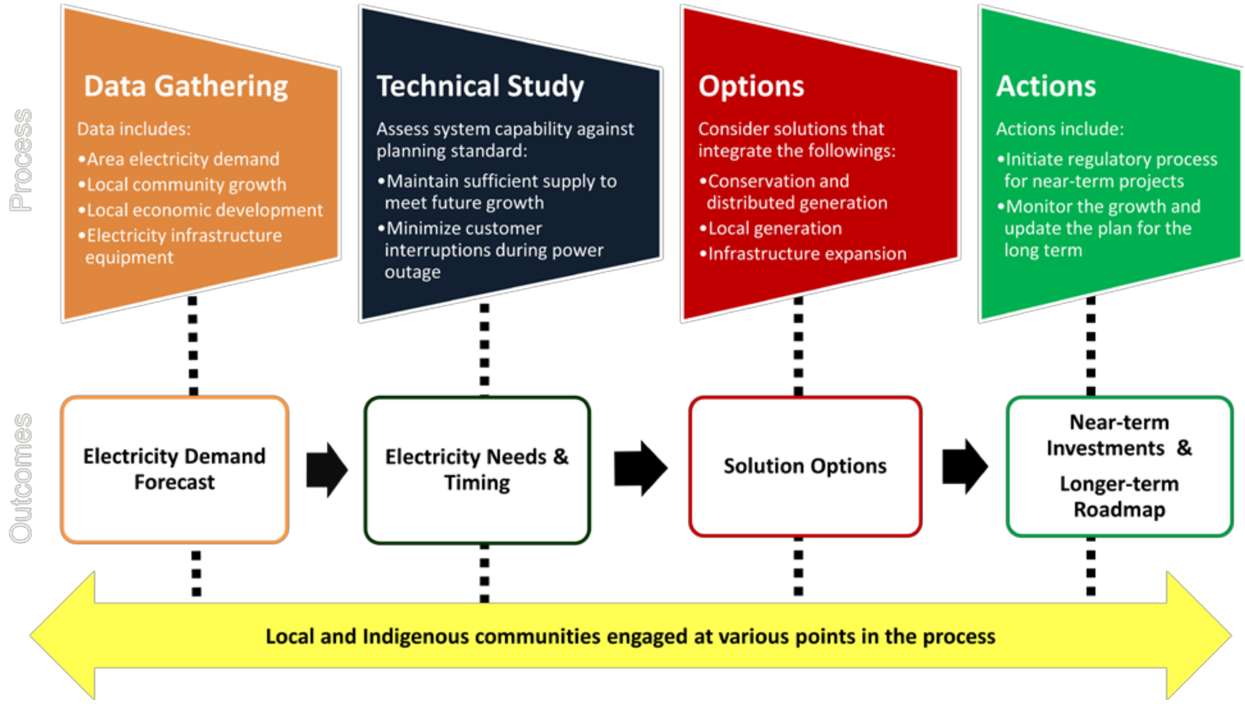
3.2 The IESO's Approach to Regional Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near and medium term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and the Working Group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2, below.

Figure 3-2: Steps in the IRRP Process



The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region or sub-region.

3.3 Bronte Sub-region Working Group and IRRP Development

The process to develop the Bronte IRRP was initiated in 2014 with the release of the Needs Screening report for the Burlington-Nanticoke Region. This product was produced by Hydro One Transmission with participation from the OPA and IESO, Brant County Power Inc.[3],

[3] Brant County Power Inc. and Cambridge and North Dumfries Hydro Inc. became one company on January 1, 2016 when the two LDCs legally joined together as Energy+ Inc.

Brantford Power Inc., Burlington Hydro Inc., Haldimand County Hydro Inc.[4], Horizon Utilities Corporation, Hydro One Distribution, Norfolk Power Distribution Inc.[5], and Oakville Hydro Electricity Distribution Inc. The Needs Screening process was carried out to identify needs which may require coordinated regional planning in those sub-regions of Burlington-Nanticoke which had not already undergone a regional planning process. The subsequent Scoping Assessment Report recommended that the needs identified for the Bronte Sub-region should be further pursued through an IRRP owing to the potential for coordinated solutions.

In 2015 the Working Group was formed to develop a Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the sub-region, and recommend the near and medium term actions.

---

[4] On March 12, 2015, the OEB approved Hydro One Network Inc.'s ("Hydro One") acquisition (EB-2014-0244) of all of the issued and outstanding shares of Haldimand County Power Inc. ("Haldimand Power"). The OEB also approved the transfer of distribution assets from Haldimand Power to Hydro One.

[5] On July 3, 2014, the OEB approved Hydro One's acquisition (EB-2013-0187) of all of the issued and outstanding shares of Norfolk Power Distribution Inc. ("Norfolk Power"). The OEB also approved the transfer of distribution assets from Norfolk Power to Hydro One.

4. Background and Study Scope

This report presents an integrated regional resource plan for the Bronte Sub-region for the 20-year period from 2015 to 2034.

To set the context for this IRRP, the scope of the planning study and the sub-region's existing electricity system are described in Section 4.1. A brief outline of the ongoing bulk system study being undertaken in the same general area, including considerations for coordination, is included in Section 4.2.

4.1 Study Scope

This IRRP develops and recommends options to meet supply needs of the Bronte Sub-region in the near-, medium and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation and demand management ("CDM" or "conservation") in the area, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, Feed-in Tariff ("FIT") and other generation uptake through province-wide programs.

This IRRP addresses regional needs in the Bronte Sub-region, including adequacy, security and relevant asset end-of-life consideration.

The following existing transmission facilities and assumptions were included in the scope of this study:

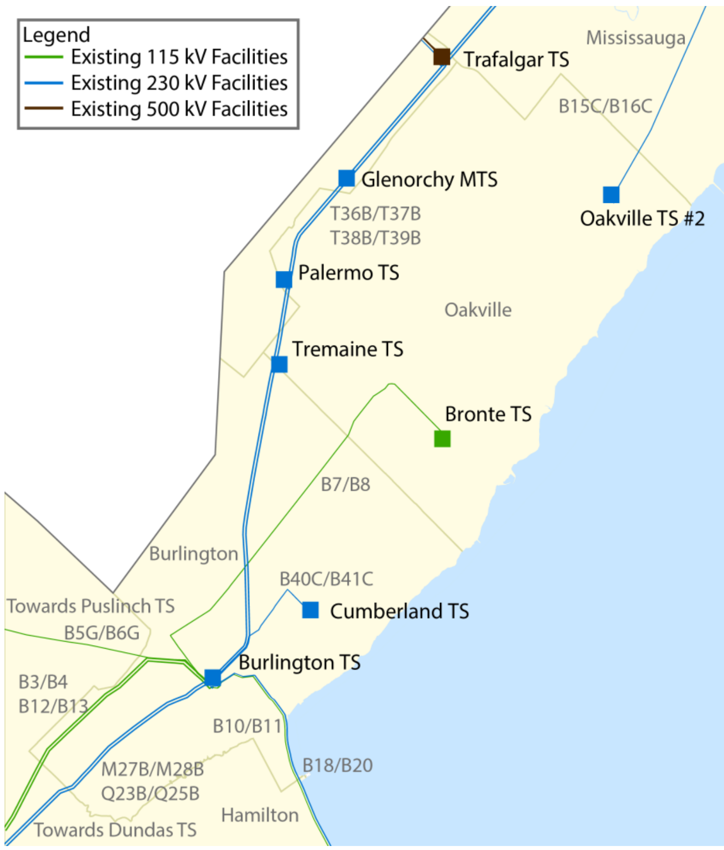
- Stations—Bronte TS, Cumberland TS, Palermo TS, Tremaine TS, Glenorchy MTS, Oakville TS #2 and Burlington DESN
- Transmission circuits—B7/B8, B40/41C, T36/37B, B15/16C

The Bronte IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the Load Meeting Capability ("LMC") and reliability of the existing transmission system supplying the Bronte Sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC.

- Establishing feasible integrated alternatives to address needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using decision-making criteria which included: technical feasibility, cost, reliability performance, flexibility, environmental and social factors.
- Developing and communicating findings, conclusions and recommendations.

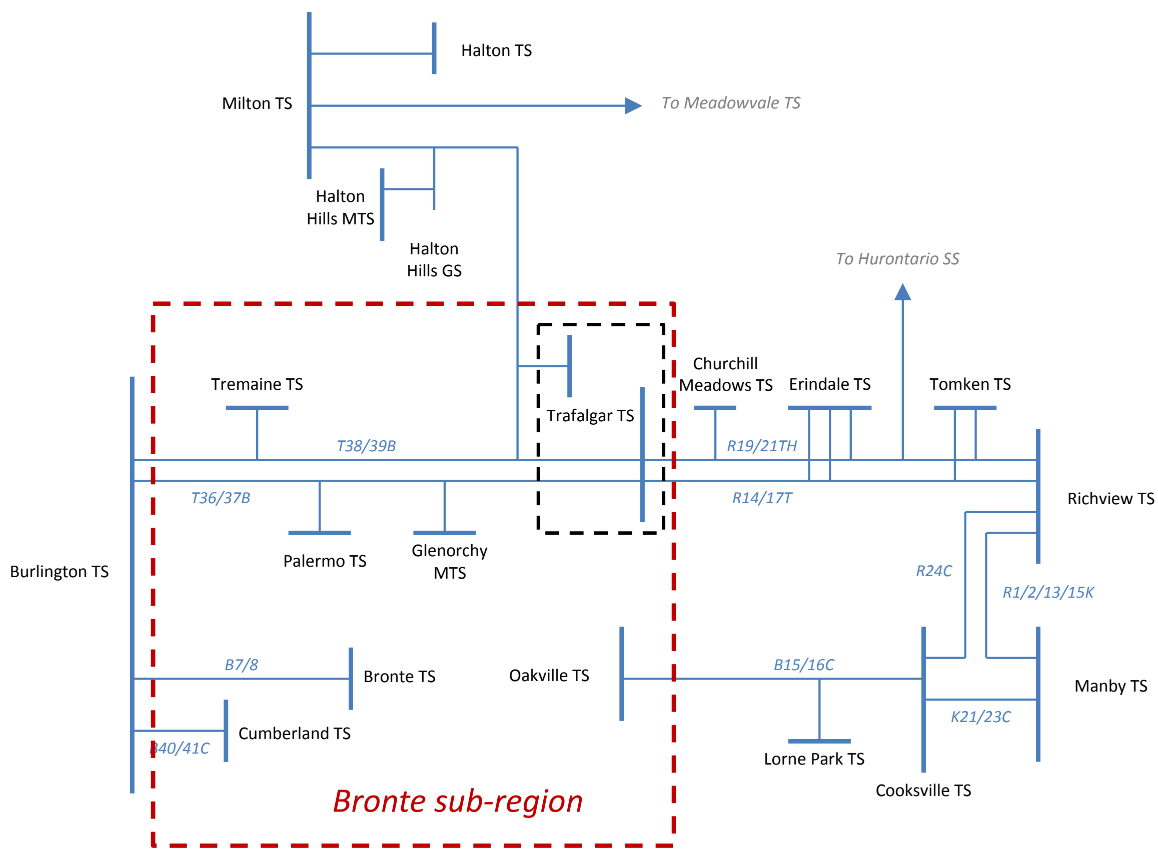
Figure 4-1: Regional Transmission Facilities



Of the step-down stations included in the Bronte Sub-region, only Bronte TS, Cumberland TS, and Burlington DESN were originally part of the Burlington-Nanticoke Region. The defined area of Bronte Sub-region, however, has been expanded outside this area to include step-down stations that serve Burlington Hydro and Oakville Hydro in the GTA West Region (Tremaine TS, Palermo TS, Glenorchy MTS, Trafalgar DESN, and Oakville TS #2). Expanding the scope of the study area to include these stations ensured that a full range of transmission and distribution alternatives was considered within the study.

Figure 4-2 shows the electrical configuration of the main stations, supply sources, and transmission assets for the Bronte Sub-region, and southern GTA West Region. Note that this diagram shows anticipated outcomes from the ongoing "GTA West Bulk System Study", detailed in Section 4.2. This includes retermination of circuits at Milton TS, and a new supply arrangement for Halton TS and Meadowvale TS. Also included is the proposed Halton Hills Hydro Inc. ("HHH") MTS, recommended as part of the North West GTA IRRP, and currently seeking approval through the HHH rate application.

Figure 4-2: Bronte Sub-region Electrical Sub-systems



4.2 Bulk Transmission System Study

Due to the potential for overlap between bulk and regional planning, as described in Section 3.1, it is important for regional planning to be coordinated with bulk system planning. This is particularly important when there is ongoing bulk planning within the study area. That is because a bulk system study can integrate bulk and regional needs that may be more efficiently solved through bulk system evaluations. Regional planning therefore needs to account for planned bulk system upgrades.

A bulk system study was initiated by the IESO for GTA West in 2014 to identify and recommend solutions to address emerging bulk transmission system needs. These needs differ from those driving the regional plan, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. These needs include planned refurbishment and retirement of nuclear generation facilities, incorporating renewable generation in southwest Ontario and changes in electricity consumption patterns across the GTA.

Preliminary results indicated that upgrades to the bulk transmission system in the GTA West area are linked to the retirement of Pickering Nuclear Generation Station ("Pickering NGS"). Recommended upgrades include the installation of new autotransformers at Milton Switching Station ("SS"), incorporation of a 230 kV switchyard, and reconfiguration of the 230 kV transmission system serving the area.

In early 2016 the Ontario government and IESO announced plans for the extended operation of Pickering NGS to 2024. This updated generation assumption requires that the original bulk system study be revised. This work is currently underway.

Following the completion of the updated bulk system study and the release of the 2017 LTEP, a review will be conducted to ensure that any outcomes of the Bronte Sub-region IRRP remain valid in light of any changing assumptions.

5. Demand Forecast

This section outlines the forecast of electricity demand within the Bronte Sub-region. It highlights the assumptions made for peak-demand load forecasts, and the contribution of conservation and DG to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times of the area's overall peak.

Within the Bronte Sub-region, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the air conditioning loads of residential and commercial customers. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day.

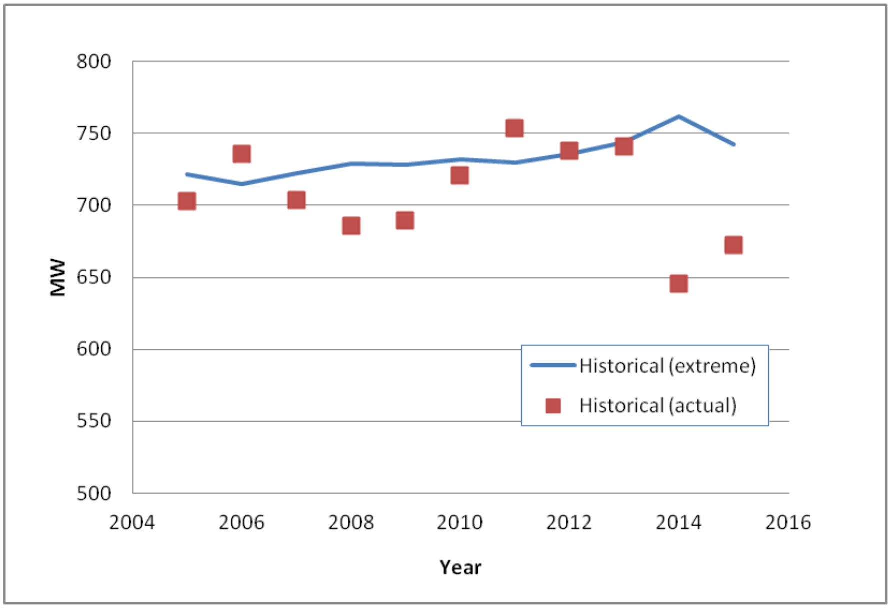
Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2014. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The Burlington and Oakville Hydro coincident peak electrical demand for the Bronte Sub-region is shown in Figure 5-1. The historical actual data (in red) shows the coincident peak demand for the year.

The historical extreme weather line (in blue) shows the demand at the same hour, but it has been adjusted to reflect the expected behaviour under extreme weather conditions. Correction factors between actual and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

Figure 5-1: Historical Peak Demand in the Bronte Sub-region

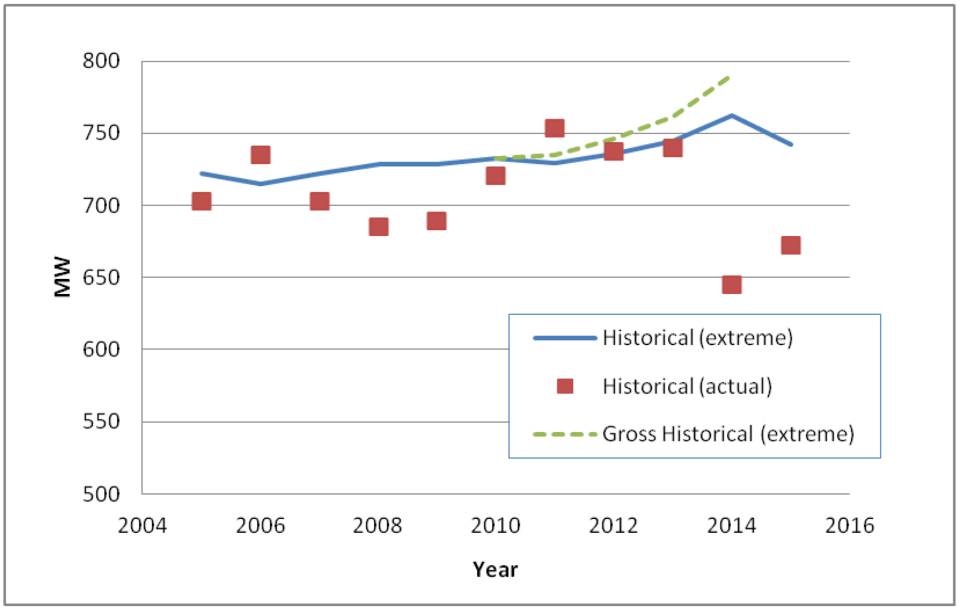


The weather corrected peak shows that demand has been generally increasing over the past decade, with a slight dip in the most recent year. However, the data for summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although an extreme weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments.

Historical demand, as measured at the station level, already accounts for the impact of conservation measures and other demand reducing programs in service at the time of peak. For example, verified peak demand savings from conservation programs show that 24.3 MW of peak demand was offset in 2014 across the combined Burlington Hydro and Oakville Hydro loads. In the absence of these conservation programs, growth in peak demand would have been more pronounced. The graph below shows the extreme weather corrected peak for 2010-2014[6], and the equivalent peak without the reduction from verified CDM programs from 2011-2014:

[6] Verified conservation impacts for summer of 2015 will be available September 2016

Figure 5-2: Historical Peak Demand in the Bronte Sub-region, Gross and Net



5.2 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs at the regional level.

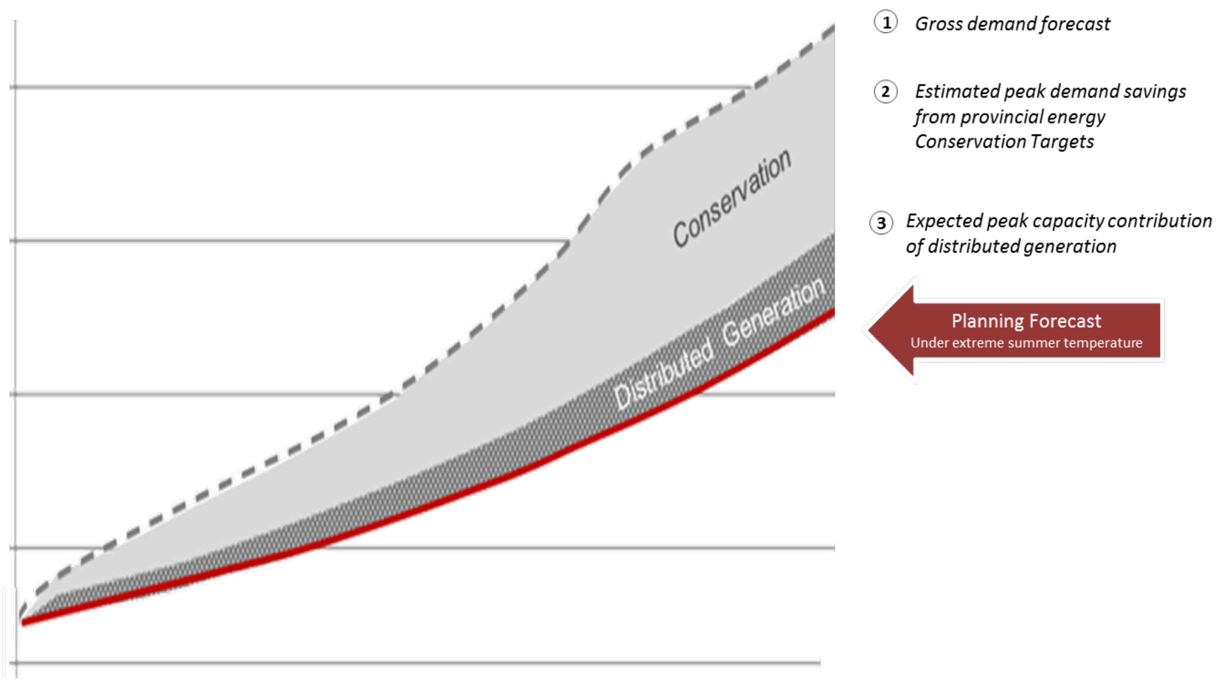
Regional electricity needs are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning therefore typically focuses on growth in regional-coincident peak demand.

The 20-year planning forecast is divided notionally into three timeframes. The near term (0-5 years) has the highest degree of certainty; any near-term needs must typically be addressed through regional transmission or distribution solutions as there is not sufficient time to address longer-term conservation or DG solutions. The medium term (5-10 years) provides more lead time to develop and incorporate conservation and DG options. The long-term forecast covers the 10-20 year period and has the lowest degree of certainty. It is used for identifying potential longer-term needs and, as necessary, considering and developing integrated solutions (including conservation, DG, major transmission upgrades). Early identification of these needs and potential solutions makes it possible to begin engagement with the local community and all levels of government long before the need is triggered. This provides the greatest opportunity to gain input on decision making, and to ensure local planning can account for new infrastructure.

The regional peak demand forecast was developed as shown in

Figure 5-3. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in the LDC's service territory. The LDC forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to produce a planning forecast — i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT and to reflect extreme weather conditions. The planning forecast was then used to assess any growth-related electricity needs in the region.

Figure 5-3: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, it also assumes that the targets will be met and that the targets, which are energy-based, will produce corresponding local peak demand reductions. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan. Additional details related to the development of the demand forecast are provided in Appendix A.

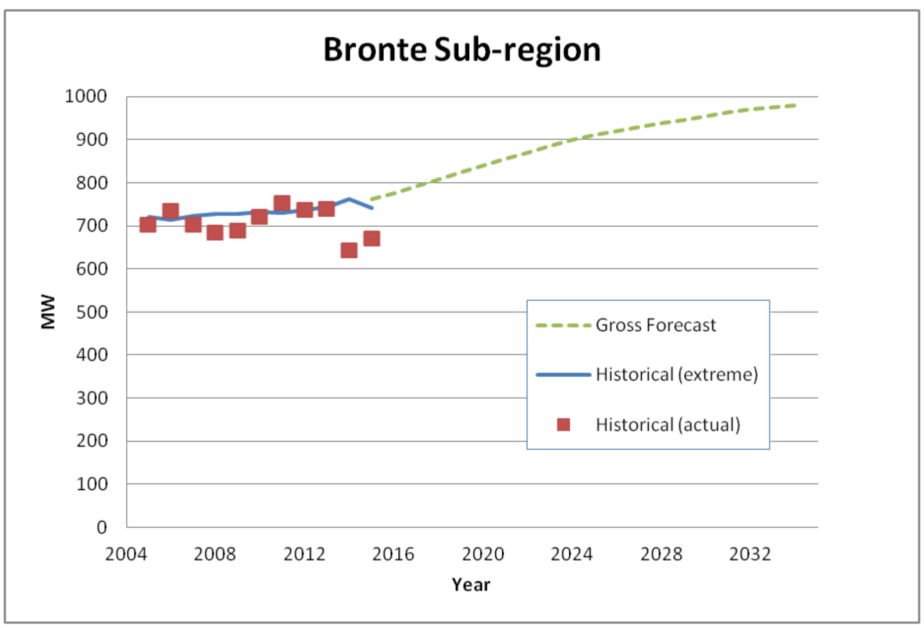
5.3 Gross Demand Forecast

Each participating LDC in the Bronte Sub-region prepared gross demand forecasts at the transformer station level or bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development, but do not account for the impact of new conservation measures such as codes & standards or DR programs. However, LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, which is termed "natural conservation".

Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The graph below shows the gross demand forecast information provided by LDCs for the Bronte Sub-region, with historical data points provided for comparison.

Figure 5-4: Bronte Sub-region Gross Forecast



Total annual growth averages 1.3% for the study area over the 20-year planning horizon. Growth is highest in the first 10 years at an average of 1.9% per year, before reducing to an average of 0.8% per year for the second 10 years. Although the forecast is shown for the entire study area, individual stations are forecast to experience different growth rates.

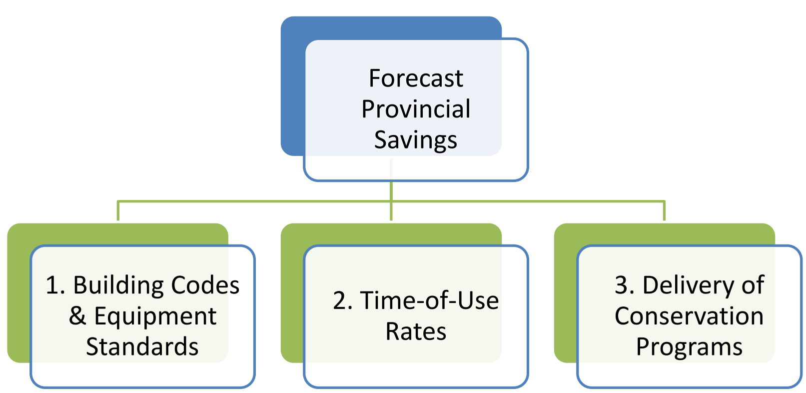
Forecasts were provided based on best available information and, as appropriate, will be updated going forward. The gross demand forecasts by station are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is the first resource to be considered in planning, approval and procurement processes. It plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. The conservation savings forecast for the Bronte Sub-region have been applied to the gross peak-demand forecast, along with DG resources (described in Section 5.5), to determine the net peak demand for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. The expected peak demand savings from meeting this target was estimated for the Bronte Sub-region. To estimate the impact of the conservation savings in the sub-region, the forecast provincial savings were divided into three main categories:

Figure 5-5: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The impact of estimated savings for each category was further broken down for the Bronte Sub-region by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Bronte Sub-region, LDCs were requested to provide a breakdown of their gross demand forecast, and a breakdown of electrical demand by sector for the forecast, at each TS. For TSs that an LDC could not provide gross load segmentation, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors[7] was used to help estimate the breakdown of demand. Once sectoral gross demand at each TS was estimated, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rates, and conservation programs. The estimates for each of the three savings groups were done separately due to their unique characteristics and available data.

The table below shows the final estimated conservation reductions applied to the gross demand to create the planning forecast. Note that only the impacts from Burlington Hydro and Oakville Hydro customers are included (as opposed to total conservation within the sub-region, including from other LDCs).

Table 5-1: Peak Demand MW Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032
Savings (MW)	9.1	19.8	36.2	45.7	57.3	70.9	83.1	94.5	100.4

Additional conservation forecast details are provided in Appendix A.

[7] OEB Yearbook of Electricity Distributors:
http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Bronte Sub-region is also forecast to offset peak demand requirements. The introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's FIT program, has increased the significance of distributed renewable generation in Ontario. This renewable generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

After applying the conservation savings to the demand forecast as described above, the forecast is further reduced by the expected peak contribution from contracted, but not yet in-service, DG in the sub-region. The effects of projects that were already in-service prior to the base year of the forecast were not included as they are already embedded in the actual demand which is the starting point for the forecast. Potential future (but uncontracted) DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of September 2015, new DG projects are expected to offset an incremental 2.68 MW of peak demand within the Bronte Sub-region by 2018. All contracts are for small scale solar projects (<500 kW). A capacity contribution of 34% has been assumed to account for expected output during peak summer conditions.

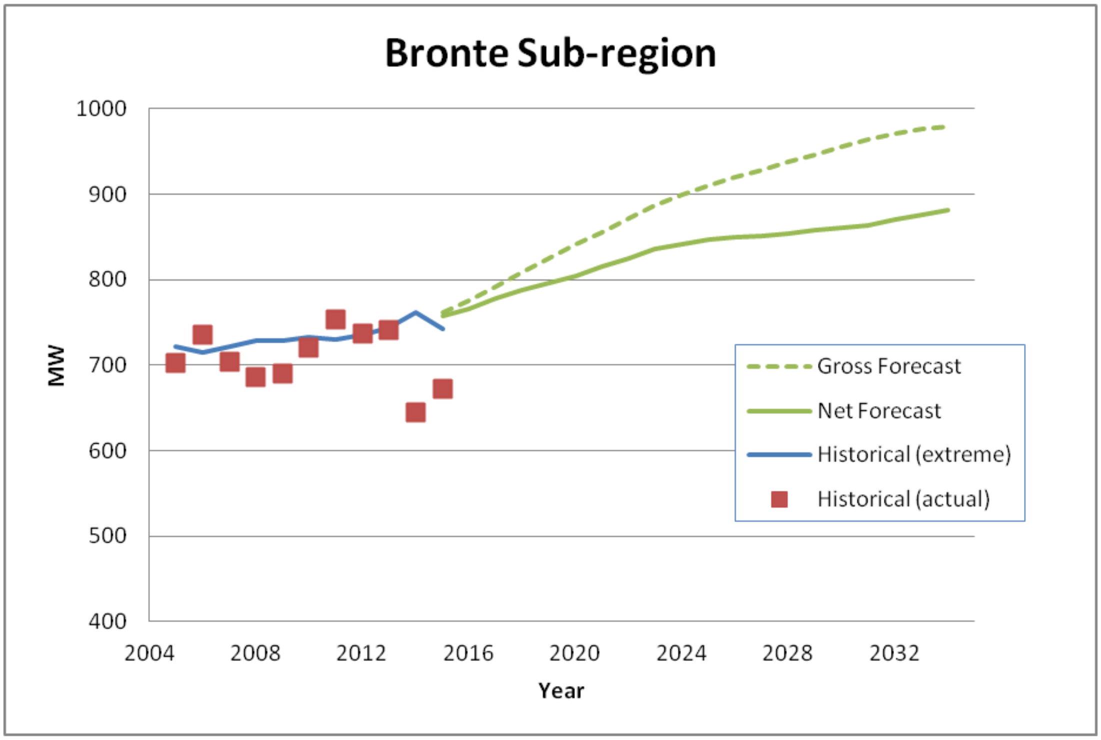
Additional details of the regional demand reductions from province-wide DG programs are provided in Appendix A.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced.

Figure 5-6 below illustrates the planning forecast, along with historic demand in the area. Note that the net forecast is for extreme weather conditions. Further details of the planning forecast scenarios are provided in Appendix A.

Figure 5-6: Bronte Sub-region Planning Forecast



6. Needs

Based on the planning forecasts, system capability, and application of provincial planning criteria, the Bronte Sub-region Working Group identified electricity needs in the near, medium, and long term. This section describes the identified needs for these three time horizons in the Bronte Sub-region.

6.1 Needs Assessment Methodology

ORTAC[8], the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements (see Appendix B for more details).

Through the application of these criteria, four broad categories of needs have been identified for the Bronte Sub-region IRRP:

- **Transformer Station Capacity** is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the 10-day Limited Time Rating ("LTR") of the step-down transformer stations in the local area. Transformer station capacity need is identified when the peak demand at step-down transformer stations in the local area exceeds the combined LTR ratings.
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the load meeting capability ("LMC") of the transmission lines supplying the area. The LMC is the maximum demand that can be supplied on a transmission line or group of lines as prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix B for more details). Supply capacity needs are identified when peak demand on the transmission lines exceeds the LMC.
- **Load Security and Restoration** is the electricity system's ability to keep the magnitude of electrical demand interrupted after a major prolonged transmission outage within the levels specified in ORTAC, including the time required to restore service. A major transmission outage would include a contingency on a double-circuit tower line resulting in the prolonged loss of both circuits. Load security concerns the magnitude of peak customer electrical demand which is susceptible to supply interruption in the event of a major transmission outage. Load restoration concerns the time periods within

[8] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

which the interrupted customer demand should be restored following a major prolonged transmission outage. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

- **Service quality** concerns factors which can impact the effective, efficient, or economic operation of the local power system, both under normal operating conditions and following contingency events. This includes maintaining voltage within specified limits, and overall reliability performance.

The needs assessment may also identify requirements related to equipment end-of-life and planned sustainment activities. Equipment reaching end-of-life and planned sustainment activities may have an impact on the needs assessment and option development.

6.2 Needs

Two separate needs were identified which impact the ability of Bronte TS to serve local loads:

1. **Overloads of 115 kV B7/B8 circuits.** The two 115 kV circuits supplying Bronte TS are limited by a 3 km line section which is rated at 750 A and is susceptible to overloading. This is lower than the 850 A for the remaining 14 km, which is not overloaded. As a result, load at Bronte TS must be kept below approximately 135 MW in order to respect the long-term emergency rating of the line.
2. **Post contingency voltage drop below acceptable criteria**. Bronte TS is made up of two separate buses, BY and Q. When load on BY exceeds approximately 80 MW, and total station load exceeds approximately 149 MW, the bus voltage drops more than 10% following the loss of circuit B7. Voltage drops of this magnitude are not acceptable under ORTAC. The exact loading limit for Bronte TS depends on the load balance between the two buses.

In addition to the two issues impacting Bronte TS, the following needs were also identified within the broader sub-region:

1. **Power Factor at Cumberland TS**. The IESO Market Rules require a station to be operated with a power factor of 0.9 or higher. Lower ratings indicate less efficient operation and can trigger thermal and voltage issues.
2. **Capacitor bank operation at Oakville TS #2**. Due to concerns over voltage imbalance, a station capacitor bank cannot currently be used. This limits the amount of load which can be served.
3. **Restoration needs**. Two areas within the Bronte study area have been identified as being at risk for not meeting restoration levels as defined in ORTAC.

These needs are described in greater detail in the following sections.

6.2.1 Overload of B7/B8

Bronte TS is served by two 115 kV circuits (B7 and B8) which emanate from Burlington TS and end at Bronte TS. Under ORTAC, each circuit must be capable of supplying total peak load for Bronte TS, without the need to curtail (reject) load, following the sudden loss of the companion circuit.

For the B7/B8 circuits, the most limiting contingency is the loss of B7, as the Long Term Emergency ("LTE") rating of B8 is the lower of the two, at 750 A (compared to 770 A). Further, the limiting section of B8 is 3 km in length, while the remaining 14 km has a slightly higher rating, at 850 A. Since the lowest rating must be respected, the effective LTE rating of the entire line is therefore 750 A.

The load in MW that can be accommodated by a rating of 750 A can vary depending on system conditions (including customer power factor and system voltage). In this case, it was determined to be approximately 135 MW based on prevailing conditions.

Total Bronte TS load is forecast to exceed 135 MW beginning in 2018 however this limit has already been exceeded during the 2012 and 2013 summer peaks. In each of these instances, B7 and B8 circuits were both in service, and as a result operated within their thermal limits. Had one of the lines experienced a sudden fault during these peaks, system operators would have required the immediate transfer of load away from the station, or load shedding, to keep the remaining circuit below its LTE. Actual LTE at the time of any fault would have been influenced by actual weather conditions, including temperature, sunlight, and wind.

Although the sudden loss of circuit is a relatively rare event, ORTAC requires that the system be capable of supplying all peak load in the event of this type of contingency.

6.2.2 Bronte TS – Post Contingency Voltage Drop

Immediately following the loss of any one system element, ORTAC requires that voltage on the distribution side of a step-down station drop no more than 10%.

The risk of a large sudden voltage drop is greater with radially supplied loads, and increases as more load is being supplied, particularly as the thermal limit of the station transformers is approached. These conditions apply at Bronte TS, making it particularly vulnerable.

Due to the configuration of Bronte TS, the loss of the B7 circuit triggers a larger voltage drop than the loss of B8, so it is again the more limiting of the two contingencies.

Voltage drop is also impacted by the distribution of load between the two Bronte TS buses. Based on the loading profiles provided by LDCs when developing the load forecast, the 10% post contingency voltage drop constraint is expected to become limiting when total station load reaches 143 MW, which is forecast to occur in 2021. This assumes BY bus loading of 83 MW, and Q bus loading of 60 MW.

However, if load is optimally distributed between the two buses, up to 149 MW of load could be served before reaching the 10% post contingency voltage drop, which is forecast to occur in 2033. This assumes BY bus loading of 79 MW, and Q bus loading of 70 MW.

Additional information on this need is provided in Appendix B.

6.2.3 Cumberland TS – Power Factor

An investigation was undertaken over the course of the IRRP to examine reported power factor issues at the Cumberland TS.

Based on historical records of hourly power factor data, it was determined that Cumberland TS has been frequently operating below a 0.9 power factor over the past several years. Lower power factors represent a less efficient operation of the system (by lowering the amount of active power which can be provided to customers), and can have a negative impact on local service quality. In addition, the high voltage side of a transformer must maintain a power factor of 0.9 or higher (leading or lagging) as per ORTAC.

This particular issue can be addressed by "wires" infrastructure. Hydro One and Burlington Hydro will further assess this issue and develop a mitigation plan as part of the RIP.

6.2.4 Oakville TS #2 – Capacitor Bank Operation

Oakville TS #2 station capacity is dependent on the operation of the capacitor bank located at one of the two buses. If not in operation, station loading is limited to around 138 MW, in order to respect 10% post contingency voltage drop. If the capacitor bank is in operation, up to 152 MW can be accommodated at the station. Although use of the capacitor bank improves load meeting capability as well as providing additional local benefits (power factor control), it has not been used over the past few years. Hydro One indicated that the reason it has not been operated is that energizing the bank could create a voltage imbalance of over 7% between the two buses, which may lead to false operation of protections at the station. Protections quickly disconnect faults which could endanger safety or cause damage to equipment if it remains energized. False operation of protections cause unnecessary interruption to customers and should be avoided.

Adding a second capacitor bank (such that both buses have equal voltage support) would eliminate this constraint and effectively increase Oakville TS #2 loading capacity from 138 MW to 169 MW. This would cost approximate $3 million.

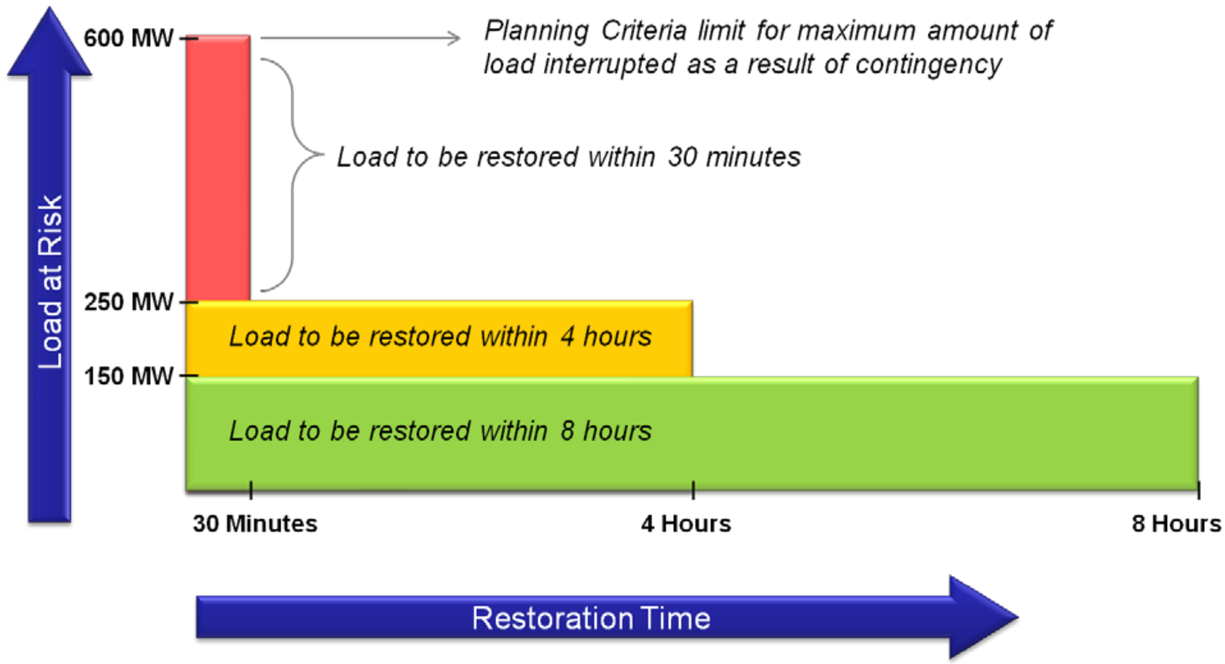
It should be noted, however, that, even with this increased station capacity, Oakville TS #2 is not a suitable location for providing supply to Bronte TS (see Section 7.1.3.2), and as a result it is not anticipated that additional capacity will be required over the study period at this station. In the event that electrical demand at Oakville TS #2 exceeds 138 MW (which may occur if a large customer connects), it is recommended that this constraint be reviewed. This need will not be considered further in the scope of this IRRP.

6.2.5 Restoration Needs

Restoration needs refer to the ability of the system to restore sufficient amount of load within required periods of time following the prolonged loss of a major supply source from the transmission system.

Several areas within the Bronte Sub-region have been identified as being at risk for not meeting restoration levels as defined in ORTAC. ORTAC indicates that, for the loss of two elements, any load in excess of 250 MW should be restored within 30-minutes and any load in excess of 150 MW should be restored within 4 hours. The assessment also considers restoration of all loads within eight hours. These restoration levels are summarized in Figure 6-1, below.

Figure 6-1: ORTAC Load Restoration Criteria



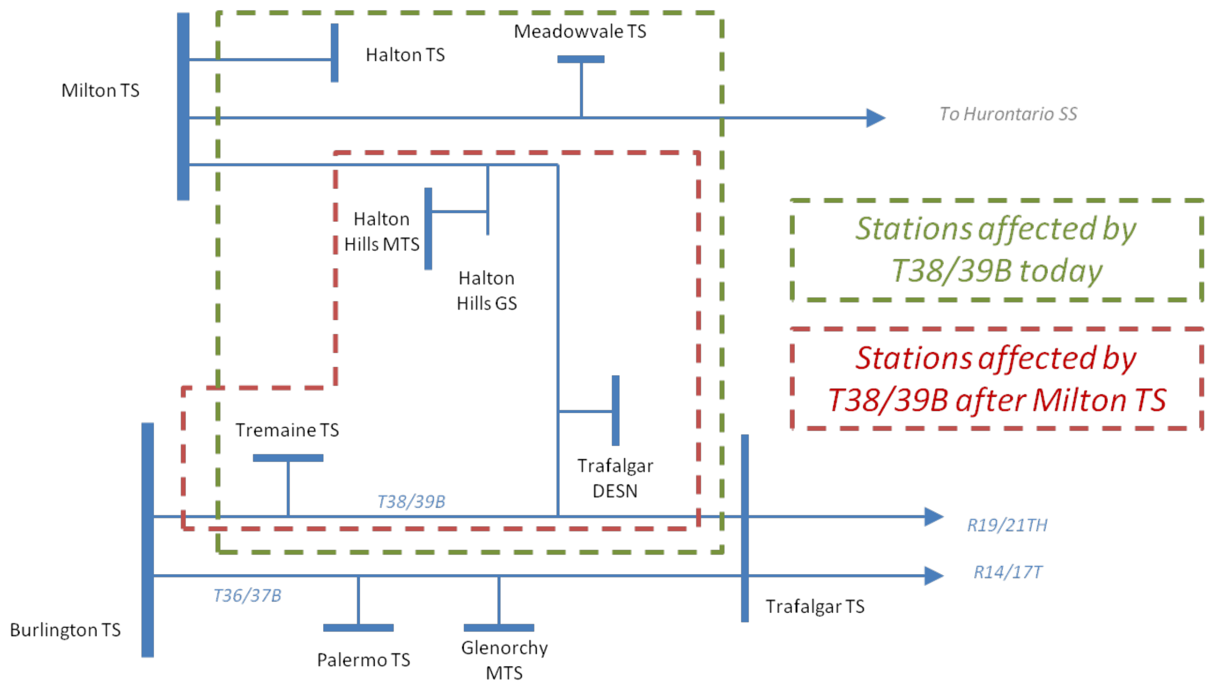
Given that the sudden loss of two transmission elements is a relatively rare event, ORTAC allows for some discretion in applying this criteria: Where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost".[9]

Some previously identified restoration needs affecting stations in this sub-region are being investigated through the West GTA Bulk System Study (more details provided in Section 4.2), particularly those related to the T38/39B circuits. It is expected that the gap in meeting restoration criteria associated with T38/39B will no longer occur following the bulk system changes planned as part of the West GTA Bulk System Study. This bulk plan includes implementing 230 kV to 500 kV transformers and a 230 kV switchyard at the existing Milton SS, and reconfiguration/retermination of transmission circuits in the area. This will remove Halton TS (including any future station expansion) and Meadowvale TS from T38/39B, lowering

[9] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

the amount of load at risk of interruption. Stations which will continue to be served by T38/39B are Tremaine TS, Trafalgar DESN, and the future HHH MTS. These measures will reduce the amount of load at risk of interruption by 2034 from 646 MW to 241 MW (already meeting acceptable 30 minute restoration criteria). Combined with the present day 4 hour restoration capability of 99 MW for these stations, this means that these restoration needs will be met following the expected bulk system upgrade in GTA West.

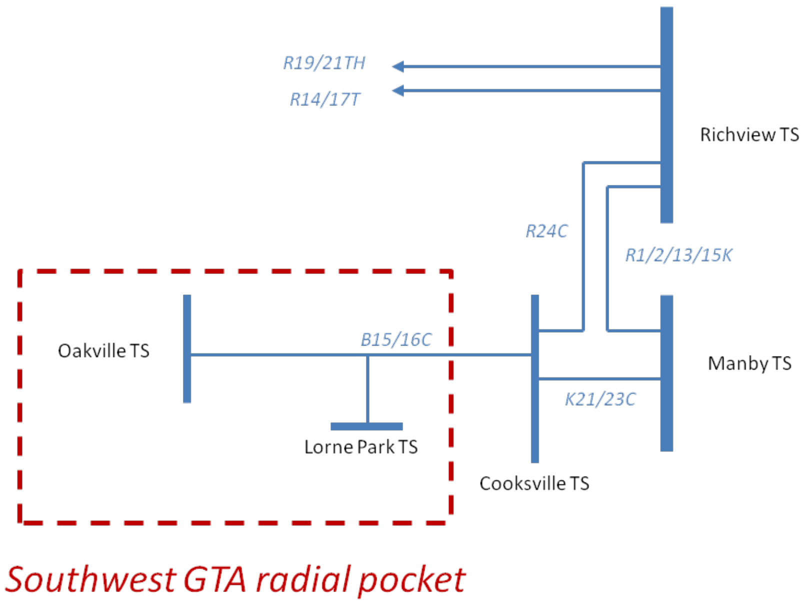
Figure 6-2: Restoration Pocket for T38/39B



Also being considered from a restoration perspective are Palermo TS and Glenorchy MTS. As shown in Figure 6-2, above, both are at risk of supply interruption following the loss of the T36/37B circuits. However, the current forecast shows the coincident load of these stations only reaching 192 MW over the next 20 years, with 61 MW capable of being restored within of 30 minute and 116 MW capable of being restored within 4 hours through distribution transfers. This means that these stations are currently meeting restoration guidelines and do not require further analysis.

The remaining area of the Bronte Sub-region which is at risk of failing to meet restoration guidelines is the southwest GTA radial pocket. Following the simultaneous loss of both B15C and B16C circuits, supply is interrupted to Oakville TS #2 and Lorne Park TS, in addition to local direct connect industrial loads (not shown in Figure 6-3, below).

Figure 6-3: Restoration Pocket for Southwest GTA, West of Cooksville



The net forecast prepared for this IRRP shows that demand is expected to be relatively flat over the next 20 years, as new demand is largely offset by new conservation initiatives. In order to fully meet criteria guidelines, all load in excess of 250 MW must be restored within 30 minutes, and all load in excess of 150 MW within 4 hours, following the sudden loss of the B15/16C circuits. Given the proximity of emergency crew and equipment, all loads should be able to be restored within 8 hours through conventional transmission supply.

Table 6-1 below shows the total peak load at risk of interruption for select years, and the 30 minute and 4 hour restoration capability which would be required to meet this criteria:

Table 6-1: Peak Load and Restoration Requirements for West of Cooksville Pocket

	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
Forecast Peak Demand	257.6	261.9	262.3	266.5	270.3	273.9	276.5	280.0	284.3	292.8
Targeted 30 Minute Restoration	7.6	11.9	12.3	16.5	20.3	23.9	26.5	30.0	34.3	42.8
30 Minute Shortfall	0	0	0	0	0	0	0	0	0	0
Targeted 4 Hour Restoration	107.6	111.9	112.3	116.5	120.3	123.9	126.5	130.0	134.3	142.8
4 Hour Shortfall	0	2.2	2.6	6.8	10.6	14.2	16.8	20.3	24.6	33.1

Based on discussions with area LDCs, up to 46 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 110 MW within 4 hours.[10] The West of Cooksville pocket is expected to be able to meet the 30 minute restoration criteria over the entire study period. This leaves a 4 hour restoration shortfall beginning in year 2018, and extending throughout the rest of the study period, up to a maximum of 33 MW by 2034.

Although the magnitude of the 4 hour restoration need is small, the vulnerability to loss of supply for customers in the West of Cooksville area was highlighted during the July 8, 2013 summer rain storm. This section of line was interrupted for several hours due to outages at Richview TS and Manby TS. The likelihood of a similar outage occurring in the future is low, as preventative measures have been implemented, based on root cause analysis. However, Enersource Hydro Mississauga Inc. ("Enersource") and Oakville Hydro have indicated that there are ongoing concerns about this reliability risk. It should be noted the bulk plan for the area is considering options which may address this situation.

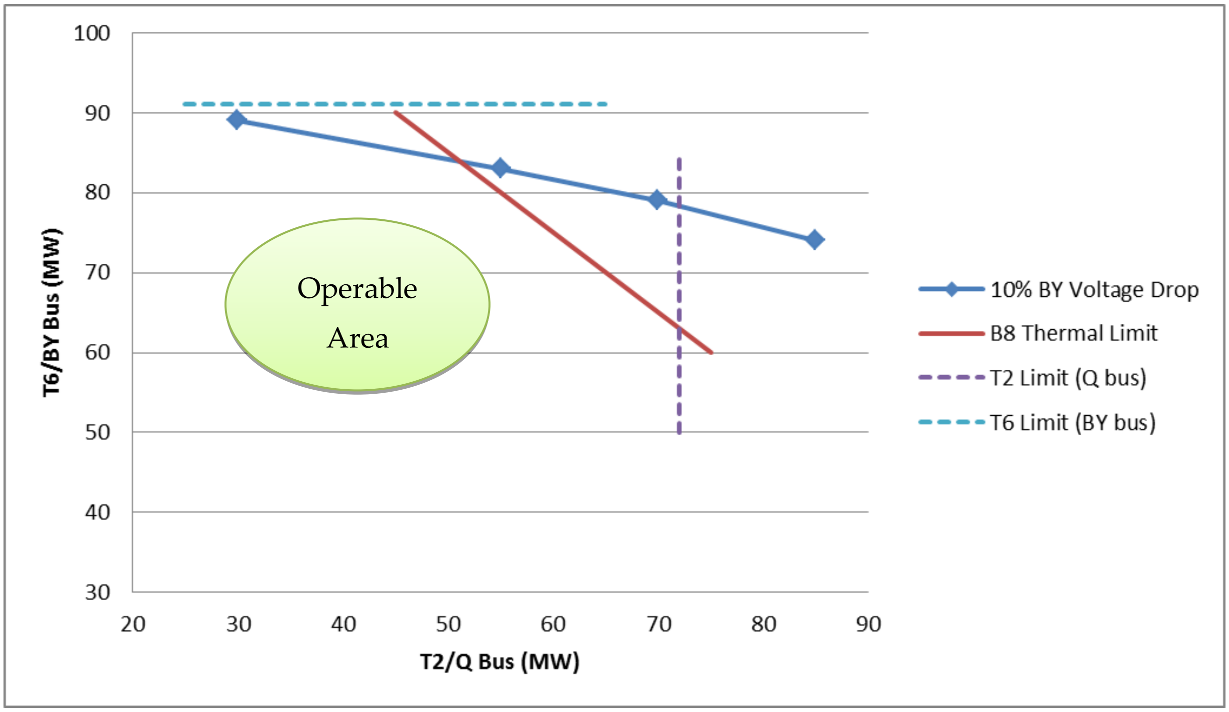
6.3 Needs Summary

The majority of needs in the Bronte Sub-region concern various loading limits on Bronte TS.

Figure 6-4, below, shows the operable area for Bronte TS, with consideration for the B7/B8 thermal limits, 10% voltage drop criteria, and LTR of the transformers following the loss of B7 (most constraining scenario).

[10] Burlington to Nanticoke Scoping Assessment Report, http://www.ieso.ca/Documents/Regional-Planning/Burlington_to_Nanticoke/Scoping%20Assessment%20Outcome%20Report.pdf

Figure 6-4: Loading Limits on Bronte TS, Multiple Constraints, for Loss of B7



The maximum load that can be carried by Bronte TS is 135 MW in order to respect thermal limits of the B8 circuit (as shown by the legend line in red). Since this limit is not sensitive to the distribution of load between buses, any point along the limit corresponds to the same 135 MW total.

If this limit were neglected, the next highest possible load which could be carried by Bronte TS is 149 MW, which coincides with the intersection between the 10% voltage drop limit and the T2 loading limit (line in blue and broken line in purple, respectively). Note that this limit is sensitive to loading between buses, which means the maximum occurs when load on the Q bus is approximately 70 MW, and load on the BY bus is 79 MW.

In addition to Bronte TS, Cumberland TS is also currently experiencing service quality needs related to the low power factor at the high voltage bus. This need will be addressed directly between the transmitter and distributor, and will not be studied further as a part of this IRRP.

An operational issue has also been identified at Oakville TS #2, which is preventing the use of the capacitor bank, and hence limiting the loading capability of the station. However, since Oakville TS #2 is currently not forecast to exceed the reduced loading limit, this need will not be studied further as part of this IRRP.

Finally, two restoration needs currently exist in the Bronte Sub-region: T38/39B, and the West of Cooksville radial pocket. The former need is expected to be addressed through the implementation following the GTA West Bulk System Study, and as a result will not be studied further as a part of this IRRP.

The table below provides a brief summary of needs which will be considered during the development of options for the plan.

Table 6-2: Summary of Needs in Bronte Sub-region

Area	Need	Description	Need Date
Bronte TS	Thermal limit of B7/B8	Flows on B8 circuit exceeds Long Term Emergency Rating following loss of B7 when load is in excess of 135 MW	2018
Bronte TS	Post contingency 10% voltage drop	Voltage at Bronte TS may drop by more than 10% following loss of B7 when load is in excess of 143 MW (or 149 MW of loads can be redistributed between buses)	2021
West of Cooksville	Restoration	Restoration shortfall for the 4 hour timeline defined by ORTAC	2018

7. Near- and Medium-Term Plan

This section describes the alternatives considered in developing the near- and medium-term plan for the Bronte Sub-region, provides details of and rationale for the recommended plan, and outlines an implementation plan.

7.1 Alternatives for Meeting Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated options. The Working Group further considered technical feasibility, cost and consistency with long-term needs and options in the Bronte Sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were given priority, where they were otherwise determined to be cost effective.

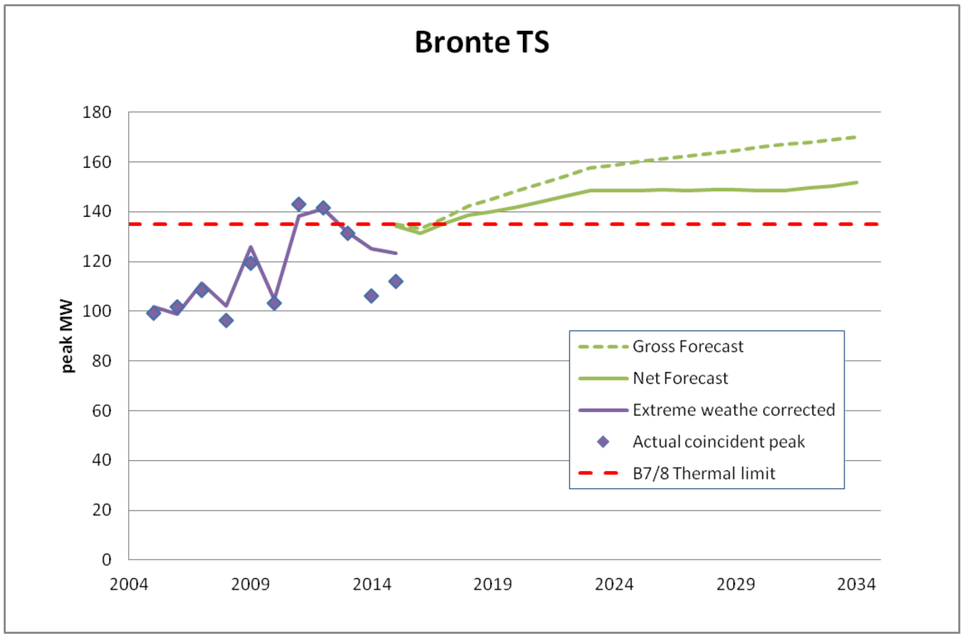
The following sections detail the alternatives considered and address their performance in the context of the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets (see Section 5.4). Across the planning area, the LTEP energy reduction targets account for approximately 57 MW, or 41% of the forecast demand growth during the first 10 years of the study. Achieving the estimated peak demand reductions of the provincial conservation targets significantly reduces the extent of the Bronte TS thermal and voltage drop needs. This results in only a 15 MW capacity gap, which makes a distribution solution viable. It also effectively offsets new demand growth at this station from 2023-2030. As a result, a solution developed to address near-term needs would be sufficient for the area until roughly 2030.

In Figure 7-1, below, Bronte TS load is shown under both the gross and net forecasts (accounting for expected conservation and contracted DG). The thermal limit of B7/B8 is also shown, as it is the more constraining of the two needs identified at Bronte TS.

Figure 7-1: Effect of Conservation Targets on Bronte TS Peak Load



Note that the majority of conservation targets are provided in terms of energy offsets (measured over an entire year), while transmission needs are triggered based on peak demand (single highest observation in a year). As a result, in order to reduce, defer, or otherwise address needs, conservation programs must have an impact during the hour of peak demand. In the case of the Bronte Sub-region, this typically means late afternoon on the hottest weekdays of summer.

The net forecast is an estimate of how meeting the mostly energy based targets translates into peak demand reductions. There is, however, uncertainty in meeting energy conservation targets and determining how meeting those targets will translate into peak demand savings. As such, there is a wide range of potential demand impacts which could be experienced (both higher and lower than forecast), even while still achieving full conservation targets. Therefore, LDCs are encouraged to focus their Conservation First Framework ("CFF") funding (Oakville Hydro - $24,575,982 and Burlington Hydro - $25,825,521) towards measures and programs that can also reduce peak and overall demand–particularly in areas where needs have been identified through regional planning–when they are working towards achieving their CFF energy savings targets.

As part of the implementation of this plan, the Working Group will review actual peak demand, including the impact of conservation, on an annual basis. The IESO is willing to consider requests from LDCs for support with the development of a localized achievable potential study to determine the specific conservation savings potential associated with Bronte TS. The study could be used to help design conservation/DSM programs that deliver optimal customer and system benefits. If net demand trends lower at Bronte TS than expected, need dates may be deferred. On the other hand, if growth trends higher, and cannot be offset through conservation or other peak reducing activities (such as DG), additional measures may be required to address needs.

The other major need identified in the Bronte Sub-region is the restoration need following a loss of transmission supply in the West of Cooksville radial pocket. Restoration is required following a loss of supply. Power must be restored through an alternate electrical supply path, or when the original fault is cleared. Conservation does not have a bearing on these factors, and as a result is not a suitable option for addressing these types of needs.

7.1.2 Local Generation

Large, transmission-connected generation and small-scale distribution-connected DG options were ruled out as viable alternatives for meeting near-term needs in the Bronte Sub-region. The sections below explain why.

7.1.2.1 Generation-based Solution to Address Bronte TS Needs

Two sets of needs are associated with Bronte TS: overloads on the B7/B8 supply circuits, and post contingency voltage drop at the station itself.

Based on the planning forecast, a transmission connected generator of approximately 20 MW would be suitable for addressing the circuit overload needs expected to emerge in 2018, but would not impact the voltage drop needs expected to begin in 2021. Although this could address some of the near-term Bronte TS needs, it was still not considered an appropriate solution for several reasons. First, it is not technically feasible to approve and construct this type of facility within the short lead time required to meet near-term needs. Second, it would be difficult and possibly infeasible to find a suitable location to host this type of facility in close proximity to Bronte TS, which is located within a highly developed area of southwest Oakville. Third, local generation would add to the overall generation capacity for the province and therefore the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the mid-2020s at the earliest.

Instead of a single large transmission connected generation facility, 20 MW worth of DG projects could address both the B7/B8 overload and Bronte TS voltage drop needs into the long term. However, DG projects were also determined to be technically, logistically and economically infeasible for addressing these needs because the DG facilities would need to be optimally dispersed across a number of distribution feeders. Generation would, in effect, have to fully offset any incremental demand, and be matched precisely where local demand requires. Developing and implementing such a complex solution within the time period of the need in this densely developed area was determined to be impractical.

While DG projects are not suitable for addressing near-term needs, they offer good potential for managing ongoing load growth, and thereby deferring longer-term needs. New development in the Town of Oakville offers potential to identify opportunities for large steam host customers to integrate combined heat and power ("CHP") projects at the earliest stage of community design to meet demand and heat needs. Typically large commercial or institutional customers have suitable profiles to accommodate this type of facility. The Town of Oakville has identified goal 2.1.1 in their Environmental Strategic Plan to "Work with Oakville Hydro and other community partners to expand, access and promote alternative green energy resources (geothermal, solar, combined heat and power, etc.)".[1] Additionally, the City of Burlington has proposed a target of 12.5 MW of peak electrical demand to be met through local sustainable generation by 2031.[11] Locating distributed energy resources in the Bronte TS service territory could provide value in deferring the need for additional investments.

Based on the planning forecast, long-term growth within the Bronte TS area is expected to average less than 1 MW per year. Assuming the recommended option (described in greater detail in Section 7.2) is adopted, new needs may begin to emerge after 2030. Acquiring approximately 10 MW of DG capacity, with the ability to dispatch during local peak demand, would thereby defer potential long-term needs for over a decade.

Potential for incremental DG to address long-term needs will be reviewed as part of future regional planning cycles, while actual uptake will be monitored on a yearly basis.

---

[1] Oakville Environmental Strategic Plan, 2011 Update, http://www.oakville.ca/assets/general%20-%20environment/2011_ESP_FINAL.pdf

11 Burlington Community Energy Plan, https://www.burlington.ca/en/live-and-play/resources/Environment/Burlington_Community_Energy_Plan.pdf

7.1.2.2 Generation-based Solution to Address Restoration Needs

Generation was ruled out as a possible option to address restoration needs in the West of Cooksville radial pocket. Large generation is not a suitable option for addressing restoration needs, as it would require the facility to have blackstart and islanded operation capabilities, a costly generation and system design feature. Additionally, finding a suitable location for major generation infrastructure could be challenging given that the West of Cooksville area is largely built up with significant residential zoning.

Smaller scale DG was determined to be impractical from a technical and economic perspective, given the scale and number of facilities that would be required within the sub-region. In order to provide restoration, each of these facilities would also have to be able to supply their local loads in islanded mode. Some high value loads (such as pumping and water purification facilities) are typically developed with on-site gas or diesel generation to ensure they can continue to operate during a power supply outage. While there is benefit to building this type of supply redundancy to ensure restoration capability for some loads, it is impractical on a large scale to address local restoration needs.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," solutions were considered by the Working Group to meet the near-term needs. "Wires" infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including lines, stations, or related equipment. These solutions are often characterized by high upfront capital costs, but have high reliability over the lifetime of the asset.

If net growth at Bronte TS cannot be fully offset through conservation, DR, or local generation initiatives, constraints on the transmission system will have to be addressed through an electricity infrastructure based solution. Even under the full achievement of conservation targets, peak demand is forecast to exceed the existing transmission system capacity by 15 MW over the next 15 years. There are potential transmission and distribution solutions to address the Bronte TS need; these are described in greater detail in Sections 7.1.3.1 and 7.1.3.2.

Likewise, an electricity infrastructure based solution could address the restoration need for the West of Cooksville radial pocket. However, given the high costs associated with electricity infrastructure solutions, low exposure to risk represented by this event, and low likelihood of occurrence, any measure would have to be assessed to ensure it is economic before it is recommended. This is further discussed and investigated in Section 7.1.3.3.

7.1.3.1 Transmission-based Solution to Address Bronte TS Need

The two 115 kV circuits supplying Bronte TS are limited by a 3 km section which is rated at 750 A for circuit B8, and 770 A for circuit B7. These are lower ratings than the remaining 14 km of the lines (850 A for B8, and 880 A for B7). As a result, load at Bronte TS must be kept below approximately 135 MW in order to respect the 750 A minimum LTE rating of the line. If the limiting 3 km line section was uprated, the new thermal limit of the remaining section would be approximately 150 MW (corresponding to 850 A). Assuming full achievement of CDM targets, this measure would successfully defer the thermal need until 2033 (assuming load distributed optimally between buses according to: maximum 79 MW on BY bus, 70 MW on Q bus). At this loading level, needs associated with post contingency voltage drop would also become limiting, and no incremental load could be served at Bronte TS. This transmission upgrade would therefore enable the full usage of the step-down transformer facilities.

B7/B8 Palermo Junction to Bronte TS (3 km) is the limiting line section. Uprating will require complete rebuild of this line section using new steel poles and 585 kcmil 26/7 Aluminum Conductor, Steel Reinforced (“ACSR”) conductor. Hydro One has indicated that budgetary estimate for rebuilding this 3 km line section is approximately $9.7 million.

The estimated time required for uprating Palermo Junction to Bronte TS line section is about three years which includes the OEB leave to construct application (Section 92), and environmental approvals.

7.1.3.2 Distribution-based Solution to Address Bronte TS Need

As an alternative to uprating the limiting section of B7/B8, needs associated with Bronte TS could be addressed by keeping the total station load below 135 MW. Assuming full achievement of conservation targets, this would require approximately 15 MW of additional capacity relief to defer the need past 2030. This relief could be achieved by transferring 15 MW of load (approximately 1 feeder worth) from Bronte TS to a neighboring station. This would require investment in the distribution system to expand the service territory of another station into an area which is currently served by Bronte TS.

There are four stations within the general vicinity of Bronte TS which are forecast to have remaining station capacity over the 20-year planning horizon, and which currently serve load from either Burlington Hydro or Oakville Hydro. These stations were reviewed to determine suitability for load transfer:

1. **Glenorchy MTS** is located approximately 14 km north and east of Bronte TS, and primarily serves Oakville Hydro load, with some embedded demand. Under the current planning forecast, over 40 MW of capacity will be available at this station over the next 20 years. Oakville Hydro has indicated that it would not be technically or economically feasible to build transfer capability between Bronte TS and Glenorchy MTS, mainly due to the presence of the Queen Elizabeth Way ("QEW") highway, which would have to be spanned or tunneled under for a connection between the two systems to be made.
2. **Trafalgar TS** is approximately 17 km north and east of Bronte TS, and serves Oakville Hydro load exclusively. Load at this station is forecast to remain steady over the next 20 years, and could accommodate up to 40 additional MW of demand. However, 17 km is too far for 27.6 kV distribution feeders to span and supply dense urban loads without a negative impact on voltage.
3. **Oakville TS #2** is located approximately 10 km east of Bronte TS, and serves load from Oakville Hydro and Enersource (City of Mississauga). This station is forecast to have at least 40 MW of available capacity over the next 20 years. Although Oakville Hydro has existing emergency transfer capability between Bronte TS and Oakville TS #2, it has indicated that it would not be technically feasible to build enhanced ties, or operate emergency transfers for prolonged periods of time.
4. **Tremaine TS** is located 8 km north and east of Bronte TS, and serves load from Burlington Hydro and Milton Hydro. Under the planning forecast, Tremaine TS is expected to have at least 80 MW of available capacity over the next 20 years. Burlington Hydro has indicated that it would be technically feasible to expand the Tremaine TS service territory southward to create an alternate supply path for the western Bronte service territory, at a cost of approximately $4.5 million.

Given that the alternative to the distribution transfer is to upgrade the transmission supply circuits at approximately two times the cost, the Tremaine TS distribution transfer is recommended as the preferred option for the near-term Bronte TS need. Burlington Hydro expects that the transfer could be made within two years.

7.1.3.3 Infrastructure-based Solution to Address Cooksville West Restoration Need

Infrastructure, such as a transmission or distribution facility, is typically the only suitable solution to address restoration needs. It provides a means of isolating a faulted section and restoring electrical demand from an alternate source. However, building redundant supply paths can be a high cost solution, depending on the configuration of the local system. Accordingly, ORTAC allows for some discretion when applying this criteria: where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost".[12] Additionally, these parties may also agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons.

Additionally, as described in Section 4.2, a bulk system study is currently underway in West GTA to address overload issues on the 500 kV and some 230 kV transmission assets in the area. The bulk transmission study will investigate major changes to the transmission system. Some local restoration needs (such as the Halton radial pocket (T38/39B), described in Section 6.2.5), are already expected to be addressed through planned system upgrades.

Work on the GTA West Bulk System Study is still underway, and final configuration and timing have not yet been determined. As a result, standalone infrastructure solutions to address restoration needs for the West of Cooksville radial pocket will not be further investigated in this IRRP.

If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process. The criteria outlined in ORTAC (probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost) will be considered before a solution is recommended to address this need.

---

[12] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

7.2 Recommended Near- and Medium-Term Plan

The Working Group recommends the actions described below to meet the near-term electricity needs of the Bronte Sub-region. Successful implementation of these actions, in addition to achievement of targeted conservation measures, is expected to address the sub-region's electricity needs until the early 2030s.

1. Transfer one feeder (approximately 15 MW) of distribution load from Bronte TS to Tremaine TS. This action should be initiated as soon as possible to address the near-term risk of thermal overloads on B7/B8 and post contingency voltage drop at Bronte TS. The implementation details for this "wires" solution will be carried out through a RIP process.
2. Pursue economic options to offset new load growth in the Bronte TS service area with CDM (including DR), and investigate opportunities for local generation, including CHP projects, where cost effective. In order to defer further long-term "wires" investments, total peak demand at Bronte TS must be kept below 135 MW.

If load at Bronte TS cannot be kept below 135 MW, additional "wires" infrastructure will be required. The preferred option would likely be a second feeder transfer from Bronte TS to a neighbouring supply station, but given the long-term nature of this need, the preferred options should be re investigated with consideration of the system in place at that time.

7.3 Implementation of Near- and Medium-Term Plan

To ensure that the near-term electricity needs of Bronte Sub-region are addressed, it is important that the plan recommendations be implemented as soon as possible. The specific actions and deliverables are outlined in Table 7-1, along with the recommended timing.

Table 7-1: Summary of Needs and Recommended Actions in Bronte Sub-region

Need	Recommended Action	Need Date
Overloads on B7/B8 circuits (2018), post contingency voltage drop at Bronte TS (2021)	Burlington Hydro to transfer one feeder from Bronte TS to Tremaine TS. Detailed design and study will be carried out through a RIP process.	2018
Ongoing load growth on	Pursue economic peak	ongoing

Need	Recommended Action	Need Date
Bronte TS potentially triggering same needs in the medium to long term	demand reducing measures, including CDM and DG, to keep Bronte TS demand below 135 MW	

In order to implement the recommended near-term actions in a timely manner, an RIP should be initiated for the Bronte Sub-region upon IRRP completion. This process will allow for detailed design and study of distribution infrastructure expansion required to complete this transfer. Both LDCs have indicated that revisions to their load forecasts may be required within the next few months, which will help inform the local "wires" plan.

The outcome of the RIP will be a more detailed development plan, including a refined estimate of expected costs and benefits to customers.

7.3.1 Implementation Challenges

Under the net forecast used in this IRRP, near-term load growth at Bronte TS is expected to be driven by Oakville Hydro, the result of intensification within Oakville's Bronte village and the midtown core. Burlington Hydro is not forecasting to increase electrical demand at this TS. This means that under the recommended solution, Burlington Hydro would implement infrastructure that serves growth in Oakville.

However, there may be additional benefits to Burlington Hydro as a result of transferring load from Bronte TS to Tremaine TS. Tremaine TS is a relatively new Hydro One Transmission owned station, currently only loaded at 45% of rated capacity. Transferring this load should contribute to Burlington Hydro's outstanding "true-up" charges. Determining the amount of relief which Burlington Hydro could expect from this transfer would require a detailed evaluation of the Connection Cost Recovery Agreement ("CCRA") in place between the two parties, in particular, as related to the Tremaine and Bronte stations. This evaluation should consider the nature and circumstances of the transfer, namely, would the transfer be on a permanent basis, or only occur during high load periods (seasonal transfer) or following the loss of a circuit when load is high (emergency transfer). It is the IESO's view that seasonal or emergency transfers would provide value to local customers by addressing the Bronte TS capacity needs in a least cost manner, and should therefore be given consideration when revising true up agreements.

In discussing implementation considerations, Burlington Hydro has indicated that it is concerned about longer-term growth in the Bronte TS service area impacting future costs. As a result, Burlington Hydro is concerned with relinquishing capacity at Bronte TS on a permanent basis. As part of the implementation Burlington Hydro has proposed a long-term (ie, 10 year) lease arrangement. Details related to implementation will be developed as part of the RIP.

The IESO has committed to working with the affected parties to assist with any regulatory matters which may arise, including providing rationale for the attribution of costs among the benefiting entities.

8. Long-Term Plan

Based on the electrical demand forecasts provided by Burlington Hydro and Oakville Hydro, implementation of the recommended near-term plan is expected to address long-term needs in the Bronte Sub-region until the early 2030s.Due to the inherent uncertainty associated with producing long-term load forecasts, there is potential that additional load could materialize within the Bronte TS service territory, potentially exceeding the load meeting capability. The solutions available to address this potential risk are dependent on the magnitude and pace of the longer-term electrical demand which may materialize.

If the magnitude and pace of growth in electrical demand is moderate in nature (up to 1.5% per year gross), it is likely that the needs over the next 20 years will be small and manageable. The anticipated needs (small in scale, spread out over many customers, and driven more by intensification than by significant new greenfield developments) are well suited to community driven solutions. This may include implementation of local distributed energy resource projects (such as small scale CHP, solar and/or storage technologies) or targeted conservation initiatives that contribute to peak demand reduction (such as DR programs). Identifying potential candidate projects or initiatives should be part of the ongoing planning and engagement process between the Working Group, local communities/ municipalities, and other stakeholders in the area. The development of local Community Energy Plans provide a valuable resource for aligning the local electricity needs with municipal goals and objectives, where appropriate.

In the event that the magnitude and pace of growth in electrical demand is higher (over 2% per year gross), an infrastructure solution may be required. Such increased demand could be the result of a single new customer (such as a data centre), changing demand profiles of existing customers (for example, as a result of widespread adoption of electrification technologies), or a combination of these factors. Higher long-term electrical demand within the Bronte Sub-region could also result from the return of the 15 MW transfer to Bronte TS, due to changed operational circumstances. This would trigger an alternative long-term infrastructure solution to serve the anticipated 15 MW of incremental Oakville Hydro growth (Burlington Hydro load would be returned to its present level). Oakville Hydro has indicated that distribution transfers from Bronte TS are not feasible at this time, but this assumption may need to be revisited in the future as changes to system configurations may occur in the interim. Assuming distribution transfers are not feasible, a likely alternative solution would be to upgrade the transmission line supplying Bronte TS.

The Working Group will work with the local communities to monitor leading indicators for growth in the Bronte Sub-region. This includes monitoring changes to growth targets, the composition and location of specific customer segments (residential, commercial, industrial) and effects on electricity related to the implementation of community energy plans. If these or other factors impact service reliability or capacity of the local electricity delivery systems a new IRRP process may be initiated ahead of the 5 year planning cycle. The potential for other measures, such as incremental DG or DR programs, will continue to be discussed through engagement with local municipalities, and in particular as the nature of the long-term needs, alternatives, and associated costs become clearer.

9. Engagement Activities

Keeping communities up-to-date on regional electricity planning is important. For the Bronte IRRP, this included meetings with the City of Burlington and the Town of Oakville to share the needs identified in the regional plan and the actions being undertaken by the IESO, Transmission Company and LDCs to ensure a reliable and economic level of service is maintained. The meetings also provided an opportunity to begin discussions with the municipalities on planning for the longer term. While no longer-term needs have been identified for the Bronte Sub-region in this planning cycle, discussions that take place now on community energy planning and municipal sustainability initiatives will help to inform future electricity plans and bring all of these processes closer together.

While this dialogue for the longer-term continues with municipalities and communities, and as future planning initiatives unfold, the Working Group will engage in accordance with the established community engagement principles.[13] Any updates will be posted on the dedicated Bronte planning webpage[14] on the IESO website. Since the Bronte planning area includes part of the broader Burlington to Nanticoke, and the GTA West planning regions, updates will be sent to all subscribers who have requested updates on these regions.

---

[13] http://www.ieso.ca/Pages/Participate/Regional-Planning/default.aspx

[14] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Burlington-to-Nanticoke/Bronte.aspx

10. Conclusion

This report documents an IRRP that has been carried out for the Bronte area, a sub-region of the OEB's Burlington-Nanticoke planning region. The IRRP identifies electricity needs in the Bronte Sub-region over the 20-year period from 2015-2034, identifies a preferred "wires" solution to address near-term needs, and lays out actions to monitor, defer, and address needs that may arise in the long term.

In order to further refine and implement the preferred near-term "wires" solution, it is recommended that an RIP be initiated. The RIP is to be led by Hydro One Transmission and include Burlington Hydro and Oakville Hydro as working group members.

The IESO will continue to provide support throughout the RIP process, and assist with any regulatory matters which may arise as challenges to plan implementation.

The Bronte Sub-region Working Group will continue to meet at regular intervals to monitor developments in the sub-region and to track progress toward the plan deliverables. In particular, the actions and deliverables associated with peak demand reducing initiatives will require annual review of system demand and program achievement to determine whether new initiatives are required. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the OEB-mandated 5-year schedule.

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

LOCAL PLANNING REPORT

BURLINGTON TO NANTICOKE REGION

Revision: Final

Date: October 28, 2015

Prepared by: Burlington to Nanticoke Region Local Planning Study Team

Burlington to Nanticoke Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Burlington Hydro Inc.
Horizon Utilities Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Local Planning Report was prepared for the purpose of developing a plan to address the local needs for which straight forward wires-only options are the only alternatives and recommending a preferred solution(s) that were identified in the Needs Assessment (NA) report for the Burlington to Nanticoke Region. These local needs 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 as part of the NA process.

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.

Executive Summary

REGION	Burlington to Nanticoke Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	September 15, 2014	**END DATE**	October 28, 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 Burlington to Nanticoke 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".

For needs that required further regional planning and coordination, were further assessed as part of the Scoping Assessment (SA) process to determine whether an Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both were required. There are two IRRPs in the region for the two sub-regions. A) Brant sub-region IRRP was completed in April 2015 B) Bronte sub-region IRRP is currently in progress.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Local needs addressed in this report include the following:

- Dundas TS T3/T4/T5/T6 Station Capacity
- Mohawk TS Supply Capacity
- Nebo TS T3/T4 Station Capacity
- Power factor at Cumberland TS
- Power factor at Kenilworth TS
- Power factor at Beach TS
- Reactive support for the Norfolk area
- System Reliability, Operation and Load Restoration

3. CONCLUSIONS AND RECOMMENDATIONS

1. **Dundas TS T3/T4/T5/T6 Station Capacity**
   There are 115/27.6 kV two (T3/T4 and T5/T6) DESNs at Dundas TS. The load at T3/T4 DESN has exceeded the supply capacity however the combined capacity of both DESNs is sufficient over the study period. By the end of the study period the combined load of both DESNs at Dundas is forecasted to be approaching the total capacity of the T3/T4 and T5/T6 DESNs.

   As a result, the study team recommended that the LDCs (Hydro One distribution and Horizon Utilities) will plan and undertake distribution load transfers from T3/T4 DESN to T5/T6 DESN to mitigate overloading of T3/T4 DESN at Dundas TS.

2. **Mohawk TS Supply Capacity**
   The load at Mohawk TS marginally exceeds station supply capacity and by the end of study period will marginally exceed the capacity of circuits supplying Mohawk TS. However, load growth in the area is small

   T1/T2 transformers at Mohawk TS are approaching end of life and are already scheduled for replacement in 2018 with the larger transformers which will address the issue of station supply capacity. In the interim, the study team recommended that Horizon Utilities manage the overloads (under contingency) by distribution loads transfers to other stations in the area.

3. **Nebo TS T3/T4 Station Capacity**
   The load at existing Nebo TS (T3/T4) DESN also exceeds marginally over station supply capacity. However, load growth in the area is small.

   The Nebo TS (T3/T4) transformers are approaching their end of life and are already scheduled for replacement with larger capacity transformers in 2022. The capacity of the new replacement transformers will be sufficient over the study period.

   In the interim, the study team recommended that Horizon Utilities manage the overload (under contingency) by distribution loads transfers to other stations in the area and also undertake any targeted and effective CDM to keep the loading within supply capacity of existing facilities.

4. **Power factor at Cumberland TS**
   The power factor at Cumberland TS under peak load conditions is lagging slightly below the ORTAC requirement of 0.9.

   The study team recommended that Burlington Hydro work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system as required to meet the power factor requirement of 0.9. Burlington Hydro will provide an update of the plan by Q2 2016.

5. **Power factor at Kenilworth TS**
   The power factor at Kenilworth TS is lagging below the ORTAC requirement of 0.9.

   The study team recommended that Horizon Utilities install capacitor bank on distribution system and/ or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9. Horizon Utilities will provide an update of the plan by Q2 2016.

6. **Power factor at Beach TS (115 kV T3/T4 DESN)**
   The power factor at Beach TS is leading beyond the ORTAC requirement of 0.9.

   The study team reviewed this requirement and recommended that no action is required at this time.

7. **Reactive support in Norfolk Area**
   The coincident load at Norfolk TS and Bloomsburg TS can be managed by load transfer and kept below the area supply limit of 87MW. The study team recommended that Hydro One distribution can manage the overload in Norfolk area by distribution loads transfers to neighboring stations.

8. **System Reliability, Operation and Load Restoration**
   In some cases, double circuit lines in the Region carry loads in excess of 150 MW and 250 MW thresholds.

   The study team based on the historical reliability data for the circuits in the region recommended that no action is required at this time.

Table of Contents

List of Figures

List of Tables

1 Introduction

The Needs Assessment (NA) for the Burlington to Nanticoke Region ("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 area supply needs. The NA for the Burlington to Nanticoke Region was prepared jointly by the study team, including LDCs (Local Distribution Company), Independent Electric System Operator (IESO), Ontario Power Authority (merged with IESO as of January 2015 and herein referred to as IESO), and Hydro One Networks Inc.. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Burlington to Nanticoke Region over the next ten years (2014 to 2023) and recommended whether they should be addressed by the transmitter-led Local Planning (LP) process or to be further assessed by the IESO-led Scoping Assessment (SA) process.

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

Table 1: Local Planning Study Team Participants for Burlington to Nanticoke Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Burlington Hydro Inc.
3.	Horizon Utilities Corporation
4.	Hydro One Networks Inc. (Distribution)

Burlington to Nanticoke Region: Description and Connection Configuration

The Burlington to Nanticoke Region is located in Southern Ontario and comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, Brant County, Haldimand County, and Norfolk County. The approximate boundaries of the Burlington to Nanticoke region and its four sub-regions (areas) are shown below in Figure 1.

The Burlington to Nanticoke 230 kV and 500 kV systems are part of East-West bulk power system transfers mainly from the generation located in Western Ontario towards the GTA. This region has two 500 kV stations, Nanticoke TS and Middleport TS, interconnected through two 500 kV circuits and connected to 500 kV Longwood TS and Milton TS. Both these 500 kV stations have transformation capacities to 230 kV systems. The Burlington to Nanticoke region's 230 kV system has three autotransformer stations at Burlington TS, Beach TS, and Caledonia

TS supplying the 115 kV transformer stations. The Dunnville TS has been included in the Niagara Region (Group 3, Region 17) instead of the Burlington to Nanticoke Region (Group 1, Region 1)- a change to the May 17, 2013 OEB Planning Process Working Group Report.

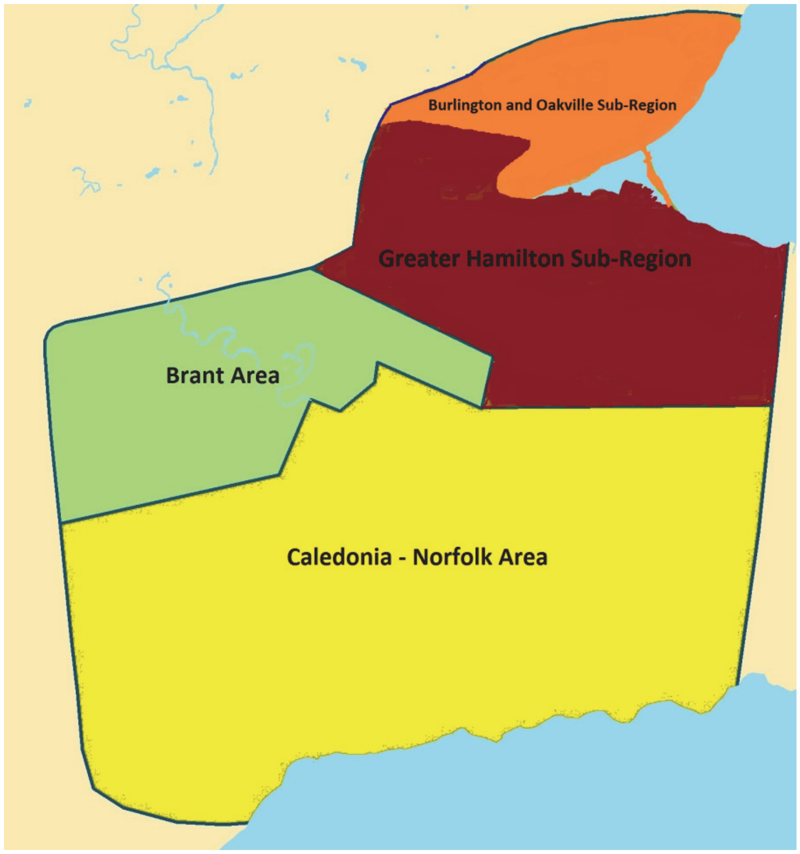


Figure 1: *Region and Sub-Region Approximate Boundaries*

The 230 kV interconnections of Burlington to Nanticoke Region to the rest of system consist of two circuits to Detweiler TS, three circuits to Buchanan TS and seven circuits to Beck TS. The 115 kV circuits are supplied from Burlington TS, Beach TS and Caledonia TS. A single line diagram of the 500kV, 230kV and 115 kV systems in the Burlington to Nanticoke Region is shown below in Figures 2 and 3.

The needs identified in the Needs Assessment are further reviewed in the next sections to determine the scope and type of regional planning study if appropriate for each of the relevant sub-regions.

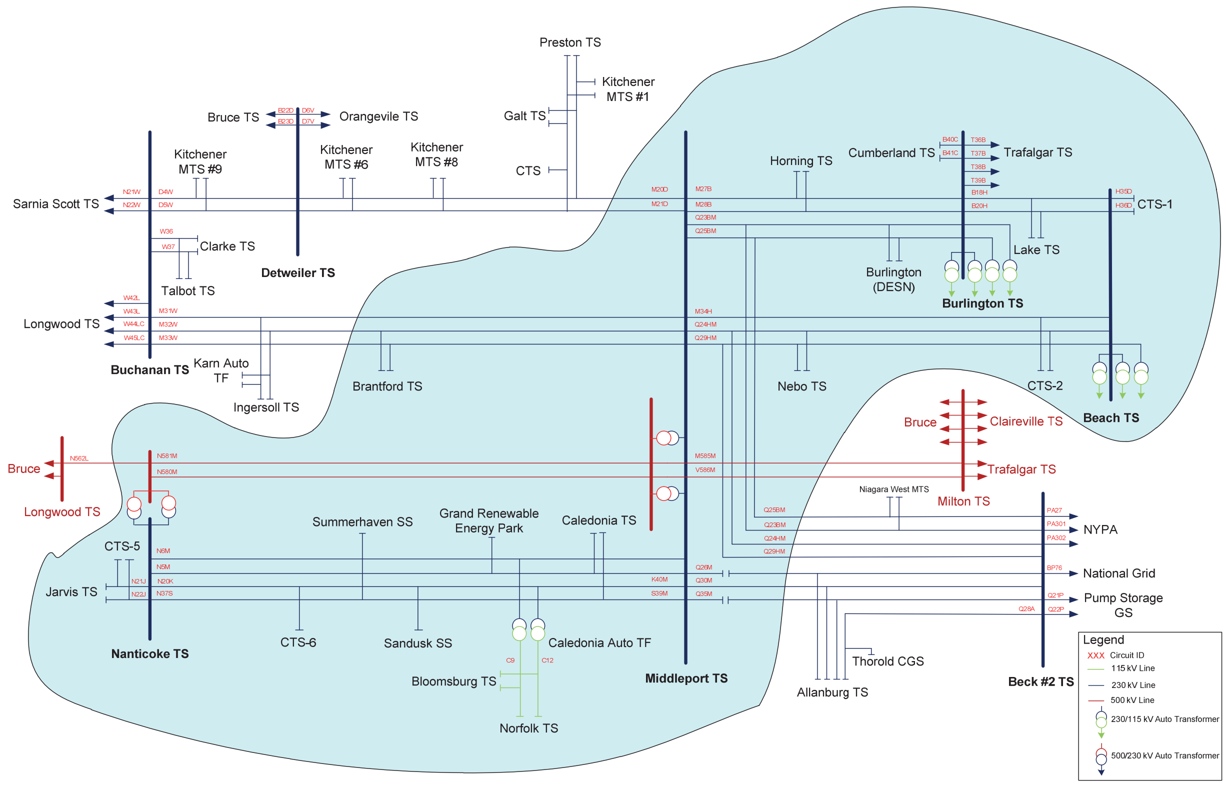


Figure 2: *Burlington to Nanticoke Region – 230 and 500 kV Single Line Diagram*

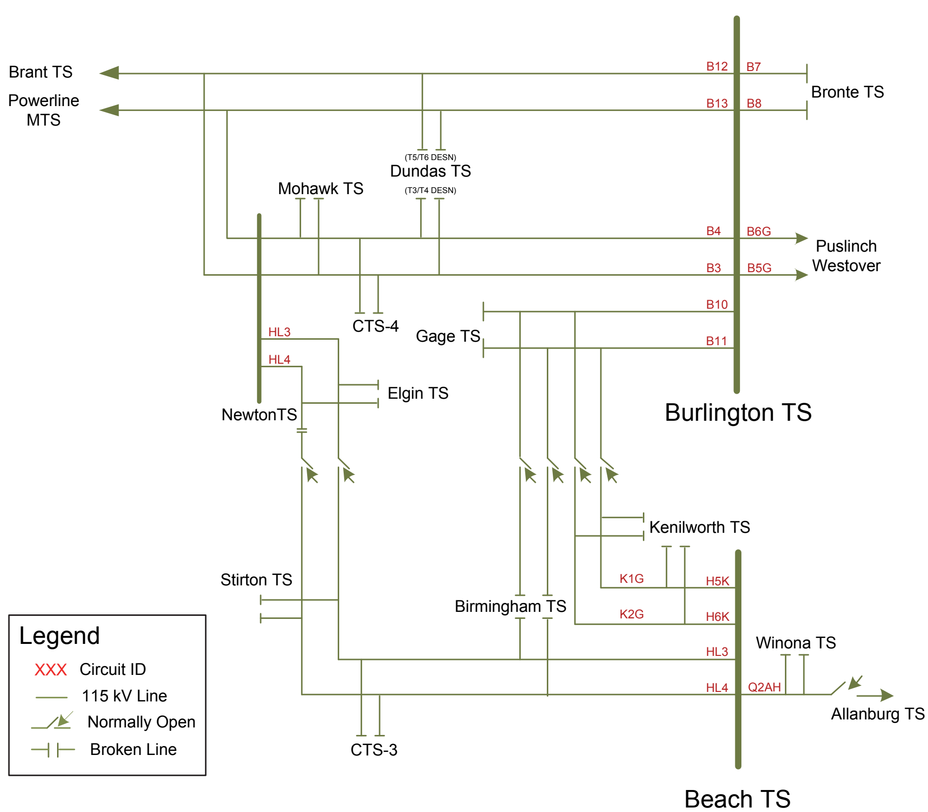


Figure 3: *Burlington and Beach 115 kV Single Line Diagram*

2 Burlington to Nanticoke Region Needs

The Brant Area (sub-region) assessment was in progress even prior to start of the Regional Planning process. An IRRP for this sub-region was completed on April 28, 2015.

Under Regional Planning process, the study team identified several needs after the Needs Assessment in the Burlington to Nanticoke Region that require further assessment and planning. The study team recommended that some of the near-term needs required “localized” wires only planning, while others required coordinated regional planning. The Needs Assessment is based upon the forecast prepared for the Burlington to Nanticoke Needs Assessment report given in Appendix –A. Where local planning was recommended to address the needs, Hydro One, as transmitter, with the impacted LDCs, further undertook planning assessments to develop options and recommend a wires only solution(s). For needs that required further regional planning and coordination, Scoping Assessment was done to determine if Integrated Regional Resource Planning (IRRP) or RIP process should be undertaken to address the needs. As a result, there are two IRRPs in the region for the two sub-regions. A) Brant sub-region IRRP was completed in April 2015 B) Bronte sub-region IRRP is currently under progress.

Brant IRRP identified that wires solution are required to provide additional capacity to serve the load as forecasted by the LDCs. The capacity needs at Bronte TS is part of the IRRP study that is still in progress while the issues with the loss of autotransformers at Burlington TS is being assessed as part of the Bulk System study led by the IESO.

The local needs identified and assessed in this region are as follow:

- Dundas TS T3/T4/T5/T6 Station Capacity
- Mohawk TS Supply Capacity
- Nebo TS T3/T4 Station Capacity
- Power factor at Cumberland TS
- Power factor at Kenilworth TS
- Power factor at Beach TS (115 kV T3/T4 DESN)
- Reactive support in Norfolk area
- System Reliability, Operation and Load Restoration

The load forecast provided in Appendix-A includes the forecast for Dundas TS, Mohawk TS and Nebo TS where capacity needs were identified in the Needs Assessment report. This forecast was prepared for the Burlington to Nanticoke Needs Assessment report and 2013 actual loads were used as a reference point. It is worth noting that the summer 2014 actual loads were lower than 2013 due to colder than normal summer and not used for planning purpose. The above listed needs are addressed in detail in the following sections and where applicable, the capital cost comparison for options for each need is provided in Appendix-B.

3 Dundas TS (T3/T4/T5/T6) Station Capacity

There are two 115/27.6 kV DESNs (T3/T4 and T5/T6) at Dundas TS with a total station capacity of 175.6 MW. The load at T3/T4 DESN exceeds its supply capacity.
The combined loading of the T3/T4 and T5/T6 DESNs at Dundas TS is forecasted to be 175.6 MW in 2023. The total capacity of the two DESNs at Dundas TS is thus sufficient over the study period i.e. until 2023.

3.1 Alternatives Considered

i. Transferring excess load from the overloaded T3/T4 DESN to the T5/T6 DESN

This was an obvious choice and no other option was considered to mitigate overloading of the Dundas TS T3/T4 DESN.

3.2 Next Steps

The study team recommends that Horizon Utilities and Hydro One Distribution develop a plan by the end of Q1 2016 and implement load balancing between the two DESNs by the end of 2016 as part of distribution planning. LDCs will provide a load balancing plan confirmation to Hydro One transmission by the end of Q1 2016.

4 Mohawk TS Supply Capacity

Mohawk TS and its supply circuits have load supplying capacity of 75.4 MW and 84.6 MW respectively. The load growth at Mohawk TS is slow with load forecast to increase from 83 MW in 2013 to 88.3 MW in 2023 exceeding station capacity by 12.9 MW.

At present the load at Mohawk TS exceeds station supply capacity and by the end of study period will marginally exceed the capacity of circuits supplying Mohawk TS.

4.1 Alternatives Considered

The mitigation options considered to address the overloading at Mohawk TS were:

i. Transfer excess load from Mohawk TS to adjacent area stations (Horning TS and Nebo TS) to reduce the loading levels under contingency conditions. There is adequate transfer capability between the stations for this purpose.

ii. Mohawk TS (T1/T2) transformers are approaching end of life and are already scheduled for replacement in 2018. The replaced T1/T2 transformers will be of higher capacity (about 90 MW) and sufficient beyond the study period.

4.2 Preferred Alternative

The preferred alternative is to replace the existing transformer with higher load supply capacity which is already scheduled to be complete in 2018. The capacity of new transformers will be sufficient over the study period and beyond.

Horizon Utilities will manage the loading at Mohawk TS within station and its supply circuit capacities during the study period by implementing operating measures such as load transfers.

4.3 Next Steps

Hydro One transmission will continue with the end of life replacement of transformers. In the interim, Horizon Utilities will develop a distribution load transfer plan to manage the load at Mohawk TS.

5 Nebo TS (T3/T4 DESN) Station Capacity

The 2013 summer peak load of Nebo TS 230 kV/13.8 kV T3/T4 DESN was 52.8 MW and exceeds the station supply capacity of 50.7 MW. The station load growth is slow with load forecasted to increase from 52.8 MW in 2013 to 54.2 MW in 2023 thus exceeding the station capacity by 3.5 MW.

5.1 Alternatives Considered

The mitigation options considered to address the overloading at Nebo TS were:

i. Transfer excess load to adjacent area station (Mohawk TS) to reduce loading under contingency conditions.

ii. Install additional new switchgear to utilize the capacity of the idle winding on the existing T3/T4 transformers. This will provide sufficient additional capacity to meet the currently projected load growth over and beyond the study period.

iii. Nebo TS (T3/T4) transformers are approaching end of life and are already scheduled for replacement in 2022. The replaced T3/T4 transformers will be of higher capacity (about 65 MW), which is sufficient over and beyond the study period.

5.2 Preferred Alternative

The preferred alternative is to transfer loads to neighboring stations until the transformers at Nebo TS are replaced in 2022. This is the most economical solution as it does not require any capital investments.

5.3 Next Steps

Hydro One will continue with the replacement of transformers reaching end of life. In the interim, Horizon Utilities will manage any overloading under contingency through distribution load transfer. Horizon Utilities will share details of load transfer plans with the study team by the end of Q2 2016 to manage overloading under emergency situations.

6 Power Factor at Cumberland TS

Cumberland TS is a 230/ 27.6 kV station having a load supplying capacity of 174.4 MW and 2013 peak load of about 135.2 MW. Under peak load conditions the power factor of Cumberland TS is 0.88 marginally below the ORTAC requirement of 0.9 lagging. An additional 8 MVARs of capacitor banks are required to meet power factor requirement.

6.1 Alternatives Considered

The options considered to improve the power factor at Cumberland TS were:

i. Installation of 20 MVAr capacitor bank (Hydro One standard size) at Cumberland TS.

ii. Installation of 8 MVAr of capacitor banks on the distribution system.

iii. Burlington Hydro to work with their existing load customers supplied by Cumberland TS to improve power factor.

6.2 Preferred Alternative

The preferred alternative is for Burlington Hydro to plan and work with their load customers supplied from Cumberland TS, and, if required, install capacitor banks on distribution system to meet the power factor requirement of 0.9. This is the most economical solution to improve the power factor at Cumberland TS.

6.3 Next Steps

The study team recommended Burlington Hydro to work with the load customers supplied by Cumberland TS to improve power factor and if needed develop a plan to install capacitor banks on distribution system. Burlington Hydro will develop and provide a distribution plan to Hydro One transmission by the end of Q2 2016.

7 Power Factor at Kenilworth TS

At present power factor at Kenilworth TS is lagging below ORTAC requirement of 0.9 lagging. Majority of the Kenilworth TS load is supplied to a large industrial customer.

7.1 Alternatives Considered

i. Installation of 20 MVAr capacitor bank (Hydro One standard size) at Kenilworth TS.

ii. Horizon Utilities to work with its load customer/s supplied at Kenilworth TS to improve power factor and/or install a 12MVar of capacitor banks on distribution system.

7.2 Preferred Alternative

The preferred alternative is for Horizon Utilities to work with the load customers supplied by Kenilworth TS and if needed install capacitor banks on distribution system to improve the power factor. This is the most economical solution for improving the power factor.

7.3 Next Steps

Horizon Utilities is requested to work with its load customer/s supplied at Kenilworth TS to improve power factor and if needed develop a plan to install capacitor bank on distribution system. Horizon Utilities will provide an update of their distribution plan to the study team by the end of Q2 2016 to improve power factor at Kenilworth TS.

8 Power Factor at Beach TS (115 kV T3/T4 DESN)

The power factor at Beach TS is leading beyond 0.9 while it is required to remain between 0.9 lagging and 0.9 leading.

8.1 Alternatives Considered

The study team reviewed this requirement and recommended that operating measures are in place and no further action is required.

8.2 Next Steps

The study team recommended that no action is required at this time.

9 Reactive support for the Norfolk area

Reactive support is required post single line contingency (for the loss of one of C9 or C12 circuits) in Norfolk area (Norfolk TS and Bloomsburg TS) when the total combined coincident load of Norfolk TS and Bloomsburg TS exceeds 87 MW. The 2013 coincident peak load of Norfolk TS and Bloomsburg TS was 85.8 MW and is forecasted to approach 87 MW by the year 2021 and 92.3 MW in 2023, exceeding Norfolk area supply limit by 5.3 MW as provided in Appendix-C.

9.1 Alternatives Considered

The following options were considered to address low voltage issue at Norfolk TS and Bloomsburg TS:

i. Installation of 20 MVAr capacitor bank at Bloomsburg TS.

ii. Installation of capacitor banks on distribution system in Norfolk area.

iii. Norfolk TS and Bloomsburg TS loads of about 6MW can be seasonally or permanently transferred to Jarvis TS.

9.2 Preferred Alternative

The preferred alternative is to transfer 6.0 MW of load from Norfolk TS and Bloomsburg TS to Jarvis TS which is sufficient to offset the 5.3 MW of load in excess of 87 MW in 2023. For the study period beyond 2021 (till 2023) the coincident load at Norfolk TS and Bloomsburg TS can be kept below the area supply limit of 87 MW through load transfers, if required. This solution requires the least investment and therefore was chosen as being the most economical.

9.3 Next Steps

Hydro One distribution will further investigate the load transfer capability from Norfolk and Bloomsburg TS to Jarvis TS and develop a distribution load transfer/s plan. Hydro One distribution will provide an update to Hydro One transmission by the end of Q2 2016.

10 System Reliability, Operation and Load Restoration

Load loss of 150 MW or more should be restored within 4 hours and 250 MW or more within 30 minutes or as agreed between the transmitter and the LDC.

By the year 2023, at peak load times only, the following circuits in the region are expected to supply loads of over 250 MW:

- Q24HM+Q29HM
- B3+B4

And over 150 MW:

- N21J+N22J
- M32W+ M33W
- Q23BM+Q25BM
- H35D+H36D
- HL3+HL4 (Load connected to Beach TS)
- B7+B8

10.1 Further Review and Assessment

The table below contains historic reliability data of last 25 years for the circuits in the region.

Table 2: Common Mode Reliability Statistics for Circuits Carrying more than 150 MW

No.	Circuits	No. of Momentary Outages	No. of Sustained Outages	Longest Outage Duration (Min)	Average Outage Duration (Min)
1	Q24 HM/ Q29HM	1	0	0	0
2	M32W/ M33W	1	1	3	3
3	N21J/ N22J	0	1	9	9
4	Q23BM/ Q25BM	0	1	7	7
5	H35D/ H36D	0	0	0	0
6	B7/ B8	0	0	0	0
7	B3/ B4	6	3	8	5.3
8	HL3/ HL4	0	1	3	3

During the past 25 years, the eight (8) pair of circuits in the above had only eight (8) momentary and seven (7) non-momentary outages. The longest non-momentary outage was nine (9) minutes which is well within the most stringent ORTAC restoration criteria of 30 minutes.

Based on the above information, Hydro One transmission and the relevant LDC/s agree that reliability and load restoration in the above area has a :

a) Historically good supply reliability and load restoration, and
b) Restoration time gains will be insignificant by line sectionalizing, and
c) Any infrastructure investments will have little or no benefit but result in cost for rate payers

As a result, no further action is required, unless there is a significant change in system conditions or configuration.

10.2 Next Steps

Based on the historical reliability data for the circuits in the region, the study team recommends that no action is required at this time.

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 Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Burlington to Nanticoke Region Needs Assessment Report
iv) Burlington to Nanticoke Region Scoping Assessment Report

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
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
SA	Scoping Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Appendix A – Load Forecast

Appendix A – Middleport Nanticoke Region Forecast

Non-Coincident Peak Station Loads

Station				LTR in MW (P.f =0.9)	Dist. Load (MW)	Forecasted Loads (MW)-------->									
No.	Name	DESN	BUS		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Bronte TS	T2		75.0	69.9	70.4	70.9	71.4	71.9	72.5	73.0	73.5	74.0	74.5	75.0
2	Bronte TS	T5/T6		90.9	84.9	85.7	86.5	87.4	88.2	89.0	89.8	90.6	91.5	92.3	93.1
3	Burlington TS DESN	T15/T16		175.5	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1
4	Cumberland TS	T3/T4		174.4	135.2	136.4	137.7	138.9	140.2	141.4	142.7	143.9	145.2	146.4	147.6
5	Caledonia TS	T1/T2		99.0	51.1	52.3	53.5	54.6	55.8	57.0	58.1	59.3	60.4	61.6	62.8
6	Jarvis TS	T3/T4	BY	99.4	82.9	83.5	84.1	84.8	85.4	86.0	86.6	87.2	87.8	88.4	89.0
7	Beach TS	T3/T4	B1B2	71.1	7.3	7.3	7.3	7.3	7.3	7.4	7.4	7.4	7.4	7.4	7.5
8	Beach TS	T3/T4	Y1Y2		18.8	18.9	18.9	19.0	19.0	19.0	19.1	19.1	19.2	19.2	19.3
9	Beach TS	T5/T6	Q1Q2	90.5	26.2	26.3	26.3	26.4	26.5	26.5	26.6	26.7	26.7	26.8	26.9
10	Beach TS	T5/T6	J1J2		23.3	23.4	23.4	23.5	23.6	23.6	23.7	23.8	23.8	23.9	23.9
11	Birmingham TS	T1/T2	BY	76.3	28.8	28.9	28.9	29.0	29.1	29.2	29.2	29.3	29.4	29.4	29.5
12	Birmingham TS	T1/T2	QJ		19.4	19.4	19.5	19.5	19.6	19.6	19.7	19.8	19.8	19.9	19.9
13	Birmingham TS	T3/T4	EZ	90.9	18.4	18.4	18.5	18.5	18.6	18.6	18.7	18.7	18.8	18.8	18.8
14	Birmingham TS	T3/T4	DK		28.4	28.4	28.5	28.6	28.6	28.7	28.8	28.9	28.9	29.0	29.1
15	Dundas TS	T3/T4		87.0	110.5	111.6	112.8	113.9	115.0	116.1	117.2	118.3	119.5	120.6	121.7
16	Dundas TS #2	T5/T6		88.6	48.3	48.8	49.4	50.0	50.5	51.1	51.6	52.2	52.8	53.3	53.9
17	Elgin TS	T1/T2	DK	79.9	33.6	33.7	33.8	33.8	33.9	34.0	34.1	34.2	34.3	34.4	34.5
18	Elgin TS	T1/T2	QJ		32.6	33.0	33.5	33.9	34.3	34.8	35.2	35.6	36.0	36.5	36.9
19	Elgin TS	T3/T4	EZ	40.2	20.1	20.1	20.2	20.2	20.2	20.3	20.3	20.4	20.4	20.5	20.5
20	Gage TS	T3/T4	ZY	56.7	26.8	26.8	26.9	27.0	27.0	27.1	27.2	27.2	27.3	27.4	27.5
21	Gage TS	T5/T6	DJ	56.7	13.3	13.3	13.3	13.4	13.4	13.4	13.4	13.5	13.5	13.5	13.6
22	Gage TS	T8/T9	EK	123.5	13.9	13.9	13.9	14.0	14.0	14.0	14.1	14.1	14.1	14.2	14.2

Appendix A- Continued…………

Station				LTR in MW (P.f =0.9)	Dist. Load (MW)	Forecasted Loads (MW)-------->									
No.	Name	DESN	BUS		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
23	Horning TS	T1/T2	B1B2	102.2	49.1	49.2	49.4	49.6	49.7	49.9	50.1	50.2	50.4	50.6	50.7
24	Horning TS	T1/T2	Q1Q2		23.5	24.6	25.6	26.6	27.6	28.7	29.7	30.7	31.7	32.8	33.8
25	Kenilworth TS	T1/T4	EJ	35.6	29.9	30.0	30.1	30.2	30.2	30.3	30.4	30.5	30.5	30.6	30.7
26	Kenilworth TS	T2/T3	B1Y1	64.8	31.0	31.1	31.1	31.2	31.3	31.4	31.5	31.6	31.6	31.7	31.8
27	Lake TS	T1/T2	BY	93.7	62.0	62.8	63.5	64.3	65.0	65.8	66.5	67.3	68.0	68.8	69.5
28	Lake TS	T3/T4	J1J2	113.1	30.8	30.8	30.9	31.0	31.1	31.1	31.2	31.3	31.4	31.4	31.5
29	Lake TS	T3/T4	Q1Q2		28.2	28.6	28.9	29.3	29.6	29.9	30.3	30.6	30.9	31.3	31.6
30	Mohawk TS	T1/T2	B1B2	75.4	41.5	41.9	42.3	42.7	43.2	43.6	44.0	44.4	44.9	45.3	45.7
31	Mohawk TS	T1/T2	Y1Y2		41.5	41.6	41.7	41.8	41.9	42.0	42.1	42.2	42.3	42.4	42.6
32	Nebo TS	T1/T2		178.3	90.0	96.7	103.3	110.0	116.6	123.3	130.0	136.6	143.3	149.9	156.6
33	Nebo TS	T3/T4		50.7	52.8	52.9	53.1	53.2	53.4	53.5	53.7	53.8	53.9	54.1	54.2
34	Newton TS	T1/T2	B	73.8	23.9	24.4	24.8	25.3	25.7	26.2	26.6	27.0	27.5	27.9	28.4
35	Newton TS	T1/T2	Y		22.5	22.6	22.6	22.7	22.7	22.8	22.8	22.9	22.9	23.0	23.0
36	Stirton TS	T3/T4	BY	105.8	23.7	23.8	23.9	23.9	24.0	24.0	24.1	24.2	24.2	24.3	24.4
37	Stirton TS	T3/T4	QZ		27.1	27.2	27.2	27.3	27.4	27.5	27.5	27.6	27.7	27.8	27.8
38	Winona TS	T1/T2		88.6	46.1	46.6	47.2	47.8	48.3	48.9	49.4	50.0	50.6	51.1	51.7
39	Norfolk TS	T1/T2		91.4	57.4	58.6	59.9	61.1	62.4	63.6	64.9	66.1	67.4	68.7	69.9
40	Bloomsburg TS	T1/T2			47.3	47.8	48.3	48.7	49.2	49.7	50.2	50.6	51.1	51.6	52.1

Appendix B - Capital Cost Comparison of Mitigation Options

Appendix B – Capital Cost Comparison of Mitigation Options

A. Reactive Support at Bloomsburg MTS

(All Costs in $ Million)

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Capacitor bank at Bloomsburg TS (20MVAr)	1	2.2	1 x 2.2	2.2
Load Transfers	0	0	0	0
Monitor loading trends	0	0	0	0

B. Dundas TS T3/T4/T5/T6 Station Capacity

(All Costs in $ Million)

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Load balancing between two DESNs	0	0	0	0

C. Power factor at Cumberland TS

(All Costs in $ Million)

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Capacitor bank at Cumberland TS (20MVAr)	1	2.2	1 x 2.2	2.2
Capacitor banks on distribution system (0.9 MVAr)	9	0.03	9 x 0.03	0.27
Load customers to improve power factor	0	0	0	0

D. Mohawk TS T1/T2 Station Capacity

(All Costs in $ Million)

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Targeted CDM	0	0	0	0
Load transfers	0	0	0	0
New T1/T2 transformers at Mohawk TS*	1	15	1 x 15	15

*- Already scheduled for replacement (approaching end of expected useful life)

Appendix B – Continued………..

E. Nebo TS T3/T4 Station Capacity **(All Costs in $ Million)**

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Targeted CDM	0	0	0	0
Load transfers	0	0	0	0
Switchgear to utilize spare winding	1	5.5	1x 5.5	5.5
New T3/T4 transformers at Nebo TS*	1	14	1 x 14	14

*- Already scheduled for replacement (approaching end of expected useful life)

F. Power factor at Kenilworth TS **(All Costs in $ Million)**

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Capacitor bank at Kenilworth TS (20MVAr)	1	2.2	1 x 2.2	2.2
Capacitor banks on distribution system (0.9 MVAr)	14	0.03	14 x 0.03	0.42
Load customers to improve power factor	0	0	0	0

G. Power Factor at Beach TS (115 kV T3/T4 DESN) **(All Costs in $ Million)**

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
No action required	0	0	0	0

H. System Reliability, Operation and Load Restoration **(All Costs in $ Million)**

Mitigation Options	No.	Unit Cost	Cost Calculation	Total Cost
Monitor loading trends	0	0	0	0

Appendix C – Norfolk Area Forecast - Coincident Load on 115kV circuit C9/C12

Appendix C – Norfolk Area Forecast - Coincident Load on 115kV circuit C9/C12

(All Values in MW)

	Forecasted Peak Loads										
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Norfolk TS	49.2	40.9	42.4	43.6	44.7	46.1	47.3	48.5	49.8	51.1	52.6
Bloomsburg TS	36.6	36.8	37.0	37.1	37.4	37.8	38.2	38.5	39.0	39.4	39.7
Total	85.8	77.7	79.4	80.6	82.1	83.9	85.5	86.9	88.8	90.5	92.3

Greater Ottawa

REGIONAL INFRASTRUCTURE PLAN

December 2, 2015

[This page is intentionally left blank]

Prepared and supported by:

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

[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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

TABLE OF CONTENTS

List of Figures

List of Tables

[This page is intentionally left blank]

1. INTRODUCTION

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

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

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

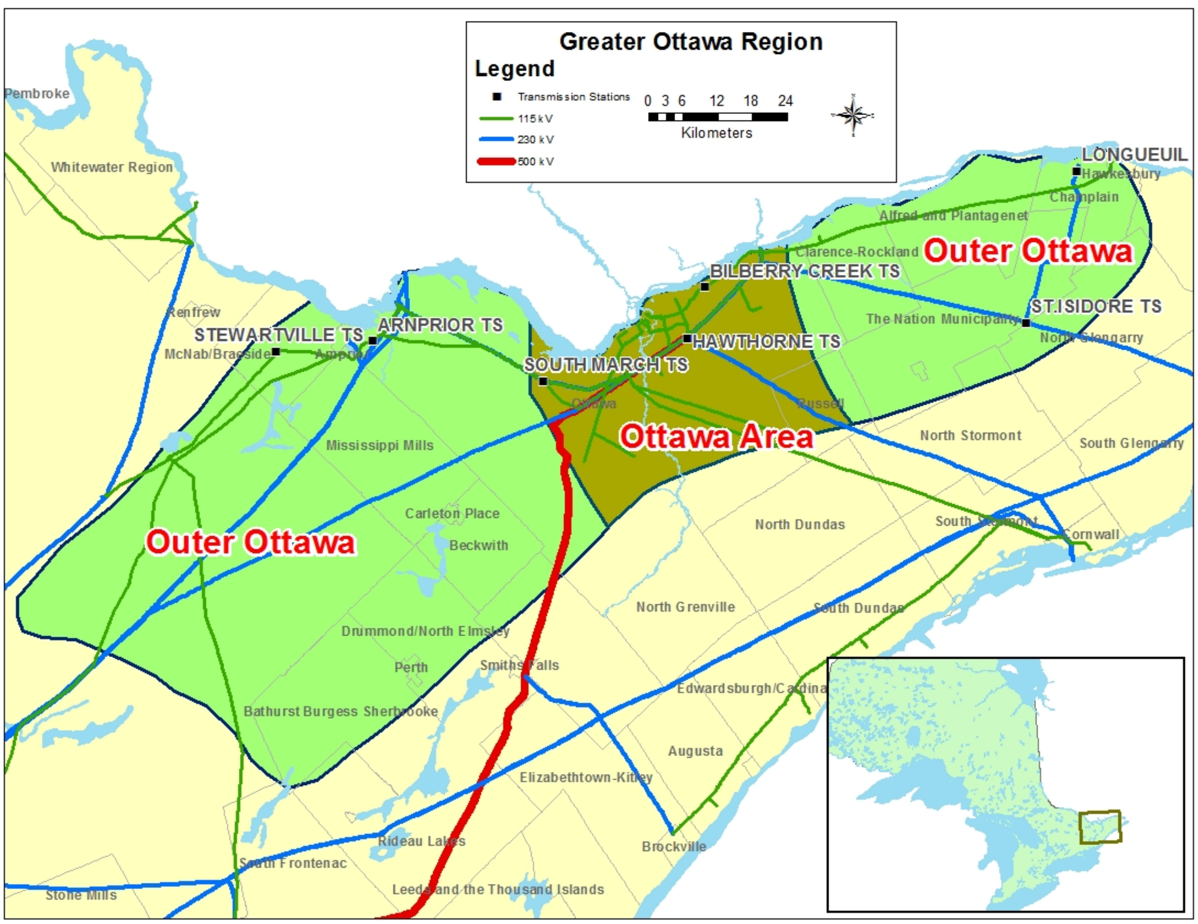


Figure 1-1 Greater Ottawa Region

1.1 Scope and Objectives

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

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

The scope of this RIP is as follows:

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

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

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

---

[1] Also referred to as Needs Screening.

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

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

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

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

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

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

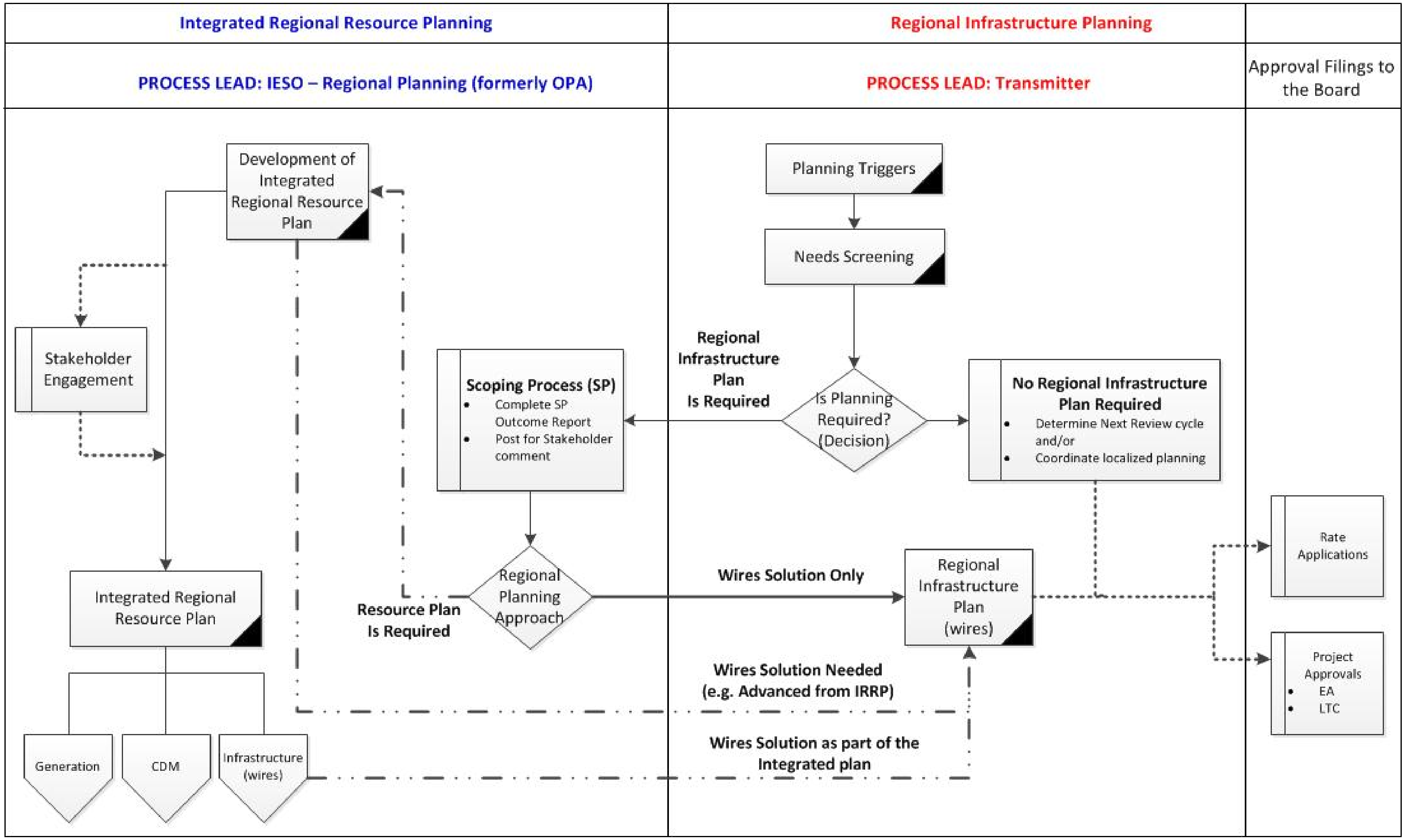


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

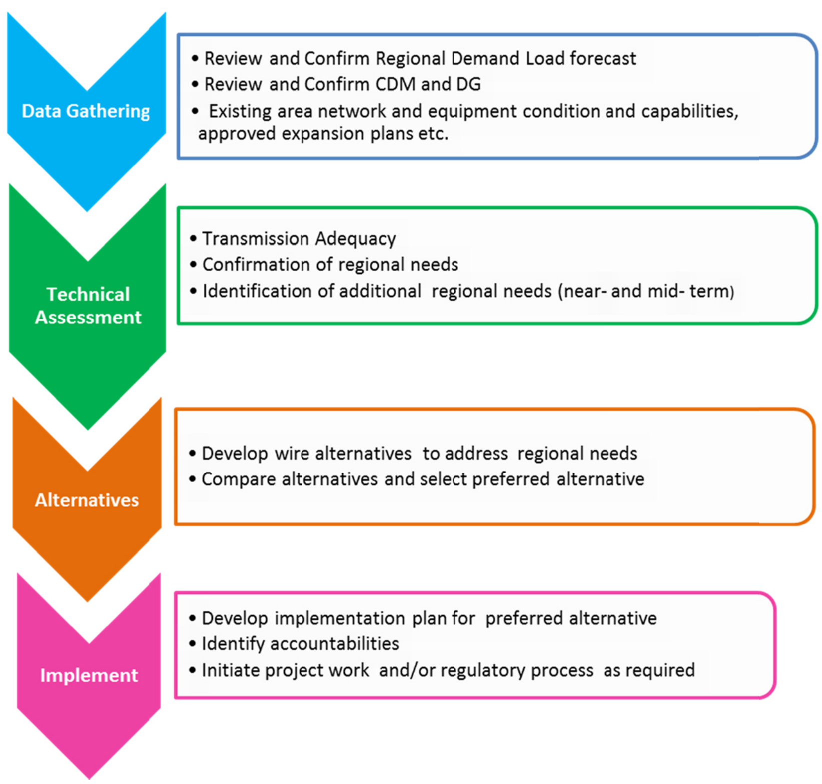


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

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

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

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

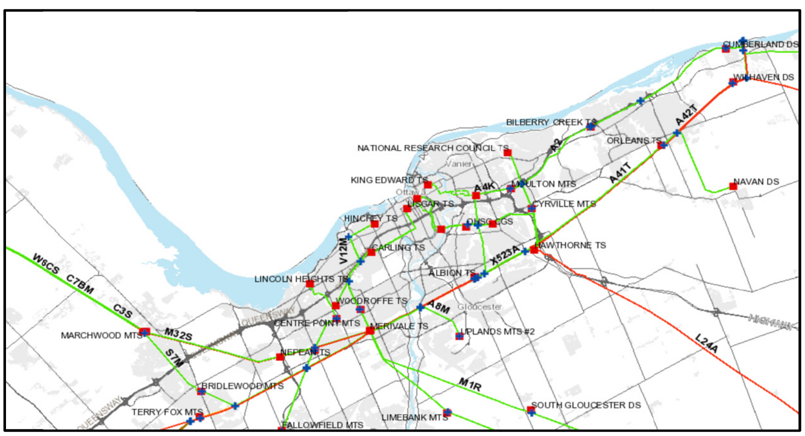


Figure 3-1 Ottawa Sub-Region

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

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

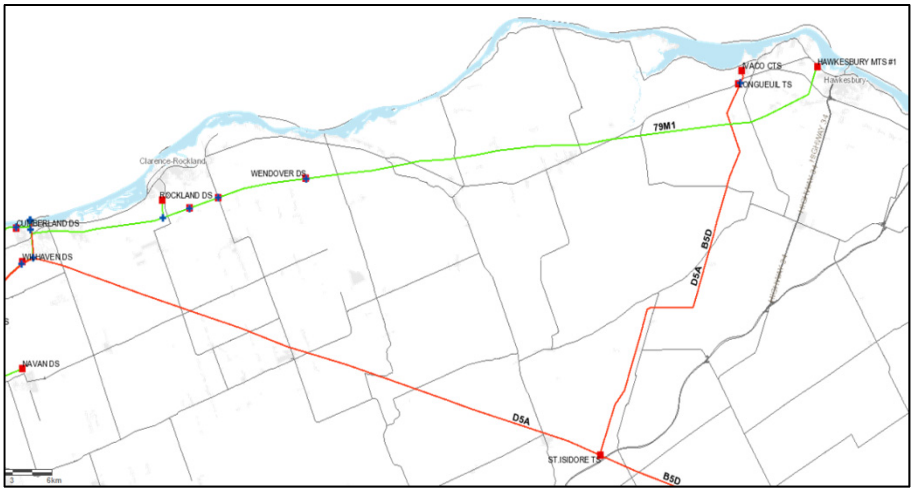


Figure 3-2 Outer Ottawa Sub-Region, Eastern Area

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

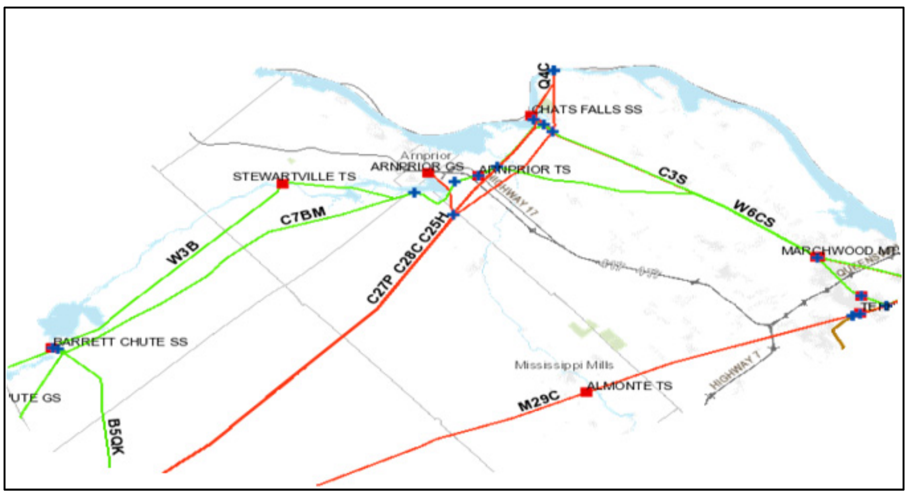


Figure 3-3 Outer Ottawa, Western Area

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

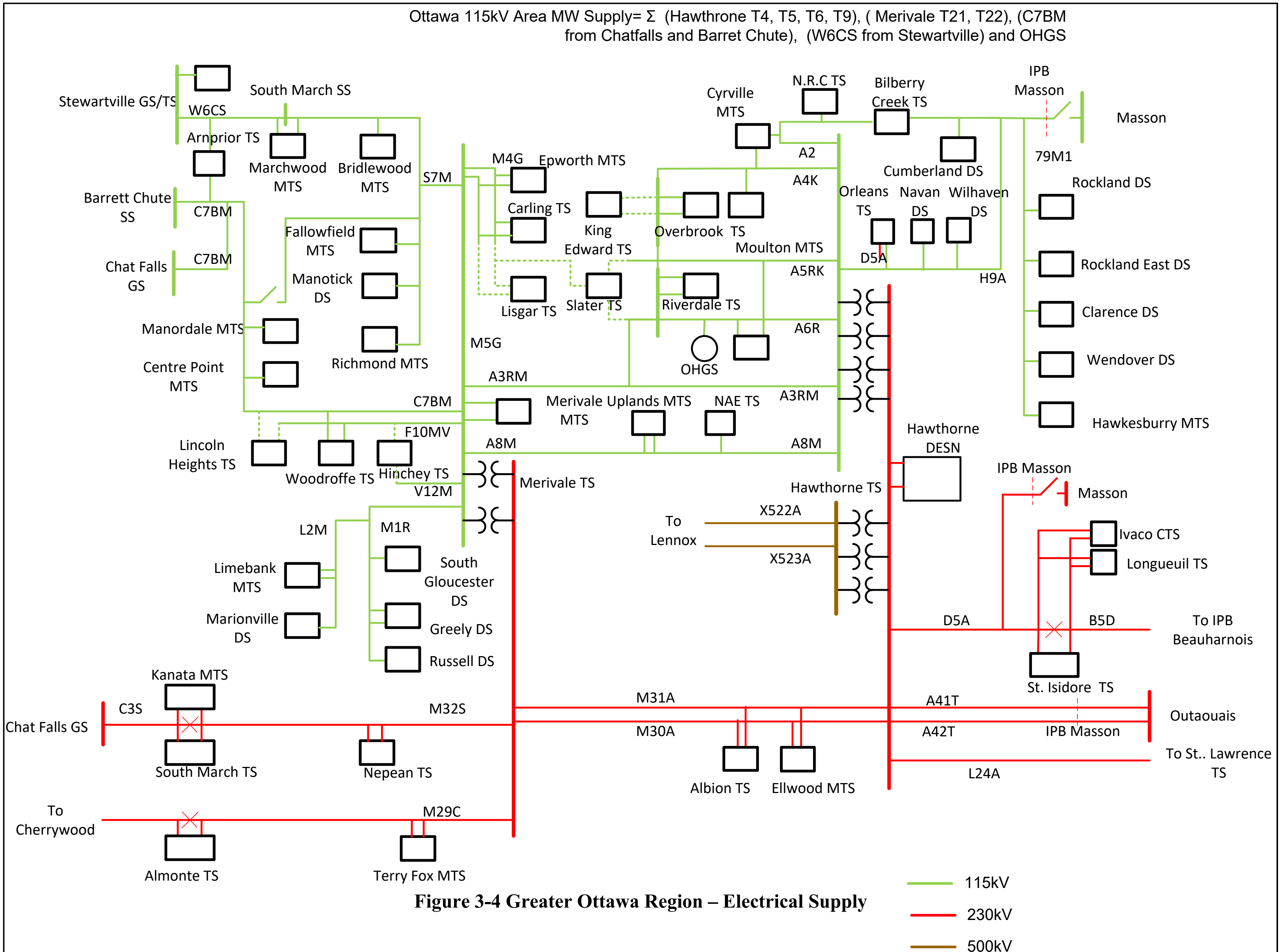


Figure 3-4 Greater Ottawa Region – Electrical Supply

21

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

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

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

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

The following projects are currently underway:

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

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

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

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

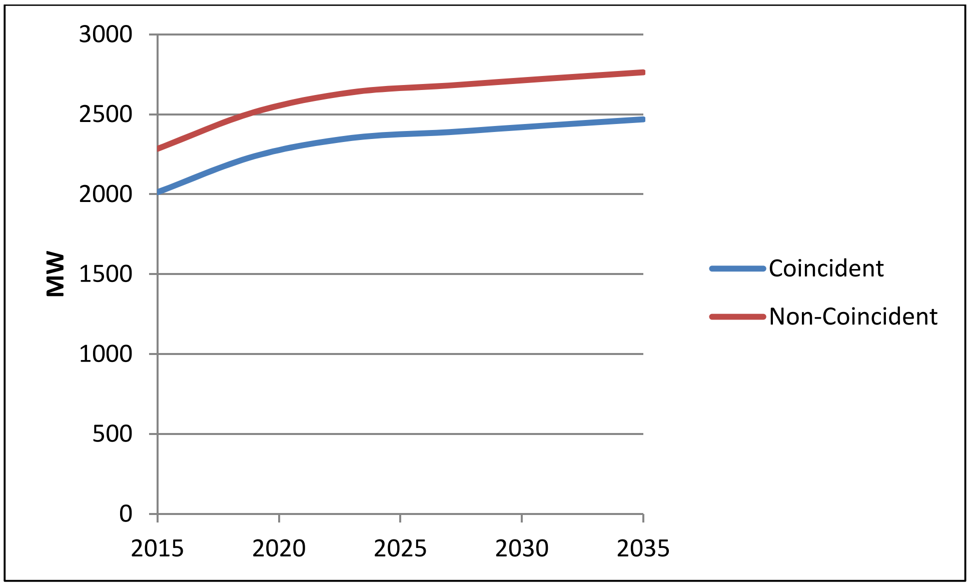


Figure 5-1 Greater Ottawa Region Summer Extreme Weather Peak Forecast

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

The RIP load forecast was developed as follows:

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

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

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per ORTAC.

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

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

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

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

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

Table 6-1 Near and Mid-Term Regional Needs

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

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

6.1 500 and 230 kV Transmission Facilities

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

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

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

6.2 230/115 kV Transformation Facilities

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

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

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

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

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

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

(1) Limited time rating exceeded.

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

6.3 115 kV Transmission Facilities

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

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

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

Table 6-3 Adequacy of 115 kV Circuits

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

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

6.4 Step-Down Transformation Facilities

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

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

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

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

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

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

(1) With Hawthorne TS 50/83 MVA transformers replaced with larger 75/125 MVA size units.
(2) Includes Longueuil TS and St Isidore TS load.

7. REGIONAL PLANS

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

7.1 Hawthorne Autotransformer T5 and T6

7.1.1 Description

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

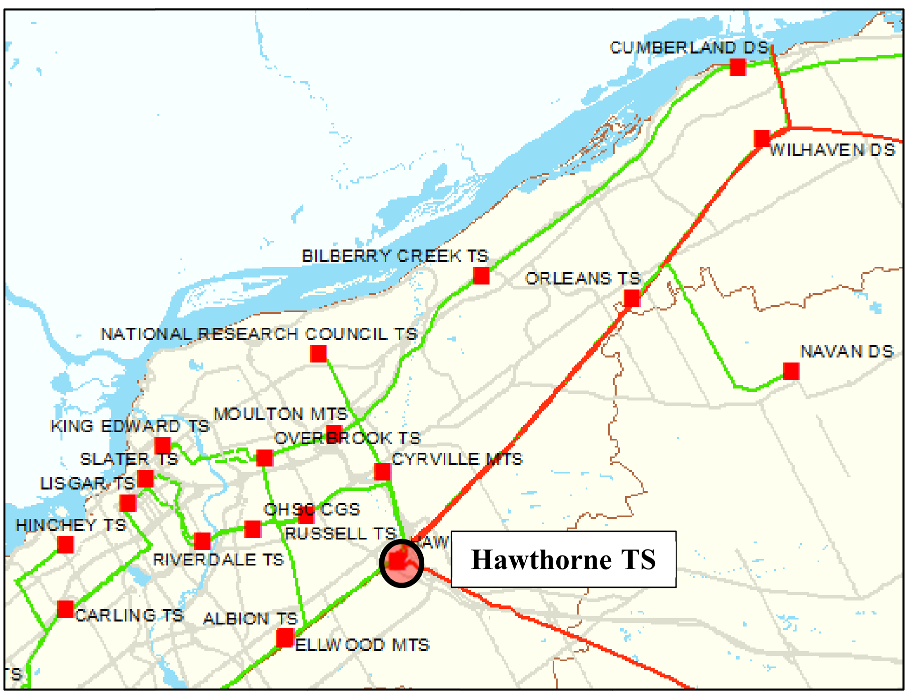


Figure 7-1 Hawthorne TS

7.1.2 Recommended Plan and Current Status

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

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

7.2 Autotransformation Capacity and South West Area Station Capacity

7.2.1 Merivale TS Autotransformers T21 and T22/Hawthorne Autotransformer T9

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

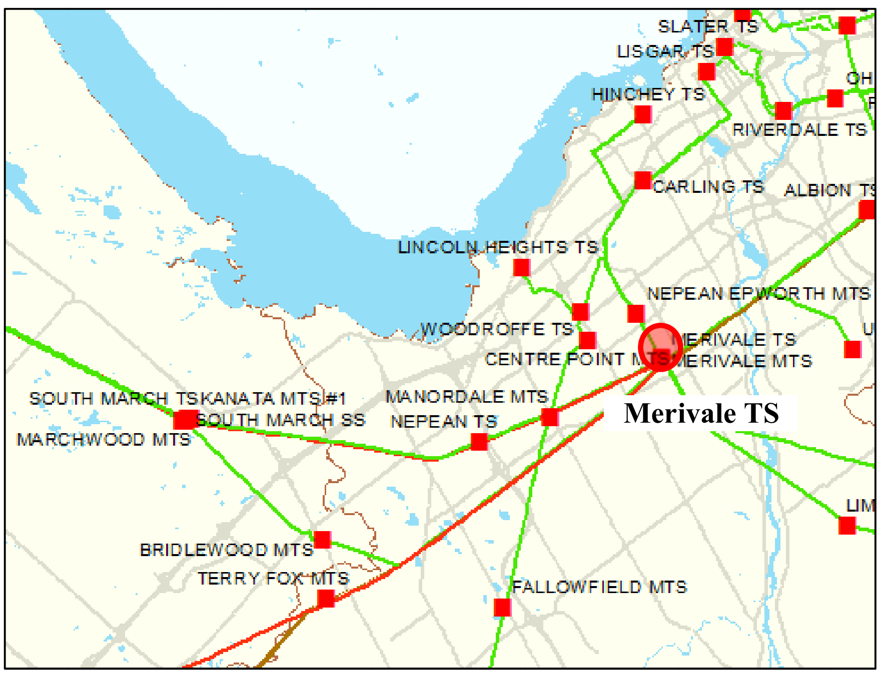


Figure 7-2 Merivale TS

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

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

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

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

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

7.2.2 Supply to South West Area – Line and Station Capacity

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

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

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

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

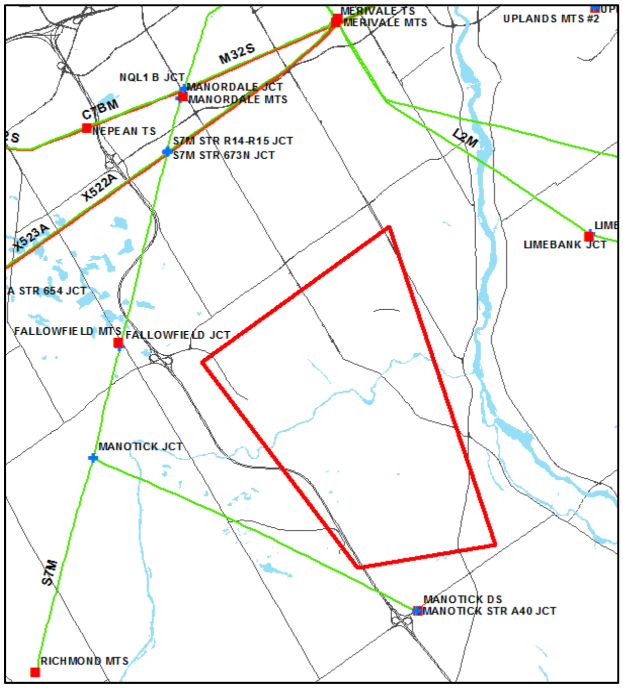


Figure 7-3 South West Area

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

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

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

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

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

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

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

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

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

7.2.3 Recommended Plan and Current Status

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

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

7.3 115 kV Transmission Circuit A4K Supply Capacity

7.3.1 Description

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

7.3.2 Current Status

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

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

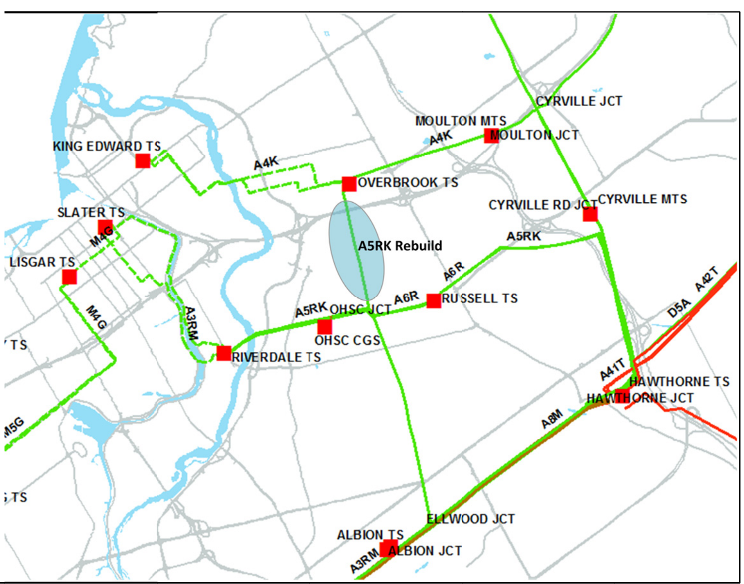


Figure 7-4 Option to Rebuild A5RK as Double-Circuit 115 kV Line

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

7.4 Station Capacity – Ottawa Centre 115 kV Area

7.4.1 Description

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

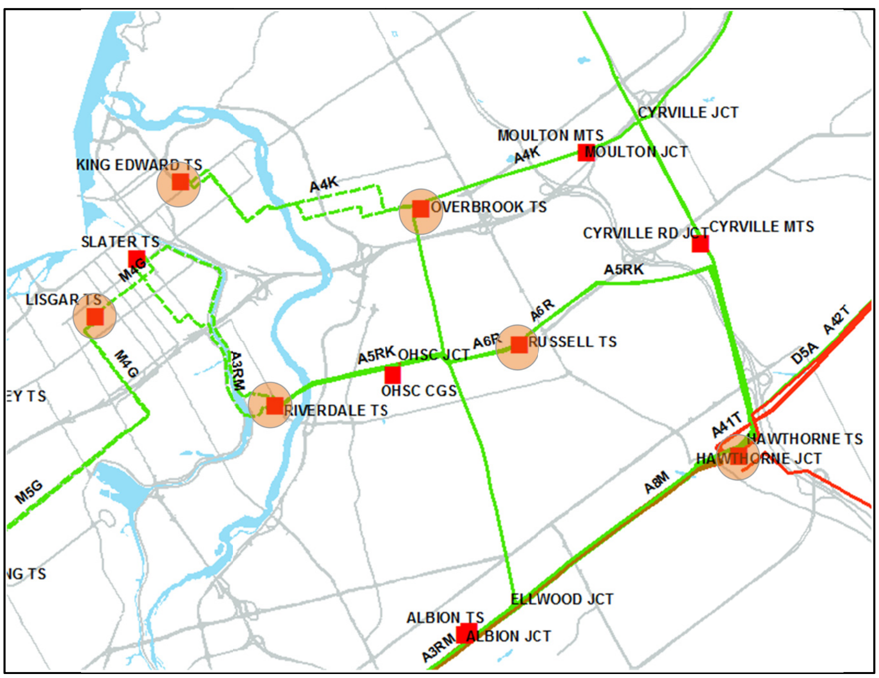


Figure 7-5 Downtown Ottawa Stations

7.4.2 Recommended Plan and Current Status

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

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

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

7.4.2.1 Russell TS and Riverdale TS

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

7.4.2.2 Overbrook TS

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

7.4.2.3 Lisgar TS

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

7.4.2.4 King Edward TS

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

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

7.5 Station Capacity - Hawthorne TS 44kV

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

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

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

7.6 Bilberry Creek TS End of Life

7.6.1 Description

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

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

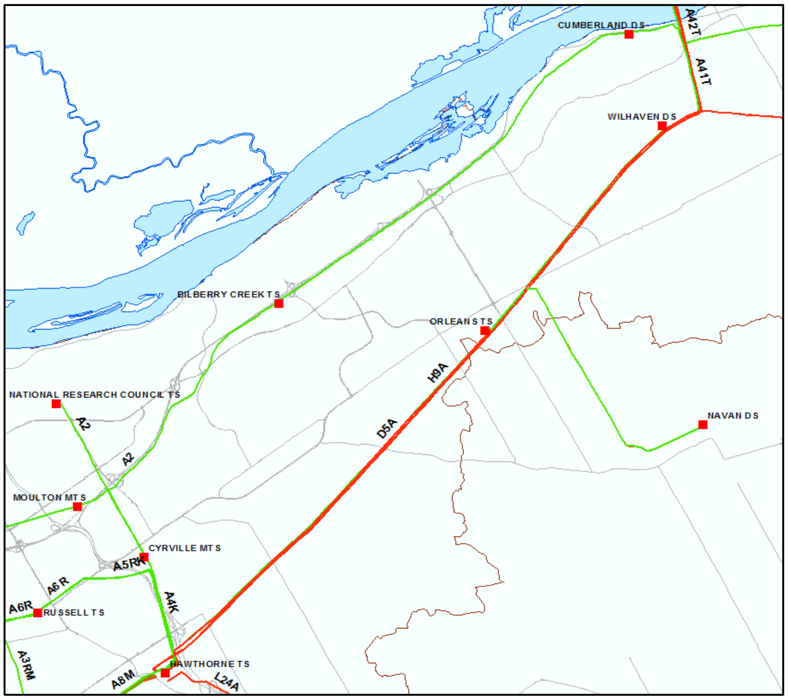


Figure 7-6 Bilberry Creek TS and the East Ottawa Area

7.6.2 Recommended Plan and Current Status

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

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

7.7 Almonte TS and Terry Fox TS Reliability

7.7.1 Description

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

7.7.2 Recommended Plan and Current Status

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

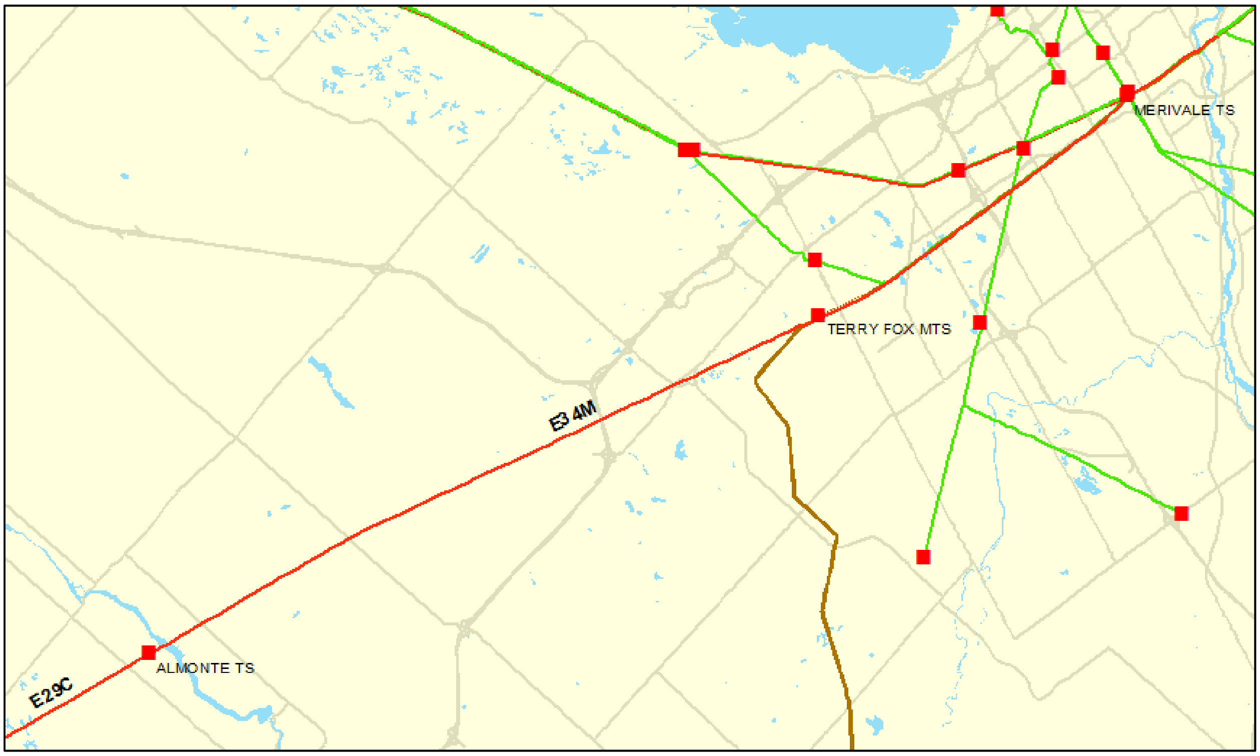


Figure 7-7 Lines E29C and E34M (M29C). In-Line Breaker at Almonte TS.

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

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

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

7.8 Orleans TS Reliability

7.8.1 Description

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

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

7.8.2 Recommended Plan and Current Status

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

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

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

7.9 Load Restoration for the Loss of B5D/D5A

7.9.1 Description and Current Status

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

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

7.10 Load Loss for S7M Contingency

7.10.1 Description and Current Status

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

7.11 Voltage Regulation on 115kV Circuit 79M1

7.11.1 Description and Current Status

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

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

7.12 Voltage at Stewartville TS

7.12.1 Description and Current Status

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

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

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

7.13.1 Description

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

7.13.2 Recommended Plan and Current Status

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

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

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

7.14 Low Power Factor at Almonte TS

7.14.1 Description and Current Status

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

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

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER OTTAWA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near term needs are summarized in the Table 8-1 below.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-2.

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

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

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

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

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

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

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

9. REFERENCES

[1]. Independent Electricity System Operator, "Ottawa Area Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Greater_Ottawa/2015-Ottawa-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Greater Ottawa Region – Outer Ottawa Sub Region", 28 July 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Needs%20Assessment%20Report%20-%20Greater%20Ottawa%20-%20Outer%20Ottawa%20SubRegion.pdf

[3]. Hydro One, "Local Planning Report – Supply to East Ottawa Area", 26 November 2015.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Local%20Planning%20Report%20-%20Supply%20to%20East%20Ottawa%20Area.pdf

[4]. Hydro One, "Local Planning Report - B5D-D5A Load Restoration", 22 September 2015.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Local%20Planning%20Report%20-%20B5D-D5A%20Load%20Restoration.pdf

[5]. Hydro One, "OPA Letter – Ottawa Area Regional Planning", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Letter%20to%20H1%20RE%20Ottawa.pdf

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

APPENDIX A: STATIONS IN THE GREATER OTTAWA REGION

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

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

APPENDIX B: TRANSMISSION LINES IN THE GREATER OTTAWA REGION

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

APPENDIX C: DISTRIBUTORS IN THE GREATER OTTAWA REGION

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

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

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1 Stations Coincident Load Forecast (MW)

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

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

Table D-2 Stations Non Coincident Forecast (MW)

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

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

APPENDIX E: LIST OF ACRONYMS

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

PICKERING-AJAX-WHITBY SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA East Planning Region | June 30, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Pickering-Ajax-Whitby Sub-region

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Pickering-Ajax-Whitby Sub-region Working Group ('the Working Group"), which included the following members:

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

The Working Group assessed the adequacy of electricity supply to customers in the Pickering-Ajax-Whitby Sub-region over a 20-year period beginning in 2015; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the Pickering-Ajax-Whitby Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. The Pickering-Ajax-Whitby Sub-region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
DR	Demand Response
DG	Distributed Generation
EA	Environmental Assessment
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC or Committee	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	Long-Term Energy Plan
LTR	Limited Time Rating
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
PV	Photovoltaic (solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TS	Transformer Station
TWh	Terawatt Hours
Veridian	Veridian Connections Inc.
Whitby Hydro	Whitby Hydro Electric Corporation
Working Group	Technical Working Group for Pickering-Ajax-Whitby IRRP

1. Introduction

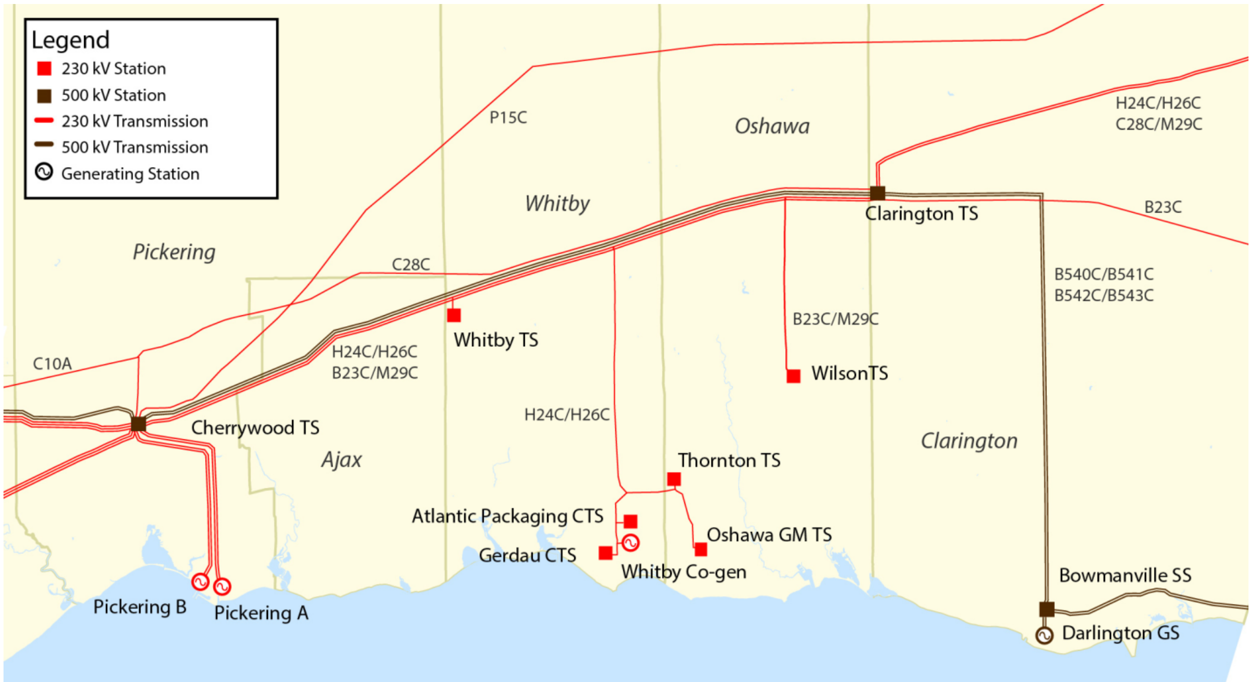
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Pickering-Ajax-Whitby Sub-region (the "sub-region") over the next 20 years, from 2015-2034. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group composed of the IESO, Veridian Connections Inc. ("Veridian"), Whitby Hydro Electric Corporation ("Whitby Hydro"), Hydro One Distribution and Hydro One Transmission [1] (the "Working Group").

The sub-region is part of the GTA East planning region ("GTA East Region"). The GTA East Region is within the Region of Durham and extends from Lake Ontario northward to the southern parts of Scugog and Uxbridge, and includes the municipalities of Pickering, Ajax, Whitby, Oshawa and the eastern part of Clarington. The area is supplied by several transformer stations ("TS") fed by the 230 kV transmission system in the area. The local distribution companies ("LDCs") providing services to the GTA East Region include: Hydro One Distribution, Oshawa PUC Networks ("Oshawa PUC"), Veridian and Whitby Hydro.

The sub-region includes the City of Pickering, Town of Ajax, the Town of Whitby and the southern parts of the Townships of Uxbridge and Scugog. The sub-region is currently served by Cherrywood TS 230/44 kV step-down transformers, Whitby TS and a portion of Thornton TS. The scope of this sub-region IRRP also includes consideration of the entire GTA East regional supply for the purposes of restoration analysis. A map of the GTA East Region is provided in Figure 1-1 below.

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

Figure 1-1: Map of Region



Source: Data provided by Hydro One Networks Inc.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB's regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the province's 21 electricity planning regions at least once every five years. The GTA East Region is one of these planning regions.

This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies investments for immediate implementation necessary to meet near-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies planning considerations over the longer term. It does not identify or recommend any specific projects for the longer term at this time but maintains flexibility to meet longer-term needs as they arise by monitoring growth and impacts of conservation and distributed generation ("DG") uptake at area transformer stations.

This report is organized as follows:

- A summary of the recommended plan for the Pickering-Ajax-Whitby Sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Pickering-Ajax-Whitby Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and DG assumptions, are described in Section 5;
- Electricity needs in the Pickering-Ajax-Whitby Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- Considerations for meeting regional growth needs in the longer term are discussed as in Section 8;
- A summary of engagement carried out to date in developing this IRRP and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

This IRRP addresses the sub-region's electricity needs over the next two decades, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC").[2] The IRRP identifies the needs that are forecast to arise in the near term (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034). The medium to longer term is referred to as the longer-term plan throughout this report as no distinct needs have been identified for the area past the near-term horizon. These two planning horizons are distinguished in the IRRP to reflect the level of commitment required to address needs over these time periods. The plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria and input received during engagement with local communities and other stakeholders. The planning criterion includes technical feasibility, cost, reliability, and, in the near-term, the IESO sought to maximize the economic use of existing electricity infrastructure.

This IRRP identifies specific projects for implementation in the near- term. This is necessary to ensure that they are in-service in time to address the sub-region's more urgent needs while respecting the lead time for development of the recommended and required infrastructure.

The IRRP also identifies possible longer-term electricity needs and considerations to keep in mind for the next round of planning. In preparation for the longer term, actions are identified to gather information and lay the groundwork for future planning processes. These actions are intended to be completed before the next IRRP cycle so that their results can inform further consideration at that time.

The needs and recommended actions comprising the near-term plan, as well as the long-term plan, are summarized below.

[2] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

2.1 Near-Term Plan (Up to 2020)

> **Near-Term Needs**
>
> - Need for additional 27.6 kV transformation capacity to supply growth
> - Need to conduct analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines

By 2019, peak summer 27.6 kV electrical demand at Whitby TS is expected to exceed the Limited Time Rating[3] ("LTR") of the transformer that supplies electricity at the 27.6 kV level by 12 MW, increasing to 132 MW by end of the study period in 2034. This increased loading is chiefly influenced by the forecast growth in demand in the greenfield community of Seaton in North Pickering. As the transformation capacity need is triggered by a new growth pocket with no current access to transmission supply, the near-term plan considers options to provide additional 27.6 kV supply to meet the entire capacity need of the new Seaton community.

Currently, a portion of customers supplied from the circuits H24/26C and M29/B23C in the GTA East Region would not be able to be restored within ORTAC timelines for rare failure events at peak times. A restoration shortfall exists for the 30 minute and 4 hour timelines. The 2015 30 minute and 4 hour shortfalls are 49 MW and 64 MW for the H24/26C circuits and 81 MW and 29 MW for the M29/B23C circuits respectively. The near-term plan considers the relative benefit of wires options versus the status quo for the 30 minute and 4 hour restoration timelines for rare double element failure events.

Recommended Actions

1. Build a new 230/27.6 kV station and upgrade an existing 230 kV line

Action is required to provide additional 27.6 kV supply capacity for the sub-region, specifically in proximity to the greenfield community of Seaton. Feeders are currently being built from Whitby TS to the new load centre to provide some additional supply to Seaton, however, the 27.6 kV transformation capacity at Whitby TS is forecast to be exceeded by 2019 and additional 27.6 kV capacity will be required to meet the forecast demand. Based on the analysis, included as Appendix B and summarized in Section 7.1.3, it has been determined that the most economic

[3] LTR determines the capacity of a station to serve load

course of action is to construct a new 230/27.6 kV station and upgrade an existing 230 kV line in the proximity of Seaton by 2018 in order to meet the need for additional capacity in 2019 (hereinafter, this solution is referred to as “Seaton MTS”). An Environmental Assessment (“EA”), which is currently underway, will recommend the preferred site for Seaton MTS. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Hydro One and Veridian undertake further planning and project development along with approval for implementation of Seaton MTS.

2. Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region

Preliminary technical and economic analysis indicates that the cost of addressing the restoration shortfall may be less than the potential cost of prolonged supply interruptions to local electricity customers. This preliminary analysis accounted for the low likelihood of the rare failure event (the simultaneous and prolonged loss of two supply lines serving the area) and assumed the higher end of customer interruption costs.

Based on this preliminary analysis it is recommended that the transmission and distribution companies conduct detailed studies to determine if specific restoration facilities can be justified. These detailed studies should be conducted as part of the Regional Infrastructure Plan (“RIP”) for the GTA East Region and should consider outage statistics, associated wires solutions/costs and incremental reliability benefits.

2.2 Longer-Term Plan (2021-2034)

Over the long term, factors such as intensification of established areas, progress on community energy plans, conservation, DG uptake at the transformation station level and the electrification of the transportation sector could affect electrical service for the sub-region. These factors could impact the capacity of the existing electricity supply infrastructure. Near-term actions in order to prepare for the long term will focus on monitoring these factors.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure — over the near, medium and long term and develops a plan to ensure cost-effective and reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board ("OEB") convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and in August 2013 formalized the process timelines through changes to the Transmission System Code and Distribution System Code, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a "wires" solution is the best option. If the

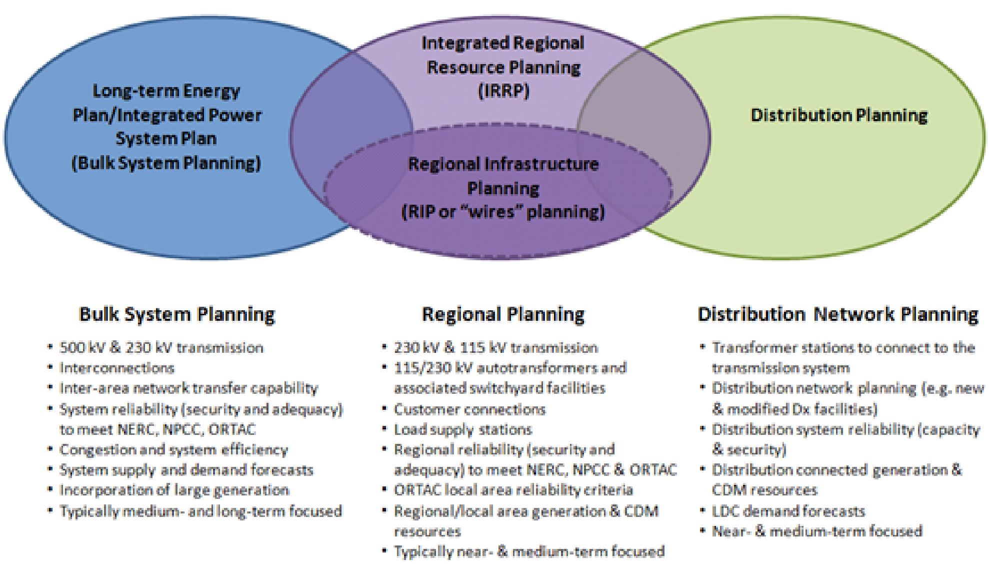
IESO recommends a wires solution, then a transmission- and distribution-focused RIP is developed. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment process, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is recommended, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it following the completion of the IRRP. Both RIPs and IRRPs must be updated at least every five years.

The final IRRPs and RIPs must be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate application or leave to construct. They may also be used by municipalities for planning purposes and by other parties to facilitate a better understanding of local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one forms of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

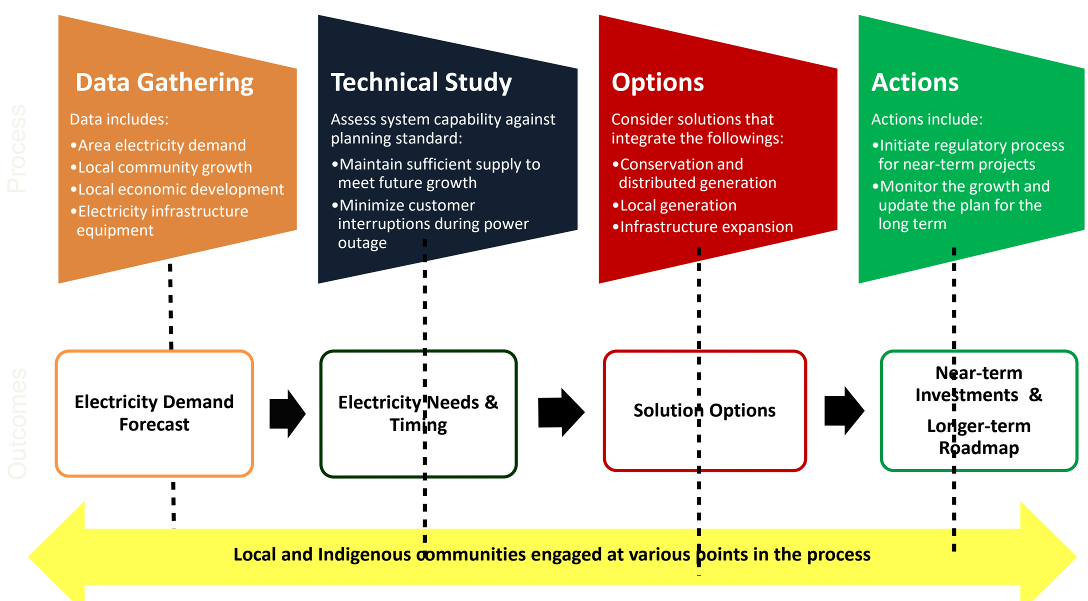
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and technical working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process. Other recommendations in the IRRP may include: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Pickering-Ajax-Whitby Sub-region Working Group and IRRP Development

The initial impetus for the sub-region IRRP was a 2014 Needs Screening report for GTA East. This report was produced by Hydro One Transmission with input from the OPA and IESO, Veridian, Whitby Hydro, Oshawa PUC and Hydro One Distribution. The Needs Screening was carried out to identify any needs which required coordinated regional planning. The Needs Screening Report found that there were needs which potentially required regional coordination, therefore the former OPA conducted a Scoping Assessment process and issued a Scoping Assessment Report in December 2014, in which it identified needs in the Pickering-Ajax-Whitby Sub-region that should be further assessed through an IRRP.

In late 2014 the Working Group was formed to develop a Terms of Reference for the IRRP, gather data, identify near to long-term needs in the sub-region, and develop the near-term recommend actions included in this IRRP.

4. Background and Study Scope

This report presents an IRRP for the Pickering-Ajax-Whitby Sub-region for the 20-year period from 2015 to 2034.

The IRRP planning approach for this sub-region was determined during the GTA East Region Scoping Assessment process. The combination of greenfield growth in North Pickering and supply capacity limitations in the area triggered the need for a coordinated approach by way of an IRRP for the sub-region.

A greenfield community -Seaton is planned to be developed in north Pickering, just north of the Cherrywood TS, within Veridian's service territory. This development is being planned for residential capacity for up to 70, 000 people and 35,000 jobs. Veridian plans to supply this new community load at 27.6 kV. Hydro One and Veridian assessed the station capacity requirements and plans for a proposed new 230/27.6 kV station called "Seaton MTS" prior to the regional planning process for the sub-region. Further assessment of the 27.6 kV supply situation was undertaken as part of this IRRP.

To set the context for this IRRP, the scope of this IRRP and the sub-region's existing electricity system are described in Section 4.1.

4.1 Study Scope

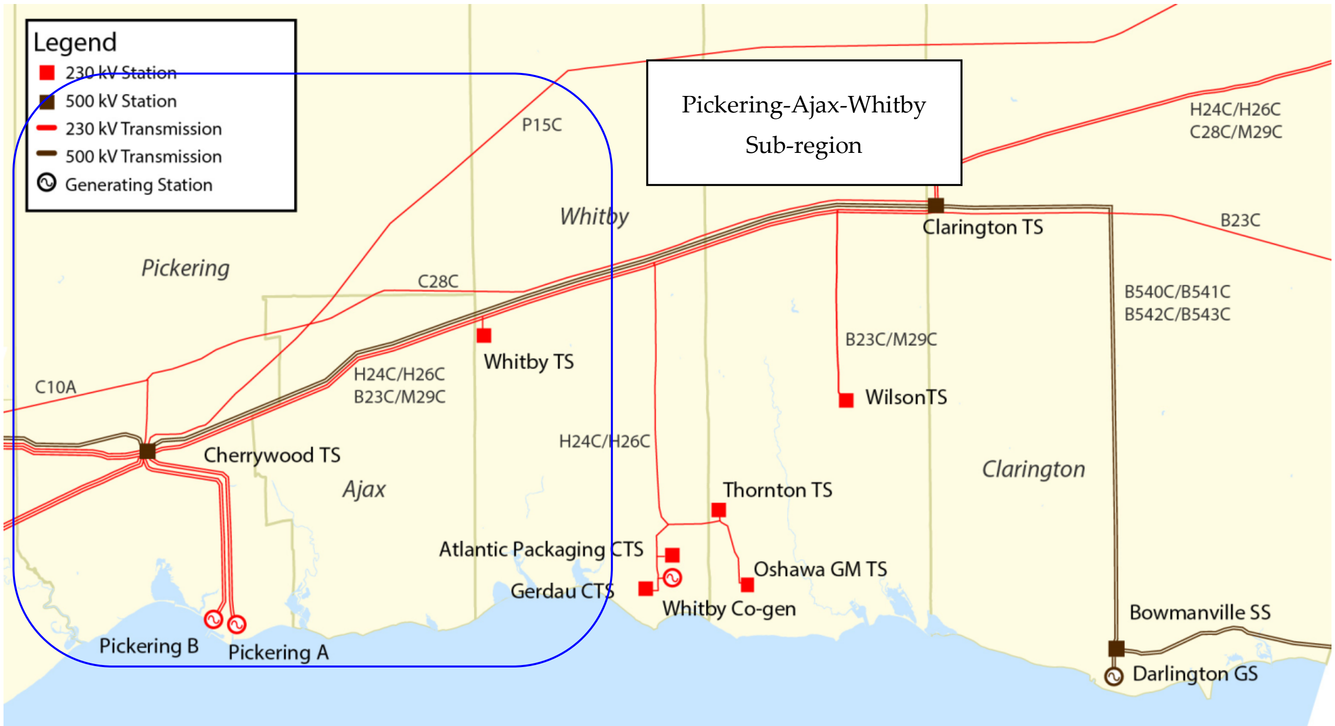
This IRRP recommends options to meet supply needs of the sub-region in the near, and longer term. The plan is a joint initiative involving the Working Group members, the IESO, Veridian, Whitby Hydro, Hydro One Distribution and Hydro One Transmission, and incorporates input from other stakeholders. The plan takes into account forecast electricity demand growth, conservation and demand management ("CDM" or "conservation") in the area, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, FIT and other generation uptake through province-wide programs.

This IRRP addresses regional needs in the sub-region, including capacity, security, reliability and relevant end-of-life consideration of assets.

The following transmission facilities are included in the plan scope and illustrated in Figure 4-1:

- Stations—Cherrywood TS, Whitby TS
- Transmission circuits—H24/26C and M29/B23C

Figure 4-1: Regional Transmission Facilities



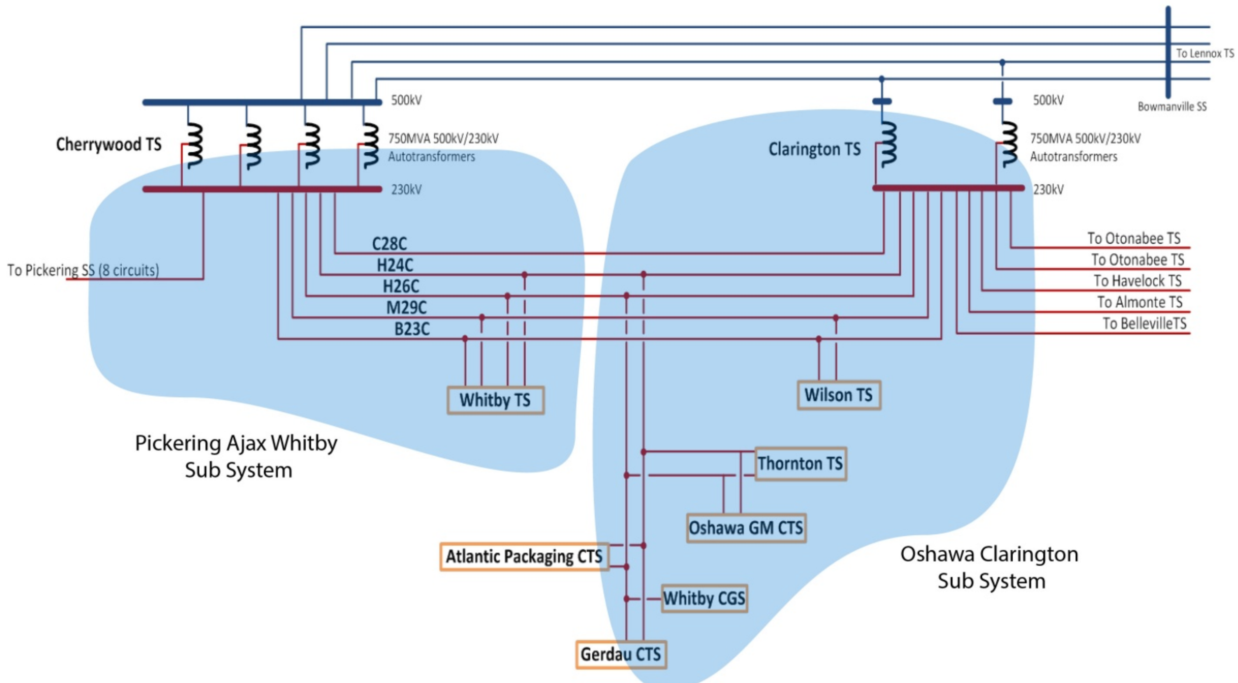
Source: Data provided by Hydro One Networks Inc.

The IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the capacity and reliability of the existing transmission system supplying the sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC.
- Establishing feasible integrated alternatives to address needs, including a mix of conservation, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using planning criteria which may include: technical feasibility, cost, reliability performance, environmental and social factors.
- Conducting community engagement to obtain local input on options for meeting the needs.
- Developing and communicating findings, conclusions, and recommendations.

Figure 4-2 below shows the electrical configuration of the main stations, supply sources, and transmission assets for the GTA East Region as a single line diagram. Note that the needs analysis includes Clarington TS which is currently under construction and is expected to be in-service for 2018.

Figure 4-2: Electrical Sub-systems



Source: Hydro One Networks Inc.

5. Demand Forecast

This section outlines the forecast of electricity demand for the Pickering-Ajax-Whitby Sub-region. It highlights the assumptions made for peak-demand load forecasts and the contributions of conservation and DG to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electricity system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times of the area's overall peak.

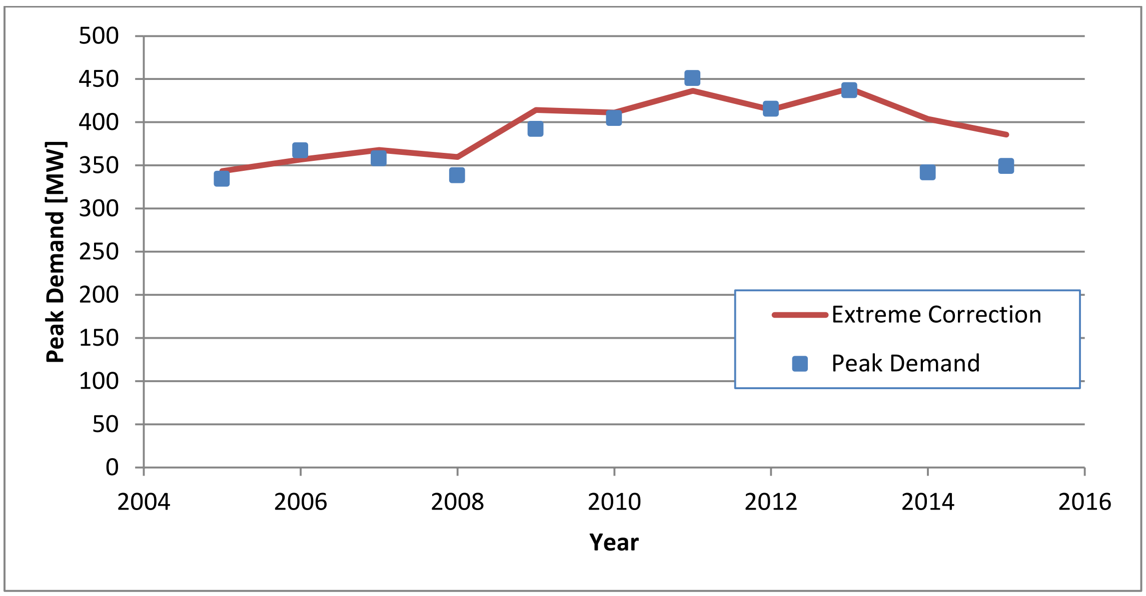
Within the sub-region, the peak loading hour for each year typically occurs in the early-evening of the hottest weekday during the summer. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day. The 2015 regional peak occurred on July 30 at 5:00 pm. Although a large group of industrial customers exists in the GTA East Region, both the regional and sub-regional peak is generally driven by the air conditioning loads of residential and commercial customers. The introduction of the IESO's Industrial Conservation Initiative program in recent years has decreased the overall effect of industrial customer load during peak hours.

Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2015. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The sub-region has seen steady demand growth since 2005. The peak demand in this sub-region is heavily driven by weather conditions. Residential and commercial customers combine for approximately 80% of the load in the area and during the summer months, load from air conditioning drives the peak demand. The recent decline in peak demand during 2014 and 2015 can be attributed to the cool summers experienced across the GTA and province-wide. The peak day temperature in 2014 and 2015 averaged 29.4 degrees Celsius, compared to 34.2 degrees Celsius from 2010 to 2013.

Figure 5-1: Historical Peak Demand in Pickering-Ajax-Whitby Sub-region



The red line in Figure 5-1 shows the weather corrected customer demand for the same hour as the actual peak demand. The weather corrected line has been adjusted to reflect the expected behaviour of the load under extreme weather conditions. Correction factors between actual and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

5.2 Demand Forecast Methodology

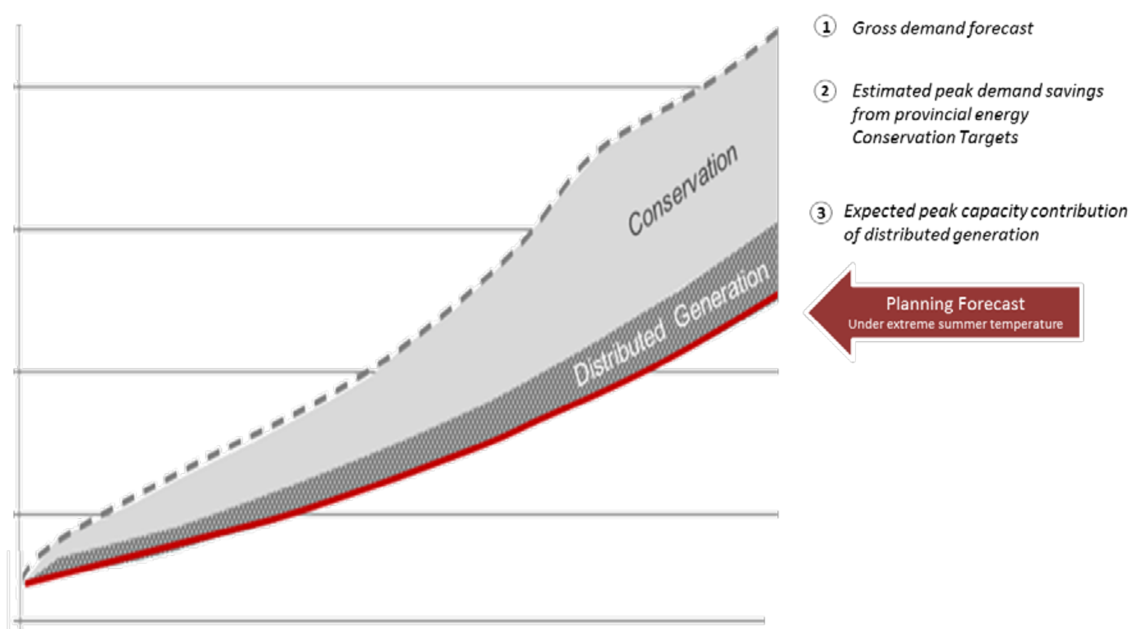
For the purpose of this IRRP, a 20-year planning forecast was developed to assess supply and reliability needs at the regional level.

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

The 20-year planning forecast is divided notionally into two timeframes. The near (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034).

The sub-region's peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in the LDCs' service territory. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to produce a planning forecast - i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT, and to reflect extreme weather conditions where necessary. The planning forecast was then used to assess any growth-related electricity needs in the sub-region.

Figure 5-2: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the corresponding local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

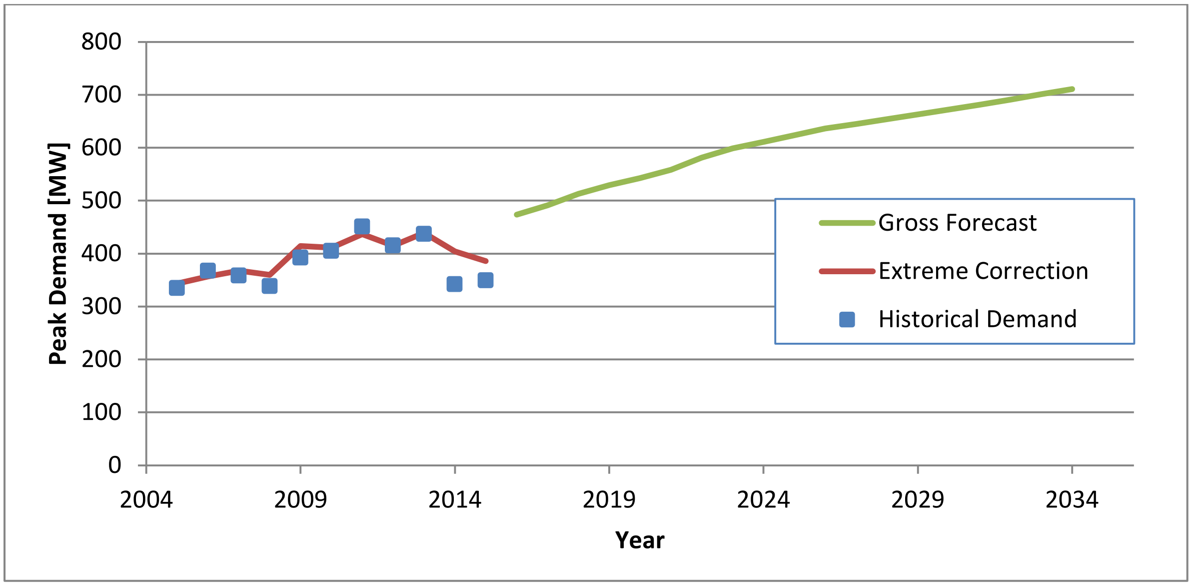
Each participating LDC and transmission-connected customer in the LDCs' service territories prepared gross demand forecasts at the TS level or bus level for multi-bus stations. Gross demand forecasts account for the increases in demand from new or intensified development, but do not account for the impact of new conservation measures such as codes & standards or demand response ("DR") programs. LDCs are only expected to account for changes in consumer demand resulting from efficiency improvements and increasing electricity prices, known as "natural conservation".

Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The graph below shows the gross demand forecast provided by the LDCs[4] for the sub-region, with historical data points for comparison. The demand in the sub-region is serviced by Whitby TS and Cherrywood TS. Whitby TS is split into two DESNs and provides supply at both 27.6 kV and 44.0 kV levels, while Cherrywood TS only provides supply at the 44.0 kV level.

[4] Forecasts are subject to change as population information continues to be updated as part of provincial and local growth plan reviews

Figure 5-3: Sub-region Gross Demand Forecast



Both the weather corrected peak and historical demand shows that demand in the sub-region has been generally increasing over the past decade, with a slight dip in the most recent year. However, the data for summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although an extreme weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments.

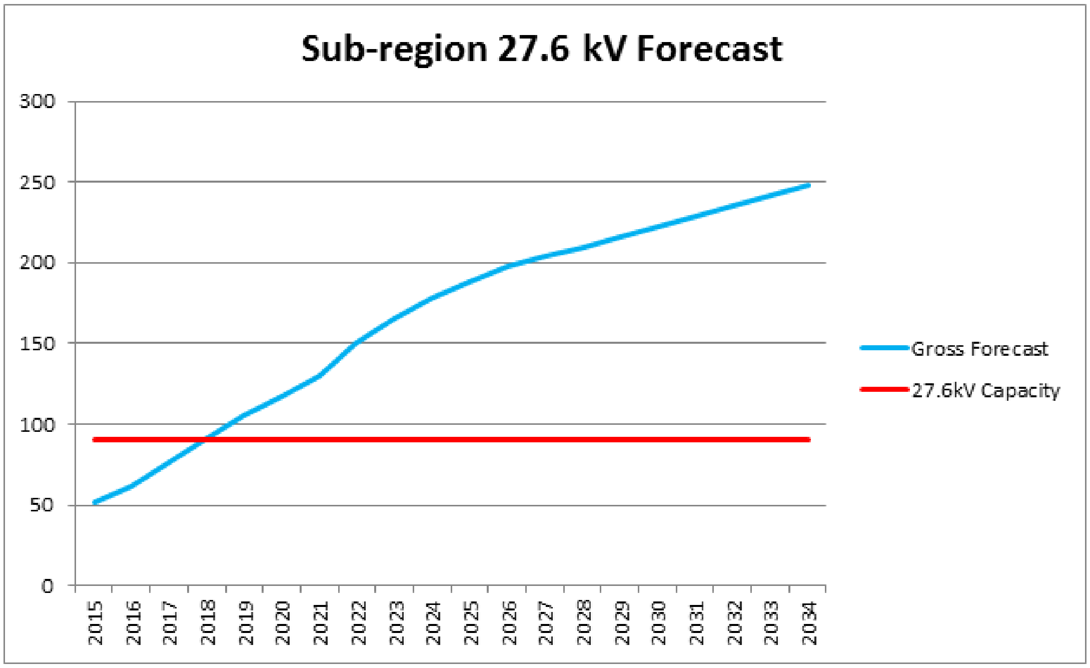
The total annual growth for this area averages 2.3% over the 20-year planning horizon. The highest growth is forecast to occur in the near term (year 0-5) at a rate of 3.7%. The demand growth decreases to 2.8% in the medium term (year 5-10) and further declines to 1.5% for the last 10 years of the planning period.

Demand growth in the sub-region is driven by a series of development projects which include the new community of Seaton, and various intensification projects in Pickering, Ajax and Whitby[5]. The new community of Seaton is envisioned as sustainable urban community[6] and is forecast to account for 22% of the total demand in the sub-region by 2034. The resulting demand of this new development will be initially serviced by available 27.6 kV capacity at Whitby TS, but is expected to exceed station capacity in 2019 as shown in Figure 5-4.

---

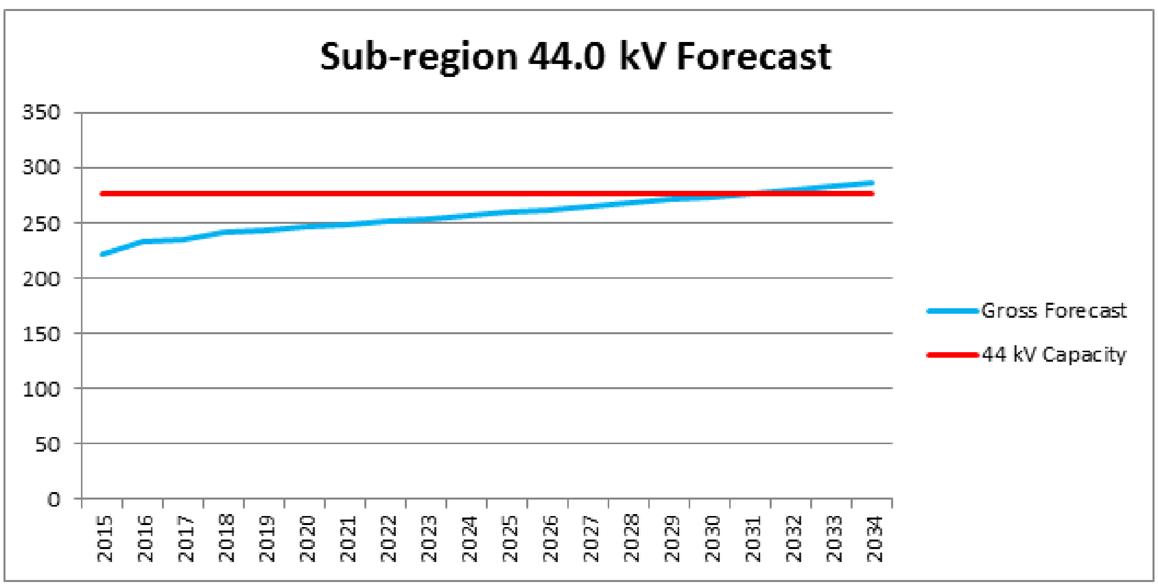
[5] https://www.pickering.ca/en/living/resources/DowntownPickering_FinalVisionDocument_June2013.pdf
https://www.ajax.ca/en/doingbusinessinajax/resources/Planning_Services/Ajax_Official_Plan_Consolidation_Jan_15_2016.pdf
http://www.whitby.ca/en/townhall/resources/pl_opa1-chart_march28_2013.pdf
[6] https://www.pickering.ca/en/cityhall/seatoncommunity.asp

Figure 5-4: Sub-region 27.6 kV Gross Forecast



The 44.0 kV demand in the area is supplied by Whitby TS and Cherrywood TS, and the 44 kV capacity is expected to be sufficient to supply forecast demand into the longer term.

Figure 5-5: Sub-region 44.0 kV Gross Forecast



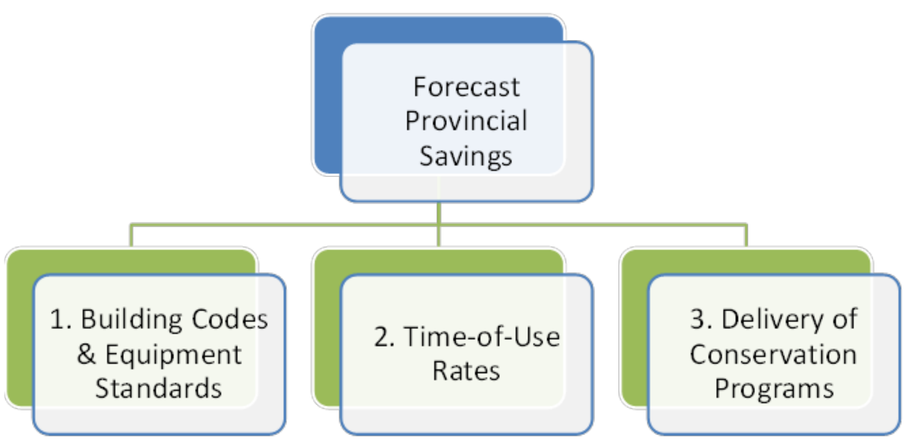
The gross demand forecasts provided by the LDCs, and forecast methodology are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is the first resource considered in planning, approval and procurement processes. It plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. The conservation savings forecast for the sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.5), to determine the net peak demand or planning forecast for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. A portion of this province-wide energy conservation target was allocated to the sub-region, and, as further described below, it was further converted to an estimated peak demand reduction for the sub-region. The expected peak demand savings for the sub-region are shown below in Table 5-1. To estimate the impact of the conservation savings in the area, the forecast provincial savings were divided into three main categories:

Figure 5-6: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time of Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The 2013 LTEP committed to establishing a new 6-year Conservation First Framework ("CFF") beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near-term, Ontario's LDCs have an aggregate energy reduction target of 7 TWh, as well as individual LDC specific targets. These targets are to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the CFF. Each LDC was required to prepare a Conservation and Demand Management ("CDM") plan by May 1, 2015 describing how their target will be achieved. LDCs are also required to provide updates to their CDM plans.

As part of the Conservation First policy, the provincial government has adopted a broad definition of conservation that includes various types of customer action and behind-the-meter generation. This means that conservation includes any programs or mechanisms that reduce the amount of energy consumed from the provincial electricity grid. Conservation initiatives, including behind the meter generation projects and on-site generation, are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the sub-region.

To provide a more regional specific forecast, the impact of the savings for each category were broken down by the residential, commercial and industrial customer sectors. The IESO then worked together with area LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of the forecast conservation, as conservation potential varies by sector due to different energy consumption characteristics and conservation opportunities.

For the sub-region, LDCs were requested to provide their gross demand forecast and provide the breakdown of their demand forecast by sector at each TS based on their knowledge of local customers. For TSs that an LDC cannot provide gross load segmentation for, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors[7] was used to help estimate the breakdown of demand. Once sector gross demand at each TS was available, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rate, and conservation programs. The estimates for each of these categories were done separately due to their unique characteristics and data availability. In general, hourly profiles of IESO's gross forecast and conservation

[7] OEB Yearbook of Electricity Distributors: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

savings were used to determine the impact that each conservation category has on peak demand. Impacts were estimated for residential, commercial and industrial sectors reflecting that various sectors have different conservation opportunities.

The planning forecast assumes that the targets will be met, and will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs.

The table below shows the final estimated conservation peak demand savings, which were applied to the gross demand to create the net forecast for the sub-region.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
Total East GTA Savings (MW)	33	57	74	92	111	134	154	174	184	185
Sub-region Only Savings (MW)	6	14	24	33	44	55	64	72	77	78

Over the 20-year time period, it is expected that conservation savings for the GTA East planning region will amount to the deferral of one TS the size of Cherrywood TS. For the sub-region the conservations savings over the study period are expected to amount to approximately 40% of the capacity provided by a station similar to Cherrywood TS

Additional conservation forecast details are provided in Appendix A.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Pickering-Ajax-Whitby Sub-region is also anticipated to help offset peak demand requirements at select stations. The introduction of the *Green Energy Act, 2009* and the associated development of Ontario's FIT program, have increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, after applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution from existing and contracted DG in the area. The effects of projects that were already in-service prior to the base year of the gross demand forecast were not included as they are already embedded in the gross demand forecast which is the starting point for the planning forecast. Potential future DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of August 2015, existing and contracted DG projects are expected to offset an incremental 18 MW of peak demand within the sub-region. The largest project in the sub-region is a renewable biomass generator in Ajax with the capability to generate up to 25 MW, and currently contracted for 18 MW. Other projects in the area are small scale solar projects (<500 kW). Table 5-2 shows the DG by technology that is currently under contract in the sub-region.

Table 5-2: Distributed Generation by Technology in the Pickering-Ajax-Whitby Sub-region

Technology	Contract Capacity [MW]	Capacity Contribution [MW]	Capacity Factor
Solar	2	1	32%
Renewable Biomass	18	17	98%

The capacity contribution for each DG project was calculated by applying a capacity factor based on fuel type to the contracted capacity of each project. The capacity factors used in this study are based on historical data gathered during Ontario's overall system peak.

In the sub-region, all of the DG projects are planned to be connected to Whitby TS to help offset some of the load during peak demand hours. Currently, new DG connection is restricted from connecting to Cherrywood TS due to short circuit ("SC") constraints because of an out-of-service 30 MW landfill gas generation facility. Hydro One is in discussions with the land and facility owner and is seeking legal and regulatory advice on the process for the removal of this allocated capacity. If capacity allocation is removed, the SC restriction can be lifted and new DG can apply to connect to this station.

The following table shows the cumulative DG in the sub-region.

Table 5-3: Cumulative DG used for Planning Forecast

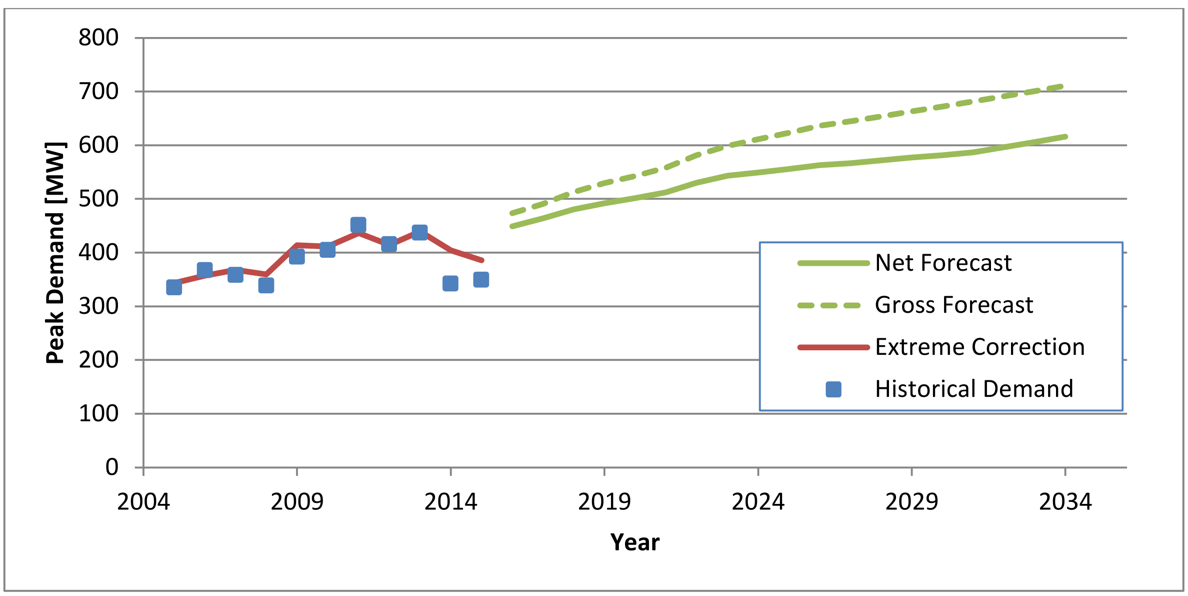
Year	2015	2016	2017	2018	2019	2020	2034
Pickering-Ajax-Whitby [MW]	18	18	18	18	18	18	18

5.6 Planning Forecasts

A 20-year planning forecast was produced based on the LDCs' gross demand forecasts and net of anticipated conservation and DG.

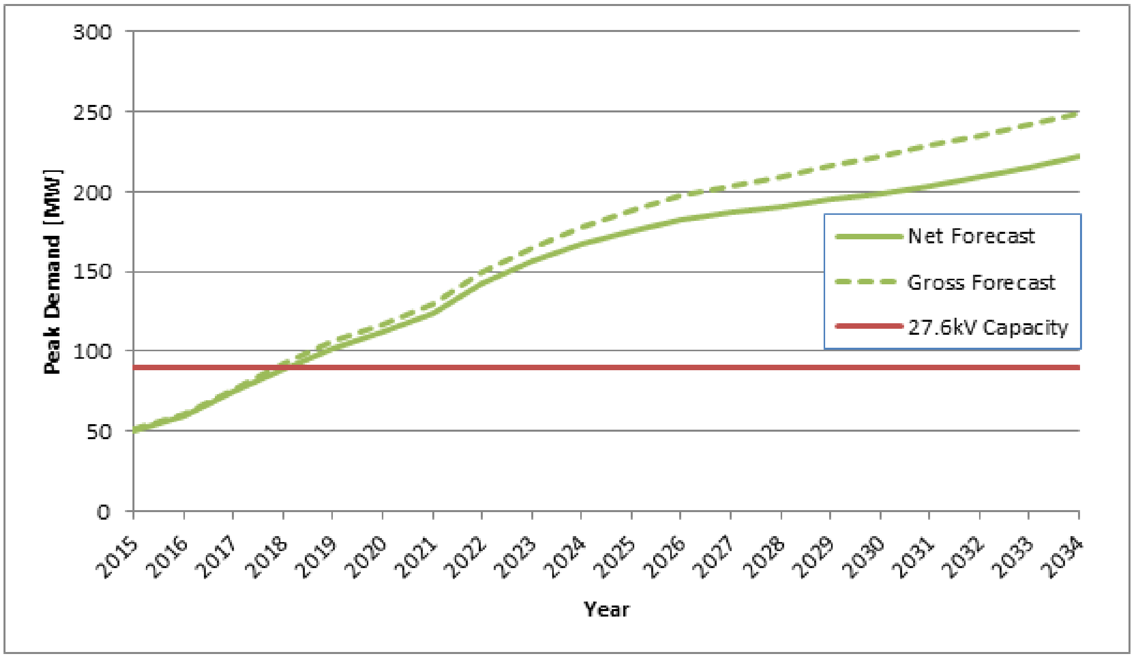
Figure 5-7 illustrates the planning forecast, along with historical demand for the sub-region. The combined effects of DG and conservation are expected to reduce the peak demand in the Pickering-Ajax-Whitby Sub-region by 95 MW by the end of the planning period in 2034. This corresponds to 13% of the overall gross demand in 2034 of 711 MW.

Figure 5-7 Pickering-Ajax-Whitby Sub-region Planning Forecast



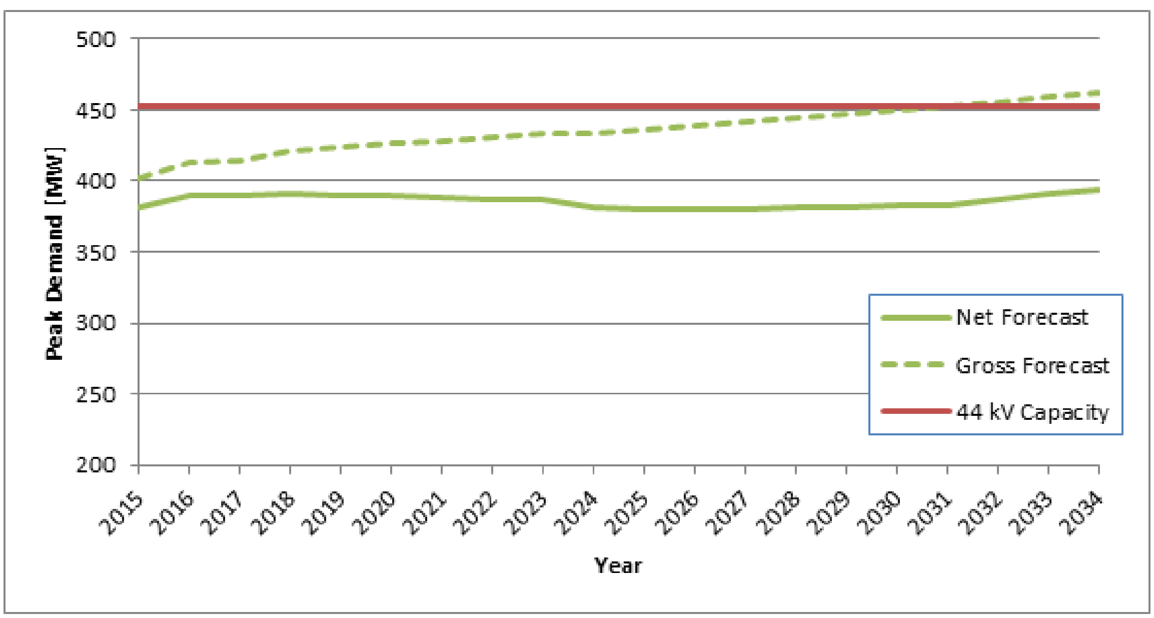
The net 20-year planning forecast for the 27.6 kV load serviced by Whitby TS is shown below in Figure 5-8. By 2034 the combined effects of DG and conservation are expected to decrease the peak demand by 27 MW; this accounts for 11% of the gross demand in 2034.

Figure 5-8 Pickering-Ajax-Whitby Sub-region 27.6 kV Planning Forecast



The net 20-year planning forecast for the 44.0 kV load serviced by Whitby TS and Cherrywood TS is shown in Figure 5-9 below. By 2034 the combined effects of DG and Conservation are expected to decrease the peak demand by 50 MW; these effects account for 15% of the gross demand in 2034.

Figure 5-9 Pickering-Ajax-Whitby Sub-region 44.0 kV Planning Forecast



6. Needs

The Pickering-Ajax-Whitby Sub-region Working Group identified two electricity needs in the near-term, based on the planning forecasts, system capability and application of planning criteria. This section describes the identified needs for the near-term in the sub-region.

6.1 Needs Assessment Methodology

The IESO's ORTAC[8] was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements.

The application of these criteria in an area is used to generally identify three broad categories of needs as follows:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the 10-day LTR of the step-down transformer stations in the local area. Transformer station capacity need arises when the peak demand at step-down transformer stations in the local area exceeds the combined LTR ratings.
- **Upstream Transmission System Capacity** describes the electricity system's ability to provide continuous supply to a local area. This is limited by the load meeting capability ("LMC") of the transmission line or sub-system and is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See **Appendix D** for more details). These capacity needs arise when coincident peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** describes the electricity system's ability to minimize the impacts of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes.

---

[8] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

6.2 Needs

Two needs were identified in the area which impact the ability to serve local loads:

1. There is a need arising in 2019 for additional 27.6 kV TS capacity to supply new growth.
2. There is a need to conduct detailed analysis to assess the economic justification for addressing a restoration shortfall (MW) that exists in the GTA East Region for rare loss of supply events.

6.2.1 Transformer Station Capacity-27.6 kV

The sub-region is supplied by two stations, Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either the 27.6 kV or 44 kV distribution levels. The Cherrywood TS provides supply at the 44 kV level while Whitby TS provides supply at the 27.6kV and 44 kV levels. Whitby Hydro provides distribution service at the 44 kV level, however Veridian uses both voltage levels to supply its service territory;. Dedicated 27.6 kV feeders from Malvern TS and Sheppard TS also supply the western portion of Veridian's service territory. These two stations are in the eastern part of an adjacent planning region-Metro Toronto.

Figure 6-1 and Figure 6-2 below show the historical and forecast 44 kV peak demand for the study area. Based on the planning forecast, sufficient 44 kV capacity exists to supply current and forecast 44 kV demand in the area until the end of the study period.

Figure 6-1: Planning Forecast for Cherrywood TS 44.0 kV

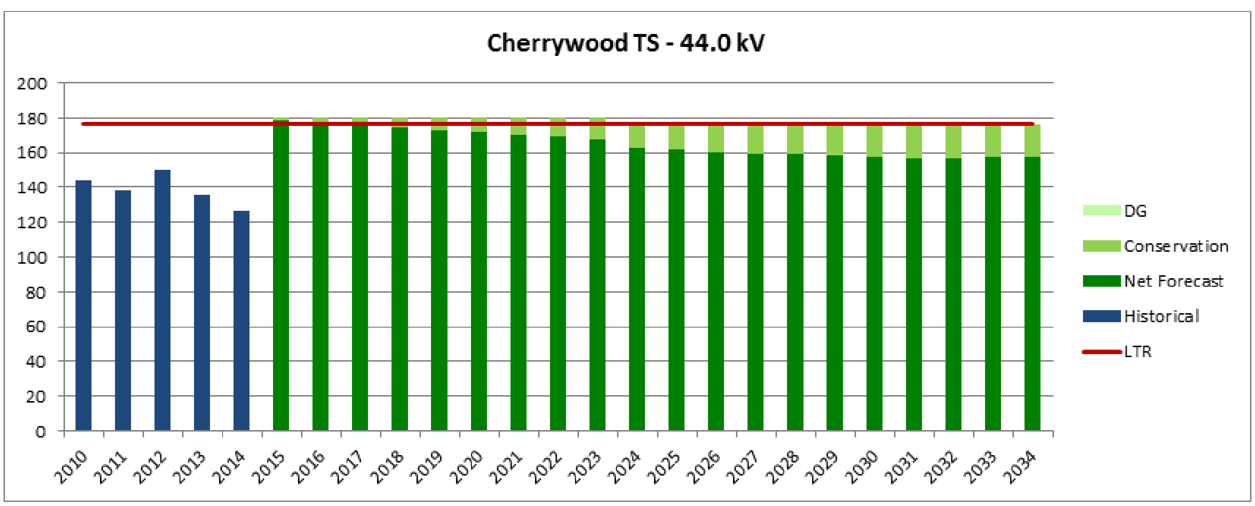


Figure 6-2: Planning Forecast for Whitby TS 44.0 kV

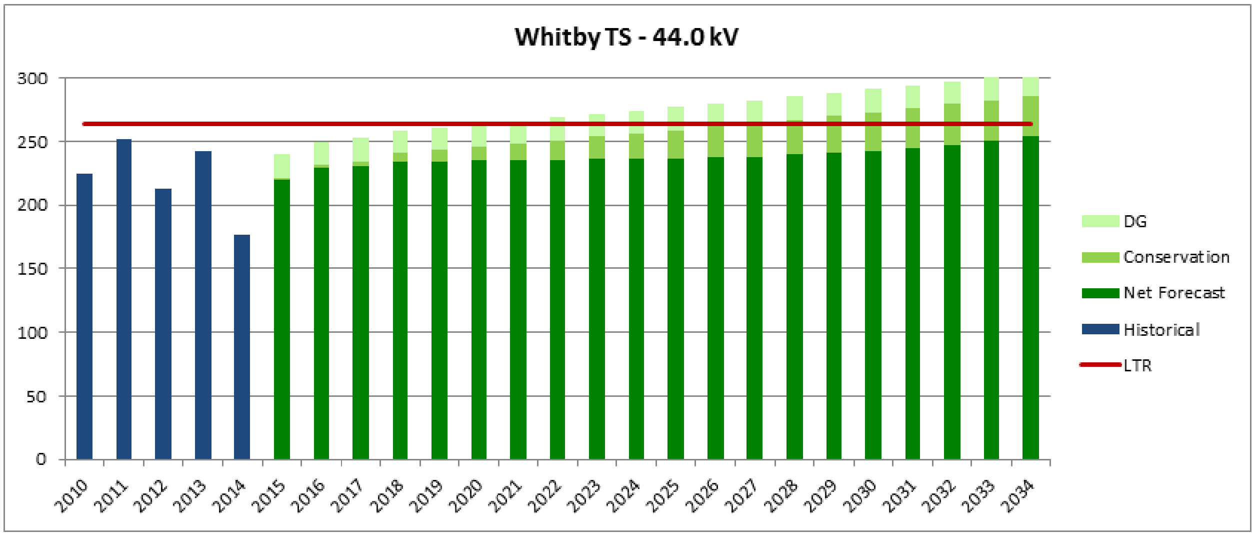
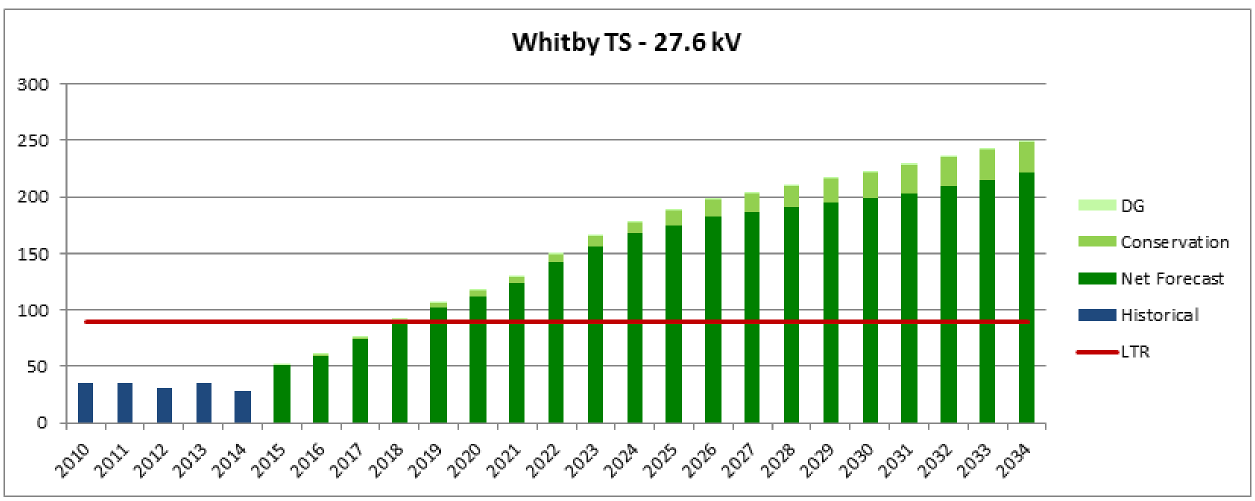


Figure 6-3 below shows the planning forecast for the 27.6 kV demand in the study area. The 27.6 kV demand in the study area is expected to exceed available capacity by 2019.

Figure 6-3: Planning Forecast for Whitby TS 27.6 kV



The 10 year forecast for 27.6 kV demand for the sub-region is shown in Table 6-1 below, with figures shown in red indicating demand levels that exceed the 90 MW transformation capacity limit for the 27.6 kV bus.:

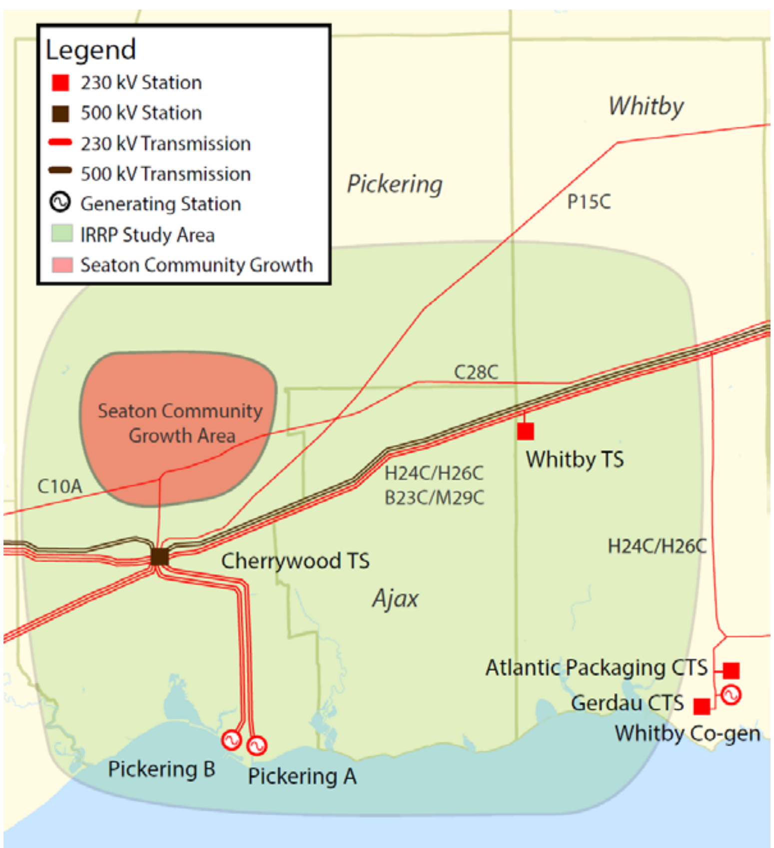
Table 6-1: Sub-region 27.6 kV Planning Forecast from 2015 to 2024

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

The new community of Seaton in North Pickering accounts for more than 60% of the total 27.6 kV demand by 2034, influencing a transformation capacity shortfall of approximately 12 MW in 2019 and up to 132 MW in 2034.

The location of the greenfield growth due to Seaton relative to the other infrastructure facilities in the area is shown in the figure below (in red). The community of Seaton is just north of Cherrywood TS and west of Whitby TS.

Figure 6-4: Location of Seaton in the Study Area



Source: Data provided by Hydro One Networks Inc. Copyright: Hydro One Networks Inc. [2016].

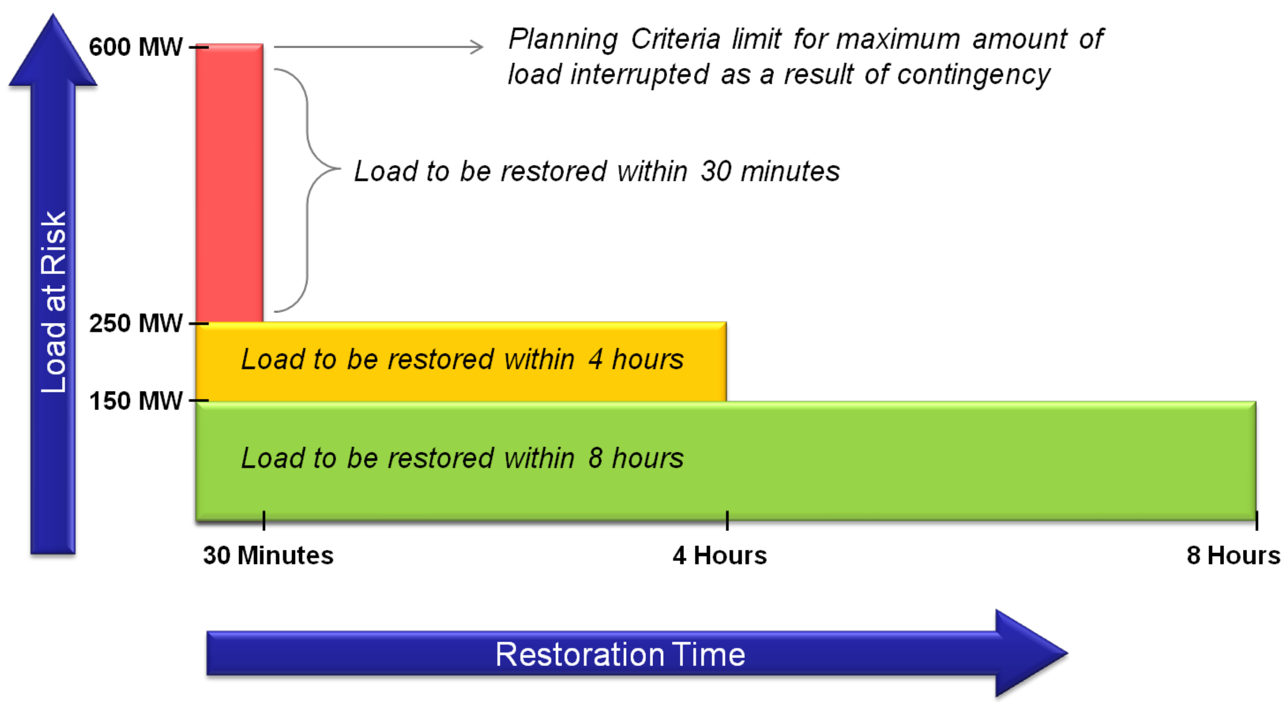
Additional 27.6 kV capacity is required for the sub-region to meet forecast 27.6 kV demand.

6.2.2 Load Restoration

Restoration refers to the ability of the system to restore sufficient amount of load within defined periods of time following the prolonged loss of a major supply source from the transmission system.

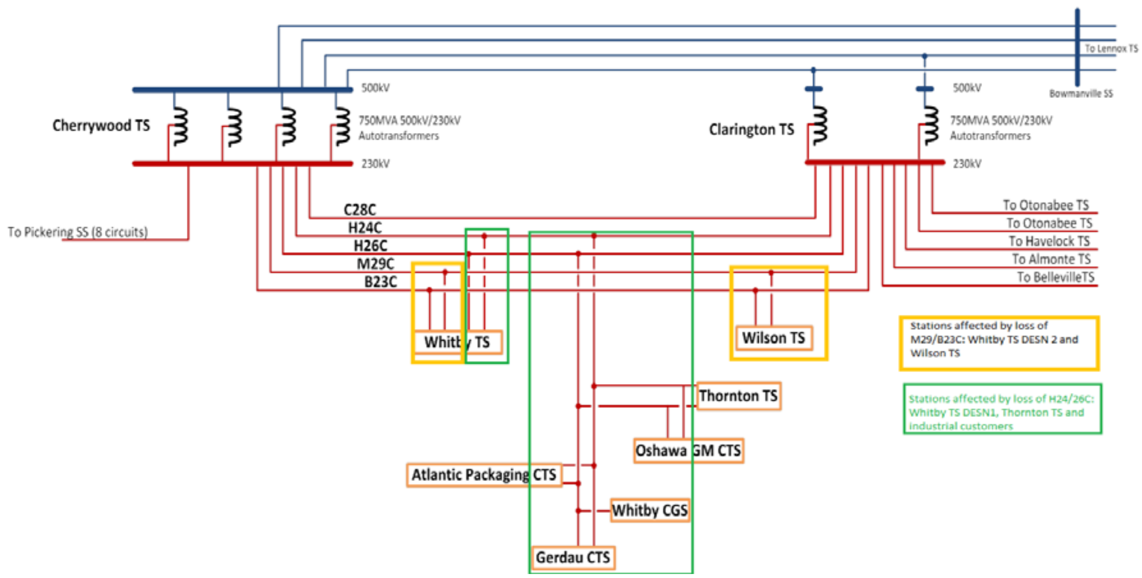
The group of stations and customers supplied from the H24/26C and M29/B23C circuits within the GTA East Region have been identified as being at risk of not meeting restoration levels as defined in ORTAC. ORTAC indicates that, for the loss of two elements, any load in excess of 250 MW should be restored within 30 minutes and any load in excess of 150 MW should be restored within 4 hours. The assessment must also consider restoration of all loads within 8 hours. These restoration levels are summarized in Figure 6-5 below.

Figure 6-5: ORTAC Load Restoration Criteria



The figure below shows the stations and customers served by each of the circuit pairs of H24/26C and M29/B23C.

Figure 6-6: Restoration Pocket for H24/26C and M29/B23C



Source: Hydro One Networks Inc. [2016].

As shown in Figure 6-6 , Whitby TS DESN 1 and the Oshawa radial pocket that includes direct connect customers and Thornton TS are served by the same circuits H24/26C, meaning both are at risk of supply interruption following the simultaneous loss of the pair of circuits. The industrial loads or direct connect customers account for 153 MW of the load supplied by the H24/26C circuits. These industrial loads cannot be restored by the LDCs in the event of an outage as these customers are connected directly to the transmission system.

For the simultaneous loss of the other pair of circuits M29/B23C, the stations Whitby DESN2 and Wilson TS are at risk of supply interruptions.

Table 6-2 below shows the total peak load at risk of interruption for select years, and the 30 minute and 4 hour restoration capability required to meet this criteria for both outages:

Table 6-2: Peak Load at Risk of Interruption for Select Years

Load Pocket	2015 Peak (MW)					2025 Net (MW)				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30-Min Restoration	30-Min Restoration Shortfal	4-Hour Restoration	4-Hour Restoration Shortfall
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	567	57	259	142	275

It is assumed that given the proximity of emergency crews and equipment, all loads would be restored within 8 hours through conventional transmission supply.

Based on discussions with area LDCs, up to 105 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 257 MW within 4 hours for customers supplied off the M29/B23C circuits. This leaves a maximum 2015 shortfall of 81 MW after 30 minutes, and 29 MW after 4 hours.

Similarly, for the H24/26C circuits, up to 57 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 142 MW within 4 hours for customers supplied off these circuits. This leaves a maximum 2015 shortfall of 49 MW after 30 minutes, and 64 MW after 4 hours.

After taking into account the load transfer capability of LDCs in the area, ORTAC restoration timelines and load levels are currently not met for the 30 minute and 4 hour criteria for both pairs of circuits. According to ORTAC[9], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The transmission customer and transmitter may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons provided the bulk power system adheres to NERC and NPCC standards". For the GTA East Region,

[9] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

there is a need to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines.

6.3 Needs Summary

Two near-term needs have been identified in the study area, and are summarized in Table 6-3 below.

Table 6-3: Summary of Needs in Pickering-Ajax-Whitby Sub-region

Area	Need	Description	Need Date
North Pickering	Transformation Capacity	Need for additional 27.6 kV transformation capacity to supply growth	2019
GTA East Region	Restoration	Need to conducted analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines	Now

7. Near-Term Plan

This section describes the alternatives considered in developing the near-term plan for the Pickering-Ajax-Whitby Sub-region, provides details of and the rationale for the recommended plan, and outlines an implementation plan. The capacity and restoration needs identified above are discussed in separate sections below.

7.1 Alternatives for Meeting the Near-Term Transformation Capacity Need

In developing the near-term plan for the capacity need in the sub-region, the Working Group considered a range of integrated options. The Working Group specifically considered technical feasibility, cost and consistency with longer-term needs and priorities in the sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were also given priority, where they were determined to be cost effective.

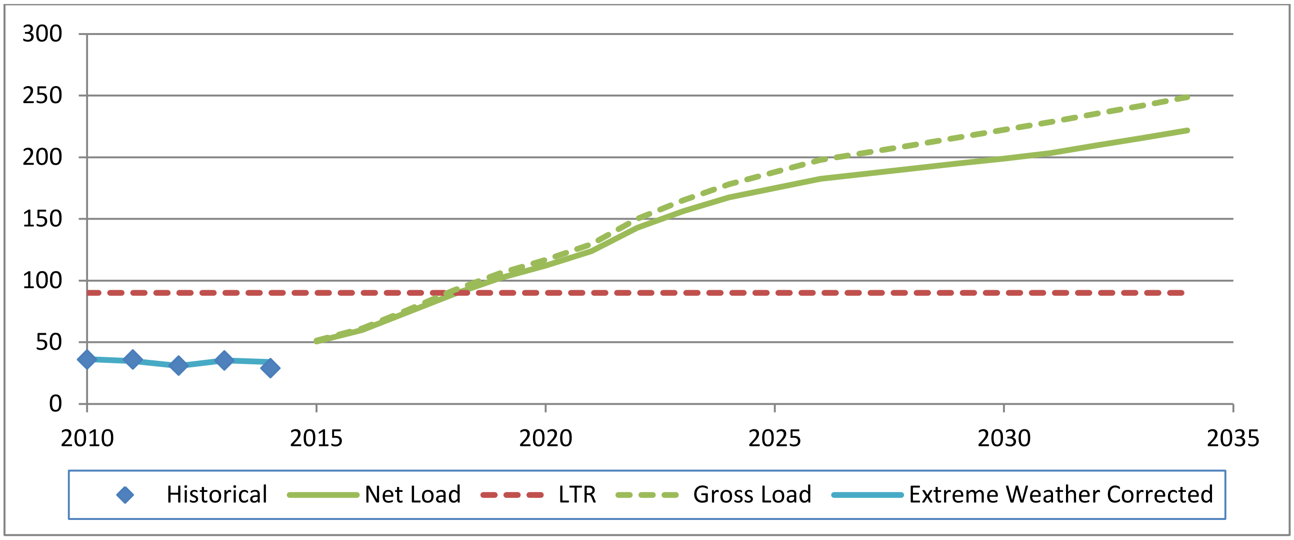
As mentioned previously, the transformation capacity need in the sub-region is mainly influenced by the forecast demand from the Greenfield development of Seaton in north Pickering. This development is being planned for residential capacity for up to 70,000 people and 35,000 jobs. Veridian is also planning to supply this community via 27.6 kV supply.

The following sections detail the alternatives considered. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets. Achieving the estimated peak demand reductions associated with the provincial conservation targets does not, however, result in deferring any of the near-term capacity needs. Achieving these conservation targets does however significantly reduce the magnitude of the 27.6 kV transformation capacity required over the long term by 27 MW, from 249 MW to 222 MW by 2034. It also effectively offsets new demand growth at Whitby TS (the only station providing supply at the 27.6 kV level in the sub-region) until 2034. The Whitby TS 27.6 kV load under both the gross and planning load forecasts is shown in Figure 7-1.

Figure 7-1: Effect of Conservation Targets on 27.6 kV Demand in the Sub-region



As explained in Section 5.4 provincial conservation targets are achieved over an entire year, while transmission needs are triggered by peak demand (single highest observation in a year). As a result, in order to reduce, defer, or address transmission capacity needs, conservation programs must have an impact during the hour of peak demand. In the case of this study area this typically means late afternoon on the hottest weekdays of summer.

The peak demand impact shown in the planning forecast represents the Working Group's estimate of how meeting the sub-region's allocation of provincial energy targets will translate into peak demand reductions. There is uncertainty in this estimate, arising both from whether the sub-region is able to meet provincial energy conservation targets and how energy conservation, in fact, translates to corresponding peak demand reductions. As a result, there is a wide range of demand impacts which could be experienced (both higher and lower than forecast).However, higher or lower demand impacts due to conservation achievement are not a significant factor in this sub-region, because 60% of the capacity need is due to greenfield growth in the new community of Seaton. Without this Greenfield growth, it is expected that there would be sufficient 27.6 kV capacity until the end of study period with the achievement of conservation targets for the localized 27.6 kV electrical demand.

7.1.2 Generation

Since the need for LMC in this area stems from residential growth served at the 27.6 kV voltage level, transmission-connected bulk generation is not a viable option. Also, the new Seaton load requires transmission/distribution infrastructure to connect to the existing grid; therefore a bulk generation solution would not avoid the above infrastructure investment.

Standalone local generation could theoretically supply the new community without the need for grid connection; however, without the diverse pool of system resources, the standalone approach would require implementing a portfolio of community based resources, including different types of generation, storage, demand management, transmission, and distribution to meet area needs (capacity, energy, operability) over the entire study period. In order to match the same level of service provided to a grid-connected system and maintain reliable supply to the community, a margin above the base generation requirements is needed to cover planned and forced generation outages. Based on the IESO's understanding of electricity service for the 25 Remote Communities (northern off-grid communities) in Ontario, it is assumed that for a standalone DG option for the Seaton community capacity redundancy would need to be approximately 130% of net-peak demand to provide reliable electricity service in the event of planned or forced generation outages.

The level of local distribution investment required to enable both the standalone option and grid-connected option would be similar in terms of design characteristics and cost. Assuming the standalone portfolio would be a mix of local natural gas generation, renewable generation, and storage, the cost associated with this approach is estimated to be at least three times that of the grid-connected option.

Local small scale generation solutions are better suited to areas with existing wires infrastructure and small incremental resource needs. The potential role of DG to manage long-term growth in the overall study area will be reviewed as part of future regional planning cycles.

7.1.3 Transmission and Distribution

As discussed in the previous sections additional conservation and generation are not feasible options to meet the near-term needs. In parallel with assessing these options, the Working Group developed transmission and distribution options to address the transformation capacity need.

These options provide new or upgraded transmission or distribution system assets, including lines, stations, feeders and related equipment. Solutions of this nature are characterized by high upfront capital costs, but have high reliability over the lifetime of the asset and enable the economic delivery of the incremental capacity and energy requirements from the provincial power system.

As noted previously, Veridian and Hydro One have been monitoring the need for station capacity in this area and given the lead times for development of a new step-down transformer station have initiated EA work for three potential sites to supply the community of Seaton. The preferred site will be determined by this EA process which is currently underway, with results expected in Q1 2017. A new station at any of the three sites will also require an upgrade to the associated 230 kV connecting circuits in the area in order to connect the station to the transmission system; this transmission line upgrade is a necessary feature of all the station alternatives discussed below. For the transformation capacity need, utilization of available station and feeder capacity from proximal stations outside the GTA East Region was also considered as part of the transmission and distribution set of options. Figure 7-2 below shows the relative locations of the infrastructure considered in the alternatives described below.

Figure 7-2: Proposed Station Sites and Related Infrastructure

Source: Data provided by Hydro One Networks Inc.

Copyright: Hydro One Networks Inc. [2016].

The alternatives to meet the transformation capacity need can be found in the Appendix B, and are summarized below. There are two main wires solutions that are suitable for addressing the need: 1. Build new feeders from existing stations, which have available capacity, followed by construction of a new step-down station, once the available capacity is utilized, or 2. Build a new step-down station near the load centre by 2019.

1. Build new 27.6 kV feeders from existing stations followed by a new 230 kV to 27.6 kV step-down station and associated 230 kV transmission line reinforcement at the proposed station sites.

Malvern TS and Sheppard TS already provide 27.6 kV supply to Veridian territory and also have a total of 85 MW of surplus 27.6 kV capacity available until the end of the study period. Combinations of building new feeders from these two stations to the Seaton load centre by 2019 were considered, followed by building a new step-down station and associated 230 kV transmission line reinforcement(see reference to three sites below) in order to meet the remaining capacity need.

2. Build a new 230 kV to 27.6 kV step-down transformer station near the Seaton load centre, with associated 230 kV transmission line reinforcement, by 2019. Three sites for the station are being considered within the EA.

Based on a net present value cost comparison, building a new station at Sites 1 or 2 was determined to be the most economic alternative, as shown below.

Table 7-1: Net Present Value of Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7 Build Seaton TS-1 or 2	60-68
8 Build Seaton TS-3 and associated feeders	94-108

Building a new step-down station at Sites 1 or 2 is the most cost-effective option[10] for meeting the 27.6 kV transformation capacity need in the sub-region. The EA, which is currently underway, will determine the preferred station site. The EA results are expected in Q1 2017.

Should Site 3 be selected through the EA process more detailed technical and economic analysis[11] is require to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

The detailed economic assumptions and methodology used to assess the options are detailed in Appendix B.

7.2 Alternatives for Meeting the Near-Term Restoration Need for the Region

The other major need identified in the area is the shortfall in meeting restoration timelines following the coincident loss of two transmission circuits to the GTA East Region. Although the IRRP is for the sub-region, the restoration analysis considers the entire GTA East Region, because the loss of two circuits impacts supply to the entire GTA East Region. This was acknowledged by the regional participants during the scoping phase of the regional planning process for the GTA East Region. The restoration analysis considers the loss of a pair of 230 kV circuit in the area, either H24/26C or M29/B23C, and the ability to restore load within the ORTAC prescribed timelines.

7.2.1 Conservation

Meeting restoration criteria requires that the faulted elements (line sections) be isolated, such that customer electrical demand can be restored from a reliable line section or an alternate source. Conservation is not a feasible option for addressing these types of needs.

7.2.2 Generation

Generation was ruled out as a feasible option to address restoration needs in the GTA East Region from both a technical and economic perspective, given the number of facilities that would be required and given the surplus generation capacity available in the province.

---

[10] See Appendix B for details on proposed station Site 3

[11] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

Approximately 93 MW of supply would be required today and 372 MW by 2025 in order to provide back-up in the event of a four hour outage on all four circuits.

Large generation is not a suitable option for addressing restoration needs because multiple facilities are needed in order to address loss of supply along the various line segments. Additionally, these facilities would need to have black start and islanded operation capabilities, a costly generation and system design feature.

Using smaller scale DG was also determined to be infeasible for the same technical and economic reasons as noted above. In order to provide restoration, each of these facilities would also have to be able to supply their local loads in islanded mode. Some high value loads (such as pumping and water purification facilities) are typically developed with onsite gas or diesel generation to ensure they can continue to operate during a power supply outage. While there is benefit to building this type of supply redundancy to ensure restoration capability for some loads, it is impractical on a larger scale to address regional restoration needs.

7.2.3 Transmission and Distribution

Since additional conservation and generation are not feasible options to meet the restoration shortfall, the Working Group considered transmission and distribution options. According to ORTAC[12], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". Additionally, these parties may also agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. A preliminary assessment was undertaken to determine high level costs and benefits of transmission and/or distribution options giving consideration to the factors outlined in ORTAC. In carrying out this assessment, the Working Group took into account that many jurisdictions justify costs of this nature by comparing the cost to customers of supply interruption for the low probability/high impact events to the cost of mitigation. These jurisdictions: 1. assess the probability of the failure event occurring; 2. estimate the expected magnitude and duration of outages to customers served by the supply lines; 3. monetize the cost of a supply interruption to the affected customers; and 4. determine the cost of solutions and their impact on supply interruptions to the affected customers. If the cost of meeting the

---

[12] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

security and restoration criteria exceeds the expected cost of customer supply interruptions, then it is not considered cost-justified.

The Working Group undertook a preliminary costs/benefit analysis (Appendix C) and concluded that there may be value in mitigating these restoration shortfalls. However a more detailed analysis is required to establish specific solutions and determine if these are cost justified. The GTA East regional participants recommended that this further restoration analysis and recommendations be conducted as part of the RIP to be led by Hydro One in collaboration with the affected LDCs and IESO.

7.3 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term transformation capacity need in the sub-region, and the restoration need identified for the GTA East Region. Successful implementation of this plan will address the region’s electricity needs until the end of the study period in year 2034.

1. Build a new 230/27.6 kV (75/125MVA) step-down station in 2018 and associated circuit upgrade to the new community of Seaton.
2. Undertake detailed restoration analysis and recommend next steps as part of the RIP for the GTA East Region.

7.4 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of the Pickering-Ajax-Whitby Sub-region are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near-term plan are outlined in Table 7-2, along with recommended timing for implementation.

The Pickering-Ajax-Whitby Sub-region Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the sub-region and to track progress.

Table 7-2: Summary of Needs and Associated Recommendations in the Pickering-Ajax-Whitby Sub-region

Area	Need	Recommendation	Implementation Date
North Pickering	Transformation Capacity	Build a new 230/27.6 kV (175/25MVA) step-down station in 2018 and associated circuit upgrade to provide supply by 2019 to the new community of Seaton.	Veridian and Hydro One to start work on implementing the station and line work as soon as possible
GTA East	Restoration	Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region.	Q3 2016

Veridian and Hydro One are pursuing a combined EA for the proposed station sites and related 230 kV line work. The assessment will determine the preferred site. It is expected to be completed by Q1 2017. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Veridian complete all work required for implementation of Seaton MTS as soon as possible.

The RIP should be initiated for the GTA East Region upon completion of the IRRP.

The IESO has committed to working with the affected parties to assist with any approval requirements associated with this IRRP.

8. Long-Term Plan

Given the uncertainty in forecasting demand beyond a 10-year timeline, the purpose of the long-term plan is to consider alternate potential demand scenarios in order to facilitate discussions about how the sub-region may need to plan its future electricity supply and to lay the groundwork for the next regional planning cycle. This section describes potential long-term needs, approaches to addressing these needs, and recommended actions.

With the implementation of the proposed new step-down station in North Pickering, the local electricity infrastructure is expected to be capable of reliably supplying the forecast growth in the sub-region over the next two decades. As a result, longer term planning initiatives will focus on monitoring developments associated with factors that could affect longer term electrical service plans for this area. This includes monitoring progress on conservation efforts at the transformer station level.

One of the potential longer term needs identified through discussion with area LDCs is growth in electrical demand exceeding the capacity of existing transmission and distribution infrastructure serving the established areas of Pickering-Ajax-Whitby, including in the lakeshore area. Reviews and updates of Official Plans in this sub-region are expected in the near future. Similar to past Official Plans[13] for the City of Pickering, the lakeshore area is expected to continue to experience intensification through development of high rise multi-unit residential and commercial buildings. Given that this area is south of a major highway-the 401 and approximately 5 km from Cherrywood TS and more than 10 km from Whitby TS, this intensification could drive the need for a new step-down transformer station closer to future growth areas. This new step-down transformer station could be supplied by the transmission lines currently dedicated to delivering bulk power from Pickering GS. When the generation facilities at Pickering GS begin retiring and plans for the site become clearer over the next few years, these transmission lines could be repurposed and used to reliably supply longer term local development.

The provincial growth plan is under review and is expected in late 2016. The plan is expected to consider growth scenarios up to the year 2040. Municipal reviews of growth plans including that of Pickering, Ajax and Whitby will follow the release of the provincial plan and potentially have an impact on the longer term electrical supply for this sub-region. Other initiatives that

[13] https://www.pickering.ca/en/cityhall/resources/op6.pdf

could impact future electricity use are the City of Pickering's corporate energy management plan, the Town of Whitby's sustainability plan and the renewable energy and energy conservation policies in the Town of Ajax Official Plan. Additionally, the upcoming Durham Region Community and Municipal Energy Plans and the projects and initiatives identified by the GTA East Local Advisory Committee could also impact future electricity use. These initiatives will be monitored over the long term (see Section 9).

On a regional and provincial basis, the province's new climate change action plan and the new LTEP is expected to have a significant electrical demand impact through encouraging the electrification of customer end uses and transportation. For instance, the new rail maintenance facility in Whitby is expected to require an incremental demand of 30 MW by 2018 from the regional supply. Such demand requirements are expected to be more frequent in the future as regional transit continues to expand and electrify.

Switching from carbon based fuel sources to electricity to meet provincial or municipal environmental goals are also a factor that could impact the capacity of the existing transmission and distribution systems servicing these developed areas in the longer term.

Monitoring of growth in electricity demand and the achievement of conservation and DG targets in the sub-region will be the key components of ongoing electricity planning in this sub-region and the supply situation will be reviewed in subsequent regional planning studies.

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date for the Pickering-Ajax-Whitby IRRP and those that will continue to take place to discuss the medium and long-term priorities and initiatives identified by the Local Advisory Committee ("LAC" or "Committee").

A phased community engagement approach was undertaken for the Pickering-Ajax-Whitby IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Pickering-Ajax-Whitby Sub-region IRRP Community Engagement Process

Creating Transparency: *Creation of GTA East IRRP Information Resources*	• Dedicated GTA East Region IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One website • Self-subscription service established for GTA East for subscribers to receive regional specific updates • Status: complete
Engaging Early and Often: *Municipal & First Nation Outreach*	• Individual meetings and discussions about the Pickering-Ajax-Whitby IRRP with the City of Pickering, Towns of Ajax and Whitby, and Region of Durham (September 2015) • Information provided to First Nation communities (April 2015, September 2015) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: *Broader Community Outreach*	• GTA East Region LAC formed in winter 2016; dedicated GTA East engagement page added to IESO website • Two LAC meetings held focused on introducing the regional planning process and initiating a discussion of the medium- and long-term priorities in the area • LAC meetings are open to the public and materials are posted to the GTA East engagement webpage • Status: begun in winter 2016; on-going

Creating Transparency

To start the dialogue on the Pickering-Ajax-Whitby IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page[14] was created on the IESO website including a map of the regional planning area,

[14] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/GTA-East/default.aspx

information on why an IRRP was being developed for the Pickering-Ajax-Whitby Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the GTA East planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the GTA East Region IRRP was to provide information to the municipalities and First Nation communities in the planning area.

In September 2015 individual meetings were held with municipal representatives from the City of Pickering, Towns of Ajax and Whitby and Region of Durham. Key topics of discussion included growth trends, discussion of the near-term needs in the sub-region, a review of the identified near-term projects including those that have already begun due to timing requirements, and a discussion of the possible approaches that can be used to address medium- and long-term needs in regional planning. The regional plan was also discussed in the context of the bulk electricity system in the area, more specifically the upcoming closure of the Pickering Nuclear Generating Station ("NGS") , the refurbishment of the Darlington NGS and the construction of the Clarington TS. The presentations and information were well received and formed the foundation for the broader engagement in the development of the Pickering-Ajax-Whitby Sub-region IRRP.

The IESO continues to work with First Nation communities to arrange a joint information session with all Williams Treaty communities and to jointly develop a plan for their engagement in this and other IRRPs moving forward. It is expected that the session will be held in the summer of 2016.

Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the GTA East Region in winter 2016. The role of a LAC is to provide advice on the development of the regional plan as well as to provide input on broader community engagement. LACs are generally comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's GTA East engagement web page[15].

---

[15] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/GTA-East/default.aspx

Development of the GTA East LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across Durham Region; localized digital advertising on The Weather Network for a two-week period and promotions through facebook and Twitter; emails sent to municipal representatives across GTA East Region; an e-blast sent to the IESO's GTA East subscribers list which includes over 700 subscribers; and inclusion of the call for nominations in the IESO's weekly Information Bulletin.

Two meetings of the GTA East LAC were held on March 10 and May 4, 2016. At the first LAC meeting, an overview of the regional planning process was presented to the Committee, along with information on the bulk level planning in the area. The Committee was also provided information on the two near-term needs in the Pickering-Ajax-Whitby Sub-region, these being: capacity needs in North Pickering and restoration needs across the entire GTA East Region. Due to the timing of the capacity needs, the Committee was informed that Veridian and Hydro One had already begun the EA process for a new TS and upgraded line in order for these critical pieces of infrastructure to be in-service by their need date of 2019. For the restoration needs, the Committee was presented with an overview of this need and promised additional information at the second LAC meeting once the Working Group undertook additional analysis.

The second meeting of the LAC included an update on the restoration work undertaken by the Working Group and a brainstorming session about the medium- and long-term priorities. For the restoration work, Committee members were informed that, due to the complexity of the required analysis, a Hydro One-led RIP subsequent to the completion of the IRRP will further develop the restoration analysis. For the medium- and long-term priorities, several questions were also posed to the Committee members to generate a group discussion on long-term growth projections and community priorities for inclusion in the plan. This meeting was followed by a two-week comment period for LAC members to provide additional information to inform the long-term portion of the plan. A summary of this discussion and feedback can be found in Appendix D along with the meeting summaries from the GTA East LAC meetings.

Moving forward, engagement will continue on both the near-term projects and the IRRP. For the transformer station and replacement line to meet near-term needs in north Pickering, Veridian and Hydro One will undertake engagement as part of the EA process. For the Pickering-Ajax-Whitby IRRP, the GTA East LAC will be provided with a presentation of the final plan and if requested by LAC members an additional LAC meeting will be held in the fall of 2016 to discuss next steps in the continued development of the long-term priorities.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website[16]. Additional information on outreach activities for the Pickering-Ajax-Whitby IRRP can be found on the GTA East webpage and updates will continue to be sent to all GTA East subscribers.

[16] http://www.ieso.ca/Pages/Participate/Regional-Planning/default.aspx

10. Conclusion

This report documents the IRRP that has been carried out for Pickering-Ajax-Whitby Sub-region. The IRRP identifies electricity needs in the sub-region over the 20-year period from 2015 to 2034, recommends a plan to address near-term needs and identifies actions to monitor long-term developments.

The step-down station solution recommended to meet the near-term need for 27.6 kV transformation capacity in the sub-region is already underway. Veridian and Hydro One have submitted a combined application for an EA of proposed station sites and related 230 kV line work. Results of the EA that is currently underway will determine the preferred station site and are expected in Q1 2017.

In order to further study and analyze the restoration needs and determine a preferred solution it is recommended that a RIP be initiated for the GTA East Region. The RIP is to be led by Hydro One Transmission, and include Veridian, Whitby Hydro, Oshawa PUC, Hydro One Distribution and IESO as Working Group members. It is recommended that this RIP be initiated after the completion of the PAW IRRP in June 2016, with RIP study completion in Q1 2017.

In the longer term, the Pickering-Ajax-Whitby Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will monitor developments focused on the factors described in the long-term section above that could impact electricity infrastructure, along with progress on conservation efforts and DG uptake at the transformer station level.

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

LOCAL PLANNING REPORT

WILSON TS AND THORNTON TS STATION CAPACITY MITIGATION

Region: GTA East
Sub-Region: Oshawa-Clarington

Revision: Final
Date: May 15, 2015

Prepared by: Oshawa-Clarington Sub-Region Local Planning Study Team

GTA East Region Local Planning Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Sachna Bobal Ajay Garg
Veridian Connections Inc.	Craig Smith
Oshawa PUC Networks Inc.	Denise Flores / Jayesh Shah
Whitby Hydro Electric Corporation	Kevin Whitehead
Hydro One Networks Inc. (Distribution)	Charlie Lee

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 GTA East 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	GTA East Region (the "Region") – Oshawa-Clarington Sub-Region		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 7, 2014	**END DATE**	May 15, 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 GTA 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".

For needs that were identified as requiring further regional planning and coordination, the IESO undertook a Scoping Assessment (SA) 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 were required. Currently, an IRRP is underway to address the following needs: Cherrywood TS T7/T8 station capacity and SC restriction, Whitby TS T1/T2 (27.6 kV Supply) station capacity, and load restoration for the loss of two elements.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Local needs addressed in this report include the following:

- Wilson TS T1/T2 Station Capacity
- Wilson TS T3/T4 Station Capacity
- Thornton TS T3/T4 Station Capacity
- Thornton TS Feeder Capability Utilization

3. OPTIONS CONSIDERED

Prior to the new regional planning process coming into effect, planning activities and interim temporary solution discussions were already underway in the Region to address immediate specific station capacity needs. To address the Wilson TS and Thornton TS station capacity needs, the study team agreed to proceed with the preferred solution identified as follows:

- Add a new 230/44 kV DESN, (previously called "Enfield TS"), at the Oshawa Area Junction site with supply from the two 230 kV Clarington TS busses.

The study team also evaluated options for different transformer sizes and initial number of feeder breaker positions for the proposed new TS.

See Section 3 for further detail.

4. PREFERRED SOLUTION

Based on the load forecast provided by the LDCs, the study team agreed and recommends that the preferred solution is to build a new TS at the Clarington TS site located at Oshawa Area Junction. This will include 2 x 75/125 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions (space to be provided for future 2 x 44 kV feeder positions and static capacitor banks).

See Section 4 for further detail.

5. NEXT STEPS

The next steps are summarized in Table 2.

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1 INTRODUCTION

The Needs Assessment (NA) for the GTA East Region ("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. This Region was subsequently expedited at the request of the affected Local Distribution Companies (LDC) and reprioritized from Group 2 to Group 1. The NA for the GTA East Region was prepared jointly by the study team, including LDCs, 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 GTA East 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 GTA East Region LP study team (Table 1) and led by the transmitter, Hydro One Networks Inc. ("HONI"). The report captures the results of the assessment based on information provided by LDCs and HONI.

Table 1: Study Team Participants for GTA East Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
4.	Veridian Connections Inc. ("Veridian")
5.	Oshawa Power and Utilities Corporation Networks Inc. ("OPUCN")
6.	Whitby Hydro Electric Corporation ("Whitby Hydro")
7.	Hydro One Networks Inc. (Distribution)

1.1 Oshawa-Clarington Sub-Region Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area. For the purposes of this Local Planning report, the region can be divided into two sub-regions: Pickering-Ajax-Whitby and Oshawa-Clarington. This Local Planning report covers the sub-region of Oshawa-Clarington, which includes the area served by Thornton TS and Wilson TS. The GTA East Region and its approximate sub-region boundaries are shown in Figure 1.

Source: IESO

Figure 1: GTA East Region and Approximate Sub-Region Boundaries

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Oshawa-Clarington sub-region. Wilson TS is supplied by B23C and M29C and Thornton TS is supplied by H24C and H26C.

It should be noted that a new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is being developed and is expected to be in-service in 2017. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 2.

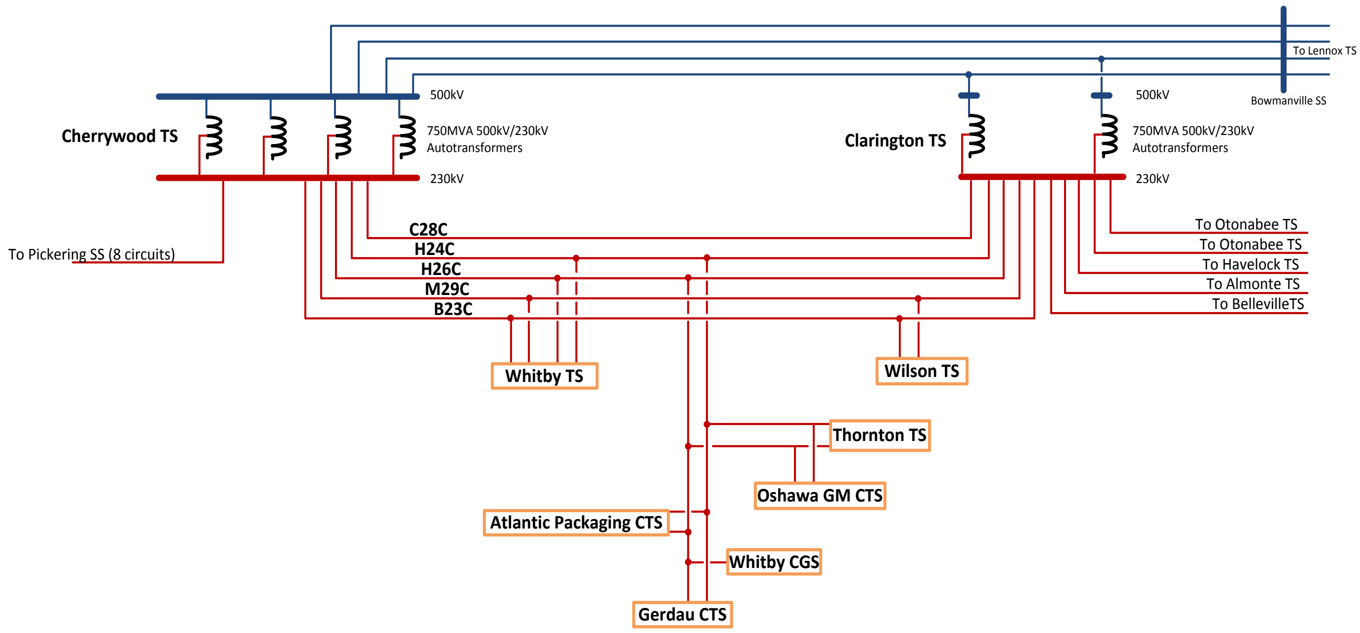


Figure 2: Single Line Diagram – GTA East Region with Clarington TS

2 GTA EAST REGION NEEDS

As an outcome of the NA process, the study team identified several needs in the GTA East Region that require further assessment and planning. The study team recommended that some of the near-term needs required "localized" wires only planning, while others required coordinated regional planning.

Where local planning was recommended to address the needs, Hydro One, as transmitter, with the impacted LDCs, further undertook planning assessments to develop options and recommend a wires only solution(s). For needs that required further regional planning and coordination, the IESO undertook a Scoping Assessment 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 were required.

2.1 Needs Assessed by IESO led Scoping Assessment – Pickering-Ajax-Whitby Sub-Region

The SA reviewed the following needs and determined that they should be addressed by an IRRP, led by the IESO:

2.1.1 Cherrywood TS (230/44 kV)

i. Station Capacity T7/T8: Based on the planned conservation and demand management (CDM) targets, the station capacity is adequate to meet the net demand over the study period, except for years 2014 and 2015. The years 2014 and 2015 may have slight overloads until the planned CDM initiatives offset the expected load.

ii. Short Circuit (SC) Constraint T7/T8: Currently, new distributed generation (DG) is restricted from connecting to Cherrywood TS T7/T8 due to short circuit constraints. Veridian Connections Inc. is supplied by this station and indicated that they have several customers that have expressed interest in connecting DG (over 5MW to date) to Cherrywood TS T7/T8, but have been unable to due to the existing SC restriction. It is worth noting that there is an existing 30 MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the SC restriction, but has been shut down for the past year.

➢ **Action:** As per the study team's recommendation, the station capacity need and SC restriction at Cherrywood TS T7/T8 is being further assessed by the IRRP study team led by the IESO.

2.1.2 Whitby TS T1/T2 (230/44/27.6 kV)

Station Capacity T1/T2 (27.6 kV): The station capacity is expected to be adequate to meet the net demand up to 2019. The existing stations in the area are not able to supply the entire projected new load. Hydro One and Veridian assessed the station capacity requirements and have discussed plans for a proposed new 230/27.6 kV station called "Seaton TS".

➢ **Action:** As per the study team's recommendation, the station capacity need at Whitby TS T1/T2 (27.6kV supply) is being further assessed by the IRRP study team to assess if CDM/Resource solutions can economically defer the wires investment. Accordingly, the study team will determine and recommend the timing for this new 230/27.6 kV station.

Note that the 230/44 kV supply capacity of Whitby TS T1/T2 and Whitby TS T3/T4 is expected to be adequate during the study period. However, Whitby TS T3/T4 is forecasted to be greater than 90% of the Summer 10-Day LTR from 2015 to the end of the study period. No action is required at this time and the capacity need will be reviewed in the next regional planning cycle.

2.1.3 Load Restoration for the Loss of Two Elements

i. The IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) require loads of 150 MW or more to be restored in 4 hours and 250 MW or more in 30 minutes. For the loss of two elements, the load interrupted by configuration in the GTA East Region may exceed 150 MW and 250 MW.

- **Action:** As per the study team's recommendation, load restoration for the loss of two elements is being further assessed by the IRRP study team.

2.2 Needs Assessed by Hydro One led Local Planning – Oshawa-Clarington Sub-Region

2.2.1 Wilson TS (230/44kV)

i. Station Capacity T1/T2: Wilson TS T1/T2 DESN1 is forecast to exceed its normal supply capacity in 2017 based on the net demand forecast. Transformation capacity relief is needed.

ii. Station Capacity T3/T4: Wilson TS T3/T4 DESN2 is forecast to exceed its normal supply capacity in 2015 based on the net demand forecast. Transformation capacity relief is needed. In the past, overloading at this DESN under certain conditions was significant enough that plans were put in place for emergency rotating load shedding, if and when required.

2.2.2 Thornton TS (230/44kV)

i. Station Capacity T3/T4: Thornton TS T3/T4 is forecast to exceed its normal supply capacity in 2015 based on the net demand forecast. Transformation capacity relief is needed.

ii. Feeder Capability Utilization: OPUCN indicated during the NA process that their four feeders at Thornton TS will exceed their maximum capability by 2015 based on their gross demand forecast. As a result, the study team recommended that feeder capability utilization at Thornton TS required review by the LDCs to ensure the efficient and cost effective use of available feeder capability.

3 OPTIONS CONSIDERED

This section describes the options considered to address the local needs described in section 2.2.

3.1 **Wilson TS and Thornton TS Station Capacity Needs** [refer to sections 2.2.1 (i), (ii) and 2.2.2 (i)]

Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address specific station capacity needs. Prior to 2010, Hydro One and impacted LDCs were in discussions and developing plans for a proposed new 230/44 kV DESN station that would provide transformation capacity relief to Wilson TS. The proposed station would accommodate the anticipated load growth at the time in Oshawa and Clarington and improve reliability of electricity supply to customers in these areas. As part of the planning process, different options were evaluated and a Class Environmental Assessment for Minor Transmission Facilities ("Class EA") was undertaken. It was determined that the preferred site for the new DESN (called "Enfield TS") would be Oshawa Area Junction. The anticipated load was not materializing to support construction at the time and as a result this plan was put on hold.

Following this and in the past few years, load growth has emerged again in the region. To help manage OPUCN's and Whitby Hydro's load growth and respect 10-Day LTRs at Wilson TS T1/T2 and Whitby TS T3/T4 (during summer peak load conditions), load transfers to Thornton TS were required and the associated distribution investments were made by impacted LDCs. At the time, OPUCN planned to utilize available feeder capability of Hydro One Distribution's (HOD) feeders at Thornton TS where Whitby Hydro is embedded. However, Whitby Hydro was also later required to transfer load from Whitby TS T3/T4 to Thornton TS in order to respect the 10-Day LTR at Whitby TS T3/T4. Currently, the most recent load forecast from LDCs show significant load growth at Thornton TS in the near term, particularly to supply the anticipated load of Metrolinx. Based on the load transfer and updated load forecast for Thornton TS, available feeder capability of HOD's feeders has reduced and consequently OPUCN has limited their load transfer to Thornton TS (see section 3.3 on Thornton TS T3/T4 Feeder Capability Utilization).

As per the current load forecast provided by the study team, transformation capacity relief is needed for both Wilson TS and Thornton TS. To accommodate the load growth of OPUCN and HOD at Wilson TS and Thornton TS, the study team agreed to proceed with the preferred solution identified previously, Enfield TS, with the exception that the current plan supplies the proposed new DESN from Clarington TS as follows:

- Build a new 230/44 kV DESN (name to be determined) at the Clarington TS site located at Oshawa Area Junction, with supply from the two 230 kV Clarington TS busses.

The study team re-emphasized some of the benefits to the preferred option which include:

- Land already acquired at Oshawa Area Junction, where the new TS is proposed to be sited (on a location on the west side of the Clarington TS property). Any location much further east or west to Oshawa Area Junction would adversely affect one or the other LDCs by having to construct longer distribution feeders.

- EA approval previously obtained for building a new TS on Hydro One lands at the Clarington TS site.

The study team also recognized and agreed that, where possible, distribution load transfers to help balance the forecasted load at Wilson TS and Thornton TS would be required in the interim prior to the proposed TS coming into service. However, this would be temporary and unsustainable solution.

3.2 Feasibility Study Results and Budgetary Cost Estimates for Proposed TS

The study team recommended that the following transformer options for the proposed new TS be compared:

a) 2 x 50/83 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions

b) 2 x 75/125 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions (space to be provided for future 2 x 44 kV feeder positions)

c) 2 x 75/125 MVA, 230/44 kV transformers with 8 x 44kV feeder breaker positions

The preliminary cost estimates for the above options are: $19 million, $23 million, and $27 million for options (a), (b), and (c) respectively (note that this cost does not include the cost for capacitor banks, which may be required if identified in the System Impact Assessment by the IESO).

As per the preliminary estimates, option (a) is not materially less than option (b). If a longer term 25-year forecast is considered for the proposed new station, it will require upgrading the 50/83 MVA transformers (which have an assumed Summer 10-Day LTR of 113 MVA) to 75/125 MVA transformers around 2025 based on the current load forecast. The study team agreed that the typical cost to replace 50/83 MVA transformers with 75/125 MVA transformers would not be cost effective as compared to installing 75/125 MVA transformers initially.

3.3 Thornton TS T3/T4 Feeder Capability Utilization [refer to section 2.2.2 (ii)]

Thornton TS T3/T4 is a 230/44 kV DESN which supplies OPUCN and HOD. This station consists of eight feeders, four of which are owned by OPUCN and the remaining four by HOD. HOD's four feeders solely supply Whitby Hydro's load (embedded customer of HOD).

OPUCN indicated that their four feeders at Thornton TS will exceed their maximum capability for normal operations by 2015 based on their gross demand forecast. HOD's feeders, however, will be adequate to meet Whitby Hydro's gross demand forecast and will also have available feeder capability remaining on their four feeders up to 2023.

The study team considered the following options to address OPUCN's need for additional feeder capability:

A. OPUCN, HOD, and Whitby Hydro to carry out a distribution planning assessment and develop an implementation plan to manage effective and efficient utilization of feeder capability at Thornton TS under both normal and emergency conditions.

B. Add additional feeder breaker positions at Thornton TS.

Option B was rejected for the following reason:

- The station already consists of eight feeders and TS capacity cannot accommodate any additional feeder breaker positions.

  Note: Consistent with the Transmission System Code (TSC) and OEB's regional planning objectives to ensure cost effective and efficient wires expansion without duplication of facility investments, existing feeder capability should be efficiently utilized before investing in new feeders. It should also be noted that as per the TSC transmission facility capacity, if available, cannot be reserved for connecting customers.

4 PREFERRED SOLUTION

4.1 Wilson TS and Thornton TS Station Capacity Needs [refer to section 3.1]

Given the forecasted load growth in the Oshawa-Clarington sub-region, the study team determined that the preferred solution to address this need would be to proceed with option (b): 2 x 75/125 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions initially (space to be provided for future 2 x 44 kV feeder positions). This will ensure reliable supply capability for OPUCN and HOD for the medium-to-long term and is a cost effective solution.

The proposed station will be located at the Oshawa Area Junction property (on the right of way of the Bowmanville x Cherrywood transmission line corridor) that HONI owns in the municipality of Clarington. This property is also the site of the new 500/230 kV autotransformer station called "Clarington TS" that will be supplied from 500kV circuits, B540C and B543C. EA approval was previously obtained for building a new TS at the Oshawa Area Junction site on a location on the west side of the property. The new TS will be supplied from the two 230 kV Clarington TS busses. It will consist of 2 x 75/125MVA, 230/44kV transformers with 6 x 44kV feeder breaker positions. Space will be provided for future 2 x 44 kV feeder positions and static capacitor banks.

The proposed in-service date for the new TS will be aligned with the Clarington TS in-service date, currently scheduled for 2017/18.

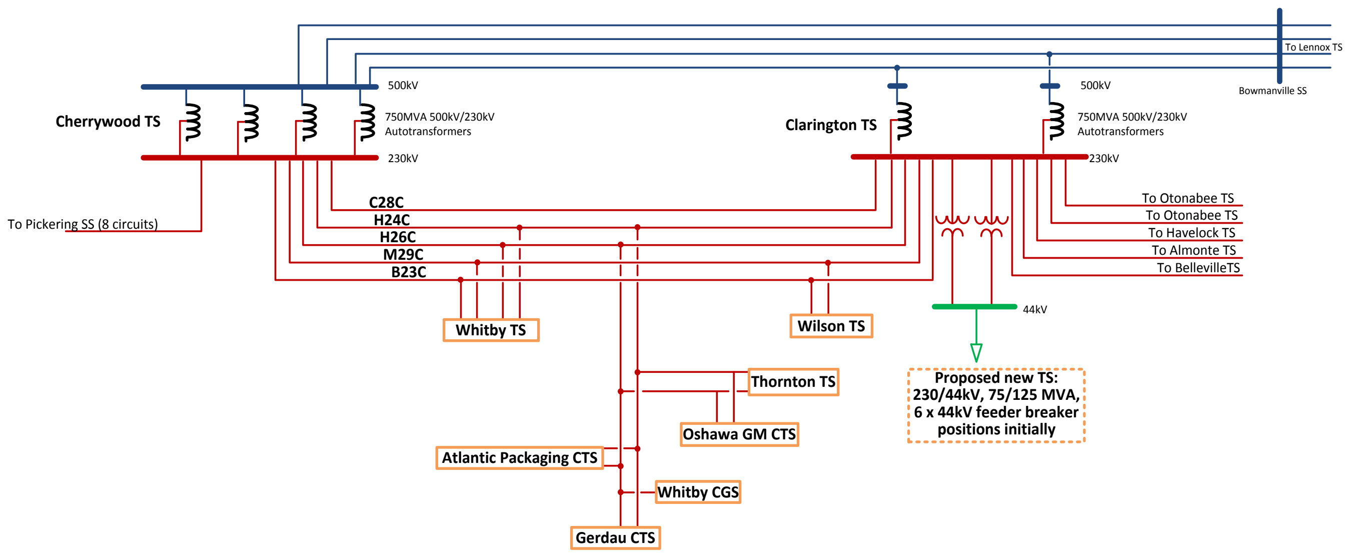


Figure 3: Single Line Diagram – GTA East Region with Proposed New TS

5 NEXT STEPS

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

Table 2: Solutions and Timeframe

Item #	Need	Action / Recommended Solution	Lead Responsibility	Timeframe
1	Wilson TS T1/T2 Station Capacity [Refer to Section 2.2.1 (i)]	• Proposed new 230/44 kV, 75/125 MVA station. This solution will be executed through Hydro One's Transmission Load Connection Process. HOD and OPCUN to initiate the process by contacting Hydro One's Account Executive (AE). • LDCs to assess and confirm if load transfers can partially mitigate forecasted overloading and provide timeline to implement required load transfers.	Affected LDCs and HONI OPUCN, HOD	To be determined (TBD) by LDCs June 2015
2	Wilson TS T3/T4 Station Capacity [Refer to Section 2.2.1 (ii)]	• Proposed new 230/44 kV, 75/125 MVA station. This solution will be executed through Hydro One's Transmission Load Connection Process. HOD and OPCUN to initiate the process by contacting Hydro One's AE. • LDCs to assess and confirm if load transfers can partially mitigate forecasted overloading and provide timeline to implement required load transfers.	Affected LDCs and HONI OPUCN, HOD	TBD by LDCs June 2015

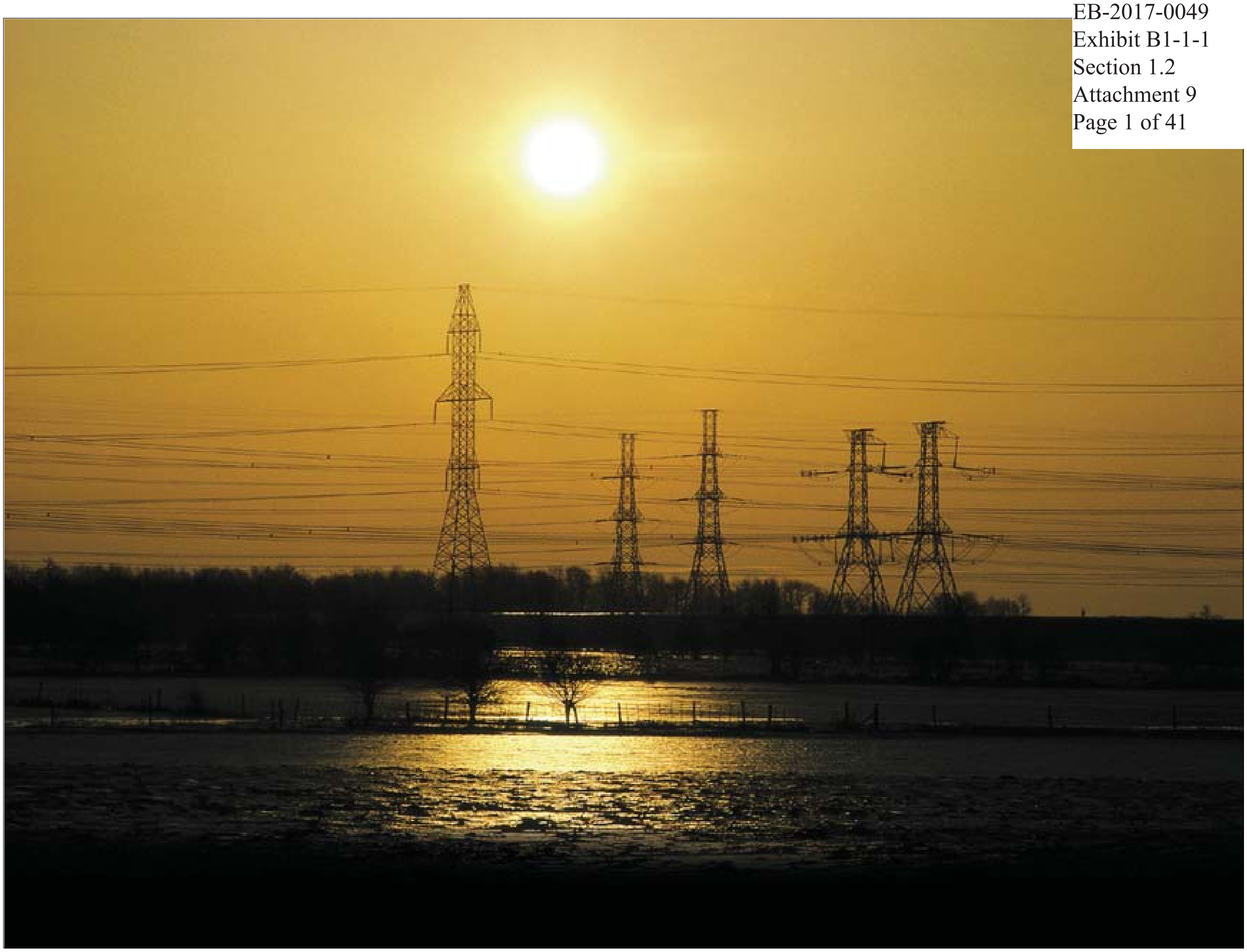
4	Thornton TS T3/T4 Station Capacity [Refer to Section 2.2.2 (i)]	• Proposed new 230/44 kV, 75/125 MVA station. This solution will be executed through Hydro One's Transmission Load Connection Process. HOD and OPCUN to initiate the process by contacting Hydro One's AE. • LDCs to assess and confirm if load transfers can partially mitigate forecasted overloading and provide timeline to implement required load transfers.	Affected LDCs and HONI OPUCN, Whitby Hydro	TBD by LDCs June 2015
7	Thornton TS Feeder Capability Utilization [Refer to Section 2.2.2 (ii)]	• LDCs distribution planning.	OPUCN, HOD, and Whitby Hydro	TBD by LDCs

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) GTA East Region Needs Assessment Report
iv) GTA East Region Scoping Assessment Report

7 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



GTA North

Regional Infrastructure Plan

February 5, 2016

[This page is intentionally left blank.]

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

With support from:

Company
Enersource Hydro Mississauga Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Newmarket-Tay Power Distribution Ltd.
PowerStream Inc.
Toronto Hydro Electric System Ltd.

[This page is intentionally left blank.]

DISCLAIMER

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

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

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

EXECUTIVE SUMMARY

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

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

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB’s mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region’s Integrated Regional Resource Planning (“IRRP”) by the IESO in April 2015 and the Western Sub-Region’s Needs Assessment (“NA”) Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

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

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream’s station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Enersource Hydro Mississauga Inc. ("Enersource"), Hydro One Brampton Networks Inc. ("Hydro One Brampton"), Hydro One Distribution, Newmarket-Tay Power Distribution Ltd. ("NTPDL"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("THESL"), and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, fifteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

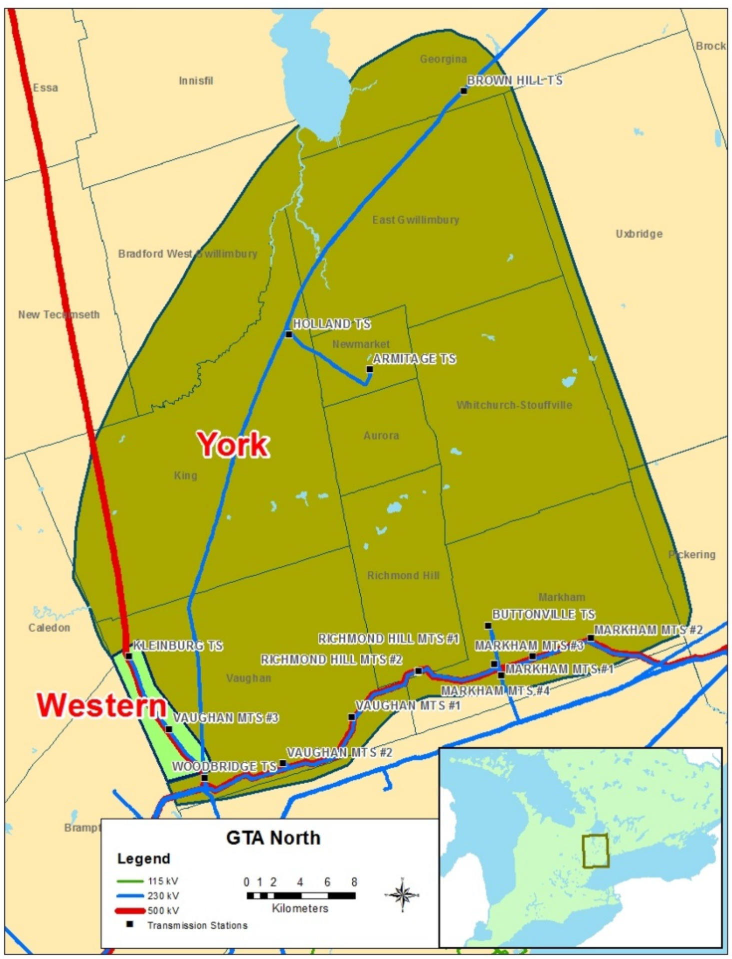


Figure 1-1 GTA North Region

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

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

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

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

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

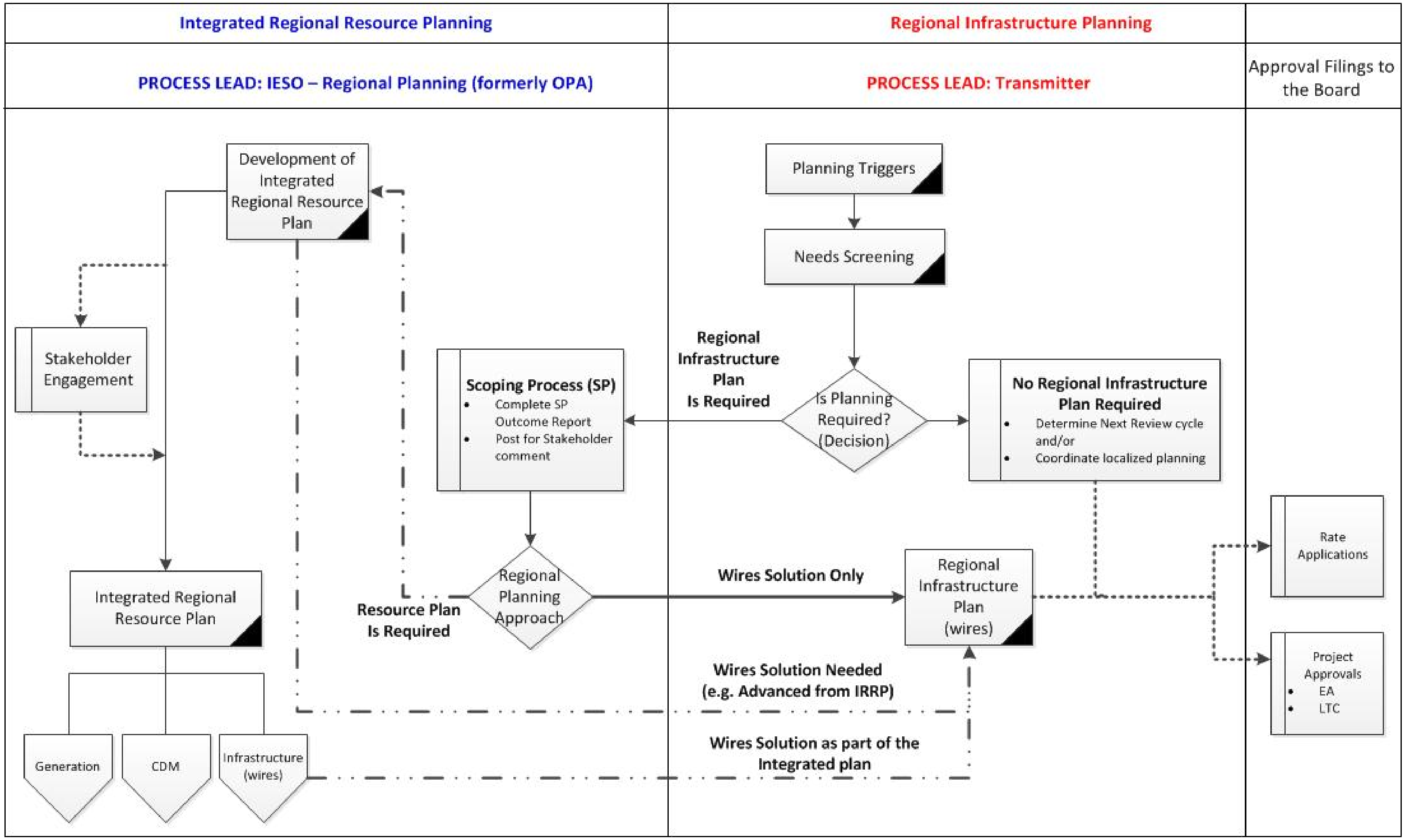


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any DG or CDM programs.
   - Existing area network and capabilities including any bulk system power flow assumptions; and,
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

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

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

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

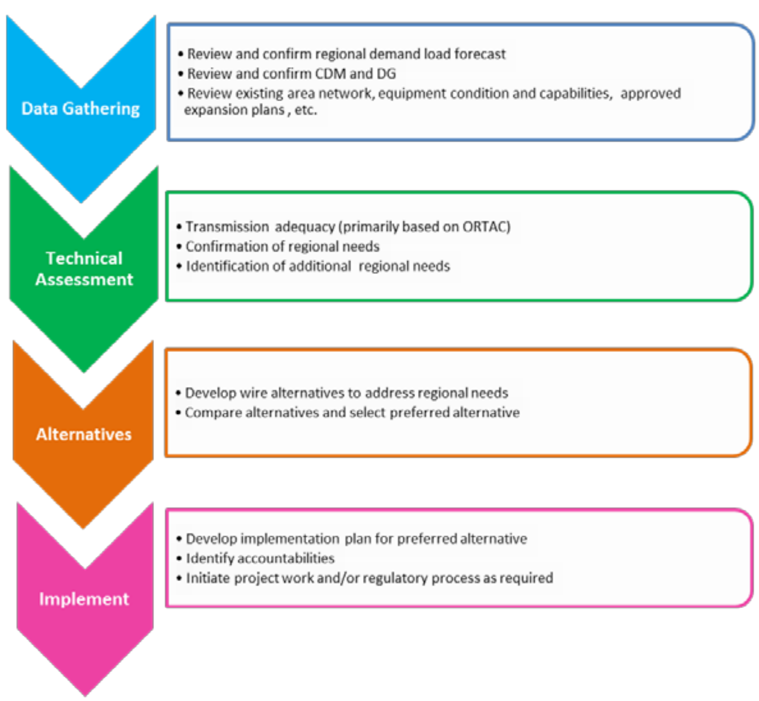


Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan ("IRRP"), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region's electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is PowerStream.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the “Kleinburg tap”) that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.

During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

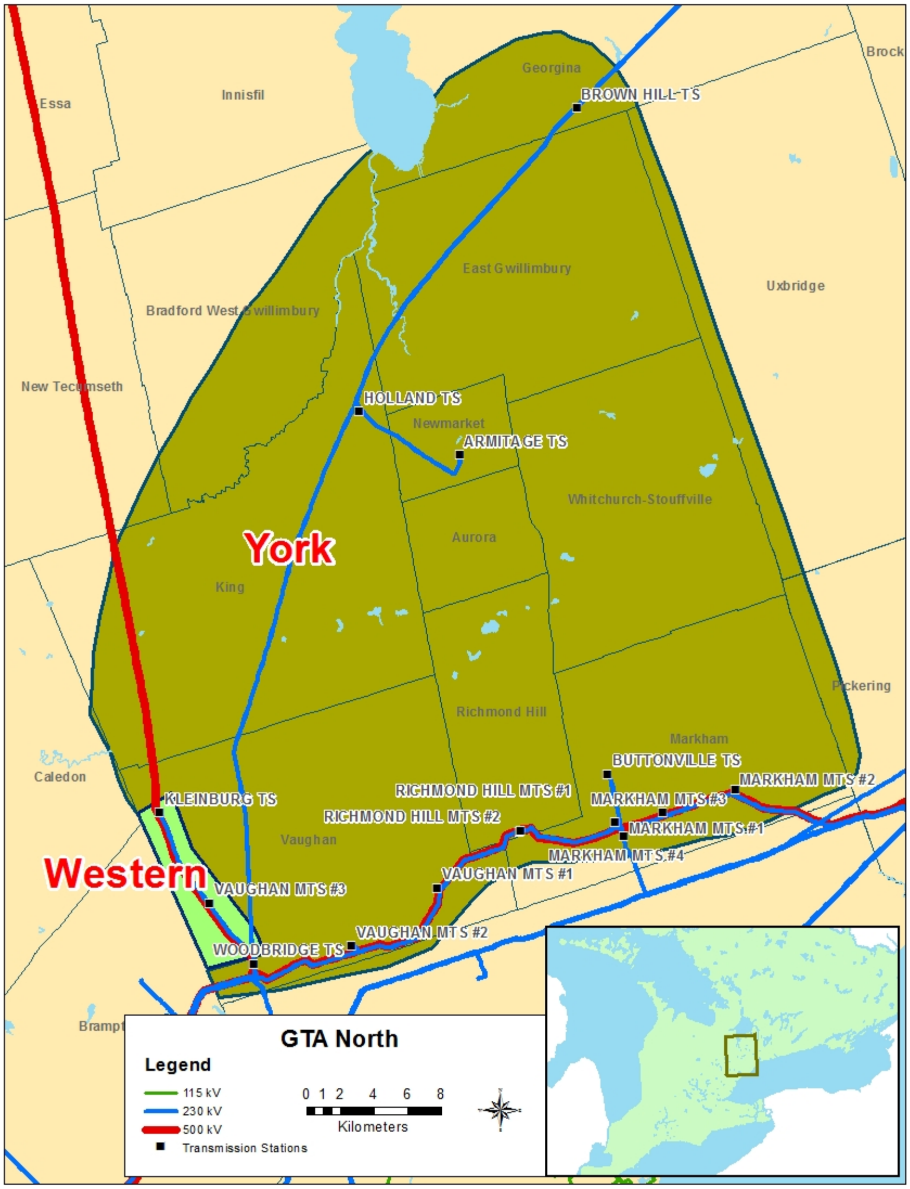


Figure 3-1 GTA North Region – Supply Areas

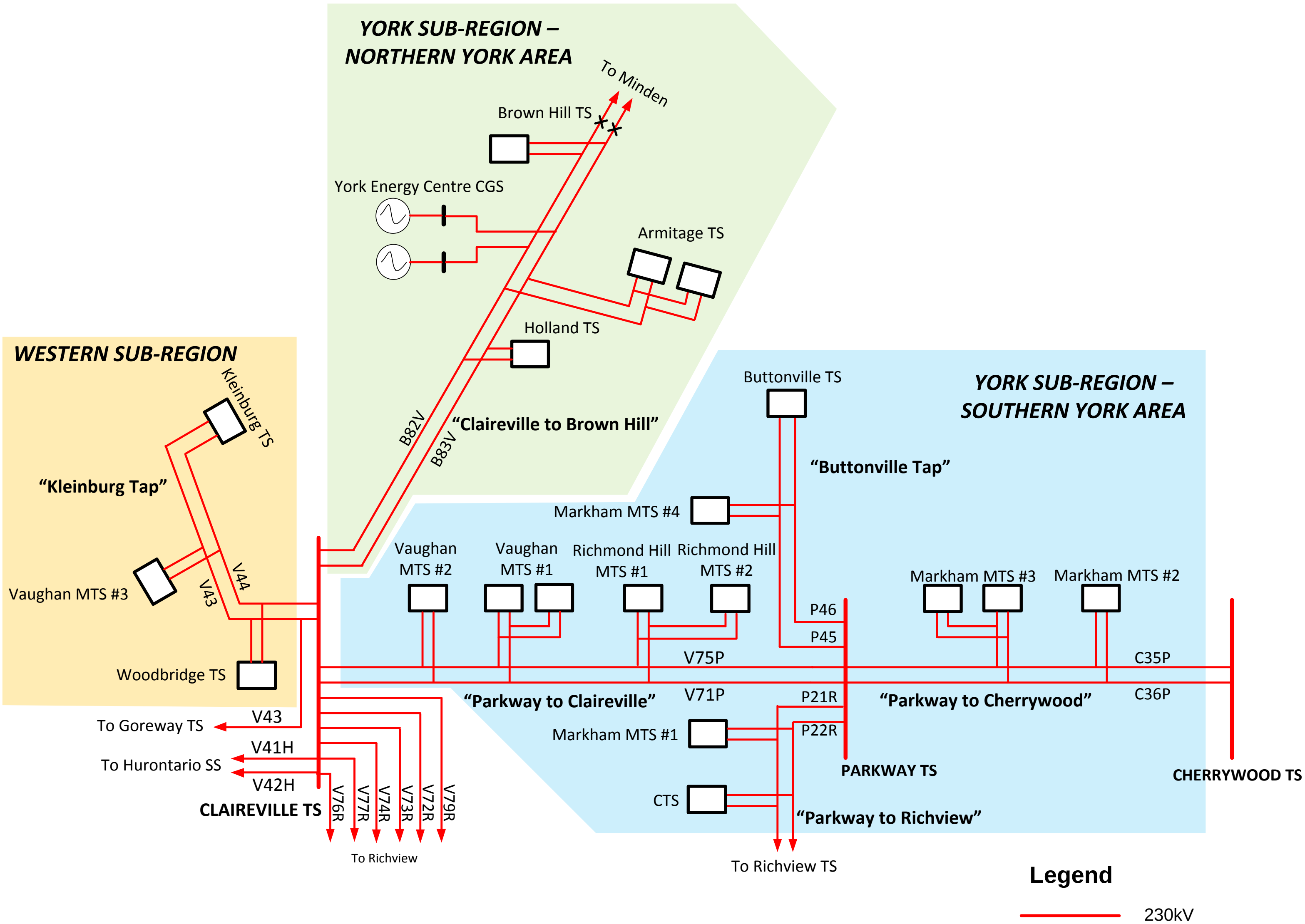


Figure 3-2 GTA North Transmission Single Line Diagram

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

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

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

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.
- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North
- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area
- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.
- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.
- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

The following development projects are currently underway:

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the York Sub-Region.

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast. The coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

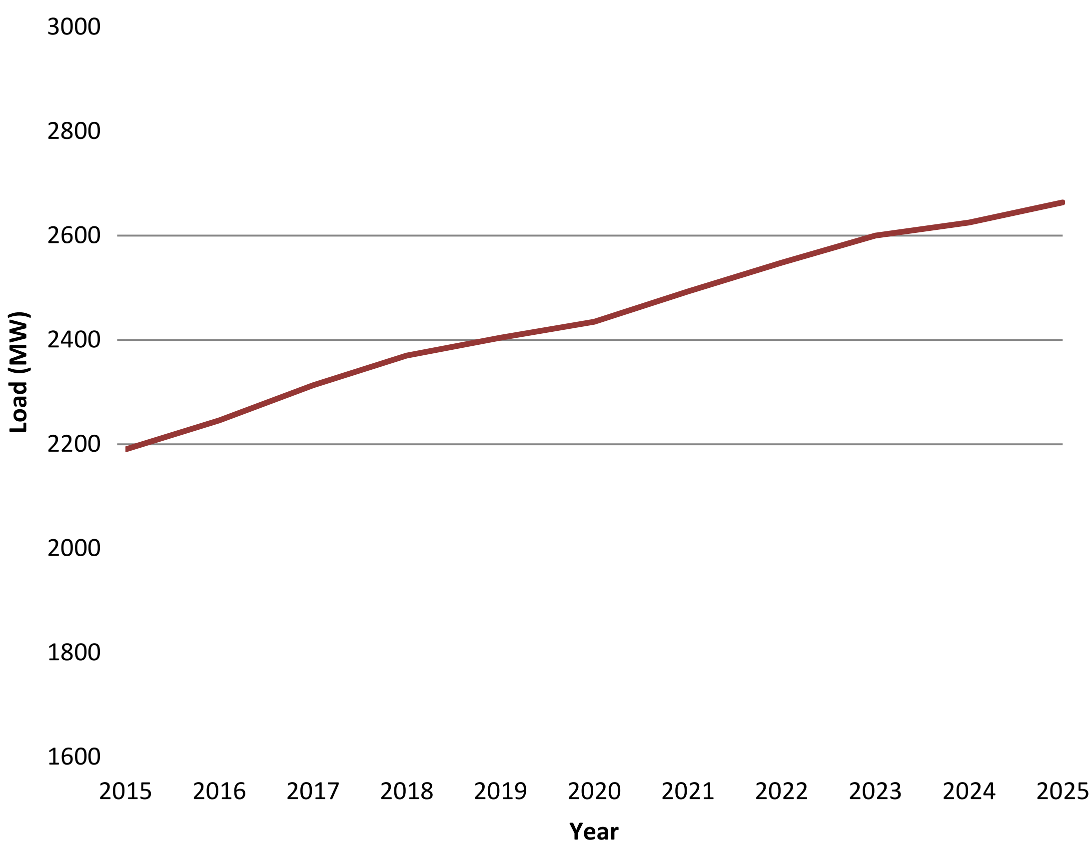


Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

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

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

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS ("Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS#1*	Markham MTS#2*
Markham MTS#3*	Markham MTS#4*	Richmond Hill MTS*
Vaughan MTS#1*	Vaughan MTS#2*	Industrial Customer

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP

** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

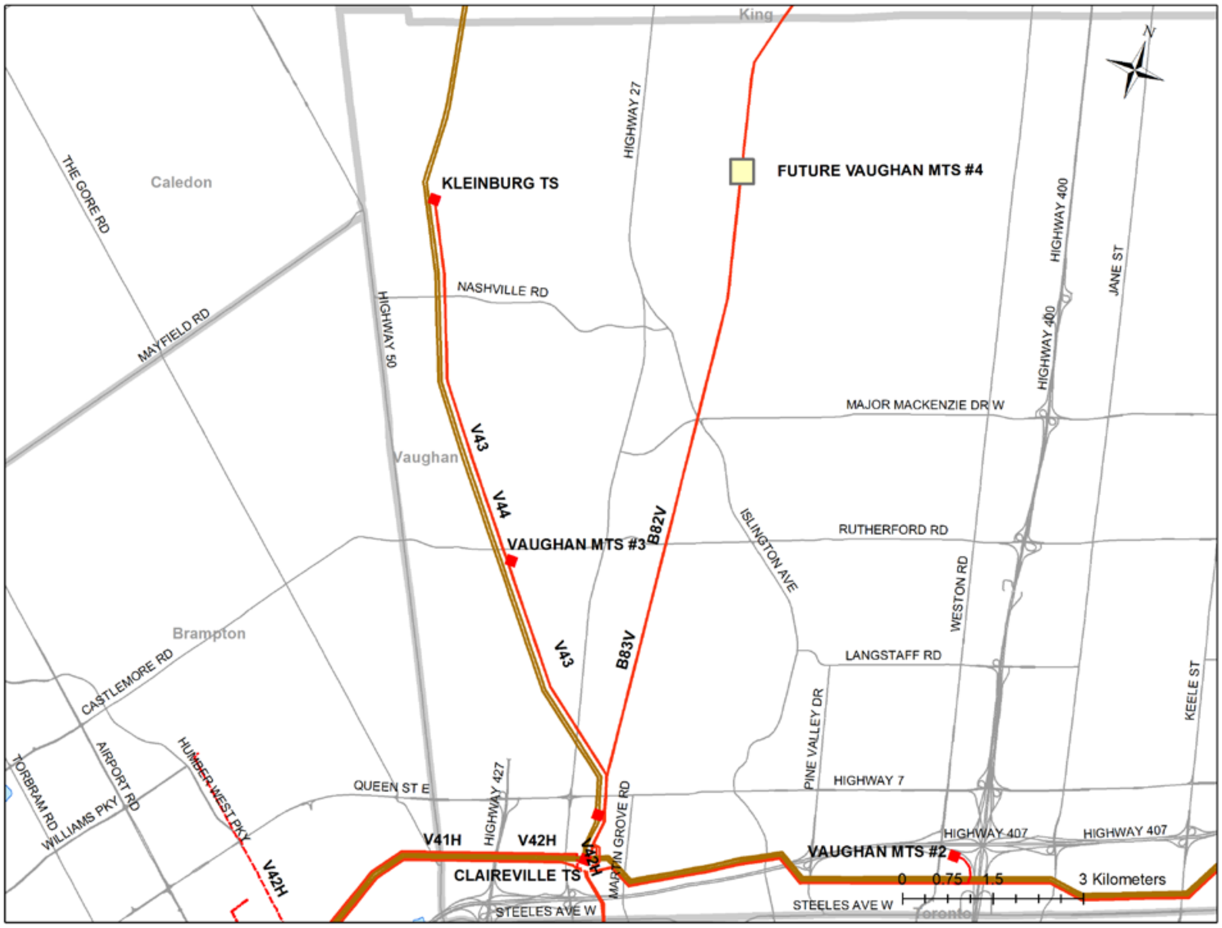


Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme (“SPS”). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP, under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

REFERENCES

[1]. Independent Electricity System Operator, "York Region Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/2015-York-Region-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, GTA North Region – Western Sub Region", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20-%20Western%20Subregion.pdf

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

[4]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[5]. Hydro One, "OPA Letter – Initiating Near-Term Transmission Components of the York Region Integrated Regional Resource Plan," 14 June 2013.
http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/OPA%20Letter%20to%20Hydro%20One%20%20Regarding%20%20York%20Subregion.pdf

[6]. Independent Electricity System Operator, "Northwest Greater Toronto Area Integrated Regional Resource Plan", 28 April 2015
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type	Area/Region
Enersource Hydro Mississauga Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Brampton Networks Inc.	Woodbridge TS	Dx	Western Sub-Region
Hydro One Networks Inc. (Distribution)	Armitage TS	Tx	Northern York Area
	Brown Hill TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Woodbridge TS	Tx	Western Sub-Region
Newmarket-Tay Power Distribution Ltd.	Armitage TS	Tx	Northern York Area
	Holland TS	Tx	Northern York Area
PowerStream Inc.	Armitage TS	Dx	Northern York Area
		Tx	Northern York Area
	Buttonville TS	Tx	Southern York Area
	Holland TS	Dx	Northern York Area
	Kleinburg TS	Tx	Western Sub-Region
	Markham MTS #1	Tx	Southern York Area
	Markham MTS #2	Tx	Southern York Area
	Markham MTS #3	Tx	Southern York Area
	Markham MTS #4	Tx	Southern York Area
	Richmond Hill MTS #1	Tx	Southern York Area
	Richmond Hill MTS #2	Tx	Southern York Area
	Vaughan MTS #1	Tx	Southern York Area
	Vaughan MTS #2	Tx	Southern York Area
	Vaughan MTS #3	Tx	Western Sub-Region
	Woodbridge TS	Dx	Western Sub-Region
		Tx	Western Sub-Region
PowerStream Inc.[Barrie]	Holland TS	Dx	Northern York Area
Toronto Hydro Electric System Limited	Woodbridge TS	Dx	Western Sub-Region
Veridian Connections Inc.	Armitage TS	Dx	Northern York Area

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

APPENDIX E: LIST OF ACRONYMS

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

GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

hydro one

[This page is intentionally left blank]

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

With support from:

Company
Burlington Hydro Electric Inc.
Enersource Hydro Mississauga Inc.
Halton Hills Hydro Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

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

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

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (“IESO”)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan (“IRRP”) in April 2015; and the GTA West Southern Sub-Region’s Needs Assessment (“NA”) and Scoping Assessment (“SA”) in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	\$19M (1)
2	Build new Halton TS #2	2020	\$29M (1)
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	\$5M
4	Upgrade (reconductor) circuits H29/H30 (2)	2023-2026	\$6.5M

Notes:

(1) Excludes cost for distribution infrastructure

(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Working Group in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville. The region includes the area roughly bordered geographically by Highway 27 to the north-east, Highway 427 to the south-east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

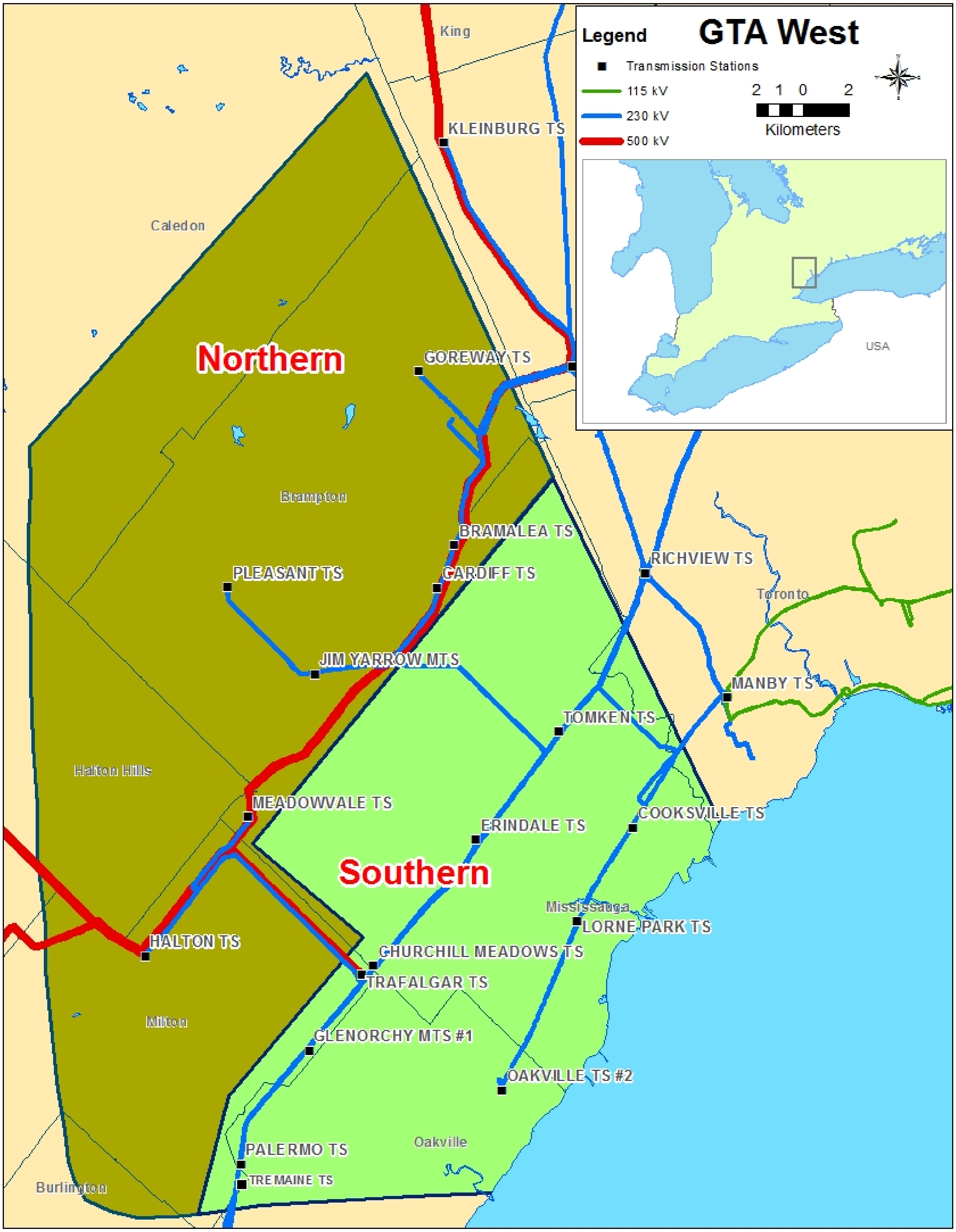


Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

[1] also referred to as Needs Screening

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

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

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

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

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

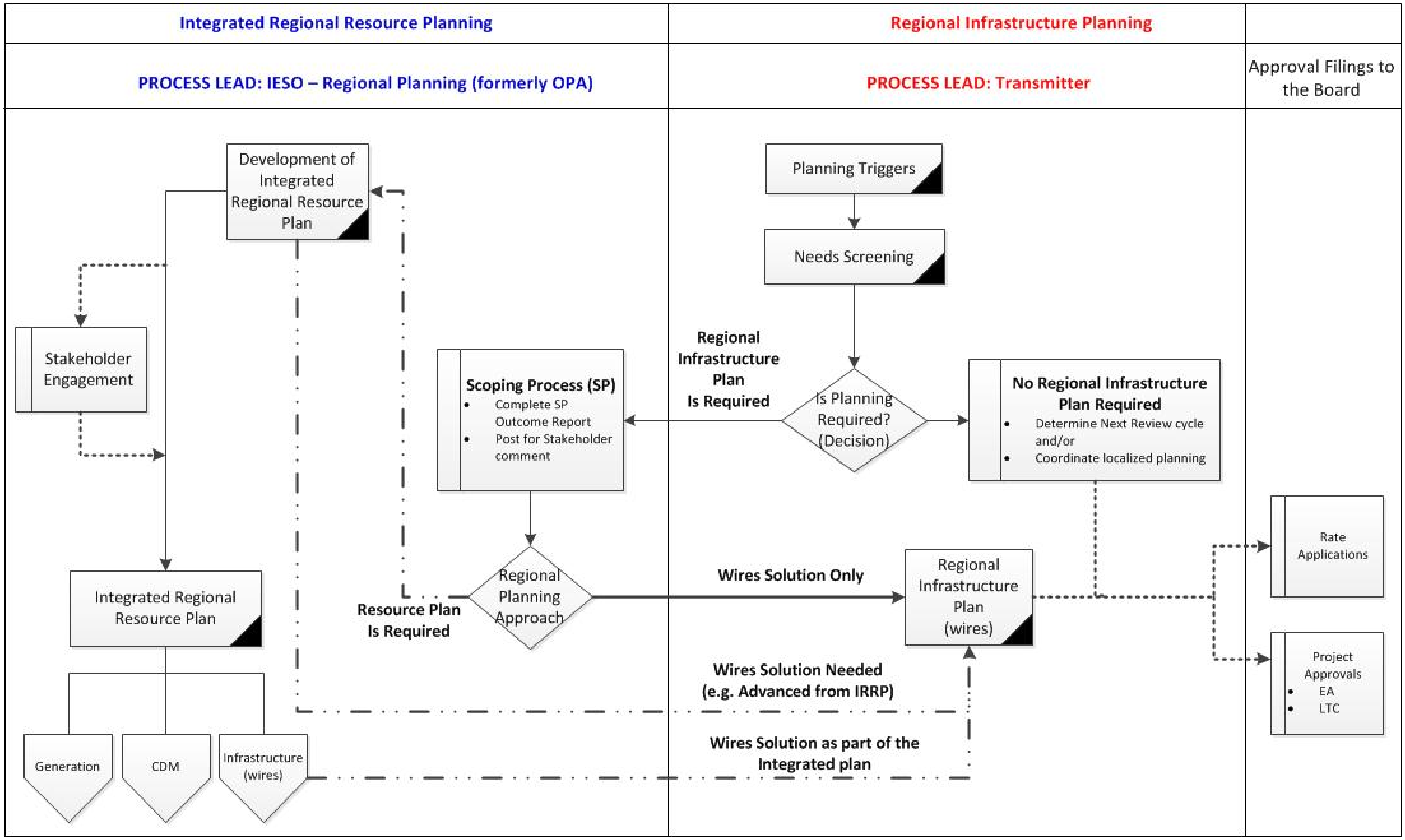


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

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

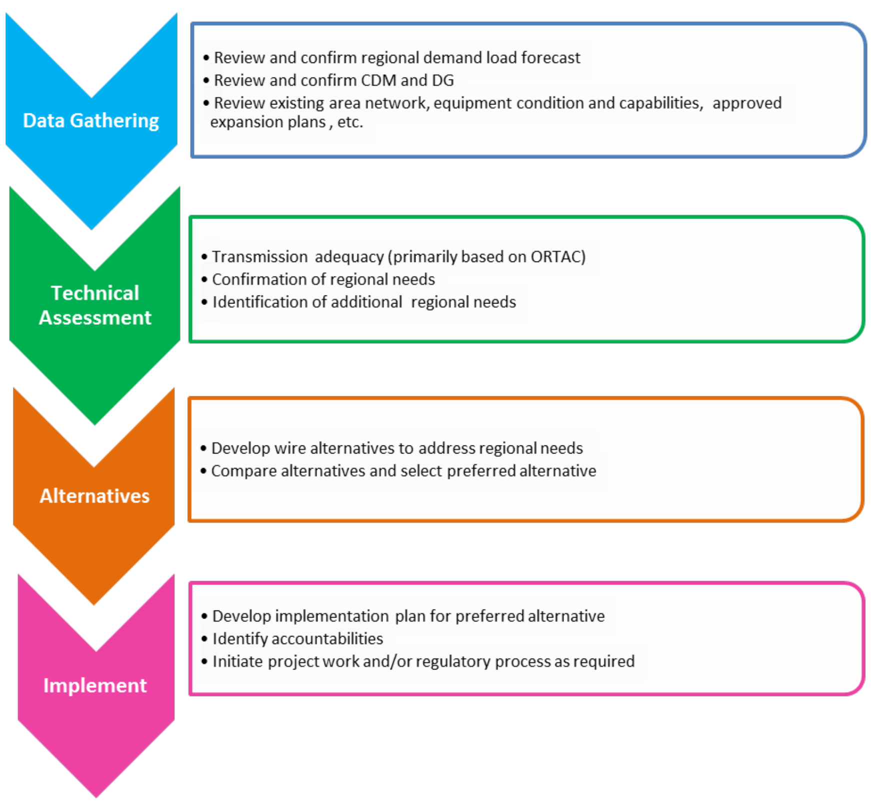


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

The GTA West – Northern Sub-Region was identified as a "transitional" sub-region, as planning activities in this sub-region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. The Northwest GTA IRRP was completed for the Northern Sub-Region in April 2015.

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

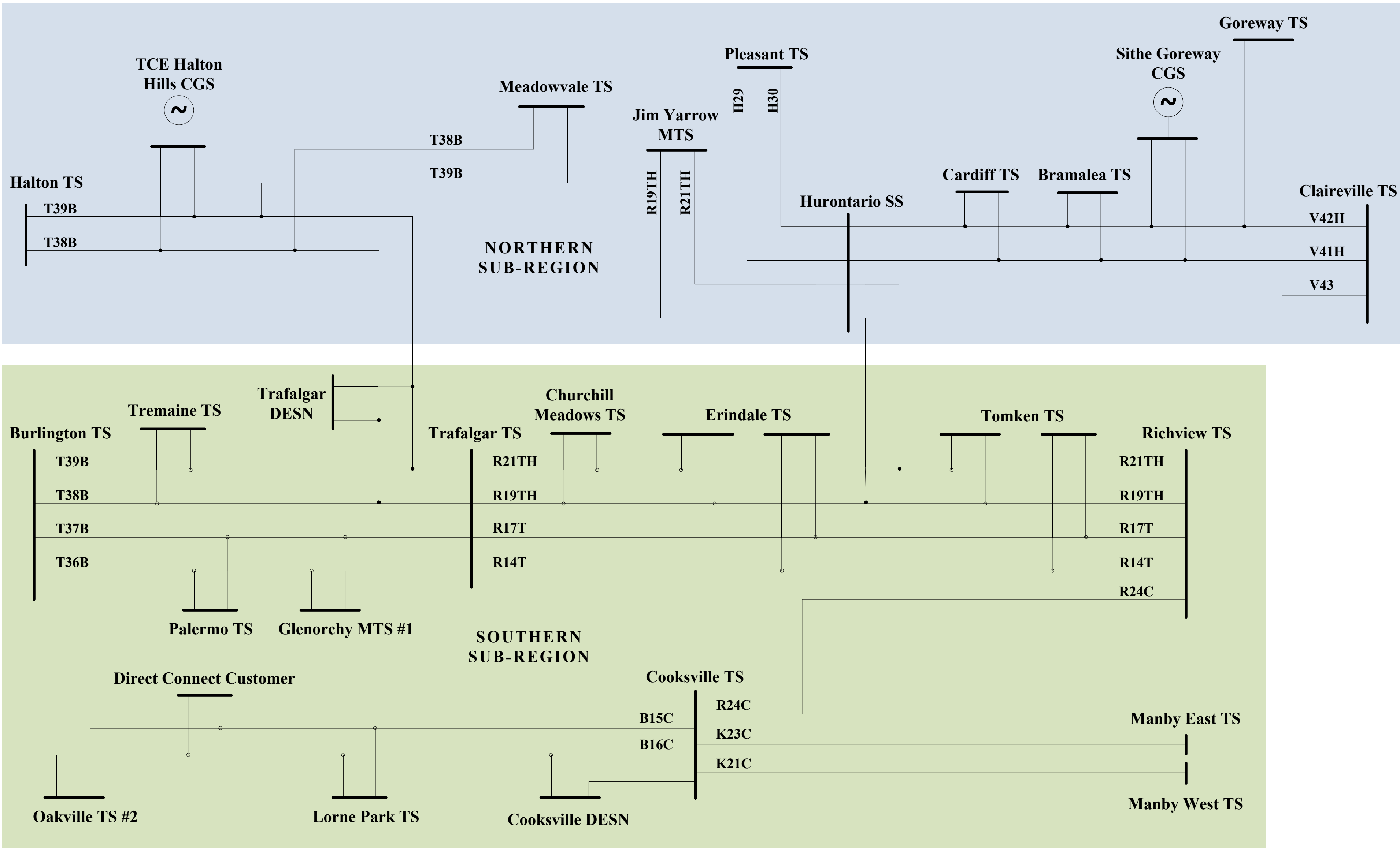


Figure 3-1 GTA West Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY IN THE LAST TEN YEARS

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.
- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).
- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Hurontario SS and underground cable work - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow TS (2010). The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills CGS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. Non-coincident forecast for the individual stations in the region is available in Appendix A, and is used to determine any need for station capacity relief.

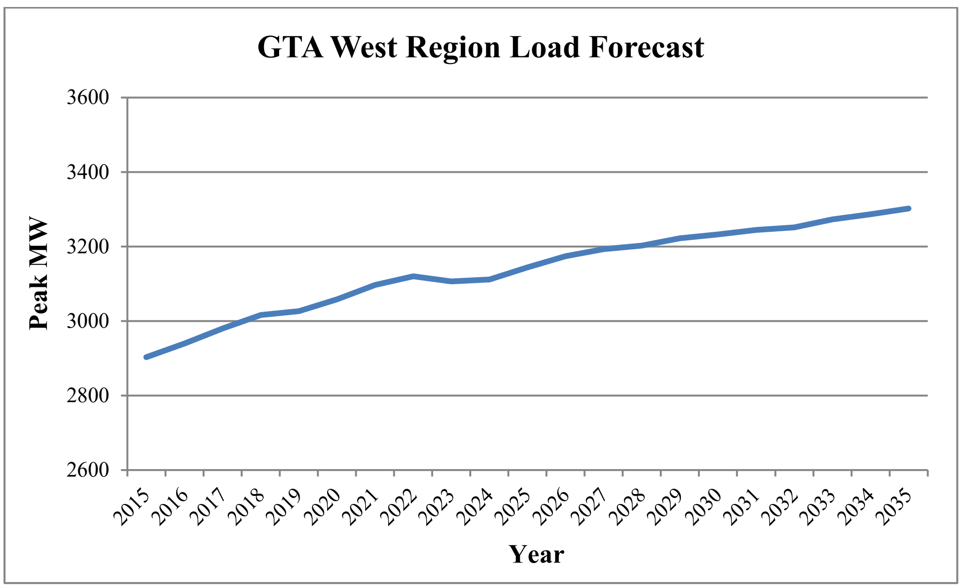


Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region's Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region's Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region [(1)]: - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess "Kleinburg Radial Pocket" supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS
3. Trafalgar TS to Burlington TS, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region's NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the "Higher Growth" scenario, while 2033 under the "Expected Growth" scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

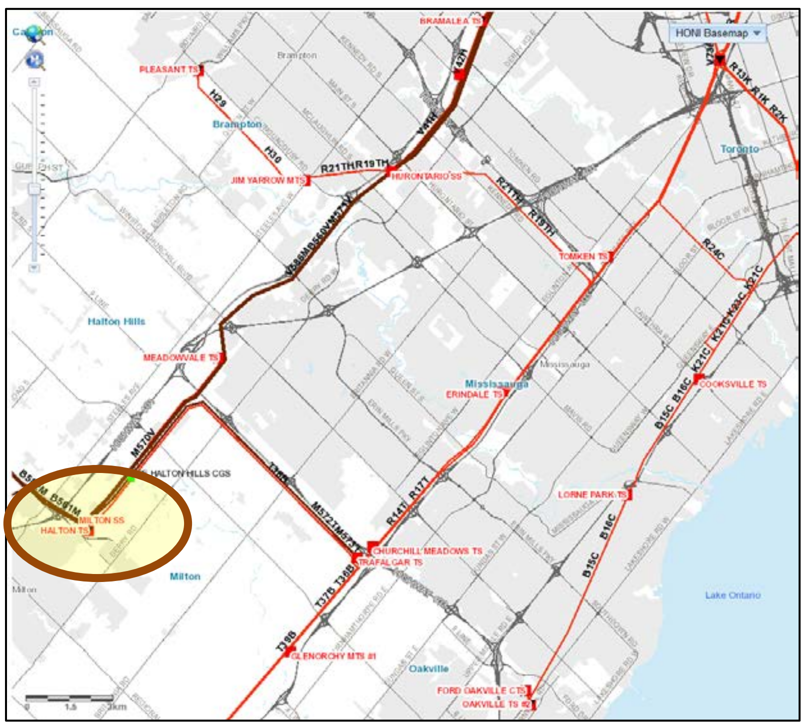


Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro proceed to gain the necessary approvals to construct, own, and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

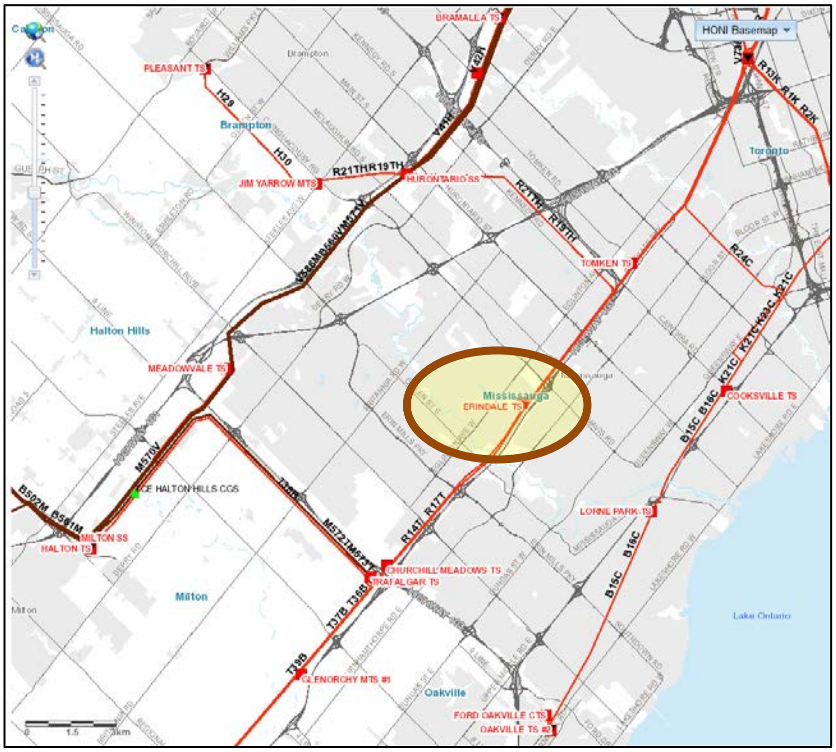


Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA WEST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans - Next Steps, Lead Responsibility and Plan In-Service Dates

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator. "Northwest GTA Integrated Regional Resource Plan". April 28, 2015. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

[2] GTA West Southern Sub-Region Study Team. "Needs Screening Report – GTA West Southern Sub-Region". May 30, 2014. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

[3] GTA West Southern Sub-Region Study Team. "GTA West Southern Sub-Region Scoping Assessment Outcome Report". September 19, 2014. http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. "Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region". July 9, 2015. http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Local%20Planning%20Report%20-%20Erindale%20TS%20Capacity%20-%209_July_2015.pdf

[5] Ministry of Infrastructure. Places to Grow: "Growth Plan for the Greater Golden Horseshoe, 2006". Office Consolidation June 2013. https://placestogrow.ca/content/ggh/2013-06-10-Growth-Plan-for-the-GGH-EN.pdf

Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
Pleasant TS (T1/T2)	230/44	H29/H30
Pleasant TS (T5/T6)	230/27.6	H29/H30
Pleasant TS (T7/T8)	230/27.6	H29/H30
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
Erindale TS (T1/T2)	230/27.6	R14T/R17T
Erindale TS (T3/T4)	230/44	R14T/R17T
Erindale TS (T5/T6)	230/44	R19TH/R21TH
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

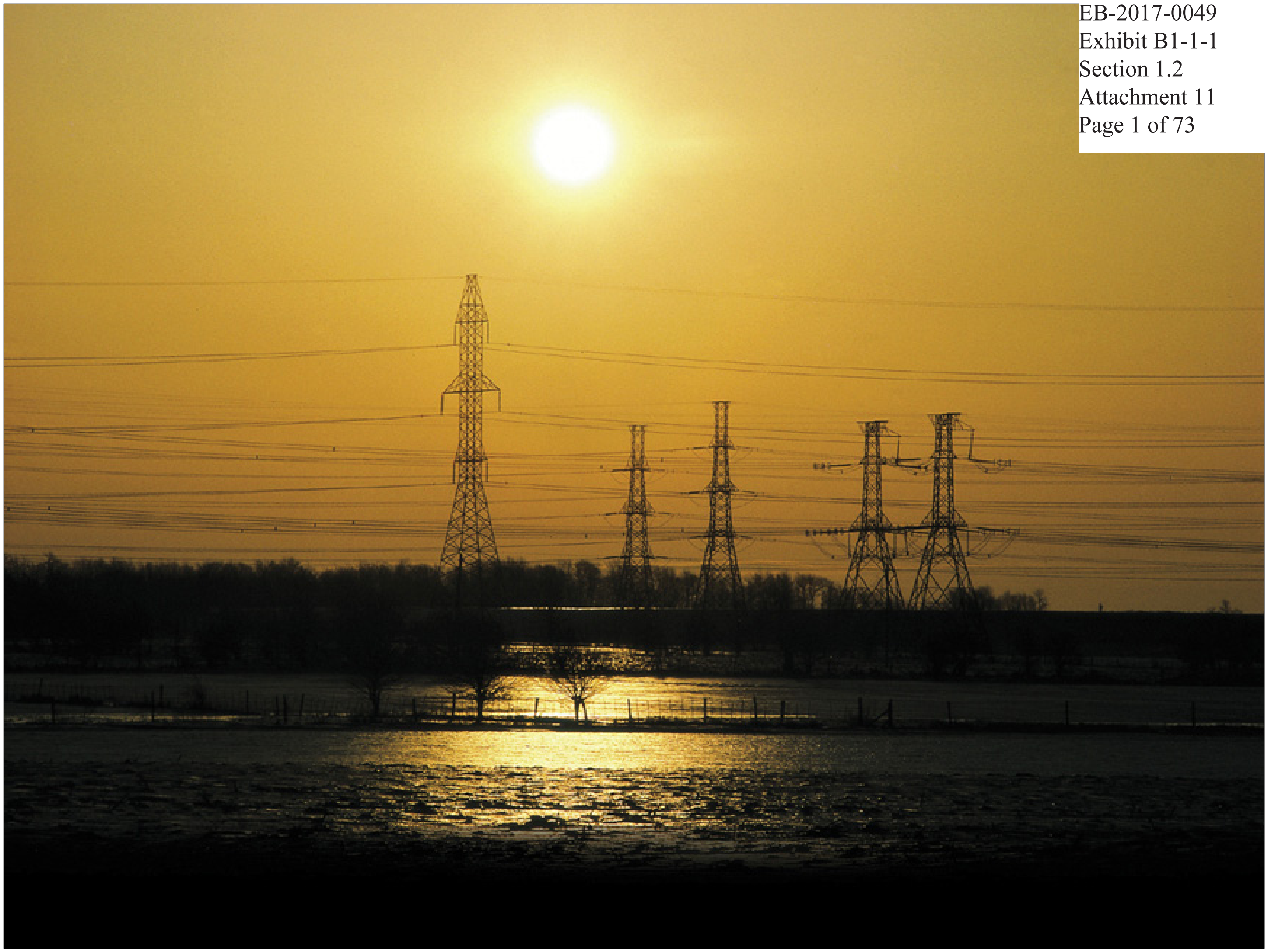
DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	S	172.5	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	S	119.8	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	S	119.7	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	S	181.3	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	S	193.0	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	S	195.1	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	S	153.0	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	S	144.6	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	S	185.2	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	S	109.5	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	S	173.3	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	S	192.8	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	S	124.0	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	S	189.5	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

Appendix E. List of Acronyms

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



Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

hydro one

[This page is intentionally left blank]

Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

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

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

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

No.	Project	In-Service Date	Cost
1	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle may be started earlier to address the need.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

[This page is intentionally left blank]

1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Kitchener-Wilmot Hydro Inc. ("Kitchener-Wilmot Hydro"), Waterloo North Hydro Inc. ("WNH"), Cambridge & North Dumfries Hydro Inc. ("CND"), Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), Hydro One Distribution and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

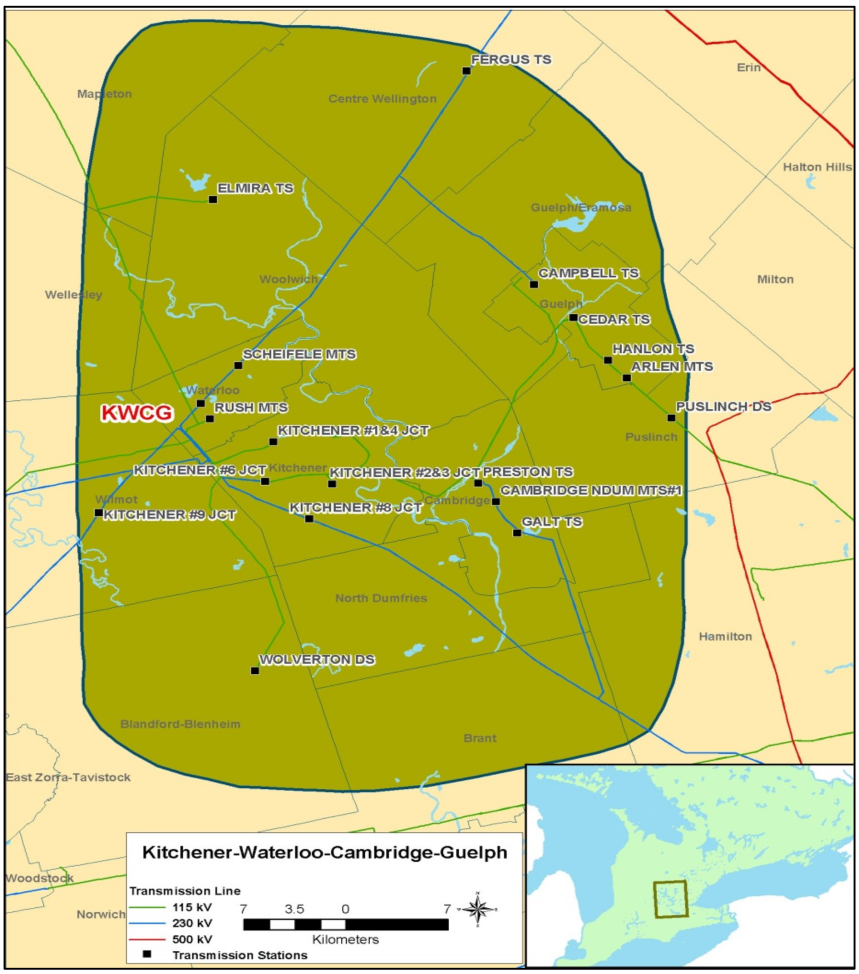


Figure 1-1 KWCG Region

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG Region. Its objectives are:

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

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

The scope of this RIP is as follows:

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

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

1.2 Structure

The rest of the report is organized as the follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

[1] Also referred to a Needs Screening

suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

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

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

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

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

Note that as the KWCG Region was identified as a “transitional” region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

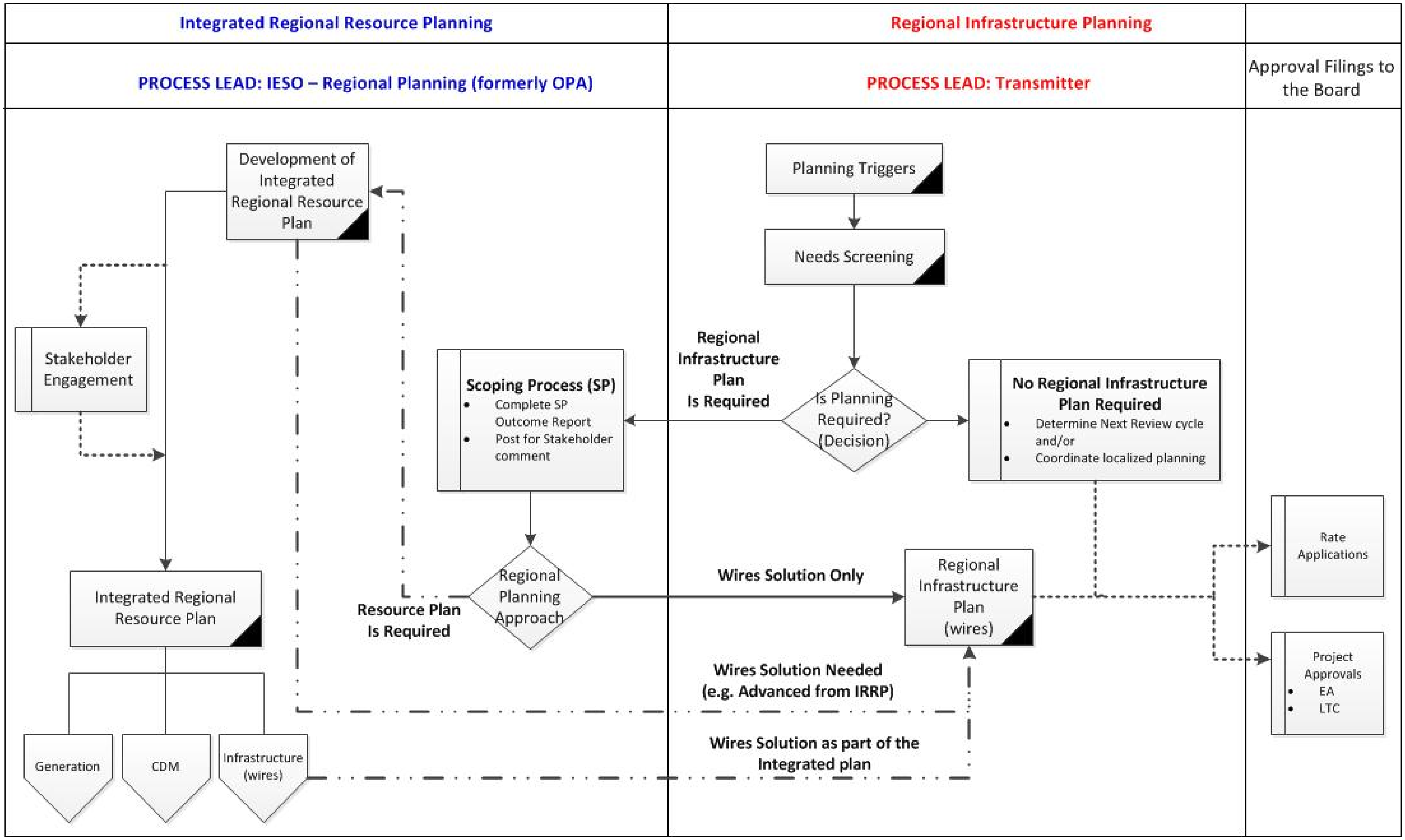


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

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

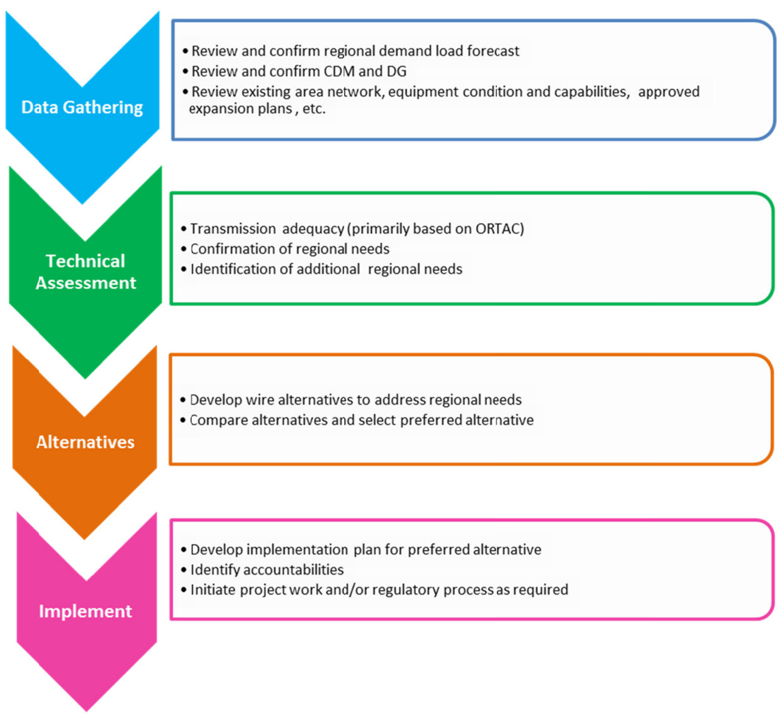


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

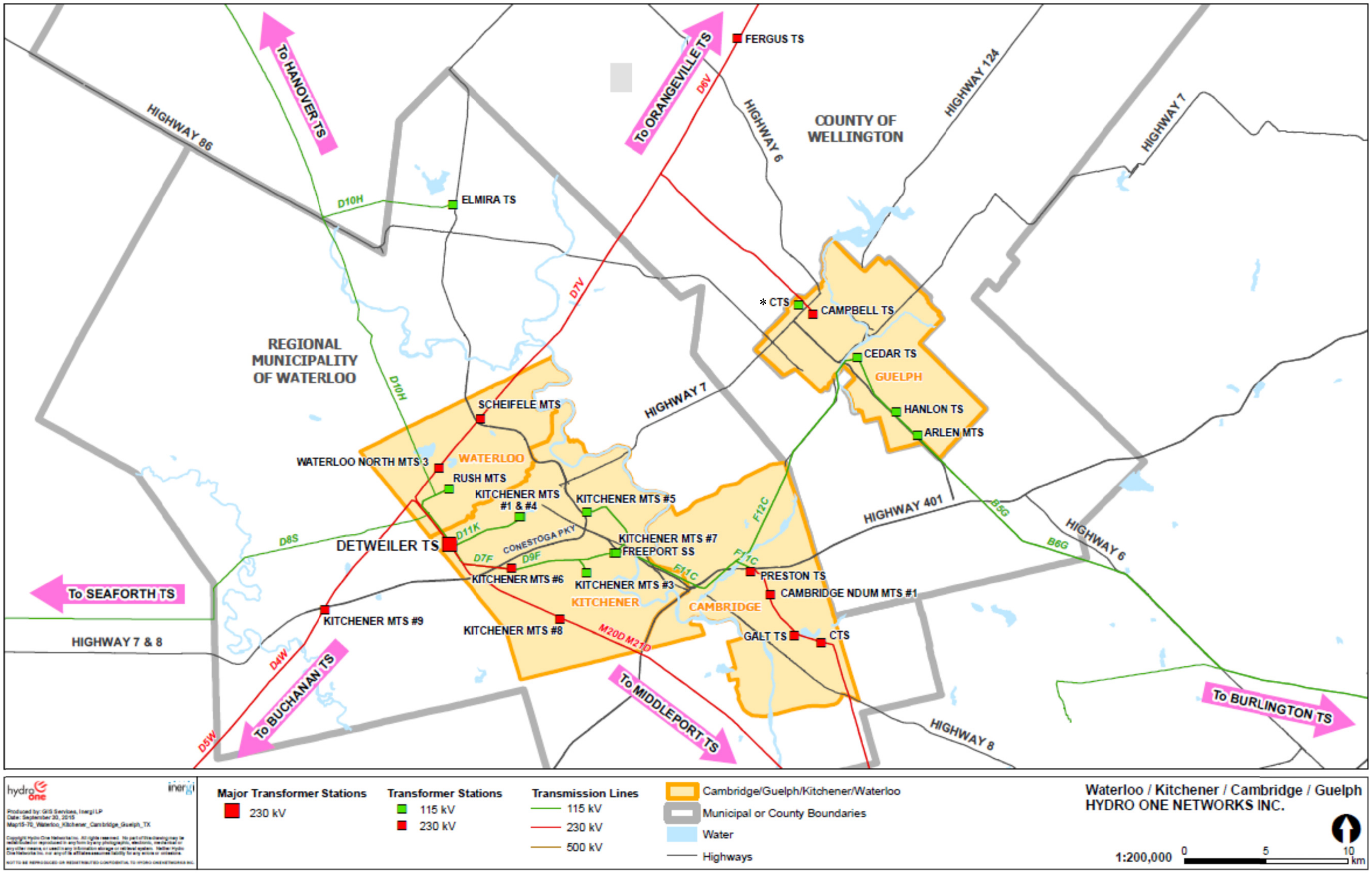


Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

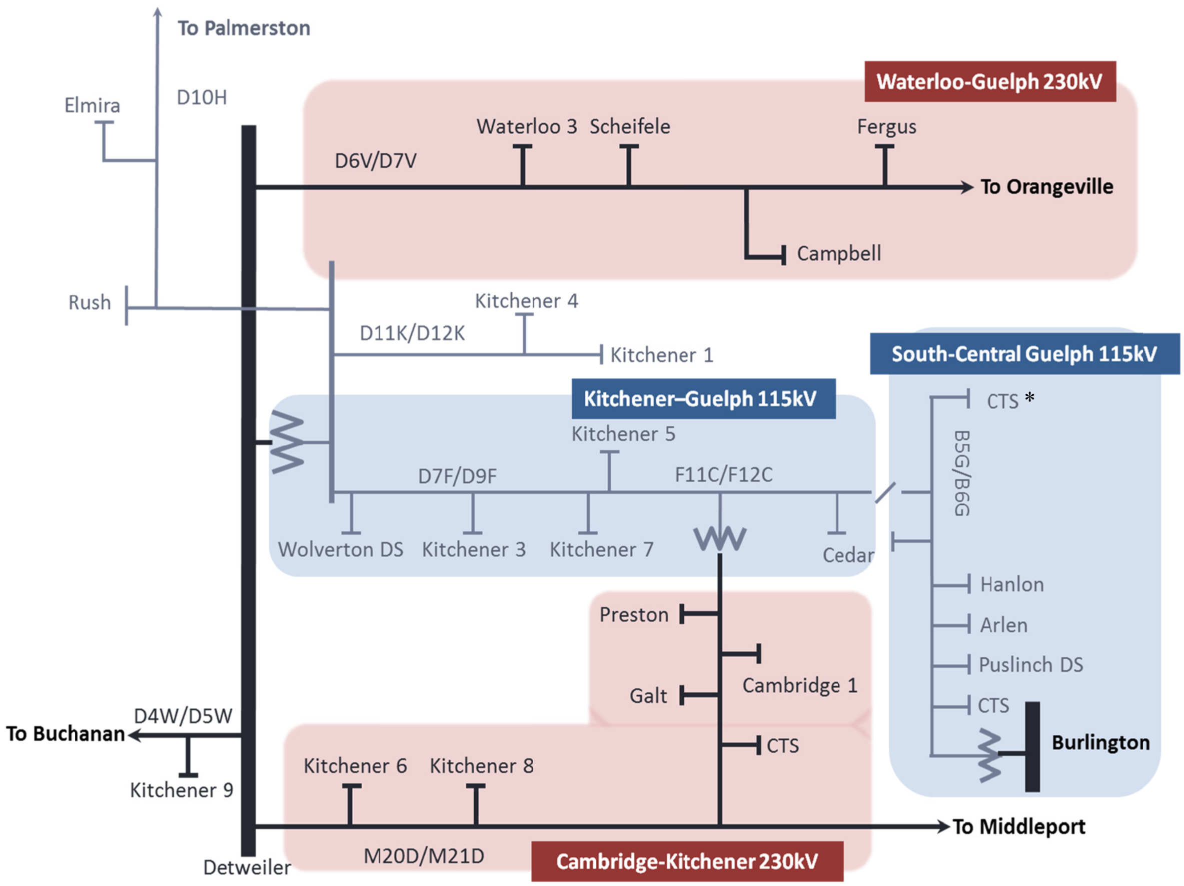


Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

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

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

These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

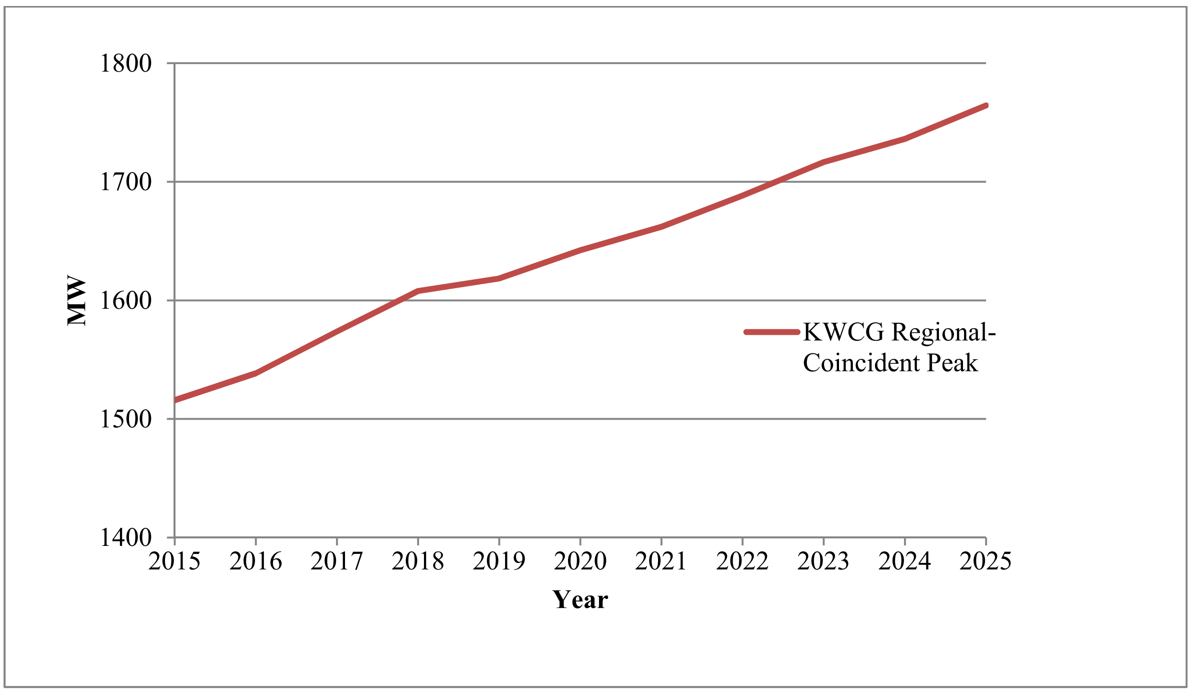


Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

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

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

6.1 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

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

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

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) Detweiler TS to Seaforth TS/Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points – supplies Rush MTS and Elmira TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment ("SIA") [4] was performed for Hydro One's application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro (“CND”) to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC’s to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs are summarized in the Table 8-1 below.

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

No.	Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013. http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer Stations in the KWCG Region

Station	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Cambridge MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5G/B6G	115 kV
Detweiler TS – Kitchener MTS #4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro (“CND”) has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro (“WNH”) are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

Appendix E. List of Acronyms

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

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
Kitchener-Wilmot Hydro	Shaun Wang L. Frank G. Cameron
Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
Guelph Hydro Electric System Inc.	Michael Wittemund K. Marouf Eric Veneman
Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the "London area") that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 KV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 KV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 LOAD RESTORATION CAPABILITY ANALYSIS

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 IMPACT OF CONTINGENCIES ON THE BPS TO THE KWCG AREA

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: “These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.”

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 Summary of Needs

Figure 1 illustrates the Needs timeline for the KWCG region.

Figure 1: Transmission Needs in the KWCG Area

4.0 Options to Address the Need

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric “initial capital cost/MW of load restored” was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 “C&ND load only” means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) Immediate Action: Install 230 kV In-Line Switches

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

Local Area Performance

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

BPS Performance

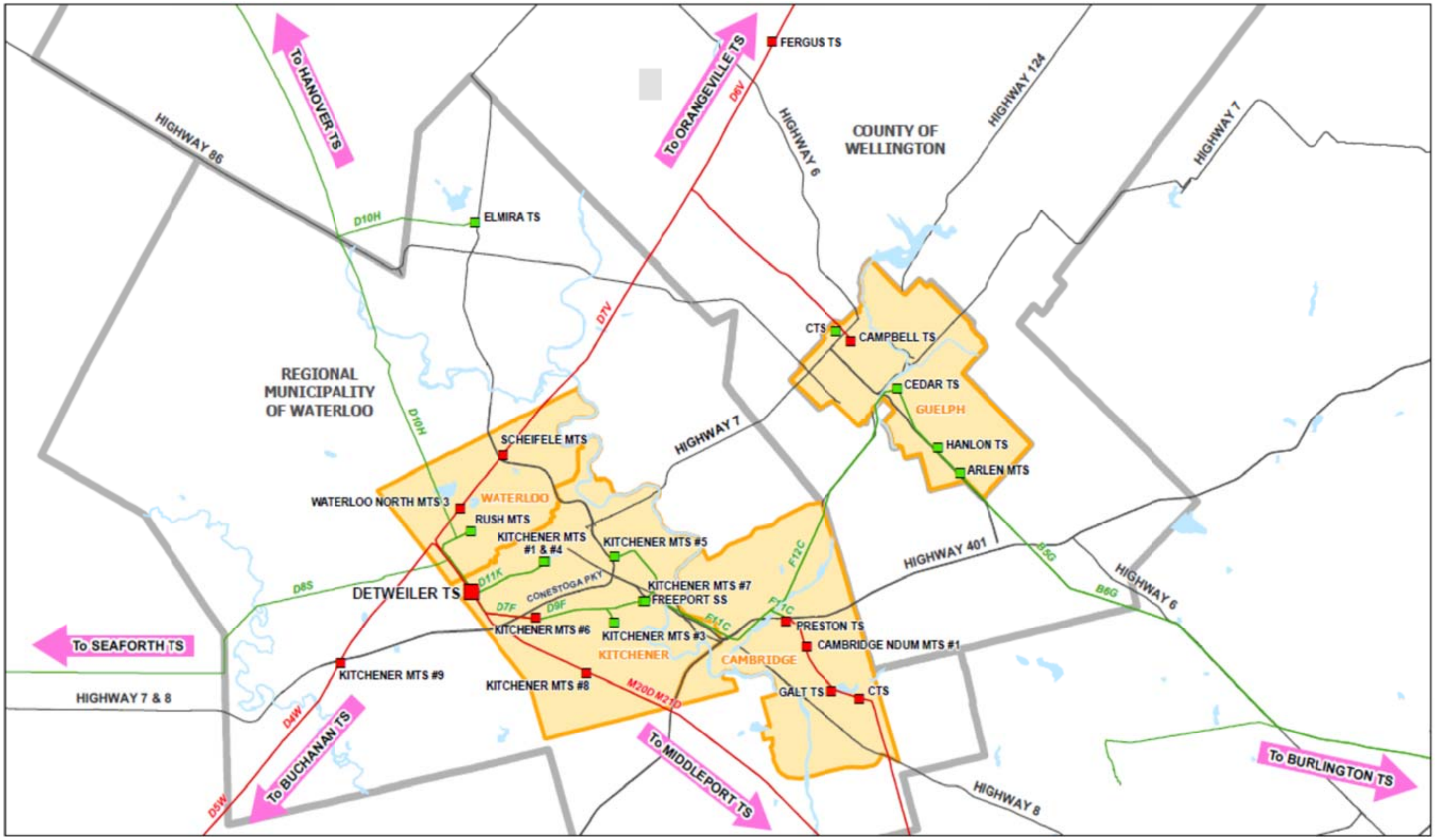
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
   i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

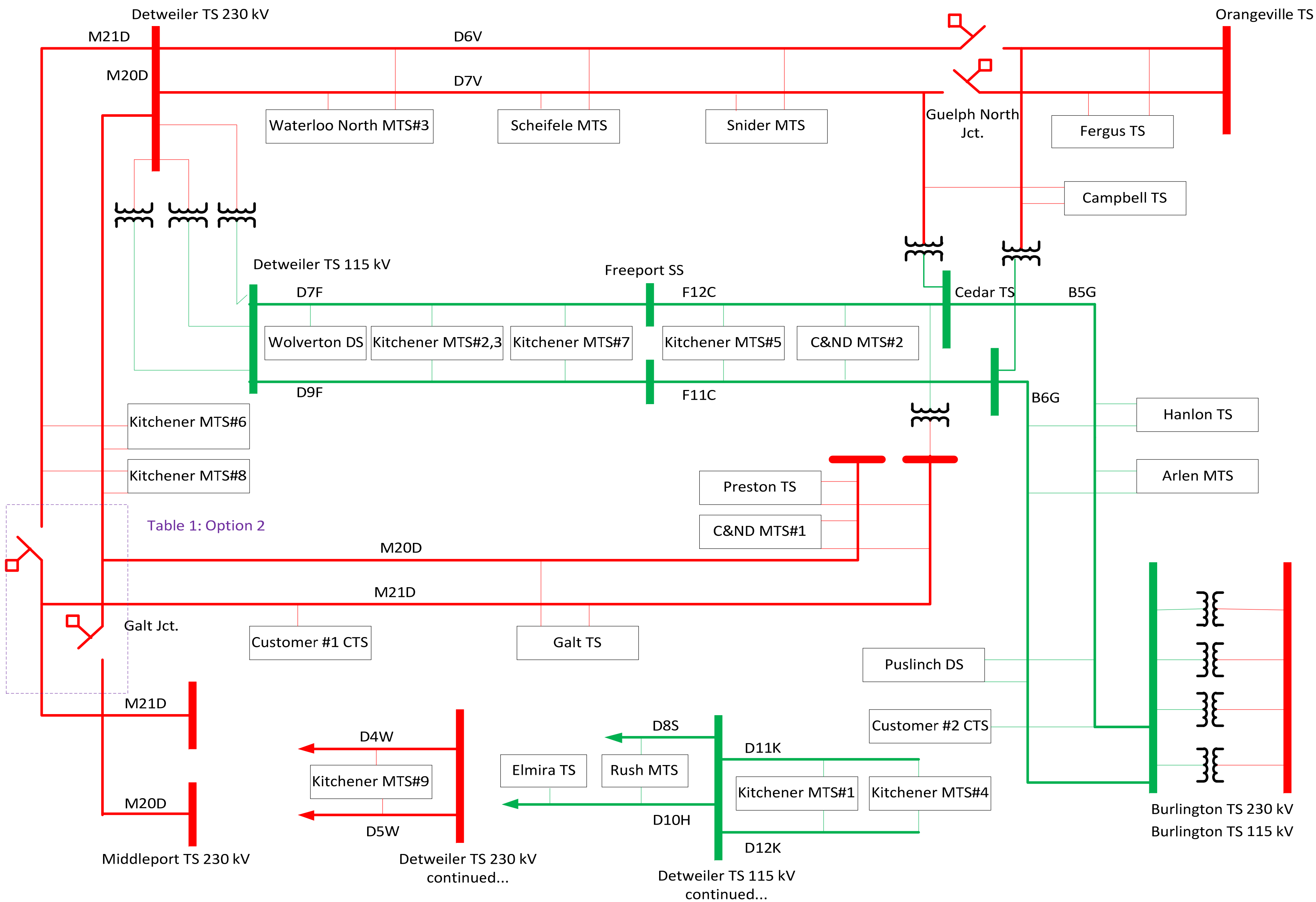
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

Loss of a Single Circuit (N-1)					
D11K	D12K	D8S	D10H	D7F	D9F
F11C	F12C	B5G	B6G	D4W	D5W
M20D*	M21D**	D6V***	D7V****		
Loss of a Single Autotransformer (N-1)					
Detw. T2	Detw. T3♦	Detw. T4♦♦	Cedar T3♦♦♦	Cedar T4♦♦♦♦	Preston T2**
Middleport T3♦♦♦♦♦		Middleport T6♦♦♦♦♦♦			
Loss of a Single HV Reactive Element (N-1)					
Detweiler 230 kV cap. bank	Middleport 230 kV cap. bank(K1D1)	Orangeville 230 kV cap. bank	Burlington 230 kV cap. bank		
Detweiler 230 kV SVC	Middleport 230 kV cap. bank(K2D2)	Detweiler 115 kV cap bank	Burlington 115 kV cap bank		

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	**Contingency**	**%LTE**
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	**Contingency**	**%LTE**
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line		
D7F and D9F	F11C and F12C	B5G and B6G
D4W and D5W	M20D and M21D	D11K and D12K
D6V and D6V		

Loss of Two Autotransformers[7]

Station	**Detweiler Auto**	**Preston Auto**	**Cedar Auto**	**Burlington Auto**
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	**Contingency**	**%STE**
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

[7] For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D4/5W

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D7/9F

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D8S/D10H

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	**Transformer Capacity (10-day LTR)**	**Year 2025 Load Forecast**
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	**Contingency**	**D10H – Detweiler TS x Waterloo Jct.**	**D8S – Detweiler TS x Leong Jct.**
		590 A Continuous *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	*590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

[This page is intentionally left blank]

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

With support from:

Company
Enersource Hydro Mississauga
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
PowerStream Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.

[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

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

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

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

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

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

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

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

[This page is intentionally left blank]

1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (“Hydro One”) on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator (“IESO”), PowerStream Inc., Toronto Hydro-Electric System (“THESL”), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

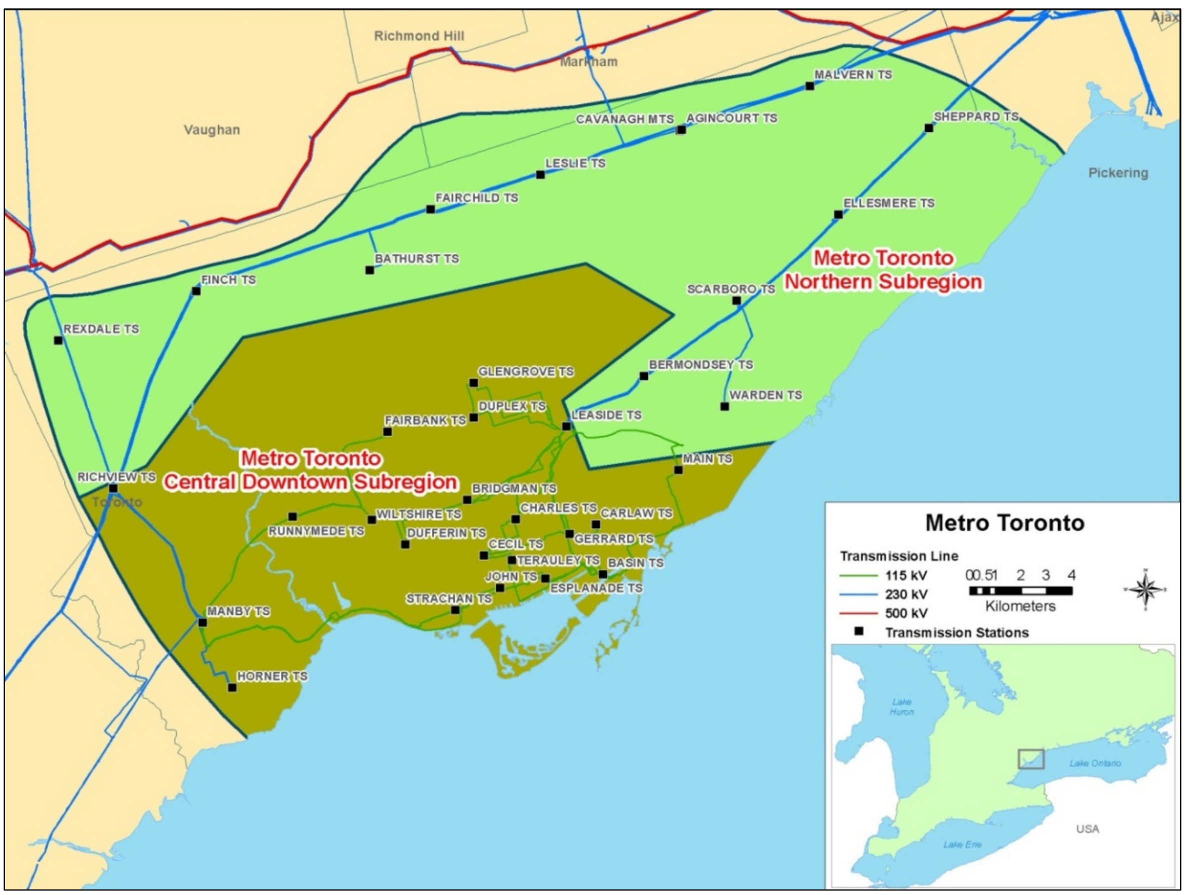


Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

This RIP report examines the needs in the Metro Toronto Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

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

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

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

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

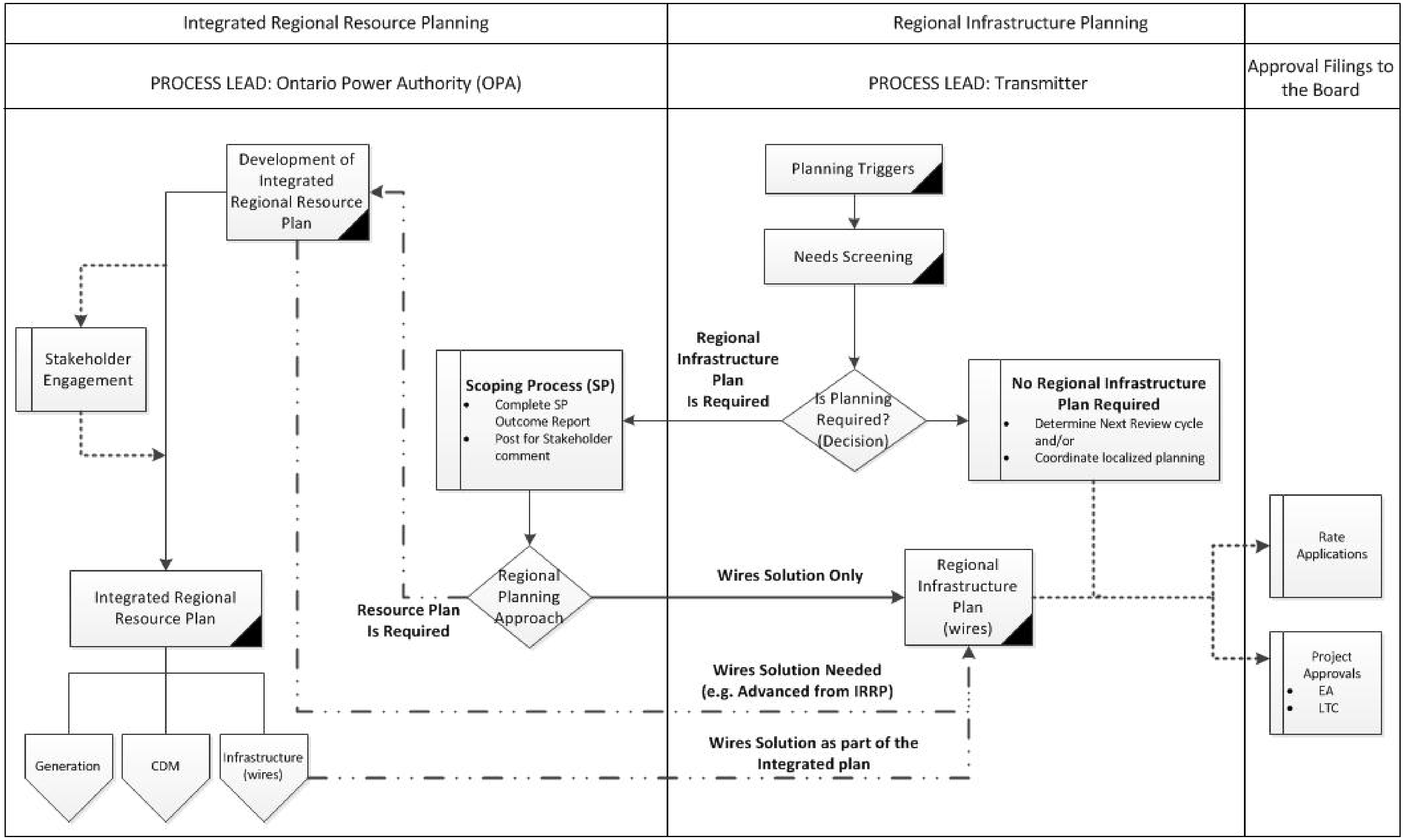


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

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

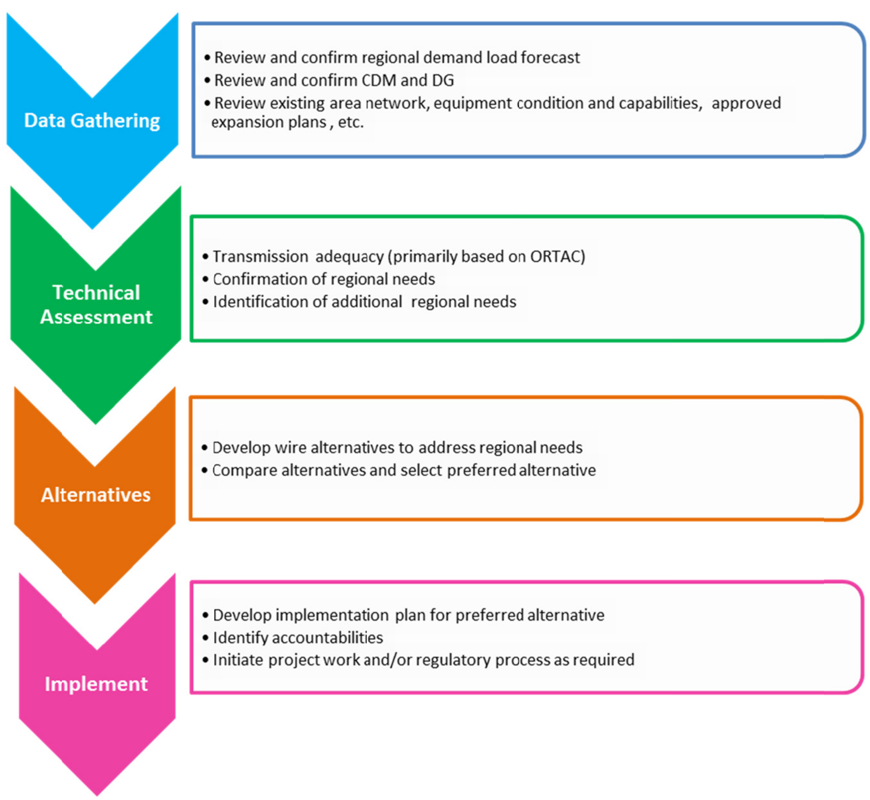


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited ("THESL") is the Local Distribution Company ("LDC") that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a "transitional" region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

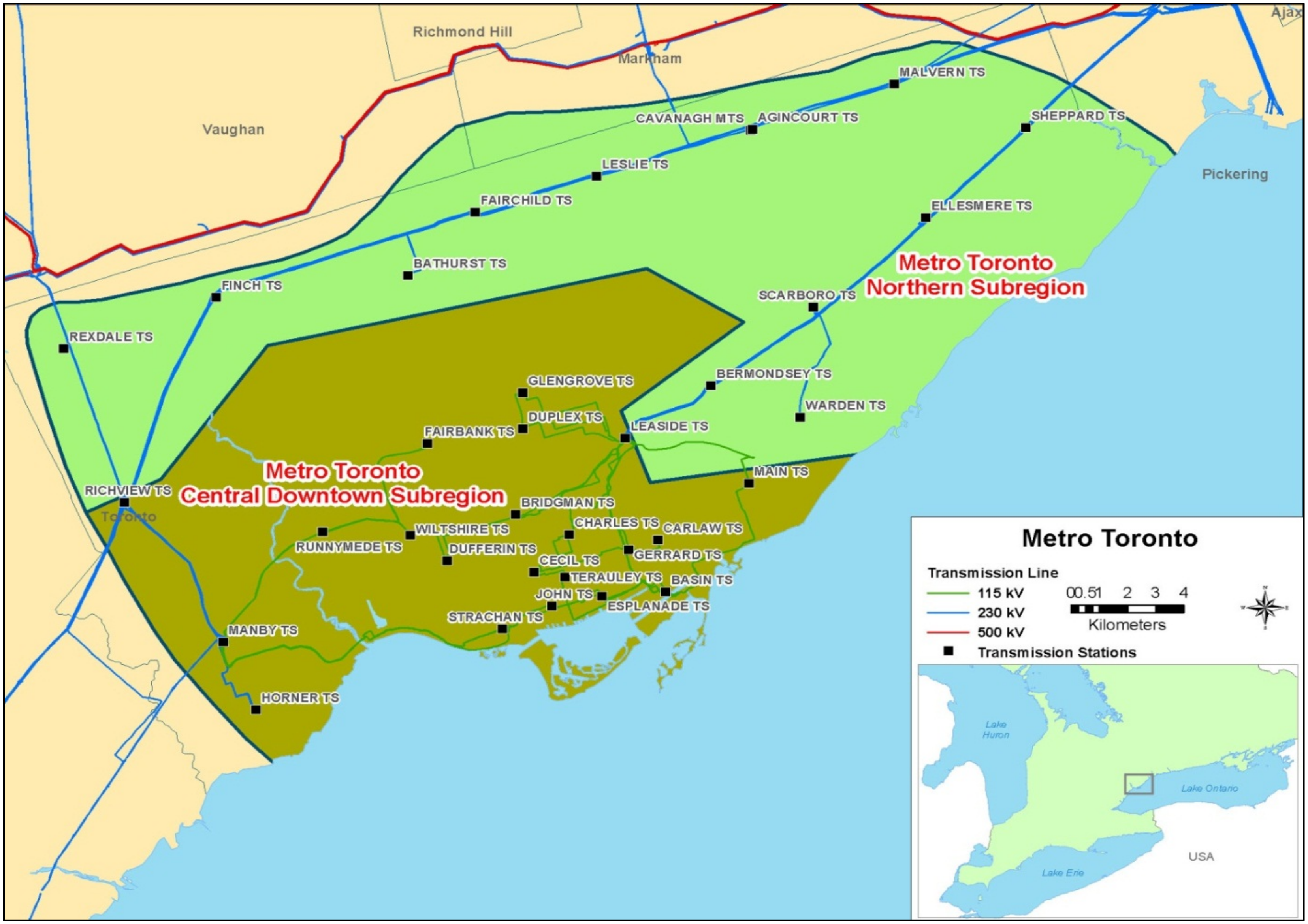


Figure 3-1 Metro Toronto Region – Supply Areas

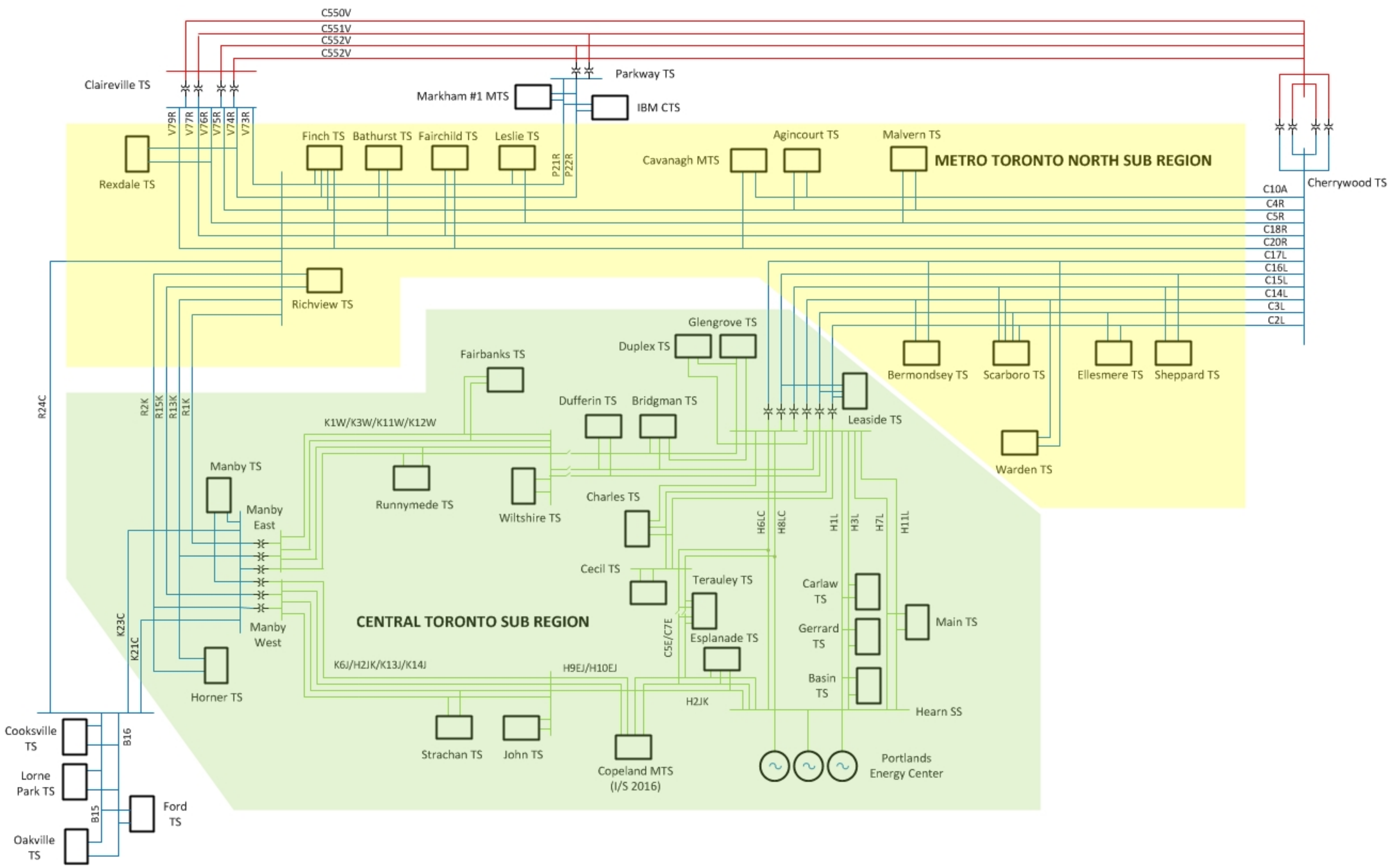


Figure 3-2 Metro Toronto Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.
- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.
- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.
- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.
- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.
- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.
- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.
- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

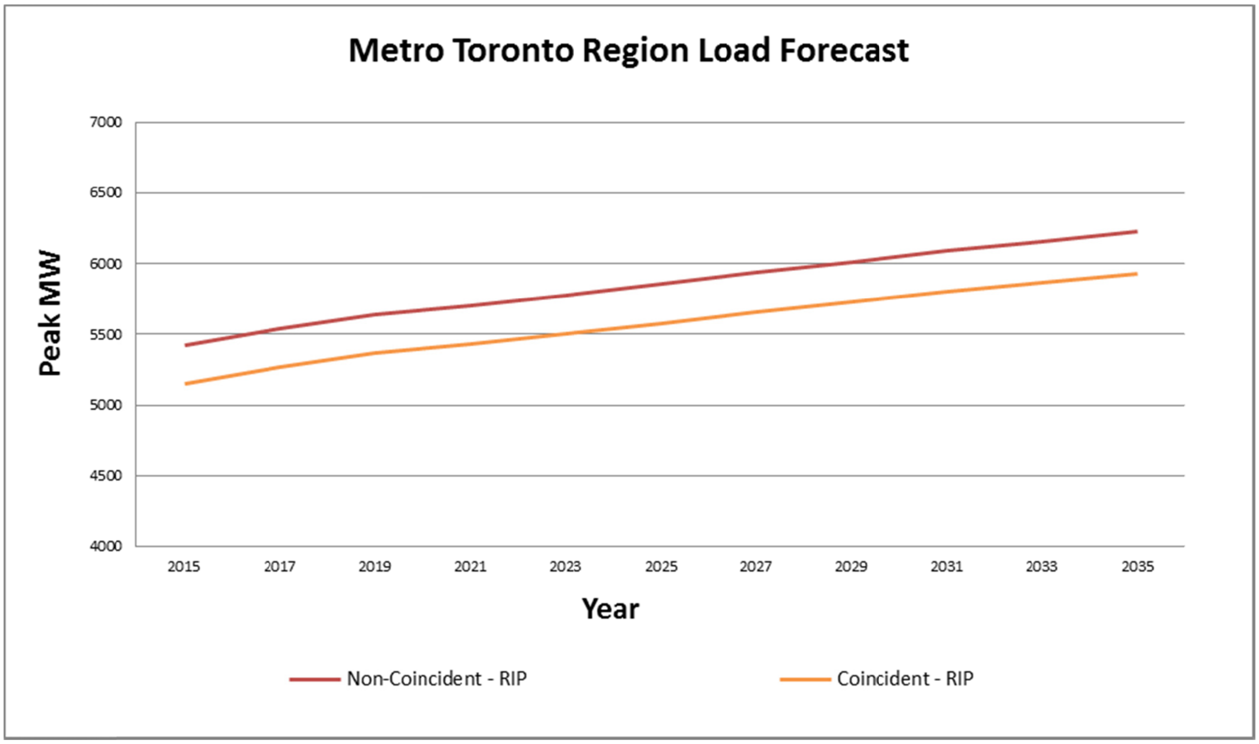


Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

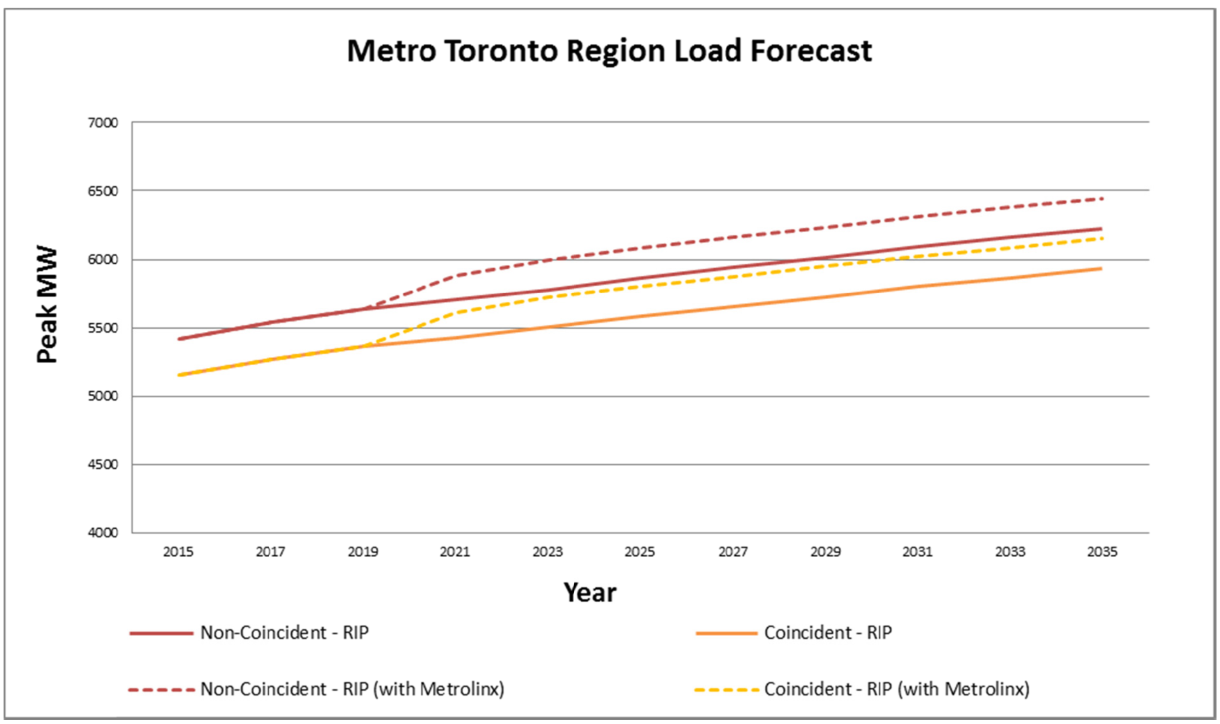


Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC[1] Area)	2020+[2]
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

[1] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.
[2] The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.

(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.

(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.

(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

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

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

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

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit (“LRT”) project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

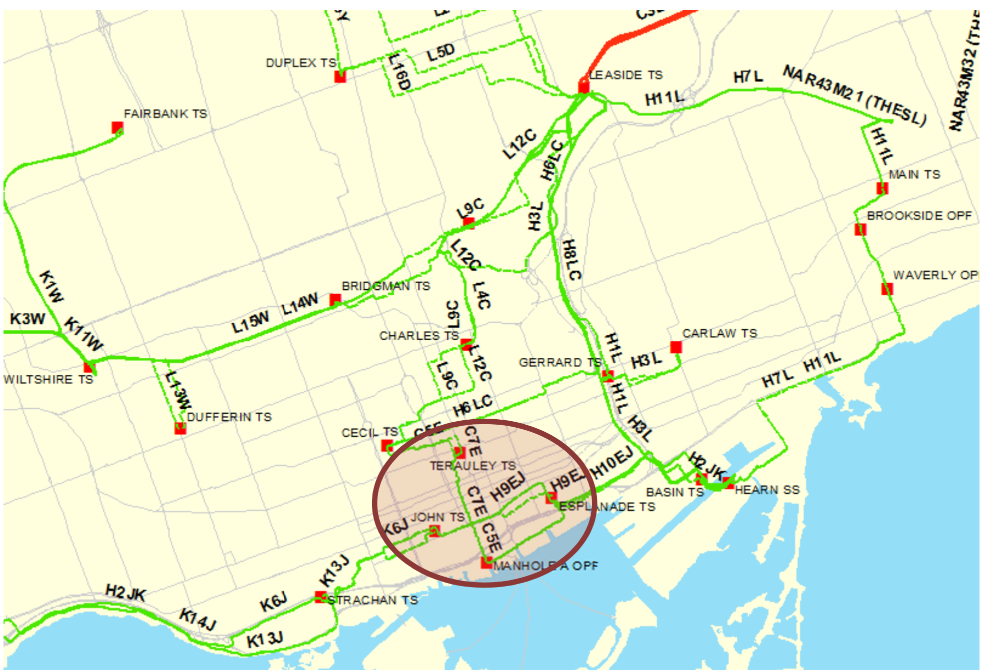


Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

---

[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

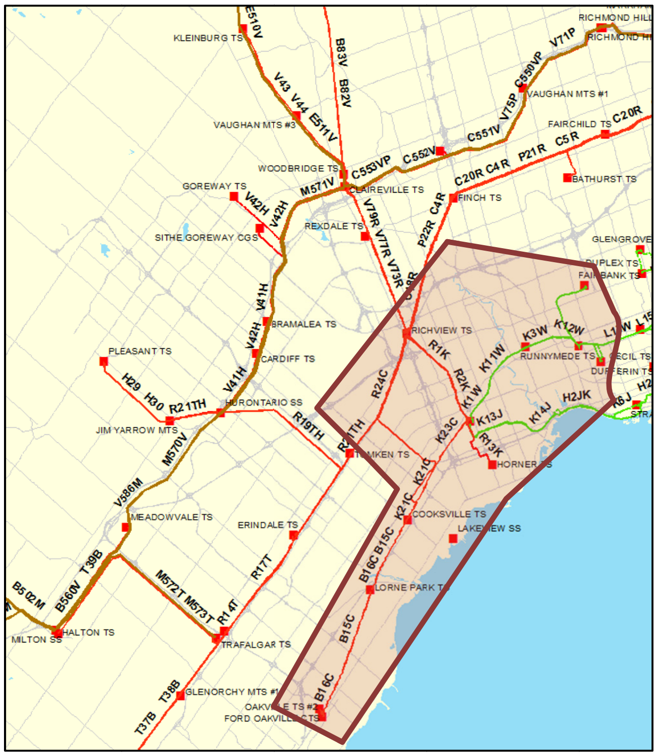


Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

Upgrade four existing 230kV Richview TS x Manby TS circuits: Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

Rebuild existing 115kV Richview TS x Manby TS line: Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

Build two new 230 kV Richview TS x Manby TS circuits: Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

Extend the Cooksville TS x Oakville TS line to Trafalgar TS: Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	**Station Name**	**Connection Type**
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	Runnymede	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	Manby230	Horner	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	**Runnymede**	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	**Manby230**	**Horner**	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

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

NORTH OF DRYDEN INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | January 27, 2015

ieso
Independent Electricity System Operator

Explanatory Note Regarding January 1, 2015 OPA-IESO Merger

On January 1, 2015, the Ontario Power Authority (OPA) merged with the Independent Electricity System Operator (IESO) to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

This report was largely completed prior to January 1, 2015. Any mention of the activities performed by the former OPA or the former IESO in this report refers collectively to the new IESO.

*Administrative change on April 1, 2015, page 22 , to correct timeframe of the Conservation Firs Framework Directive.

Contents

Table of Figures

Summary of Plan Highlights

- Drivers for increased electricity demand in the areas surrounding Red Lake, Pickle Lake and Ring of Fire include *connecting remote First Nation communities and growth in the mining sector*.

- The OPA recommends a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake and upgrades to existing lines between Dryden and Red Lake for immediate implementation to address near- and medium- term needs for the Pickle Lake and Red Lake areas.

- Incremental longer term solutions to supply Ring of Fire and Red Lake are not required at this time. Longer term options will be re-evaluated in the next planning cycle (1-5 years).

- Options to supply the Ring of Fire include transmission utilizing an East-West or North South corridor, or on-site generation. East-West and North-South transmission options are comparable in cost under the high demand scenario and the potential need for a transmission line should be considered in the planning of a common infrastructure corridor to the Ring of Fire.

- Long-term options for the Red Lake area include local gas generation or new transmission.

Summary of Updates from August 2013 draft IRRP

- Revised demand forecast used different methodology, includes updated data and is represented by three scenarios – reference, high and low; August 2013 draft included high and low scenarios, but did not include a reference scenario.

- Revised demand forecast indicates relatively higher forecasted demand in the Pickle Lake subsystem, and relatively lower forecasted demand in the Red Lake subsystem than in the August 2013 draft.

- Recommendation is for new 230 kV line to Pickle Lake in this version; voltage recommendation was not specified in the August 2013 draft.

- Recommended line upgrades from Dryden to Red Lake are expected to be sufficient to the end of the planning period for the reference and low forecast scenarios, and to 2030 for the high forecast scenario. The August 2013 draft indicated that the upgrades may be insufficient in the medium-term for the high scenario.

- Recommendation to discuss reactive services of Manitou Falls GS with OPG, as per OPG's written submission.

- Revised economic analysis methodology – refer to Appendices 10.6, 10.7, and 10.8 for details.

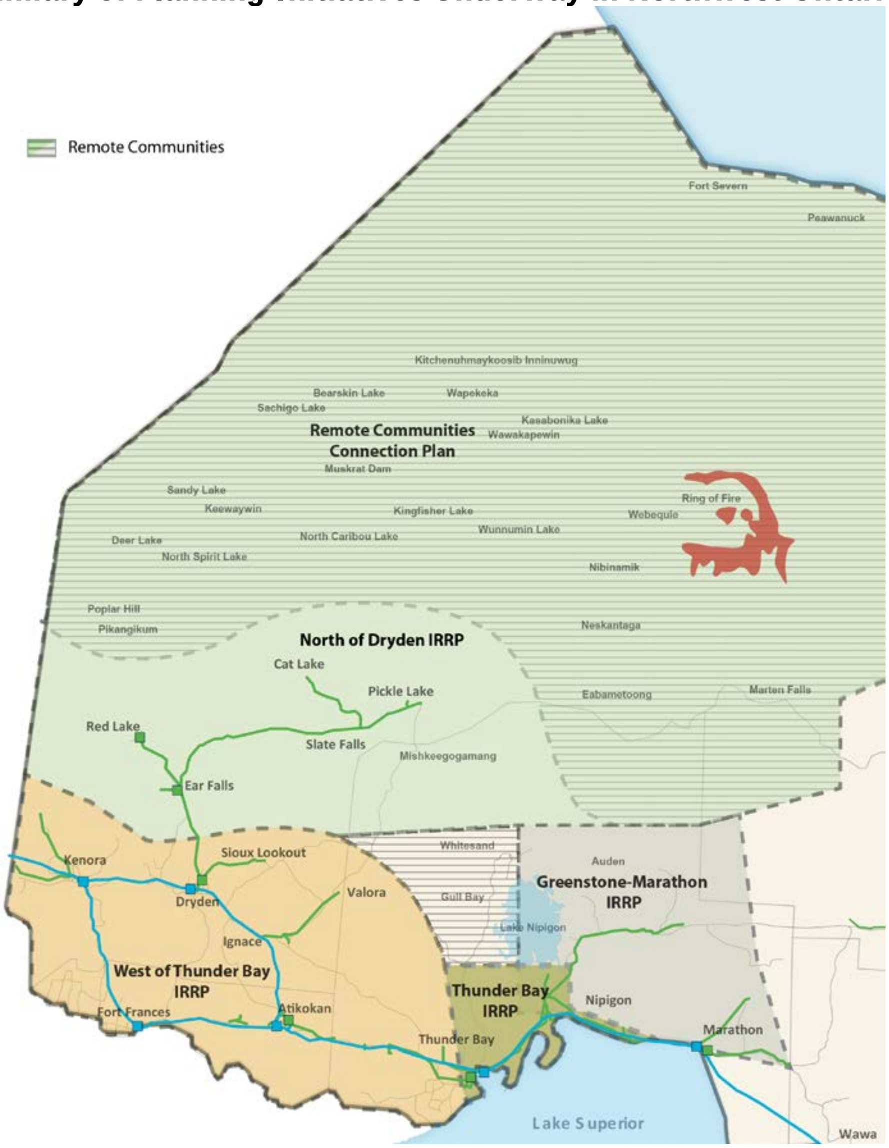
1 EXECUTIVE SUMMARY

Context and Purpose

The purpose of the North of Dryden Integrated Regional Resource Plan (“regional plan”, “North of Dryden IRRP”, or “IRRP”) is to identify the near-term and medium- to long-term electricity supply needs of the area and assess options that are available to address the needs in a timely, reliable and cost-effective manner. The IRRP is intended to provide the overall planning context to address regional supply adequacy and reliability needs.

The North of Dryden IRRP is one of several electricity planning initiatives that the the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 1 identifies the IRRP initiatives currently being undertaken by OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region. This includes requirements at Pickle Lake and Red Lake related to the connection of the 21 remote First Nation communities (“remote communities”) that are economic to connect, as outlined in the Remote Community Connection Plan as well as new mining developments forecasted in the area. It also coordinates with the West of Thunder Bay IRRP, ensuring that the West of Thunder Bay transmission system is able to accommodate the expected growth north of Dryden. The North of Dryden IRRP will also coordinate options related to supply to the Ring of Fire with the Greenstone-Marathon IRRP.

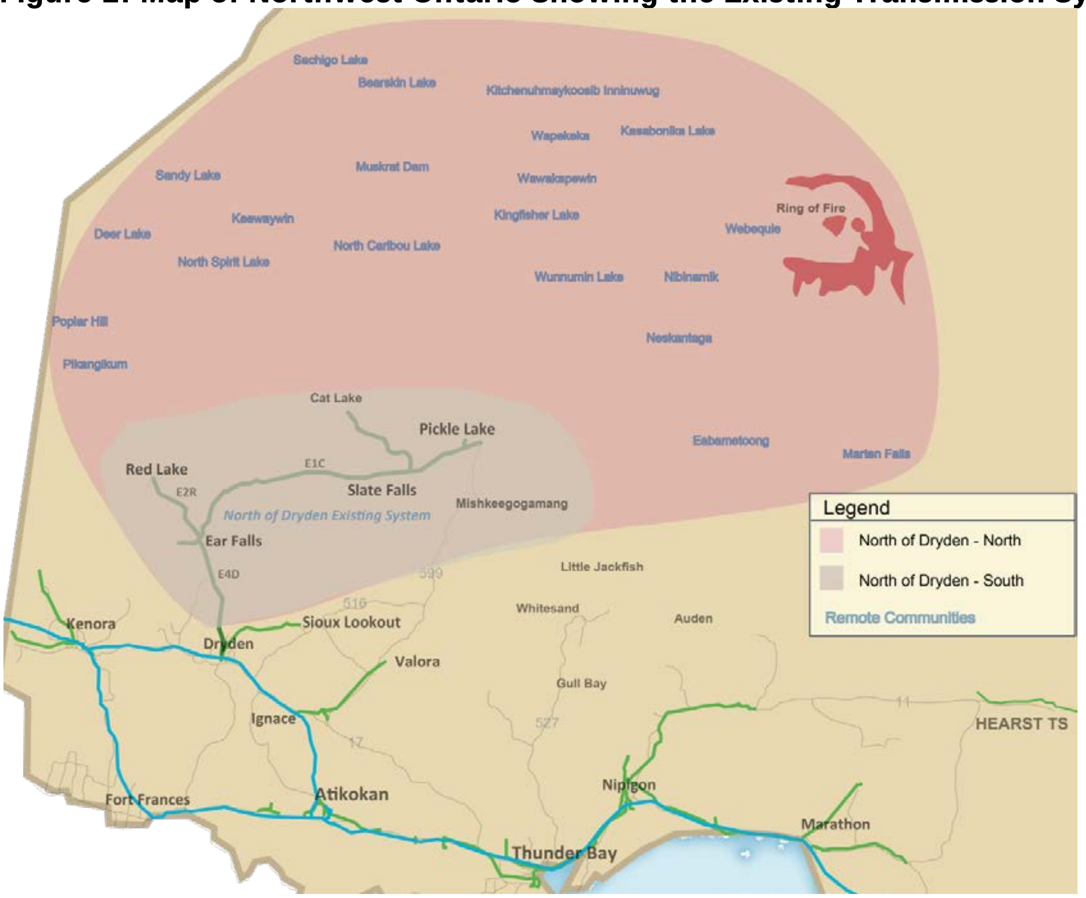
Figure 1: Summary of Planning Initiatives Underway in Northwest Ontario



The North of Dryden sub-region is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the sub-region (shown in Figure 2) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest and Pickle Lake to the northeast. Existing mining activity is primarily located in this southern portion of the North of Dryden sub-region and is largely focused around the towns of Ear Falls, Red Lake and Pickle Lake. The northern portion of the North of Dryden sub-region (shown in Figure 2) contains the

21 remote First Nation communities which are economic to connect, one operating mine, and the mine development area known as the Ring of Fire. At present, only one mine north of Pickle Lake is connected to the transmission grid through a privately owned transmission line.

Figure 2: Map of Northwest Ontario Showing the Existing Transmission System



The North of Dryden sub-region is forecast to experience some of the highest growth in electrical demand in Ontario. Currently the electricity transmission system serving the area is at capacity and is unable to accommodate demand growth.

Mining sector expansion is the primary driver of electricity demand growth in the area; through the expansion of existing mines and the development of new mines, as well as growth in the industries and communities that support the mining sector. Remote

11

communities in the North of Dryden sub-region are currently supplied by diesel generation, however the draft Remote Community Connection Plan[1] developed jointly by the remote communities and the OPA indicates that there is an economic case for connecting the majority of these communities to Ontario's transmission system. The Remote Community Connection Plan is the OPA's primary planning document for these communities, however, the connection would put additional demand requirements on the local transmission system in the areas of Red Lake and Pickle Lake, which is considered in this IRRP.

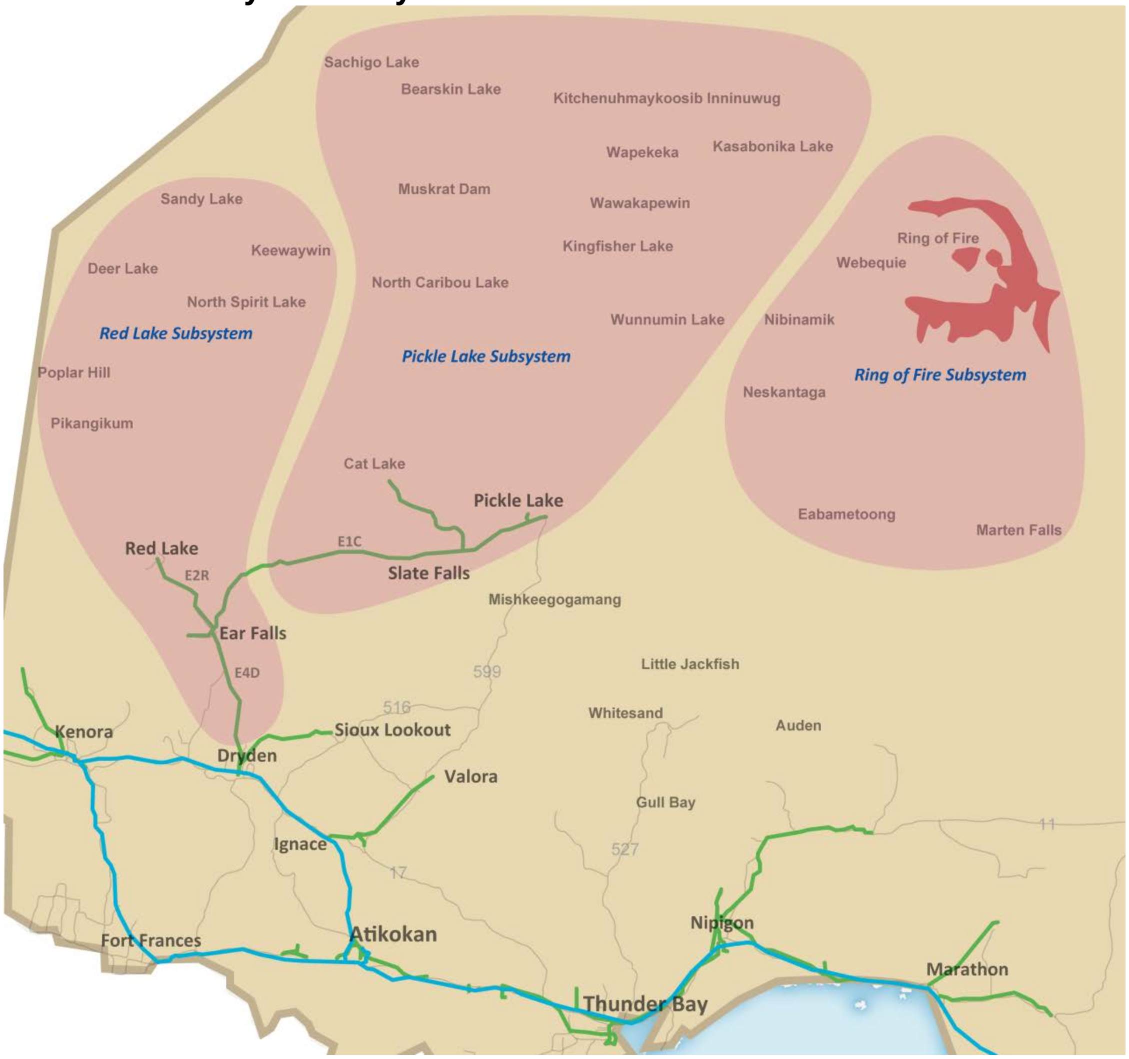
Need Identification

Over the past decade, the annual electricity demand growth in the North of Dryden sub-region has averaged about 1.9%. Growth plans of existing and future customers that are expected to be supplied from the local transmission system indicate that there will be a significant increase in electricity demand over the next 20 or more years.

For study purposes, the area has been segmented into three subsystems generally surrounding Red Lake, Pickle Lake and the Ring of Fire.

[1] A report entitled "Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario" was developed by the Northwest Ontario First Nations Transmission Planning Committee and the OPA. The document can be found at this website: http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 3: North of Dryden Subsystems



Where growth in electricity demand identified in these subsystems cannot be met by the existing system, technically feasible conservation, local generation, and transmission options are identified and compared based on their ability to cost effectively meet the needs.

The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information available at the time.

This regional plan has identified that there is a near-term (2014 to 2018) need for additional Load Meeting Capability[2] ("LMC") in the transmission system currently serving the Red Lake and Pickle Lake subsystems. The regional plan has also identified that the majority of the forecasted growth is expected to occur during the medium term between 2019 and 2023. This is the period when remote communities and new mines are expected to develop and connect to the transmission system. The long term is characterized by steadily increasing demand over the remainder of the planning period (to 2033). The need for incremental LMC by subsystem is summarized in Table 1 below.

Table 1: Incremental Capacity Needs by Subsystem

Sub-system	Near-term Capacity Needs (Present to 2018 in MW)			Medium-term Capacity Needs (2019-2023 in MW)			Long-term Capacity Needs (2024-2033 in MW)		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

Given the magnitude of the increase in electrical demand associated with expanding an existing mine or opening a new mine, as well as growth in electricity demand from growing communities, the area is currently deficient in supply capacity and is expected to become increasingly deficient over the near, medium, and long term.

Options Analysis

The technically feasible options available to meet needs in the Red Lake, Pickle Lake and Ring of Fire subsystems and their implementation timing are outlined in Table 2 below. All costs are net present cost in 2014 dollars, unless stated otherwise (a detailed description of costing methodology can be found in Appendices 10.6, 10.7, and 10.8):

[2] Existing system is thermally limited.

Table 2: Summary of Options

Implementation Timing	Pickle Lake Subsystem	Red Lake Subsystem	Ring of Fire Subsystem
	Conservation and DG Options		
Near term and medium to long term (2014-2033)	Customers may investigate opportunities for additional conservation beyond targets and DG resources to suit their own electrical requirements; Industrial Accelerator Program ("IAP"), Aboriginal Conservation Program, Aboriginal Community Energy Plans Program, remote renewable opportunities after grid expanded to supply remote First Nation communities.		
	Transmission Options		
Near term (2014-2018)	Build a new 115 kV OR 230 kV transmission line from the Dryden/Ignace area to Pickle Lake **Cost: $80 M - $114 M**	Upgrade existing transmission lines serving Red Lake (E4D and E2R) **Cost: $11 M**	East-West Corridor Option: Build a new 115 kV transmission line from Pickle Lake to Ring of Fire for demand up to 67 MW, or build a new 230 kV line if greater than 67 MW. **Cost: $106 M - $156 M** OR North-South Corridor Option: Build a new 230 kV transmission line from either Marathon or a point east of Nipigon to Ring of Fire **Cost: $175 M**
Medium to long term (2019-2033)		If load in the Red Lake subsystem exceeds 109 MW: Install additional voltage support **Cost: $1 M** If load in the Red Lake subsystem exceeds 130 MW: Build a new 115 kV or 230 kV transmission line between Dryden and Ear Falls **Capital Cost: $91 M - $132 M**[3]	
	Generation Options		
Near term (2014-2018)	Gas-fired generator at Pickle Lake fuelled by compressed natural gas, sized and expanded to meet demand growth of up to 31 MW in medium term and up to 76 MW in long	Gas fired generator utilizing up to 30 MW of available gas pipeline capacity at Red Lake **Cost: $51 M**	On-site generation fuelled by compressed natural gas or diesel, **Cost: $209 M - $946 M**[4] Separately connect remote communities
Medium to long term (2019-2033)		Gas-fired generator utilizing up to 30 MW of available gas pipeline	

[3] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of transmission in the long term is $10-15 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[4] Range indicates variation in cost of diesel and compressed natural gas as well as sizing of the generation facility to accommodate the low, reference or high forecast scenarios.

	term **Cost: $158 M - $317 M**	capacity at Red Lake, followed by additional 30 MW at Ear Falls if a new gas pipeline is built **Capital Cost: $95 M - $ 153 M**[5]	**Cost: $ 62 M** **Total Cost: $ 272 M - $1,009 M**

This regional plan considers overall societal costs[6] in determining the least-cost options for supplying the study area. The analysis in this regional plan does not consider the allocation of costs that are attributable to individual customers in the area or how this may affect individual customer decisions on pursuing the societal least-cost options. The final determination of cost allocation between parties will be made through the applicable regulatory process and/or through commercial agreements. For example, cost allocation of transmission and distribution infrastructure is made by the Ontario Energy Board ("OEB"), benefitting customers, and/or transmitters and distributors in the area in accordance with rules set out in the Transmission System Code ("TSC") and Distribution System Code ("DSC").

Summary of Aboriginal, Stakeholder, and Public Feedback

Aboriginal Consultation

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on

[5] For comparison with other options, the long-term Red Lake options are presented as capital costs. The NPV of generation in the long term is $6-8 M. This number is low as the majority of costs are not incurred in the 20 year planning period of this IRRP and the NPV is expressed in 2014 dollars (multiple years of discounting). A fuller description of costing methodology can be found in Appendices 10.6, 10.7, and10.8.

[6] Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment, operations and maintenance, fuel, etc.) but excludes the cost of land, taxes and potential impact benefit agreements that may be reached with affected First Nations, which proponents may be required to pay. Governments (and their agencies) undertake projects of infrastructural, environmental or health and safety enhancements in the wider public interest, assessing project merits in terms of the long-term return to current and future generations of society as a whole, using a social discount rate ("SDR"). The OPA uses a four-percent SDR to determine the present value of options over the planning period.

the Draft North of Dryden IRRP. The OPA and Ministry of Energy provided written notice to each community. The OPA also followed up by telephone to each community and sent all presentation material to each community in advance of the sessions.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. The OPA met with Red Sky Métis Independent Nation on June 19, 2014 at Red Sky’s office in Thunder Bay.

The OPA was in contact with the Métis Nation of Ontario (“MNO”) on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO’s member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights.

Municipal Engagement

The OPA met with municipal representatives in person to solicit feedback on the Draft North of Dryden IRRP to be incorporated into the North of Dryden IRRP. The OPA met with municipal representatives from Pickle Lake, Greenstone, Red Lake, Sioux Lookout, Marathon, Dryden and Ignace in December 2013 and February 2014.

Following the municipal engagement meetings, several common themes emerged from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Written Feedback

Since the posting of the Draft North of Dryden IRRP, the OPA has received written feedback and has followed up with those who contributed written submissions. Written feedback was submitted from the Common Voice Northwest Energy Task Force

(“CVNW”), the township of Pickle Lake, Imperium Energy on behalf of the municipality of Greenstone, the Ontario Waterpower Association, Ontario Power Generation (“OPG”), Gold Canyon Resources Inc., Energy Acuity, and an independently represented stakeholder.

In general, written submissions asked clarifying questions regarding the content in the draft report. It should be noted that CVNW submitted a 51-page report of comment covering topics across the entire Northwest. The OPA has considered the input in this report, has met with CVNW since publishing the draft report, and will continue to consider their feedback for regional planning initiatives across northwestern Ontario.

Based on written feedback provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, OPG identified that Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls Switching Station (“SS”) associated with the installation of voltage control devices. The OPA has considered this feedback in finalizing the plan.

Webinar

The first draft of the North of Dryden IRRP was posted to the OPA’s website in August 2013 and a webinar was held on November 21, 2013 to present the draft IRRP and solicit feedback. Main points of feedback were consistent with that received in written submissions and engagement and consultation meetings.

Recommended Solutions/Actions to be initiated in the near term

The OPA recommends the following solutions for implementation as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem), installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control

devices at Pickle Lake, and transferring the existing load on the line between Ear Falls and Pickle Lake (E1C) to be supplied by this new line;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. Having the Independent Electricity System Operator ("IESO")/OPA initiate discussions with OPG for new reactive power services provided by Manitou Falls Generating Station ("GS") if it is confirmed to be beneficial to the ratepayer.

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long-term forecast scenarios.

The estimated combined present value cost of recommendations (1) and (2) during the planning period is about $124 million[7]. Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

The OPA understands that near-term actions for implementing a new line to Pickle Lake have been initiated by two proponents. Additionally, the OPA understands that Hydro One and various customers in the Red Lake area have initiated discussions to implement the upgrades from Dryden to Red Lake. Implementation of the new 230 kV line to Pickle Lake and the 115 kV line upgrades from Dryden to Red Lake continue to be supported by the OPA.

[7] The August 2013 draft identified this cost as $234-271 million. This change in cost is due to a change in methodology for the NPV economic analysis – treating avoided system generation as a benefit of generation options, rather than a cost to transmission options (as in the 2013 draft). NPV economic analysis is an analysis tool to compare costs over a time horizon, and is not the same as the total project cost for the option being investigated.

Options for the medium to long term period

Pickle Lake Subsystem

The recommendation to build a new single-circuit 230 kV line from Dryden/Ignace to Pickle Lake in the near term would be sufficient under all forecast scenarios for the medium to long term.

Red Lake Subsystem

Following the completion of the near-term recommendations, the 130 MW LMC is expected to be sufficient beyond the planning period for the low and reference forecast scenarios, and until 2030 for the high scenario as shown in Table 1. Therefore, the near-term recommendations are expected to be sufficient to meet the needs of the Red Lake subsystem for the long term.

As shown in Table 2, two options have been investigated for the Red Lake subsystem to address any forecasted load in excess of 130 MW. The OPA recommends that these options, incremental natural gas-fired generation at Red Lake and a new transmission line, be retained as viable long term options and re-evaluated in the next planning cycle (1-5 years) for this IRRP. Re-evaluating plans up to every 5 years is consistent with OEB requirements in the TSC, DSC and the OPA license.

Ring of Fire Subsystem

There are several options for supplying the Ring of Fire subsystem depending on the load growth scenario. The analysis indicates that the Ring of Fire subsystem can be cost-effectively served by a 115 kV transmission connection from Pickle Lake (serving five remote communities and mines at the Ring of Fire), if demand over the long term is 67 MW or less. If demand is reasonably certain to exceed 67 MW in the subsystem, a 230 kV transmission line utilizing an East-West corridor from Pickle Lake, or a 230 kV transmission line utilizing a North-South corridor from either Marathon or east of Lake Nipigon would be required, where these alternatives have approximately equal cost.

The 230 kV transmission options are also expected to be more cost-effective from a societal perspective than the combined cost of developing local generation to serve the total mining load and separately connecting remote communities to Pickle Lake.

The OPA is aware of ongoing work for infrastructure development for the Ring of Fire. Common infrastructure corridors serving multiple uses provide synergies for cost and environmental approvals, and may reduce environmental impacts. The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

Conservation Options

Recently, the OPA has received new direction[8] from the Minister of Energy pertaining to the framework for conservation programs moving forward. Directives from the Minister of Energy set conservation targets, which Local Distribution Companies ("LDC") will plan to meet through the development of conservation plans and programs for their service area. The spirit of this new direction is to provide more opportunity for LDCs, communities, and industry to participate in conservation initiatives so a broader scope of programs is expected to be tailored to the local needs of the region. For remote communities, conservation opportunities are considered in the Remote Community Connection Plan.

Furthermore, the following programs are available through the OPA to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and

[8] *2015-2020 Conservation First Framework (March 31, 2014), Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014), and Industrial Accelerator Program (July 25, 2014).*

band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario's energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Electricity demand of the industrial sector is quite significant in this area. The Industrial Accelerator Program ("IAP") is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA.

Given the large component of industrial demand and number of First Nation and Métis communities in the area, the above mentioned programs should be pursued.

Generation Options for the Medium- to Long-term Period

On May 30, 2014, the OPA closed submissions for the Northwest Ontario Request for Information ("NW RFI"). The purpose of the NW RFI was to gather information on the potential availability of diverse resource options in northwestern Ontario, with particular focus on the interim period to 2020. As part of the NW RFI, the OPA received submissions totaling over 4000 MW for the entire Northwest region. Of the over 4000 MW, a few potential projects were identified in the North of Dryden sub-region and were consistent with the generation options investigated as part of this IRRP.

Procurement of generation is not recommended to be pursued at this time for meeting needs in the North of Dryden sub-region. However, if a generation solution is required for other areas of the Northwest, local benefits of these options to the North of Dryden sub-region will be re-evaluated.

2 INTRODUCTION

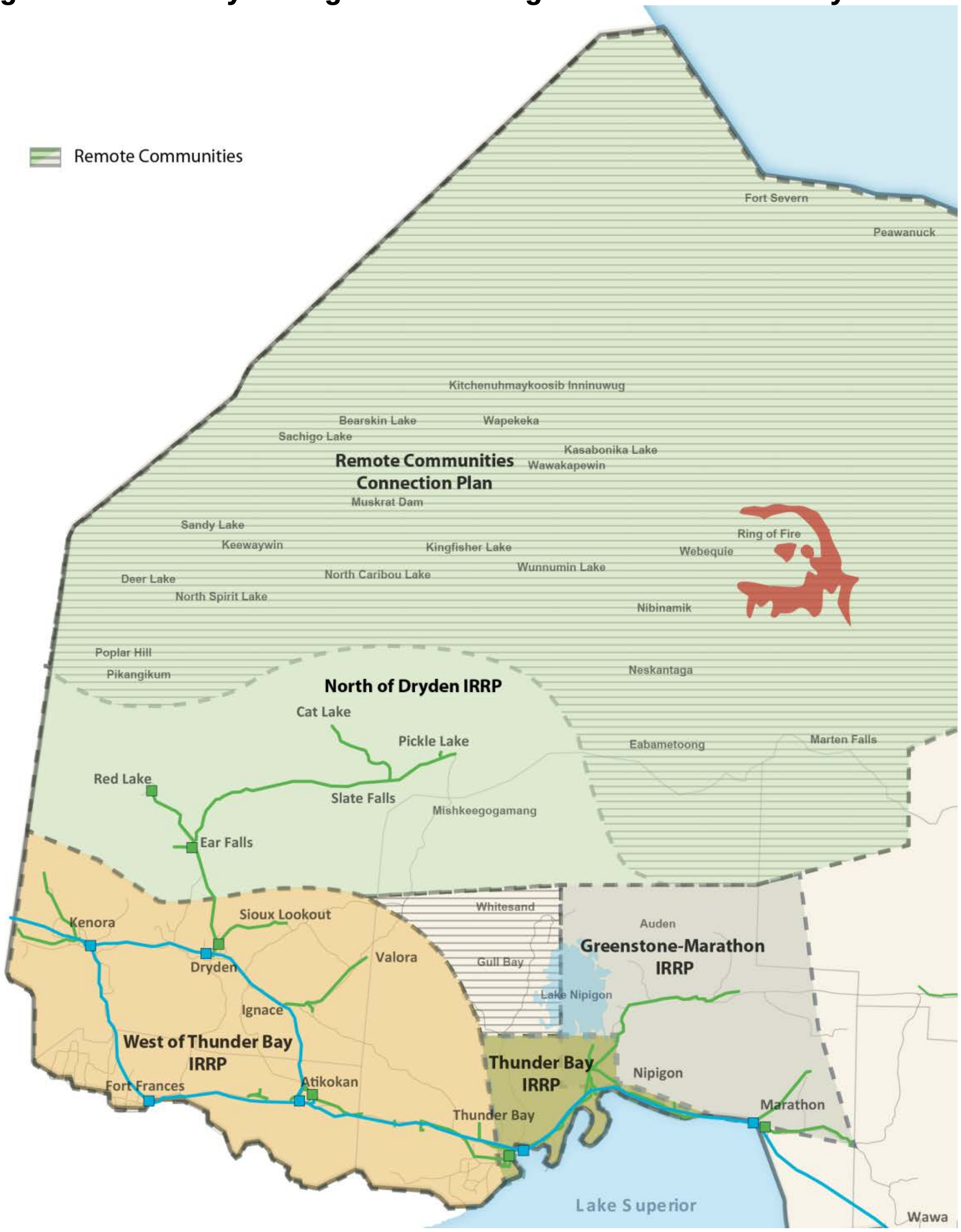
2.1 The North of Dryden Sub-Region

The North of Dryden Integrated Regional Resource Plan (“IRRP”) is one of several electricity planning initiatives that the Ontario Power Authority (“OPA”) is undertaking for the Northwest Ontario region. Figure 4 identifies the IRRP initiatives currently being undertaken by the OPA in the Northwest Ontario region. The North of Dryden IRRP accounts for the demand requirements in the North of Dryden sub-region.

The Thunder Bay IRRP, West of Thunder Bay IRRP and Greenstone-Marathon IRRP were initiated fall 2014. A Scoping Outcome Assessment Outcome Report for northwestern Ontario, which includes the Terms of Reference for three new IRRPs, is available on the OPA’s website, consistent with Ontario Energy Board (“OEB”) requirements. The Terms of Reference for the West of Thunder Bay IRRP and the Greenstone-Marathon IRRP include considerations for relationships with the North of Dryden IRRP.

The North of Dryden sub-region is a natural resource rich area in northwestern Ontario, with existing mining, forestry, and hydroelectric generation operations, as well as potential for substantial new resource development. Mining sector expansion, including expansion of existing mines as well as the development of new mines, is a major driver for electricity demand growth in the area, both at mine sites and through growth in industries that support the mining sector. Another major driver for electricity demand growth in the area is the economic connection of remote First Nations communities (“remote communities”) to the provincial transmission grid, which are currently served by isolated diesel generation systems.

Figure 4: Summary of Regional Planning Initiatives Underway in Northwest Ontario



The transmission system supplying the North of Dryden sub-region is currently at capacity. This IRRP recommends options to provide new high voltage electrical capacity to meet near-term growth, while providing options to meet future growth as it becomes more certain. These near-term recommendations are presented as action items for immediate or early deployment. Options to address potential longer-term needs are also identified, but the OPA does not make a recommendation on a preferred option at this time, as the longer term still remains uncertain and adequate time is available to continue to monitor the situation closely. The OPA will continue to monitor demand growth and reevaluate longer-term options in future planning cycles for the North of Dryden sub-region. When a decision for the longer-term is required, the OPA will make a recommendation for solutions to be implemented.

The North of Dryden sub-region (shown in more detail in Figure 5) is contained within First Nation Treaty areas 3, 5, 9 and the Robinson-Superior Treaty area. It also includes portions of Region 1 and Region 2 of the Métis Nation of Ontario ("MNO"). The southern portion of the area (as shown in Figure 5) is currently served by Ontario's transmission grid and is bounded by Dryden to the southwest, Red Lake to the northwest, and Pickle Lake to the northeast. Current mining activity is mostly contained in this portion of the area, and broadly focused around the Towns of Ear Falls, Red Lake and Pickle Lake.

The northern portion of the North of Dryden sub-region (as shown in Figure 5) is comprised of 21 remote communities, one operating mine and the mine development area in the Hudson Bay lowlands known as the Ring of Fire. At present, the mine north of Pickle Lake is connected to the transmission grid by a privately owned transmission line. There are 25 remote First Nations communities that are distant from the existing provincial transmission system and are currently supplied electricity by local diesel generation facilities. On August 21, 2014, an updated draft Remote Community Connection Plan was made available on the OPA website.[9] The Remote Community Connection Plan demonstrates a business case to connect 21 of 25 remote communities that currently rely on diesel generation, to the provincial transmission grid. The business case is based on the avoided cost of diesel fuel. For the purpose of this regional plan, 21 of the 25 communities are assumed to connect to Ontario's transmission system as per the OPA's Remote Community Connection Plan. Communities are expected to begin connecting in the early 2020s.

[9] http://www.powerauthority.on.ca/sites/default/files/planning/OPA-technical-report-2014-08-21.pdf

Figure 5: Map of Northwest Ontario Showing the Existing Transmission System

Distribution connected customers in the North of Dryden sub-region are served by Hydro One's distribution system. There are also a number of large industrial customers that are connected directly to the transmission system in the area and served by Hydro One's transmission system.

2.2 Purpose and Scope of the IRRP

This regional plan assesses the near-term and medium- to long-term electricity supply needs of the North of Dryden sub-region and identifies the options which are available to address these needs in a cost-effective, reliable, and timely manner. The regional plan is intended to identify alternatives and recommended options to local customers, proponents, and local government so development work may proceed. Proponents may also choose to use this regional plan to support the regulatory proceedings they will undertake to seek approval for their projects.

Regional planning for the North of Dryden sub-region began before the OEB's formalized regional planning process was developed as part of the Renewed Regulatory Framework for Electricity ("RRFE"). Consequentially the North of Dryden IRRP does not have a corresponding Scoping Assessment Outcome Report. The North of Dryden IRRP is considered a "transition plan" as per the Planning Process Working Group ("PPWG") report on Regional Planning to the OEB. This version of the North of Dryden IRRP has transitioned and aligned with OEB requirements for the IRRPs as per the OPA's license.

In 2010, the OPA, Hydro One and the Independent Electricity System Operator ("IESO") began working together to assess the ability of the electricity system in the North of Dryden sub-region to meet forecast growth over the near, medium and long term, and to develop integrated plans to address needs that have been identified. Since beginning this planning work, the OPA has engaged existing and potential customers in the area to identify the size and scope of their future electricity needs in the North of Dryden sub-region. The IESO has also completed a number of System Impact Assessments ("SIAs") and feasibility studies for customers requesting additional capacity.

In addition to the regional planning requirements outlined by the OEB, the Minister of Energy identified in the 2010 Long-Term Energy Plan ("LTEP") that the OPA would develop plans to enable the connection of remote First Nations communities, and identified the development of a new transmission line to Pickle Lake to be a priority transmission project, with the scope and timing to be determined by OPA. In February 2011, the OPA received an updated Supply Mix Directive ("SMD") from the Minister of Energy. The updated SMD requires that the OPA develop a plan to connect remote First Nation communities north of Pickle Lake. In December 2013, the Ministry of

Energy released the second LTEP which reiterated that connecting remote First Nation communities in northwestern Ontario is a priority.

Since 2009, the OPA has been working with remote First Nations communities through the Northwestern Ontario First Nation Transmission Planning Committee ("NWOFNTPC") to identify communities that are economic to connect to the provincial transmission system. Through this partnership, planning is underway for connecting most of these communities to the grid and for developing local solutions for the remaining communities to cost-effectively reduce their reliance on diesel fueled generation.

The North of Dryden IRRP is affected by connection of remote communities in two primary ways:

1. The transmission facilities serving the area must be capable of supplying the electrical demand resulting from the connection of these remote communities; and

2. Options for coordinating connection with mining developments, especially in the Ring of Fire area, must be investigated in accordance with assumptions in the Remote Community Connection Plan.

As new information on the connection of the remote communities becomes available, the North of Dryden IRRP will be updated accordingly and consistent with the regional planning process and PPWG report.

It should also be noted that regional plans consider overall societal costs[10] in determining the least cost options for supplying a study area. This analysis does not

---

[10]Societal costs include direct electricity project costs associated with real incremental goods and services (capital cost of engineering, equipment etc, operating and maintenance, fuel etc.), but excludes the cost of land, taxes, and potential Impact Benefit Agreements that may be reached with affected First Nations, which proponents may be required to pay. cont'd...

consider how the allocation of costs attributable to individual customers in the area may affect their decision to pursue the societal least cost options. The final determination of cost allocation between parties will be determined by the appropriate regulatory process or commercial agreement. For example, cost allocation of transmission and distribution infrastructure is made by the OEB, benefitting customers, and/or transmitters and distributors in the area in accordance with the rules set out in the Transmission System Code (“TSC”) and Distribution System Code (“DSC”).

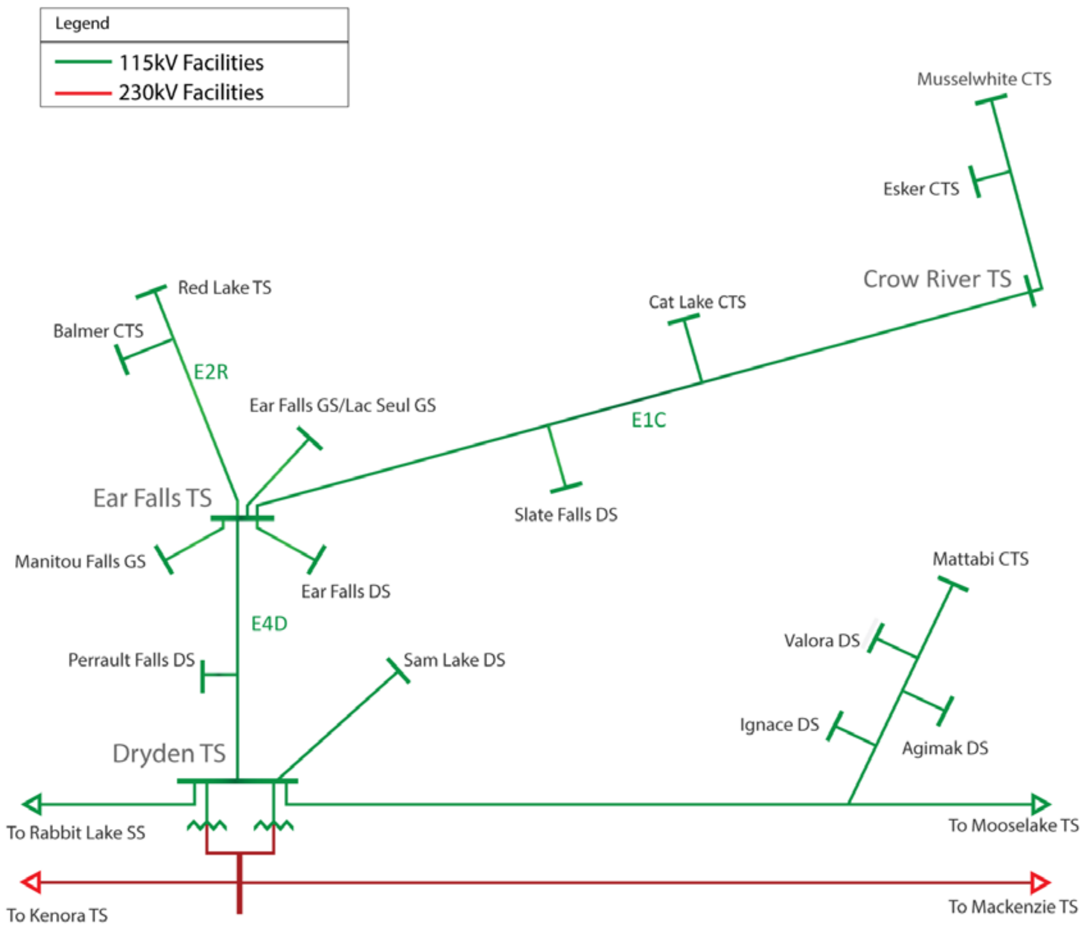
Other planning activities for the region will consider supply needs to the Dryden area for supply of expected load growth in the North of Dryden sub-region. Some of the planning and development work that is underway to ensure an adequate supply is available in the overall Northwest region includes development work being undertaken by NextBridge Infrastructure for an expanded East-West Tie (“EWT”), the May 30, 2014 Northwest Request for Information (“NW-RFI”), and the regional planning initiatives summarized in Figure 4.

...Governments (and their agencies) undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Real Social Discount Rate (Real “SDR”). The OPA uses a 4% Real Social Discount Rate for determining the present value of options over the planning period.

3 NORTH OF DRYDEN TRANSMISSION AND GENERATION FACILITIES

Currently, electricity customers in the North of Dryden sub-region are supplied by a single-circuit 115 kV radial transmission line (“E4D”) emanating from Dryden TS and by local hydroelectric generation. Dryden TS is a major supply station for this area, where the voltage is stepped down from the regional 230 kV system to 115 kV to serve local community and industrial customers as shown in Figure 6 below.

Figure 6 Existing North of Dryden Transmission System



30

At Ear Falls TS, the 115 kV supply branches to the north, east, and west to supply customers and incorporate generation in the area. Hydroelectric generation is connected to the transmission system at Ear Falls generating station (“GS”) (17 MW Ear Falls + 12.1 MW Lac Seul) and at Manitou Falls GS (73.1 MW). To the north of Ear Falls, the E2R transmission line (“E2R”) supplies Red Lake area mining and community customers. East of Ear Falls, the E1C transmission line (“E1C”) supplies the Town of Pickle Lake, Cat Lake First Nation, Slate Falls First Nation, Mishkeegogamang First Nation, as well as a mine via a privately-owned 115 kV transmission line (“M1M”).

For the purposes of this regional plan, the North of Dryden sub-region is divided into three main subsystems, as shown in Figure 7, the Pickle Lake subsystem, the Red Lake subsystem, and the Ring of Fire subsystem. At present, the Ring of Fire subsystem has no transmission infrastructure and is not connected to the provincial transmission grid, and the Pickle Lake subsystem is supplied downstream of the Red Lake subsystem from Ear Falls via E1C.

The Pickle Lake subsystem includes all demand planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as a mine north of Pickle Lake and any new customers that may connect in the Pickle Lake area in the future. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are identified to connect to Pickle Lake in the 2014 Remote Community Connection Plan.

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities north of Red Lake that are identified as being economic to connect to Red Lake TS in the 2014 Remote Community Connection Plan. As mentioned previously, there is 102.2 MW of hydroelectric generation at Ear Falls GS and Manitou Falls GS.

Figure 7: North of Dryden Subsystems

The Ring of Fire subsystem does not include any existing transmission facilities. The subsystem includes five remote communities that are identified for connection in the 2014 Remote Community Connection Plan as well as potential future industrial customers at the Ring of Fire mine development area.

Due to the current system configuration, when a transmission line in the North of Dryden sub-region is forced out of service all load connected to it is lost. In the event that E4D is removed from service, some of the North of Dryden system can be restored by islanded[11] hydroelectric generation in the Ear Falls area until E4D is returned to service. While the area is islanded from the system and supplied by local generation, the amount of load that can supplied is limited to the available generation output.

Historically, the reliability of electricity supply to some customers in the North of Dryden sub-region has been worse than the average for other customers in northwestern Ontario. Specifically, customers in the Pickle Lake subsystem (currently supplied by E1C) have experienced, on average, 14 unplanned outages per year over the past 10 years.[12] This compares to an average of about three unplanned outages per year for customers served by the other 115 kV lines in northwestern Ontario.[13] Planning for the north of Dryden system includes consideration of this historical performance.

---

[11] Islanded: when one part of the system is disconnected and operated separately from the rest of the Ontario electricity system.
[12] Hydro One Networks Inc. through correspondence.
[13] Hydro One Networks Inc. through correspondence.

4 HISTORICAL ELECTRICITY DEMAND

4.1 Historical Electricity Demand

Demand for electricity in the North of Dryden sub-region is driven by a number of factors including mining and forestry activity, as well as local community growth. Mining sector expansion is the primary driver of growth in electricity demand in the area. The north of Dryden area is currently winter-peaking. As shown in Figure 8, peak demand in the North of Dryden sub-region has been growing by approximately 1.9% since 2004. Historical demand includes only the Pickle Lake and Red Lake subsystems, since the Ring of Fire subsystem has not yet developed beyond the five remote communities located east of Pickle Lake. Historical demand figures also do not include remote community demand, since they are not currently connected to the provincial transmission system.

Figure 8: North of Dryden Historical Transmission Connected Demand

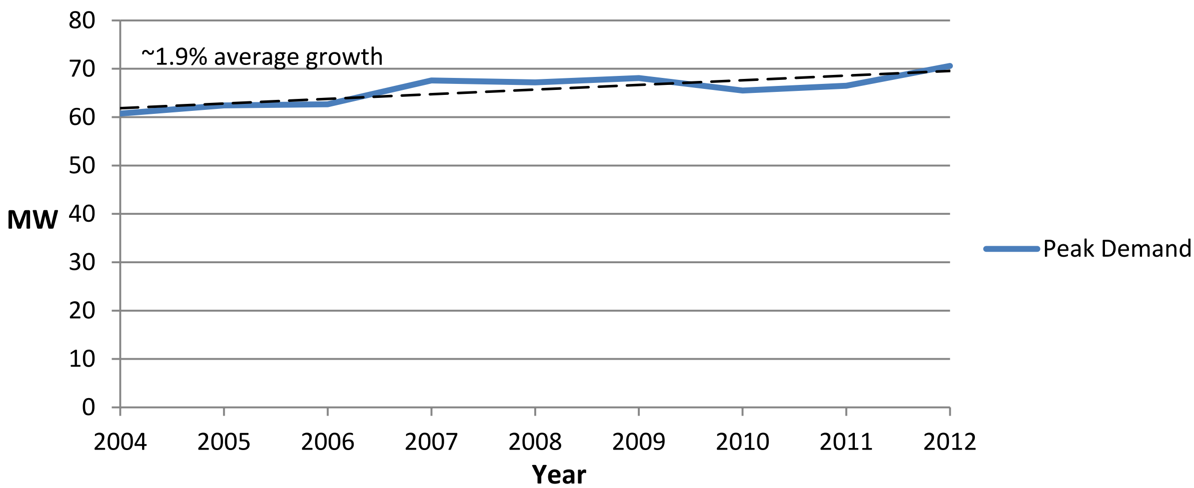
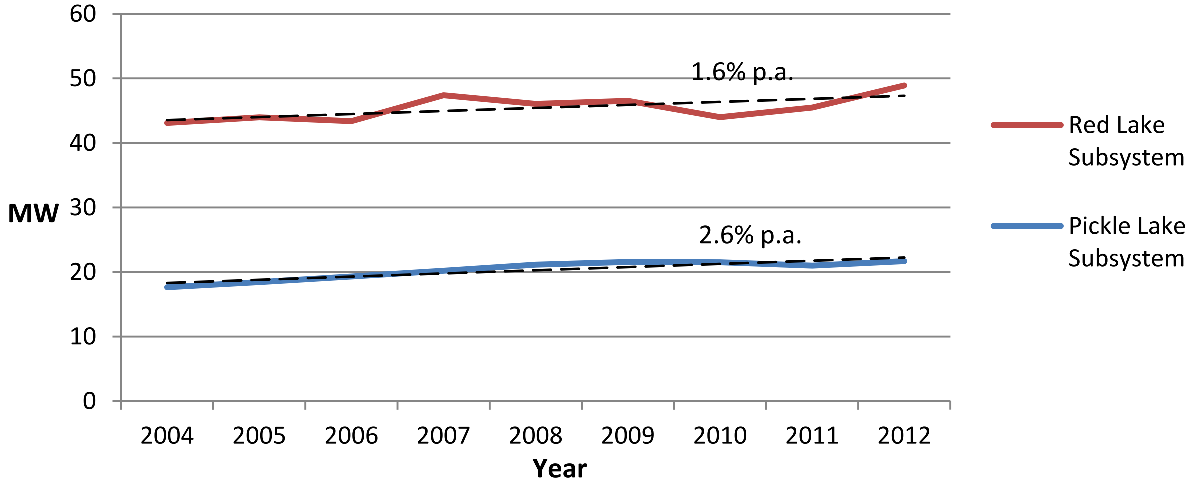


Figure 9 shows that growth in electricity demand has also varied between the Red Lake and Pickle Lake subsystems, with annual growth in electricity demand averaging 1.6% in the Red Lake subsystem and 2.6% in the Pickle Lake subsystem between 2004 and 2012.

Figure 9: North of Dryden Historical Demand by Subsystem



In 2012, 61 MW of capacity was allocated to customers in the Red Lake subsystem, while 24 MW of capacity was allocated to customers supplied in the Pickle Lake subsystem. When the load of the remote communities in each subsystem are added to the connected load, the total load in 2012 increases to 67 MW in the Red Lake subsystem and 31 MW in the Pickle Lake subsystem. At present, no customers in the Ring of Fire subsystem are connected to the provincial grid; however, the combined demand of the five remote communities in the subsystem was about 3 MW in 2012.

4.2 Existing Distributed Generation Resources

Distributed generation is small-scale generation sited close to load centers; it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the *Green Energy and Green Economy Act, 2009* and the associated development of the Feed-in Tariff ("FIT") program have encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Presently, there are five contracted microFIT projects, and one contracted FIT project in the North of Dryden sub-region. All of these projects are located in the Red Lake subsystem. Of these projects, four microFIT solar projects are located in Red Lake with a total contract capacity of 39.3 kW and one microFIT solar project is in Ear Falls with a contract capacity of 10 kW. Analysis of the ability of solar resources in the North of Dryden sub-region to contribute to meeting local demand during the fall months has been estimated to be 5% of contract capacity. Therefore, these units are expected to contribute 2.5 kW to the LMC of the Red Lake subsystem. The FIT project is the Trout Lake River FIT small hydro project, a run of river hydroelectric project near Ear Falls, with a contract capacity of 3.75 MW[14]. The dependable generation level for this project (see Appendix 10.3.2) and its contribution to the LMC of the Red Lake subsystem is assumed to be 0 MW.[15] In total, the contribution of these DG units to the LMC of the Red Lake subsystem is expected to be 2.5 kW (0.0025 MW).

Currently, there are a number of diesel generators that provide backup/emergency supply at mine sites, which are required for health and safety purposes. Generally, these units are not configured for grid connection and thus are not currently available to supply the system. Even if they were configured to connect to the grid, there may be other limitations on their ability to reliably supply load customers on a regular basis including: their age, efficiency, level of emissions, prescribed limits in their operating approvals and their operating and maintenance costs. These units may have some potential to operate as short-term demand management resources, but given the available information they cannot be relied upon to provide the capacity and energy required to meet the needs of the North of Dryden sub-region. Therefore, they have not been considered further in this regional plan.

The Request for Information for Electricity Resources in Northwestern Ontario ("NW-RFI") was issued to better understand the availability of all potential resources in northwest Ontario including the North of Dryden sub-region, with particular focus on the

[14] Trout Lake River GS, is a contracted FIT small hydro project currently under development, with an expected commercial operation date of Q1 2015.

[15] The performance of the facility during drought conditions has not yet been determined, however, the anticipated contribution based on similar facilities in the area, is much less than the tolerance of the modelling software used for this study.

interim period to 2020. The OPA has received submissions to the NW-RFI. Generation options in this plan have considered the relevant NW-RFI submissions. Should new information become available it will be included at the next update of this regional plan.

5 FORECAST ELECTRICITY DEMAND

To develop the demand forecast the OPA worked with Hydro One (the transmitter and local distribution company serving the North of Dryden sub-region), existing and potential transmission connected industrial customers around Ear Falls, Red Lake, and Pickle Lake[16] and the Ring of Fire, municipalities, business associations, as well as remote First Nations communities in northwest Ontario.

5.1 New Demand from Connection of Remote First Nation Communities

The findings of the Remote Community Connection Plan indicate that due to the high and growing cost of diesel fuel as well as the high cost of operating and maintaining remote diesel generation systems, transmission connection of up to 21 remote communities can avoid substantial future costs of about $1 billion over 40 years and therefore economically justifies the connection of the corresponding 21 remote communities to the provincial transmission grid. For the purposes of this IRRP, it has been assumed that these communities will pursue a connection and therefore includes the demand of the corresponding remote communities in the North of Dryden IRRP forecast. The Remote Community Connection Plan indicates that communities may begin connecting between 2018 and 2020, following the development of required capacity in the North of Dryden sub-region transmission system.

5.2 Residential and Commercial Forecasted Demand

The OPA worked with Hydro One to establish the Residential and Commercial component of the demand forecast in the North of Dryden sub-region. The OPA then removed the industrial component of the load that is connected to the distribution system to determine the forecasted residential and commercial forecasted demand. Hydro One Distribution supplies electricity to customers at the following transformer

[16] The load growth is based on information provided to the OPA by Hydro One Networks Inc. and industrial customers in the North of Dryden sub-region. Hydro One provided information relating to existing distribution facilities North of Dryden; this includes existing community loads and some industrial loads. The OPA worked with existing and potential industrial customers to determine their expected near and long-term electricity needs. The forecast has been shared with Common Voice Northwest's Energy Task Force among other interested stakeholders.

stations: Perrault Falls DS, Ear Falls DS, Red Lake TS, Crow River DS, and Slate Falls DS. Cat Lake CTS is owned by Cat Lake Power Utility Ltd., and is supplied by Hydro One's transmission system from circuit E1C.

5.3 New and Expanding Mining Projects

The majority of forecasted demand growth in the North of Dryden sub-region is anticipated to be primarily driven by the mining sector.

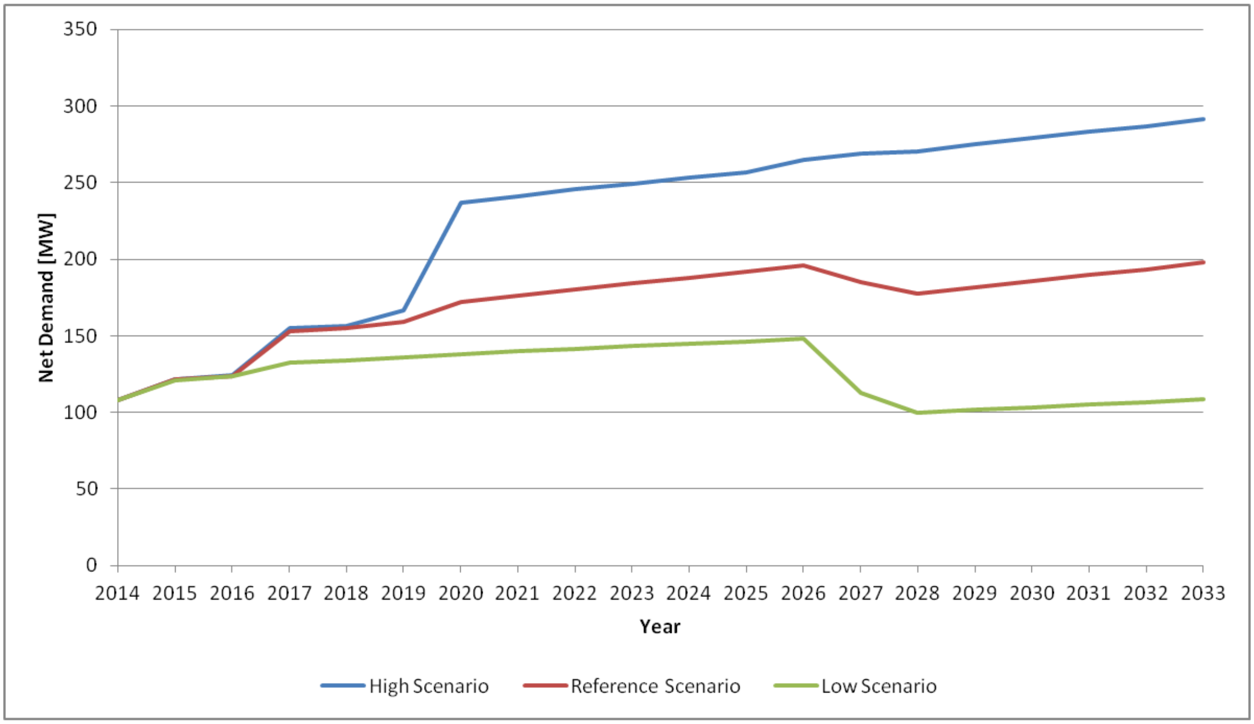
Numerous projects have been proposed in the region, representing a variety of mineral resources, stages of feasibility and development and potential environmental impacts. As mining is a commodity-based industry, there is uncertainty with the timing of mining projects, especially those that are in the relatively early stages of development. This corresponds to uncertainty in the forecasted electrical demand for the area. Recognizing the risk associated with uncertainty in the forecasted demand, the OPA produced three load scenarios. The OPA produced high and low forecast scenarios to capture the range of variability in future electrical demand and a reference forecast to reflect a likely scenario of future demand based on the information presently available.

Through engagement with the mining companies, mining associations and other stakeholders in the region, and by reviewing available technical documents produced by the mining companies regarding their proposed projects, the OPA categorized projects according to the likelihood that they will be developed within their proposed timelines. The projects have been categorized based on several factors, including:

- Stage of development (e.g. under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g. results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g. commodity prices, customers and demand)

Figure 10 shows the forecast range over the planning period.

Figure 10: North of Dryden sub-region Net Demand Forecast

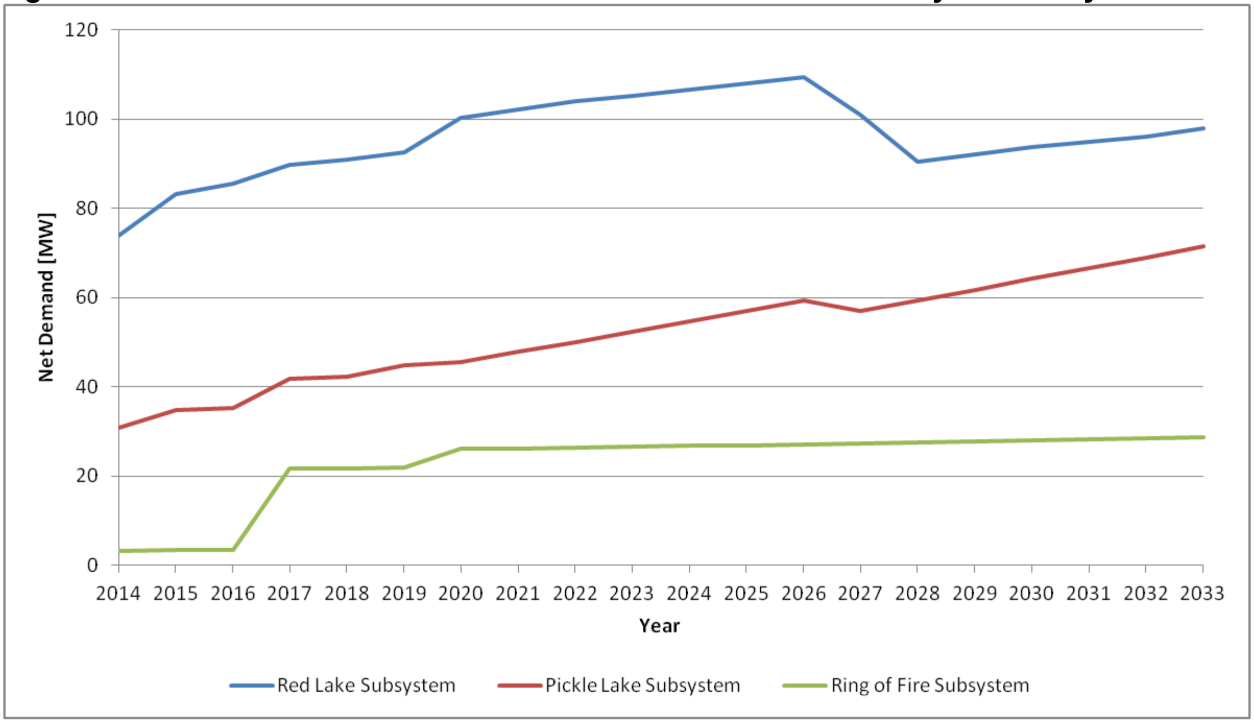


The following descriptions provide the scope of regional activity under the three scenarios.

5.4 Reference Scenario Demand Forecast

Under this scenario, it is assumed that projects currently under construction will be completed and commissioned on schedule. It is assumed that projects with high grade mineral deposits and positive economic assessments will be developed by the timelines specified in their project descriptions with relatively high probability. Projects with potential for extensive environmental impacts are assumed to be unlikely to proceed in the near term as well as projects which are still in the exploration phase. Furthermore, the reference scenario assumes that modest electrical demand driven by the mining sector in the Ring of Fire area is likely to appear before 2024.

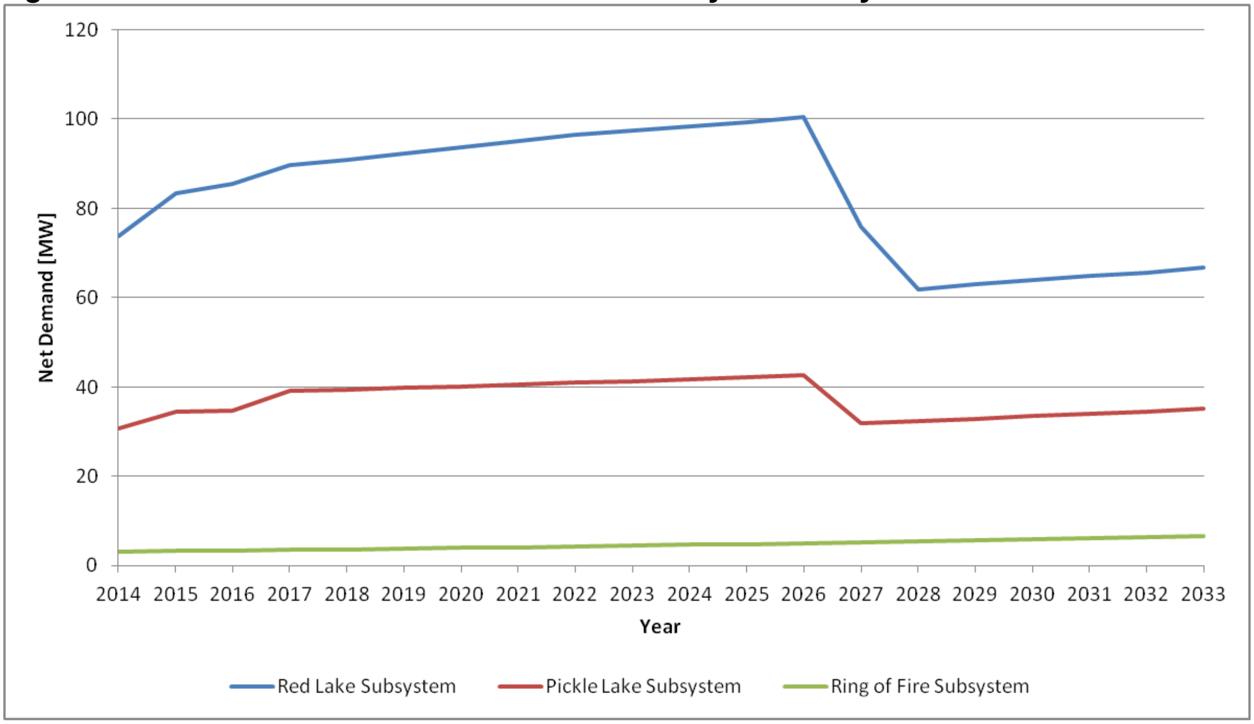
Figure 11: Reference Scenario Demand Forecast for North of Dryden Subsystems



5.5 Low Scenario Demand Forecast

This scenario assumes only the most mature and developed projects (e.g. currently under construction or applying for a leave to construct) are likely to be developed before 2024. It is assumed that other projects with a positive economic assessment will be fully developed with a 50% probability. Early stage exploration projects and projects with marginal economics or environmental, infrastructure and/or accessibility hurdles are assumed to not be developed. This scenario also assumes the Ring of Fire will not be developed before 2034.

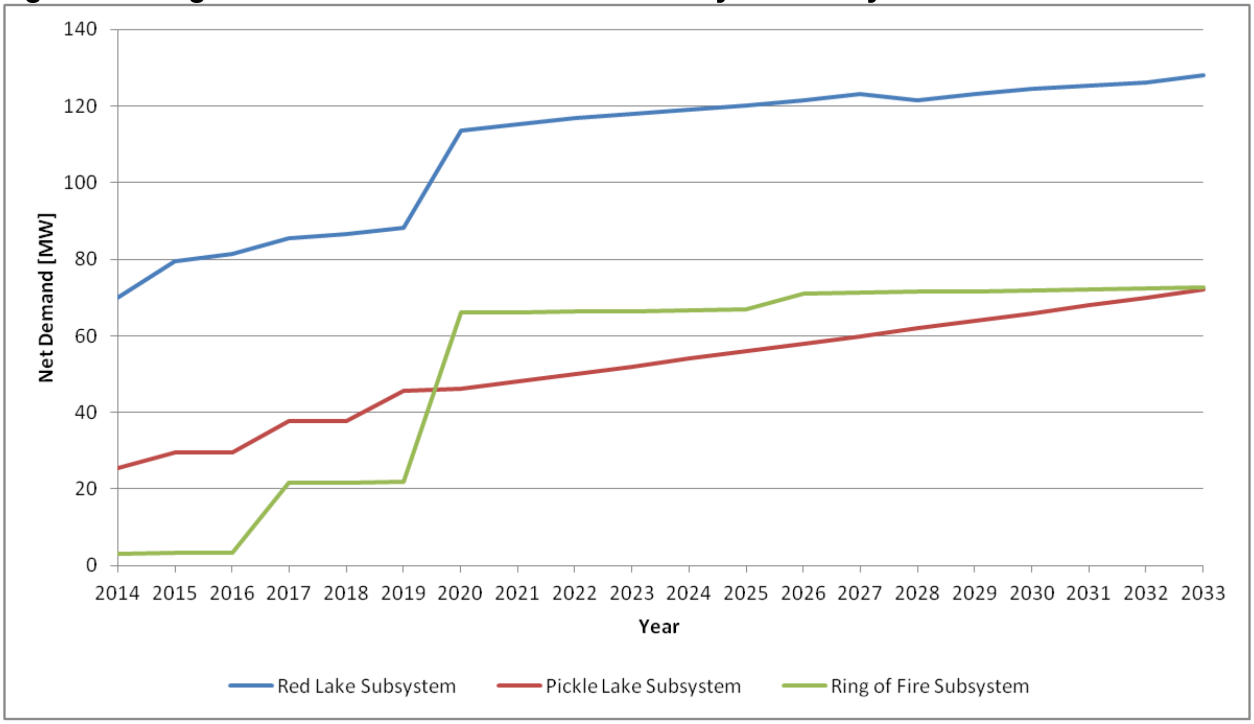
Figure 12: Low Demand Forecast for North of Dryden Subsystems



5.6 High Scenario Demand Forecast

Under the high scenario, most proposed projects are considered likely to be developed and commissioned in the near term. This scenario assumes sufficiently high commodity prices will provide financial feasibility to many projects that may otherwise be considered marginal or uneconomic. The high scenario also assumes an extensive, near- to medium-term build out of the Ring of Fire area, and that multiple mines will be operating in the region by 2020. The expansion of the mining sector is assumed to result in additional expansion of the residential sector in the region, which is also captured in this scenario.

Figure 13: High Demand Forecast for North of Dryden Subsystems



The OPA will continue to monitor electricity demand growth and work with existing and potential customers to maintain up to date electrical demand forecasts for the area. This information will be used to develop regular updates to the North of Dryden IRRP as per the formalized OEB Regional Planning Process.

5.7 North of Dryden Sub-Region Net Electricity Demand

A summary of the net demand forecast scenarios for the North of Dryden sub-region is presented in Table 3.

Table 3: Detailed Net Demand Forecast[17]

NET FORECAST [MW]

Red Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67

Pickle Lake Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35

Ring of Fire Subsystem	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7

[17] Source: OPA developed forecast as described above. Also includes forecasted values provided by Hydro One.

6 NEEDS IN THE NORTH OF DRYDEN SUB-REGION

Planning for the reliable supply of electricity requires anticipating potential equipment outages before they occur and designing a power system that limits the impacts to consumers, based on good utility practices as outlined in the OEB's TSC. This is accomplished through the application of planning criteria. In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC")[18].

In accordance with ORTAC, the transmission system shall have sufficient capability under peak demand conditions to withstand specific outages while keeping voltages, and equipment loading within applicable limits. The maximum demand that can be supplied by an electricity system in a defined area is known as the load meeting capability ("LMC") of that area. Where an area is served by a single transmission line and local generation, the LMC is determined as the capability of the transmission line during normal operation, with the dependable level of local generation respecting the loss of the largest generating unit. If the area is served by a single transmission line without local generation, the LMC is determined as the capability of the transmission line during normal operation since the loss of the single line will result in the total loss of all connected load. The following factors are considered when determining the LMC of a transmission system serving an area:

- the configuration of the system;
- the capabilities of individual elements comprising the system, for the north of Dryden system, this includes the limits of the transmission lines and the dependable levels of hydroelectric generation;[19] and

[18] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf
[19] the dependable level of the existing run of river hydroelectric generation (that is available during drought water flow conditions) is assumed to be available. Details regarding the method for determining the dependable level of hydroelectric and other renewable generation resources for the IRRP are provided in Appendix 10.3.2. Drought conditions are expected to occur about one year in every 10 years and can persist for several months at a time, when watersheds are at their lowest levels in the late summer, fall and early winter months.

- the distribution of demand in the area being supplied.

In general, the greater the distance a given electrical load is located from the inter-regional transmission system (bulk system) supply point (Dryden and/or Marathon or east of Nipigon), the lower the LMC of the system will be. This is due to losses and the need to maintain system voltages within criteria.

6.1 Capability of the Existing North of Dryden System to Supply Forecast Electricity Demand

At present the entire North of Dryden system is supplied from Dryden TS (via E4D) and supported by hydroelectric generation at Ear Falls. The application of ORTAC to the 115 kV transmission system serving the North of Dryden results in an LMC of 85 MW, based on the current line ratings and available dependable hydroelectric generation resources in the Ear Falls area. Existing customers have been allocated 85 MW of capacity on the system and thus the area has reached its capacity limit or LMC. Of this LMC, 24 MW is allocated to the Pickle Lake subsystem and the remaining 61 MW serves the Red Lake subsystem. Mining load in the Ring of Fire subsystem has yet to develop, and the five remote communities in the subsystem are currently supplied by isolated diesel generation. Since the Remote Community Connection Plan identifies that it is economic to connect these communities and there is currently no transmission system serving the Ring of Fire subsystem, the corresponding LMC of the existing provincial power system is 0 MW.

For new customer load to be connected and served in any of the subsystems, additional supply capacity is required. The new capacity needed in order to meet forecast demand growth as provided by Hydro One Distribution, existing and future industrial customers, and the Remote Community Connection Plan (net of planned conservation), is summarized in Table 4 below.

Table 4: Summary of Capacity Needs to Meet the Net Demand Forecast for each Subsystem

Red Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
High Scenario	74	83	85	90	91	93	118	120	122	123	125	126	127	129	128	130	131	133	134	136
Need - High Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*57*	*59*	*61*	*62*	*64*	*65*	*66*	*68*	*67*	*69*	*70*	*72*	*73*	*75*
Reference Scenario	74	83	85	90	91	93	100	102	104	105	107	108	109	101	90	92	94	95	96	98
Need - Reference Scenario	*13*	*22*	*24*	*29*	*30*	*32*	*39*	*41*	*43*	*44*	*46*	*47*	*48*	*40*	*29*	*31*	*33*	*34*	*35*	*37*
Low Scenario	74	83	85	90	91	92	94	95	96	97	98	99	100	76	62	63	64	65	66	67
Need - Low Scenario	*13*	*22*	*24*	*29*	*30*	*31*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*15*	*0*	*0*	*0*	*0*	*0*	*0*

Pickle Lake Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
High Scenario	31	35	35	44	44	52	53	55	57	60	62	64	66	69	71	73	76	78	81	83
Need - High Scenario	*7*	*11*	*11*	*20*	*20*	*28*	*29*	*31*	*33*	*36*	*38*	*40*	*42*	*45*	*47*	*49*	*52*	*54*	*57*	*59*
Reference Scenario	31	35	35	42	42	45	46	48	50	52	55	57	59	57	59	62	64	67	69	71
Need - Reference Scenario	*7*	*11*	*11*	*18*	*18*	*21*	*22*	*24*	*26*	*28*	*31*	*33*	*35*	*33*	*35*	*38*	*40*	*43*	*45*	*47*
Low Scenario	31	34	35	39	39	40	40	41	41	41	42	42	43	32	32	33	33	34	35	35
Need - Low Scenario	*7*	*10*	*11*	*15*	*15*	*16*	*16*	*17*	*17*	*17*	*18*	*18*	*19*	*0*	*0*	*0*	*9*	*10*	*11*	*11*

Ring of Fire Subsystem	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
LMC of Existing System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Scenario	3	3	3	22	22	22	66	66	66	67	67	67	71	71	71	72	72	72	72	73
Need - High Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*66*	*66*	*66*	*67*	*67*	*67*	*71*	*71*	*71*	*72*	*72*	*72*	*72*	*73*
Reference Scenario	3	3	3	22	22	22	26	26	26	27	27	27	27	27	27	28	28	28	28	29
Need - Reference Scenario	*3*	*3*	*3*	*22*	*22*	*22*	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*27*	*28*	*28*	*28*	*28*	*29*
Low Scenario	3	3	3	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	7
Need - Low Scenario	*3*	*3*	*3*	*4*	*4*	*4*	*4*	*4*	*4*	*5*	*5*	*5*	*5*	*5*	*5*	*6*	*6*	*6*	*6*	*7*

There is a near-term (present to 2018) need for additional capacity (incremental LMC) in each subsystem. The summary of capacity needs indicates that there will be need for 18 MW and up to 20 MW in the Pickle Lake subsystem, 30 MW in the Red Lake subsystem and 22 MW in the Ring of Fire subsystem in the near term.

The majority of forecast demand growth for the North of Dryden sub-region is expected to occur in the medium-term period between 2019 and 2023. This is the period when remote communities and most new mines are expected to connect their load to the system. The long term is characterized by steadily increasing demand over the remainder of the forecast period (2024 to 2033).

In the medium term, capacity needs in the Pickle Lake subsystem are forecast to be 28 MW and up to 36 MW, and up to 59 MW by the end of the planning period in 2033. In the Red Lake subsystem needs are forecast to be 44 MW and up to 62 MW in the medium term, and up to 75 MW by the end of the planning period in 2033.

The capacity need for the Ring of Fire subsystem, which includes potential mines at the Ring of Fire and the connection of five remote communities east of Pickle Lake, is driven by when and if mines connect to the transmission system. If the mines do not connect, then only the demand of the five remote communities will need to be supplied by the system. This is forecast to be 4 MW at the time of connection and up to 7 MW by the end of the planning period in 2033. If the potential Ring of Fire area mines that are considered in the load forecast develop, the capacity need for the Ring of Fire subsystem is forecast to be up to 73 MW by the end of the planning period.

The near-, medium- and long-term capacity needs of each subsystem are summarized in Table 5 below.

Table 5: Summary of Incremental Capacity Needs by Subsystem[20]

Subsystem	Near-term Capacity Needs (Present to 2018 in MW)			Medium-term Capacity Needs (2019-2023 in MW)			Long-term Capacity Needs (2024-2033 in MW)		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
Pickle Lake	20	18	15	36	28	17	59	47	11
Red Lake	30	30	30	62	44	36	75	48	39
Ring of Fire	22	22	4	67	27	5	73	29	7

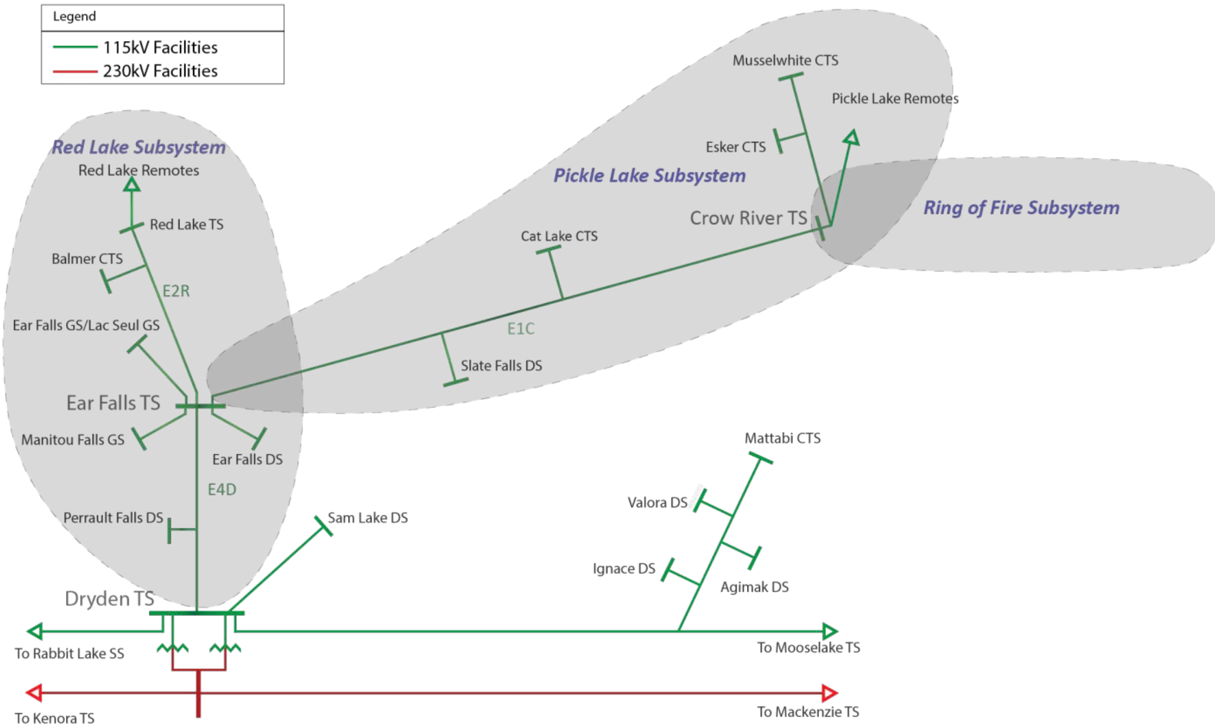
[20] Includes LMC required to supply remote communities that are economic to connect.

6.2 Interdependence between Subsystems

Due to the existing connection of the Pickle Lake subsystem to the Red Lake subsystem at Ear Falls, there is an existing interdependency between these subsystems. Identifying the interrelationships between subsystems is necessary because the supplying subsystem will need to have sufficient capacity to serve the needs of both subsystems. If the Pickle Lake subsystem is supplied completely by a new dedicated transmission connection, then it would be possible (and advantageous during drought conditions) to open the connection between Pickle Lake and Ear Falls (on E1C) and remove this interdependency.

Further, if the Pickle Lake subsystem has sufficient capacity in the future and the Ring of Fire subsystem is connected to Pickle Lake, then a new interdependency between the Pickle Lake and Ring of Fire subsystems would be created. These relationships are highlighted on the map below in Figure 14, which shows the amount of load in the dependent subsystem that is or would be served from the supplying subsystem. The ultimate capacity needed in the Red Lake and Pickle Lake subsystems will depend on the how the Pickle Lake and Ring of Fire subsystems are supplied in the future.

Figure 14: North of Dryden Subsystems and Points of Intersection



51

7 OPTIONS AND ALTERNATIVE DEVELOPMENT

This section identifies and evaluates options for developing integrated solutions that meet the needs identified in Section 6. Options applicable for all subsystems are described first, subsystem-specific options are then discussed. The options for the Pickle Lake subsystem are then evaluated,[21] followed by those of the Red Lake subsystem and the Ring of Fire subsystem. The options for addressing the needs of the North of Dryden sub-region are divided into those that can meet near-term needs (present-2018) and those which can meet the medium- and long-term needs (2019-2033) for each subsystem. Technically viable options are identified and evaluated in the context of their ability to meet the needs of each subsystem based on cost,[22] ability to meet reliability criteria, incremental capacity enabled, and in-service date.

7.1 Conservation, Renewable and Distributed Generation

Opportunities for Further Cost Effective Conservation in the North of Dryden sub-region

Conservation is important in managing the demand in the North of Dryden sub-region. However, the high levels of load growth anticipated for the sub-region, resulting from connection of new industrial customers and the remote communities require the incorporation of supply-side solutions such as new transmission, distribution and/or generation facilities in the near term. New industrial facilities are assumed to install relatively efficient equipment from the beginning given the inherent economic benefits and the improved codes and standards.

[21] The Pickle Lake subsystem is assessed first because of its interdependence with both Red Lake and Ring of Fire subsystems. Decisions for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem and available options for the Ring of Fire subsystem.

[22] The costs represented in this report are incremental to costs that would have otherwise been incurred for the overall Ontario power system generation capacity needs. The Ontario electricity system will require incremental generation capacity to reliably serve all Ontario customers during peak demand periods by about 2018. Generation resources developed in the North of Dryden sub-region would contribute to meeting this provincial need. Cost for generation in the North of Dryden area is represented as the incremental cost above the least-cost generation option for Ontario. Details of costing methodology can be found in Appendix 10.4.

The OPA evaluates, measures and verifies ("EM&V") conservation program savings. Moving forward, the OPA will continue to monitor conservation achievement in the North of Dryden sub-region and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the medium and long term.

In Achieving Balance: Ontario's Long-Term Energy Plan ("LTEP 2013"), the government established a provincial Conservation and Demand Management ("CDM") target of 30 TWh in 2032. To assist the government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015. Meeting these targets was included in establishing the needs described in Section 6. These targets apply to currently grid-connected communities and customers. The Conservation included in the net demand forecast for each subsystem is provided in Table 6 below. For remote communities, conservation opportunities are considered in more detail in the Remote Community Connection Plan.

Table 6: Forecasted Conservation Savings in North of Dryden Sub-Region

	2014	2019	2024	2029	2033
Pickle Lake Subsystem	0.1 MW	0.5 MW	1.2 MW	2.0 MW	2.6 MW
Red Lake Subsystem	0.2 MW	1.1 MW	2.6 MW	4.0 MW	5.3 MW
Ring of Fire Subsystem	0.0 MW	0.2 MW	0.4 MW	0.7 MW	0.9 MW

It is anticipated that the energy efficiency savings identified in Table 6 above will be achieved mainly through measures aimed at the current load base and the load added through connection of the remote communities. The 9 MW in reduced peak demand represents about a 7% reduction of load in this area. The additional mining load is expected to be built using current codes and standards and will be operating at better energy efficiency compared to older facilities. Thus it is not anticipated that the new mining load will be able to contribute much more to energy efficiency programs. Conservation forecast in the region is derived from the provincial target and is consistent with LTEP 2013.

Given the anticipated electricity demand growth, there are opportunities in the medium to long term for proponents to pursue conservation savings. The following tools and programs could be used to achieve conservation savings in the sub-region.

Recently, the OPA has received direction from the Minister of Energy pertaining to the framework for Conservation programs[23] moving forward:

1. *2015-2020 Conservation First Framework (March 31, 2014):* To remain on track to achieve Ontario's 2013 LTEP CDM target, it is forecasted that 7 TWh needs to be achieved between 2015 and 2020 through Distributor CDM programs enabled by the Conservation First Framework. In addition, transmission-connected customers will continue to have access to OPA CDM programs. The OPA is directed to coordinate, support and fund the delivery of CDM programs through Distributors to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020.

2. *Continuance of the OPA's Demand Response Program under IESO management (March 31, 2014):* In LTEP 2013, Ontario signaled that responsibility for existing demand response ("DR") initiatives and introduction of new DR initiatives will be transferred from the OPA to the IESO.

3. *Industrial Accelerator Program (July 25, 2014):* The 5-year Industrial Accelerator Program ("IAP") established through the March 4, 2010 ministerial direction, will conclude on June 23, 2015. The Minister has directed the OPA to deliver the IAP for the period commencing June 23, 2015 through December 31, 2020, with a CDM target of 1.7 TWh for the period.

The spirit of the directive is to provide more opportunity for Local Distribution Companies ("LDCs"), industry, and communities to participate in conservation initiatives

[23] The current framework for Conservation programs does not apply to remote communities. These communities are anticipated for connection post-2020, which is the end of the existing framework.

so a broader scope of programs is expected to be tailored to the local needs of the region.

Each LDC will develop their conservation plans and programs to demonstrate. In assisting LDCs, the OPA has launched an online Tool Kit to provide LDCs with the information and planning resources needed to design an effective CDM plan to serve their customers. One of these resources is the Regional Achievable Potential Calculator which assists the utilities in estimating potential Conservation savings in their service regions. Use of this tool can also achieve an understanding of the potential for further conservation specific to the North of Dryden sub-region.

The IAP is available to industrial customers as a means of achieving conservation savings with financial assistance from the OPA. Given that electricity demand of the industrial sector is significant in the area, this could be a good opportunity for conservation in the sub-region. Also, the IAP program expanded the eligibility to allow commercial and institutional customers. These customers can be directly connected to the grid or connected via an LDC.

Furthermore, the following programs are available to Aboriginal Communities:

- Aboriginal Conservation Program, with the aim to provide customized conservation services designed to help First Nation communities, including remote and northern communities, reduce their electricity use in residential housing, and in commercial and institutional buildings, like stores, schools and band offices. This program will be offered for one additional year (ending December 31, 2015) until such time as LDCs are able to develop a CDM program which recognizes the specific requirements of on-reserve First Nation communities as per the 2015-2020 Conservation First Framework Directive.

- Aboriginal Community Energy Plans program to support Aboriginal participation in Ontario’s energy sector by providing up to $90,000 per community in funding to First Nation or Métis communities for local energy planning activities, with remote communities being eligible for an additional $5,000.

Opportunities for Renewable and Distributed Generation in the North of Dryden sub-region

A high level assessment of the cost of renewable and distributed generation resources to meet the capacity needs of the North of Dryden sub-region was completed, estimating the dependable capacity of hydroelectric (run of river), wind, and solar resources. Dependable capacity refers to the portion of the total installed capacity that can be relied upon to meet local or system peak capacity needs. This refers to 98-percentile output. Based on the dependable capacity, costs were developed for these renewable resources. Based on the cost of other local generation and transmission options that are discussed in the following sub-sections, run of river hydroelectric, wind, and solar are not cost effective solutions for meeting the needs of the North of Dryden sub-region in the near and medium-term periods.

Details of these alternative generation resources are provided in Appendix 10.3.2 and summarized below in Table 7.

Table 7: Summary of Alternative Generation Options

Resource Type	Dependable Capacity	Capital Cost per MW of Dependable Capacity	Levelized Unit Energy Cost[24]	Development Duration
Hydroelectric (Run of River)	15-30%	$16 M-$66 M /MW	$60-$110/MWh	5 to 10 Years
Intermittent Renewables	5-28%	$7.5 M -$100M /MW	$80-$400/MWh	3 Years

While run of river hydroelectric or renewable resources are not cost-effective to meet the North of Dryden sub-region peak capacity needs, there may be opportunity for proponents to develop such projects for broader Ontario supply needs in accordance

[24] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.

with renewable policy objectives for the provincial supply mix as set in the 2013 LTEP. Additionally, the connection of remote communities may provide the opportunity to explore development opportunities in the far north, in the longer term.

The remainder of Section 7 will assess the generation and transmission options that can cost effectively meet the identified capacity needs of the North of Dryden sub-region.

7.2 Summary of Recommended and Assessed Options for Meeting Pickle Lake Subsystem Needs

Based on the following analysis, the OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario. A line built to 230 kV standards also mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when the local system is capacity constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand periods coincident with drought hydroelectric conditions.

The following section summarizes the analysis and comparison of options.

Within the context of the North of Dryden IRRP, the Pickle Lake subsystem is assessed first because of its interdependence with both the Red Lake subsystem and the Ring of Fire subsystem as discussed in Section 5.2. Decisions made for serving the Pickle Lake subsystem will impact the capacity needs for the Red Lake subsystem at Ear Falls TS and the options for serving the Ring of Fire subsystem.

As mentioned previously, the Pickle Lake subsystem is currently supplied by the 115 kV line E1C from Ear Falls TS and the subsystem has reached its LMC. The forecasted near-term growth and medium- to long-term growth cannot be met by the existing system and other supply options are required. Identified needs for the Pickle Lake subsystem are summarized in Table 8, below.

Table 8: Needs for Pickle Lake Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (Present-2018)	***Near term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem*	***43***	***46***	***48***
	Near term Total 2: *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem*	***43***	***64***	***66***
Medium and long term (2019-2033)	***Medium and long term Total 1:*** *Supply Mining and Community Demand in the Pickle Lake Subsystem, and Supply the 5 Communities in the Ring of Fire Subsystem*	***48***	***78***	***90***
	Medium and long term Total 2: *Supply Mining and Community Demand in the Pickle Lake Subsystem and in the Ring of Fire Subsystem*	***48***	***100***	***156***

The following generation and transmission options have been identified to fully or partially meet these needs.

Table 9: Summary of Options to Meet the Needs for Pickle Lake Subsystem[25]

Options	Capital Cost	PV Option Cost	Incremental Load Meeting Capability [MW]	PV Unit Cost of Utilized Capacity
CNG Generation at Pickle Lake[26,27]	$132 M	$294 M	54	$5.44 M/MW
115 kV line to Pickle Lake[28]	$126 M	$80 M	18 + 35	$1.31 M/MW
230 kV line to Pickle Lake[18]	$167 M	$106 M	54 + 35[29]	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake, Stage 1: operate at 115 kV[18] Stage 2: upgrade to 230 kV	$155 M $14 M	$98 M $5 M	46 + 35 114	$1.08 M/MW $0.63 M/MW

The 115 kV transmission line option would not be adequate to meet the needs of the Pickle Lake subsystem, with or without the Ring of Fire mining load supplied from Pickle Lake under the reference scenario forecasted load. The reference scenario forecast is considered the most likely scenario. The only scenario assessed that the 115 kV transmission line option would be adequate for the long term is the low scenario. The reference and high scenarios with and without the Ring of Fire mining load supplied from Pickle Lake would require a new 230 kV line.

Based on the following factors, the OPA recommends that a single circuit 230 kV line be developed as soon as possible:

- There is currently insufficient capacity to supply existing electrical demand; and
- A 115 kV line is insufficient to meet the reference scenario forecast demand, which is considered most likely, and therefore there is material risk in not meeting the long-term demand of the Pickle Lake subsystem with a 115 kV line; and

[25] Description of the method for calculating costs is provided in Appendix 10.7.1 and 0. Note all costs include reactive compensation required to meet stated LMC.
[26] Requires continued supply of 24 MW of load via E1C from Ear Falls TS
[27] Generation could be developed in 2-3 years
[28] Transmission options cannot be developed before 2016
[29] 35 MW are in the Red Lake subsystem. System is voltage limited and can reach a higher LMC with additional reactive compensation. Costing does not include reactive compensation required to supply Ring of Fire.

- A 230 kV line to Pickle Lake is required to preserve the option of supplying the Ring of Fire utilizing an East-West corridor; and
- An East-West infrastructure corridor to the Ring of Fire continues to be a viable option being considered by mining developers.

Decisions made regarding a common infrastructure corridor (e.g. transportation, etc.) to the Ring of Fire should be monitored and reflected in updates to this IRRP.

7.2.1 **Discussion of Options to Meet the Needs of the Pickle Lake Subsystem**

Both generation and transmission options are considered for meeting the needs of the Pickle Lake subsystem. In developing these options, the economic connection of remote communities and maintaining supply options to the Ring of Fire are key planning factors.

The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect in accordance with the conclusions of the Remote Community Connection Plan. The lowest cost transmission connection option for the five remote communities in the Ring of Fire subsystem, independent of the Ring of Fire mines, is to connect to Pickle Lake. Therefore, for the purposes of the IRRP, sufficient capacity would need to be made available in the Pickle Lake subsystem to connect up to five remote communities in the Ring of Fire subsystem as a minimum. Given the uncertainty around other infrastructure development plans for the Ring of Fire area, there is also long-term value in maintaining the option for Ring of Fire mines to connect at Pickle Lake. This connection could be realized utilizing an East-West multi-use corridor, which is being promoted by some mining developers in the area. Details are discussed in the following sections.

7.2.1.1 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

From Table 8, this scenario requires an LMC of 46 MW for the near term, and 78 MW for the medium and long term.

Generation Options

There is no existing supply of natural gas in the Pickle Lake subsystem and the OPA is not aware of any plan to expand natural gas pipeline service to Pickle Lake. However, generators fueled by Compressed Natural Gas (“CNG”) could be developed in the Pickle Lake area, as CNG could be produced and transported from the TransCanada Pipelines Limited (“TCPL” or “TransCanada”) mainline near Ignace to Pickle Lake along Highway 599 and beyond as needed. The cost of developing a CNG production facility at Ignace and transporting CNG from Ignace to Pickle Lake is significant and results in a much higher delivered cost of natural gas than in areas that are served by natural gas pipelines, such as Red Lake. To minimize generation costs in this option, it is assumed that the Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will continue to be served from Ear Falls TS.

The remaining 22 MW of LMC for the near term and 54 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 22 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 47.5 MW would be required with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). Similarly, to make available 54 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total installed generation capacity of 76 MW would be required with a maximum unit size of 9.5 MW (i.e. 8x9.5 MW).

This arrangement of units would ensure that load could be supplied with up to two units unavailable by either forced or planned outages, while maintaining flows on E1C and at Ear Falls TS within thermal and voltage limits consistent with requirements outlined in ORTAC. Table 10 summarizes the gas generation capacity required and the increase in the Pickle Lake LMC it will provide.

Table 10: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term Reference Forecast Demand[30] [MW]	Medium and Long term Reference Forecast Demand[20] [MW]
Near term: 47.5 MW CNG Generation at Pickle Lake[31]	28.5	52.5	46	78
Medium and Long term 76 MW CNG Generation at Pickle Lake[21]	57	81	46	78

The cost (summarized in Table 11) of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation includes any additional required voltage control devices at Pickle Lake.

Table 11: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW
76 MW CNG Generation at Pickle Lake[32]	1-2 Years	$132 M	$294 M	$5.44 M/MW

Generation resources in the Pickle Lake subsystem would be operated to serve local demand in the Pickle Lake subsystem in the event that load exceeds 24 MW and would likely not be dispatched in the Ontario market for supplying provincial system load due to relatively high cost of operation. At present the Ontario system has sufficient generation capacity to meet system peak and energy needs; however, by 2018 a need for additional peak capacity is forecasted. Local generation at Pickle Lake would serve demand that would otherwise be served by generation somewhere else in the system and would help to offset some of this Ontario system need.

Transmission Options

[30] Includes demand for Ring of Fire remote communities (7 MW).
[31] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.
[32] Size is cumulative.

The OPA has identified three transmission options for reinforcing the supply to the Pickle Lake area.

The transmission options are:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake.

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer.

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and initially operated at 115 kV by connecting it to M2D on the 115 kV system near Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be operated at 230 kV by re-terminating on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Pickle Lake.

The 230 kV line options, Options 2 or 3, are capable of supplying the reference scenario forecasted demand for the Pickle Lake subsystem including the five remote communities in the Ring of Fire subsystem until the end of the planning period.

The 115 kV line option is capable of supplying the Pickle Lake subsystem, including the five remote communities in the Ring of Fire subsystem up to a demand of 70 MW, which is the LMC of the option. This corresponds to year 2030 for the reference scenario forecasted demand.

By opening E1C at Ear Falls TS, the Red Lake subsystem no longer supplies the Pickle Lake subsystem. Under this arrangement the capacity that was allocated to the Pickle Lake subsystem (24 MW, which corresponds to 35 MW at Ear Falls due to losses), is offloaded. In other words, a new line to Pickle Lake also provides 35 MW of incremental LMC to the Red Lake subsystem. This occurs because the new line would serve the entire load along E1C. This benefit must be accounted for in the analysis.

Details of these options have been summarized in Table 12 and Table 13 below.

Table 12: Capacity of Transmission Options

Transmission Options	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term Reference Forecast Demand[33] [MW]	Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[33] [MW]
115 kV line to Pickle Lake[34]	46	35	81	70	46	78
230 kV line to Pickle Lake[35]	136	35	171	160	46	78
Pre-build 230 kV line to Pickle Lake[35] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[35]	 46 136	 35 35	 81 171	 70 160	46	78

[33] Includes demand for Ring of Fire remote communities (7 MW).
[34] Transmission options cannot be developed before 2016.
[35] Upgrade completed in 2023 when three Ring of Fire mines are forecast to be operating

To serve the forecasted electrical demand of the reference scenario to the end of the planning period, without any additional investments, transmission options 2 or 3, a new 230 kV single circuit line to Pickle Lake would be required.

Transmission Option 1, a 115 kV single circuit line to Pickle Lake is insufficient to meet the identified needs of the Pickle Lake subsystem, including connection of up to five remote communities in the Ring of Fire subsystem, for the reference forecast scenario beyond 2030. The reference forecast scenario load exceeds the LMC of a 115 kV single circuit line by 8 MW at the end of the planning period, in 2033.

The OPA recommends that the new line be operated at 230 kV from the onset. Deferring 230 kV operation to when the incremental capacity is required for load supply is not expected to incur any cost savings relative to initially operating at 230 kV. This is due to the fact that some additional voltage control equipment required for 115 kV operation would no longer be required after converting the line to 230 kV operation. This results in a stranded cost which is approximately equal to the deferral value.

Transmission Option 3 is the development of a 230 kV line that is staged to provide additional capacity with deferral of some capital cost to when and if the capacity is needed. This would be done by pre-building the line to 230 kV specifications but initially operating it at 115 kV. When additional capacity is required the line would be reterminated on the bulk 230 kV system on circuit D26A and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake. As indicated above, this option is not expected to result in any relative savings compared to Transmission Option 2.

In order to properly compare costs of transmission options (which also provide incremental capacity to the Red Lake subsystem) to generation options (which do not provide incremental capacity to the Red Lake subsystem) the unit costs consider the total incremental LMC for both the Pickle Lake and Red Lake subsystems that is made available by the option. Table 13 provides a summary of costs and timing for these options.

Table 13: Costs and Timing of Transmission Options

	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[36]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.2 Reference Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The Ring of Fire subsystem reference forecasted load from mines and communities is 22 MW in the near term and 29 MW in the medium and long term. Options to supply the Ring of Fire subsystem mines include on-site generation consistent with the Environmental Assessment cases for the mining developments, as well as building a new transmission line utilizing a North-South corridor and originating from either

[36] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Marathon or east of Nipigon, or utilizing an East-West corridor originating from Pickle Lake. Detailed analysis of these options is included in 7.4. As indicated in 6.2, if the Ring of Fire subsystem is supplied from Pickle Lake utilizing an East-West corridor, interdependency between the Pickle Lake subsystem and the Ring of Fire subsystem is introduced.

The following assesses the requirements for supply to the Pickle Lake subsystem under the reference forecast scenario if the mines and communities in the Ring of Fire subsystem are supplied from Pickle Lake. The corresponding LMC required for the Pickle Lake subsystem under this reference scenario is 64 MW in the near term and 100 MW in the medium and long term as indicated by the reference scenario "*Total 2*" in Table 8.

Generation Options

Generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than self-generation options at the mining sites within the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Transmission Options

The LMC and costs for the respective transmission options are repeated below:

Table 14: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem[1] [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability[37] [MW]	Pickle Lake Subsystem Near term Reference Forecast Demand[27] [MW]	Pickle Lake Subsystem Medium and Long term Reference Forecast Demand[27] [MW]
115 kV line to Pickle Lake[38]	46	35	81	70	64	100
230 kV line to Pickle Lake[28]	136	35	171	160	64	100
Pre-build 230 kV line to Pickle Lake[28] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[39]	46 136	35 35	81 171	70 160	64	100

[37] Includes Ring of Fire subsystem.
[38] Transmission options cannot be developed before 2016.
[39] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 15: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake[40]	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$1.07 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[41]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.08 M/MW $0.63 M/MW

From the above tables, and consistent with the analysis in 7.2.1.1, the following conclusions can be made for the forecasted load under the reference scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is the approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution.

This analysis reinforces the need to build a new 230 kV line to Pickle Lake, rather than a new 115 kV line.

7.2.1.3 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 43 MW for the near term, and 48 MW for the medium and long term as indicated by the low scenario "*Total 1*" in Table 8.

---

40 Sufficient for near term, insufficient for medium to long term.
41 Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

The remaining 19 MW of LMC for the near term and 24 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 19 MW or 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 38 MW and 47.5 MW would be required, respectively, with a maximum unit size of 9.5 MW (i.e. 4x9.5 MW and 5x9.5 MW).

Table 16: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term Low Forecast Demand[42] [MW]	Medium and Long term Low Forecast Demand[32] [MW]
Near term: 38 MW CNG Generation at Pickle Lake[43]	19	43	43	48
Medium and Long term 47.5 MW CNG Generation at Pickle Lake[33]	28.5	52.5	43	48

Table 17: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
38 MW CNG Generation at Pickle Lake	1-2 Years	$57 M	$131 M	$6.89 M/MW
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW

[42] Includes demand for Ring of Fire remote communities (7 MW).
[43] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Based on the low forecast demand scenario, the initial near-term generation option does not change. However, less capacity is needed to meet the medium- and long-term needs compared to the reference scenario.

Sensitivity Analysis for Transmission Options

Under the low forecast scenario, the LMC required for the Pickle Lake subsystem is 43 MW in the near term and 48 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 43 MW in the near term and 48 MW in the medium and long term, a new line to Pickle Lake at 115 kV would be required as a minimum and would be the most economic. It should be noted that the low scenario forecast is the only scenario that the 115 kV line option is feasible; the 115 kV line option is not feasible for all other demand scenarios.

Table 18: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term Low Forecast Demand[44] [MW]	Pickle Lake Subsystem Medium and Long term Low Forecast Demand[34] [MW]
115 kV line to Pickle Lake[45]	46	35	81	70	37	41
230 kV line to Pickle Lake[35]	136	35	171	160	37	41
Pre-build 230 kV line to Pickle Lake[35] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[46]	46 136	35 35	81 171	70 160	37	41

[44] Includes demand for Ring of Fire remote communities (7 MW).
[45] Transmission options cannot be developed before 2016.
[46] Upgrade assumed to be completed in 2023 when three Ring of Fire mines are forecast to be operating.

Table 19: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	3-5 Years	$126 M	$80 M	$1.31 M/MW
230 kV line to Pickle Lake	3-5 Years	$167 M	$106 M	$2.12 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV[47]	3-5 Years	$155 M	$98 M	$1.85 M/MW

7.2.1.4 Low Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

The low scenario does not include any additional load within the planning period from the Ring of Fire area mines compared to 7.2.1.3 and therefore this scenario is identical to 7.2.1.3 and not considered further.

7.2.1.5 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Communities in the Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 48 MW for the near term, and 90 MW for the medium and long term as indicated by the high scenario "*Total 1*" in Table 8.

Sensitivity Analysis for Generation Options

Similarly to what was done with the Reference Scenario analysis, in order to minimize generation cost, it is assumed that 24 MW of load in the Pickle Lake subsystem will continue to be served by the Red Lake subsystem from Ear Falls TS via the circuit E1C.

[47] Stage 2 would not be required for the low forecast scenario without the Ring of Fire

The remaining 24 MW of LMC for the near term and 66 MW of LMC for the medium and long term (which includes the remote communities in the Ring of Fire subsystem), would be served by CNG fueled generation at Pickle Lake.

To make available 24 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 47.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 5x9.5 MW). To make available 66 MW of incremental LMC in the Pickle Lake subsystem with local generation, a total generation capacity of 85.5 MW would be required in the near term with a maximum unit size of 9.5 MW (i.e. 9x9.5 MW).

Table 20: Capacity of Generation Option

Option	Incremental LMC [MW]	Pickle Lake Subsystem LMC [MW]	Near term High Forecast Demand[48] [MW]	Medium and Long term High Forecast Demand[38] [MW]
Near term: 47.5 MW CNG Generation at Pickle Lake[49]	28.5	52.5	48	90
Medium and Long term: 85.5 MW CNG Generation at Pickle Lake[39]	66.5	90.5	48	90

Table 21: Costs and Timing for Generation Option

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
47.5 MW CNG Generation at Pickle Lake	1-2 Years	$75 M	$158 M	$6.59 M/MW
85.5 MW CNG Generation at Pickle Lake	1-2 Years	$140 M	$317 M	$4.80 M/MW

[48] Includes demand for Ring of Fire remote communities (7 MW).
[49] Requires continued supply of 24 MW of load via E1C from Ear Falls TS.

Sensitivity Analysis for Transmission Options

Under the high forecast scenario, the LMC required for the Pickle Lake subsystem is 48 MW in the near term and 90 MW for the medium and long term. Consistent with the reference scenario, building a new line to Pickle Lake allows for a capacity increase to the Red Lake subsystem of 35 MW by opening circuit E1C from Ear Falls during capacity-constrained conditions, where peak demand is coincident with drought hydroelectric generation output.

In order to supply 48 MW in the near term and 90 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required.

Table 22: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[50] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[51]	46	35	81	70	48	90
230 kV line to Pickle Lake[41]	136	35	171	160	48	90
Pre-build 230 kV line to Pickle Lake[41] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[52]	46 136	35 35	81 171	70 160	48	90

[50] Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem

[51] Transmission options cannot be developed before 2016

[52] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 23: Costs and Timing of Transmission Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[53]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem communities supplied from Pickle Lake*:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is about the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium- and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.1.6 High Scenario Options Analysis for Pickle Lake Subsystem and Connection of Mines and Communities in the Ring of Fire Subsystem to Pickle Lake

Under the high scenario forecasted load, the LMC required is 66 MW for the near term, and 156 MW for the medium and long term as indicated by the high scenario "*Total 2*" in Table 8.

---

53 Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Sensitivity Analysis for Generation Options

Consistent with the reference scenario analysis, generation options from the Pickle Lake subsystem to supply Ring of Fire mining load were screened out as they are less cost effective than generation options from the Ring of Fire subsystem to supply Ring of Fire mining load (which is investigated in 7.4). Therefore, only transmission options are investigated for this scenario.

Sensitivity Analysis for Transmission Options

In order to supply 66 MW in the near term and 156 MW in the medium and long term, a new line to Pickle Lake built to 230 kV standards would be required. This may be achieved by either Transmission Option 2 or Option 3.

Table 24: Capacity of Transmission Options

Option	Incremental LMC for Pickle Lake Subsystem [MW]	Incremental LMC for Red Lake Subsystem [MW]	Total Incremental LMC for Option [MW]	Pickle Lake Subsystem Load Meeting Capability [MW]	Pickle Lake Subsystem Near term High Forecast Demand[1] [MW]	Pickle Lake Subsystem Medium and Long term High Forecast Demand[1] [MW]
115 kV line to Pickle Lake[2]	46	35	81	70	66	156
230 kV line to Pickle Lake[2]	136	35	171	160	66	156
Pre-build 230 kV line to Pickle Lake[2] Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[3]	46 136	35 35	81 171	70 160	66	156

(1) Includes 7 MW of forecast demand for the remote communities in the Ring of Fire subsystem
(2) Transmission options cannot be developed before 2016
(3) Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

Table 25: Costs and Timing of Transmission Options

Options	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
115 kV line to Pickle Lake	Not technically feasible			
230 kV line to Pickle Lake	3-5 Years	$180 M	$114 M	$1.20 M/MW
Pre-build 230 kV line to Pickle Lake Stage 1: operate at 115 kV Stage 2: upgrade to 230 kV[54]	 3-5 Years 1-2 Years	 $155 M $14 M	 $98 M $5 M	 $1.29 M/MW $0.25 M/MW

From the above tables, and consistent with the analysis for the reference scenario, the following conclusions can be made for the forecasted load under the high scenario *with the Ring of Fire subsystem supplied from Pickle Lake*, including the community and mining load:

1. A line built to 115 kV standards would be insufficient to meet the medium- and long-term need, and is only marginally sufficient to meet the near term need.
2. A line pre-built to 230 kV standards with staged 115 kV and 230 kV operation is approximately as cost effective as initially operating at 230 kV. While cost is the same, initially operating at 115 kV will require the installation of voltage control devices that will no longer be useful when the line operates at 230 kV.
3. A line built and initially operated at 230 kV is also a cost effective option that meets the medium-and long-term need, and will not result in stranding of transmission devices. This is the recommended solution option.

7.2.2 Pickle Lake Subsystem Recommended Solutions

The OPA recommends that a new 230 kV single circuit line to Pickle Lake be built as soon as possible in order to meet the needs of the Pickle Lake subsystem. Building the new line to 230 kV standards is the most economic option to meet the reference forecast scenario, which is regarded as the most-likely scenario, and mitigates the long-term risk associated with higher forecasted demand scenarios and maintains the flexibility to supply the Ring of Fire mining development from Pickle Lake. The OPA also recommends that circuit E1C be opened at Ear Falls as an operational measure when

[54] Upgrade completed in 2023, when 3 Ring of Fire mines are forecast to be operating

the local system is capacity-constrained. This operational measure maximizes the capability of the transmission system in the area, resulting in incremental LMC to the Red Lake subsystem. The capacity constraint is expected to occur during high demand coincident with drought hydroelectric conditions.

It is recommended that development work on a new 230 kV single circuit line to Pickle Lake is completed as soon as possible. The OPA understands that preliminary development work has been started by two First Nations-owned transmission development companies. This work was initiated after the project was identified as a priority transmission project in the Government of Ontario’s 2010 and 2013 Long-Term Energy Plans, and was identified for inclusion in future power system plans in the Minister of Energy’s 2011 SMD to the OPA.

Implementation of the new line to Pickle Lake continues to be supported by the OPA. The OPA is following the development process for the two development companies closely. The OPA expresses urgency in the need for a new 230 kV single circuit line to Pickle Lake and will support this project to obtain the necessary approvals as soon as possible.

7.3 Summary of Recommended and Assessed Options for Meeting Red Lake Subsystem Needs

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C open at Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA’s forecast scenarios, beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and Ontario Power Generation ("OPG"), with assistance from the OPA, negotiate a new contract for amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Table 62 in Appendix 10.6 outlines the cash-flows associated with the circuit upgrades including the station costs being referred to above.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This analysis will consider an updated forecast. The economics of additional gas-fired generation compared to a new transmission line will depend on the amount of load that materializes – gas generation is scalable, while transmission has greater economies of scale if enough demand is present for a sufficient level of utilization. Re-evaluating options in future planning cycles is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

The following section summarizes the analysis and comparison of options.

As mentioned previously, the Red Lake subsystem is currently supplied by the 115 kV line E4D from Dryden TS as well as local run of river hydroelectric generation around Ear Falls. At present the subsystem has reached its LMC. Therefore, forecasted near term growth and medium and long term growth cannot be met by the existing system and other supply options are required. Identified needs for the Red Lake subsystem are summarized in Table 26, below.

Table 26: Needs for Red Lake Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	Reference	High
Near term (2014-2018)	• Supply of mining and community demand in the Red Lake subsystem	91	91	91
	Total Near term	***91***	***91***	***91***
Medium and long term (2019-2033)	• Supply of mining and community demand in the Red Lake subsystem	100	109	136
	Total Medium and Long term	***100***	***109***	***136***

The following near term generation and transmission options have been identified for meeting these needs.

Table 27: Summary of Options to Meet the Near-term Needs of the Red Lake Subsystem

Options to Meet Near-term Needs	Capital Cost	PV Cost	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	$89 M	$51 M	30 MW	$1.94 M/MW
Off Load E1C to New Line to Pickle Lake[55]	$66 M	$42 M	35 MW	
Upgrade E4D and E2R	$16 M	$11 M	34 MW	$1.11 M/MW[56]
Off Load E1C to New Line to Pickle Lake	$66 M	$42 M	35 MW	

The OPA recommends upgrading E4D and E2R, as this option has the lowest NPV cost for meeting the near-term needs of the Red Lake subsystem. This option also has the shortest lead time and the highest incremental capacity.

[55] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[56] Note that utilized capacity is 30 MW in the near term.

Table 28: Summary of Options to Meet the Medium- and Long-Term Needs of the Red Lake Subsystem

Options to Meet Medium- and Long-Term Needs	Capital Cost	PV Cost[57]	Incremental Load Meeting Capability	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)[58]	$95 M	$6 M	30 MW	$0.20 M/MW
Ear Falls and Red Lake Gas Generation (60 MW)	$153 M	$8 M	60 MW	$0.13 M/MW
Install Voltage Compensation at Ear Falls and Red Lake (130 MW)	$9 M	$1 M	21 MW	$0.05 M/MW
New 115 kV line to Ear Falls (160 MW)	$91 M	$10 M	30 MW	$0.34 M/MW
New 115 kV line to Ear Falls (190 MW)	$108 M	$12 M	60 MW	$0.20 M/MW
New 230 kV line to Ear Falls (190 MW)	$132 M	$15 M	60 MW	$0.25 M/MW

Once the upgrades to E4D and E2R are complete and the new line to Pickle Lake is in service, the Red Lake subsystem will have an LMC of 130 MW, which is sufficient to meet the supply needs of the Red Lake subsystem for the long term.

Costs do not need to be incurred at this time for additional enhancements for the Red Lake subsystem beyond E4D and E2R upgrades. Under the low scenario and reference scenario (which is considered most likely) no incremental LMC is required beyond 130 MW. Only under the high scenario is incremental LMC forecasted to be required in 2030. The lead times for the long-term incremental options allow for re-evaluation of the demand forecast and options in future planning cycles. Future planning cycles will contain more certainty in the demand forecast as mines and related development materialize. The next planning cycle for the North of Dryden sub-region is between 1-5

[57] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until about 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[58] Same as the near term option, with install date of 2030 and therefore cannot be combined with the near term option.

years, as per the OEB-sanctioned regional planning process. The prudent course of action for the long term is monitoring load growth and re-evaluating in a timely manner.

7.3.1 **Discussion of Options to Meet the Needs of the Red Lake Subsystem**

Both generation and transmission options are considered for meeting the needs of the Red Lake subsystem.

The following sub-sections will outline the evaluation of various integrated options to meet the near-term and medium-to long-term needs of the Red Lake subsystem for the reference, low, and high load forecast scenarios.

7.3.1.1 Reference Scenario Options Analysis for Red Lake Subsystem

Under the reference scenario, the LMC required is 91 MW for the near term, and 109 MW for the medium and long term as indicated by the reference scenario in Table 26. The existing LMC for the Red Lake subsystem is 61 MW, which is not sufficient.

In establishing the need for incremental LMC for the Red Lake subsystem, it is assumed that, consistent with the recommendations for addressing supply needs for the Pickle Lake subsystem, a new line to Pickle Lake will be implemented and circuit E1C will be operated open at Ear Falls SS. Opening circuit E1C from Ear Falls SS relieves circuit E4D of 35 MW.

Generation Options

At Red Lake, there is a limited supply of natural gas on the existing Union Gas pipeline. This pipeline was extended to serve the needs of an industrial customer at Red Lake and the Town of Red Lake. Based on information provided by the industrial customer, there is sufficient pipeline capacity to increase the LMC by 30 MW from gas-fired generation at Red Lake.

The OPA studied the costs and benefits of implementing gas fired generation to provide incremental LMC in the Red Lake subsystem. The generators could operate both as a local area resource and as a system resource to support growth in northwest Ontario, by reducing loading on the bulk transmission system at Dryden TS. Gas generators in the Red Lake subsystem would be expected to operate for local area needs primarily during periods when run of river hydroelectric generation near Ear Falls is low and when the demand in the area is high.

Due to the availability of gas on the pipeline and the distribution of load in the Red Lake subsystem, gas generation at Red Lake would increase the LMC of the Red Lake subsystem by 30 MW. Table 29 summarizes the capability and Table 30 summarizes the cost and timing associated with the gas generation option.

Table 29: Capacity for Generation Options

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Reference Forecast Demand [MW]	Medium and Long term Reference Forecast Demand [MW]
Red Lake Gas Generation (30 MW) and Transfer of Pickle Lake load to new line to Pickle Lake	30 MW	91 MW	91	109
	35 MW	126 MW		

Table 30: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	$89 M	$51 M	$1.94 M/MW
Transfer of E1C load to new line to Pickle Lake[59]	3-5 Years	$66 M	$42 M	

It is important to note that the transfer of Pickle Lake load from E1C to relieve the Red Lake subsystem can be made once a new line to Pickle Lake is in service. This again

[59] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

emphasizes the urgent need to implement the new line to Pickle Lake, as it has broader benefits for incremental LMC for the Red Lake subsystem.

Transmission Options

Hydro One Networks Inc. owns and operates transmission lines E4D and E2R and has confirmed that they can be upgraded from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. This upgrade increases the LMC of the Red Lake subsystem by 34 MW. To enable this higher transmission capability, additional voltage control would also be required at Ear Falls TS. Hydro One has indicated that upgrading E4D and E2R and the installation of the required voltage control devices would take two years and could be completed within the near-term period.

Table 31: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Reference Forecast Demand [MW]	Medium and Long term Reference Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R	34	95	91	109
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		

Upgrading the transfer capability of E4D and E2R and installation of the required amount of voltage control is the recommended solution for the Red Lake subsystem. This option satisfies the reference scenario forecasted demand at the least cost. When E4D and E2R are upgraded and the required amount of voltage control is installed at Ear Falls TS, there will be 95 MW of capacity at Ear Falls TS to serve load in the Red Lake subsystem and 35 MW available to continue to serve the Pickle Lake subsystem. Once a new line to Pickle Lake is implemented and circuit E1C is operated open at Ear Falls SS, an additional 35 MW of LMC is provided to the Red Lake subsystem because currently the Pickle Lake subsystem currently requires 35 MW of supply from Ear Falls to serve 24 MW of load (due to losses). This brings the total LMC for the Red Lake subsystem to 130 MW. The combination of the line upgrades to E4D and E2R as well as a new line to Pickle Lake is expected provide enough LMC for the Red Lake subsystem until the end of the study horizon for the reference forecast scenario.

It should be noted that the incremental LMC of 35 MW provided to the Red Lake subsystem from transferring E1C load to the new line to Pickle Lake requires the E4D and E2R upgrades to be completed. Without the upgrades, E2R would limit the supply into Red Lake because E2R is not relieved from transferring E1C load (E1C transfer only relieves E4D).

This again emphasizes the urgent need to implement both the upgrades to circuits E4D and E2R, as well as the new line to Pickle Lake, as combined these solutions provide a significant increase in LMC for the Red Lake subsystem.

Table 32: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[60]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.11 M/MW
Transfer of E1C load to new line to Pickle Lake[61]	3-5 years	$66 M	$42 M	

Based on the above analysis of Generation and Transmission Options for the reference scenario, the upgrading of circuits E4D and E2R in combination with the relief provided by transferring E1C demand to a new line to Pickle Lake is the most economic solution to meet the needs of the Red Lake area. This solution would be sufficient to meet the electrical demand in the Red Lake subsystem until beyond the planning period.

[60] Capital cost does not include the capital cost for new system generation
[61] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

The IESO recently completed SIAs for three customers in the Red Lake subsystem that are interested in increasing their demand on the system. Upgrading of E4D and E2R was also identified by the IESO as the preferred solution to meet the load increase requests. The IESO's analysis is consistent with the OPA's findings.

7.3.1.2 Low Scenario Options Analysis for Red Lake Subsystem

Under the low scenario, the LMC required is 91 MW for the near term, and 100 MW for the medium and long term as indicated by the low scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the generation option assessed for the reference scenario remains unchanged and is therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

Table 33: Capacity for Generation Options

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term Low Forecast Demand [MW]</th><th>Medium and Long term Low Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30 MW</td><td>91 MW</td><td rowspan="2">91</td><td rowspan="2">100</td></tr>
<tr><td>35 MW</td><td>126 MW</td></tr>
</table>

Table 34: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	$89 M	$51 M	$2.38 M/MW
Transfer of E1C load to new line to Pickle Lake[62]	3-5 Years	$66 M	$42 M	

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Red Lake subsystem under the low scenario, the transmission options assessed for the reference scenario remain unchanged and are therefore not sensitive to the low scenario demand. A summary of capacity and costs are repeated in the following tables for convenience:

Table 35: Capacity of Transmission Option

Option	Incremental LMC [MW]	Red Lake Subsystem LMC [MW]	Near term Low Forecast Demand [MW]	Medium and Long term Low Forecast Demand [MW]
Near-term Option				
Upgrade E4D and E2R	34	95	91	100
and Transfer of Pickle Lake load to new line to Pickle Lake	35	130		

Table 36: Cost and Timing of Transmission Option

Options	Time to Complete	Capital Cost[63]	PV During Planning Period	PV Unit Cost of Utilized Capacity
Upgrade of E4D and E2R	1-2 years	$16 M	$11 M	$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[64]	3-5 years	$66 M	$42 M	

[62] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[63] Capital cost does not include the capital cost for new system generation
[64] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

7.3.1.3 High Scenario Options Analysis for Red Lake Subsystem

Under the high scenario, the LMC required is 91 MW for the near term, and 136 MW for the medium and long term as indicated by the high scenario in Table 26.

Consistent with the analysis performed for the reference scenario, it is assumed that a new line to Pickle Lake will be implemented and circuit E1C is operated open at Ear Falls SS, which relieves circuit E4D of 35 MW.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, additional gas generation at Ear Falls or Red Lake would be required in the long term compared to the reference scenario. However, it should be noted that based on information from the existing industrial customer gas pipeline capacity is not available to support gas-fired generation beyond 30 MW.

The option of incremental gas generation has been assessed assuming that industrial customers may require additional natural gas supply to serve their industrial processes.

A summary of capacity and costs are summarized in the following tables:

Table 37: Capacity for Generation Options

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term High Forecast Demand [MW]</th><th>Medium and Long term High Forecast Demand [MW]</th></tr>
<tr><td rowspan="2">Red Lake Gas Generation (30 MW)

and

Transfer of Pickle Lake load to new line to Pickle Lake</td><td>30</td><td>91</td><td rowspan="2">91</td><td rowspan="2">136</td></tr>
<tr><td>35</td><td>126</td></tr>
<tr><td colspan="5">Incremental Long term Options</td></tr>
</table>

Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[65]	30	156	91	136

Table 38: Costs and Timing for Generation Options

Option	Time to Complete	Capital Cost	Total PV During Planning Period	PV Unit Cost of Utilized Capacity
Red Lake Gas Generation (30 MW)	2 Years	\$89 M	\$51 M	\$1.36 M/MW
Transfer of E1C load to new line to Pickle Lake[66]	3-5 Years	\$66 M	\$42 M	
Incremental Potential Gas Generation at Red Lake or Ear Falls (30 MW)[67]	TBD[1]	\$95 M[68]	\$6 M[69]	\$1.00 M/MW

From the above, the option of 30 MW of gas-fired generation at Red Lake using existing pipeline capacity in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake would result in an LMC of 126 MW for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2027 under the high scenario.

The sensitivity analysis does not impact the decisions that are required during this planning cycle. Demand forecasts and long term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Red Lake subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged and

[65] Contingent on new gas pipeline to serve new electricity and gas customers
[66] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.
[67] Contingent on new gas pipeline to serve new electricity and gas customers
[68] Capital Cost does not include pipeline costs. It is assumed that if the pipeline was needed anyway, there would be no incremental pipeline costs to incorporate generation
[69] Present Value costs for long-term options consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2026 at earliest, and therefore only 3 years of costs discounted over 13 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

are therefore not sensitive to the high scenario demand. A summary of capacity and costs are repeated in the following tables:

Table 39: Capacity of Transmission Option

<table>
<tr><th>Option</th><th>Incremental LMC [MW]</th><th>Red Lake Subsystem LMC [MW]</th><th>Near term High Forecast Demand [MW]</th><th>Medium and Long term High Forecast Demand [MW]</th></tr>
<tr><td colspan="5">Near-term Option</td></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34</td><td>95</td><td rowspan="2">91</td><td rowspan="2">136</td></tr>
<tr><td>35</td><td>130</td></tr>
<tr><td colspan="5">Incremental Long-term Options</td></tr>
<tr><td>New 115 kV line to Ear Falls (160 MW LMC)</td><td>30</td><td>160</td><td>91</td><td>136</td></tr>
<tr><td>New 115 kV line to Ear Falls (190 MW LMC)</td><td>60</td><td>190</td><td>91</td><td>136</td></tr>
<tr><td>New 230 kV line to Ear Falls (190 MW LMC)</td><td>60</td><td>190</td><td>91</td><td>136</td></tr>
</table>

Table 40: Cost and Timing of Transmission Option

<table>
<tr><th>Options</th><th>Time to Complete</th><th>Capital Cost[70]</th><th>PV During Planning Period[71]</th><th>PV Unit Cost of Utilized Capacity</th></tr>
<tr><td>Upgrade of E4D and E2R</td><td>1-2 years</td><td>$16 M</td><td>$11 M</td><td rowspan="2">$0.78 M/MW</td></tr>
<tr><td>Transfer of Pickle Lake load to new Line at Pickle Lake[72]</td><td>3-5 years</td><td>$66 M</td><td>$42 M</td></tr>
<tr><td>New 115 kV line to Ear Falls (160 MW LMC)</td><td>4-7 years</td><td>$91 M</td><td>$10 M</td><td>$1.72 M/MW</td></tr>
<tr><td>New 115 kV line to Ear Falls (190 MW LMC)</td><td>4-7 years</td><td>$108 M</td><td>$12 M</td><td>$2.04 M/MW</td></tr>
<tr><td>New 230 kV line to Ear Falls (190 MW LMC)</td><td>4-7 years</td><td>$132 M</td><td>$15 M</td><td>$2.5 M/MW</td></tr>
</table>

[70] Capital cost does not include the capital cost for new system generation

[71] Present Value costs for long-term options (i.e. all except E4D and E2R upgrades, and Transfer of Pickle Lake load to new Line at Pickle Lake) consider only the costs incurred within the 20 year planning horizon. These numbers appear low because costs are assumed to be incurred when a need is forecasted. Costs are not expected to need to be incurred until 2030 at earliest, and therefore only 3 years of costs discounted over 17 years are included. Present Value costs are a method of comparison and should not be misinterpreted as total project costs.

[72] Costs assumed for transfer of E1C load to new line to Pickle Lake are pro-rated based on LMC for Red Lake subsystem and the LMC for Red Lake subsystem plus the LMC for Pickle Lake subsystem.

From the above, upgrading lines E4D and E2R (Dryden to Red Lake) in combination with relieving circuit E4D of the E1C load following the installation of a new line to Pickle Lake, an LMC of 130 MW would result for the Red Lake subsystem. This LMC would be forecasted to be exceeded by 2030 under the high scenario forecasted demand, but not under the reference scenario (which is considered most likely). Incremental transmission options are available if forecasted demand consistent with, or greater than, the high scenario is realized. This is not expected to occur until 2030 under the high scenario and beyond the planning period for the reference scenario. A recommendation for incremental enhancements in addition to the line upgrades and the new line to Pickle Lake does not need to be made at this time. Demand forecasts and long-term options will be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region.

7.3.2 Cost Saving Opportunities Utilizing Existing Facilities

OPG provided information to the OPA on voltage control capabilities of the generating units at Manitou Falls as part of their comments on the Draft North of Dryden IRRP. This information was submitted in writing on November 8th, 2013. Part of this submission indicated that the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power for voltage control during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices. Total station costs for upgrading E4D and E2R are referenced in Table 62 of Appendix 10.6.

OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is of benefit to the rate payer.

7.3.3 Red Lake Subsystem Recommended Solutions

The OPA recommends the upgrading of circuits E4D and E2R from a summer ampacity of 470 A to 660 A and 420 A to 610 A, respectively. The upgrading of E4D and E2R, in addition to a new line to Pickle Lake coupled with operating circuit E1C normally open at

Ear Falls would provide an additional 70 MW of LMC, bringing the LMC for the Red Lake subsystem to 130 MW. The LMC of 130 MW meets the needs of the Red Lake subsystem for the long term for all the OPA's forecast scenarios; beyond the planning period for the low scenario and reference scenario (which is considered the most likely), and until 2030 for the high scenario.

In addition, the OPA recommends that the IESO and OPG, with assistance from the OPA, negotiate a new contract or amended reactive services contract for Manitou Falls GS if it is beneficial to the rate payer. Based on information provided by OPG on the Draft North of Dryden IRRP, submitted November 8th, 2013, the Manitou Falls units G1, G2, and G3 all have condense features which could be contracted to provide reactive power during drought conditions. The contracting of these units could avoid some of the station investments at Ear Falls SS associated with the installation of voltage control devices.

The OPA also recommends that the potential long-term options of incremental natural gas-fired generation at Red Lake or a new transmission line be re-evaluated in the next planning cycle (1-5 years) for the North of Dryden sub-region of the Northwest region. This is consistent with OEB requirements in the Transmission System Code, Distribution System Code and the OPA license.

7.4 Summary of Options to Meet Ring of Fire Subsystem Needs

The Ring of Fire subsystem is a large geographic area on the edge of the Hudson Bay Lowlands approximately 350 km north of Long Lac and approximately 300 km east of Pickle Lake. There are five remote First Nations ("FN") communities in the area (Eabametoong FN, Neskantaga FN, Marten Falls FN, Nibinamik FN and Webequie FN) and a proposed mine development area called the Ring of Fire, where a number of companies are developing mining claims. At present the five remote First Nations communities are supplied electricity by local diesel generators.

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem, including the connection of the remote communities, be coordinated with other infrastructure being investigated or planned, such as transportation corridors to the communities and potential mining development. Mining development companies have indicated different transportation corridor preferences for the Ring of Fire. The OPA understands that a transportation corridor may be developed in an East-West orientation from the Pickle Lake area, or in a North-South orientation from the Nakina area. Transmission options may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or a point east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The OPA has included transmission supply options for the Ring of Fire subsystem that are consistent with these general corridor orientations identified by mining proponents. A shared East-West or North-South transmission corridor, in alignment with a transportation corridor, could be a way to reduce overall cost and environmental impact. Mining development companies have also indicated self-generation as their electrical supply base case in their EA documentation. Consistent with the EA documentation of mining development companies, the OPA has considered self-generation as a possible option for the forecasted mining load in the Ring of Fire subsystem. The decision as to whether the mining load in the Ring of Fire subsystem is supplied by transmission or generation will ultimately lie with the mining companies as they will be the beneficiaries of a direct transmission supply. The OPA has already indicated in the Remote Community Connection plan that there is a business case for connecting the five remote communities in the vicinity of the Ring of Fire on their own merit, without the connection of the mining development. The connection of the mining development with the five remote communities creates a stronger business case for the connection of the remote communities. The OPA will continue to support the economic connection of remote communities.

The relative economics of generation versus transmission to supply mining load in the Ring of Fire subsystem depends on the amount of electrical demand that materializes. The reason for this is because transmission is generally more economic for relatively large electrical demand, while generation is scalable and generally more economic for lower levels of electrical demand. Details of the various options are explained further later in this section.

The OPA also recognizes that there may be potential for further utilization of a North-South transmission supply to the Ring of Fire subsystem through integration with supplying new growth in the Greenstone area. The detailed needs and supply options specific for new growth in the Greenstone area will be assessed as part of the Greenstone-Marathon IRRP, which may be used to supplement the findings in this IRRP.

The needs identified for the Ring of Fire subsystem are to connect the five remote communities to the provincial transmission system and to supply the potential future mines. The connection of the five remote communities cannot be completed until at least 2018, as indicated in the Remote Community Connection Report. Also, mines at the Ring of Fire are not expected to start up until 2017 at the earliest. A summary of the needs is provided in Table 41.

Table 41: Needs for the Ring of Fire Subsystem

Timing	Needs	Required Load Meeting Capability [MW]		
		Low	**Reference**	**High**
Near term (2014-2018)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	4	22	22
	Total Near term	***4***	***22***	***22***
Medium and long term (2019-2033)	• Connect 5 remote communities and supply mining demand in the Ring of Fire subsystems	7	29	73
	Total Medium and Long term	***7***	***29***	***73***

An assessment developed for the Remote Community Connection Plan determined that up to five remote First Nation communities in the subsystem are economic to connect to the grid (see Appendices 11.2 and 11.4). As a result, all options identified for this subsystem include the connection of the five remote communities included in this subsystem.

Options to meet these requirements include:

- Connection of mines and remote communities to the transmission system; or
- Connection of the remote communities and on-site generation fueled by diesel or natural gas for the mines.

Transmission supply options being considered for the Ring of Fire subsystem include a new supply from Pickle Lake, a point east of Nipigon, or Marathon. These options were developed with the understanding that both East-West and North-South transportation corridors are being considered and linear corridor planning with electricity may provide greater economic efficiencies and reduce environmental impacts. It should also be noted that 230 kV supply to Pickle Lake is the minimum technical requirement for connecting any mining load at the Ring of Fire to Pickle Lake.

Options for supply to the Ring of Fire subsystem are summarized in Table 42 below.

Table 42: Summary of Options to Meet the Medium- and Long-Term Needs of the Ring of Fire Subsystem[73]

	Capital Cost[74]	PV Cost	Utilized Capacity	PV Unit Cost of Utilized Capacity
Diesel Generation + Remote Connection	Low: $186 M High: $277 M	Low: $456 M High:$1,009 M	29 MW 73 MW	$15.7 M/MW $13.8 M/MW
CNG Generation + Remote Connection	Low: $240 M High: $421 M	Low: $272 M High: $480 M	29 MW 73 MW	$9.37 M/MW $6.58 M/MW

[73] Transmission options routed from Pickle Lake include a prorated portion (based on the relative amount of load that would be supplied to each party) of the cost for a new 230 kV transmission line to Pickle Lake.
[74] Description of capital costs can be found in the following tables: Generation, Table 26; Transmission, Table 27

115 kV Line from Pickle Lake to Ring of Fire	$189 M	$106 M	29 MW	$3.64 M/MW
230 kV Line from Pickle Lake to Ring of Fire	$277 M	$156 M	73 MW	$2.14 M/MW
230 kV Line from Marathon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW
230 kV Line from east of Nipigon to Ring of Fire	$327 M	$175 M	73 MW	$2.40 M/MW

Options that are developed for the scenario that the Ring of Fire subsystem mining developments and remote communities are supplied from a transmission connection to the provincial power system assumes the cost for the transmission option with road access. The option for connecting only the remote communities from a transmission connection to the provincial power system assumes the cost for the transmission option without road access. Road access may be provided from the development of a multi-use corridor.

7.4.1 **Discussion of Options to Meet the Needs of the Ring of Fire Subsystem**

Currently, the electric supply of the five remote communities in the Ring of Fire subsystem is provided by local diesel generators. As discussed previously, up to five of these communities have been shown to be economic to connect to the transmission system in the Remote Community Connection Plan. Hence, for the purpose of the North of Dryden IRRP, these five communities are assumed to connect to the transmission system.

Given the timelines required to obtain approvals and to design and construct transmission facilities of this scale, the OPA has assumed that transmission options for serving remote communities would not be in service until 2018 at the earliest.

7.4.1.1 Reference Scenario Options Analysis for Ring of Fire Subsystem

Under the reference scenario electrical demand forecast, the LMC required is 22 MW for the near term, and 29 MW for the medium and long term as indicated in Table 41. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Generation Options

Two Environmental Assessment Terms of Reference published by mining developers in the Ring of Fire have included electricity supply options for on-site generation for their particular mining projects. They have identified that diesel or CNG fueled generation plants can provide sufficient capacity and energy to reliably meet their needs and can be brought into service within their mine development timelines. Assuming that a proposed all-season road would connect the Ring of Fire to the provincial highway system, the transportation of the large volumes of fuel required to operate on-site generation of this scale would be enabled.

As mentioned earlier, the five remote communities in the Ring of Fire subsystem have been identified as economic to connect to the transmission system at Pickle Lake. Should the Ring of Fire mines choose the self–generation option for their electricity needs, it is assumed that the remote communities will connect to Pickle Lake through a separate remote community connection project. This option is discussed in detail in the Remote Community Connection Plan. The cost of serving the remote communities by transmission and the Ring of Fire area mines with on-site generation are considered together as an integrated option for serving the Ring of Fire subsystem.

The OPA evaluated the feasibility and relative economics of various on-site generation options to supply the mining load. Findings indicated that reciprocating engines fueled either by diesel or natural gas could power future mines at the Ring of Fire, which is consistent with the respective EA Terms of Reference of developers. These units are available in a large range of sizes which allows for capacity to be scaled to meet a wide range of needs for individual mines initially and over time. Mine developers at the Ring of Fire have plans for transportation systems that would connect the Ring of Fire to the provincial transportation network, by either road or rail. One of these options is an all-season road from the Ring of Fire to the railway near Nakina. In order to develop cost estimates for this regional plan it is assumed that fuel would be transported to the Ring of Fire via the provincial road network to Nakina and then from Nakina to the Ring of Fire via the proposed all-season road[75].

Supplying diesel fuel to mine sites for power generators is common practice. Diesel fuel can be purchased at a number of bulk storage facilities in northwest Ontario and transported to mine sites. CNG also appears to be feasible though there are no direct examples that the OPA could reference for remote mining applications. The OPA has leveraged available public information and worked with industry to establish a reasonable set of assumptions and inputs that were used to develop cost models for both remote diesel and CNG fueled DG. The cost of fuel transportation infrastructure (trucks and trailers) required to transport both diesel and CNG to the mine sites has been included in the cost analysis.

The infrastructure required to fuel a natural gas generation facility at the Ring of Fire would include a compression station located along the TCPL mainline with road access to the proposed all-season road to the Ring of Fire beginning near Nakina. Due to the complexities and permitting required to build a CNG storage facility at the mine site, the OPA understands that no CNG storage facilities are planned for the mine sites and that fuel would be delivered on a just in time basis, with allowance for only a few trailers to be kept on site. Each trailer stores approximately 2 hours supply of fuel.

While the process is not substantially different from the transport and use of diesel, there are more steps and facilities required to compress, transport and decompress the gas before it can be used. Without significant on-site storage facilities, natural gas transportation logistics will be more challenging particularly during inclement weather when the all-season road may be closed for extended periods. To account for such challenges, it is likely that the generators will have to be capable of using both diesel and natural gas. Mines will have large scale diesel storage on site to fuel their vehicles and heavy equipment which could be used to fuel the generators when natural gas

---

[75] The OPA does not have expertise in transportation planning; this assumption is solely for developing cost estimates for generation OM&A and does not indicate a preference of the OPA.

supply is interrupted. The OPA has also discussed the results of its CNG cost model with industry to ensure the findings are reasonable.

Liquefied natural gas (“LNG”) may also be a feasible option to fuel generators. However, it is not clear what minimum production volume is required to establish a natural gas liquefaction facility in northwest Ontario or what the economics of such facilities would be. As a result, the OPA does not have sufficient information to assess either the feasibility or the economics of LNG at this time.

Table 43: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Near term Reference Forecast Demand (Mines Only) [MW]	Medium and Long term Reference Forecast Demand (Mines Only) [MW]
Diesel Generation	22	18	22
CNG Generation	22		

From the above, in order to meet the reference scenario demand for the Ring of Fire mining load, up to 22 MW of diesel or CNG generation are considered.

The costs for supplying the forecasted Ring of Fire subsystem mining load by either 22 MW of diesel or CNG generation at the Ring of Fire mines are summarized in Table 44.

Table 44: Generation Options at the Ring of Fire Mines

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	22	$72 M	$39 M	$393 M
CNG Generation	22	$127 M	$20 M	$209 M

As discussed above, the integrated options for serving the needs of the remote communities and the mines in the Ring of Fire subsystem includes a transmission connection option to serve the five remote communities from Pickle Lake in the case where the Ring of Fire mines opt for self-generation. This option would consist of a 115 kV transmission line from Pickle Lake to an end point near Webequie FN, passing near Neskantaga FN. Transformer stations to serve the communities would be sited near Neskantaga FN and at the end of the line near Webequie FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would be connected via distribution lines and stations to the transformer station near Neskantaga FN, while Webequie FN and Nibinamik FN would be connected by distribution lines and stations to the transformer station near Webequie FN. Figure 36 in Appendix 11.4 shows this planned connection system for the five remote communities.

The OPA has estimated the cost of connecting the five remote communities in this subsystem to be $64 million, consistent with the 2014 Remote Community Connection Plan. The costs of the integrated options for mine site generation and transmission connection of remote communities are summarized in Table 45.

Table 45 Integrated Options for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$393 M	$62 M	$456M
CNG Generation + Remote Connection	$209 M	$62 M	$272 M

Therefore, in order to supply the entire need for the Ring of Fire subsystem – connection of remote communities and generation supply to mines – a new 115 kV connection for remote communities and 22 MW of generation would be required and would total $273-$457 M, depending on fuel.

Transmission Options

Transmission options for supplying the five remote communities and mining load at the Ring of Fire together include the following:

1. East-West corridor
    a. A new 115 kV single circuit line from Crow River DS or a new station at Pickle Lake to the Ring of Fire
    b. A new 230 kV single circuit line from a new 230/115 kV station at Pickle Lake to the Ring of Fire, and new 230/115 kV TS near Neskantaga FN
2. North-South corridor
    a. A 230 kV single circuit line from Marathon TS to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN
    b. A 230 kV single circuit line from east of Nipigon to a new transformer station at the Ring of Fire and a new 230/115 kV station near Marten Falls FN

The LMC of these options are summarized in Table 46 below

Table 46: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term Reference Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term Reference Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	29
230 kV line from Pickle Lake	78	22	29
North-South corridor			

230 kV line from Marathon TS	78	22	29
230 kV line from east of Nipigon	78	22	29

Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 67 MW of load at the Ring of Fire (60 MW of mining load plus 7 MW of remote community load). Figure 36 in Appendix 11.4 shows a potential configuration of the North of Dryden system with a 115 kV connection to the Ring of Fire from Pickle Lake. This would be sufficient and would be the least-cost option to supply the reference scenario forecasted demand.

It is not economic under the reference scenario forecasted demand to supply the Ring of Fire subsystem by a 230 kV transmission line.

If mining and remote community load exceeds 67 MW a new 115 kV supply would no longer be sufficient and a 230 kV connection to the Ontario transmission system is required for the Ring of Fire subsystem.

The North-South options will be assessed in further detail in the Greenstone-Marathon IRRP by considering possible economic synergies with potential load growth in the Greenstone area.

As mentioned in Section 7.4.1, the five remote communities in the Ring of Fire subsystem have been identified in the Remote Community Connection Plan as being economic to connect on their own. It is therefore assumed that if the Ring of Fire mines do not connect to the grid, then the five remote communities will continue to pursue a connection to the transmission system at Pickle Lake. The lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN.

A summary of the cost and capabilities of these options is provided in Table 47.

Table 47: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	$146 M	$44 M	$189 M	$106 M
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

The cost responsibility for the new line to Pickle Lake and any connection line to the Ring of Fire shared by mines and remote communities would be determined through commercial agreements and/or through the OEB's Leave to Construct application process.

7.4.1.2 Low Scenario Options Analysis for Ring of Fire Subsystem

Under the low scenario forecasted load, the LMC required is 4 MW for the near term, and 7 MW for the medium and long term as indicated by the low scenario in Table 41. This scenario corresponds to the load associated with only the five remote communities in the Ring of Fire subsystem.

Therefore, under this scenario, only the connection of the five remote communities is considered. As indicated in the previous section, the lowest cost transmission connection for these communities is a single circuit 115 kV line from Pickle Lake to a new 115/44 kV transformer station near Webequie FN. This is expected to cost $115 M net-present value over the planning period.

Details are included in the Remote Community Connection Report. This scenario does not require any additional consideration.

7.4.1.3 High Scenario Options Analysis for Ring of Fire Subsystem

Under the high scenario forecasted load, the LMC required is 22 MW for the near term, and 73 MW for the medium and long term as indicated by the high scenario in Table 41. Of the 73 MW, 66 MW is mining load and 7 MW is community load. The existing LMC for the Ring of Fire subsystem is 0 MW, as it is currently not connected to the provincial power system.

Sensitivity Analysis for Generation Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the high generation option would be required. The tables outlining the generation options are repeated for convenience:

Table 48: Generation Options at the Ring of Fire

Options for Mining Load	Mining Generation [MW]	Initial Capital Cost	Average Annual Fuel and O&M	Total PV
Diesel Generation	71	$163 M	$102 M	$946 M
CNG Generation	71	$307 M	$46 M	$418 M

Table 49: Integrated Option for the Ring of Fire Subsystem: Mine Generation and Remote Community Connection to Pickle Lake

Integrated Options	PV of Mine Site Generation	PV Remote Connection	Total PV of Integrated Option
Diesel Generation + Remote Connection	$946 M	$62 M	$1,009 M
CNG Generation + Remote Connection	$393 M	$62 M	$456 M

Sensitivity Analysis for Transmission Options

In order to meet the required LMC for the Ring of Fire subsystem under the high scenario, the transmission options assessed for the reference scenario remain unchanged. A summary of capacity and costs are repeated in the following tables for convenience:

Table 50: Capacity of Transmission Options

Options	Ring of Fire Subsystem Load Meeting Capability [MW]	Ring of Fire Subsystem Near term High Forecast Demand [MW]	Ring of Fire Subsystem Medium and Long term High Forecast Demand [MW]
East-West corridor			
115 kV line from Pickle Lake	67	22	73
230 kV line from Pickle Lake	78	22	73
North-South corridor			
230 kV line from Marathon TS	78	22	73
230 kV line from east of Nipigon	78	22	73

Table 51: Capacity and Costs of Transmission Options

Options	Capital Cost	Prorated Capital of Line to Pickle Lake	Total Capital	Total PV During Planning Period
Remote Community Only Connection from Pickle Lake (115 kV)	$101 M	$13 M	$114 M	$62 M
New 115 kV line from Pickle Lake to Ring of Fire	Not Technically Feasible for medium to long term			
New 230 kV line from Pickle Lake to Ring of Fire	$196 M	$35 M	$231 M	$127 M
New 230 kV Line from Marathon to Ring of Fire	$327 M	N/A	$327 M	$175 M
New 230 kV Line from east of Nipigon to Ring of Fire	$327 M	N/A	$327 M	$175 M

As indicated previously, a 115 kV line to the Ring of Fire subsystem could supply up to 67 MW, and a 230 kV line would be required to serve demand greater than 67 MW.

Based on the high demand scenario, a 230 kV supply to the Ring of Fire subsystem would be required. A recommendation for a specific solution is not required at this time. The magnitude and timing of the potential mining load is still very uncertain, and decisions regarding transportation infrastructure to the Ring of Fire have not yet been made. A common corridor to the Ring of Fire should consider the potential need for a transmission line.

7.4.2 **Ring of Fire Subsystem Recommendations**

The OPA recommends that electricity infrastructure to supply the Ring of Fire subsystem is coordinated with other infrastructure being investigated, such as transportation. Transmission may also utilize either an East-West corridor (originating from Pickle Lake) or a North-South corridor (originating from either Marathon or east of Nipigon). The OPA therefore recommends that development of an infrastructure corridor to the Ring of Fire should consider the potential need for a transmission line.

The lowest cost option for meeting the medium- and long-term identified needs is a transmission connection from either Pickle Lake, Marathon, or east of Nipigon to the Ring of Fire. The incremental cost of developing a transmission connection capable of serving mines and remote communities is substantially lower than the cost of generation to serve mines and separately connect the remote communities.

8 FEEDBACK FROM ENGAGEMENT AND CONSULTATION

8.1 Aboriginal Consultation

The OPA recognizes the importance of engaging with First Nation and Métis communities and carrying out the procedural aspects of Aboriginal consultation where delegated by the Crown.

The Ministry of Energy delegated the procedural aspects of consultation to the OPA and identified 44 First Nation communities and four Métis communities to be consulted on the Draft North of Dryden IRRP. The Ministry of Energy wrote to each community on the consultation list by letter dated April 25, 2014 to provide notice of the consultation and the delegation of the OPA's role as a delegate of the Crown. The OPA then wrote to each community by letter dated May 26, 2014 to provide the dates and locations of the consultation sessions scheduled for June 2014. The letters included the OPA's commitment to cover the cost of travel and accommodation expenses associated with attending a consultation session. OPA staff then phoned each community to follow up and to answer questions about the North of Dryden IRRP consultation and provided presentation materials in advance of all sessions. The OPA sent additional invitation letters by registered mail on September 26, 2014 for the consultation session that occurred on October 16, 2014. The OPA followed up by phoning each community to ensure that leadership and/or band staff were aware of the North of Dryden consultation.

The OPA held consultation sessions for the First Nation communities in Thunder Bay on June 18, 2014, June 25, 2014, and October 16, 2014, and in Dryden on June 26, 2014. Representatives from 15 communities attended the sessions. Two communities informed the OPA that the North of Dryden IRRP is outside their area of interest. Representatives from the Chiefs of Ontario, Grand Council Treaty 3, and Nishnawbe Aski Nation also attended the sessions but did so for informational purposes only. Notes of these sessions were prepared by the OPA and posted in the regional planning section of the OPA's website.

The OPA was in contact with the Métis Nation of Ontario ("MNO") on a number of occasions via telephone and email to set up appropriate times for regional consultation meetings with MNO's member communities. The OPA endeavoured to meet with the MNO and its chartered communities and remains open to such meetings.

The OPA met with Red Sky Métis Independent Nation on June 19 at Red Sky's office in Thunder Bay. OPA staff delivered a presentation on the North of Dryden IRRP and answered questions posed by Red Sky's representatives.

To date there have not been any specific concerns expressed regarding potential impacts of the regional plan on any Aboriginal or treaty rights. Some clarifying questions were asked during the sessions, and there were some non-consultation related questions regarding electricity rates following the connection of the remote communities identified in the Remote Community Connection Plan. At this point in time, it is not yet known how the distribution service would be structured and therefore it is not possible to determine the impact to rates in a detailed manner. Rates similar to other rural distribution customers in northwestern Ontario are believed to be expected. Other general comments included:

- the need for capacity building in communities to facilitate greater participation in consultation sessions
- some communities wish to focus on project-level consultation with proponents due to the more immediate potential impacts.

8.2 Municipal Engagement

Following the publication of the Draft North of Dryden IRRP, the OPA travelled across the northwest to meet with various municipal representatives from affected municipalities. The following summarizes these meetings:

Table 52: Municipal Engagement Summary

Meeting Date	Municipality
December 10, 2013	Pickle Lake
December 10, 2013	Greenstone
December 12, 2013	Red Lake
December 12, 2013	Sioux Lookout
December 13, 2013	Marathon
February 12, 2014	Dryden
February 13, 2014	Ignace

Following the municipal engagement meetings, several themes emerged as common feedback from the various municipalities and mainly centered on option preference, cost responsibility, and urgency for development.

Various municipal representatives provided input that any new transmission being contemplated in northwestern Ontario should be built to 230 kV standards in order to accommodate potentially high growth and encourage economic development. In general, the OPA agrees with this philosophy if there is sufficient justification to spend the incremental cost associated with a more expensive 230 kV option compared to a less expensive 115 kV option.

The OPA considered this feedback in updating the Draft North of Dryden IRRP that was released on August 16th, 2013. In the draft IRRP, the OPA indicated that it had no preference to the voltage for the recommended new line to Pickle Lake. In this version of the IRRP, the OPA was able to find sufficient justification for initially building and operating the recommended new line to Pickle Lake to 230 kV. The justification is based on the fact that the reference scenario forecast exceeds the capability of a 115 kV line in the longer term, and the provision of option flexibility for supplying the Ring of Fire as described in Section 7.2.

Cost responsibility was another common point of feedback. Generally the municipal representatives communicated that the infrastructure being contemplated in the North of Dryden IRRP is to enable economic development. Economic development was said to provide broader benefits than the local customers and costs should therefore be shared more broadly. Cost responsibility for new transmission and distribution infrastructure will be determined by the OEB during the appropriate regulatory process. For example for applicable transmission lines, cost responsibility would be determined during the leave to construct application.

Another common theme communicated by municipal representatives was the sense of urgency to develop the near term recommendations of a new line to Pickle Lake and the line upgrades from Dryden to Red Lake. The OPA agrees that the recommendation of building a new 230 kV single circuit line to Pickle Lake and upgrading the lines between Dryden and Red Lake are required as soon as possible, and will continue to support their development within the capacity of the OPA.

8.3 Other Engagement Activities

Prior to the publication of the Draft North of Dryden IRRP, the OPA engaged with remote communities, municipalities, stakeholder groups and industry to better understand the needs of the North of Dryden sub-region and communicate options that the OPA was considering for the North of Dryden IRRP. Presentations were made to the following groups and events:

- Ontario Mining Conference – June, 2013
- Common Voice Northwest – May, 2013
- Kenora District Municipal Association AGM – February, 2013
- Central Corridor Energy Group/Wataynikaneyap Power – various meetings 2011-2014
- Sagatay Transmission L.P. – various meetings 2012-2014

- Sioux Lookout Aboriginal Advisory Management Board - Trades Conference Fall 2012
- Aboriginal Energy Forum – December 2012
- Keewaytinook Okimakanak Chiefs Annual Meeting – December 2012
- Red Lake Mining Forum – October 2012
- NWOFNTPC - various meetings 2011-2012

With the release of draft IRRP in August 2013, the OPA hosted a webinar on November 21, 2013 to provide a high-level overview of the plan and to start the dialogue on further developing and refining the plan. An archive of the webinar was posted to the OPA website for stakeholders and communities who were not able to participate.

The OPA also established a dedicated email address – northofdryden@powerauthority.on.ca – to receive written feedback on the draft IRRP and for correspondence about the plan.

9 SUMMARY OF RECOMMENDATIONS

The existing North of Dryden sub-region has met its load meeting capability. In order to accommodate the economic connection of remote First Nation communities and to enable forecasted growth in the mining sector, it is prudent to develop and implement the following recommended solutions as soon as possible:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

These recommendations are the most cost-effective options that can be implemented in a timely manner and provide flexibility for meeting a broad range of long term forecast scenarios.

The estimated combined cost of recommendations (1) and (2) during the planning period is about $124 million (net present value). Recommendation (3) may reduce the estimated cost further. Together these projects increase the LMC of the Pickle Lake subsystem from 24 MW to 160 MW, and increase the LMC of the Red Lake subsystem from 61 MW to 130 MW.

Based on the reference scenario forecast, the recommended solutions are expected to satisfy the forecasted demand requirements for the Pickle Lake and Red Lake subsystem until beyond the end of the planning period. The high scenario forecast indicates that additional investments for the Red Lake subsystem may be required by

2030. The transmission and generation options available have relatively short lead times compared to the 2030 need date, based on the high scenario forecast. As a result, no further action needs to be taken at this time.

The OPA has also shown that under all forecast scenarios assessed in this version of the North of Dryden IRRP, transmission supply options to supply the Ring of Fire subsystem are more economic than remote generation options. The OPA therefore recommends that common infrastructure corridor planning to the Ring of Fire should include the consideration of the potential need for a transmission line to ensure economic and regulatory efficiencies. The OPA will monitor developments in the Ring of Fire subsystem to ensure potential customers, stakeholders and Aboriginal groups are aware of these findings.

The OPA will continue to monitor developments in the North of Dryden sub-region, such as: progress on the recommendations in this version of the plan, demand growth, conservation activities, and progress on developments at the Ring of Fire.

As developments in the North of Dryden sub-region reach new milestones, a new planning cycle for the sub-region will be initiated. The next planning cycle will take place within the next 1-5 years, consistent with the TSC, DSC, and the OPA's license, depending on if and when currently uncertain developments take place.

When the long-term needs for the Red Lake and Ring of Fire subsystems become more certain, reinforcement projects can be triggered in the next planning cycle with appropriate lead times to ensure that the needs will be met.

Some projects may require funding by customers, in accordance with the TSC. In these cases the projects cannot proceed until customers have committed the required resources and funding for development work to be completed. Therefore, the timing of these facilities may be dependent on when customers can identify their needs and provide commitment to the project.

Additionally, conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the North of Dryden sub-region. The OPA has and will continue to actively work with existing and future customers in the North of Dryden sub-region to pursue conservation and DG. The OPA will continue to work with interested customers to understand the availability of potential resources including conservation and customer based DG in the North of Dryden sub-region.

The recommended solutions in the North of Dryden sub-region are consistent with the broader planning and development work that is underway to ensure an adequate supply is available in the Northwest as a whole.

10 APPENDICES

10.1 List of Remote First Nation Communities in Northwest Ontario

10.2 List of Terms and Acronyms

10.3 Planning Methodologies

10.4 Technical Studies and Analysis Methodologies

10.5 Existing System Description and It’s Load Meeting Capability

10.6 Analysis of Recommended Options

10.7 Generation Options

10.8 Transmission Options

10.1 List of Remote First Nation Communities in the Remote Community Connection Plan

Pickle Lake Subsystem Communities

- Sachigo Lake
- Bearskin Lake
- Kingfisher Lake
- Wawakepewin
- Kasabonika Lake
- Wunnumin Lake
- Wapekeka
- Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
- North Caribou Lake (Weagamow)
- Muskrat Dam

Red Lake Subsystem Communities

- Deer Lake
- North Spirit Lake
- Poplar Hill
- Pikangikum
- Keewaywin
- Sandy Lake

Ring of Fire Subsystem Communities

- Eabametoong (Fort Hope)
- Neskantaga (Landsdowne House)
- Webequie
- Nibinamik (Summer Beaver)
- Marten Falls

Communities that are not Economic to Connect at this Time

- Peawanuk
- Fort Severn
- Gull Bay
- Whitesand

10.2 List of Terms and Acronyms

ACF	Average Capacity Factor
Board or OEB	Ontario Energy Board
C&S	Codes and Standards
CNG	Compressed Natural Gas
CTS	Customer Transformer Station
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
DSC	Distribution System Code
EA	Environmental Assessment
EE	Energy Efficiency
EM&V	Evaluation, Measurement & Verification
EUF	End Use Forecast
FIT	Feed-In Tariff Program
FN	First Nation
GAM	Global Adjustment Mechanism
GS	Generating Station
Hydro One or HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan
IRRP	Integrated Regional Resource Plan
Km	Kilometers
kV	kilovolts
kW	Kilowatts
LDC	Local Distribution Company
LMC	Load Meeting Capability
LNG	Liquefied Natural Gas
LTEP	Long-Term Energy Plan of the Ministry of Energy dated November 23, 2010
M	Million
M/MW	Million/Megawatt
Medium to Long term	(2019-2033)
MOE	Ministry of Energy
MTS	Municipal Transformer Station
MW	Megawatts
MWh	Megawatt hour

Near term	(2014-2018)
NoD	North of Dryden
NWOFNTPC	Northwestern Ontario First Nation Transmission Planning Committee
O&M	Operating & Maintenance
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria (IESO document)
PPWG	Ontario Energy Board - Planning Process Working Group's Report to the Board as part of the Renewed Regulatory Framework for Electricity
PV	Present Value
RFEI	Request for Expression of Interest
RoF	Ring of Fire
SCGT	Single Cycle Gas Turbine
SIA	System Impact Assessment
SMD	Supply Mix Directive dated February 17, 2011
SPS	Special Protection Schemes
TCPL or TransCanada	TransCanada PipeLines Limited
TOR	Terms of Reference
TS	Transformer Station
TSC	Transmission System Code

10.3 Study Methodologies

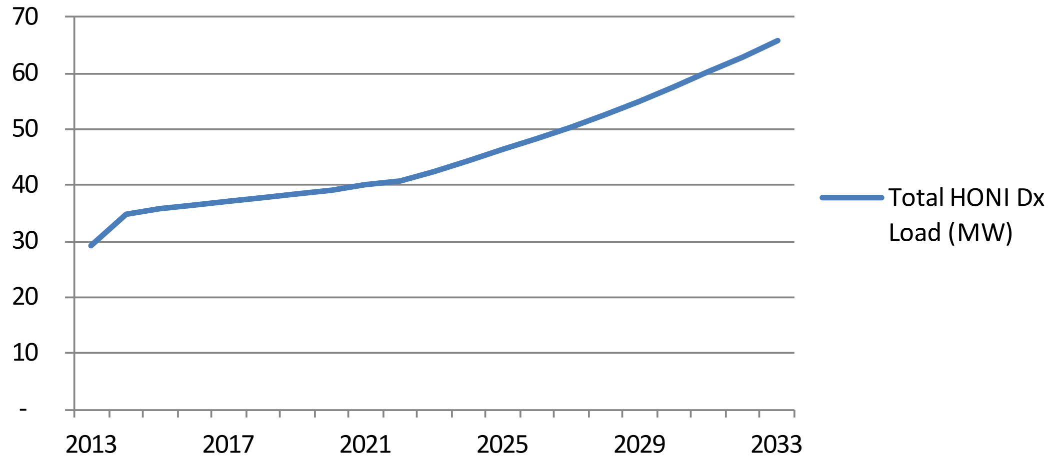
10.3.1 Hydro One Distribution - Reference Demand Forecast Methodology

Hydro One Distribution services the North of Dryden sub-region via six step-down stations:

- 115/12.5 kV Perrault Falls DS supplied by circuit E4D
- 115/44 kV Ear Falls TS supplied by 115 kV circuit E4D
- 115/44 kV Red Lake TS supplied by 115 kV circuit E2R
- 115/24.9 kV Cat Lake CTS supplied by 115 kV circuit E1C
- 115/24.9 kV Slate Falls DS supplied by 115 kV circuit E1C
- 115/27.6 kV Crow River DS supplied by 115 kV circuit E1C

The Hydro One reference demand forecast was developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. Thus historical relationships between actual load growth and economic/demographic factors were utilized in preparing the forecast. In addition, local knowledge, as well as information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast. The forecast is net of the load impact of conservation so that it is consistent with actual load for the base-year and expected load in the future in a manner consistent with the on-going provincial conservation efforts. It also reflects the expected weather impact on peak load under average peak-time weather conditions, known as weather-normal. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast.

Figure 15: North of Dryden sub-region Reference Distribution Demand Forecast (Net of Conservation)



10.3.2 **Methodology for Dependable Renewable Generation Assumptions**

Determining Dependable Wind and Solar Generation

For planning purposes, the dependable capacity of generation is the prorated amount of installed generation capacity that can be relied on to meet demand during peak need hours. Since each type of distributed generation exhibits unique behavior, specific capacity contribution assumptions were used for wind and solar to determine the dependable capacity of these resource types in the North of Dryden sub-region.

Table 53: Capacity Contributions from Wind and Solar

Resource Type	Capacity Contribution	Data Source
Wind	30%	Wind Profiles from AWS Truepower
Solar	5%	Solar Profiles from AWS Truepower

The capacity contribution of solar generation depends on both random and predictable elements, such as weather conditions, latitude, and sunrise/sunset times. The capacity contribution of wind generation depends on weather conditions and can vary significantly. To achieve an accurate representation of these resources, hourly solar and wind profiles for the Northwest zone were estimated by AWS Truepower for the years between 2004 and 2008.

The fall period is typically the most constrained supply period for the North of Dryden sub-region as it is when hydroelectric generation in the Ear Falls area is at its lowest. To calculate the expected solar and wind output in the area, hourly capacity factors from the AWS data corresponding to the top 10% of historical demand hours during October and November were averaged. This result provides a dependable level of output that can be reasonably expected from solar and wind resources in the North of Dryden sub-region during the period of peak need.

Determining Dependable Hydroelectric Generation

The hydroelectric generators located in the North of Dryden sub-region are listed below in Table 54. Lac Seul GS is an expansion of the Ear Falls GS that was undertaken by OPG with the Lac Seul First Nation.

Table 54: Existing and Contracted Hydroelectric Generation

Name	Owner	No. Unit (Total)	Unit Size (MW)	Circuit
Manitou Falls GS	Ontario Power Generation	5	4x14.9 + 1x13.5	M3E
Ear Falls GS	Ontario Power Generation	4	2x5.4 + 2x3.1	Ear Falls TS bus
Lac Seul GS	Ontario Power Generation	1	12.1	Ear Falls TS bus
Trout Lake River GS	Horizon Hydro Inc.	1	3.75	E1C

Northern hydroelectric generation is an energy limited resource known to have significantly reduced output and availability during drought conditions of the river system supplying these generating units. Neither Manitou Falls nor Ear Falls/Lac Seul are currently configured to condense. The OPA has met with OPG and are aware that configuring some select units for condense mode under drought conditions may be a low cost option to provide voltage support.

Dependable generation is defined in ORTAC as the level of generation that is available for at least 98% of hours during the evaluation period. At Manitou Falls GS, output has been at least 14.4 MW 98% of the time, while at Ear Falls GS output has been at least 6.7 MW, 98% of the time.

At Manitou Falls GS, four of the five units are connected on the secondary of one step up transformer (T1), with the fifth unit having its own transformer (T2). Because of this configuration, if T1 is unavailable, only one Manitou Falls GS unit (G5) can remain operational during the duration of the outage of T1.

The units at Manitou Falls GS units are also much larger (13.5 MW and 14.9 MW) than the Ear Falls GS units (3.1 MW and 5.4 MW), therefore the presence of one additional Ear Falls GS unit (assuming sufficient water is available during the outage of Manitou Falls T1) does not significantly improve the transfer limits in the subsystem. The single Lac Seul unit is of a similar size to the Manitou Falls GS units and its operation does significantly improve the transfer capability of the Red Lake subsystem, when it is available.

However, the performance of the Lac Seul unit and the future Trout Lake River GS during drought conditions is not yet known. Until drought condition performance is determined at these units they are assumed to be unavailable during drought conditions. The dependable generation assumptions for hydroelectric units in the Ear Falls area that have been used in this plan are summarized in Table 55.

Table 55: Existing and Contracted Hydroelectric Generation

Name	No. Units (Total)	Unit Size (MW)	Dependable Output (MW)
Manitou Falls GS	5	4x14.9 + 1x13.5	14.4
Ear Falls GS	4	2x5.4 + 2x3.1	6.7
Lac Seul GS	1	12.1	0
Trout Lake River GS	1	3.75	0

High Level Cost Assessment of Renewable Generation

The seasonal and annual variations of run of river hydroelectric generation and the intermittent output of potential wind and solar resources in the North of Dryden sub-region lead to dependable capacities for these resources that are between 5% and 30% of their nameplate capacity, as described above. If these types of resources were used to meet capacity needs for the North of Dryden sub-region, then their dependable capacity would be used to assess their contribution to meeting peak demand. To be an alternative to other generation resources or transmission reinforcements, the nameplate capacity of these renewable resources would have to be built to a level substantially greater than the capacity required for the subsystem. Furthermore, because of this over-sizing, during times of high renewable output, these resources may be partially constrained by limited existing transmission capability connecting them to the rest of the Ontario system.

Developing these resources to serve capacity needs would require between 3 MW and 20 MW of nameplate capacity to dependably supply 1 MW of load.

It is estimated that the capital cost of dependable run of river hydroelectric capacity ranges from $15 million to $65 million per MW, while wind and solar range from $15 million to $100 million per MW. The curtailment of generation would have an associated cost, or alternatively, new implementation of transmission to deliver excess energy would also have societal costs and is an alternative to renewable generation for meeting the needs of the North of Dryden sub-region. Neither of these additional costs were considered in this high level cost analysis. A summary of the results of this cost analysis is in Table 56, below.

Table 56: Summary of Renewable Generation Options

Resource Type	Firm Capacity	Capital Cost per MW of Firm Capacity	Levelized Unit Energy Cost[76]	Development Duration
Hydroelectric (Run of River)	15-30%	$16 M - $66 M /MW	$60-$110/MWh	5 to 10 Years
Intermittent Renewables	5-28%	$7.5 M - $100M /MW	$80-$400/MWh	3 Years

10.4 Technical Studies and Analysis Methodologies

The following section outlines the assumptions and methodology used for performing the technical analysis for determining the load meeting capability of the existing system, and the options being considered. The load meeting capability for options being considered are mostly limited by acceptable voltage performances. Consequently, a significant portion of the costs for options being considered is for the installation of voltage control devices. When developing cost estimates, planning level unit costs were used, which typically have an accuracy of +/-50%.

10.4.1 Base Case Setup and Assumptions

The system studies for this plan were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the base case that was produced by the IESO for the 2012 North of Dryden Feasibility Study.

Bulk System Assumptions

The North of Dryden sub-region is connected to the bulk transmission system at Dryden TS. The forecasted capacity requirements for the North of Dryden sub-region are coordinated with the West of Thunder Bay IRRP. Therefore, for the purpose of this assessment, it is assumed that the bulk system supply to the North of Dryden sub-

[76] Levelized Unit Energy Cost (LUEC) is a method to compare electricity system resources on a $/MWh basis, considering the costs incurred (capital, fixed, variable, fuel, etc.) and the production of energy over the lifetime of the resource, discounted appropriately. LUEC assumes that all energy generated can be delivered without transmission constraints.
.

region will be stable. A healthy supply voltage from the bulk 230 kV (nominal) system of 245 kV has been assumed.

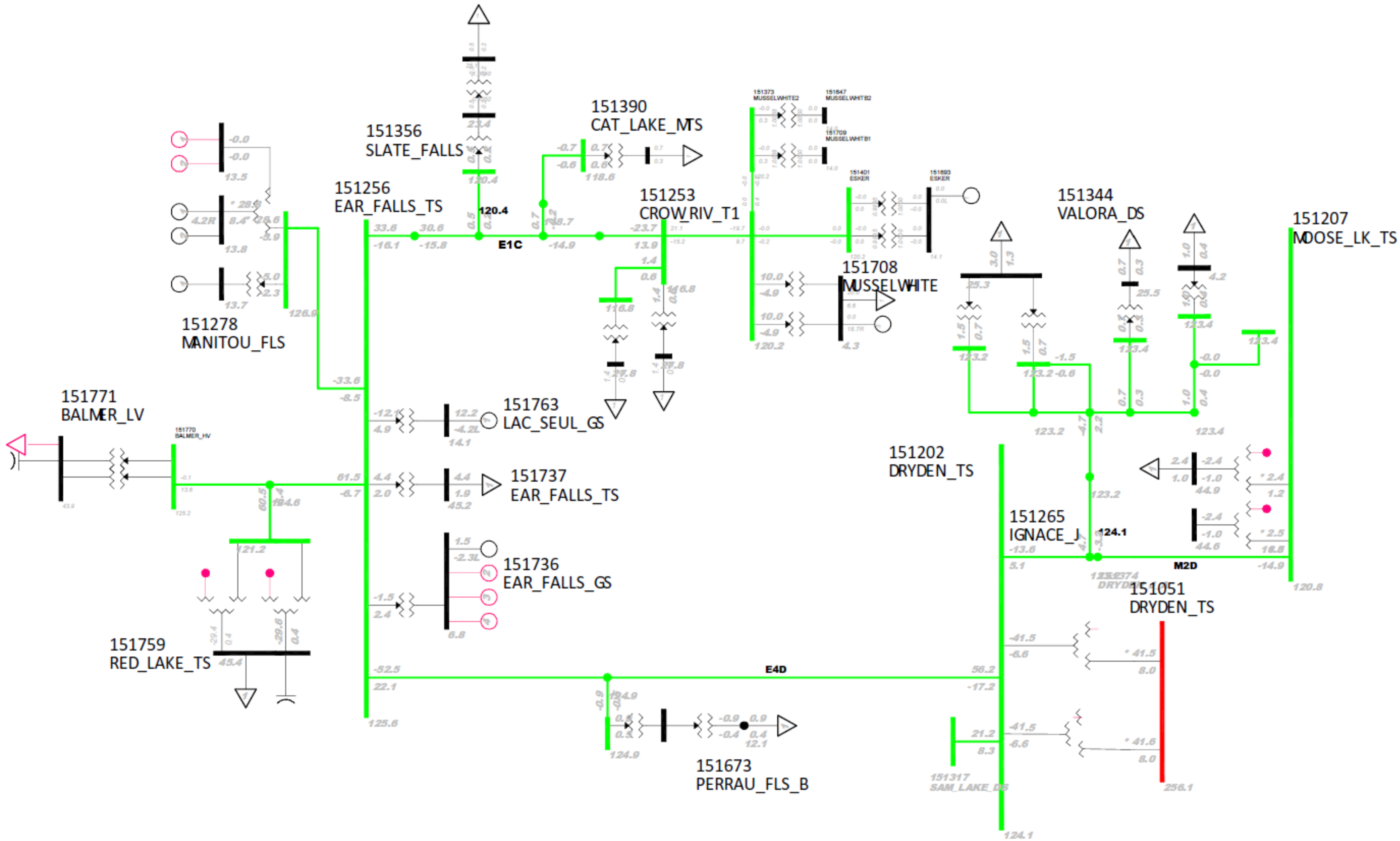
Local Area Assumptions

These load flow cases include the following assumptions:

- Dependable (drought) level hydroelectric generation, which totals 21.1 MW in the Ear Falls area (Manitou Falls GS (14.4 MW), Ear Falls GS (6.7 MW))
- Summer ambient temperature of 30°C and 0-4 km/hr wind for ampacity of overhead transmission circuits
- Peak forecasted load corresponding to the reference, high, and low scenarios for the near term and medium to long term
- All proposed 115 kV circuits had line characteristics equivalent to that of a 477 kcmil ACSR conductor (similar to existing M2D), and all proposed 230 kV circuits had line characteristics equivalent to that of a 795 kcmil ACSR conductor (similar to existing circuit D26A)
- The 115 kV step-down transformers at Mc Faulds (Ring of Fire mines) were assumed to be similar to the existing transformers at Red Lake TS. Other 115 kV step-down transformers were assumed to be similar to the existing transformers at Crow River DS for loads greater than 3 MVA, or the Slate Falls transformer for loads smaller than 3 MVA. The Pickle Lake 230/115 kV autotransformer was assumed to be similar to the existing Lakehead autotransformers.
- Dependable capacity at Trout Lake River GS is assumed to be 0 MW
- 5% of installed solar capacity is assumed to be dependable. This includes four microFIT projects in Red Lake providing capacity of 39.3 kW and one microFIT project in Ear Falls with an capacity of 10 kW, providing a 2.5 kW of dependable output
- For steady state and voltage assessment, the loads are modeled as constant megavolt-ampere (MVA)
- All new voltage control devices are assumed to be Static Var Compensation (SVC) devices

- It was assumed that the loss of voltage control devices connected at load stations (McFaulds, Esker, Musselwhite, Red Lake, Balmer, Sandy Lake, Pickle Lake area Mine) would also result in the loss of the associated load.

Figure 16: North of Dryden 2012 Peak Load Flow Case



130

10.4.2 **Application of IESO Planning Criteria**

In Ontario, the criteria for planning the transmission system are specified in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[77]. In accordance with ORTAC, the transmission system supplying a local area shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. In determining the load meeting capability for each subsystem, ORTAC requires certain conditions to be respected. The supply options that are discussed for the North of Dryden sub-region assume that where new lines are built parallel to existing lines, some or all of the incremental load that is enabled for connection to the system, may be curtailed in the event of a forced outage of either line. This following is an excerpt from Section 7.1 of ORTAC which states:

> "The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.
>
> With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.
>
> With any one element out of service3, equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario."

Additionally, the following were assumed in this study to comply with ORTAC:

- Run of river hydroelectric generation should be assumed at a level that is available 98% of the time (ORTAC Section 2.6);

[77] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

- Load power factors is assumed to be 0.95 at the low voltage busbar to comply with the Market Rule of 0.9 at the defined meter point at the HV busbar (ORTAC Section 2.4);
- Voltage operating range of 113 kV to 132 kV for the 115 kV nominal system, and 220 kV to 250 kV for the 230 kV nominal system (ORTAC Section 2.4);
- Pre-contingency voltage maintained to the greater of (ORTAC Section 4.2):
  - At least 10% margin above the instability point
  - Minimum continuous voltage pre-contingency: 113 kV for 115 kV nominal system, and 220 kV for 230 kV nominal system
  - That which results in a post-contingency voltage of at least 108 kV for 115 kV nominal system, and 207 kV for 230 kV nominal system
- All line and equipment loading is within the continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service (ORTAC Section 4.7.2 and 7.1); and
- If the subsystem has transmission connected generation, the largest generator unit is assumed to be on outage pre-contingency and not available post-contingency.

The load meeting capability for each subsystem and each option are determined with the aid of PSS/E simulation, which represents a full model of the system, accounting for active and reactive power flows, losses, voltage drops, etc.

Table 57: Conditions for Determining Subsystem LMC

Local Area Supply	Conditions for LMC
Single Radial Line	Limit of the line during normal operating conditions.
Single Radial Line + Local Generation	Limit of the line during normal conditions; and Loss of the largest generating unit.

10.4.3 **Technical Study Procedures**

Once the needs for the subsystems were determined based on an assessment of the existing system and forecast net demand growth, the technical study identified how various options could meet the identified needs. From these needs, a range of generation and transmission options were developed that are capable of partially or fully meeting the identified needs. The capability of the options to serve the needs including the amount of voltage control required to meet the required LMC was determined.

Contingencies Considered in Option Assessment

A detailed list of the contingencies considered for the North of Dryden sub-region is outlined below in Table 58. All contingencies are limited to the loss of a single element (N-1) considering pre-contingency outage conditions consistent with ORTAC.

Table 58: Contingencies Considered in the Technical Study

Subsystem	Supply Option	Contingencies
Pickle Lake	CNG generation at Pickle Lake	Loss of single generating unit (10 MW) at Pickle Lake
		Loss of Manitou Falls GS
	New Line to Pickle Lake	N/A
Red Lake	NG generation at Red Lake	Loss of single generating unit (10 MW) at Red Lake
		Loss of Manitou Falls GS
	New Line to Ear Falls	Loss of New Line
		Loss of Manitou Falls GS
Ring of Fire	All	N/A

Determining Voltage Control Requirements

For each option in each subsystem, base cases were developed for both peak and light load conditions. Each subsystem was considered independently, and the effects of each option on the bulk system around Dryden TS and/or at Marathon TS were included.

Location and size of the voltage control devices for each test case was determined under the following load scenarios to satisfy the assumptions listed above.

1. Peak load conditions, all elements in service: This test determined the voltage control devices are required to ensure sufficient margin from the voltage collapse point. Voltage control devices were used to maintain the voltage within the ranges stated in the assumptions.

2. Zero load conditions: This test determined the amount of voltage control required to manage high voltages.

3. Light load conditions, all elements in service: This test was used to determine the required switching size and range of the voltage control devices.

4. Peak load conditions, largest local element out of service: In areas where contingencies were tested, voltage control device requirements before tap changing were determined.

Determining Load Meeting Capability of Options

This study uses the base cases that were developed for the peak load scenario in determining voltage control requirements, as stated above. For each subsystem, the LMC of the option following the installation of all facilities and voltage control devices that are required to meet the peak load forecast was determined for each option for each forecast scenario.

The LMCs for each option were determined using the following procedure:

1. The range of voltage control that was determined in the previous analysis was assumed to be available.

2. Peak load was assumed as a base. Thermal loading of transmission equipment was assessed.

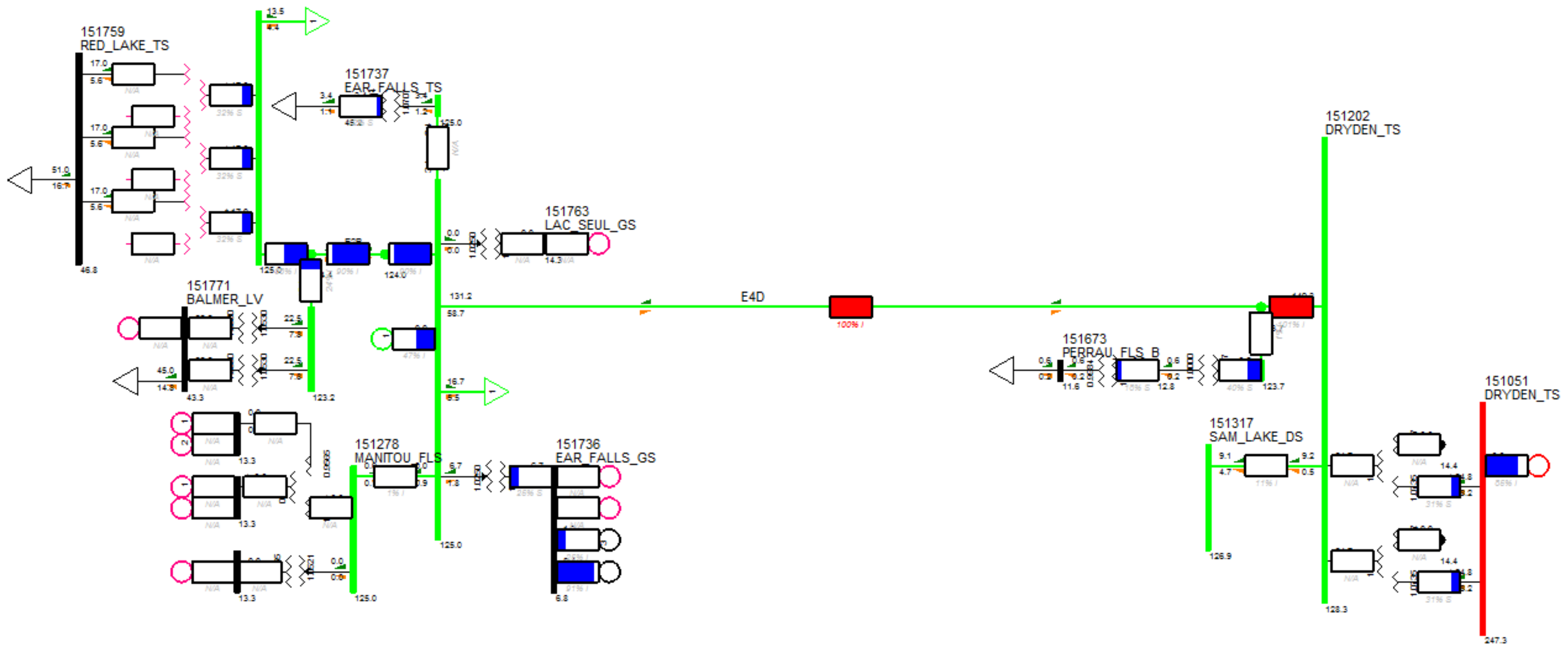
3. Where there was existing thermal capacity on transmission equipment, load was increased and new voltage control requirements were established, to determine the LMC. Load was increased at a central system bus within the subsystem (Pickle Lake area TS for the Pickle Lake subsystem, Ear Falls TS for the Red Lake subsystem, Mc Faulds TS for the Ring of Fire subsystem).

4. Following this, the system was tested allowing voltage control requirements to increase within reasonable limits.

More detailed studies for particular reinforcements may determine that voltage control devices can be located in alternative places closer to large loads, which may be found to optimize their value and reduce the overall cost. Specific connection requirements for individual customers, including requirements for additional voltage control devices will be identified by the IESO in future System Impact Assessments (“SIA”).

A sample load flow case that was used to determine the LMC of the Red Lake subsystem after the upgrade of E4D and E2R is provided in Figure 17 below. In this case, the LMC for subsystem is 130 MW.

Figure 17: Sample of Methodology – Determining Post-Upgrade LMC of E4D and E2R Upgrade

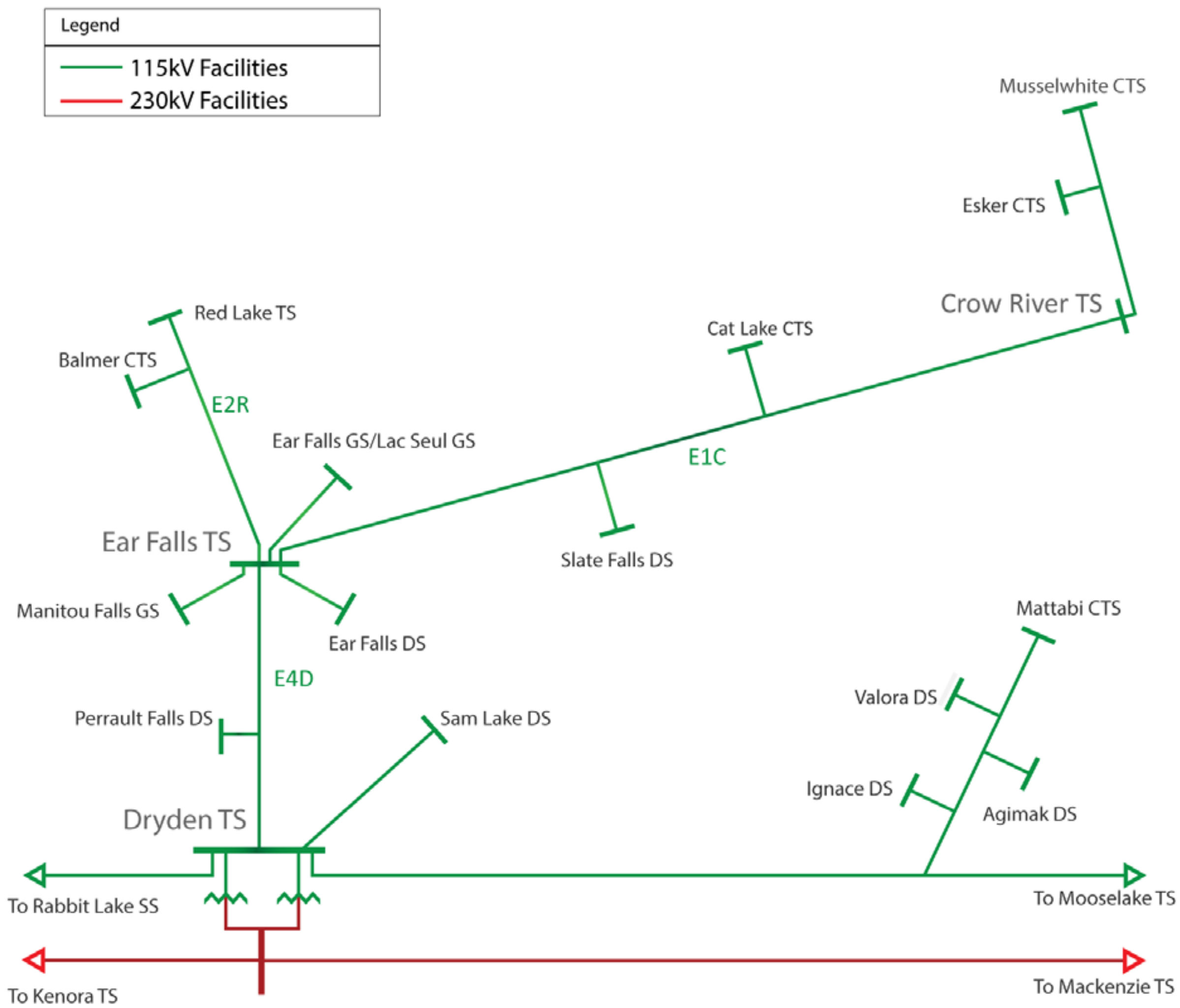


136

10.5 Existing System Description and Load Meeting Capability

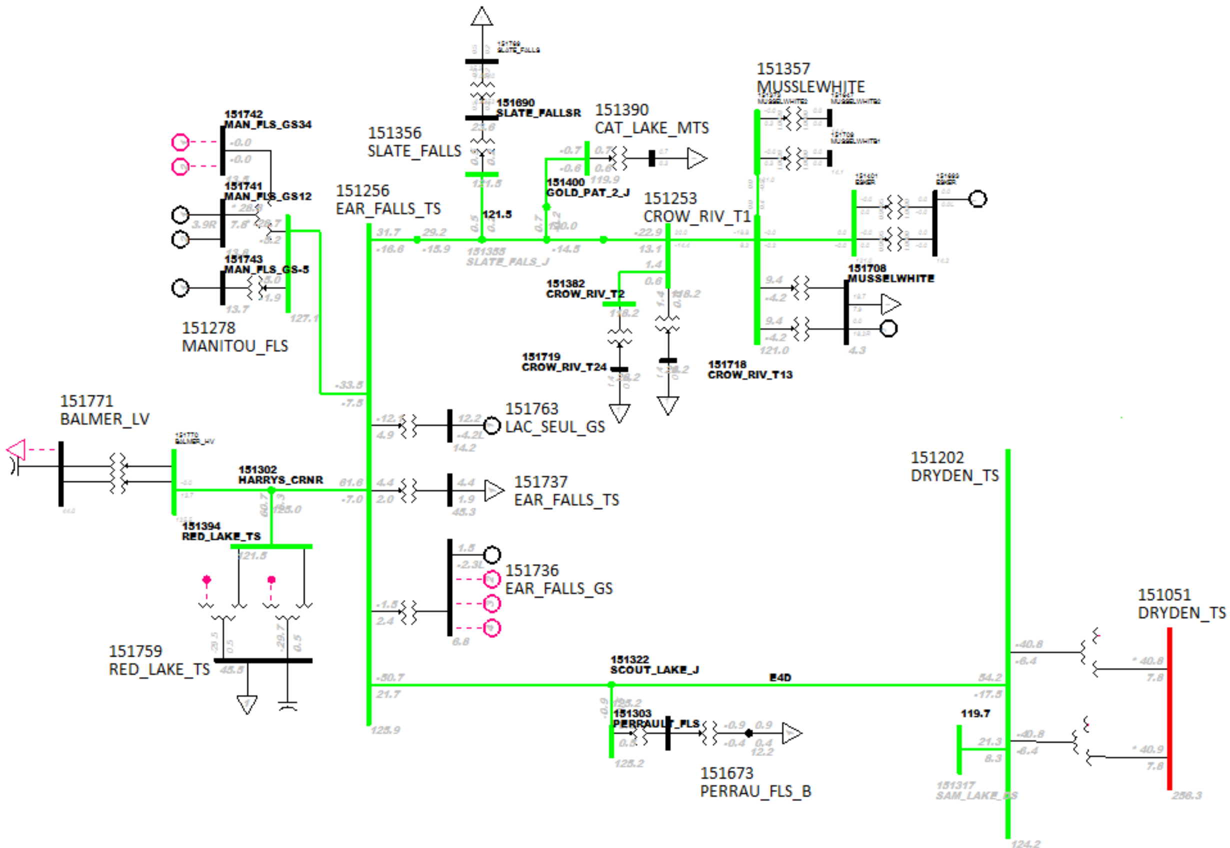
The North of Dryden electricity system is shown in Figure 18.

Figure 18: Existing North of Dryden Transmission System



137

Figure 19: Existing North of Dryden Transmission System Load Flow Plot



Pickle Lake Subsystem

The Pickle Lake subsystem includes all load currently and planned to be served by E1C at Cat Lake CTS, Slate Falls DS, Crow River DS, as well as Musselwhite mine. The Pickle Lake subsystem also includes 10 remote communities north of Pickle Lake that are planned to connect to Pickle Lake via a transmission line to Crow River DS.

Currently, the Pickle Lake subsystem has an LMC of 24 MW. Due to losses on the line E1C, supply of close to 35 MW is required from Ear Falls TS to serve this load along the line and at Pickle Lake. The LMC for the Pickle Lake subsystem is determined by the load that can be met during normal operating conditions.

138

Red Lake Subsystem

The Red Lake subsystem includes all load and generation connected and planned to be served by E4D and E2R, at Perrault Falls DS, Ear Falls TS, Red Lake TS, Balmer CTS, and the six remote communities that lie north of Red Lake that are planned to connect to Red Lake TS. There is 102.2 MW of hydroelectric generation at Ear Falls/Lac Seul GS and at Manitou Falls GS.

Currently, the E4D and Ear Falls area generation is capable of supplying 85 MW from Ear Falls TS, which includes 61 MW in the Red Lake subsystem and 24 MW in the Pickle Lake subsystem.

Ring of Fire Subsystem

The Ring of Fire subsystem includes five remote communities that are planned for connection to the provincial transmission system as well as potential future industrial customers at the Ring of Fire. This subsystem may be connected to the provincial transmission system either at Pickle Lake, Marathon TS, or east of Nipigon.

The Ring of Fire subsystem is not currently supplied from the IESO-controlled grid and thus has a load meeting capability of 0 MW. However the 5 remote communities are currently served by local diesel generation in their communities.

10.6 Analysis of Recommended Options

As indicated in Section 0, the recommended options for the North of Dryden sub-region are:

1. Building a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake (for the Pickle Lake subsystem) and installing a new 230/115 kV autotransformer, related switching facilities, and the necessary voltage control devices at Pickle Lake;

2. Upgrading the existing 115 kV lines from Dryden to Ear Falls (E4D) and from Ear Falls to Red Lake (E2R) (for the Red Lake subsystem) and install the necessary voltage control devices; and

3. IESO/OPA to initiate discussions with OPG for new reactive power services provided by Manitou Falls GS if it is confirmed to be beneficial to the ratepayer

   For the list of assumptions and procedure pertaining to the assessment of generation options, refer to Section 10.7. For a list of assumptions and procedure pertaining in the assessment of transmission options, refer to Section 10.8

Recommendation 1: New single circuit 230 kV line to Pickle Lake and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 59: Summary of Load Meeting Capability of Recommendation

Recommendation	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
230 kV line to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

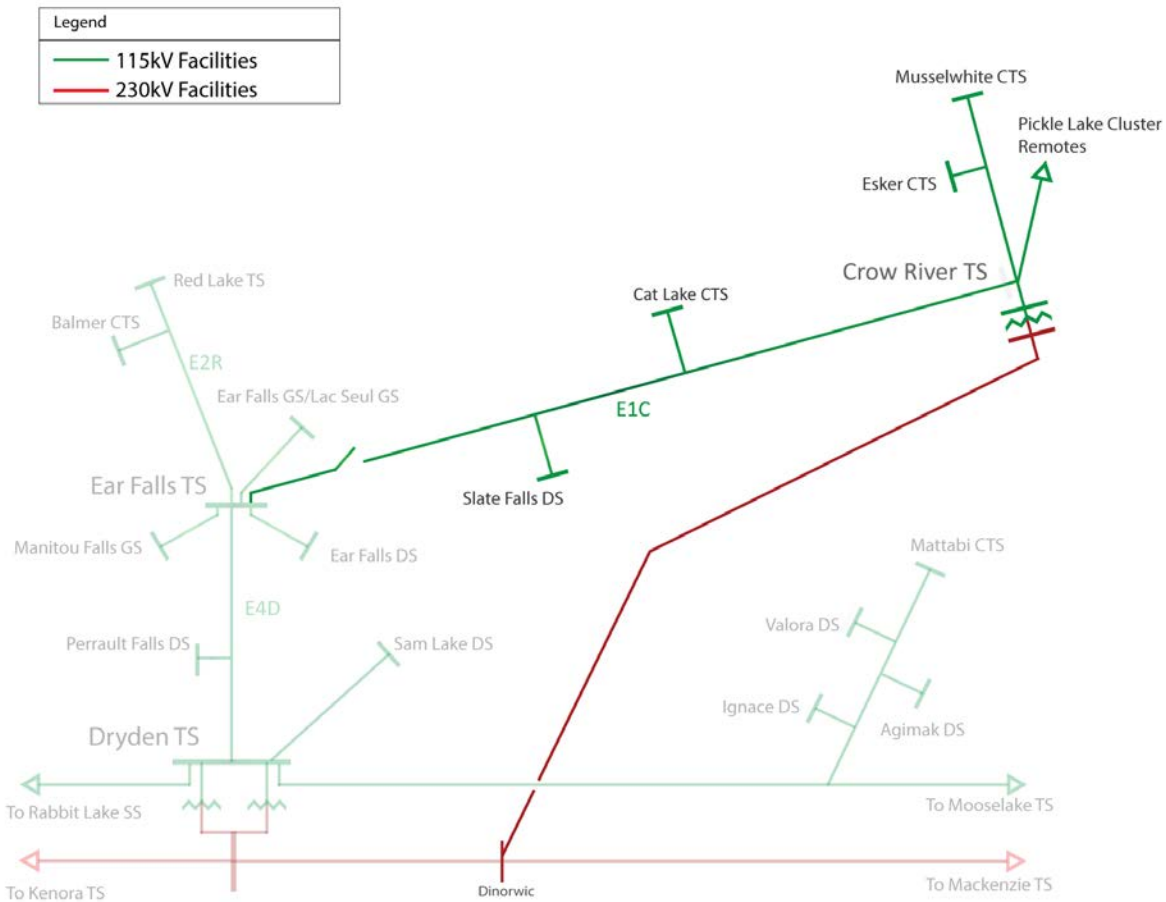
Table 60 outlines the cash flows used for the net present value economic analysis. Figure 20 and Figure 21 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 60: Summary of Cashflow for New Line to Pickle Lake at 230 kV[78]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

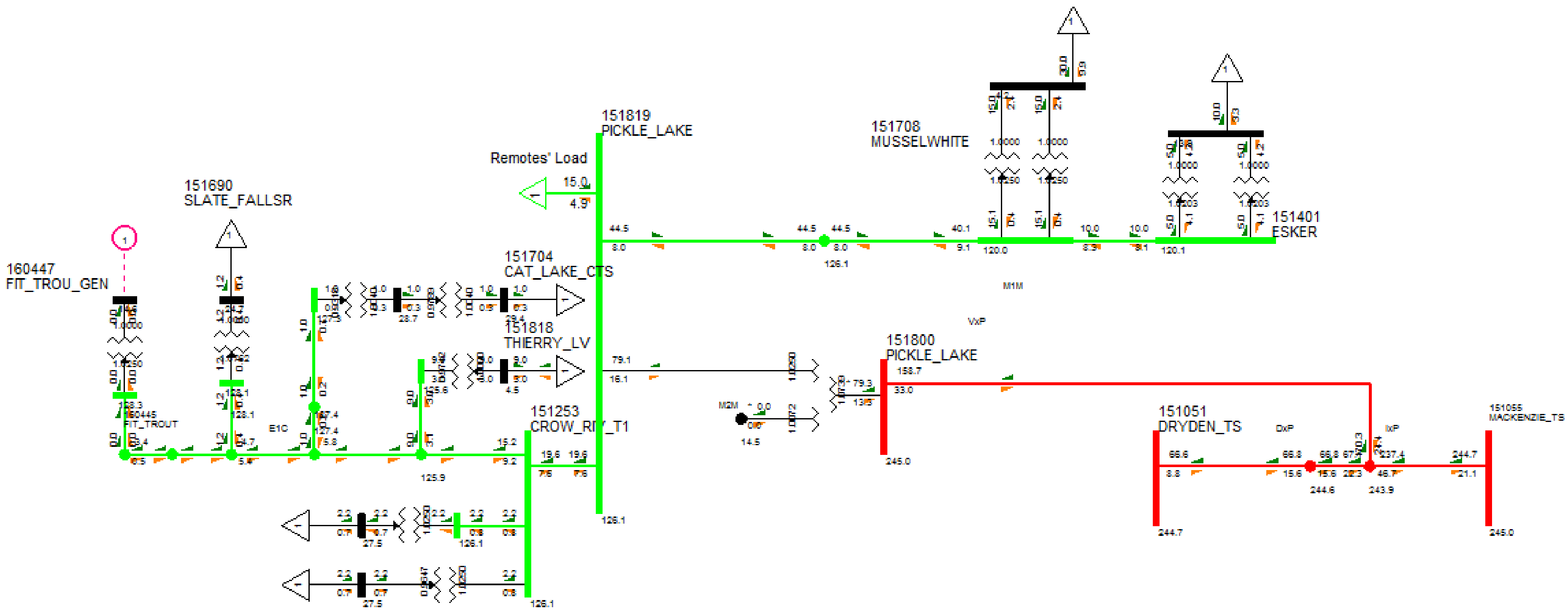
[78] Includes compensation required to supply Reference load forecast scenario (78 MW in 2033).

Figure 20: New 230 kV line to Pickle Lake Diagram



142

Figure 21: 230 kV Line Option Pickle Lake Subsystem Configuration



143

Recommendation 2: Upgrade circuits E4D and E2R and supporting facilities

The following table outlines the load meeting capability provided by the option and the long-term forecasted load.

Table 61: Summary of Load Meeting Capability of Recommendation

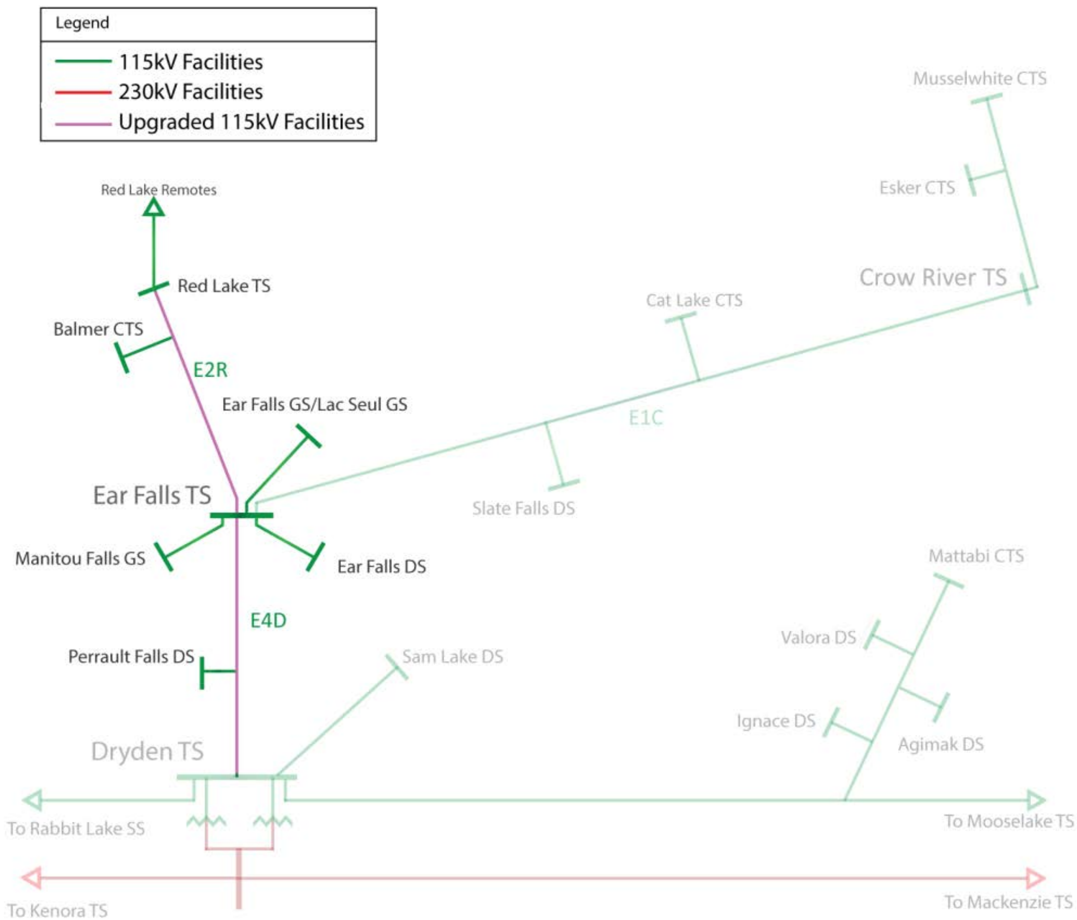
<table>
<tr><th>Recommendation</th><th>Incremental Capacity</th><th>Load Meeting Capability</th><th>Low Forecast Demand</th><th>Reference Forecast Demand</th><th>High Forecast Demand</th></tr>
<tr><td rowspan="2">Upgrade E4D and E2R
and
Transfer of Pickle Lake load to new line to Pickle Lake</td><td>34 MW</td><td>95 MW</td><td rowspan="2">100 MW</td><td rowspan="2">109 MW</td><td rowspan="2">136 MW</td></tr>
<tr><td>35 MW</td><td>130 MW</td></tr>
</table>

Table 62 outlines the cash flows used for the net present value economic analysis. Figure 22 and Figure 23 illustrate the single line diagram of the option and the power flow simulation for the reference scenario.

Table 62: Summary of Cashflows for Upgrade to E4D and E2R

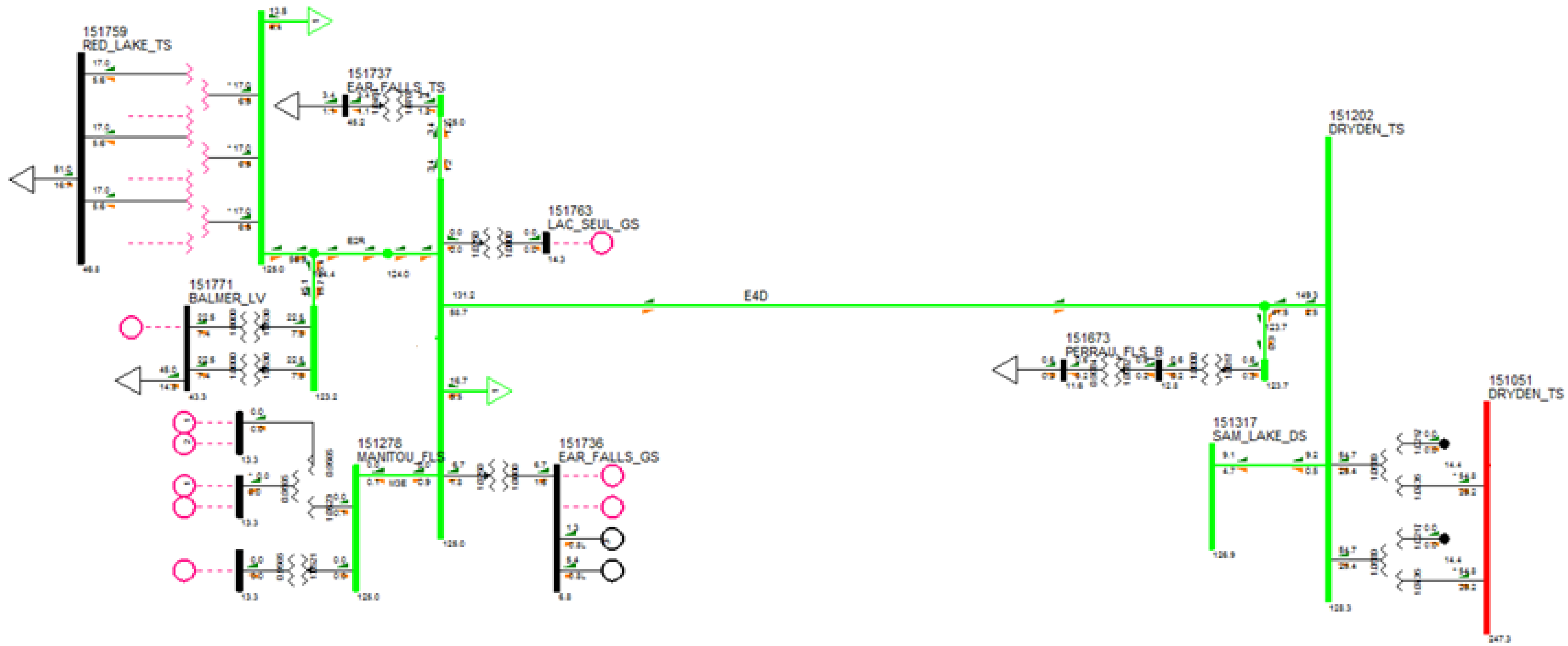
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 22: E4D and E2R Upgrade Diagram



146

Figure 23: E4D and E2R Upgrade Red Lake Subsystem Configuration



147

Recommendation 3: Manitou Falls condense operation during drought conditions

In order to accommodate future growth in the Red Lake subsystem, new voltage control devices would need to be installed in the Ear Falls and Red Lake areas. New voltage control devices would be required in order to release the thermal capability provided to the Red Lake subsystem from the system upgrades being recommended.

OPG has informed the OPA that Manitou Falls units G1, G2, and G3 could be made to condense with minor maintenance work. Units G1, G2, and G3 would have a capability of approximately +/-14 MVar each, for a total of +/- 42 MVar. The OPA anticipates that the NPV cost associated with enabling and operating the condense features over the planning period is likely to be significantly less than the NPV cost of installing new voltage control devices.

10.7 Generation Options

For each of the three subsystems, at least one generation option was studied in detail. However, due to the different nature of each system, and thus the differing needs, each system was approached with a unique methodology to ensure that the generation option/s studied reflect the need of the subsystem.

The assumptions and methodologies used for developing the generation options are described below.

10.7.1 Pickle Lake Subsystem

Assumptions

The following assumptions were used to estimate the cost of CNG electricity generation in the Pickle Lake subsystem:

- Pickle Lake subsystem will remain connected to Ear Falls TS and 24 MW of load in the Pickle Lake subsystem will be served from Ear Falls TS

- Forecasted demand greater than 24 MW in the Pickle Lake subsystem (including remote communities in the Ring of Fire subsystem connecting at Pickle Lake) would be served by CNG fueled generation at Pickle Lake
- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed
- Generation would be fueled mainly by CNG, which would be compressed and transported from TCPL pipeline in the Ignace area via Highway 599
- Decanting stations would be required to decompress the natural gas for use
- CNG fuel delivery would be on a just in time basis due to challenges with large scale on-site CNG storage
- If CNG is unavailable generators will run on diesel, cost of supplying diesel and storage has not been included
- A sufficient number of trailers would be required to transport CNG as well as provide for some limited on-site storage to ensure a stable flow of fuel
- A Special Protection System triggered by the loss of more than one generator in the new facility, may be required to automatically shed load sufficient to maintain operation of E1C within appropriate limits
- Discrete generator unit sizes of 9.5 MW

Study Procedure

To determine the feasibility and estimate the cost of implementing a CNG generation facility in the Pickle Lake subsystem, the following procedure was undertaken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity at Pickle Lake that would be required to meet the peak forecast demand of the subsystem.
2. Using established transmission limits, hydroelectric generation profiles and load profiles for the subsystem, the capacity and energy that would need to be served by new CNG generation resources was estimated.
3. Using energy requirements estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;

4. Using generator capacity, number of trailers and annual energy requirements, capital, operations and maintenance, and fuel costs of the system were calculated.
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

A summary of the technical capability of the generation options that were considered for the Pickle Lake subsystem is summarized below.

Table 63: Summary of Capacity for Gas Generation at Pickle Lake

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
CNG Generation at Pickle Lake (38 MW)	19 MW	43 MW	41 MW	78 MW	90 MW
CNG Generation at Pickle Lake (47.5 MW)	23.5 MW	47.5 MW			
CNG Generation at Pickle Lake (76 MW)	57 MW	81 MW			
CNG Generation at Pickle Lake (85.5 MW)	66.5 MW	90.5 MW			

*Requires continued supply of 24 MW of load via E1C from Ear Falls

**Includes demand for Ring of Fire remote communities (7 MW)

The cost of supplying the growth needs of the Pickle Lake subsystem with CNG fueled generation are shown in Table 64 through Table 69. Figure 24 shows operation of the Pickle Lake subsystem with this option in the peak load case. Voltage profiles throughout the subsystem remain healthy in the general range of 118 kV to 125 kV. The installation of generation at Pickle Lake also provides some voltage control to the Pickle Lake subsystem.

Table 64: Summary of Cost for 38 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	56.8	0.0	0.0	0.0	4.7	0.0	0.0	0.0	4.0	0.0	16.0	0.0	3.0	0.0	0.0	0.0	2.9
O&M and Fuel	0.0	0.0	0.0	10.5	10.2	9.8	9.4	9.1	8.7	8.4	8.1	7.7	7.4	5.3	5.3	5.3	5.3	5.3	5.3	5.4
System Gen Credit	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Total Annual Gx Cost	0.0	0.0	0.0	67.2	8.7	8.3	7.9	12.2	7.2	6.9	6.6	10.2	6.0	19.8	3.8	6.8	3.8	3.8	3.8	6.8
Annual Amortized cost	0.0	0.0	0.0	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	10.3	20.3	29.8	39.0	47.9	56.4	64.5	72.4	80.0	87.2	94.2	100.9	107.4	113.6	119.6	125.3	130.8

Table 65: Summary of Cost for 47.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	66.4	0.0	0.0	0.0	7.2	0.0	0.0	0.0	8.0	0.0	27.7	0.0	5.6	0.0	0.0	0.0	6.4
O&M and Fuel	0.0	0.0	0.0	12.7	13.0	13.3	13.6	13.9	14.2	14.6	14.9	15.3	15.7	9.7	10.1	10.4	10.8	11.2	11.7	12.2
System Gen Credit	0.0	0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1
Total Annual Gx Cost	0.0	0.0	0.0	79.1	5.9	6.1	6.4	14.0	7.1	7.4	7.8	16.2	8.5	30.2	2.9	8.8	3.7	4.1	4.6	11.5
Annual Amortized cost	0.0	0.0	0.0	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	12.1	23.7	34.9	45.6	56.0	65.9	75.5	84.6	93.5	102.0	110.1	118.0	125.5	132.8	139.8	146.5	152.9

Table 66: Summary of Cost for 76 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	124.2	0.0	0.0	0.0	9.6	0.0	0.0	0.0	12.8	0.0	52.4	0.0	15.2	0.0	0.0	0.0	18.4
O&M and Fuel	0.0	0.0	0.0	16.0	16.3	17.8	18.4	19.9	21.2	22.6	24.0	25.6	27.0	25.9	27.3	28.9	30.4	31.9	33.4	35.1
System Gen Credit	0.0	0.0	0.0	0.0	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1	-14.1
Total Annual Gx Cost	0.0	0.0	0.0	140.2	2.2	3.7	4.3	15.3	7.1	8.5	9.9	24.2	12.9	54.1	13.2	30.0	16.3	17.8	19.3	39.4
Annual Amortized cost	0.0	0.0	0.0	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	22.8	44.8	65.9	86.1	105.7	124.4	142.4	159.8	176.5	192.5	207.9	222.7	237.0	250.7	263.9	276.5	288.7

Table 67: Summary of Cost for Compensation Associated with up to 76 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				8.1																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	8.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumulative PV	0.0	0.0	0.0	0.4	0.8	1.2	1.5	1.9	2.2	2.5	2.8	3.1	3.4	3.7	4.0	4.2	4.5	4.7	4.9	5.1

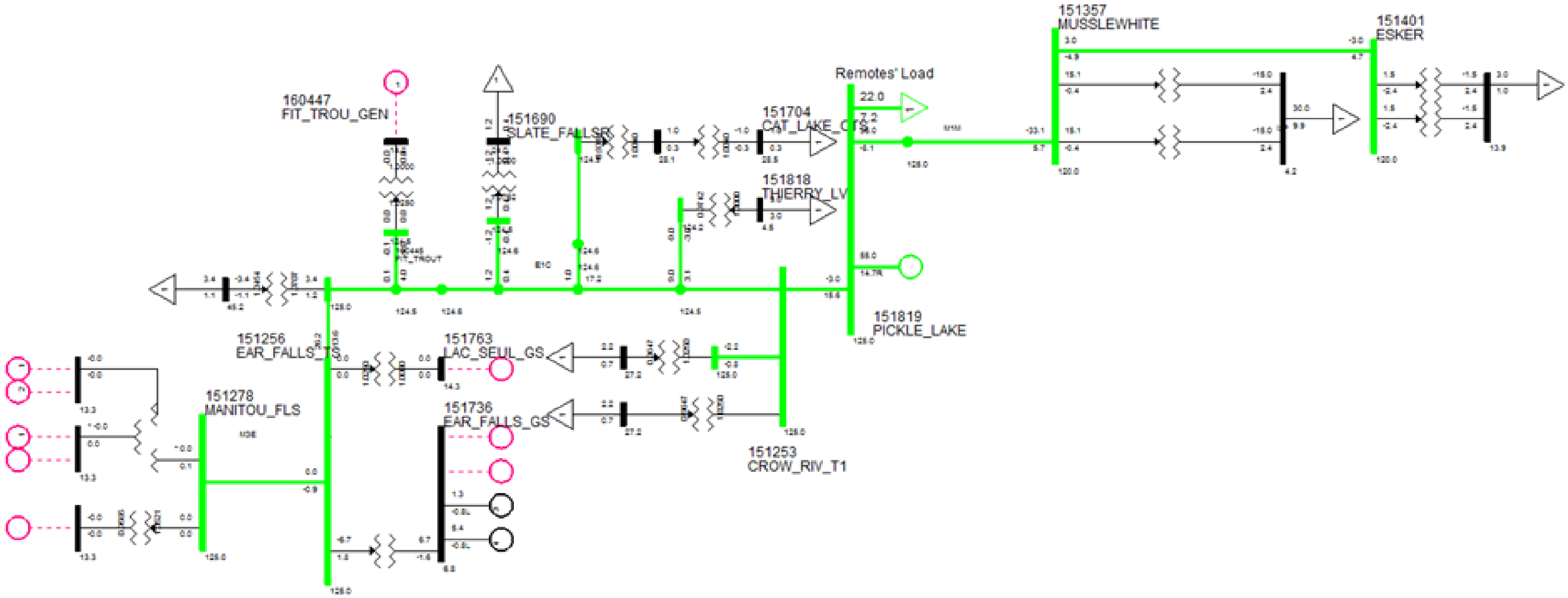
Table 68: Summary of Cost for 85.5 MW of CNG Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	125.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	15.2	0.0	52.4	0.0	18.4	0.0	0.0	0.0	22.4
O&M and Fuel	0.0	0.0	0.0	17.1	17.3	22.0	22.5	24.1	25.4	26.8	28.2	29.8	31.2	32.6	34.1	35.7	37.2	38.7	40.2	41.9
System Gen Credit	0.0	0.0	0.0	0.0	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4	-17.4
Total Annual Gx Cost	0.0	0.0	0.0	142.1	0.0	4.6	5.1	18.7	8.0	9.4	10.8	27.6	13.8	67.6	16.7	36.7	19.8	21.3	22.8	46.9
Annual Amortized cost	0.0	0.0	0.0	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.3	47.7	70.2	91.8	112.6	132.5	151.8	170.2	188.0	205.1	221.5	237.3	252.5	267.1	281.1	294.6	307.6

Table 69: Summary of Cost for Compensation Associated with up to 85.5 MW of Gas Generation in Pickle Lake Subsystem

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost				14.7																
O&M				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	14.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost				0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.7	1.4	2.1	2.8	3.4	4.0	4.6	5.2	5.7	6.2	6.7	7.2	7.7	8.1	8.5	8.9	9.3

Figure 24: Generation Option Pickle Lake Subsystem Configuration



10.7.2 Red Lake Subsystem Generation Options

Assumptions

The following assumptions were used to estimate the cost of natural gas electricity generation in the Red Lake subsystem:

- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area for 30 MW generation (near-term) option;
- Natural gas would be supplied via the existing Union Gas pipeline in the Red Lake area and a new gas pipeline to future customer(s) for the 60 MW (long-term) option;
- Pipelines are assumed to be available and associated costs are not included in this analysis (except gas management charges). New pipeline capacity required for the second 30 MW of gas generation at Ear Falls is assumed to be linked to a future potential load customer, therefore if the incremental gas capacity is not developed neither will the load be present in the subsystem; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing natural gas generation in the Red Lake subsystem, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to find the installed generation capacity required to meet the need of the Red Lake subsystem;
2. Using established transmission limits, hydroelectric generation profiles and the identified need for the subsystem, determine the capacity and energy that new generation resources would need to served;
3. Using established unit costs, capital, operations and maintenance, and fuel costs of the new generation resources were calculated;
4. Using capacity size, gas management charges for a peaking facility in the area were estimated; and
5. These capital, operations and maintenance costs, were levelized over the project life and the present value over the planning period (2014-2033) was calculated.

Planning Assessment of Near-Term Option

Table 70 summarizes the incremental capacity provided by this option as well as the total LMC of the Red Lake subsystem with this option, while Table 71 summarizes the cost of the option in the Red Lake subsystem.

Table 70: Capacity and LMC Summary for Generation Options at Red Lake

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Near-term Demand	Reference Forecast Near-term Demand	High Forecast Near-term Demand
NG Generation at Ear Falls (30 MW)	30 MW	91 MW	91 MW	91 MW	91 MW

Figure 25 illustrates the system state of the Red Lake subsystem with this option.

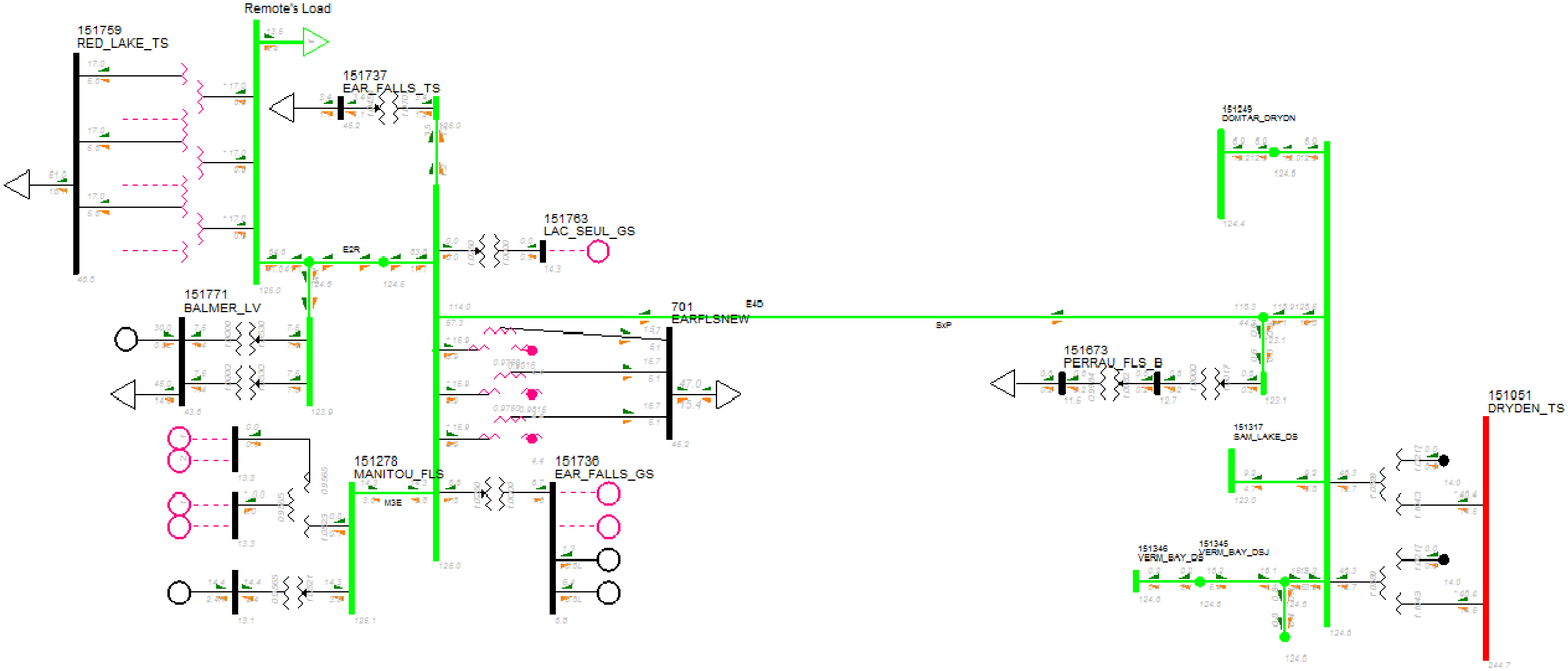
Table 71: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost		80.9																		
Fixed O&M		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Variable O&M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided System Gen Cost		0.0	0.0	0.0	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6
Total Annual Gx Cost		82.7	1.8	1.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8
Levelized Annual Cost	0.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Annual Amortized cost	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Cumulative PV of Amortized cost	0.0	5.3	10.3	15.2	17.7	20.1	22.4	24.6	26.8	28.8	30.8	32.7	34.5	36.2	37.9	39.5	41.1	42.6	44.0	45.4

Table 72: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Near Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost		8.1																		
O&M	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	8.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumulative PV	0.0	0.4	0.9	1.3	1.7	2.0	2.4	2.7	3.1	3.4	3.7	4.0	4.3	4.6	4.8	5.1	5.3	5.6	5.8	6.0

Figure 25: 30 MW Generation Option Red Lake Subsystem Configuration



157

Given the existing opportunity for 30 MW of gas generation at Red Lake, a second gas generator at Ear Falls could be sized to serve the remaining capacity needs of the Red Lake subsystem. With a total of 60 MW of gas generation in the Red Lake subsystem, the LMC of the subsystem would increase by 60 MW to 190 MW (assuming all Pickle Lake subsystem load on E1C is transferred to the new line to Pickle Lake). Table 73 summarizes the capacity provided by a single 30 MW facility at Red Lake as well as two facilities in the subsystem.

Table 73: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability*	Low Forecast Long-term Demand	Reference Forecast Long-term Demand	High Forecast Long-term Demand
NG Generation at Ear Falls (30 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
NG Generation at Ear Falls (60 MW)	60 MW	190 MW			

*Includes the capability of E4D and E2R after upgrading

Figure 25 and Figure 26, show the state of the Red Lake subsystem with each of these options implemented, while Table 74 to Table 77, provide a detailed summary of the costs for each option. The generators at Red Lake and/or Ear Falls help to maintain the voltages at those buses to a healthy range of 120 kV to 125 kV.

Table 74: Summary of Cost for 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	80.9			
Fixed O&M																	1.8	1.8	1.8	1.8
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-2.7	-2.7	-2.7	-2.7
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.1	-0.9	-0.9	-0.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9	4.9	4.9	4.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.3	3.4	4.4

Table 75: Summary of Cost for Compensation Associated with 30 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	14.1			
O&M																	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2	0.1	0.1	0.1
Annual Amortized Cost																	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.2	1.6

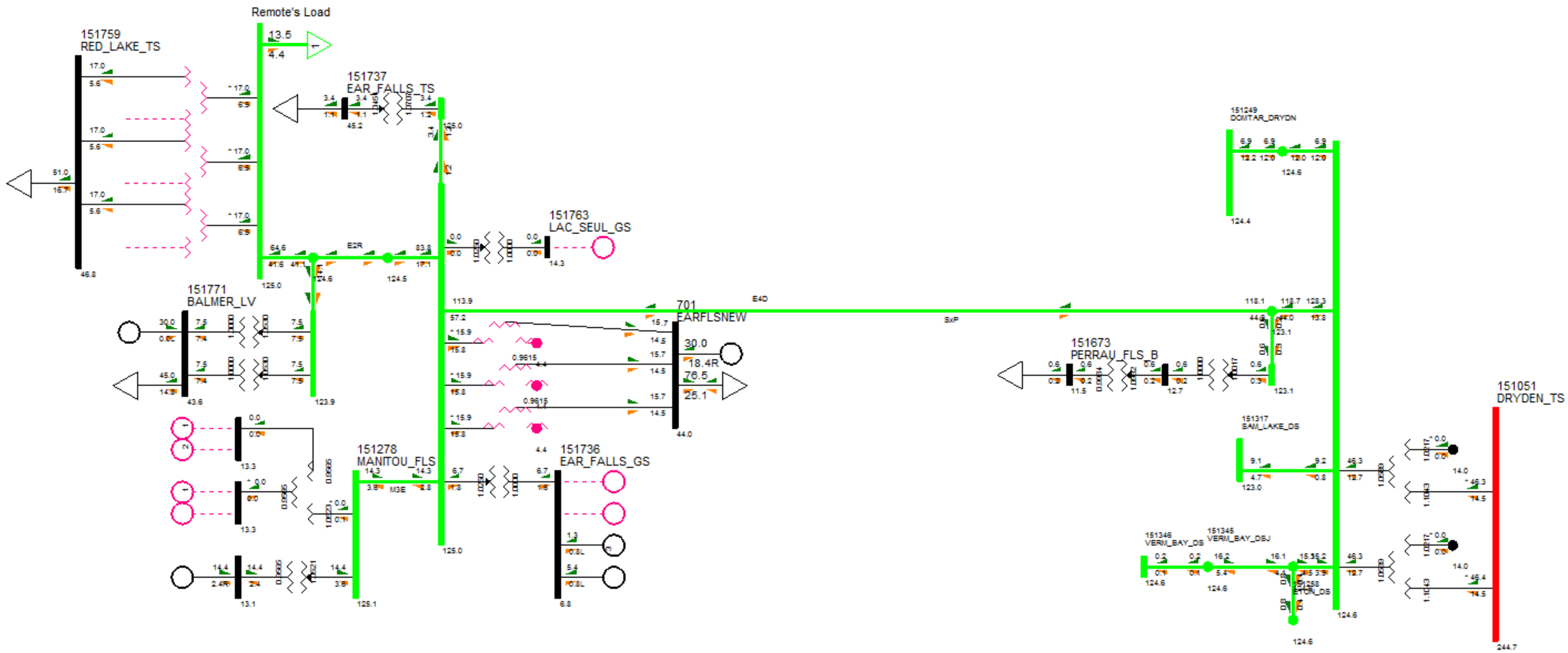
Table 76: Summary of Cost for 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gx Capital Cost																	145.7			
Fixed O&M																	3.0	3.0	3.0	3.0
Variable O&M																	0.0	0.0	0.0	0.0
Fuel Cost																	0.0	0.0	0.0	0.0
Avoided System Gen Cost																	-4.9	-4.9	-4.9	-4.9
Total Annual Gx Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	143.8	-1.9	-1.9	-1.9
Annual Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.4	8.4	8.4	8.4
Cumulative PV of Amortized cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	3.7	5.5	7.2

Table 77: Summary of Cost for Compensation Associated with 60 MW of Gas Generation in Red Lake Subsystem in the Long Term

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Station Cost																	6.9			
O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.1	0.1	0.1
Annual Amortized Cost																	0.4	0.4	0.4	0.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8

Figure 26: 60 MW Generation Option Red Lake Subsystem Configuration



10.7.3 **Ring of Fire Subsystem Options**

Assumptions

The following assumptions were made to determine the infrastructure required to implement diesel and CNG fueled generation at the mine-sites and its costs. Based on the infrastructure requirements, costs for capital, operating and maintenance and capital sustainment were estimated to determine the total cost of generating electricity at Ring of Fire mine-sites. For both fuel options, generators are assumed to not be connected to the Ontario electricity system.

Assumptions for CNG Fueled Mine-site Generation:

- Generators will be dual fuel CNG/Diesel reciprocating engines. Engines will be capable of running predominantly on CNG, but can run on pure diesel as needed;
- CNG would be compressed at a new compressor station in the Nakina area and transported on specialized high pressure transport trailers via the proposed road to the mine-sites;
- Decanting stations near the generators would be required to decompress the natural gas for use;
- CNG fuel delivery would be on a just in time basis due to challenges and additional cost of large scale on-site CNG storage;
- If CNG is unavailable generators will run on diesel;
- A sufficient number of trailers would be required to both transport fuel as well as provide for some limited on-site storage to ensure a stable flow of fuel; and
- Discrete generator unit sizes of 9.5 MW.

Assumptions for Diesel Fueled Mine-site Generation:

- Generators will be diesel fueled reciprocating engines;

- Diesel would be supplied from the Thunder Bay area and transported to the mine-sites via the proposed all-weather road, stored on site and used for in-mine equipment as well as for electricity generation;
- On-site diesel storage is available due to the variety of uses for diesel at the mine-sites, therefore timing and logistic challenges with fuel transport and delivery will not be as significant as for CNG; and
- Discrete generator unit sizes of 9.5 MW.

Study Procedure

To estimate the cost of implementing a CNG or diesel electricity generation facility at the Ring of Fire mine-sites, the following procedure was undertaken:

1. Determine forecast peak load for the Ring of Fire mines based on the demand forecast;
2. Determine the required amount of generation capacity based on peak load;
3. Calculate the energy requirements (total kWh per year) by applying a estimated load factor to the peak load;
4. Calculate fuel required daily based on energy requirements;
5. Estimate number of trucks and trailers (size of fleet) required to transport fuel based on a) trailer volume assumptions, b) fuel requirements and c) one day round trip;
6. (CNG option only) Determine number of compressor and decanting stations based on amount of fuel required per day; and
7. Use the calculated values (generator capacity, number of trucks, annual fuel requirements, and decanting/compressing stations) to calculate initial capital costs, refurbishment costs, operation and maintenance costs, and fuel costs of the system.
8. These capital, operations and maintenance costs, were amortized over the project life and the present value over the planning period (2013-2033) was calculated.

Planning Level Assessment

The generation options considered for supplying the Ring of Fire subsystem would only supply the mining load. The five remote communities in the Ring of Fire subsystem have been determined to be economic to connect as per the findings of the Remote Community Connection Plan. Backup generation capacity is considered to use consistent reliability criteria specified under ORTAC. Table 78 outlines the generation solution options considered for the Ring of Fire subsystem mining demand.

Table 78: Summary of Incremental Capacity and LMC

Option	Incremental Capacity	Load Meeting Capability for Mining	Low Forecast Long-term Mining Demand	Reference Forecast Long-term Mining Demand	High Forecast Long-term Mining Demand
38 MW of CNG	22 MW	22 MW	0 MW	22 MW	66 MW
38 MW of Diesel	22 MW	22 MW			
57 MW of CNG	44 MW	44 MW			
57 MW of Diesel	44 MW	44 MW			
85.5 MW of CNG	71 MW	71 MW			
85.5 MW of Diesel	71 MW	71 MW			

Table 79 through Table 83 below summarize the cost profiles for each option.

Table 79: Summary of Cost for 38 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	39.8	0.0	0.0	0.0	1.8	0.0	0.0	0.0	1.8	0.0	24.7	0.0	1.8	0.0	0.0	0.0	1.8
O&M and Fuel	0.0	0.0	0.0	31.6	32.1	32.6	33.1	33.7	34.2	34.8	35.4	36.0	44.5	45.2	45.9	46.7	47.4	48.1	48.8	49.6
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	71.4	23.8	24.3	24.8	27.1	25.9	26.5	27.0	29.5	36.1	61.5	37.6	40.1	39.1	39.8	40.4	43.1
Annual Amortized cost	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Cumulative PV of Amortized cost	0.0	0.0	0.0	31.1	61.0	89.7	117.3	143.9	169.5	194.0	217.7	240.4	262.2	283.2	303.4	322.8	341.5	359.4	376.7	393.3

Table 80: Summary of Cost for 57 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	58.8	0.0	0.0	0.0	3.0	0.0	0.0	0.0	3.0	0.0	37.1	0.0	3.6	0.0	0.0	0.0	3.6
O&M and Fuel	0.0	0.0	0.0	32.2	32.7	33.2	72.7	74.0	75.2	76.5	77.8	79.2	88.4	39.8	91.2	92.7	94.3	95.6	97.0	98.6
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	91.0	15.9	16.4	55.9	60.2	58.4	59.7	61.0	65.4	71.6	110.0	74.4	79.5	77.5	78.8	80.2	85.4
Annual Amortized cost	0.0	0.0	0.0	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7	59.7
Cumulative PV of Amortized cost	0.0	0.0	0.0	53.1	104.1	153.2	200.4	245.8	289.4	331.4	371.7	410.5	447.8	433.7	518.1	551.3	583.2	613.8	643.3	671.7

Table 81: Summary of Cost for 85.5 MW Diesel Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	87.3	0.0	0.0	0.0	4.8	0.0	0.0	0.0	4.8	0.0	55.6	0.0	5.4	0.0	0.0	0.0	5.4
O&M and Fuel	0.0	0.0	0.0	33.1	33.5	34.1	112.6	114.6	116.5	118.5	120.5	122.7	132.6	134.7	136.8	139.1	141.5	143.5	145.5	148.0
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	120.4	6.5	7.1	85.6	92.4	89.5	91.5	93.5	100.5	105.6	163.3	109.8	117.5	114.5	116.5	118.5	126.4
Annual Amortized cost	0.0	0.0	0.0	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	74.8	146.7	215.9	282.3	346.3	407.7	466.9	523.7	578.3	630.9	681.4	730.0	776.7	821.6	864.8	906.3	946.3

Table 82: Summary of Cost for 38 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	65.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	8.0	0.0	24.7	0.0	10.4	0.0	0.0	0.0	10.4
O&M and Fuel	0.0	0.0	0.0	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	18.7	18.7	18.7	18.9	18.9	18.9	18.9	18.9
System Gen Credit	0.0	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Total Annual Gx Cost	0.0	0.0	0.0	80.7	7.4	7.4	7.4	15.4	7.4	7.4	7.4	15.4	10.4	35.1	10.4	20.9	10.5	10.5	10.5	20.9
Annual Amortized cost	0.0	0.0	0.0	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Cumulative PV of Amortized cost	0.0	0.0	0.0	16.5	32.4	47.7	62.4	76.6	90.2	103.2	115.8	127.9	139.5	150.7	161.4	171.7	181.7	191.2	200.4	209.2

Table 83: Summary of Cost for 57 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	93.5	0.0	0.0	0.0	18.4	0.0	0.0	0.0	18.4	0.0	37.1	0.0	20.0	0.0	0.0	0.0	20.0
O&M and Fuel	0.0	0.0	0.0	16.6	16.6	16.6	33.2	33.7	33.7	33.7	33.7	33.7	36.7	36.7	36.7	36.8	36.8	36.8	36.8	36.8
System Gen Credit	0.0	0.0	0.0	0.0	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Total Annual Gx Cost	0.0	0.0	0.0	110.1	-0.2	-0.2	16.4	35.3	16.9	16.9	16.9	35.3	19.9	57.0	19.9	40.0	20.0	20.0	20.0	40.0
Annual Amortized cost	0.0	0.0	0.0	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9	27.9
Cumulative PV of Amortized cost	0.0	0.0	0.0	24.8	48.6	71.6	93.6	114.8	135.2	154.8	173.6	191.7	209.1	225.9	242.0	257.5	272.4	286.7	300.4	313.7

Table 84: Summary of Cost for 85.5 MW CNG Option for Ring of Fire

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capital Cost	0.0	0.0	0.0	136.3	0.0	0.0	0.0	28.0	0.0	0.0	0.0	28.0	0.0	55.6	0.0	29.6	0.0	0.0	0.0	29.6
O&M and Fuel	0.0	0.0	0.0	17.9	17.9	17.9	51.1	52.1	52.1	52.1	52.1	52.1	55.1	55.1	55.1	55.2	55.2	55.2	55.2	55.2
System Gen Credit	0.0	0.0	0.0	0.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0	-27.0
Total Annual Gx Cost	0.0	0.0	0.0	154.1	-9.1	-9.1	24.1	53.1	25.1	25.1	25.1	53.1	28.1	83.7	28.1	57.8	28.2	28.2	28.2	57.8
Annual Amortized cost	0.0	0.0	0.0	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
Cumulative PV of Amortized cost	0.0	0.0	0.0	33.0	64.7	95.2	124.6	152.8	179.9	206.0	231.1	255.2	278.3	300.6	322.1	342.7	362.5	381.6	399.9	417.5

10.8 Transmission Options

Assumptions

In determining the cost of transmission options, the following were assumed:

- Unit cost estimates for new facilities were provided by a study conducted for the OPA by SNC Lavalin T&D. The report has been included in Section 11.3;
- Operations and maintenance costs were estimated as a percentage of the capital cost of the project, and would be incurred every year from the in-service date to the end of the projects useful life;
- Land cost was not included. Land costs are difficult to determine given the types of land and the variety of land holders that certain options described in this report may occupy; and
- Impact Benefit Agreements that may be negotiated between future projects proponents and impacted First Nations have not been estimated or included in the costs of options.

Procedure

To estimate the cost of transmission options to supply the North of Dryden sub-region, the following procedure was taken:

1. Load flow assessment in PSS/E (provided in this Section) was done to determine the capability of each option and the amount of capability of voltage control devices required to achieve the LMC;
2. Using unit costs for lines and stations, line lengths, number and types of new stations and/or station upgrades and voltage control requirements, capital, operations and maintenance costs of the system were calculated;
3. The amount of system generation that could be displaced after 2018, by associated local generation options for the subsystem was calculated; and
4. These capital, operations and maintenance costs and attributed costs for incremental system generation beginning in 2018, were levelized over the project life and the present value over the planning period (2013-2033) was calculated.

10.8.1 **Red Lake Subsystem Transmission Options**

Near-term Option - Upgrade of E4D and E2R

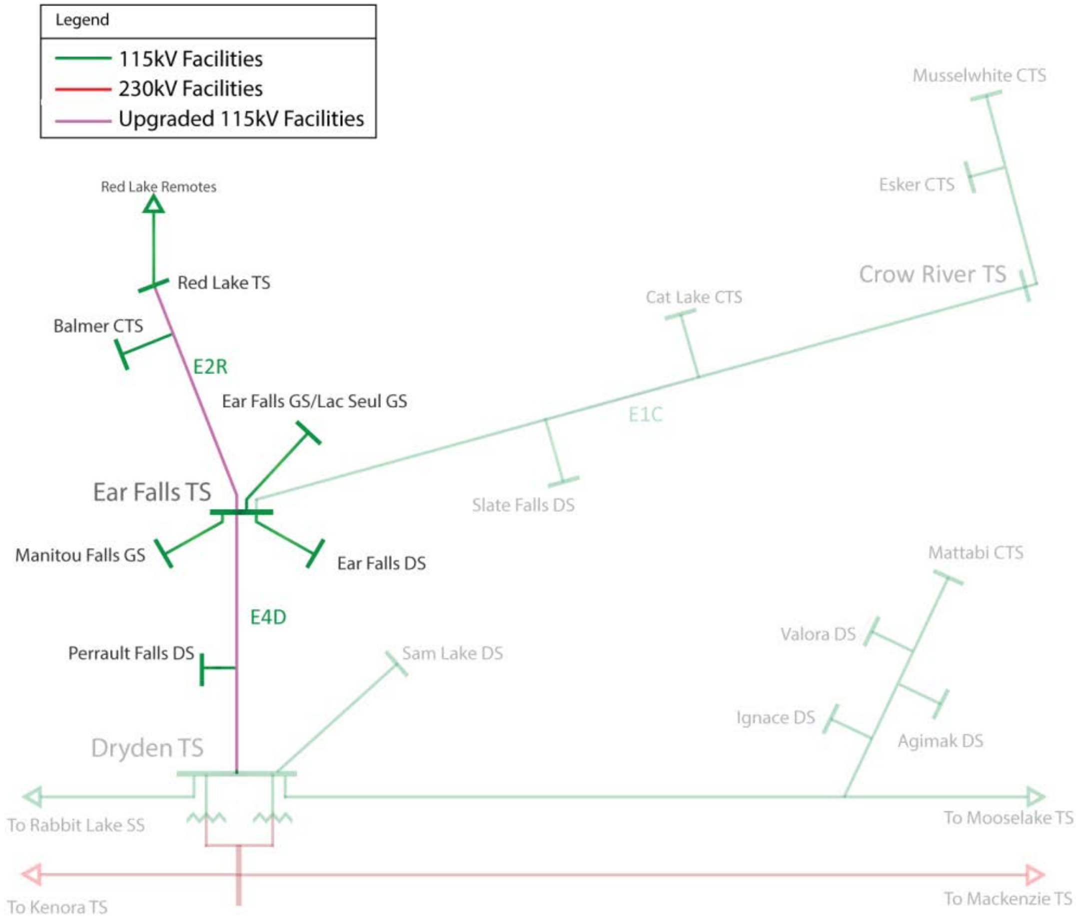
The existing lines serving the Red Lake subsystem are E4D, from Dryden to Ear Falls, and E2R, from Ear Falls to Red Lake. E4D has a thermal rating of 470 amps, and a transfer capability of 100 MVA (at 125 kV nominal voltage), while E2R a thermal rating of 420 amps, and a transfer capability of 91 MVA (125 kV nominal voltage). Based on dependable hydroelectric generation at Manitou Falls GS, Ear Falls GS and Lac Seul GS, and the current summer transmission line ratings, 85 MW of load can be served from Ear Falls TS. The Red Lake subsystem has an LMC of 61 MW, while the Pickle Lake subsystem has an LMC of 24 MW.

Hydro One has identified that E4D can be upgraded to a thermal rating of 670 amps, while E2R can be upgraded to 620 amps. After these line upgrades and the installation of an appropriate amount of voltage control at Ear Falls TS the Red Lake subsystem LMC will rise to 95 MW, assuming the Pickle Lake subsystem continues to be supplied solely from Ear Falls via circuit E1C and the LMC remains at 24 MW. A diagram of the upgrade of E4D and E2R is provided in Figure 27.

Table 85: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Upgrade E4D and E2R	34 MW	95 MW	100 MW	109 MW	136 MW
and Transfer of Pickle Lake load to new line to Pickle Lake	35 MW	130 MW			

Figure 27: E4D and E2R Upgrade Diagram

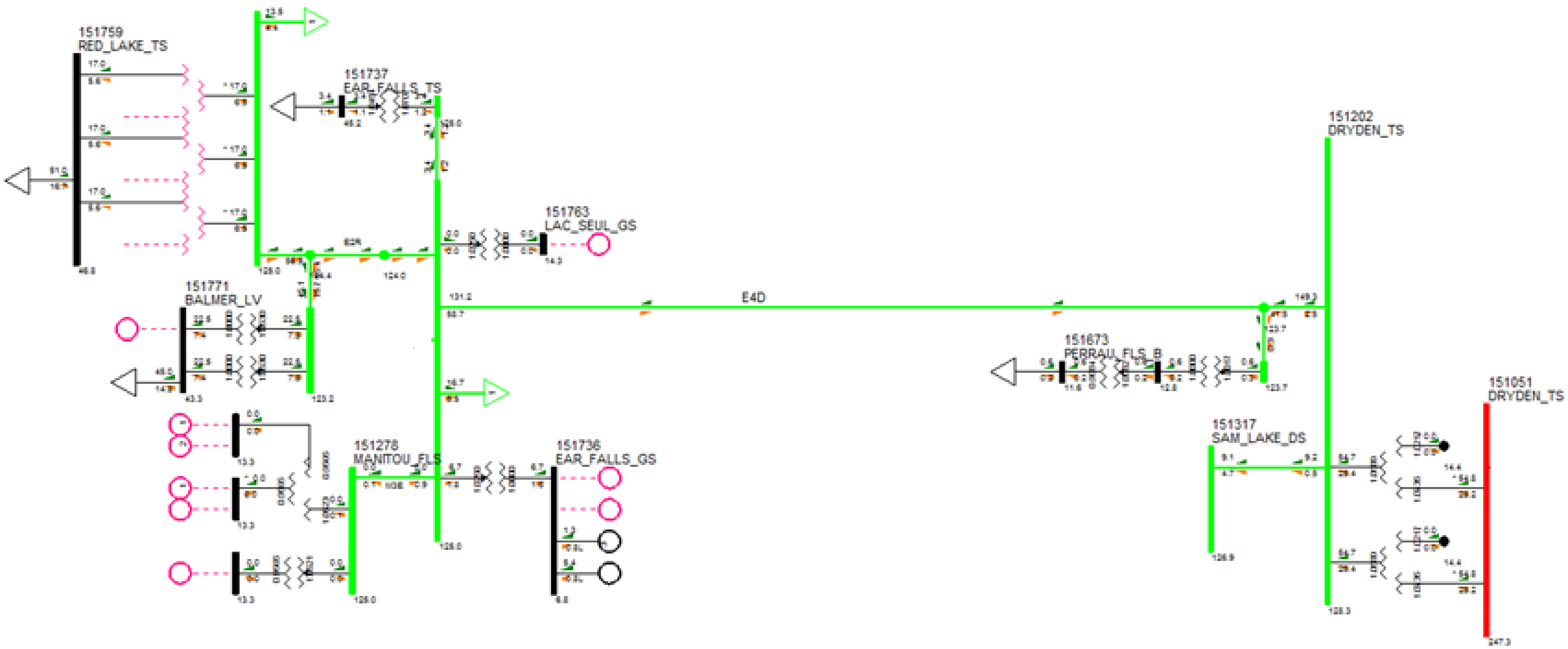


Hydro One has indicated that upgrading these lines as well as the installation of required voltage control devices could be completed within the near-term period. Table 86 below shows the cost breakdown of the upgrade option which includes the required voltage control devices. Figure 28 shows the load flow case during peak load. Ear Falls TS and Red Lake TS voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 86: E4D and E2R Upgrade Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line Cost	0.0	5.0																		
Station Cost	0.0	10.5																		
O&M	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost	0.0	15.7	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cumulative PV	0.0	0.8	1.6	2.4	3.2	3.9	4.6	5.2	5.9	6.5	7.1	7.7	8.2	8.7	9.2	9.7	10.2	10.6	11.1	11.5

Figure 28: E4D and E2R Upgrade Red Lake Subsystem Configuration



169

Medium- and Long-term Option - 115 kV Line from Dryden TS to Ear Falls TS

This option is to build a new 115 kV single circuit line connecting at Dryden TS running to Ear Falls TS. A diagram of this option is provided in Figure 29. Because there are two local generation options for the Red Lake subsystem (30 MW, 60 MW), the 115 kV transmission option has been developed for an LMC of 160 MW and 190 MW. The option designed to have an LMC of 160 MW is comparable to the capability of the 30 MW Red Lake generation option and 190 MW LMC option is comparable to the 60 MW gas generation option, which meets the needs of the high scenario demand forecast. This difference in transmission LMC is determined by the voltage control requirements at Ear Falls TS.

Table 87: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 115 kV line from Dryden to Ear Falls with less compensation (160 MW)	30 MW	160 MW	100 MW	109 MW	136 MW
New 115 kV line from Dryden to Ear Falls with more compensation (190 MW)	60 MW	190 MW			

Figure 29: New 115 kV line to Ear Falls Diagram

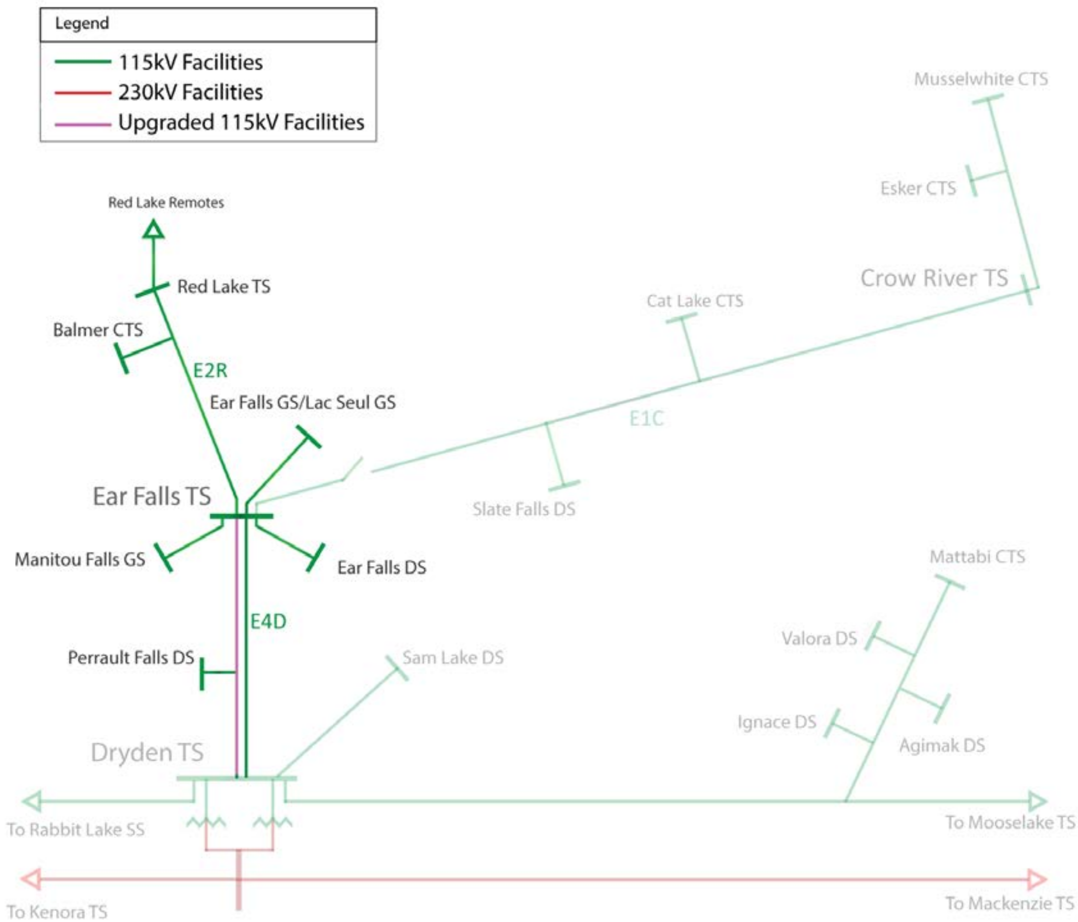


Figure 30, shows the peak load flow case for this option. Voltage at Ear Falls TS is maintained within a healthy range of 120 kV to 125 kV.

Table 88 and Table 89 summarize the annual cashflows and cumulative NPV cost for the options.

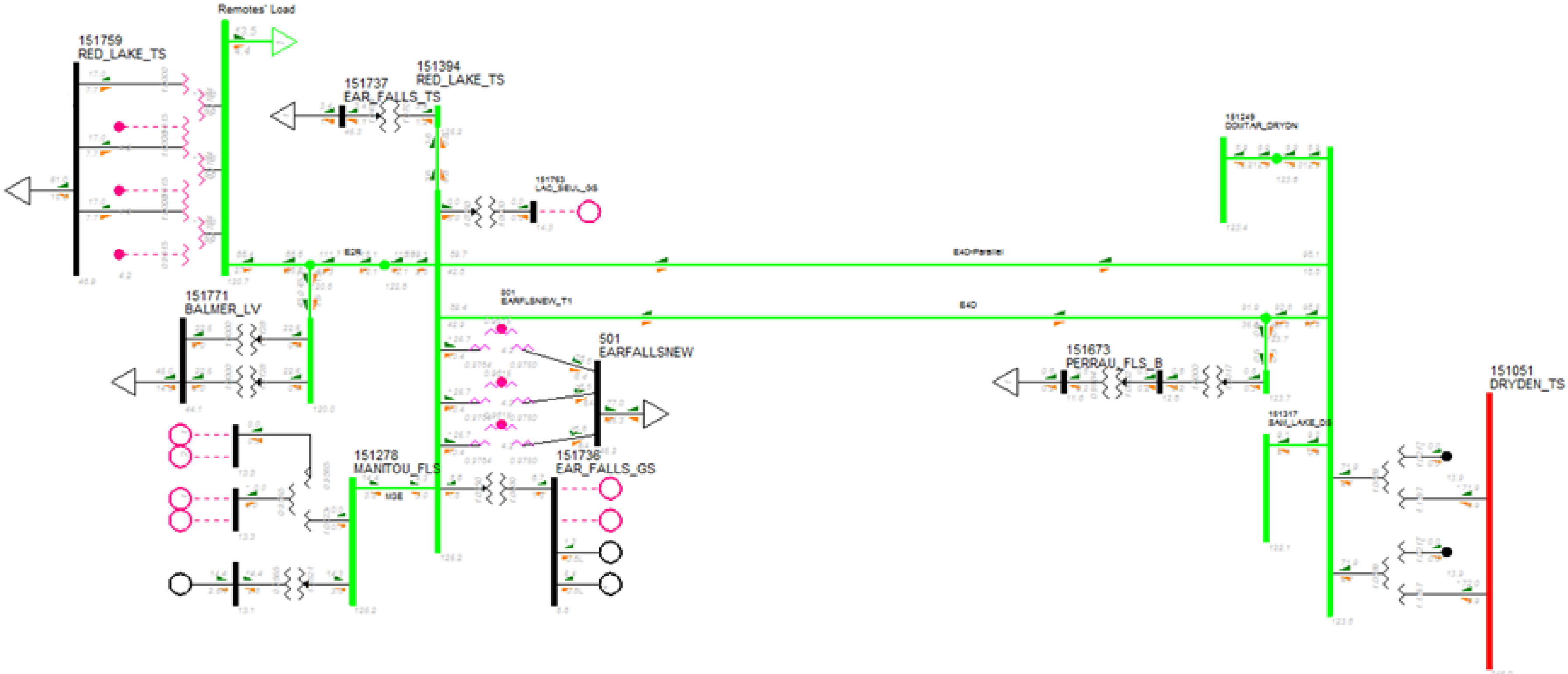
Table 88: 115 kV line to Ear Falls 160 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	45.6			
O&M																	0.9	0.9	0.9	0.9
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.8	0.9	0.9	0.9
Annual Amortized Cost																	5.1	5.1	5.1	5.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	5.4	7.9	10.3

Table 89: 115 kV line to Ear Falls 190 MW LMC Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																	45.3			
Station cost																	62.4			
O&M																	1.1	1.1	1.1	1.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	108.7	1.1	1.1	1.1
Annual Amortized Cost																	6.1	6.1	6.1	6.1
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	6.4	9.4	12.2

Figure 30: 115 kV Line Option Red Lake Subsystem Configuration



173

10.8.2 Pickle Lake Subsystem Transmission Options

The transmission options for the Pickle Lake subsystem include:

1. A new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker on the tap line and terminating at Crow River DS in Pickle Lake;

2. A new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker on the tap line and running to Pickle Lake terminating at Crow River DS or a new TS in the Pickle Lake area with a new 230/115 kV autotransformer at Crow River DS or a new station; and

3. A new single circuit line pre-built to 230 kV standards (230 kV structures, and hardware) and connecting it to M2D on the 115 kV system east of Dryden with an in-line breaker on the tap line. When additional capacity is required the line would be reterminated on the 230 kV system near Dryden (D26A) and a 230/115 kV autotransformer would be installed at Crow River DS or a new station in Pickle Lake.

For all of these transmission options, it is assumed that following the installation of a new line to Pickle Lake, the line E1C, connecting Ear Falls TS to Crow River DS (at Pickle Lake), would be normally open at Ear Falls. As a result, all customers in the Pickle Lake subsystem would be normally supplied by the new line to Pickle Lake. During sustained outages of the new line to Pickle Lake, some load in the Pickle Lake subsystem may be able to be restored by closing the normally E1C at Ear Falls TS and serving load in the Pickle Lake subsystem from Ear Falls TS. The amount of load that can be restored in the Pickle Lake subsystem from Ear Falls TS will be limited by the available capacity of circuits E4D and E1C.

115 kV Line to Pickle Lake

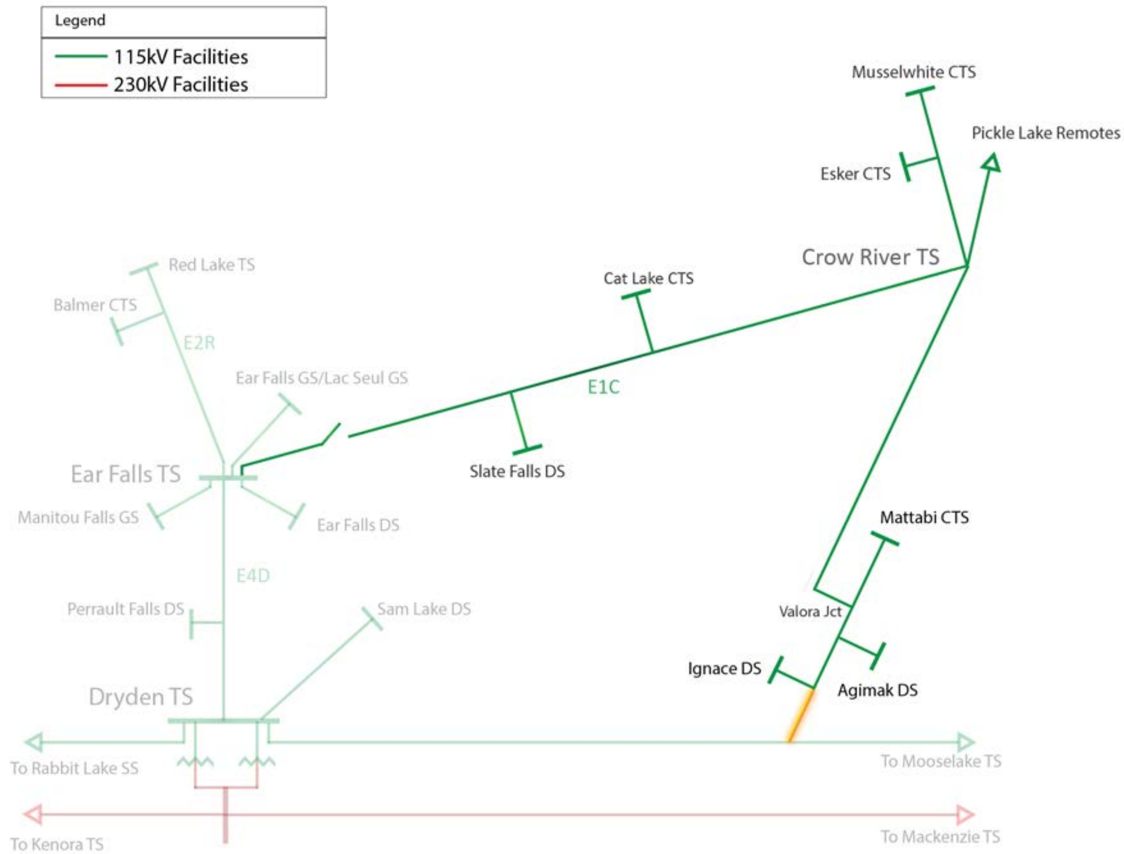
This option is to install a new 115 kV single circuit line tapping the 115 kV line 29M1 near Valora with an in-line breaker and terminating at Crow River DS in Pickle Lake. Currently, there are a number of short sections of 29M1 between Ignace and Valora which have thermal ratings which are lower than the rest of the line. These sections will need to be upgraded to a thermal rating of at least 500 amps to allow the new line to Pickle Lake to have the required transfer capability.

Table 90: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 115 kV line from Valora to Pickle Lake	46 MW	70 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 31 shows the Pickle Lake subsystem with this option, highlighting the section of 29M1 that would require upgrading.

Figure 31: New 115 kV line to Pickle Lake Diagram



A summary of the cost for this option can be found in Table 91 below.

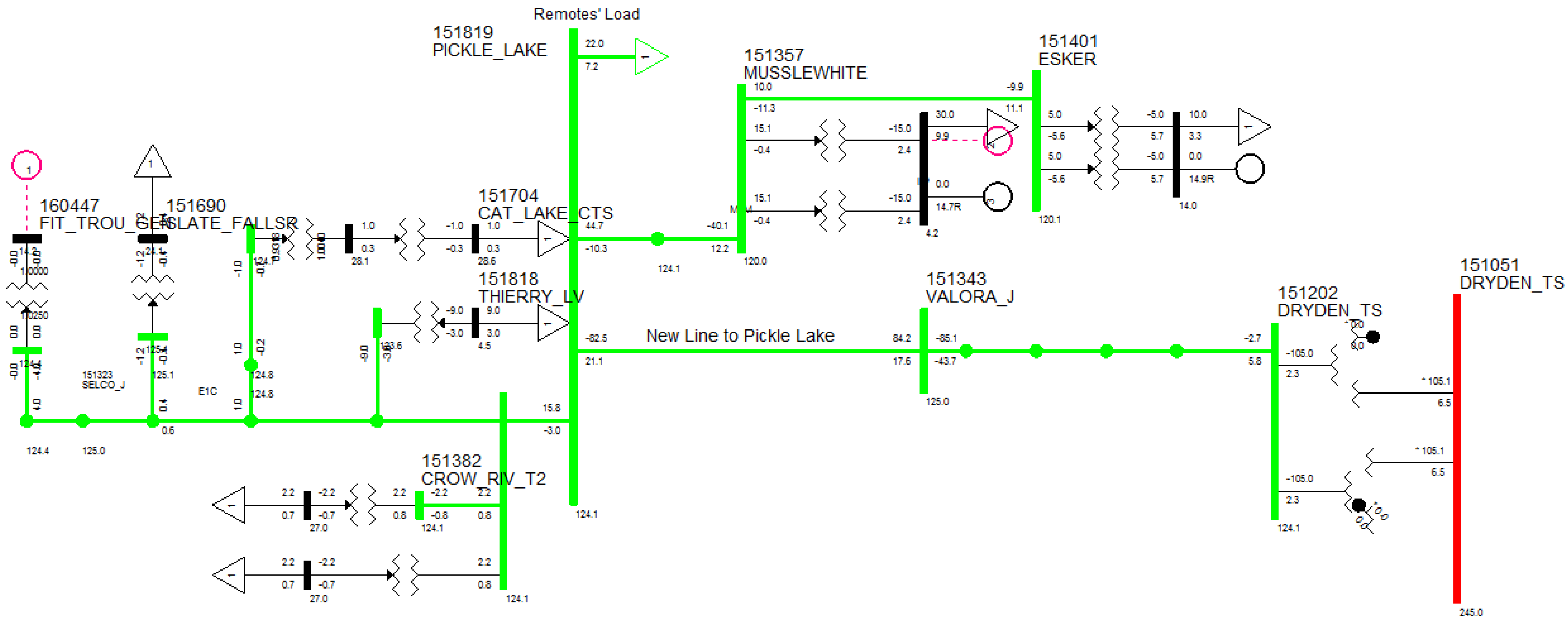
176

Figure 32 shows the load flow case during peak load. The Pickle Lake bus voltage is maintained in a healthy range of 120 kV to 125 kV.

Table 91: 115 kV line to Pickle Lake Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				104																
Station cost				22.5																
O&M				1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total Annual Cost	0.0	0.0	0.0	127.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Annual Amortized Cost				7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Cumulative PV	0.0	0.0	0.0	6.4	12.5	18.3	24.0	29.4	34.6	39.7	44.5	49.1	53.6	57.9	62.0	66.0	69.8	73.5	77.0	80.4

Figure 32: 115 kV Line Option Pickle Lake Subsystem Configuration



230 kV Line to Pickle Lake

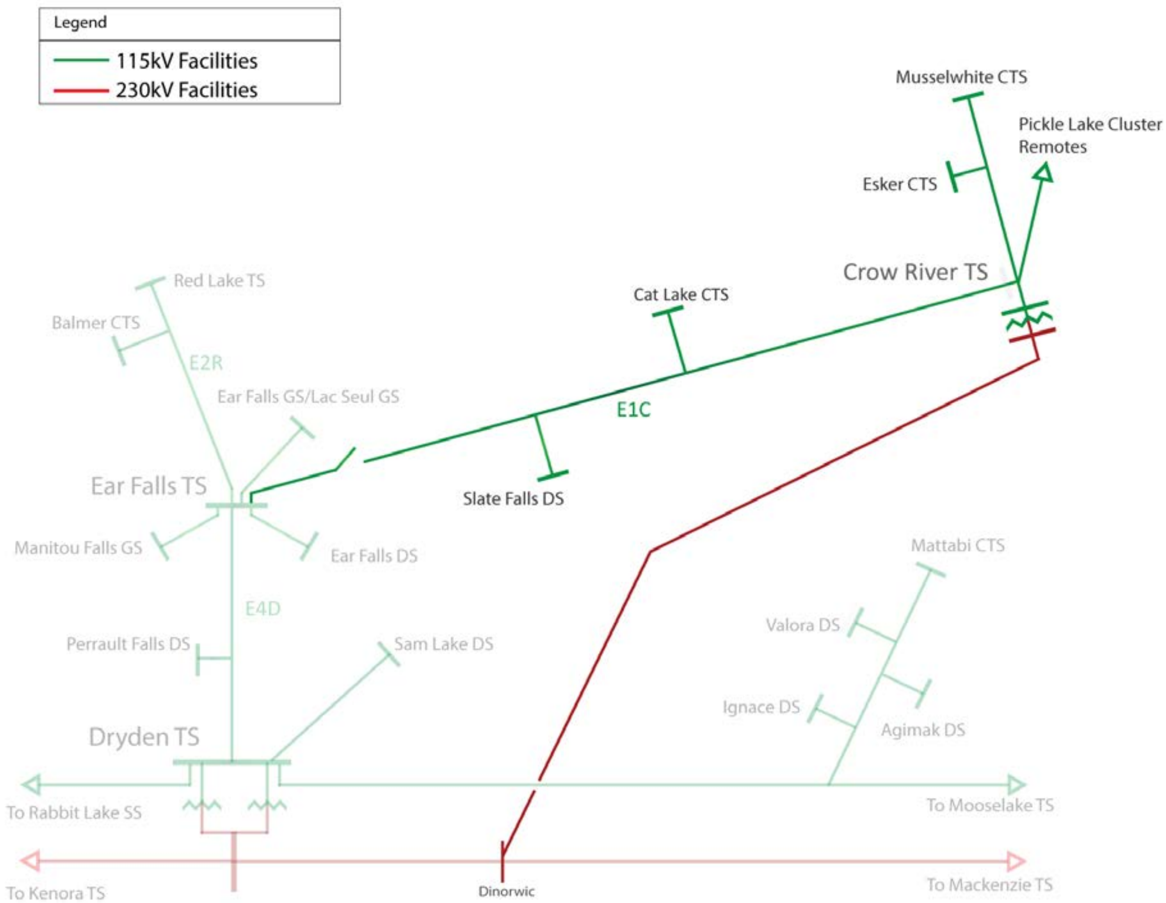
This option is to install a new 230 kV single circuit line tapping D26A east of Dryden with an in-line breaker running to Pickle Lake terminating at Crow River DS or at a new 230 kV station where a new 230/115 kV autotransformer will be installed.

Table 92: Summary of Load Meeting Capability

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
New 230 kV line from Dryden/Ignace to Pickle Lake	136 MW	160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

A diagram of this option is shown in Figure 33 below.

Figure 33: New 230 kV line to Pickle Lake Diagram



A summary of the cost for this option can be found in Table 93 and Table 94 below.

Table 94 shows an illustration of the peak load flow case for the new 230 kV line to Pickle Lake option. The voltage in the Pickle Lake area is maintained in a range of 240 kV to 245 kV, which helps to maintain voltages on existing and planned facilities within a healthy range.

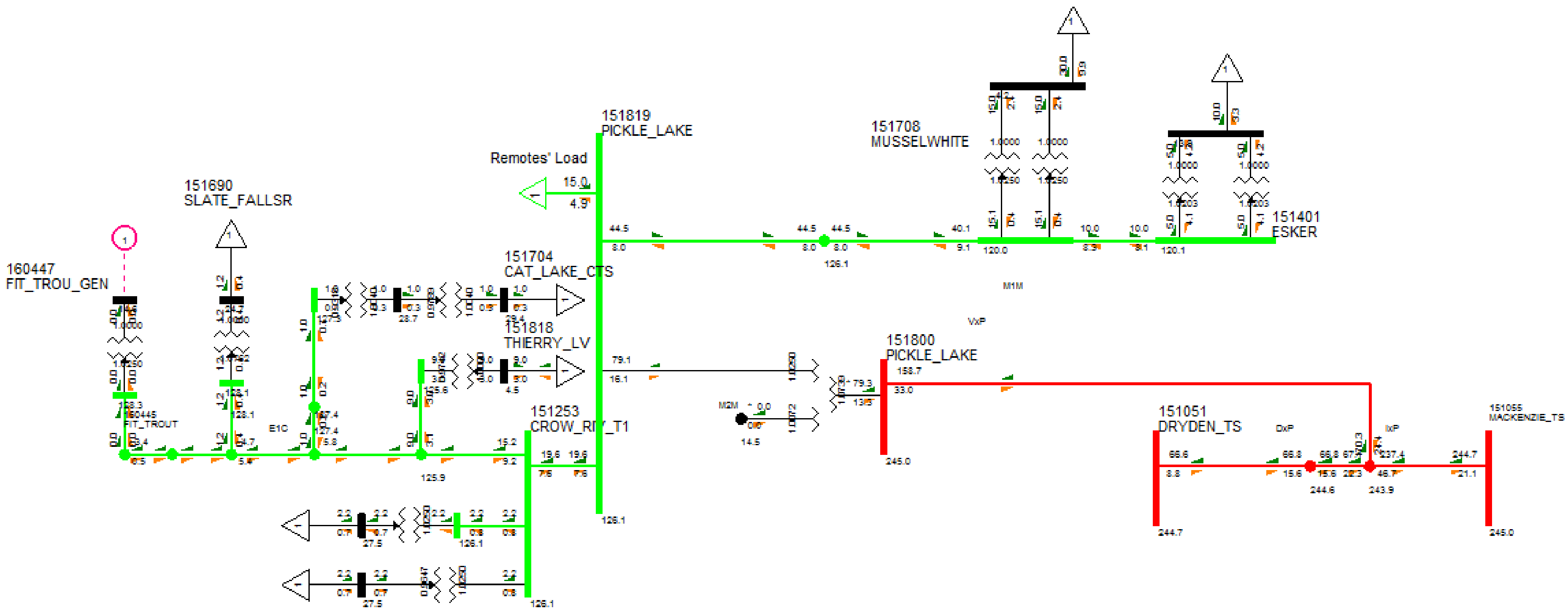
Table 93: 230 kV line to Pickle Lake Cost Summary for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				28.4																
O&M				1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	0.0	0.0	0.0	168.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost				9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	0.0	0.0	0.0	8.4	16.4	24.1	31.5	38.7	45.5	52.1	58.5	64.6	70.5	76.1	81.5	86.8	91.8	96.6	101.2	105.7

Table 94: 230 kV line to Pickle Lake Cost Summary for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				42.2																
O&M				1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Total Annual Cost	0.0	0.0	0.0	182.2	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Annual Amortized Cost				10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Cumulative PV	0.0	0.0	0.0	9.0	17.7	26.1	34.1	41.9	49.3	56.5	63.3	69.9	76.3	82.4	88.3	93.9	99.4	104.6	109.6	114.4

Figure 34: 230 kV Line Option Pickle Lake Subsystem Configuration



183

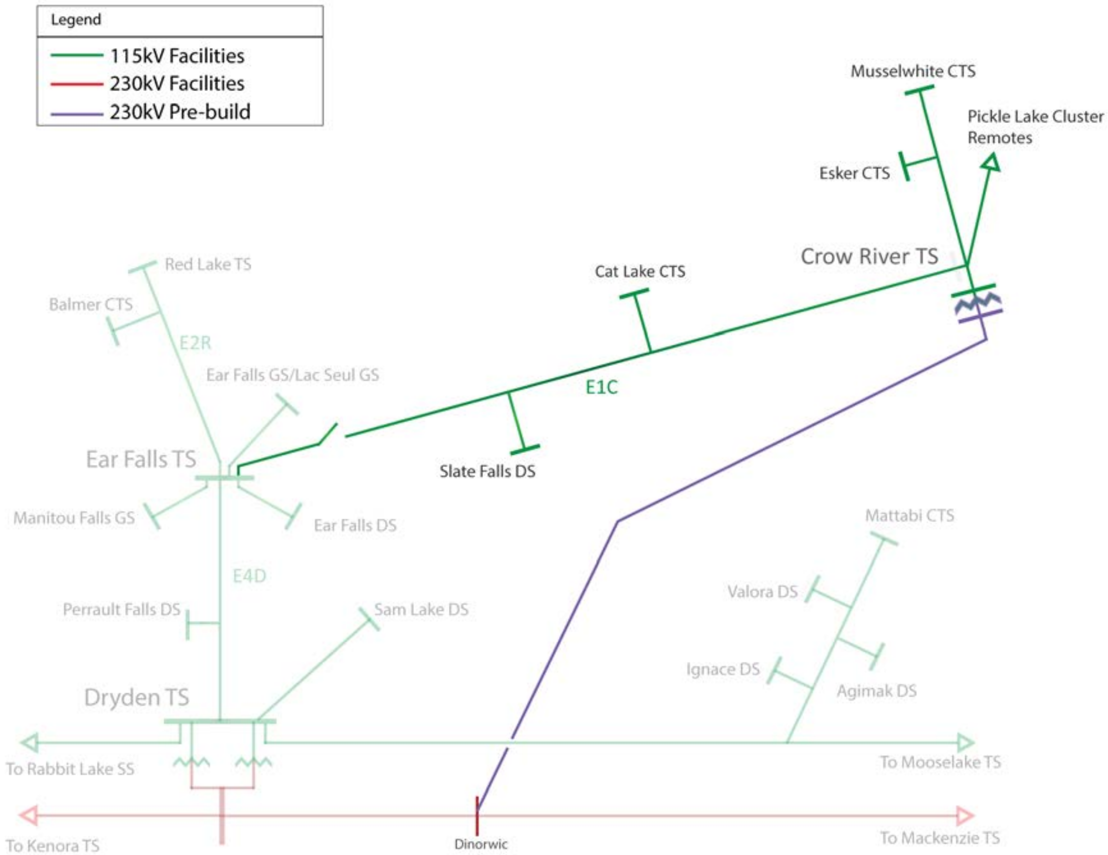
Pre-build 230 kV Line to Pickle Lake

This option would pre-build a new single circuit line to 230 kV standards (230 kV structures and hardware) and connect it to the 115 kV system on M2D east Dryden with an in-line breaker and running to Pickle Lake where it would terminate at Crow River DS. When additional capacity is required, the line would be reterminated on the regional 230 kV system (D26A) east of Dryden and a 230/115 kV autotransformer would be installed either at Crow River DS or at a new TS in Pickle Lake.

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
Pre-build 230 kV line from Dryden/Ignace to Pickle Lake: Stage 1: operated at 115 kV Stage 2: operated at 230 kV	 46 MW 90 MW	 70 MW 160 MW	48 MW	78 MW (100 MW)	90 MW (156 MW)

Figure 35 provides a diagram of the area with this option, while Table 95 provides a summary of costs and timing for this option.

Figure 35: Pre-build 230 kV Line to Pickle Lake Option



Note: the above diagram illustrates the second stage configuration (operated at 230 kV).

Table 95: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost				138																
Station cost				16.6																
O&M				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	156.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost				8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Cumulative PV	0.0	0.0	0.0	7.8	15.2	22.4	29.3	35.9	42.3	48.4	54.3	60.0	65.5	70.7	75.8	80.6	85.3	89.7	94.1	98.2

Table 96: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 78 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										14.0										
O&M										0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost										0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	1.6	2.1	2.6	3.0	3.5	3.9	4.3	4.7	5.1

Table 97: Pre-build 230 kV line to Pickle Lake Cost Summary Stage 2 for LMC up to 90 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost																				
Station cost										26.0										
O&M										0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Annual Amortized Cost										1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Cumulative PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	3.9	4.8	5.6	6.4	7.2	8.0	8.7	9.4

10.8.3 Ring of Fire Subsystem Transmission Options

The following table summarizes the capability of various transmission options to meet the forecasted demand levels for the Ring of Fire sub-system for the reference, high, and low scenarios:

Option	Incremental Capacity	Load Meeting Capability	Low Forecast Demand	Reference Forecast Demand	High Forecast Demand
East-West corridor			7 MW	29 MW	73 MW
115 kV line from Pickle Lake	60 MW	60 MW			
230 kV line from Pickle Lake	78 MW	78 MW			
North-South corridor					
230 kV line from Marathon TS	78 MW	78 MW			
230 kV line from east of Nipigon	78 MW	78 MW			

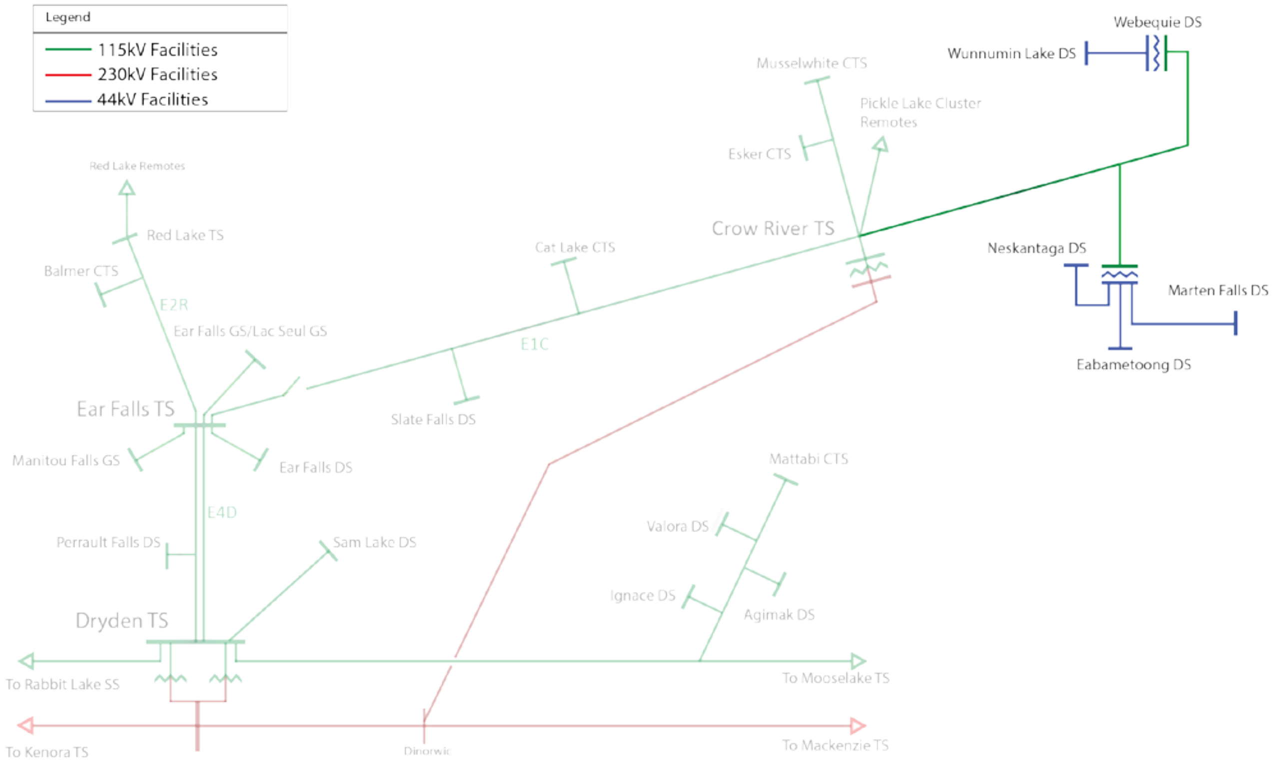
The options and costs of the options are discussed in further detail below.

115 kV Line Connection for Ring of Fire Remote Communities from Pickle Lake

In a scenario where mines at the Ring of Fire do not connect to the transmission system, it has been assumed that the 5 remote communities in the Ring of Fire subsystem would develop a connection to Pickle Lake, based on the findings of the draft Remote Community Connection Plan. This option is to build a 115 kV line from Pickle Lake to a point near Webequie FN passing near Neskantaga FN. Neskantaga FN, Eabametoong FN and Marten Falls FN would connect by distribution lines to a new transformer station near Neskantaga FN, while Nibinamik FN and Webequie FN would connect by distribution line to a transformer station near Webequie FN.

Figure 36, provides an illustrative schematic of this option, while costs are provided in Table 98.

Figure 36: 115 kV Line from Pickle Lake to Matawa Remotes



189

Table 98: 115 kV line from Pickle Lake to Ring of Fire Subsystem Remote Communities Cost Summary

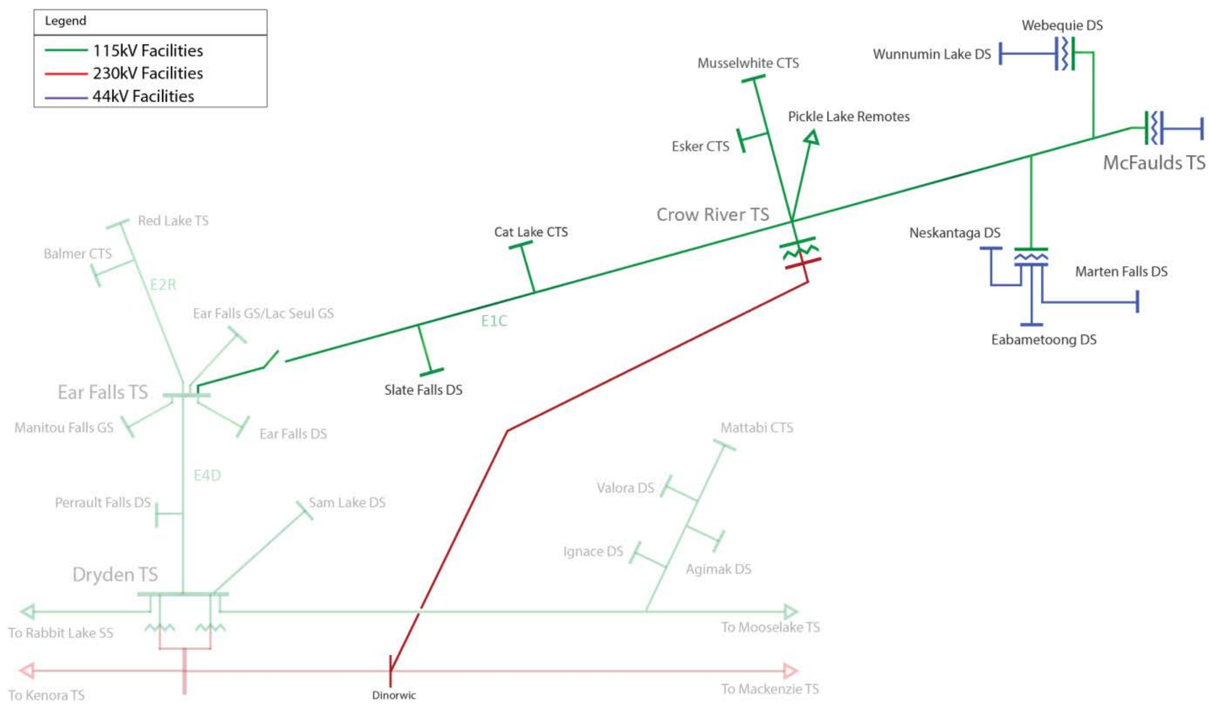
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						94.3														
Station cost						6.6														
O&M						1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	101.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Annual Amortized Cost						5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Cumulative PV	0.0	0.0	0.0	0.0	0.0	4.7	9.2	13.5	17.7	21.6	25.5	29.2	32.7	36.2	39.4	42.6	45.6	48.6	51.4	54.1
Line to Pickle Lake Portion	0.0	0.0	0.0	0.7	1.3	1.9	2.5	3.0	3.6	4.1	4.6	5.1	5.5	6.0	6.4	6.8	7.2	7.6	8.0	8.3
NPV with PL Line	62.4																			

115 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 115 kV line from Pickle Lake to the Ring of Fire mining development area, and connecting the five remote communities in the Ring of Fire subsystem. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. Power flow studies show that a single circuit 115 kV line from Pickle Lake could supply up to 60 MW of mining load at the Ring of Fire plus 7 MW of remote community load.

Figure 37, shows this option with the Pickle Lake subsystem.

Figure 37: 115 kV Line from Pickle Lake to Ring of Fire



A prorated portion of the costs for new a 230 kV transmission line and 230/115 kV transformer station from the Dryden area to Pickle Lake is included in the cost of this option because it is required for this option to be undertaken as is shown in the cost summary in Table 99.

191

Figure 38 provides the peak load flow for the North of Dryden sub-region, illustrating that voltages throughout the subsystem are maintained in a healthy range of 120 kV to 125 kV.

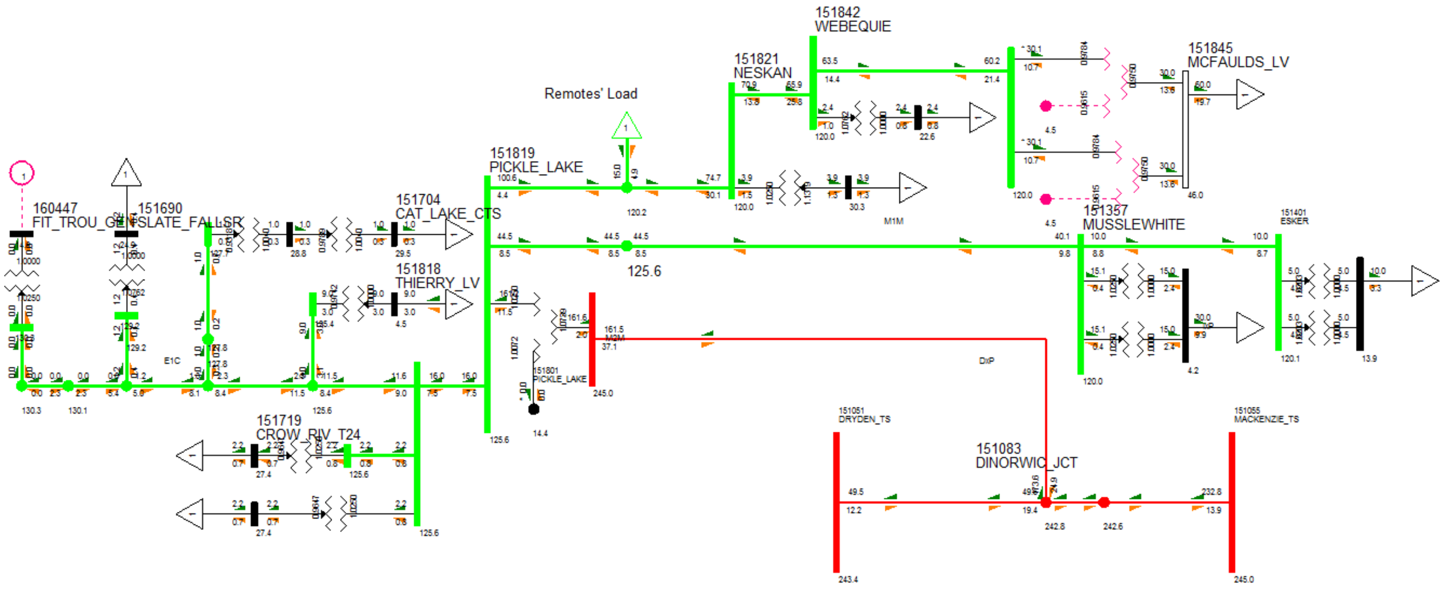
Table 99: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 29 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						13.6														
O&M						1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	147.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Annual Amortized Cost						8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Cumulative PV	0.0	0.0	0.0	0.0	0.0	6.8	13.3	19.5	25.5	31.3	36.9	42.2	47.4	52.3	57.1	61.6	66.0	70.3	74.3	78.2
Line to Pickle Lake Portion	0.0	0.0	0.0	2.2	4.3	6.3	8.2	10.1	11.9	13.6	15.3	16.9	18.4	19.9	21.3	22.7	24.0	25.2	26.4	27.6
NPV with PL Line	105.8																			

Table 100: 115 kV line from Pickle Lake to Ring of Fire Cost Summary for LMC up to 51 MW

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						132														
Station cost						23.2														
O&M						1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	157.1	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Annual Amortized Cost						8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Cumulative PV	0.0	0.0	0.0	0.0	0.0	7.2	14.1	20.8	27.2	33.4	39.3	45.0	50.5	55.8	60.8	65.7	70.4	74.9	79.2	83.4
Line to Pickle Lake Portion	0.0	0.0	0.0	3.2	6.3	9.2	12.1	14.8	17.5	20.0	22.4	24.8	27.0	29.2	31.3	33.3	35.2	37.0	38.8	40.5
NPV with PL Line	123.9																			

Figure 38: 115 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration

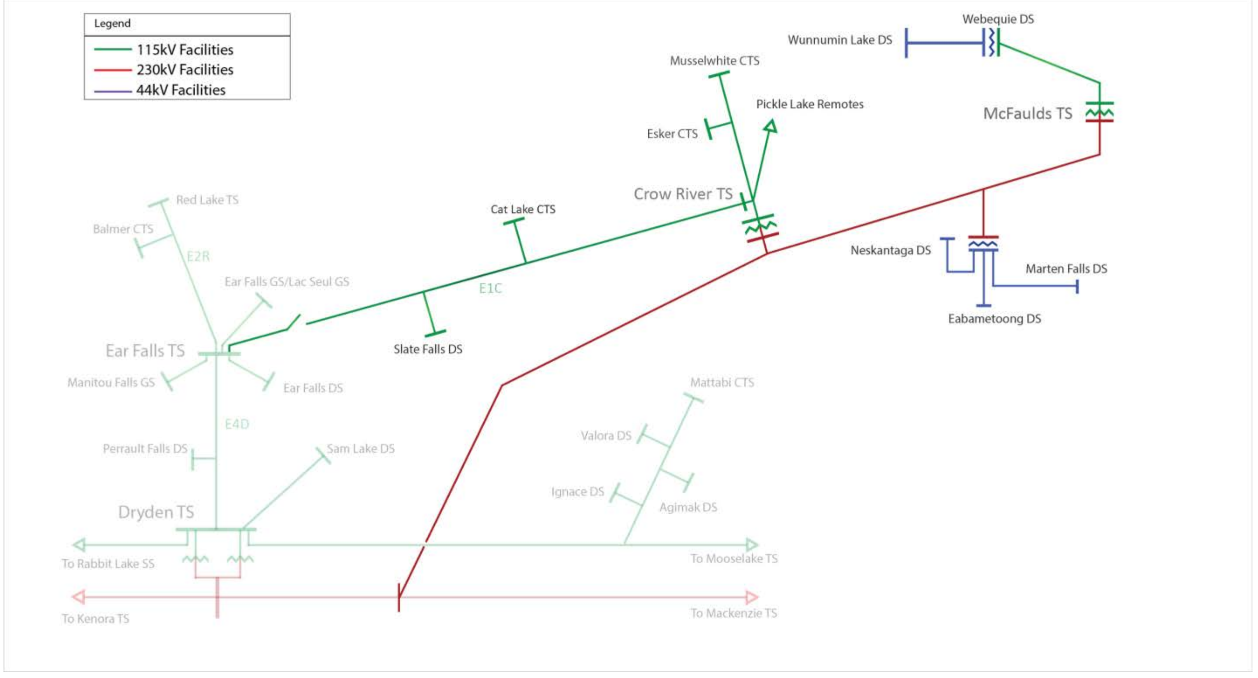


194

230 kV Line from Pickle Lake to Ring of Fire

This option considers building a new 230 kV single circuit line from a new 230 kV station at Pickle Lake to the Ring of Fire, and a new 230/115 kV TS near Neskantaga FN and at the Ring of Fire. The feasibility of this option is contingent on the completion of a new 230 kV line from east of Dryden to Pickle Lake. This line would enable the connection of the five Matawa remote communities in the Ring of Fire subsystem as well as serve the high growth scenario (MW) for mining load at the Ring of Fire. Figure 39 shows the Pickle Lake and Ring of Fire subsystems with a new 230 kV line from the Dryden area to Pickle Lake and this option for a new 230 kV line from Pickle Lake to the Ring of Fire. Figure 39, shows this option implemented with the Pickle Lake subsystem.

Figure 39: 230 kV Line from Pickle Lake to Ring of Fire

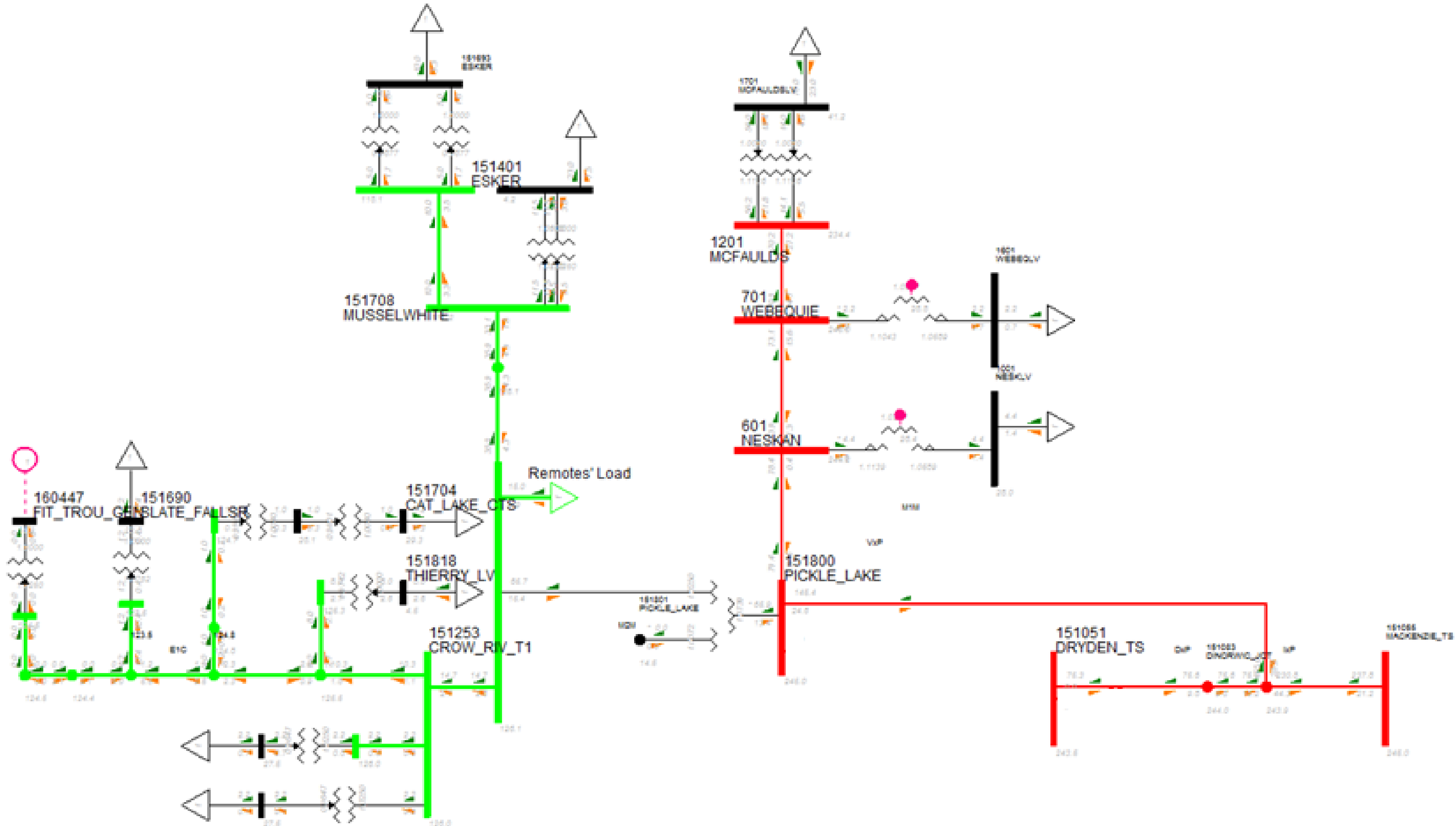


A prorated portion of the costs for new a 230 kV transmission line and station from the Dryden area to Pickle Lake is included in the cost of this option, as shown in the cost summary in Table 101 below.

Table 101: 230 kV line from Pickle Lake to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						165														
Station cost						30.4														
O&M						2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	197.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Annual Amortized Cost						11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Cumulative PV	0.0	0.0	0.0	0.0	0.0	9.1	17.8	26.2	34.3	42.0	49.5	56.6	63.5	70.2	76.5	82.7	88.6	94.2	99.7	104.9
Line to Pickle Lake Portion	0.0	0.0	0.0	4.1	8.0	11.8	15.4	18.9	22.2	25.4	28.5	31.5	34.4	37.1	39.7	42.3	44.7	47.1	49.4	51.5
NPV with PL Line	156.4																			

Figure 40: 230 kV Line from Pickle Lake Option Ring of Fire Subsystem Configuration

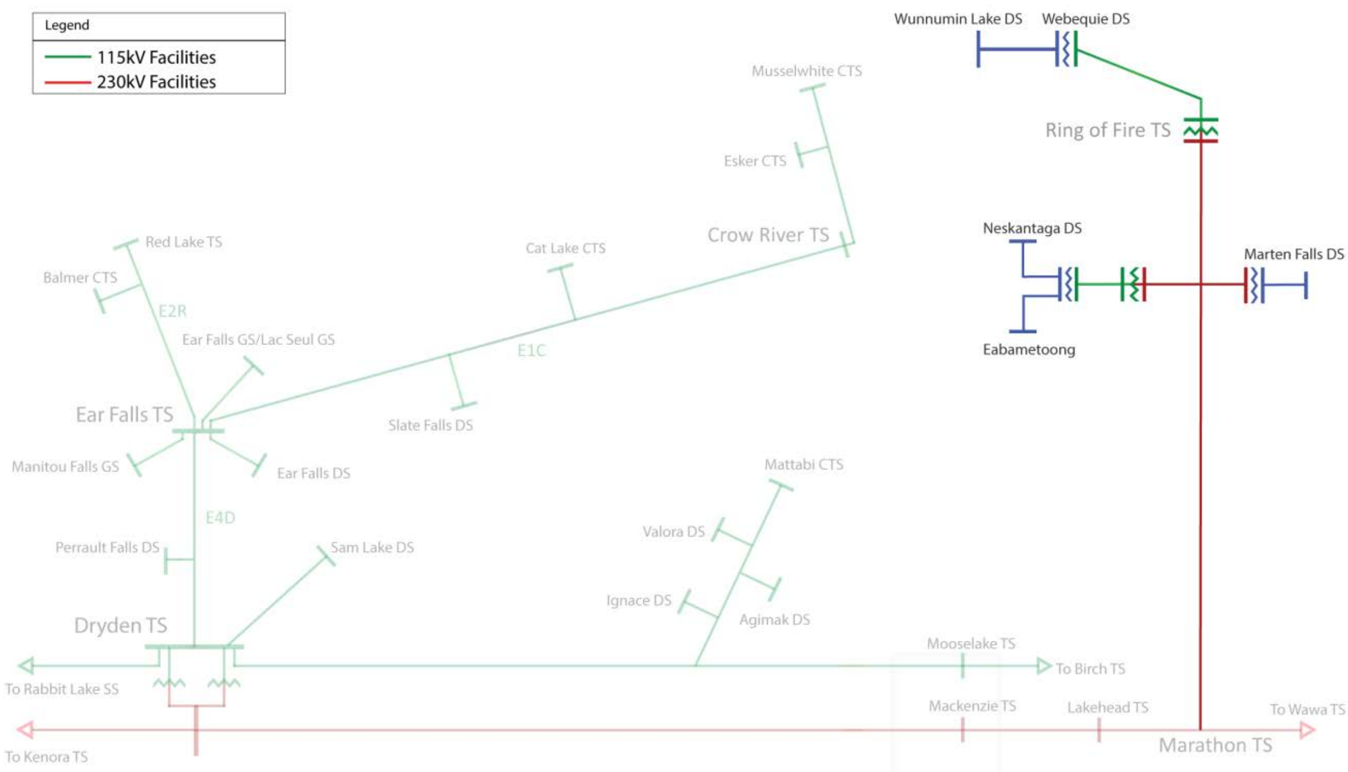


197

230 kV Line from Marathon TS or east of Nipigon to Ring of Fire

Given the potential for a new all season road to serve the Ring of Fire mining development area from around Nakina, this option was developed to leverage the availability of the all season road assuming they can share a common right of way from Nakina. The existing transmission supply serving the Long Lac\Nakina area is the single circuit 115 kV line A4L, which has insufficient capability to serve the forecast load growth of the Ring of Fire subsystem. Therefore, a new 230 kV single circuit transmission line from either Marathon TS or east of Nipigon would be required for this option. These options have similar line lengths and are expected to have approximately the same costs. A diagram of this option is provided in Figure 41 below.

Figure 41: 230 kV Line from Marathon or East of Nipigon to Ring of Fire

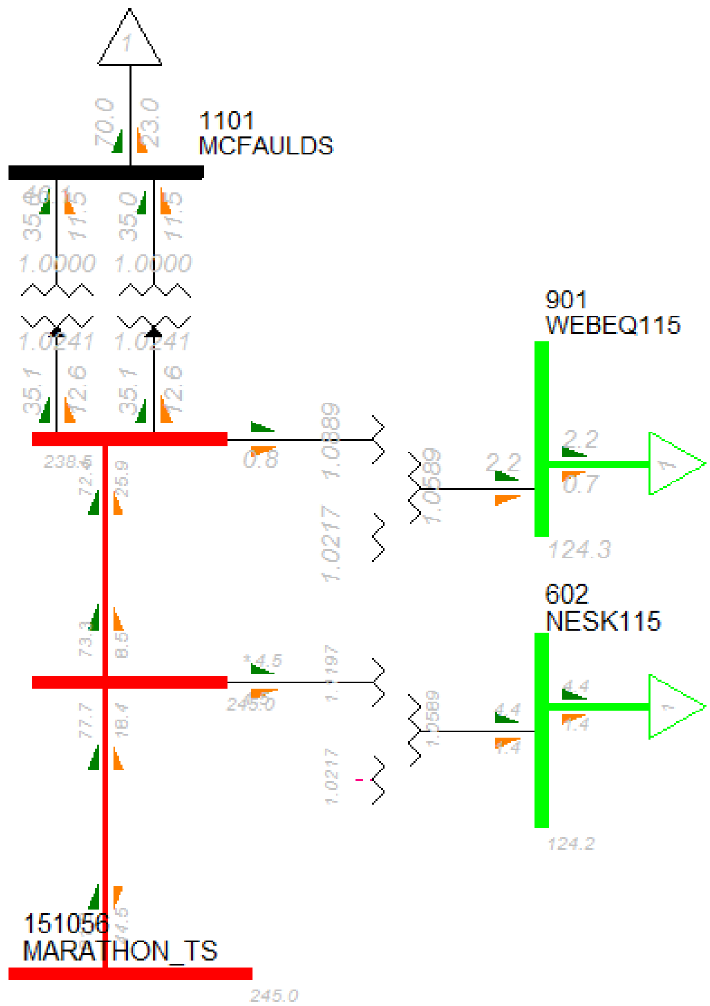


The LMC of the Ring of Fire subsystem for this option is 77 MW. This includes 7 MW for the communities on the line as well as 70 MW at the Ring of Fire. A summary of the cost for this option can be found in Table 102 below.

Table 102: 230 kV line from Marathon TS or east of Nipigon to Ring of Fire Cost Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Line cost						262														
Station cost						64.7														
O&M						3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Annual Cost	0.0	0.0	0.0	0.0	0.0	330.0	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Annual Amortized Cost						18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Cumulative PV	0.0	0.0	0.0	0.0	0.0	15.1	29.7	43.7	57.2	70.1	82.6	94.6	106.1	117.1	127.8	138.0	147.9	157.3	166.4	175.2
NPV	175.2																			

Figure 42: 230 kV Line from Marathon Option Ring of Fire Subsystem Configuration



201

11 OTHER REPORTS PROVIDED

11.1 IESO/OPA North of Dryden and Remote Communities Study – May 2012

11.2 Draft Remote Community Connection Plan – August 2012

11.3 Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North – SNC Lavalin T&D, 2011

11.4 Draft Remote Community Connection Plan – August 2014

GREENSTONE-MARATHON INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | June 30, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Greenstone-Marathon Area

This Integrated Regional Resource Plan (“IRRP”) was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066, and was prepared by the IESO on behalf of the Greenstone-Marathon Sub-region Working Group (“Working Group”), which included the following members:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The preparation of the IRRP included extensive discussions with industrial developers, as well as engagement with communities who may have interest in the potential industrial developments or options for providing the required electrical supply. The Working Group would like to acknowledge and thank the members of two Local Advisory Committees which were established to provide community input into the development of the IRRP. Their input provided valuable guidance in shaping the electrical supply options.

The Working Group assessed the adequacy of electricity supply to customers in the Northwest Ontario Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers customer needs, community input, opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions. Based on all the planning information provided, an implementation plan was developed. The implementation plan seeks to maintain flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP’s recommendations and support implementation of the plan through the recommended actions. As the recommendations are directly related to a few large industrial developments, the onus lies with those developers to initiate the implementation of the plan. Working Group members cannot commit to any capital expenditures until the necessary commercial agreements, regulatory and other approvals to implement recommended actions are obtained by the appropriate parties.

In addition to the requirements set out in the IESO's licence, analysis that was requested from communities and was determined by the IESO to provide value to the overall context of electricity planning for the Greenstone-Marathon Sub-region, has also been included in this report.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
ACSR	Aluminum Conductor, Steel Reinforced
AZA	Animbiigoo Zaagi'igan Anishinaabek
AEMO	Australian Energy Market Operator
BZA	Biinjitiwaabik Zaaging Anishinaabek
BNA	Bingwi Neyaashi Anishinaabek
CCRA	Connection Cost Recovery Agreement
CDM	Conservation and Demand Management
C/I	Commercial and Industrial
CVNW	Common Voice Northwest Energy Task Force
CGS	Customer Generating Station
DG	Distributed Generation
DR	Demand Response
DSC	Distribution System Code
ERCOT	Electric Reliability Council of Texas
EA	Environmental Assessment
EUE	Expected Unserved Energy
GS	Generating Station
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LUEC	Levelized Unit Energy Cost
MVA	Mega Volt Ampere

Abbreviation	Description
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOMA	Northwestern Ontario Municipal Association
NPCC	Northeastern Power Coordinating Council
NPV	Net Present Value
NUG	Non-Utility Generator
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report
RAS	Remedial Action Scheme (Formerly Special Protection System)
Region	Northwest Ontario
RIP	Regional Infrastructure Plan
Scoping Report	Scoping Process Outcome Report
SIA	System Impact Assessment
SS	Switching Station
STATCOM	Static Synchronous Compensators
Sub-region	Greenstone-Marathon Area as a sub-region of the Northwest Ontario Region
SVC	Static Var Compensators
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer
VCR	Value of Customer Reliability
VOLL	Value of Lost Load
WZI	Waaskiinaysay Ziibi Inc.
Working Group	Technical Working Group for Greenstone-Marathon Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP" or "Plan") for the Greenstone-Marathon Sub-region addresses the electricity needs for the sub-region over the next 20 years. The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group for the Greenstone-Marathon Sub-region composed of the IESO, Hydro One Distribution and Hydro One Transmission[1] (the "Working Group").

The Greenstone-Marathon Sub-region includes several First Nation communities: Red Rock Indian Band, Bingwi Neyaashi Anishinaabek ("BNA"), Biinjitiwaabik Zaaging Anishinaabek ("BZA"), Animbiigoo Zaagi'igan Anishinaabek ("AZA"), Long Lake #58, Ginoogaming, Aroland, Pays Plat, Ojibways of the Pic River and Pic Mobert. The area also encompasses the Town of Marathon, the Municipality of Greenstone, and the Townships of Nipigon, Manitouwadge, Schreiber, Terrace Bay, Hornepayne and White River. The area covered by the Greenstone-Marathon IRRP is a sub-region of the Northwest Ontario Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process.

The regional planning process considers the local needs of a region over a 20-year planning horizon, and seeks to ensure cost-effective, reliable electricity supply to Ontario's communities over the long term. An IRRP takes into consideration, among other things, existing electricity infrastructure in an area, anticipated growth, and electricity requirements. The IRRP then establishes a guide for electricity infrastructure investments, resource development, and procurement decisions for a region, and may include conservation, generation, transmission and/or distribution.

In early 2015, the Municipality of Greenstone and the electricity customers in the area advised the Working Group that the 18-month timeline for IRRPs established by the OEB could not satisfy the timeline of industrial developments anticipated in the area. Given that the forecast growth in the sub-region is driven by the potential for large industrial development, the Municipality and the electricity customers requested that an interim planning report be developed to align with near-term development timelines. The Greenstone-Marathon Interim IRRP ("Interim IRRP") was released June 22, 2015 for the purpose of facilitating critical decision making for customers in a manner that accommodates near-term development timelines,

---

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

considers electricity supply needs in the area, and ensures that the electricity system can support the pace of development.

This IRRP for the Greenstone-Marathon Sub-region updates the options and recommendations established for the near term in the Interim IRRP, and extends the analysis to include the medium term (5-10 years) and long term (10-20 years). This IRRP is organized as follows:

- A summary of the recommended plan for Greenstone-Marathon is provided in Section 2;
- The process used to develop the IRRP is discussed in Section 3;
- The context for electricity planning in Greenstone-Marathon and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in Greenstone-Marathon are presented in Section 6;
- Alternatives and recommendations for meeting near-term needs are addressed in Section 7;
- Near-term plan recommendations are set out in Section 8;
- Options for the medium and long term are described in Section 9;
- A summary of community and stakeholder engagement to date is provided in Section 10; and
- A conclusion is provided in Section 11.

2. The Integrated Regional Resource Plan

The Greenstone-Marathon IRRP addresses the area's electricity needs over the next 20 years. The IESO prepared the IRRP based on consideration of integrated planning criteria (reliability, cost, feasibility, flexibility, and social and environmental considerations), and based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP uses a scenario-based analysis to identify requirements based on major industrial development for the near term (present-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required. In the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

The IRRP identifies least societal cost options to assist customers and proponents in near-term decision making for meeting the overall electricity needs of the Greenstone-Marathon Sub-region. The IRRP identifies specific investments that respect development lead times, while meeting the various needs in the area and considering feedback from local communities.

For the medium and long term, the IRRP identifies a number of alternatives to meet needs. The medium and long-term needs identify developments that may materialize in the future and could result in cost, environmental, and societal synergies with the identified near-term options. For needs that are forecast to occur in the long term, it is not necessary (given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead, near-term actions are identified to develop alternatives and engage with local communities, to gather information and lay the groundwork for future options. Actions identified for the near term will be directionally consistent with and inform the actions for the medium to long term.

Below is a summary of needs and recommended actions.

2.1 Near-Term Plan Summary

The plan to meet the near-term needs of electricity customers in the Greenstone-Marathon Sub-region was developed considering the planning criteria, including reliability, cost, feasibility, and maximizing the use of the existing electricity system where it is economic to do so.
The near-term needs for the area consist of providing additional capacity to supply industrial development, while considering reliability and service quality requirements for the individual industrial developments.

The recommended elements of the near-term plan depend primarily on the outcome of two potential industrial customers: a mining development in Geraldton (the "Geraldton mine"), and a major gas to oil pipeline conversion project. The Geraldton mine developers have publically communicated an in-service date of 2019, and the major gas to oil pipeline conversion project developers have publically communicated an in-service date of 2020. A scenario-based planning approach has been taken in order to provide recommendations that address the different potential development scenarios that may arise in the area.

2.2 Recommended Actions for the Near Term

Since publishing the Interim IRRP in June, 2015, the Geraldton mine developers notified the IESO of adjustments to their project schedule and scope. Specifically, they now expect to commission in a single stage in 2019, as opposed to two stages in 2018 and 2020 (which was considered in the Interim IRRP). The IESO's recommendations have been revised accordingly.

The IESO recommends a staged approach to accommodate forecast demand from the Geraldton mine and the pumping stations from the gas to oil pipeline conversion project. Stage 1 economically maximizes the use of the existing system to supply the Geraldton mine, while Stage 2 recommends the incremental infrastructure expansion necessary to accommodate the additional demand from the pumping stations.

Stage 1 – Coincident with the Geraldton mine in-service

- Install +40 MVar of reactive compensation at the Geraldton mine
- Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the mining company. A 2x10 MW reciprocating engine plant was used for costing, and would meet North American standards.[2]

[2] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards. If the generation can operate in island-mode, it may be advantageous to pursue due to the inherent supply diversity that it offers. The customer may also wish to investigate the applicability of conservation incentives that the IESO offers to compliment this option.

Figure 2-1: Recommended Actions – Stage 1

Stage 2 – Coincident with the gas-oil pipeline conversion project

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, and a new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac Transformer Station ("TS") to be in-service coincident with the pumping stations loads.
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the incorporation of the pumping stations as part of the major pipeline conversion project.

Figure 2-2: Recommended Actions – Stage 2

The following should be noted:

- If the Geraldton mine and the major gas to oil pipeline conversion project do not materialize or do not choose to connect to the power system, no new system enhancements are required to supply distribution customer growth.[3]
- If the Geraldton mine materializes, but the major gas to oil pipeline conversion project does not materialize or does not choose to connect to the power system, only Stage 1 is required.
- If the Geraldton mine and the major gas to oil pipeline conversion project choose to connect to the power system, Stage 1 and Stage 2 are required.

[3] It should be noted that even with growth in population and employment due to the industrial customer developments, the distribution customer demand does not increase to the point where the existing system would require a capacity increase.

- If the Geraldton mine and the major gas to oil conversion project choose to connect to the power system, it may be advantageous to the Geraldton mine to advance the new 230 kV line from Stage 2 to reduce or avoid its gas generation costs associated with Stage 1.
- The implementation of Stage 1 and Stage 2 of the near-term plan requires a commercial agreement to be established between the future service provider and the new customers before development work can proceed.
- Further changes to timelines that have been communicated to the IESO by industrial developers may alter the timing and scope of near-term recommendations.

2.3 Medium- and Long-Term Plan Summary

In the medium and long term, the likely drivers of future electricity demand for the Greenstone-Marathon planning area are:

- Additional mining claims in the Greenstone area, specifically near Beardmore (the "Beardmore mine"),
- The potential supply option of utilizing a north-south corridor to supply the Ring of Fire and remote communities of Eabametoong, Marten Falls, Neskantaga, Nibinamik, and Webequie, and
- Community-level energy efficiency opportunities in the Town of Marathon to reduce electric heating demand.

A scenario-based planning approach has also been taken for the medium and long term to address the different potential development scenarios for the area.

2.4 Actions to Maintain Flexibility for the Medium and Long Term

The following actions are proposed to maintain flexibility for accommodating additional growth, within the study area:

- Mine developers in Greenstone retain the option of upgrading circuit A4L from Alexander Switching Station ("SS") to Beardmore TS as an economic alternative for supplying the Beardmore mine and additional mining in Greenstone. Mine developers should engage Hydro One, the transmission owner of circuit A4L, recognizing that a lead-time of approximately five years is required if they wish to pursue this option.
- Those investigating a multi-use infrastructure corridor to the Ring of Fire consider the need for a new transmission line, as outlined in this Plan. The IESO is available to provide planning advice associated with a new transmission line on this corridor. The

IESO will also update electricity plans associated with this corridor as additional information becomes available.

- The Town of Marathon conduct a detailed study of community energy options related to cogeneration. The IESO can support studies within the context of electricity planning, demand, and reliability, as well as IESO-coordinated conservation programs and funding, if applicable.

The IESO does not have the authority to direct or implement these actions on behalf of the indicated parties. These actions are documented to provide customers, communities, and stakeholders with the IESO's independent assessment of the technically feasible and least societal cost options for meeting the various needs in the area.

3. Development of the Integrated Regional Resource Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[4] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code ("TSC") and Distribution System Code ("DSC") in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and

---

[4] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a straightforward "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that an RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

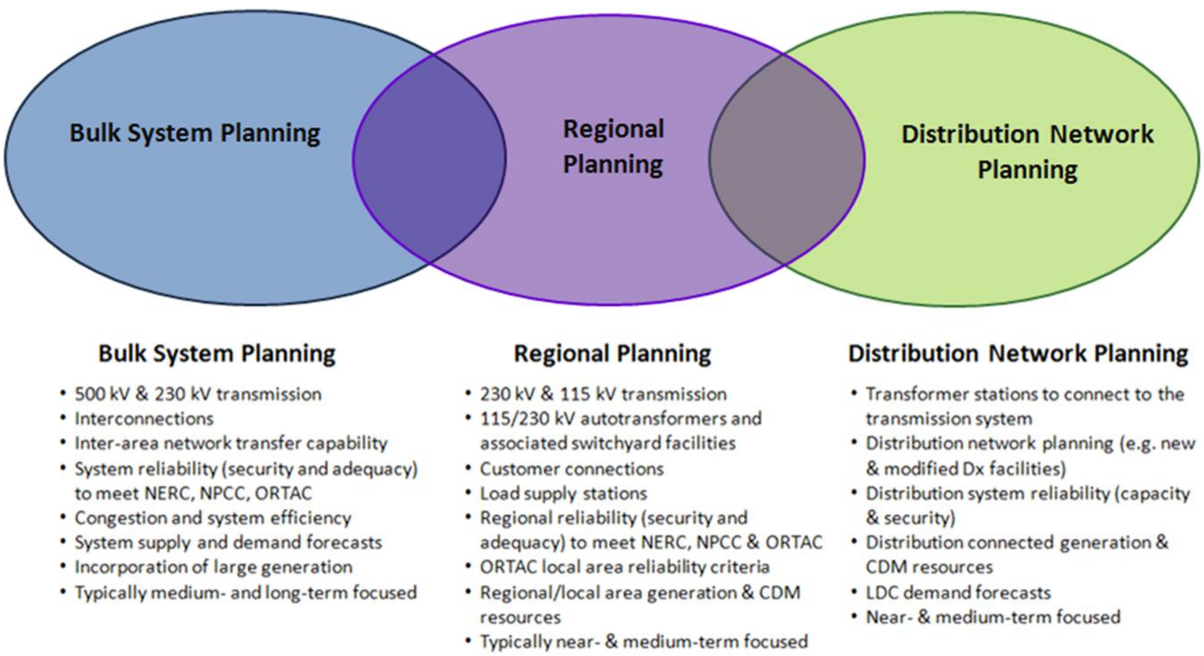
The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Integrated Regional Resource Planning

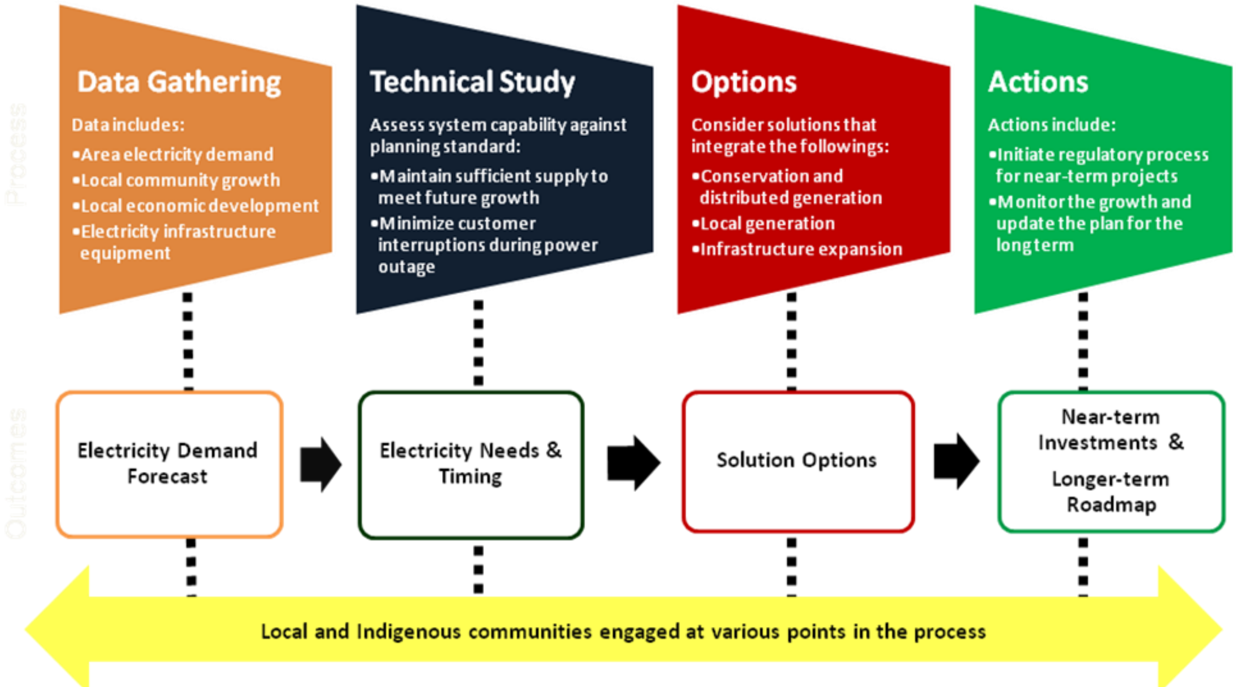
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

Planning in northwestern Ontario requires a unique approach. In southern Ontario, most of the forecast load growth is driven by growth in the LDC customer base. In northwestern Ontario the majority of the forecast load growth is driven by new or expanding large transmission-connected industrial customers, most of which are in the resource sector or are unique development projects. Therefore, when establishing the need for electricity enhancements and developing integrated alternatives, industrial customers generally drive the nature and magnitude of the electrical demand requirements.

The IRRP describes recommendations for system enhancements based on different scenarios, including staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with individual large customers. The recommendations in this report seek to ensure flexibility is maintained in order to accommodate changing long-term conditions.

In developing this IRRP, the Working Group followed a number of steps including: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Greenstone-Marathon Sub-region Working Group and IRRP Development

The Working Group consists of representatives from the IESO, Hydro One Transmission, and Hydro One Distribution.

The IESO also met regularly with potential transmission-connected load and generating customers in the area and the IRRP was informed by these meetings. In particular, important information related to changes in electrical demand and generation production was provided by these potential customers.

3.4 Community and Stakeholder Engagement

Meaningful engagement with all communities in northwestern Ontario was an important element in developing this IRRP report. Early engagement meetings were held in October 2014 and were attended by a broad range of stakeholders and First Nation and Métis community members. In addition, the IESO attended meetings with municipalities, the Northwestern Ontario Municipal Association (“NOMA”), Common Voice Northwest (“CVNW”), and met with the board members of Waaskiinaysay Ziibi Inc. (“WZI”) and a number of the Chiefs of the represented First Nations, and separately visited and met with Ojibways of Pic River First Nation and Pic Mobert First Nation, Constance Lake First Nation, Aroland First Nation, Ginoogaming First Nation, and Long Lake #58 First Nation. The IESO also met with the two Greenstone-Marathon Local Advisory Committees (“LAC”). Greater detail regarding community and stakeholder engagement activities is provided in Section 10 of this report.

4. Background and Study Scope

In 2014, the lead transmitter – Hydro One – initiated a Needs Screening process for the Northwest Ontario Region. The North of Dryden IRRP[5] and Remote Community Connection Plan[6] were already underway prior to the formalization of the regional planning process and were therefore not included within the scope of the Needs Screening process.

The Northwest Ontario Region Needs Screening study team determined that the need for coordinated regional planning had already been established and that a formal Needs Screening process was not required for the Northwest Ontario Region. A Scoping Assessment was then initiated.

4.1 Study Scope

On December 12, 2014, a draft Scoping Assessment Outcome Report ("Scoping Report") was posted for public comment. The Scoping Report[7] was finalized on January 28, 2015 incorporating feedback from communities, stakeholder, and First Nation and Métis community meetings.

The Scoping Report identified three new planning sub-regions for coordinated regional planning: Thunder Bay, West of Thunder Bay, and Greenstone-Marathon.

Regional planning initiatives in northwestern Ontario are illustrated in Figure 4-1.

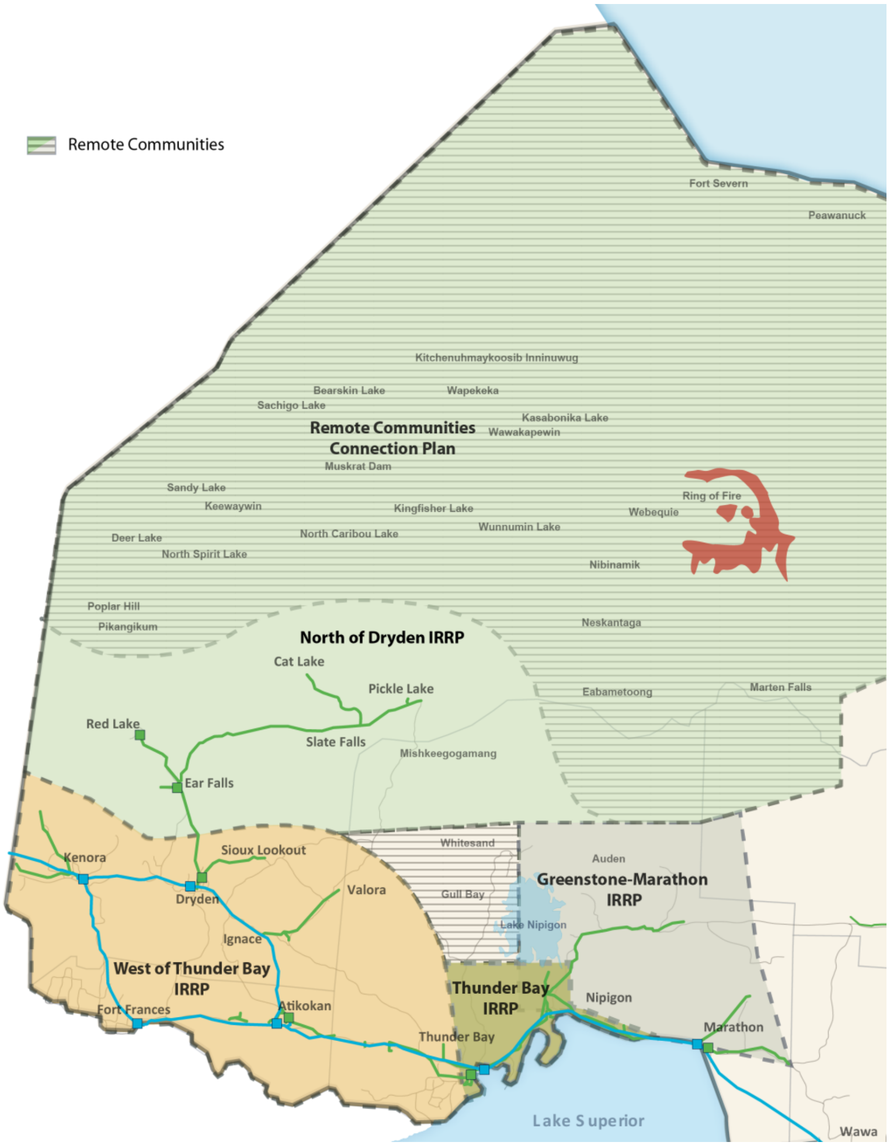
---

[5] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/North-of-Dryden.aspx

[6] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan.aspx

[7] http://www.ieso.ca/Documents/Regional - Planning/Northwest_Ontario/Final%20Northwest%20Scoping%20Process%20Outcome%20Report.pdf

Figure 4-1: Northwest Ontario Planning Region and Sub-regions



4.2 The Greenstone-Marathon Area Electricity System

Electricity is supplied to the Greenstone-Marathon Sub-region from two main sources: Marathon TS and Alexander SS. Marathon TS is located in the Town of Marathon and is a 230/115 kV station supplied at 230 kV from the East-West Tie which connects the northwest system near Thunder Bay and at Marathon to the northeast system at Wawa. At Marathon TS, power is then transformed from 230 kV to 115 kV for transmission customers. Alexander SS is located outside of the Township of Nipigon and is a large switching station where a number of hydroelectric generators south of Lake Nipigon - Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - inject power into the system.

The Municipality of Greenstone and surrounding communities are supplied via a single-circuit 115 kV line (A4L) that connects from Alexander SS. Circuit A4L is approximately 150 km and generally follows the Highway 11 corridor. The natural gas-fired Nipigon GS, which holds a non-utility generator ("NUG") contract, is also connected to A4L.

The Town of Marathon and surrounding area is supplied via a single-circuit 115 kV line (M2W) that originates at Marathon TS and branches north to Manitouwadge and east to White River. Circuit M2W has a total distance of approximately 200 km. Hydroelectric generation at Umbata Falls GS and Wawatay Customer Generating Station ("CGS") also contributes to the electricity supply of the local area.

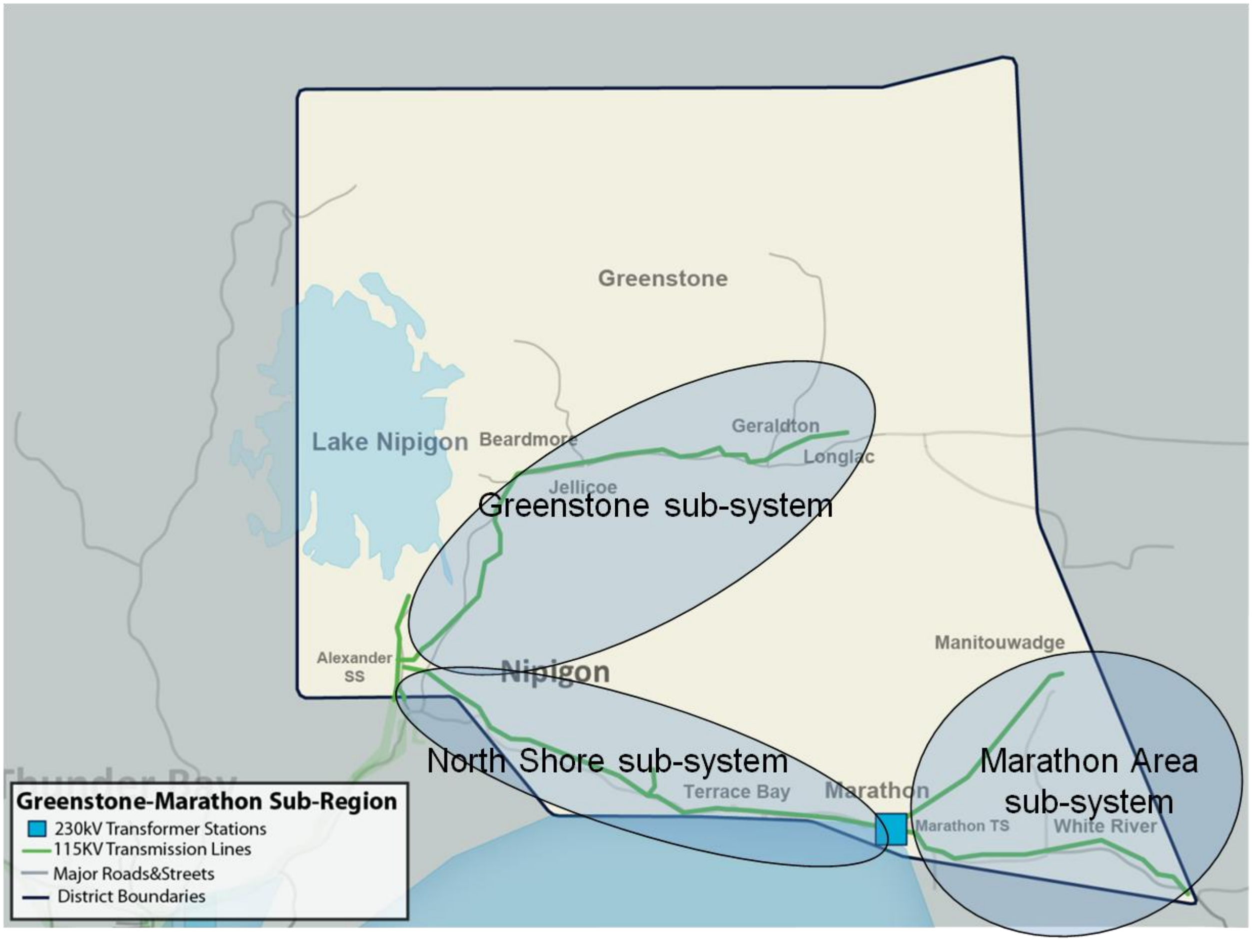
The communities along the north shore of Lake Superior between Nipigon and Marathon are supplied from three circuits in series (A5A / A1B / T1M) that terminate at Marathon TS and Alexander SS. The three circuits generally follow the Highway 17 corridor and have a total distance of approximately 170 km. Hydroelectric generation at Aguasabon GS is connected at Aguasabon SS, which is the terminus for circuits A5A and A1B, and also contributes to the supply of the local area.

4.3 Greenstone-Marathon Area Sub-systems

Within the Greenstone-Marathon Sub-region, there are three electrical sub-systems: Greenstone, North Shore, and Marathon Area.

The facilities supplying each sub-system are illustrated in Figure 4-2.

Figure 4-2: Greenstone-Marathon Sub-Region and Sub-systems



4.3.1 Greenstone Sub-system

The Greenstone sub-system is defined as being comprised of the existing and potential customers serviced from circuit A4L from Alexander SS to Longlac TS. Circuit A4L generally follows Highway 11 from Nipigon to Longlac. Circuit A4L serves the communities comprising the Municipality of Greenstone and serves as connection for Nipigon GS.

4.3.2 North Shore Sub-system

The North Shore sub-system is defined as being comprised of the existing and potential customers serviced from circuits A5A, A1B, and T1M, from Alexander SS to Marathon TS. Circuits A5A, A1B, and T1M are in series and generally follow the Highway 17 corridor. Together, these circuits interconnect Alexander SS to Marathon TS, however, each circuit comprises its own protection zone such that a fault on any one of the three circuits will not interrupt supply on the other two. Hydroelectric generation at Aguasabon GS is connected to the system at Aguasabon SS which is the interconnection between A5A and A1B.

4.3.3 Marathon Area Sub-system

The Marathon Area sub-system is defined as being comprised of the existing and potential customers serviced from circuit M2W, radial from Marathon TS to Manitouwadge TS and White River DS. Hydroelectric generation at Umbata Falls GS and Wawatay CGS is also connected to the system by circuit M2W.

5. Demand Forecast

5.1 Methodology for Establishing a Planning Forecast

The first step in developing an IRRP is establishing a planning forecast. A planning forecast is developed from a compilation of electrical demand data collected from LDCs and potential large customers connected directly to the transmission system. The effects of weather and coincidence factors are considered. Also, the demand reduction from CDM and DG are accounted for when developing the planning forecast.

As part of the lead transmitter's Needs Screening, LDCs are required to submit 10-year gross station demand forecasts. Consistent with the PPWG Report, LDC demand forecasts are further refined and a long-term (10-20 years) projection is also produced. Hydro One Distribution is the sole distributor in the Greenstone-Marathon Sub-region and it provided the Working Group with the gross station demand forecast and related assumptions. The effects of DG and expected conservation from LDC conservation targets were then applied.

The IESO regularly communicates with existing and potential transmission-connected industrial customers to ensure there is an understanding of their future electricity demand requirements. In the Greenstone-Marathon Sub-region, new industrial customers account for the majority of the forecast demand growth. However, the magnitude and timing of the electrical demand growth associated with large industrial customers, especially those in the natural resource sector (e.g., mining, oil, forestry) depend on a number of external factors such as the commodity price of the resource, the economic viability of the industrial project, and the ability to secure capital. In order to account for uncertainty of natural resource-based customers, the IESO developed multiple demand scenarios for potential and existing transmission-connected industrial customers by considering a number of factors, including:

- Customer plans
- Stage of development (e.g., under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g., results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g., commodity prices, customers and demand)

Planning forecasts were developed based on LDC station demand forecast, the impact of CDM and DG, and the forecast scenarios of transmission-connected industrial customers.

5.2 Forecast Elements

The forecast developed for the Greenstone-Marathon IRRP includes quantitative and qualitative contributions from a number of parties including Hydro One Distribution, individual existing and potential industrial customers, local municipalities, First Nation communities and Métis community councils, industry associations, and interest groups.

5.2.1 Local Distribution Company Gross Demand Forecast

To support the regional planning process, the DSC requires that the LDCs provide gross station demand forecasts representing distribution customer demand projections. Hydro One Distribution has provided gross forecast projections for the step-down supply stations within the Greenstone-Marathon Sub-region indicated in Table 5-1 below.

Table 5-1: Step-down Stations by Sub-system

Greenstone Sub-system	North Shore Sub-system	Marathon Area Sub-system
Beardmore DS #2	Marathon DS	Manitouwadge DS #1
Jellicoe DS #3	Schreiber Winnipeg DS	Manitouwadge TS
Longlac TS		Pic DS
		White River DS

LDC forecasts also include small industrial customers, such as saw mills connected to the distribution system. One notable inclusion is the re-start of two saw mills in the Municipality of Greenstone.

5.2.2 Conservation Assumed in the Forecast

In developing planning forecast scenarios, the Working Group also considered the extent to which planned CDM may impact peak demand.

In the report "Achieving Balance: Ontario's Long-Term Energy Plan" ("2013 LTEP"), the Ontario government established a provincial CDM target of 30 TWh in electricity reduction by 2032. To assist in achieving this target, the 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015. In order to represent the effect of provincial conservation targets within regional planning, the IESO developed an annual forecast for peak demand savings based on the provincial energy savings target which it expressed as a percentage of demand in each year. These percentages were apportioned to the

LDC demand forecast to develop an estimate of the peak demand impacts from the provincial targets in the Greenstone-Marathon Sub-region. The CDM targets included in developing the net demand forecast are provided in Table 5-2 below.

Table 5-2: Conservation Targets by Sub-system

Sub-system	Peak Reduction due to Conservation [MW]				
	2015	2020	2025	2030	2035
Greenstone	0.1	0.4	1.4	2.2	2.5
North Shore	0.1	0.6	1.2	2.0	2.3
Marathon Area	0.2	1.0	1.9	3.0	3.5

5.2.3 Transmission Connected Customer Demand Forecast

The majority of forecast demand growth in the Greenstone-Marathon Sub-region is anticipated to be driven by potential large industrial customers that may connect directly to the transmission system. In the near term, potential industrial projects include a gold mine near Geraldton, and the pumping stations associated with a portion of a large gas to oil pipeline conversion project that generally follows the Highway 11 corridor. The life extension of an existing mine near Marathon, and a precious metals mine near Marathon are also considered.

In the medium and long term, a gold mine near Beardmore, and potential new supply to mining and remote communities in the Ring of Fire area using a North-South corridor are considered in the forecast scenarios.

5.3 Planning Forecast

To address peak electricity demand requirements for the sub-region, a scenario-based planning approach was used to account for uncertainty in demand forecast. As a result, the Greenstone-Marathon planning forecast consists of a number of scenarios which account for different possible industrial development outcomes. The scenarios all represent plausible outcomes that must be considered in planning for the electricity needs of the sub-region.

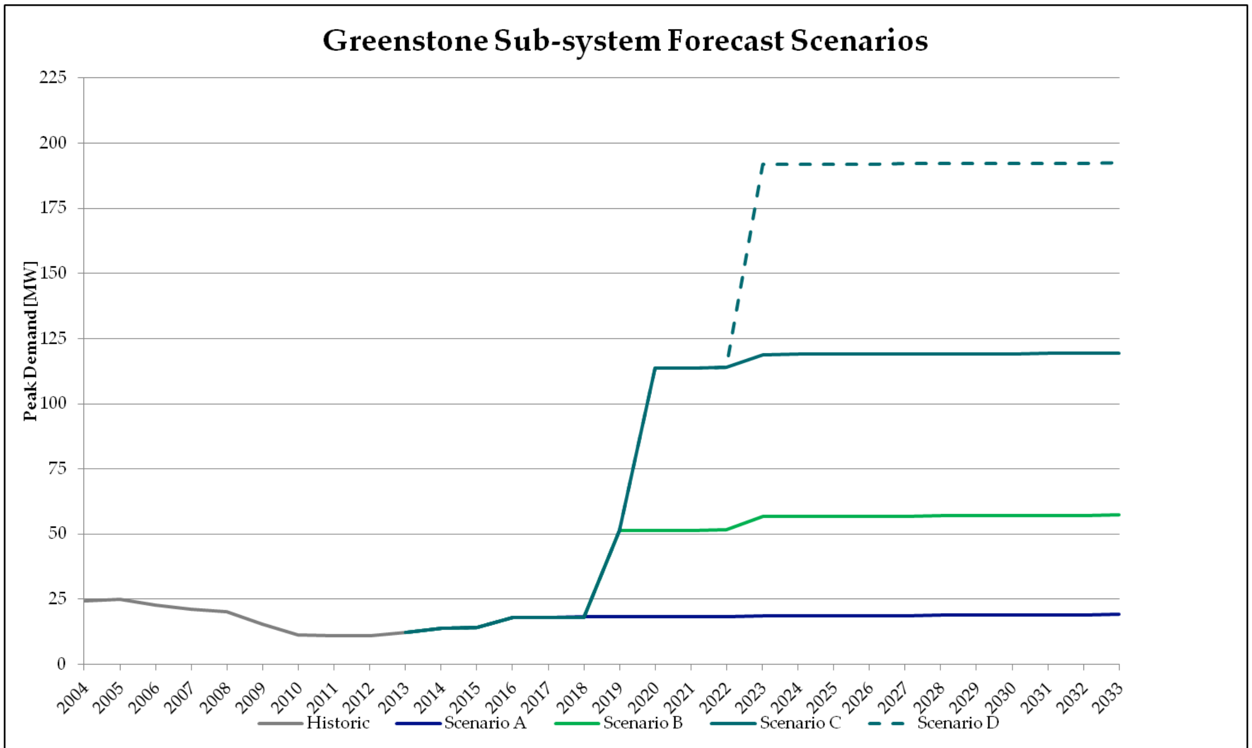
5.3.1 Greenstone Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the Greenstone sub-system. Since publishing of the Interim IRRP, scenarios have been updated to reflect the latest timelines and include medium and long-term developments, including the Beardmore mine and Ring of Fire.

Table 5-3: Greenstone Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth (including two saw mill re-starts)
B	Hydro One Distribution customer growth (including two saw mill re-starts), Geraldton mine materializes, and Beardmore mine materializes
C	Hydro One Distribution customer growth (including two saw mill re-starts), Geraldton mine materializes, Beardmore mine materializes and gas to oil pipeline conversion project materializes
D	Scenario C with the Ring of Fire area fully developed by 2023

Figure 5-1: Greenstone Sub-system Forecast Scenarios



Impacts to population and employment from potential industrial customers are considered in the respective scenario. It should be noted that the Greenstone sub-system forecast Scenarios B and C are equivalent until 2020, at which point they diverge. This is important when considering staging of options and will be discussed further in Section 7.2.2.

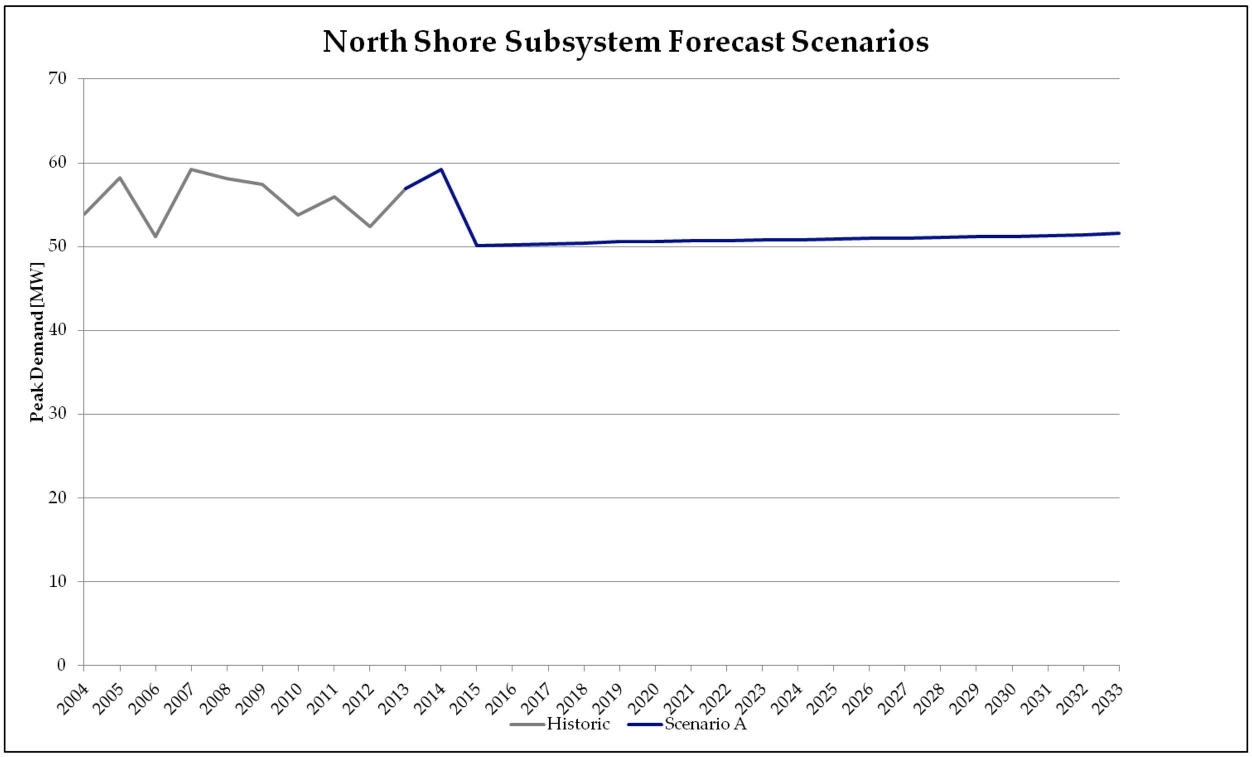
5.3.2 North Shore Sub-system Forecast Scenarios

Since the publishing of the Interim IRRP, the industrial customer is no longer considering behind-the-meter generation and so the accompanying scenarios that were included in the Interim IRRP have been removed from the IRRP analysis. Therefore, a single scenario is used for analysis in this IRRP for the North Shore sub-system and is summarized in Table 5-4 and Figure 5-2, below.

Table 5-4: North Shore Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth

Figure 5-2: North Shore Sub-system Forecast Scenarios



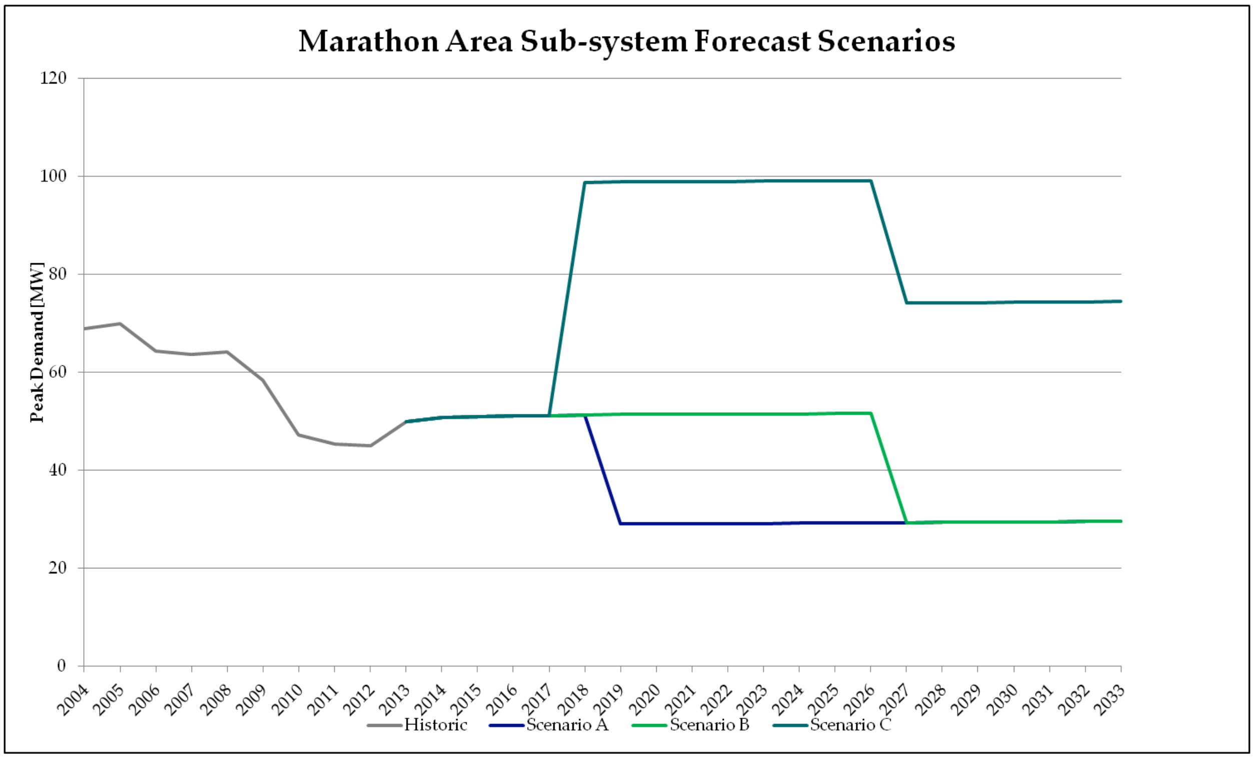
5.3.3 Marathon Area Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the Marathon Area sub-system, which have remained unchanged since the publishing of the Interim IRRP.

Table 5-5: Marathon Area Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth, no life extension of existing Marathon Area mine
B	Hydro One Distribution customer growth, with life extension of existing Marathon Area mine
C	Hydro One Distribution customer growth, with life extension of existing Marathon Area mine, and new Marathon Area precious metals mine materializes

Figure 5-3: Marathon Area Sub-system Forecast Scenarios



6. Electricity System Needs

For the purpose of this IRRP, the following section details the near-, medium-, and long-term needs established by the Working Group.

6.1 Methodology for Establishing Power System Needs

Once the planning forecast is developed, power system needs are established by determining the load meeting capability ("LMC") of the power system and determining if a shortfall exists between the electricity that can be supplied by the system in comparison to the forecast demand.

In order to determine the LMC of the power system supplying the Greenstone-Marathon Sub-region, Ontario and North American electricity planning standards are applied consisting of: the ORTAC, the Northeastern Power Coordinating Council ("NPCC") Directory #1 Standards, and the North American Electric Reliability Corporation ("NERC") Transmission Planning Standards ("TPL-001-4"). These documents outline power system planning and design standards and all are publically available.[8]

ORTAC represents the compilation of standards and best-practices in Ontario for long-term electricity plans, including IRRPs. ORTAC identifies certain system conditions, including contingencies, and the required level of performance under those conditions. The performance of the system is categorized based on equipment loading, voltage performance, load security and restoration (acceptable time periods for restoring customers after specified contingencies). Appendix A details the criteria applied in this IRRP.

The IESO recognizes that ORTAC, NERC, and NPCC planning criteria may not necessarily align with customer risk tolerances or their ability to pay for system reinforcement. Ultimately the decision of electric power supply resides with the benefitting customers so long as the reliability of the bulk system is not negatively impacted.

---

[8] ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf
NPCC Directory #1:
https://www.npcc.org/Standards/Directories/Directory%201_Design%20Ops%20BPS%20clean%20GJD%2020150331_GJD.pdf
NERC TPL-001-4: http://www.nerc.com/files/TPL-001-4.pdf

6.2 Existing System Load Meeting Capability

In order to establish electricity supply requirements for the Greenstone-Marathon Sub-region, it is necessary to determine the LMC of each of the Greenstone, North Shore and Marathon Area sub-systems. The LMC of each sub-system is largely dependent on the connection point of the new customers forecast to connect. This is especially true in northwestern Ontario where the LMC of long circuits may be limited by voltage.

6.2.1 Greenstone Sub-system Load Meeting Capability

The Greenstone sub-system is limited by voltage for new customers near the Longlac area. The existing system, consisting of the A4L transmission line, has a total LMC of approximately 25 MW assuming the majority of load is concentrated in the Geraldton and Longlac areas near the end of the circuit. Based on demand forecast Scenario A, the Greenstone sub-system is not expected to be limiting, however all other scenarios are forecast to exceed the 25 MW limit in the near term. It should be noted that although circuit A4L is currently limited by voltage, it has a summer thermal rating of 260 A, or approximately 45 MW.[9]

6.2.2 North Shore Sub-system Load Meeting Capability

In addition to supplying customers, the North Shore sub-system also serves as the bulk system underlay for the East-West Tie. The North Shore sub-system can accommodate a total of approximately 100 MW of load and through-flow (from bulk transfers) during normal conditions. Flow along the North Shore sub-system is not expected to exceed 100 MW during normal conditions, even when the East-West Tie is loaded to its fair weather transfer limit and under a variety of local hydroelectric conditions.

Under the post-contingency condition where the double-circuit line M23L/M24L (which is a portion of the East-West Tie) between Marathon to Lakehead is lost, flows may exceed 100 MW along the North Shore sub-system during high transfer conditions. Overloading is mitigated and reliability is maintained by ensuring load is continuously supplied pre-contingency by the availability of the Northwest Remedial Action Scheme ("RAS"). Following the reinforcement of the East-West Tie between Wawa TS and Lakehead TS, currently planned to be in-service for 2020, reliability to the Northwest will be improved and the North Shore sub-system will also be

[9] In order to release the full thermal capability of facilities that are limited by voltage, reactive compensation of sufficient amounts to address the voltage limit would need to be installed. This is considered further in the Alternatives section of the report.

able to accommodate further growth. Therefore the North Shore sub-system is not expected to be limiting for new customers during this planning cycle.

6.2.3 Marathon Area Sub-system Load Meeting Capability

The Marathon Area sub-system is limited by voltage performance. Incremental reactive compensation may be required to connect additional customers. The further customers are from Marathon TS, the more reactive compensation will be required. The maximum load that the Marathon Area sub-system can accommodate based on the ORTAC load security limit for a single-circuit line is 150 MW. Based on existing forecasts, the Marathon Area sub-system is not expected to be limiting for new customers during this planning cycle.

6.3 Near-Term Needs

The near-term needs are described below by sub-system for each planning forecast scenario.

6.3.1 Near-Term Needs: Greenstone Sub-system

Capacity

The near-term capacity needs have been determined by comparing the near-term demand forecast, driven by the Geraldton mine and the gas to oil pipeline conversion project, to the LMC of the sub-system, and are tabulated below:

Table 6-1: Summary of Near-Term (present-5 years) Capacity Needs for the Greenstone Sub-system[10]

Demand Forecast [MW]	2015	2016	2017	2018	2019	2020
Scenario A	14	18	18	18	18	18
Scenario B	14	18	18	18	51	51
Scenario C	14	18	18	18	51	114
Greenstone LMC[11] [MW]	**25**					
Capacity Need [MW]						
Scenario A	0	0	0	0	0	0
Scenario B	0	0	0	0	26	26
Scenario C	0	0	0	0	26	89

[10] Scenario D is not considered for the near-term, as it is identical to Scenario C from 2015-2023

[11] Based on the capability of circuit A4L without any additional reactive compensation.

Power flow studies are included in Appendix B.

Load Security and Restoration

All demand forecast scenarios being considered up to 2020 remain less than 150 MW. This complies with the load security criteria outlined in ORTAC for a single-circuit line, which requires that no more than 150 MW be lost due to an outage on that line. Also, restoration from a normal outage should remain under eight hours, consistent with ORTAC.

Restoration from forced outages has generally performed within ORTAC. In the last five years, forced outages have been restored within eight hours with the exception of three sustained outages. These outages required crews to perform restoration work into the overnight period. The intent of the 8-hour criterion is that all non-catastrophic forced outages can be restored within a working day. Provisions exist in ORTAC to account for outages that take place outside of normal working hours and away from staffed centres; "approximate restoration times are intended for locations that are near staffed centres… [and] restoration times should be commensurate with travel times and accessibility"[12] (ORTAC 7.2). Therefore, no load security or restoration needs have been identified in the near term. A comprehensive reliability analysis is included in Appendix E.

Additional Customer Requirements

Fault analysis indicates that the available short-circuit at the end of circuit A4L is about 140 MVA[13] at the Longlac TS 115 kV bus. A potential mining customer near Geraldton has indicated that it requires at least 150 MVA available short circuit at 13.8 kV supply to ensure the functioning of its equipment. It has been estimated that the available short circuit would be about 105 MVA at 13.8 kV at the proposed Geraldton mine. Therefore, solutions for the area that consider the Geraldton mine scenarios must increase the available short circuit level, for example: through the use of generators, synchronous condensers or static synchronous compensators ("STATCOM"). Passive devices such as capacitors or Static Var Compensators ("SVCs") cannot provide the required short circuit level.

As well, for forecast scenarios that include the large gas to oil pipeline conversion project, the developer has informed the IESO that adjacent pumping stations cannot be lost for the same

---

[12] ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[13] Assuming the outage of Nipigon GS, representing a scenario that short-circuit availability is low

contingency. Therefore, provisions for appropriate supply diversity must be included for these relevant scenarios.

6.3.2 Near-Term Needs: North Shore Sub-system

The existing electrical system supplying the North Shore sub-system is expected to be sufficient for the planning horizon, given the latest information made available to the IESO. As indicated in Section 5.3, the North Shore sub-system is not forecast to experience net demand growth. Power flow study results are included in Appendix B for reference, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.3.3 Near-Term Needs: Marathon Area Sub-system

The existing electrical system supplying the Marathon Area sub-system is expected to be sufficient for the near-term.

This is also supported by the Stillwater Canada Inc. System Impact Assessment ("SIA") Report for the Marathon Platinum Group Metals (PGM) Copper Project, available on the IESO website.[14]

Power flow study results are included in Appendix B, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.4 Medium- and Long-Term Needs and Initiatives

The medium- and long-term needs for the Greenstone-Marathon Sub-region are discussed below in the context of four medium- and long-term initiatives including: additional mining claims in Greenstone, the possibility of an infrastructure corridor to the Ring of Fire, the Little Jackfish hydroelectric project, and community energy efficiency activities.

6.4.1 Additional Mining Claims in Greenstone

Other mining claims, beyond the Geraldton mine, exist along the Highway 11 corridor in the Greenstone area and additional local system reinforcement may be required if mines develop. Of particular interest is a potential gold mine near Beardmore that may be operational within the medium term. The mining developer's preliminary economic assessment results[15] indicate

---

[14] http://www.ieso.ca/Documents/caa/CAA_2012-476_Final_Report.pdf
[15] http://www.premiergoldmines.com/i/pdf/2014-01-28_NR.pdf

that it would be economically advantageous for the Beardmore mine if processing and gold recovery were performed at the Geraldton mine.

Therefore, it has been assumed for purposes of this IRRP, that the Beardmore mine is included in scenarios that also include the Geraldton mine.

6.4.2 Infrastructure Corridor to the Ring of Fire

A North-South multi-use infrastructure corridor from near Nakina to the Ring of Fire continues to be a possibility for developers. As concluded in the 2015 North of Dryden IRRP, transmission supply for mining and remote communities is economic and the need for a new 230 kV transmission line to the Ring of Fire should be considered when developing an infrastructure corridor to the Ring of Fire. The 2015 North of Dryden IRRP also concluded that an East-West corridor from Pickle Lake or a North-South corridor from East of Nipigon or Marathon were comparable in cost if the Ring of Fire fully develops.

This IRRP report extends the analysis of a new 230 kV North-South transmission line to the Ring of Fire to consider the extent of possible economic efficiencies from multiple customers.

6.4.3 Little Jackfish Hydroelectric Project

The Little Jackfish hydroelectric project would require a new 180 km 230 kV connection line in order to provide power to the provincial electricity grid. The details of the connection line are included in Ontario Power Generation's ("OPG") project description[16] (pursuant to the Canadian Environmental Assessment Act).

The purpose of all IRRPs is to provide plans to reliably serve electricity demand, not to develop plans to connect system generation. However, potential transmission options exist that are detailed in Section 7 that may result in economic efficiencies for connecting the Little Jackfish hydroelectric project. Section 9.3 quantifies the economic efficiencies under the specific system expansion scenario that such efficiencies may result.

6.4.4 Community Energy Efficiency Activities

In a number of communities within the IRRP study area, electricity is the primary source for heating because there is no natural gas pipeline infrastructure. During municipal engagement

---

[16] http://www.opg.com/generating-power/hydro/projects/little-jackfish/Documents/LJF_Project_Description.pdf

activities, the Town of Marathon communicated that electric heating has resulted in budgetary pressures and that the town is investigating the potential for cogeneration options. Section 9.4 provides a high-level avoided cost analysis for cogeneration. Similar solutions may also be a consideration for other communities without access to natural gas pipeline infrastructure. The IESO is including this planning-level economic analysis to provide communities with a methodology that they may use to determine planning-level feasibility.

7. Alternatives for Meeting Near-Term Needs

7.1 Methodology for Alternatives Development and Comparison

Once needs are identified, alternatives are developed that are technically feasible and are then compared on a relative basis against planning criteria. If a decision is required, given the forecast timing of needs and lead times for implementing feasible alternatives, a recommendation is made.

Alternatives may consist of one or a combination of CDM, generation, transmission, and/or distribution. Integrated alternatives that are capable of satisfying criteria for the forecast system condition and for the applicable scenario being assessed are then considered. Alternatives that are not capable of satisfying criteria are screened out and not considered further.

An economic analysis of the technically feasible alternatives is performed and the net present value ("NPV") of each option is determined based on the amortized costs that are incurred within a 20-year planning horizon.[17] The IESO used a real social discount rate of 4% in this analysis.[18] Generation and conservation options that contribute to provincial system supply needs are appropriately credited with the related economic benefit to ensure consistent comparison with all other options. Other factors such as environmental impact and social acceptance are considered, including information obtained from the engagement process. Detailed environmental impact analysis is performed by proponents during the implementation phase for projects requiring environmental assessment.

7.2 Alternatives Considered

7.2.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

---

[17] This is not the total project cost.

[18] The real social discount rate may be different than individual customer discount rates which account for the individual customer's own return on equity, risk, tax, etc.

However, within the Greenstone-Marathon Sub-region, the majority of the forecast load growth is anticipated to come from new industrial development, which is assumed to include relatively efficient equipment given the inherent economic benefits and latest codes and standards. Conservation expected to be achieved through provincial targets has already been included in the net demand forecast. Therefore, the potential for an additional amount of significant conservation that could address needs is limited.

Two of the available programs that transmission-connected industrial customers could be eligible for are the Industrial Conservation Initiative ("ICI") and the Industrial Accelerator program ("IAP"). The ICI encourages Class A customers to reduce their peak demand contributions, by providing a means to reduce their Global Adjustment charges.[19] IAP is geared to reducing electricity consumption on the provincial system, and to helping companies become more competitive by providing financial incentives that encourage investment in innovative process changes and equipment retrofits.[20] Opportunities for energy savings will continue to be explored for new and existing transmission-connected customers in the Greenstone-Marathon Sub-region.

7.2.2 Renewable Distributed Generation

A high level assessment of the cost of renewable DG resources to meet capacity needs in the Greenstone-Marathon Sub-region was conducted. This was performed by estimating a range of dependable capacity values for run-of-river hydroelectric, wind, and solar resources, based on median historical and simulated data for facilities in the Northwest Ontario Region. Dependable capacity refers to the portion of the total installed capacity that can be relied upon to meet local or system peak capacity needs. Consistent with ORTAC, this refers to the 98-percentile output of the resource. Based on the dependable capacity, unit costs were developed for these renewable resources. These unit costs are summarized in Table 7-1, below and range from $16 M/MW - $100 M/MW. Compared to the unit costs of detailed local generation and transmission options that are considered later in this report that range between $1.4 M/MW - $7.3 M/MW, renewable DG is not economic and can be screened out of further assessment.

---

[19] More information on how Global Adjustment is calculated for Class A customers is available at http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx
[20] More information on IAP available: http://www.ieso.ca/Pages/Participate/Industrial-Accelerator-Program/default.aspx

Table 7-1: Summary of Analysis of Renewable DG

Resource Type	Dependable Capacity [%]	Unit Capacity Cost [M$/MW-dependable]	Levelized Unit Energy Cost [$/MWh]
Run of River Hydroelectric	15-30	16-66	60-110
Wind and Solar	5-28	7.5-100	80-400

It should be noted that storage systems may be effectively sized to increase the overall dependable capacity of an integrated renewable DG - storage system, though the unit costs of such system are expected to also increase due to the added battery systems. It is also expected that given the magnitude of the needs described in Section 6 of up to 89 MW of incremental LMC by 2020, and the dependability of the resources required, renewable DG options would be of impractical physical size. For example, a solar facility with a dependable capacity of 28% would need to be rated at approximately 320 MW to provide an LMC of 89 MW. Typical solar facilities can require over 5 acres of land per 1 MW.[21]

Although renewable DG is neither economic nor practical to meet the regional needs identified in the Greenstone-Marathon Sub-region, customers connected to the provincial power system have access to renewable energy programs which they may be eligible to participate. From a customer perspective, these programs may be effective in offsetting their individual electric utility costs. Ultimately, this is a customer decision that includes adherence to the corresponding program and connection availability rules.

7.2.3 Greenstone Sub-system Alternatives

The following sections describe the analysis of the different alternatives considered for each of the Greenstone sub-system forecast scenarios.

As indicated earlier, the Greenstone sub-system consists of one single-circuit 115 kV transmission line (A4L) with limited capacity and the near-term need for new capacity is driven by two specific industrial developments. Given that the options must account for a number of

[21] http://www.nrel.gov/docs/fy13osti/56290.pdf

factors such as the limitations of the existing system, the identified needs, and the staging of industrial customer electrical demand increases, a single transmission, generation, or DG alternative may not fulfill the range of customer requirements. In order to develop options that provide for the full scope of existing system limitations and customer capacity requirements, combinations of transmission, large generation, and DG facilities are considered. Off-grid alternatives are also considered for the purpose of cost comparisons. These alternatives include the following scenarios:

Table 7-2: Summary of Alternatives Considered for Scenarios

Scenario	Alternative	NPV Cost [M$]
A	"A0" – Continued sustainment of existing transmission system	0[22]
B	"B1" – Install reactive compensation and distributed generation	65
	"B2" – Install off-grid generation	190
	"B3" – Install reactive compensation and replace sections of circuit A4L	40
C	"C1" – Install reactive compensation, new 230 kV transmission supply and off-grid generation	170
	"C2" – Install reactive compensation, new 230 kV transmission supply and 115 kV connection line	160
	"C3" – Install new grid-connected gas generation and 115 kV connection line	340
	"C4" – Install off-grid generation	530

The result of the scenario-based alternative analysis is summarized below.

Scenario A does not result in the need for any new facilities. As a result, the continued sustainment of existing transmission infrastructure is adequate.

Analysis of Scenarios B and C indicates that a staged approach for recommended capacity enhancements best aligns with the timing of industrial developments. Stage 1 would economically maximize the existing system, while Stage 2 outlines the infrastructure expansion

[22] There is a cost of sustainment and maintenance programs. However, in the context of this option those costs would have been undertaken anyway as regular and good utility practice.

to accommodate a substantial increase in demand. Recommended Stage 1 and Stage 2 are summarized below.

Recommended Stage 1 – to accommodate the Geraldton mine
• Install +40 MVar of reactive compensation in the form of either a synchronous condenser or STATCOM at the Geraldton mine, to be in-service coincident with the mine • Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the Geraldton mine [23]

In 2020, Scenarios B and C diverge. Scenario B includes only the demand from the Geraldton mine, whereas Scenario C includes both the mining demand and the demand from the gas to oil pipeline conversion project.

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service according to schedule (2020), and consistent with Scenario C, the recommendation is:

Recommended Stage 2 – to accommodate the gas to oil pipeline conversion project
• Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the connection of the pumping stations loads • Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to connect the pumping station loads

If the gas to oil pipeline conversion project does not proceed or does not commit to grid supply, consistent with Scenario B, Stage 1 is sufficient to meet forecast demand. The following sections provide a detailed analysis of the alternatives listed in Table 7-2.

[23] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards. If the generation can operate in island-mode, it may be advantageous to pursue this option due to the inherent supply diversity that it offers in comparison to replacing circuit sections of A4L (Option B3). The customer may also wish to investigate conservation incentives that the IESO offers, such as the ICI and IAP, to compliment this option.

7.2.3.1 Continued Sustainment of Existing System ("Option A0")

Under forecast Scenario A, no new industrial customers are supplied from the transmission grid. Under this scenario, the existing transmission system is sufficient to meet electrical capacity requirements in the Greenstone sub-system. No new facilities are required.

A comprehensive reliability analysis is included in Appendix E.

To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One's maintenance practices and sustainment plans are expected to be adequate and meet planning criteria. Customers may choose to pursue further reliability investments independently.

7.2.3.2 Install Reactive Compensation and Distributed Generation ("Option B1")

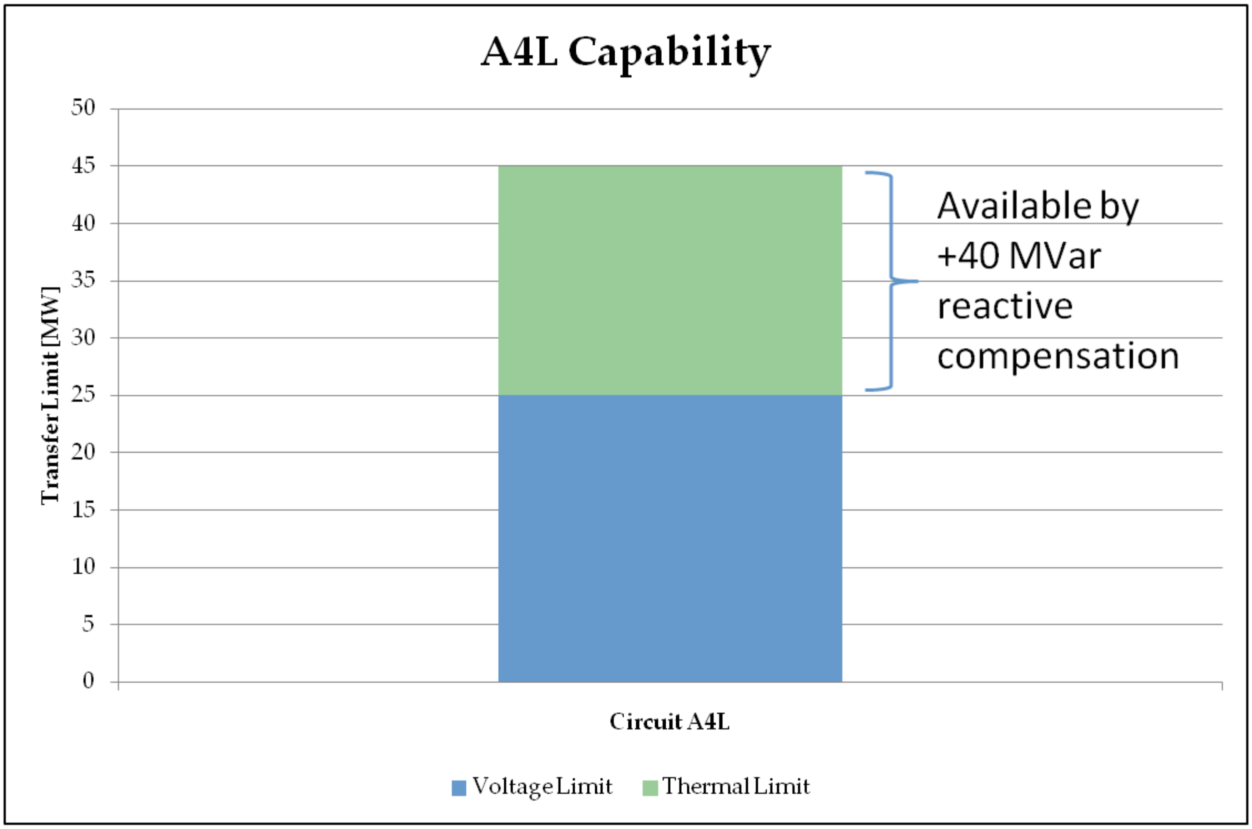
This option considers the needs based on load forecast Scenario B.

This alternative consists of installing additional reactive compensation totaling approximately +40 MVar in the form of either synchronous condenser(s) or STATCOM(s).[24] This would make available the full thermal capability of the circuit of 260 A, or approximately 45 MW (i.e. incremental LMC of 20 MW). As indicated in Section 6.3.1, considering motor starting requirements of the Geraldton mine, reactive compensation solutions would need to increase short circuit levels to 150 MVA at the mine site. Devices such as synchronous condensers or STATCOMs would be able to increase the available short circuit level, but passive devices such as capacitor banks or SVCs would not. This has been considered in the economic analysis by assuming the planning level capital cost estimate of the reactive compensation consistent with that of a synchronous condenser, which is approximately $7.5 million (or $5 M NPV).[25] It should be noted that STATCOMs are expected to be comparable in cost, based on information available to the IESO.

[24] In order to accommodate planned and unplanned outages, a RAS is also recommended.

[25] Estimate provided by Hydro One, based on information received from ABB.

Figure 7-1: Increase in A4L Capability with +40 MVar of Reactive Compensation



In order to accommodate the remaining capacity deficiency associated with the Geraldton mine, two 10 MW gas-fired generators may be installed.[26] For costing purposes, these generators are expected to produce about 43 GWh per year, which corresponds to the electricity that the mine is expected to require in excess of the 25 MW of capacity that may be grid-supplied.

A major benefit of using a combination of grid supply and local generation compared to Options B2 and B3 is the supply diversity. A contingency involving the grid or the on-site generators would still allow the mine to continue with some degree of production.[27] The customer may also wish to investigate conservation incentives that the IESO offers, such as the ICI and IAP, to complement this option and further reduce their costs.

[26] The IESO has assumed N-1 reliability of the plant (single redundant unit), consistent with North American electricity reliability standards.

[27] The level of supply security described for Option B1 would require that provisions are made such that the on-site generators being described can operate in island mode.

Power flow study results are included in Appendix C, and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D for reference.

The details of Option B1 are summarized below:

Table 7-3: Summary of Option B1

Option B1[28]	
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	65
Net Present Value Cost [M$]	65
Net Present Value Cost per Utilized Capacity [M$/MW]	2.5
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

7.2.3.3 Install Off-Grid Generation ("Option B2")

This option considers the needs based on load forecast Scenario B.

Circuit A4L, which serves the Greenstone sub-system, runs parallel to a portion of the TransCanada natural gas pipeline. A possible option is to continue to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine to supply their entire facility with on-site natural gas generation (i.e. not interconnected with the IESO-controlled grid). This option is included to provide existing and future customers with the full range of available options. It should be noted that the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid.[29]

[28] Using cost estimates for 9.5 MW gas engines as a representative cost.
[29] An exception is the December 16, 2013 ministerial directive which directed the former OPA to work with those remote First Nation communities where transmission connection is not economic and implement solutions for on-site renewable generation projects that reduce their dependency on diesel fuel and promote the use of renewable energy sources. http://www.powerauthority.on.ca/sites/default/files/news/December-16-2013-Directive-Renewable-Energy.pdf

The publically available draft EA Terms of Reference[30] for the Premier Gold Mines Ltd. Hardrock Mine indicates that 56 MW of generation capacity is anticipated to be required to meet demand with necessary redundancy.

For the purpose of the economic comparison, the installation of a 6x9.5 MW gas-fired engine power plant with dual-fuel capability is assumed. This arrangement would provide the required capacity indicated and account for N-2 redundancy, and address gas delivery risks. The on-site generation would produce approximately 260 GWh per year to supply the mine's energy needs.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-4: Summary of Option B2

Option B2	
Installed Capacity [MW]	57 (6x9.5)
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	173
Net Present Value Cost [M$]	190
Net Present Value Cost per Utilized Capacity [M$/MW]	7.3
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

7.2.3.4 Install Reactive Compensation and Replace Sections of Circuit A4L ("Option B3")

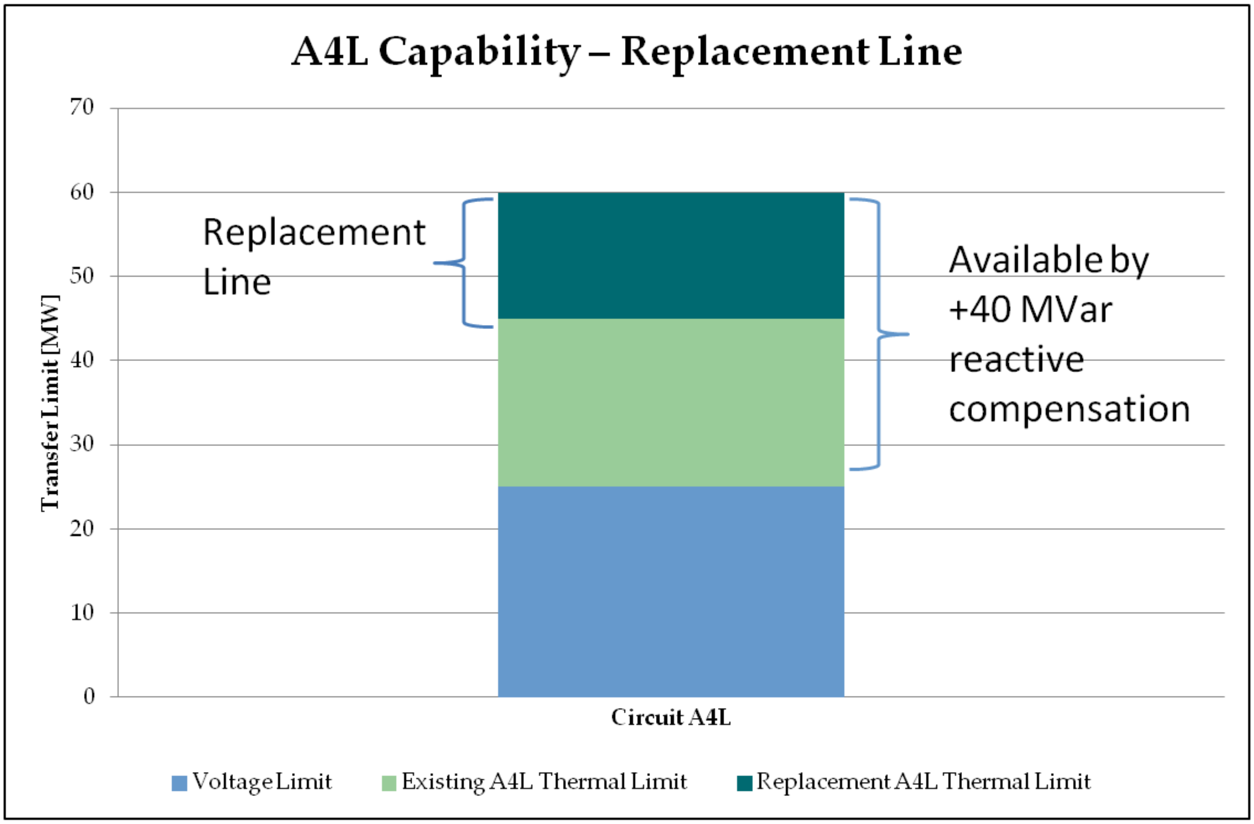
This option considers the needs based on load forecast Scenario B.

This option consists of installing additional reactive compensation of approximately +40 MVar in the form of either a synchronous condenser or STATCOM, and replacing the sections of circuit A4L between Nipigon and Longlac with a new 115 kV line using 477 kcmil Aluminum Conductor, Steel Reinforced ("ACSR") conductors. This would increase the ampacity of the

[30] http://www.premiergoldmines.com/i/pdf/HRTOR/EN/Main_ToR_fnl.pdf

circuit from 260 A to 310 A. If the circuit is fully compensated, this would increase the LMC to about 60 MW[31] which would accommodate the full 51 MW forecast for Scenario B.

Figure 7-2: Increase in A4L Capability with Nipigon to Longlac replaced with a new line equipped with 477 kcmil conductors and with +40 MVar of Reactive Compensation



This option would be optimally staged by first installing +40 MVar of compensation to provide an LMC of 45 MW to accommodate 25 MW of new demand. This would be followed by building the new line sections. The line sections may be constructed while the existing line serves customers, if right-of-way space is available. Otherwise, a bypass would be needed to allow for replacement of the existing line, which may increase costs by approximately 20%. Once the new line sections are constructed, existing facilities can be re-tapped on the new line sections. Following the installation of the new line sections, no additional reactive compensation

[31] The limiting section following the replacement of A4L between Nipigon Junction and Longlac is the section between Alexander SS and Nipigon Junction, which is 310 A. If this section was also replaced, the ampacity of the circuit could increase up to 620 A, which corresponds to an LMC of up to about 120 MW fully compensated. However, since forecast Scenario B only requires an LMC of 51 MW, upgrades were only considered from Longlac TS to Nipigon Junction and a full replacement of A4L was not considered further.

would be required to meet forecast demand beyond the +40 MVar as the larger conductors result in a reduced voltage drop across the line.

Power flow study results are included in Appendix C and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-5: Summary of Option B3

Option B3	
Incremental Utilized Capacity [MW]	26
Undiscounted Capital Cost [M$]	62
Net Present Value Cost [M$]	40
Net Present Value Cost per Utilized Capacity [M$/MW]	1.4
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

The result of the analysis is that Options B1 and B3 (the grid-connected options) are comparable in cost based on the degree of accuracy of planning cost estimates, and are more economic than Option B2 (the off-grid generation option). Option B1 is recommended over Option B3 due to lead-time constraints. On-site compensation and gas-fired generation typically has a lead time of 1-2 years, while replacing a transmission line with a new line equipped with higher capacity conductors typically has a lead time of approximately five years due to required approvals, including Leave to Construct. However, if the in-service date of 2019 communicated to the IESO by the Geraldton mine developer is delayed, Option B3 is the most economic option and should therefore be pursued. Ultimately this decision rests with the Geraldton mine developer.

An additional consideration for the Geraldton mine developer is that the NPV cost of a new 230 kV line from the East-West Tie over the planning period, as recommended in Stage 2 to meet incremental demand in Scenario C, is approximately $70 million. The $70 million is comparable in cost to Option B1. Although a new 230 kV line may not be technically required immediately, and may require a similar lead time as Option B3 of five years, a new 230 kV source would provide greater reliability to the Geraldton mine customer and the existing

Greenstone customers. A new 230 kV line has been communicated by the LAC to be the preferred supply option by the local community. There may therefore be merit in the Geraldton mine developer pursuing a new 230 kV line immediately, considering the benefits of reliability and community support, while being mindful of the required lead times.

7.2.3.5 Install New 230 kV Transmission Supply to Longlac and Off-Grid Generation ("Option C1")

This option considers the needs based on load forecast Scenario C.

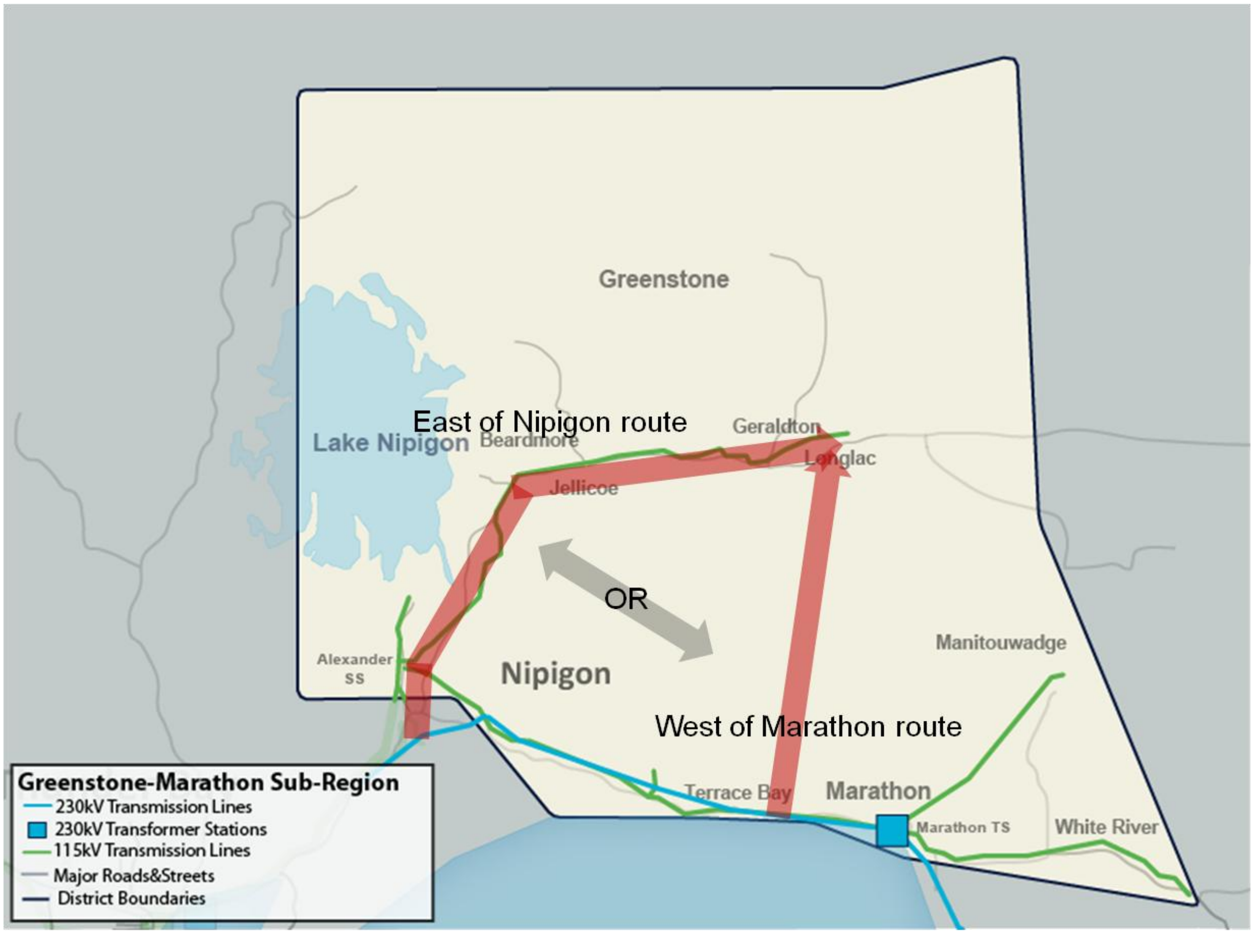
In order to accommodate an incremental capacity deficiency of about 60 MW, (associated with the Geraldton mine and connecting two large oil pumping stations that are located within the vicinity of the existing transmission system), an additional 230 kV supply would be required. The 230 kV supply option would consist of a new single-circuit 230 kV line, a new 230/115 kV auto-transformer located at or near Longlac TS, the associated protection and switching facilities, and reactive compensation (including +40 MVar of reactive compensation at the Geraldton mine consistent with Options B1 and B3). Detailed routing for the 230 kV line option can only be determined through an EA process. However, for planning purposes this report has considered two conceptual routing options for cost comparisons.[32] These two routing options are generally consistent with the routing options that have been communicated to the IESO by interested development groups and consist of an "East of Nipigon" route option, and a "West of Marathon" route option.

The East of Nipigon routing option is based on utilizing the existing Highway 11 corridor, generally running parallel with circuit A4L to Longlac TS and tapping M23L and/or M24L (the existing East-West Tie) between Marathon TS and Lakehead TS, near Nipigon. The length of the East of Nipigon route option would be approximately 150 km. The costing of this option considers single-circuit 230 kV H-frame wood poles with road access in northwestern Ontario.

The West of Marathon routing option is based on utilizing a least-distance, straight line route from the existing East-West Tie, tapping M23L and/or M24L west of Marathon, near Terrace Bay. The length of the West of Marathon route option would be approximately 100 km. The costing of this option considers single-circuit 230 kV H-frame wood poles without road access in northwestern Ontario (since it is considered to be on relatively undeveloped land).

[32] A 230 kV transmission line routing other than the two concepts listed may be considered by proponents if the proposed arrangement provides equivalent or relatively better technical, economic, environmental, and social performance.

Figure 7-3: Option C1 illustrative[33] route map



The East of Nipigon route has the benefit of utilizing an existing corridor with highway access, and a lower per-distance cost (associated with road access), but is longer. The West of Marathon route option has the benefit of being more secure (since common mode failures of both A4L and a new line would be significantly reduced by a separate corridor) and is shorter. However, this option is more costly per-distance (since it has limited road access), and may have greater environmental impact. Details of environmental impacts would be considered during an EA process, where different routes would be considered by the project proponent.

Finally, the two pumping stations to the east of Longlac would be supplied from dedicated gas-fired generation (i.e. not interconnected with the IESO-controlled grid). This would account for the final approximately 30 MW (to total 89 MW) incremental capacity for this scenario. These

[33] The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

stations are geographically distant from the existing transmission system. As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with a broader range of options for comparison.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of Option C1 are summarized below:

Table 7-6: Summary of Option C1

Option C1	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	235
Net Present Value Cost [M$]	175
Net Present Value Cost per Utilized Capacity [M$/MW]	2.0
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	225
Net Present Value Cost [M$]	170
Net Present Value Cost per Utilized Capacity [M$/MW]	1.9
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Under this scenario, the N-1 load security would be 45 MW. This accounts for the loss of the new circuit. In considering the N-1 contingency scenario where the 230 kV line (option) is lost, the remaining system would consist of circuit A4L, which is all that exists today. Fully compensated, circuit A4L can accommodate 45 MW.

In order to remain within facility ratings, load would need to be reduced to 45 MW following the loss of the new circuit.[34] The resulting N-1 load security does not satisfy ORTAC requirements. Provisions exist in ORTAC to allow for a customer to agree to higher or lower levels of reliability, provided the bulk system is not negatively impacted. This provides flexibility to customers in the event that ORTAC required enhancements are not cost-effective for them.

Option C2 and Option C3 result in N-1 load security that is greater than Option C1 and satisfies ORTAC.

7.2.3.6 Install New 230 kV Transmission Supply to Longlac and New 115 kV Line from Longlac to Manitouwadge ("Option C2")

This option considers the needs based on load forecast Scenario C.

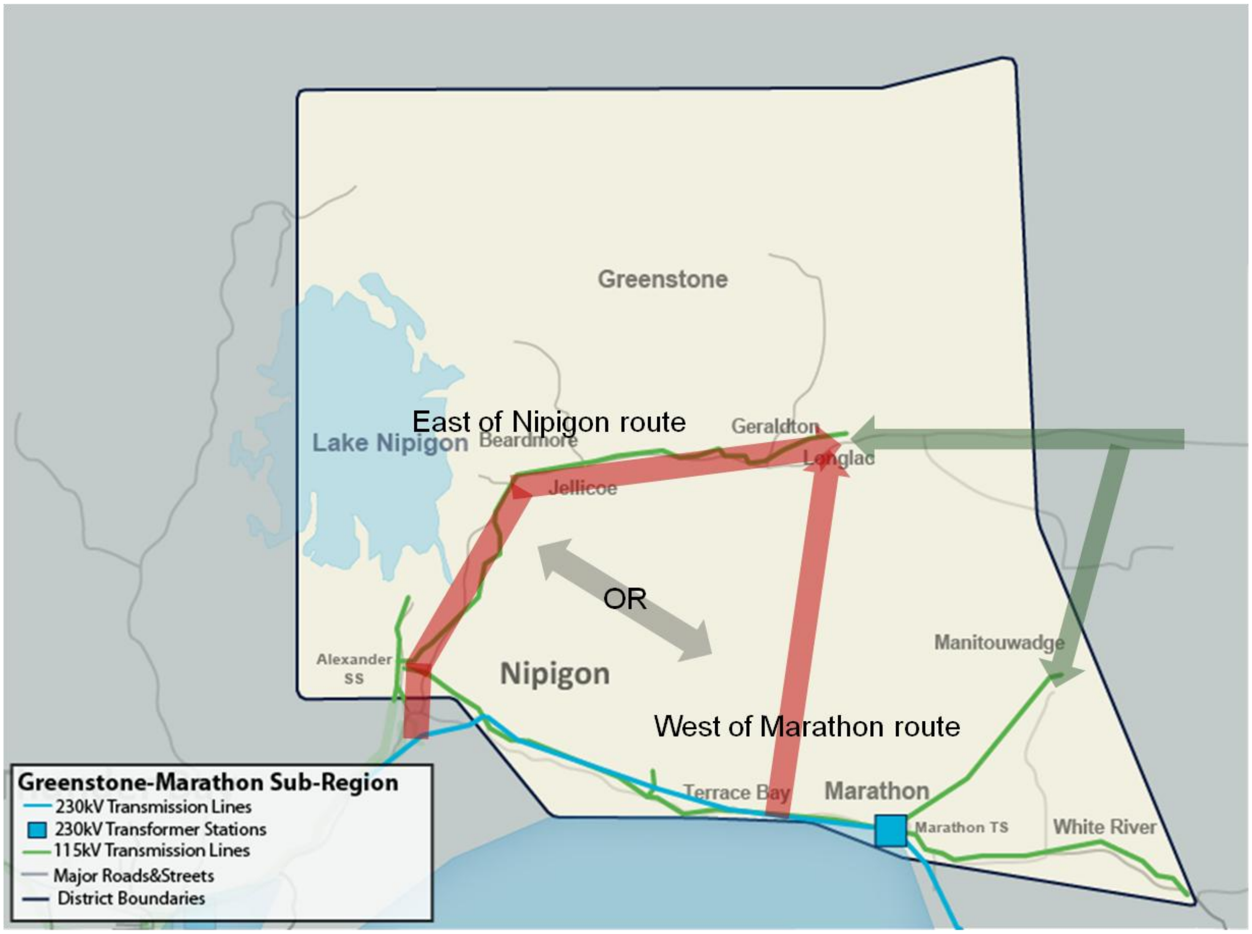
Option C2 builds on Option C1 and consists of installing a new 230 kV supply to the Greenstone area as well as installing reactive compensation (including +40 MVar reactive compensation at the Geraldton mine consistent with Option B1 and Option B3).

In addition, there are two pumping stations that are distant from the existing transmission system and would therefore require a new line if connection is preferred. This option considers installing a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS, as well as the associated protection, voltage control, and switching facilities.

This option also considers the re-termination of the Longlac TS load station on the 230 kV terminal, which would be installed to terminate the 230 kV line option. This is to reduce the overall risk of load loss by distributing load supply stations across different protection zones. The cost of the re-termination has been accounted for by including the cost of new step-down transformers.

[34] To reduce loading to 45 MW, considerations may be built into design configuration, or a Remedial Action Scheme may be installed.

Figure 7-4: Option C2 illustrative[35] route map



Installing switching facilities with appropriate redundancy to separately protect each pumping station can allow all four pumping stations in the area to be supplied from an expanded transmission system. The cost of this protection arrangement has been incorporated by including the cost of new in-line breaker facilities.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of the option are summarized below:

[35] The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

Table 7-7: Summary of Option C2

Option C2	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	270
Net Present Value Cost [M$]	160
Net Present Value Cost per Utilized Capacity [M$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	260
Net Present Value Cost [M$]	160
Net Present Value Cost per Utilized Capacity [M$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Option C2 would satisfy ORTAC and is comparable to the cost of Option C1 based on the degree of planning cost estimates.

7.2.3.7 Install New Generating Plant Near Longlac and New 115 kV Line from Longlac to Manitouwadge ("Option C3")

This option considers the needs based on load forecast Scenario C.

An alternative to Option C2, is to develop a generation-based option to provide a secure supply. Option C3 includes installing a new large grid-connected generation facility near Longlac TS, and building a new 115 kV single-circuit line to connect the two distant pumping stations. The generation plant would provide the required voltage support and short-circuit level to the area. Studies indicate that SVCs would still be required to address credible outage conditions, which have been factored into the costing of this option.

The available capacity of the generating plant would need to be 80 MW at a minimum to provide a secure supply under applicable criteria. For a natural gas-fired generation plant, this would correspond to the summer capability of the plant of 80 MW with at least one unit out of service, a substation with at least two step-up transformers, and a RAS to automatically shed load in the event of additional outage and/or contingency conditions. For the purpose of establishing planning level cost estimates, a 6x18 MW arrangement has been assumed. Other feasible arrangements may be considered.

This option is depicted in Figure 7-5 below.

Figure 7-5: Option C3 illustrative[36] route and generation map

The generating facility would need to be dispatched-on to at least minimum loading whenever the load in the area is expected to exceed 25 MW. The generation facility would also require an output level that ensures the local transmission facilities are able to respect N-1 conditions,

[36] The routes and generation sites are for illustrative purposes only and are not an indication of suggested routing/siting for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

which is limited by the 45 MW thermal capability of A4L. Based on the forecast energy profile of the area, the generation is expected to operate due to local constraints 100% of the time, and would need to produce on average approximately 85 GWh per year in 2019 and 425 GWh per year in 2020 and onward.

Power flow study results are included in Appendix C.

Related economic analysis is included in Appendix D.

Table 7-8: Summary of Option C3

Option C3	
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost [M$]	466
Net Present Value Cost [M$]	340
Net Present Value Cost per Utilized Capacity [M$/MW]	3.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

7.2.3.8 Install Off-Grid Generation ("Option C4")

This option considers the needs based on load forecast Scenario C.

Similar to Option B2, a possible option is to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine and the major pipeline project to supply their own facilities with on-site natural gas generation.

As indicated in Section 7.2.2.3, Option B2 would include provisions for 56 MW of power generation capacity at the Geraldton mine. Additionally this option would include provisions to supply each pumping station with on-site power generation that would not be interconnected with the IESO-controlled grid. For the purpose of establishing cost estimates, 9.5 MW units are assumed.

As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with a broader range of options for comparison. Based on the average annual energy forecast for the Geraldton mine and the pumping stations, the energy production is expected to be approximately 260 GWh per year in 2019, and 555 GWh in 2020 and onward.

Table 7-9: Summary of Option C4

Option C4	
Installed Capacity [MW]	57 (6x9.5) + 76 (8x9.5)
Incremental Utilized Capacity [MW]	89
Undiscounted Capital Cost	403
Net Present Value Cost [M$]	530
Net Present Value Cost per Utilized Capacity [M$/MW]	6.0
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

The result of the analysis is that Options C1 and C2 are more economic than Options C3 and C4. Option C2 is recommended based on economics and reliability. It should also be noted that given the recent timeline change for the Geraldton mine to a single stage in 2019, there may be economic merit in developing a new 230 kV line, consistent with Option C1 and Option C2, in advance of the pipeline project proceeding. This would result in avoiding some or all costs associated with the customer generation at the Geraldton mine described in Option B1 (section 7.2.2.2) for the years that a new 230 kV line may be advanced. Implementation will still require the necessary customer agreements to be in place to ensure the future transmitter can recover prudent costs.

7.3 Near-Term Plan Implementation Considerations

The near-term needs identified in the Greenstone area are driven by a few potential large industrial loads that may develop and choose to connect to the transmission system.

7.3.1 Implementation of Local Transmission Options

Local transmission serves the purpose of reliably supplying specific customer demand. Consistent with the current rules in the TSC, beneficiaries of transmission facilities must pay for the facilities. This is an established requirement and applies to all customers province-wide.

When developing new local transmission, as defined by the OEB, transmitters require financial commitment for capital recovery before incurring any costs associated with developing transmission. This commitment is usually in the form of an agreement between the transmission company and the customer. Customers are typically required to commit to a Connection Cost Recovery Agreement ("CCRA") with the transmitter before the transmitter commits investments for development work. This report therefore does not provide any implementation authority, but simply documents the Working Group's assessment of need and options available for these customers.

Note, on January 11, 2016 the OEB issued a letter stating that it will be holding a Regional Planning and Cost Allocation Review (EB-2016-0003) aimed at ensuring that cost responsibility provisions for load customers under the TSC and DSC are aligned to facilitate regional planning and implementation of regional infrastructure plans. This process may result in changes to the current cost allocation rules contained in the TSC and DSC.

7.3.2 Implementation of Grid-Connected Generation Options

The IESO procures generation resources when needed to supply the Ontario system demand. When doing so, the IESO seeks to minimize marginal energy costs for all Ontario ratepayers. In considering local generation options, the IESO takes into account system needs, feedback from the local community, whether the lowest marginal cost resource can be sited in that local area and whether that option could defer or completely address local needs.

The IESO does not generally procure new generation resources to supply a set of customers in a particular local area if there is no need for system generation, or if that local generation option results in a relatively higher marginal cost compared to other available generation options. If the benefitting customers wish to establish a capacity and energy agreement directly with a local merchant generation company for grid-connected generation, as opposed to other potential supply options (e.g., local transmission or off-grid generation), then they may do so. The local merchant generator would still be subject to all the requirements to connect to the IESO-controlled grid.

The onus is on the customer to engage the electricity service provider that meets its needs. This report therefore does not provide any implementation authority, but simply documents the Working Group's assessment of need and options available for these customers.

7.3.3 Implementation of Off-Grid Generation Options

The IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. Therefore, it is the responsibility of the customer to develop these options.

To inform customers and local communities of the technical viability and expected costs, some off-grid generation options have been developed for the purpose of illustrating a planning-level cost comparison with grid-connected options.

8. Recommended Near-Term Plan

The following elements of the Greenstone-Marathon IRRP are recommended for near-term development to address demand forecast Scenarios A, B, or C. These scenarios are based on the Working Group's understanding of the various long-term opportunities, and on feedback from the community.

Since publishing the Interim IRRP in June, 2015, the Geraldton mine developers notified the IESO of adjustments to their project schedule and scope. Specifically, they now expect to connect in a single stage in 2019, as opposed to two stages in 2018 and 2020 (which was considered in the Interim IRRP[37]). The IESO's recommendations have been revised accordingly.

The IESO recommends a staged approach to accommodate forecast demand from the Geraldton mine and the pumping stations from the gas to oil pipeline conversion project.

Demand Scenario A

The existing system is sufficient to meet the demand requirements presented in Scenario A. To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One's maintenance practices and sustainment plans are expected to be adequate and meet planning criteria.

Demand Scenario B

Demand requirements for Scenario B considers the Geraldton mine proceeding in 2019. The Working Group therefore recommends the following to address Stage 1 requirements for Scenario B:

Recommended Stage 1 – to accommodate the Geraldton mine
• Install +40 MVar of reactive compensation in the form of either a synchronous condenser or STATCOM at the Geraldton mine, to be in-service coincident with the mine • Install a customer-based grid-connected gas-fired generation plant of sufficient redundancy to meet the risk tolerance of the Geraldton mine.

[37] http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/Greenstone-Marathon-Interim-IRRP-Report-only-Final-20150622.pdf

Figure 8-1: Recommended Near-Term Plan: Stage 1

By initially installing reactive compensation, this maximizes the use of the existing system. The associated NPV cost of +40 MVar of compensation is estimated at approximately $5 million.

Incremental electrical demand needs would be met by customer-based generation. The associated NPV cost of this generation is estimated at approximately $60 million.

The recommendation for customer-based grid-connected gas generation is due to the lead-time requirements communicated to the IESO by the Geraldton mine developer of 2019. However, it should be noted that if the in-service date of 2019 is delayed, Option B3 – upgrading of circuit A4L – is the most economic option under Scenario B and should therefore be pursued. Ultimately this decision rests with the Geraldton mine developer.

Demand Scenario C

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service, and consistent with Scenario C, the Working Group recommends:

Recommended Stage 2 – to accommodate the gas to oil pipeline conversion project
• Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the connection of the pumping stations loads • Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to connect the pumping station loads

Figure 8-2: Recommended Near-Term Plan: Stage 2

Under Scenario C, a new 230 kV transmission supply to Longlac is the most economic option. The associated NPV cost of a new 230 kV supply to the area including associated line, transformation, switching, and terminations is estimated at approximately $70 million.

This option maintains long-term flexibility for a North-South corridor to the Ring of Fire. From a long-term perspective, it is advantageous to develop a transmission supply to Longlac, rather than installing large grid-connected generation. This is because in order to develop a new North-South transmission supply to the Ring of Fire, a 230 kV line to Longlac would be required, and therefore developing large generation would represent an added cost. A North-South corridor option to the Ring of Fire is discussed further in section 9.2.

Should the pipeline developer decide to connect all pumping station loads in the Greenstone-Marathon Sub-region to the transmission system with N-1 supply security, it is recommended that a new 115 kV transmission line linking Longlac TS and Manitouwadge TS be developed. The associated NPV cost of the new 115 kV single-circuit line, compensation, in-line breaker stations and switching facilities is estimated at approximately $90 million.

The total NPV cost of Stage 2 is estimated at approximately $160 million.

It should also be noted that given the recent timeline change for the Geraldton mine, now planned as a single stage in 2019, there may be economic merit for the Geraldton mine in the development of a new 230 kV line in advance of the pipeline project proceeding. This would result in avoiding some or all costs associated with the customer generation at the Geraldton mine described in Stage 1 for the years that a new 230 kV line may be advanced. Implementation would still require the necessary customer agreements to be in place to ensure the future transmitter can recover prudent costs.

9. Options for Meeting Medium- and Long-Term Needs

This section describes approaches, alternatives, and recommendations for the medium- and long-term planning periods. Specific options and initiatives are described in detail related to the medium- and long-term as indicated in Section 6.4 and include: additional mining claims in Greenstone, infrastructure to the Ring of Fire, Little Jackfish hydroelectric project, and community energy efficiency initiatives. Recommended actions and implementation considerations for the medium- and long-term plan are discussed.

The specific alternatives considered for the medium and long term depend on the level of growth that materializes in the near term, as well as the extent to which the local electricity system is reinforced in the near term to accommodate that growth. The specific scenarios being considered are described below for the respective medium and long-term initiatives.

9.1 Additional Mining Claims in Greenstone

A number of mining claims exist along the Highway 11 corridor in the Greenstone area. Of particular interest is a potential gold mine near Beardmore that may be operational in the medium term. As indicated in the Beardmore mine developer's preliminary economic assessment results[38], it would be economically advantageous for the Beardmore mine if processing and gold recovery were performed at the Geraldton mine.

Therefore, for planning purposes, it has been assumed that the Beardmore mine is included in Geraldton mine scenarios. The Geraldton mine is considered in all scenarios except Scenario A.

The recommended near-term plan to meet forecast demand outlined in Scenario C consists of Stage 1 and Stage 2. If Stage 1 and Stage 2 are implemented by the respective developers and service providers, then sufficient capacity would be available to accommodate the Beardmore mine. Power flow analysis is included in Appendix F.

If the Geraldton mine and the major gas to oil pipeline conversion project proponents decide to pursue off-grid options, which are not recommended by the Working Group, then the existing system would have sufficient margin to accommodate the Beardmore mine.

The recommended near-term plan to meet forecast demand outlined in Scenario B consists of only Stage 1. If Stage 1 is implemented by the respective developers and service providers, then

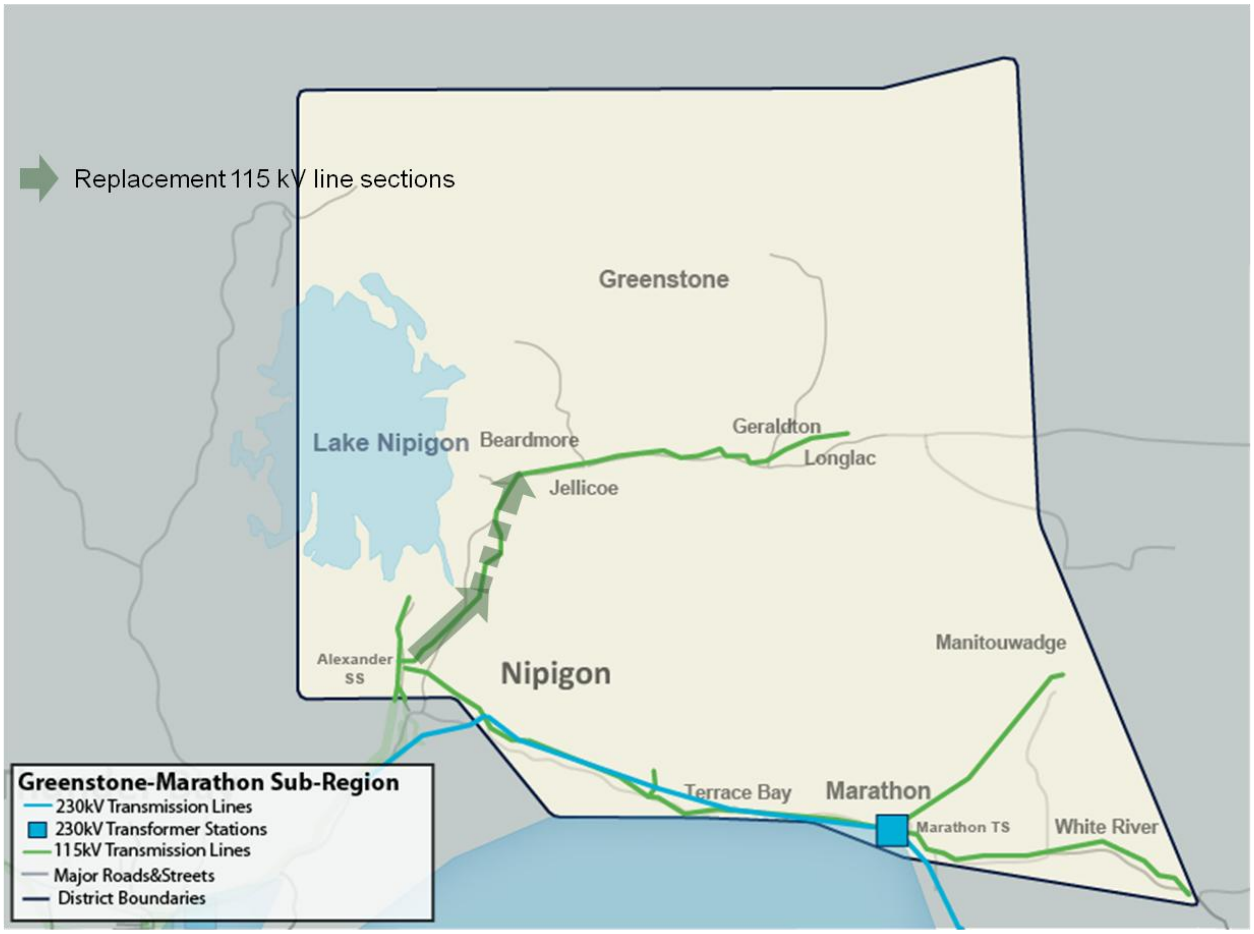
[38] http://www.premiergoldmines.com/i/pdf/2014-01-28_NR.pdf

additional capacity enhancements would be required to accommodate additional customer demand. Power flow analysis is included in Appendix F, which illustrates the need for additional enhancements. Therefore, this analysis of additional mining is focused on Scenario B. As indicated in sections 9.1.1 and 9.1.2, transmission upgrade options and new or expanded local generation options are available. Analysis indicates that the transmission upgrade options available are more economic than generation options to supply the Beardmore mine under Scenario B.

9.1.1 Transmission Upgrade

Incremental capacity to accommodate additional mining development may be in the form of transmission system enhancements to deliver power to the Beardmore mine customer. This would be economically achieved by upgrading or replacing sections of circuit A4L from Alexander SS to the Beardmore mine. If this option is combined with replacing A4L from Nipigon Junction to Longlac TS in Option B3 (i.e. replacement of all of A4L), then the Greenstone sub-system would be capable of supporting up to approximately 120 MW, fully compensated.

Figure 9-1: Transmission Upgrade Option for Additional Mining in Greenstone



It has been estimated that the NPV cost associated with this option is $10-15 M.[39]

9.1.2 Local Generation

Incremental capacity to accommodate additional mining development may be in the form of new or expanded local generation resources. Two possible generation options to provide capacity to supply the demand from the Beardmore mine have been considered: a new 2x10 MW gas generating facility near Beardmore, or 1x10 MW expansion of a gas generating facility in Geraldton (considered if 2x10 MW gas generating plant is implemented for Stage 1).

---

[39] The cost associated with this option depends on the decision by the customer. If this option is combined with replacing A4L from Nipigon Junction to Longlac TS as in Option B3, then only the sections from Alexander SS to Nipigon Junction of 35 km need to be upgraded ($8 M NPV), as opposed to from Alexander SS to Beardmore TS of 65 km ($15 M NPV).

Figure 9-2: Local Generation Option for Additional Mining in Greenstone

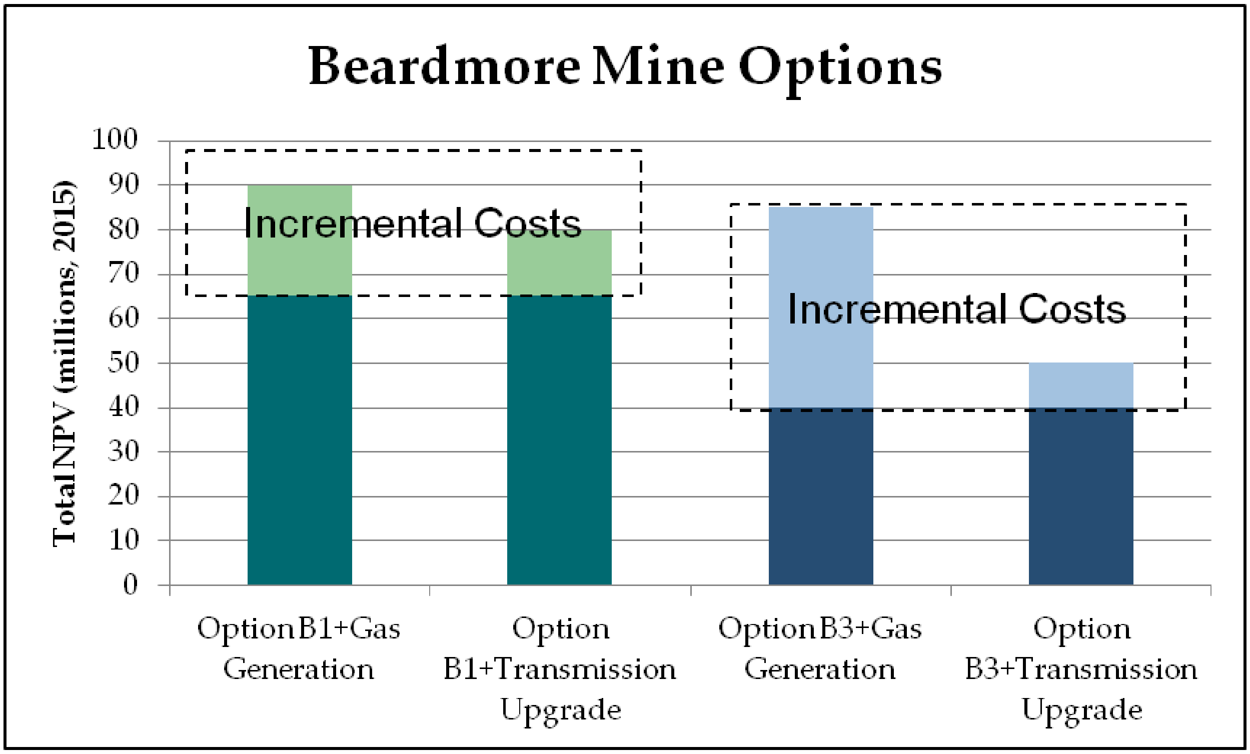
It has been estimated that the NPV cost associated with this option is $25-45 M.[40]

9.1.3 Comparison of Options

As indicated, depending on the solution selected for supplying the Geraldton mine, different incremental costs may result. This is illustrated in Figure 9-3 below.

[40] The cost associated with this option depends on the decision by the customer. If this option is combined with a 2x10 MW gas generating plant at the Geraldton mine as in Option B1, the facility could be expanded by one gas genset ($25 M NPV), as opposed to the installation of a separate facility with at least two gas gensets ($45 M NPV).

Figure 9-3: Comparison of Options for Additional Mining in Greenstone



9.2 Infrastructure Corridor to the Ring of Fire

The 2015 North of Dryden IRRP included an analysis that considered the supply to the Ring of Fire. This analysis included a planning-level cost-comparison between the following options: mine self-generation and separately connect remote communities, an East-West transmission corridor from Pickle Lake, and a North-South transmission corridor from either east of Nipigon or Marathon.

The analysis contained in this report expands the work completed as part of the 2015 North of Dryden IRRP to consider potential cost savings by the potential customers in the Ring of Fire area and Greenstone-Marathon Sub-region. This analysis is based on typical cost allocation principles consistent with the TSC, namely that capital contribution is generally determined based on the relative proportions of non-coincident peak demand of individual customers to that of other customers benefitting from the facility.[41]

[41] Ultimately cost allocation is determined by the OEB. This report simply presents a reasonable assumption to illustrate the potential for cost savings and communicate that it is advantageous for multiple customers to share the utilization of new facilities.

The greatest potential cost savings to benefitting customers results when the new infrastructure is highly utilized by a large number of customers. This is consistent with the following scenario illustrated in Table 9-1.

Table 9-1: Scenario Assumed for Ring of Fire Cost Sharing Evaluation

Timing	New Customers	Infrastructure
Near Term (0-5 years)	Geraldton mine, gas to oil pipeline conversion project	Recommended Stage 1 and Stage 2
Medium and Long Term (5-20 years)	Beardmore mine, Ring of Fire mines and remote communities	North-South transmission line to Ring of Fire

Table 9-1 describes the forecast Scenario D presented in section 5.3.1. It is important to note that Recommended Stage 2 consists of a new 230 kV transmission line from the East-West Tie to Longlac TS. This facility could also serve as the southern sections of a new North-South transmission line to the Ring of Fire, if that option is pursued. Therefore, it would be reasonable to suggest that all new customers under this scenario would contribute to the 230 kV transmission line from the East-West Tie to Longlac TS (southern section), as per recommended Stage 2. This greater utilization and cost-sharing could reduce costs for all new customers in the area.

The remaining northern sections of a new North-South transmission line from Longlac TS to the Ring of Fire would only serve customers in the Ring of Fire area, and no additional cost-sharing is expected.

Table 9-2: Relative Utilization of a 230 kV Line to Supply Greenstone and the Ring of Fire

Customer Group	New Customer Peak Demand	230 kV Line – Southern Section Utilization	230 kV Line – Northern Section Utilization
All	170 MW	170 MW	75 MW
Greenstone sub-system	95 MW	56%	0%
Ring of Fire sub-system	75 MW	44%	100%

Table 9-2 indicates that a significant potential for cost-sharing could result for all new customers from shared utilization of a 230 kV transmission line being recommended as part of Stage 2 (referred to as 230 kV line – southern section in Table 9-2).

9.3 Little Jackfish Hydroelectric Project

Similar to the potential cost savings outlined in the previous section related to the Ring of Fire, recommended Stage 2 could also result in some connection cost savings to the Little Jackfish hydroelectric project. Although analysis of individual generation projects is not within the typical scope of IRRPs, following discussion with the proponents it was agreed that assessing the potential connection cost savings would be valuable information.

The 230 kV transmission line recommended as part of Stage 2 could utilize the East of Nipigon route option, as described in sections 7.2.3.5 and 7.2.3.6. Most notably, the southern routing of this option from the East-West Tie to near Beardmore is largely consistent with the southern routing of the 230 kV connection line routing that OPG considered as part of the EA for the project. This section of the East of Nipigon 230 kV line route option as part of recommended Stage 2 would result in a reduction in the length of the connection line for the Little Jackfish project by approximately one half. During earlier economic evaluations of Little Jackfish, it was believed that the cost of the connection line significantly impacted its viability. The IESO has included updated economic analysis based on the possible development of a new East of Nipigon 230 kV line.

This results in a reduction in the connection line cost by about half and a reduction in the Levelized Unit Energy Cost ("LUEC") from $150/MWh to $144/MWh, or about a four percent reduction. With the reduced LUEC, the Little Jackfish project is $50- $80/MWh[42] more than the cost of system supply. Additional details are included in Appendix H.

Therefore, further analysis has found that the potential reduction in connection cost for the Little Jackfish project does not result in a significant reduction in the overall project LUEC. The IESO is cognizant of the potential for anticipated carbon policies in the province of Ontario to positively impact the business case for new hydroelectric generation development. It should be noted that the IESO is not currently active in procuring provincial generation resources for capacity or energy needs. As capacity needs are forecast to arise in the mid-2020s, and as carbon policy is further clarified, alternatives will be evaluated and compared at the appropriate time.

[42] Depending on cost of carbon scenarios

9.4 Community Energy Efficiency Activities

A large number of communities in the Greenstone-Marathon Sub-region do not have access to natural gas delivery infrastructure, and rely on electricity as their primary source of heating. During early engagement activities, the Town of Marathon identified their interest in developing cogeneration to supply some of their community facilities which require a significant amount of heat load thereby creating budgetary constraints for the community.

The electricity infrastructure serving the North Shore sub-system, and Marathon Area sub-system has been determined to be sufficient. The analysis of individual proposals in the absence of power system need is not typically within the scope of an IRRP. However, from discussions with the local community and as part of the IESO's authority to coordinate provincial and regional conservation programs, it was agreed that a high-level analysis to help demonstrate the feasibility of cogeneration opportunities would be valuable within the context of this IRRP.

An analysis is described below to demonstrate the feasibility for cogeneration in the Town of Marathon. A similar methodology may be applied by other communities with no access to pipeline natural gas infrastructure. Details of the step-by-step methodology and analysis are included in Appendix I.

It was determined from the publicly available data reported for the Broader Public Sector regulation for public sector facilities in Marathon that the three largest municipal electricity consumers in Marathon are the hospital, arena/theatre, and high school. These total nearly 50% of the municipal electrical energy use. These facilities and others are also located within a 150 m radius, making logical candidates for a shared cogeneration solution.

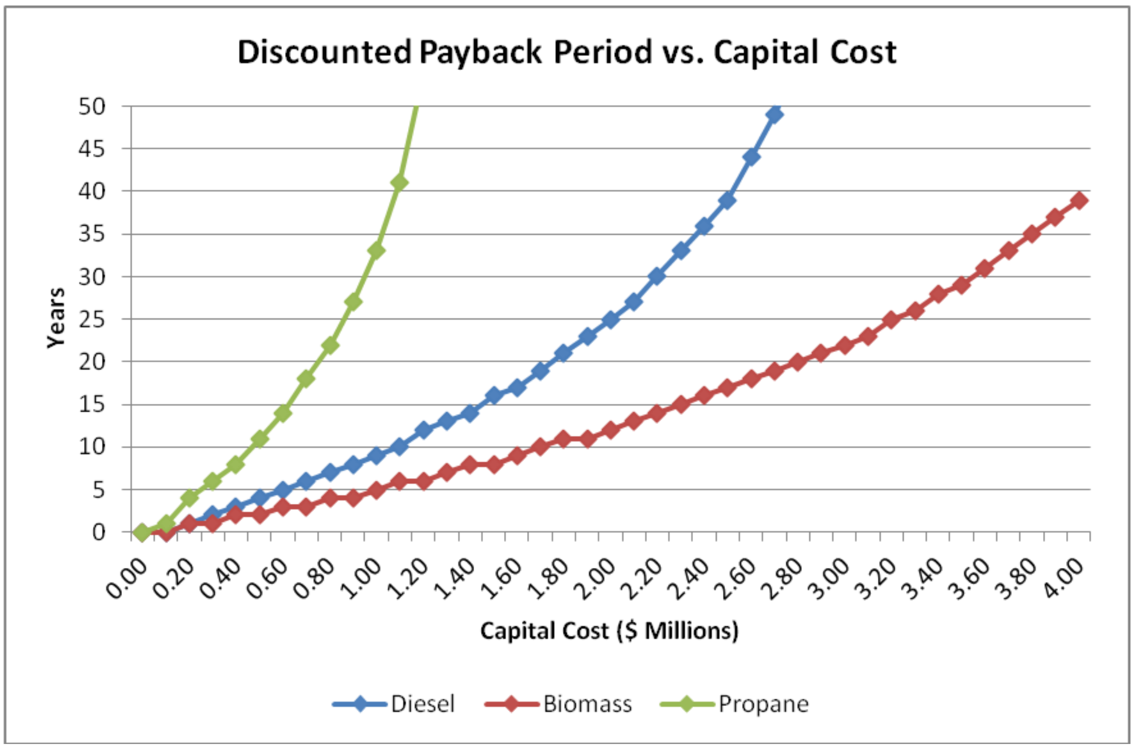
This analysis did not consider the sale of cogeneration services to facilities not reported by the Broader Public Sector regulation (e.g., private businesses), which may help to improve the business case.

Depending on the capital cost of the facility and the type of fuel being considered, a range of payback scenarios may result which are illustrated in Figure 9-4.

It is cautioned that this analysis has been done at a planning-level and investments should not be made solely based on this high level analysis. Furthermore, a number of development projects, regulatory proceedings, and legislative processes are underway that may impact this analysis. This includes the possible development of Liquefied Natural Gas infrastructure and delivery, the possible expansion of natural gas service to Ontario communities that are currently not served, the impact of cap and trade regulation, and the evolution of carbon policy.

Therefore, the Town of Marathon may find value in undertaking a detailed study of cogeneration solutions in the community, considering public and private customers, and the associated risks. Noteworthy, is that the IESO has funded engineering studies to support cogeneration initiatives through the "Save on Energy" program which are accessible through its website.[43]

Figure 9-4: Marathon Cogeneration Discounted Payback Period Analysis



9.5 Actions to Maintain Flexibility for the Medium and Long Term

The following actions are proposed to maintain flexibility for accommodating additional growth, within the study area for the medium and long term:

- Mine developers in Greenstone retain the option of upgrading circuit A4L from Alexander SS to Beardmore TS as an economic alternative for supplying the Beardmore mine and additional mining in Greenstone. Mine developers should engage Hydro One,

[43] https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades/Engineering-Studies.aspx

the transmission owner of circuit A4L, recognizing that a lead-time of approximately five years is required if they wish to pursue this option.

- Those investigating a multi-use infrastructure corridor to the Ring of Fire consider the need for a new transmission line, as outlined in this plan. The IESO is available to provide planning advice associated with a new transmission line on this corridor. The IESO will also update electricity plans associated with this corridor as additional information becomes available.
- The Town of Marathon conduct a detailed study of community energy options related to cogeneration. The IESO can support studies within the context of electricity planning, demand, and reliability, as well as IESO-coordinated conservation programs and funding.

The IESO does not have authority to direct or implement these actions on behalf of the parties indicated. These actions are documented to provide customers, communities, and stakeholders with the IESO's independent assessment of the technically feasible and least societal cost options for meeting the various needs in the area.

10. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the Greenstone-Marathon IRRP.

A phased community engagement approach was undertaken for the Greenstone-Marathon IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 10-1: Summary of the Greenstone-Marathon Community Engagement Process

Creating Transparency: ***Creation of Greentone-Marathon IRRP Information Resources***	• Dedicated Greenstone-Marathon IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One website • Self-subscription service established for the Northwest Ontario planning region for subscribers to receive regional planning updates • Status: complete
Engaging Early and Often: ***Municipal & First Nation Outreach***	• Early engagement on regional planning and the draft Northwest Ontario Scoping Assessment Report (October - December 2014) • Two group meetings held with municipalities from across the planning region held in Greenstone and Marathon (April 2015) • Meetings held with First Nation communities throughout the planning region (May 2015 -February 2016) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: ***Broader Community Outreach***	• Greenstone-Marathon Local Advisory Committees (LAC) formed in spring 2015; dedicated Greenstone-Marathon engagement page added to IESO website • Three LAC meetings held to discuss the Interim IRRP released June 2015, further development of the near-term options and priorities for the long-term, as well as a review of draft IRRP • LAC meetings are open to the public and broadcast via live webinar; materials are posted to the engagement webpage • Status: begun in spring 2015; on-going

10.1 Creating Transparency

To start the dialogue on the Greenstone-Marathon IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the Greenstone-Marathon Sub-region, the IRRP terms of reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader Northwest Ontario planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

10.2 Engage Early and Often

Early communication and engagement activities for the Greenstone-Marathon IRRP were initiated in October 2014 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across Northwest Ontario. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the Northwest Ontario Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation and Métis community members, federal and provincial representatives, electricity customers, CVNW, transmission and generation project developers, and others.

10.2.1 Northwest Ontario Scoping Assessment Outcome Report

The draft Northwest Ontario Scoping Report was posted to the IESO website in December 2014 for comment. Feedback on the draft report was received from the Municipality of Greenstone indicating the need for an accelerated timeline for the Greenstone area plan. In response, the Working Group added an interim document on the near-term elements to the Terms of Reference for the Greenstone-Marathon IRRP. The Interim Greenstone-Marathon IRRP was released June 22, 2015 in response to this request.

10.2.2 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In April 2015, the Working Group held group municipal meetings in Marathon and Greenstone to discuss the findings and options developed to date. Attendees were generally pleased with the progress of the plan, and indicated that planning needs to be cognizant of the implementation risks involved and the need to ensure electricity prices do not increase unnecessarily.

10.2.3 First Nation and Métis Community Meetings

On May 11, 2015 the IESO met with the Board members of WZI and Chiefs Pelletier, Gustafson and Nelson of Red Rock Indian Band, Whitesand First Nation and AZA, respectively. WZI is an economic development corporation established by five First Nations: Red Rock Indian Band, BNA, BZA, AZA, and Whitesand First Nation. The feedback received from WZI focused on the desire for infrastructure to be planned so that environmental disturbance is minimized. WZI requested that, when possible, existing infrastructure corridors are optimally utilized before developing a new corridor resulting in a new disturbance.

On May 11, 2015 the IESO met with Chief Duncan Michano of Ojibways of Pic River First Nation. A follow-up discussion with additional community members may be required. The IESO remains open to additional meetings to support further engagement of the IRRP.

On May 12, 2015 the IESO met with a Councilor and staff of Pic Mobert First Nation. The feedback from this meeting was that decisions regarding electricity should not result in unnecessary price increases and the need for greater community-level economic development opportunities for First Nation communities in general.

On July 7, 2015 the IESO met with the Highway 11 First Nations Energy Working Group, which consisted of representatives from the following First Nation communities: Aroland, Constance Lake, Long Lake #58 and Ginoogaming. The feedback shared was that there is a preference by the Highway 11 First Nations Energy Working Group that grid-connected solutions be pursued by the customers. The Highway 11 First Nations Energy Working Group also expressed an interest in developing some solutions consistent with the IRRP recommendations. Finally, the Group emphasized their support for long-term supply options to the Ring of Fire and the need to coordinate planning efforts.

On November 11, 2015 the IESO met with Chief Richard Allen and representatives from Constance Lake First Nation, as well as representatives of Long Lake #58 First Nation. The feedback shared by some representatives was that they would like to see a connection from Longlac TS (Greenstone) to Hearst TS (interconnected to the Northeast power system). The IESO responded that this would not be technically feasible because the respective 115 kV systems are equipped with relatively small conductors and by effectively shorting the connection between the Northwest and Northeast along a new 115 kV link would result in overloading of that connection and possible stability concerns. The IESO indicated that reinforcement of the connection between the Northwest and Northeast systems is being considered through the planning of the expanded East-West Tie. There was also discussion around the possible option of connecting the remote Matawa communities via a north-south corridor option from near Geraldton to the Ring of Fire via a logging road that passes by

Eabametoong First Nation. The IESO will investigate this option as part of its continued support for the economic connection plan for remote First Nation communities.

On February 3, 2016 the IESO met with representatives of Long Lake #58 First Nation. Updates were shared by the IESO and Long Lake #58 regarding the progress made, and confirming the IESO's opinion regarding options and recommendations.

The IESO invited all other local First Nations communities and Métis councils to similar meetings and remains open to further engagement with those communities on the plan.

The IESO has been made aware of a Matawa Chief's resolution and a WZI Board resolution. Both these resolutions indicate support for grid-connected electric supply solutions for the region, and opposition to off-grid solutions. The WZI Board resolution specifically supports the new 230 kV East of Nipigon line option identified in the IRRP. The IESO will continue to work with the local First Nations and Métis in future planning initiatives.

10.3 Bringing Communities to the Table

To continue the dialogue on regional planning, two Local Advisory Committees - a general LAC and a First Nations LAC - were established for the Greenstone-Marathon regional planning area in spring 2015. The role of LACs is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. General LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. First Nations LACs are comprised of representatives from the First Nation communities in the planning area. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's Greenstone-Marathon engagement webpage.[44] The Greenstone-Marathon general LAC meetings are also broadcast as live webinars to allow participation from across the planning region.

Development of the Greenstone-Marathon general LAC was completed through a request for nominations process promoted by the following activities: advertisements in five local newspapers across the planning area and one Thunder Bay newspaper; digital (website) advertising in eight communities throughout the planning area; emails sent to municipal representatives across the region; and an e-blast sent to the IESO's Northwest Ontario

[44] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

subscribers list. Each Métis council in the Greenstone-Marathon area appointed a member of their community to the General LAC. The development of the Greenstone-Marathon First Nation LAC was established through a letter to the leadership of each First Nation in the Greenstone-Marathon area inviting them to appoint a representative to the First Nations LAC. The First Nations LAC then appointed members to the general LAC.

On June 29, 2015, following the release of the Interim Greenstone-Marathon IRRP, the IESO held the first LAC meetings in Nipigon. The focus of these meetings was to introduce the regional planning process to the newly formed LACs and review the newly released Interim IRRP. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.[45]

On November 24-25, 2015 the IESO held the second LAC meetings at the Red Rock Indian Band Lake Helen Reserve. The focus of these meetings was to discuss and receive feedback on the development of the medium and long-term options for the IRRP. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.

On May 11-12, 2016 the IESO held the third LAC meetings at the Red Rock Indian Band Lake Helen Reserve. The focus of these meetings was to discuss and receive feedback on the full set of recommendations to be included in the IRRP prior to finalizing the plan. The LAC members decided to produce a report outlining the local socio-economic impacts of the electricity solutions being explored in this IRRP and compliment the Working Group's technical and economic analyses. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.

Copies of the meeting summaries from the Greenstone-Marathon general LAC meetings can be found in Appendix K.

Moving forward, the Working Group will present the final IRRP to both of the Greenstone-Marathon LACs and discuss with members how they would like to continue the dialogue on regional planning in the area following the completion of the plan.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website. Additional information on outreach activities for the Greenstone-

---

[45] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

Marathon IRRP can be found on the webpage and updates will continue to be sent to all Northwest Ontario email subscribers.

10.4 Additional Meetings and Presentations

The IESO recognizes CVNW's unique mandate that includes investigating and making recommendations to NOMA on issues related to energy in the Northwest Ontario Region. The IESO continues to meet regularly with CVNW to discuss the status of electricity planning for northwestern Ontario.

The IESO also presents regularly at the NOMA Spring Annual General Meeting and Fall Regional Conference, the Association of Municipalities of Ontario ("AMO") conference, as well as the Ontario Mining Association ("OMA") Conference, among others. These presentations have included high-level status updates on the development of the Greenstone-Marathon IRRP, along with other electricity topics.

11. Conclusion

This report documents an IRRP that has been carried out for Greenstone-Marathon, a sub-region of the OEB's Northwest Ontario planning region. The IRRP identifies electricity needs in the Greenstone-Marathon Sub-region over the 20-year period from 2015-2035, recommends a plan to address near-term needs, and identifies actions to retain economic alternatives for the medium and long term.

Implementation

Implementation of the near- and medium-term plan requires action from the industrial developers. This action consists of customers establishing a commercial agreement for the facilities required to provide the required electrical service. These agreements may include the following elements.

Stage	Recommended Near-Term Facilities	Implementation Agreement
Stage 1	Synchronous condenser or STATCOM	Relevant agreements such as, but not limited to, Reactive Power Service and/or Capacity Agreement
	New 2x10 MW gas engine generating facility	Relevant agreements such as, but not limited to, Capacity and Energy Agreement
Stage 2	New 230 kV line, 115 kV line, 230/115 kV autotransformer station, switching, and voltage control devices	Detailed planning as appropriate, Connection Application, Connection Assessment and Approvals, Cost Recovery, and other agreements consistent with TSC
Medium-Term Actions		**Implementation Agreement**
Mine developers in Greenstone should retain the option of replacing sections of A4L[46]		Detailed planning as appropriate, Connection Application, Connection Assessment and Approvals, Cost Recovery, and other agreements consistent with TSC

[46] This facility is not required if Stage 2 is developed.

The IESO will provide support to individual customers and proponents within the context of the Working Group's recommendations as documented in the IRRP. The IESO does not have the mandate to procure on behalf of individual customers.

The IESO will continue to participate in planning activities related to long-term initiatives such as supply to the Ring of Fire, and community energy efficiency projects.

First Nations and Métis, Community, and Stakeholder Engagement

This report documents the engagement that has been conducted to support the development of the Greenstone-Marathon IRRP.

The IESO will continue to engage First Nation communities, Métis community councils, as well as municipalities and other major interest groups through the LAC and individual meetings as requested.

The LAC meetings and engagements with First Nation communities, municipalities, industry, and stakeholders have provided valuable feedback on the 2015 Interim Plan and input in the development of this IRRP. The Greenstone-Marathon LACs have undertaken a complimentary socio-economic document. The IESO looks forward to subsequent meetings with the two Greenstone-Marathon LACs and continued engagements with communities and stakeholder in the area to discuss the recommendations included within this IRRP, and the future implementation of this plan.

WEST OF THUNDER BAY SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | July 27, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

West of Thunder Bay

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board electricity licence, EI-2013-0066.

This IRRP was prepared on behalf of the West of Thunder Bay Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Fort Frances Power Corporation
- Atikokan Hydro Inc.
- Kenora Hydro Electric Corporation Ltd.
- Sioux Lookout Hydro Inc.

The Working Group assessed the reliability of electricity supply to customers in the West of Thunder Bay Sub-region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the West of Thunder Bay Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals. Where growth in the sub-region is directly related to potential large industrial developments, the onus lies with those developers to initiate the implementation of the plan.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Atikokan Hydro	Atikokan Hydro Inc.
CDM or Conservation	Conservation and Demand Management
CEP	Community Energy Plan(s)
CFF	Conservation First Framework
CHP	Combined Heat and Power
C&S	Codes and Standards
DR	Demand Response
DG	Distributed Generation
EA	Environmental Assessment
EE	Energy Efficiency
Fort Frances Power	Fort Frances Power Corporation
GHG	Greenhouse Gas
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
Kenora Hydro	Kenora Hydro Electric Corporation Ltd.
kV	Kilovolt
kW	Kilowatt
LAC or Committee	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	Long-Term Energy Plan
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board

OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Sioux Lookout Hydro	Sioux Lookout Hydro Inc.
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt Hours
Working Group	Technical Working Group for the West of Thunder Bay IRRP
QUEST	Quality Urban Energy Systems of Tomorrow

1. Introduction

This Integrated Regional Resource Plan ("IRRP") for the West of Thunder Bay Sub-region addresses the electricity needs for the sub-region over the next 20 years ("study period") from 2015-2034. The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group (the "Working Group") for the West of Thunder Bay Sub-region composed of the IESO, Hydro One Networks Inc. (Hydro One Distribution and Hydro One Transmission[1]), Atikokan Hydro Inc. ("Atikokan Hydro"), Kenora Hydro Electric Corporation Ltd. ("Kenora Hydro"), Fort Frances Power Corporation ("Fort Frances Power"), and Sioux Lookout Hydro Inc. ("Sioux Lookout Hydro").

The area covered by the West of Thunder Bay IRRP is a sub-region of the Northwest Ontario Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process. This sub-region is defined as the area bordered to the south and west by the United States and Manitoba borders respectively, and extending north to include the City of Kenora, the City of Dryden and the Municipality of Sioux Lookout, and east as far as (but not including) the City of Thunder Bay, and does not include the area North of Dryden. This sub-region is characterized by:

- **Diverse communities**: In addition to the "unorganized areas"[2] in the Kenora and Rainy River Districts, there are 26 First Nation communities and 16 municipalities included in this sub-region, all of which are listed in Section 4.1. Each community has local priorities and distinct electricity needs. Many of these communities are engaging in community energy planning activities.

- **Mining, pulp and paper and other industrial developments:** Industrial customers are major electricity consumers in this sub-region and are sensitive to varying economic conditions, such as commodity price and changes in economic growth. Often these factors can lead to material changes in their annual electricity demand and uncertainty in the sub-region's electricity demand forecast.

- **Large geographical area:** Long and expansive transmission and distribution infrastructure is required to bring electricity supply to the various communities and customers across this sub-region. The geography and sparsely populated areas make it challenging and costly to develop and maintain infrastructure.

---

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

[2] Unorganized areas are parts of the province where there is no municipal level of government. Services in these unorganized districts are typically administered by local service boards.

- **Complex electricity infrastructure network:** The sub-region's electricity system is comprised of a 230 kilovolt ("kV") bulk system, 115 kV regional system, local distribution networks and variable, local generation resources. The system is interconnected with Manitoba and Minnesota. This system not only supplies the communities and customers in the West of Thunder Bay Sub-region, it also provides an important source of supply to the North of Dryden Sub-region. The interactions between these interconnections and the bulk, regional and distribution network will have an impact on the reliability of supply for the West of Thunder Bay Sub-region.

This IRRP took into consideration the characteristics discussed above. Given the uncertainties associated with the timing and magnitude of potential industrial developments, the Working Group identified regional electricity needs and solutions under three demand forecast scenarios (Reference, High and Low) as described in Section 5.3.4., and developed a flexible, comprehensive, integrated plan to accommodate these potential scenarios. The challenges, costs and lead times required to develop and maintain infrastructure in this sub-region were also taken into consideration in the development of the plan.

The primary focus of this IRRP is to identify and address electricity reliability needs on the 115 kV regional transmission systems in the sub-region. Given the complex nature of the electricity system and the diverse needs in this sub-region, bulk, distribution and community energy planning activities are also underway. To facilitate coordination of the various electricity planning activities in this sub-region, this IRRP also documents and considers bulk and distribution system needs and community planning activities. Section 3 describes the types of electricity planning in Ontario and the linkages between them, as well as, how important it is to coordinate regional planning with bulk and distribution system and community energy planning.

This IRRP fulfills the requirements for the sub-region as required by the IESO's OEB electricity licence. IRRPs are required to be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. This IRRP will be revisited in 2021, or earlier if significant changes occur relative to the current forecast.

This IRRP report is organized as follows:

- A summary of the recommended plan for the West of Thunder Bay Sub-region is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;

- The context for electricity planning in the West of Thunder Bay and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in West of Thunder Bay are presented in Section 6;
- Options to address regional and local needs are addressed in Section 7;
- Recommended actions are set out in Section 8;
- A summary of community, indigenous and stakeholder engagement to date is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The West of Thunder Bay IRRP addresses the sub-region's electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP was developed in consideration of a number of factors, including reliability, cost, technical feasibility and also the diverse needs and unique characteristics of the sub-region. Given the uncertainty associated with the demand forecast, the Working Group identified regional electricity needs and solutions under various demand scenarios and developed a flexible, comprehensive, integrated plan for these varying conditions.

In addition to regional planning, bulk, distribution and community energy planning activities are also underway in the sub-region. While these activities are beyond the scope of the regional planning process, they were identified and taken in consideration in the development of this IRRP.

The needs and recommended actions are summarized below.

The 20-Year Plan (2015-2034)

Aside from the potential need for additional supply on the 230 kV bulk transmission system, the Working Group did not identify any major regional 115 kV supply and reliability needs in the West of Thunder Bay Sub-region under Low and Reference scenarios. Under the High scenario, there is the potential need for an additional 50 MW of supply on the Dryden 115 kV sub-system.

Given the uncertainty with the location, timing and magnitude of demand growth, early development work for major infrastructure projects is not required at this time. Instead, the Working Group has sought to lay the ground work for the next planning cycle by exploring potential options for the Dryden 115 kV sub-system and monitoring demand growth closely to determine if and when an investment decision on the Dryden 115 kV sub-system would be required. End-of-life replacements/sustainment activities and transformer station capacity needs were also identified in this area, but these are not expected to have regional implications. Options to address the 230 kV bulk transmission system needs are being considered as part of the bulk system planning process led by the IESO.

In this sub-region, many communities and customers are supplied by long transmission and distribution networks and rely on a single supply source. They are concerned about service reliability and performance. The transmission and distribution service reliability performances of the West of Thunder Bay Sub-region are within the provincial service reliability and performance standards. Communities and customers may consider working with Hydro One Transmission and local distribution companies ("LDCs") to explore opportunities to further improve transmission and distribution service reliability and performance. Cost-benefit and cost-responsibility for investments will need to be considered.

A number of communities in this sub-region are also in the process of developing community-energy plans ("CEPs"). While regional planning focuses on maintaining reliability of electricity supply, CEPs takes into consideration other energy uses, such as transportation, natural gas and electricity. CEPs also have different goals, including net zero energy, electrification, and reducing emissions. Since CEP and regional planning processes have different objectives and scope, greater coordination between community energy planning and regional planning processes is required to help provincial system and municipal planners develop a common understanding of growth and local developments and to identify opportunities to develop community-based energy solutions.

Recommended Actions

1. Monitor electricity demand growth closely to determine if and when an investment decision for the Dryden 115 kV sub-system is required

On an annual basis, the Working Group will review electricity demand growth in the West of Thunder Bay and the North of Dryden Sub-regions with the members of the Local Advisory Committees ("LACs"). This information will be used to determine if and when an investment decision for the Dryden 115 kV sub-system is required.

2. Ensure communities are informed of bulk and distribution planning activities in the West of Thunder Bay Sub-region

The Working Group will provide a status update at LAC meetings on bulk and distribution planning activities and associated projects.

3. Explore opportunities to further improve service reliability and power quality in consideration of cost-benefit and cost allocations

Communities and customers who are looking to further improve service reliability and performance may work with Hydro One Transmission and LDCs to develop transmission, distribution and community energy solutions. The cost and benefit of improvements and how costs would be allocated will need to be considered.

4. Coordinate regional and community energy planning activities

Greater coordination between community energy planning and regional planning processes can inform dialogue on energy issues and can assist provincial system planners and local communities in developing a common understanding of the growth and local developments and in identifying opportunities to develop community-based energy solutions. Going forward, LAC meetings can be used as an opportunity to facilitate discussions on: (1) status of local growth and developments, (2) local planning priorities, (3) energy planning activities, (4) impact of supply interruptions, and (5) the potential, feasibility and challenges of implementing community-based energy solutions. Due to the unique energy planning challenges in northwestern Ontario, it would be helpful to identify initiatives to facilitate knowledge sharing and coordinate community energy planning activities in northern Ontario (e.g., a community energy planning webinar or workshop for communities in northern Ontario).

3. Development of the Integrated Regional Resource Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[3] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and

---

[3] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a more limited "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that a RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

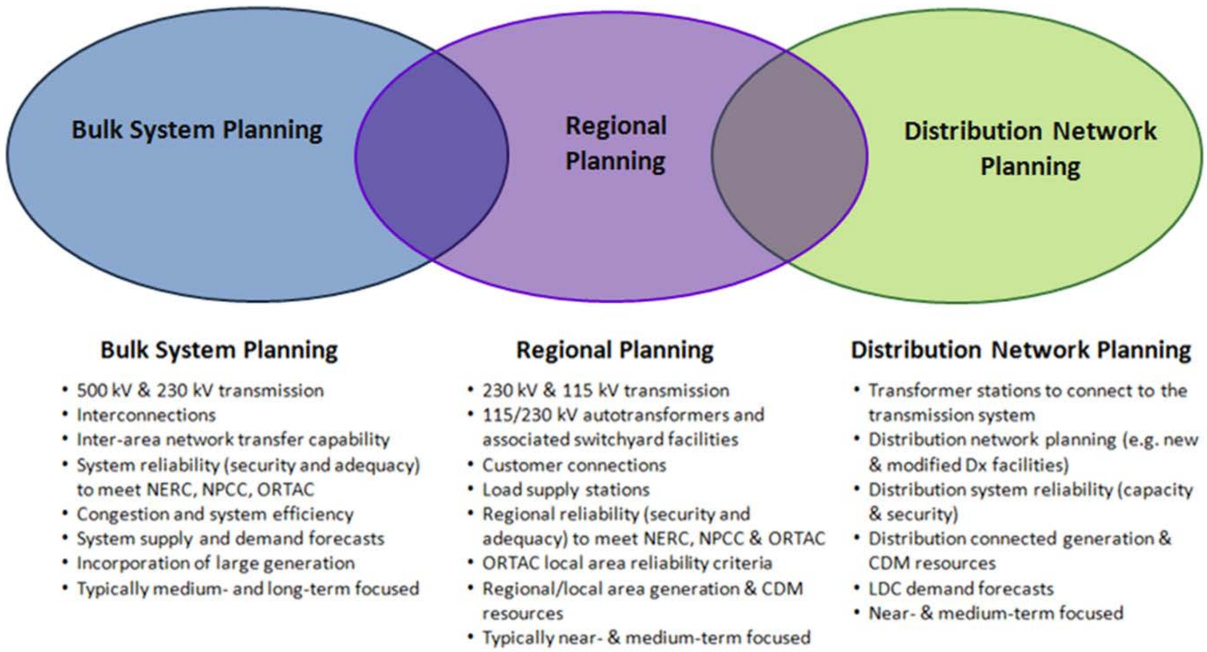
The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nations communities and Métis community councils for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Integrated Regional Resource Planning

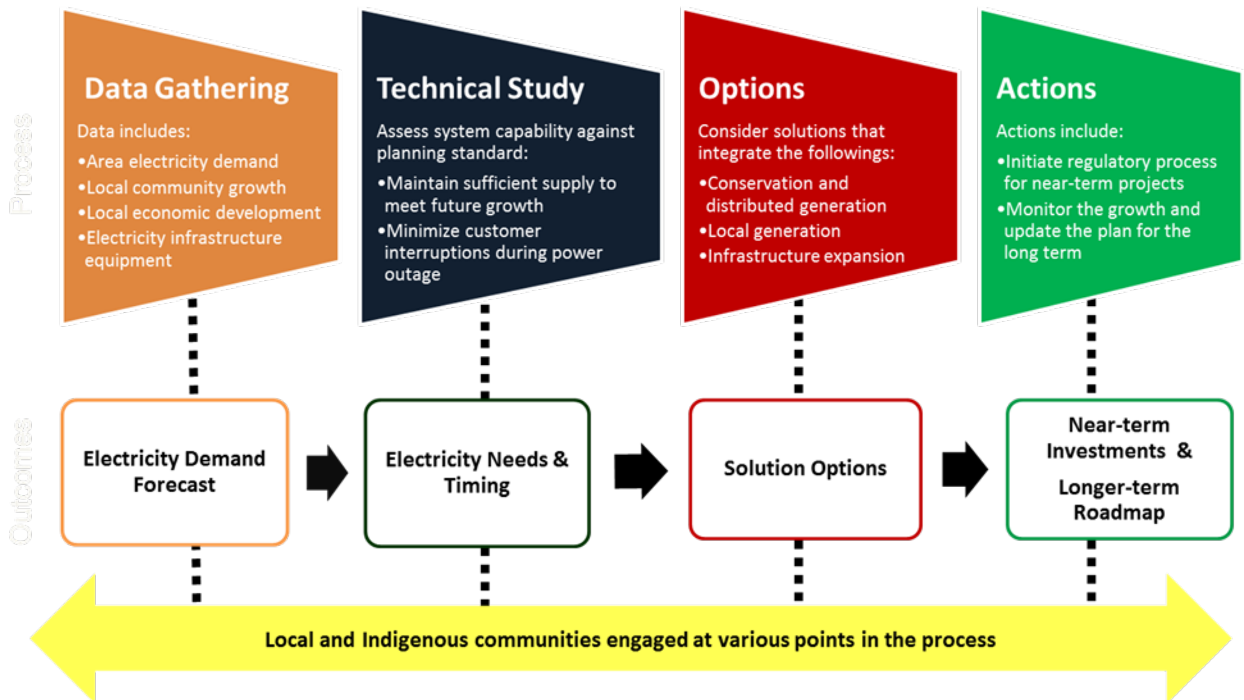
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

Planning in northwestern Ontario requires a unique approach. In southern Ontario, most of the forecast load growth is driven by growth in the LDC customer base. In northwestern Ontario the majority of the forecast load growth is driven by new or expanding large transmission-connected industrial customers, the majority of which are in the resource sector or are unique development projects. Therefore, when establishing the need for electricity enhancements and developing integrated alternatives, industrial customers generally drive the nature and magnitude of the electrical demand requirements.

The IRRP describes the Working Group's recommendations for system enhancements based on different scenarios. The Working Group also recommends staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with individual large customers. The recommendations of the IRRP seek to ensure flexibility is maintained such that changing long-term conditions may be accommodated.

In developing this IRRP, the Working Group followed a number of steps. These steps included: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 West of Thunder Bay Sub-region Working Group and IRRP Development

In 2014, the lead transmitter – Hydro One Transmission– initiated a Needs Screening process for the Northwest Ontario Region. The North of Dryden IRRP[4] and Remote Community Connection Plan[5] were already underway prior to the formalization of the regional planning process and were therefore not included within the scope of the Needs Screening process. The Northwest Ontario Region Needs Screening study team determined that the need for coordinated regional planning had already been established, and that a formal Needs Screening process was not required for the Northwest Ontario Region. A Scoping Assessment was then initiated to identify new planning sub-regions within the Northwest Ontario Region that were not already identified in previous planning studies.

---

[4] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/North-of-Dryden.aspx
[5] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan.aspx

On December 12, 2014, a draft Scoping Assessment Outcome Report ("Scoping Report") was posted for public comment. The Scoping Report was finalized on January 28, 2015, and it incorporated feedback from community, stakeholder, and First Nation and Métis community meetings. The Scoping Report identified the West of Thunder Bay Sub-region as one of three new planning sub-regions for coordinated regional planning, as illustrated in Figure 3-3.

Figure 3-3: Northwest Ontario Region and Sub-regions

Subsequently, the Working Group was formed to carry out the IRRP for the West of Thunder Bay Sub-region.

For the purpose of regional planning, two LACs have been established for this sub-region: a General LAC and a First Nation LAC. The LACs were informed of the planning activities in the area and provided their input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), local electricity concerns, and opportunities to implement community-based energy solutions. Greater detail regarding community and stakeholder engagement activities is provided in Section 9 of this report.

4. Background and Study Scope

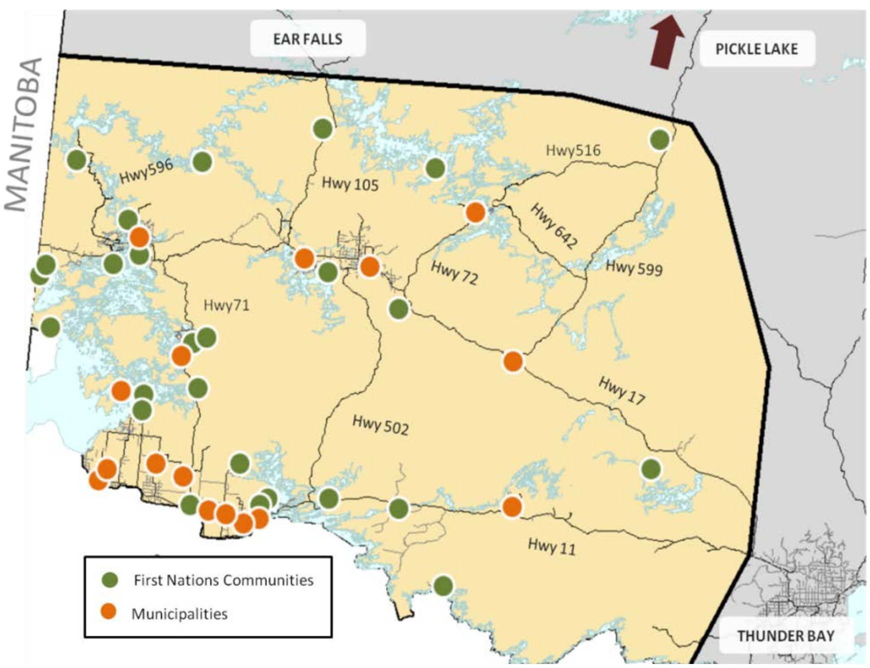
The sub-region and the scope of the IRRP are described in Section 4.1. Section 4.2 details the electricity system supplying the West of Thunder Bay Sub-region.

4.1 West of Thunder Bay - Study Scope

The West of Thunder Bay IRRP assesses the reliability of the regional electricity system supplying the West of Thunder Bay Sub-region and identifies integrated solutions for the 20-year period from 2015 to 2034.

The West of Thunder Bay Sub-region is defined as the area bordered to the south and west by the United States and Manitoba borders; it extends north to include Kenora, Dryden and Sioux Lookout, and east as far as (but not including) the City of Thunder Bay; the study area does not include the area north of Dryden[6]. The approximate geographical boundaries of the sub-region are shown in Figure 4-1.

Figure 4-1: Geographical Boundaries of the West of Thunder Sub-region



[6] The North of Dryden IRRP published in 2015 addresses the reliability of the electricity system supplying the North of Dryden sub-region (see http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf)

The West of Thunder Bay Sub-region includes the following First Nations:

- Anishinabe of Wauzhushk Onigum
- Anishinaabeg of Naongashiing
- Big Grassy
- Couchiching
- Eagle Lake
- Grassy Narrows
- Iskatewizaagegan #39
- Lac Des Mille Lacs
- Lac La Croix
- Lac Seul
- Mitaanjigamiing
- Naicatchewenin
- Naotkamegwanning
- Nigigoonsiminikaaning
- Northwest Angle #33
- Northwest Angle #37
- Obashkaandagaang
- Ochiichagwe'Babigo'Ining
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Rainy River
- Seine River
- Shoal Lake #40
- Wabaseemoong
- Wabauskang
- Wabigoon Lake Ojibway

The sub-region also includes the following municipalities:

- Township of Alberton
- Town of Atikokan
- Township of Chapple
- Township of Dawson
- Township of Emo
- Town of Fort Frances
- Township of Lake of the Woods
- Township of La Vallee
- Township of Morley

- Town of Rainy River
- City of Dryden
- City of Kenora
- Municipality of Machin
- Municipality of Sioux Lookout
- Township of Ignace
- Township of Sioux Narrows-Nestor Falls

In addition, there are a number of unorganized areas[7] in the Rainy River and Kenora Districts.

This IRRP addresses the reliability of the 115 kV regional transmission systems. The reliability of the 230 kV bulk transmission system and distribution systems supplying the area is beyond the scope of the regional planning process and this IRRP. 230 kV Bulk system and distribution system related concerns are for context referenced in Section 6.3, but they will be formally addressed through the bulk system and distribution systems planning processes.

It is important to note that connection assessment of generation resources for procurement programs, such as the Feed-in-Tariff and, the Large Renewable Procurement, are beyond the scope of this IRRP. Generation projects participating in procurement programs will be assessed according the rules and specifications of the procurement programs.

4.2 West of Thunder Bay Electricity System

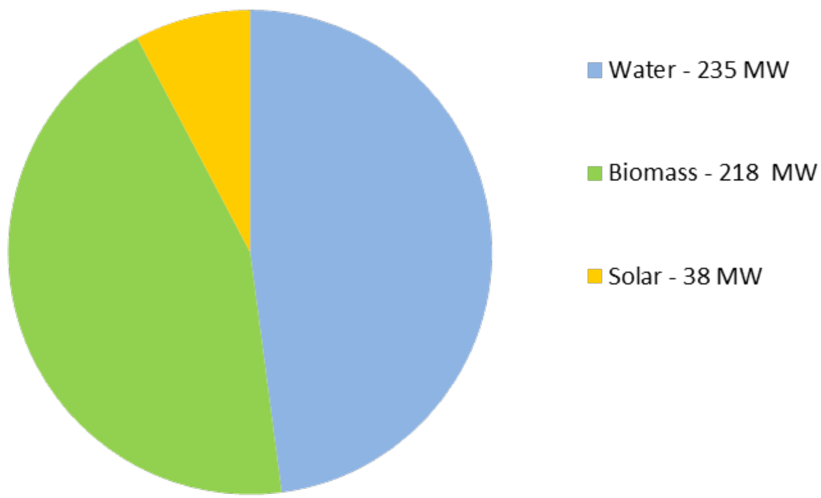
The West of Thunder Bay electricity system consists of local generation resources, 230 kV bulk transmission, 115 kV regional transmission and low voltage distribution networks. Local generation resources provide important sources of electricity supply to the communities and customers in this sub-region. However, under certain system conditions (e.g., generation outages or if electricity demand exceeds the capability of local generation), local generation sources would need to be supplemented with power delivered to the sub-region from the rest of the province through the 230 kV bulk transmission system. From the 230 kV bulk transmission system, power is then delivered to various communities and customers through the regional 115 kV and low-voltage distribution networks. The following sub-sections discuss these components in more details.

[7] Unorganized areas are parts of the province where there is no municipal level of government. Services in these unorganized districts are typically administered by local service boards.

4.2.1 Local Generation Resources

There are three types of generation resources totaling to about 491 Megawatts ("MW") in the West of Thunder Bay Sub-region: hydroelectric (water), biomass and solar, as shown in Figure 4-2.

Figure 4-2: Installed Capacity of Generation Resources in the West of Thunder Bay Sub-region (MW)



In Ontario, the electricity system is designed to meet regional coincident peak demand – i.e., the 1-hour period each year when total demand for electricity in the region (or sub-region) is the highest. While hydroelectric, biomass and solar resources are a potential source of energy, only a certain amount of power can be relied upon at the time of peak due to the variable nature of these resources. In the West of Thunder Bay Sub-region, electricity demand typically peaks during the evening in the winter season. For the purposes of infrastructure planning, the installed capacity of distributed and variable generation is adjusted to reflect the reliable power output at the time of the local winter peak.

Below is a description of local generation resources in the West of Thunder Bay Sub-region.

- **Hydroelectric (Water):** Hydroelectric resources account for almost 50 percent of the installed capacity in the sub-region (about 235 MW). While there are a number of small scale hydroelectric generators, the major facilities, Caribou and Whitedog Generating Stations, are situated in the Kenora area. All hydroelectric resources in this sub-region are run-of-river facilities and have limited storage capability. As such, hydroelectric output is highly variable and is dependent on water conditions. During drought and low water conditions, power output is reduced to less than a third of the installed capacity. In some cases, high waters and flooding conditions may also reduce the power output from these facilities.

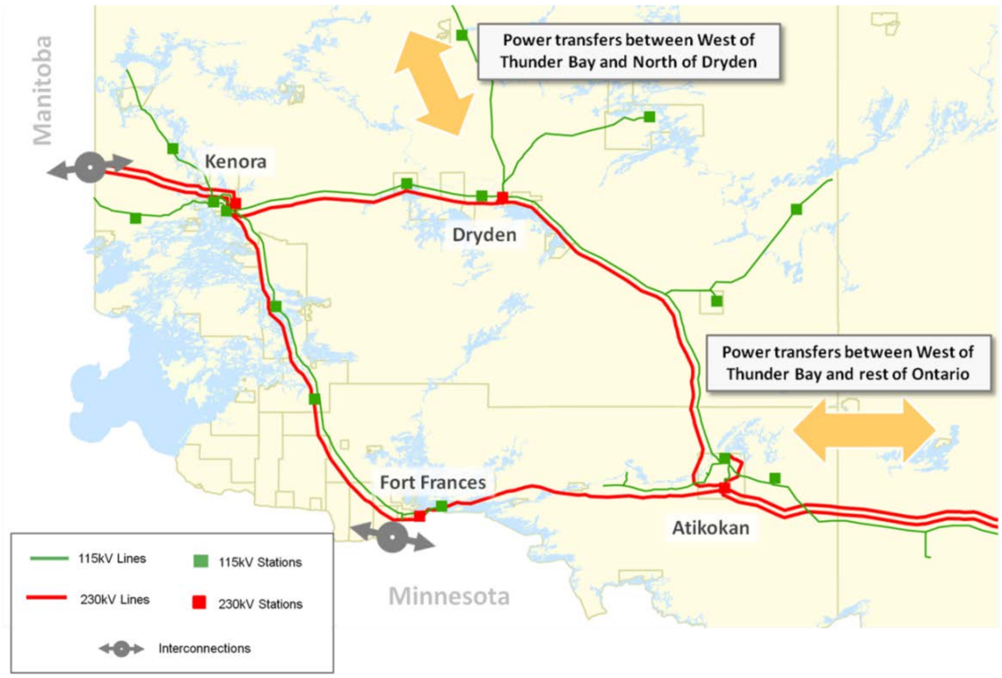
- **Biomass:** In 2014, the coal-fired generation facility at Atikokan was converted to burn biomass (wood pellets). This facility currently is contracted with the IESO until 2024 and has the capacity to generate up to 200 MW. Based on the current contract terms, the facility purchases up to 90,000 tonnes of biomass fuel annually. The forecast fuel availability will limit energy production to 140 GWh per year and may limit the amount of hours it can operate at the maximum capacity. For the purpose of this IRRP, it is assumed that Atikokan facility may operate as a merchant facility upon expiration of the contract. There are currently two merchant biomass generation facilities near Dryden and Fort Frances.

- **Solar:** A 25 MW transmission-connected solar facility is in operation in the Rainy River area. Many communities have also installed small-scale, distribution-connected solar facilities. Today, solar resources account for a small portion of the local, installed capacity. Solar is an intermittent resource and power output can vary depending on factors such as cloud cover, location, time of day, and season. As the local peak typically occurs during the evening in the winter, solar resources are not expected to contribute to the reduction of the local peak demand.

4.2.2 Transmission System

The transmission system in the sub-region consists of 230 kV and 115 kV lines and stations, as shown in Figure 4-3.

Figure 4-3: West of Thunder Bay Sub-region – Transmission System



The West of Thunder Bay transmission system is interconnected with Manitoba at Kenora and with Minnesota at Fort Frances. The interconnections with Manitoba and Minnesota handle transfers scheduled on an economic basis to address provincial needs and are not relied upon for maintaining local reliability. As the electricity system in this area is a source of supply to the North of Dryden Sub-region, its electricity requirements are affected by the potential growth in the area north of Dryden.

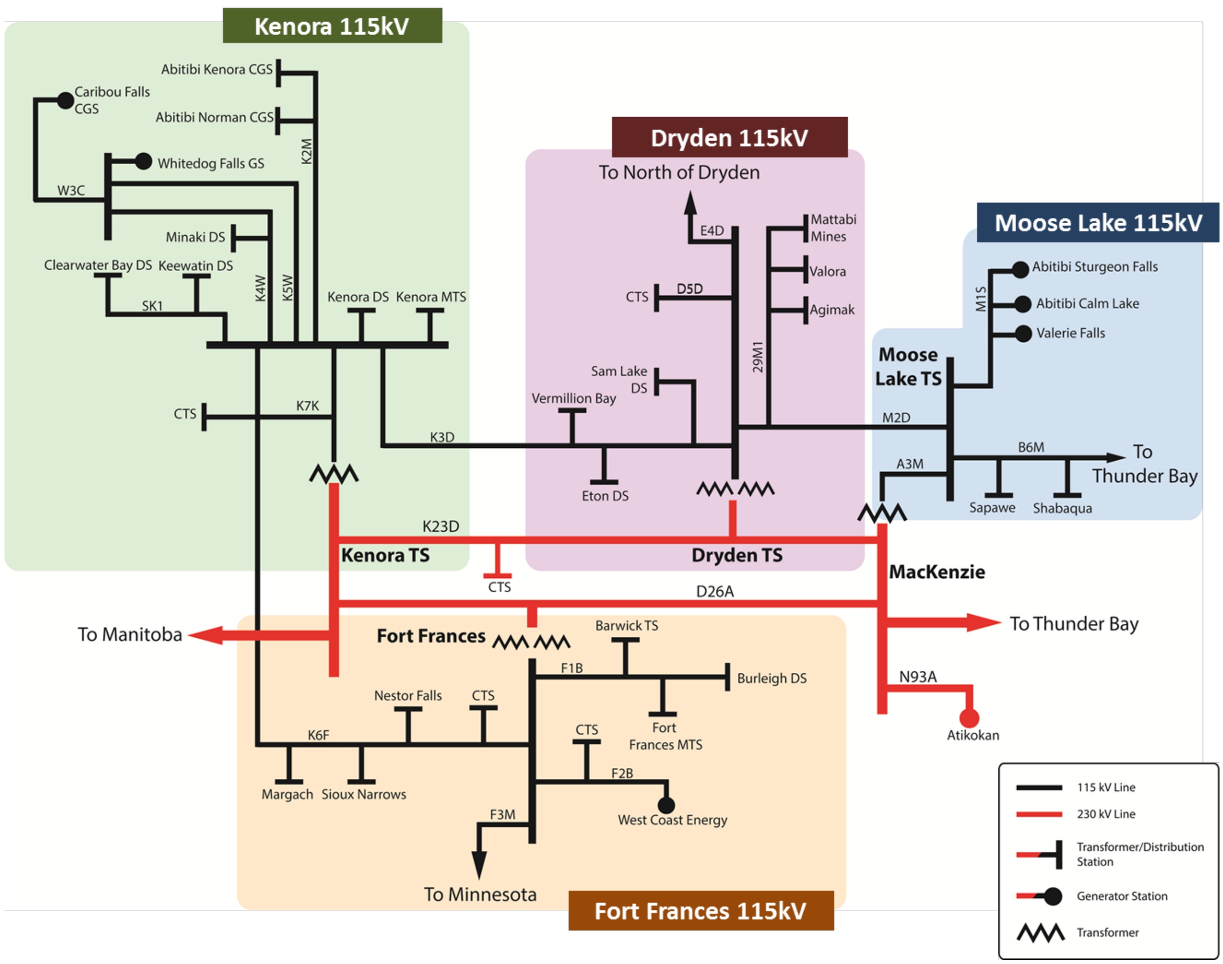
The West of Thunder Bay transmission system can be broken down into two components: 230 kV bulk transmission system and 115 kV regional sub-systems. These components are described in more detail below.

__230 kV Bulk Transmission System__

The bulk transmission system consists of a double circuit 230 kV line and a single-circuit 115 kV line between Thunder Bay and Atikokan. These lines bring power into the West of Thunder Bay Sub-region to supplement local generation resources. To the west of Atikokan, a diamondshaped, 230 kV bulk transmission network connects to Fort Frances, Dryden and Kenora. There are step-down stations that connect to local 115 kV networks at Kenora, Fort Frances, Dryden and Atikokan. Issues related to the bulk system are for context discussed in this IRRP, but these issues will be addressed as part of bulk transmission system planning.

Regional 115 kV Sub-systems

Figure 4-4: Regional 115 kV Sub-systems in the West of Thunder Bay Sub-region



The regional 115 kV sub-systems (as shown in Figure 4-4) enable power to be delivered to communities and customers in the West of Thunder Bay Sub-region. There are four 115 kV sub-systems in the sub-region:

- **Dryden 115 kV sub-system:** Today, this sub-system provides up to 65 MW of power to customers and communities in the Dryden and surrounding areas and supplies up to 68 MW to the North of Dryden Sub-region through the 115 kV line from Dryden to

Ear Falls. The two 230 kV/115 kV autotransformers at Dryden are the primary sources of supply into this sub-system. This sub-system also includes 115 kV connection lines to the Kenora and Atikokan areas.

- **Kenora 115 kV sub-system**: The Kenora and surrounding areas are supplied by this 115 kV sub-system. Today, this sub-system has a winter peak demand of about 60 MW. In addition to the 230 kV/115 kV autotransformer at Kenora, this sub-system relies on local hydroelectric facilities, including Norman, Caribou and Whitedog, as the main sources of electricity supply. This sub-system also has 115 kV connections to Fort Frances and Dryden.

- **Fort Frances 115 kV sub-system:** During the winter season, this sub-system provides up to 75 MW of supply to customers and communities in the Fort Frances and surrounding areas. This sub-system is supplied by local hydroelectric facilities and the two 230 kV/115 kV autotransformers at Fort Frances and has 115 kV connections to Kenora and Minnesota.

- **Moose Lake 115 kV sub-system:** Today, this sub-system provides up to 13 MW of electricity supply to customers and communities in the Atikokan and surrounding areas. While this sub-system is primarily supplied by the two 230 kV/115 kV autotransformers near Atikokan, the 115 kV connections to Dryden and Thunder Bay and the small hydroelectric facilities also provide electricity supply.

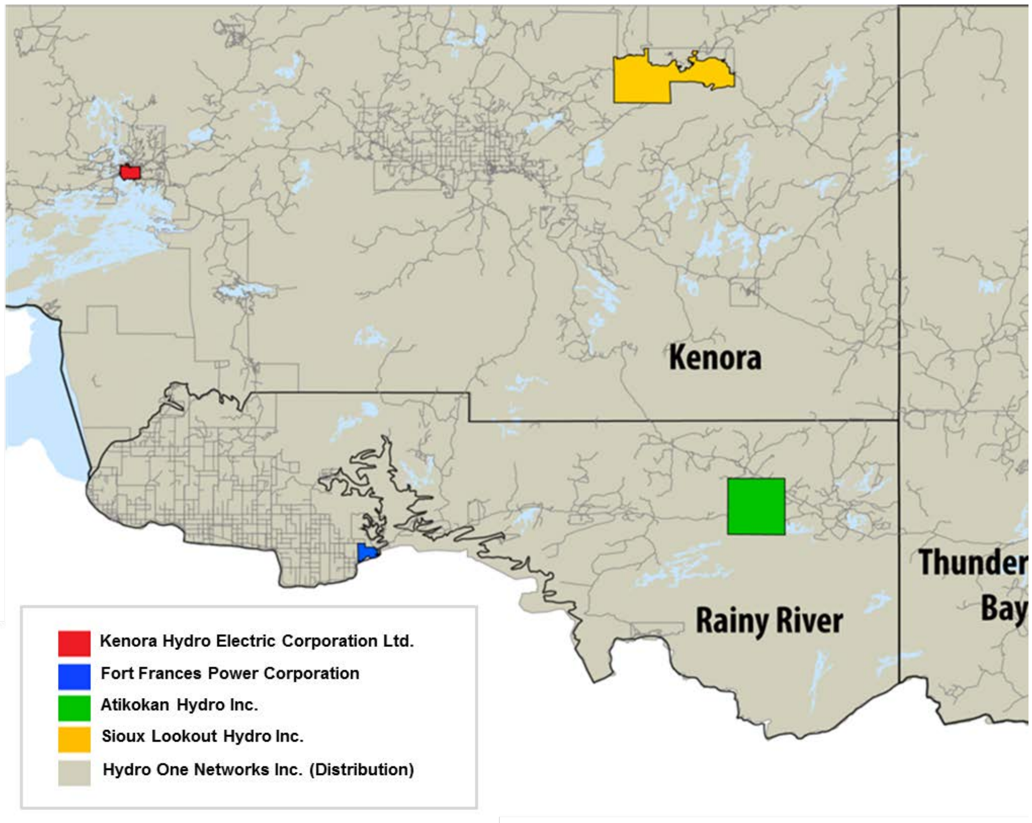
The focus of this IRRP will be on the reliability of the 115 kV regional sub-systems in the West of Thunder Bay Sub-region.

4.2.3 Distribution System

From the regional 115 kV sub-systems, power is delivered through transformer stations to the low-voltage distribution systems. There are 36 customer and utility-owned transformer stations that service the various communities and industrial customers in this sub-region. Given the large geographic and sparsely populated areas, many communities and customers in the West of Thunder Bay Sub-region are supplied by long distribution lines and a single source of supply.

The low-voltage distribution system is managed and operated by five LDCs: Atikokan Hydro, Fort Frances Power Corporation, Kenora Hydro, Sioux Lookout Hydro, and Hydro One Networks (Distribution), as shown in Figure 4-5.

Figure 4-5: Local Distribution Companies (LDCs) Service Area



Distribution system planning is beyond the scope of the regional planning process. Issues related to the distribution system may for context be discussed in this IRRP, but they will be addressed as part of the distribution planning process led by the LDCs.

The details regarding the characteristics of the LDC service areas can be found in Appendix A.

5. Demand Forecast

Regional electricity systems in Ontario are designed to meet regional coincident peak demand – the one-hour period each year when total regional demand for electricity is the highest.

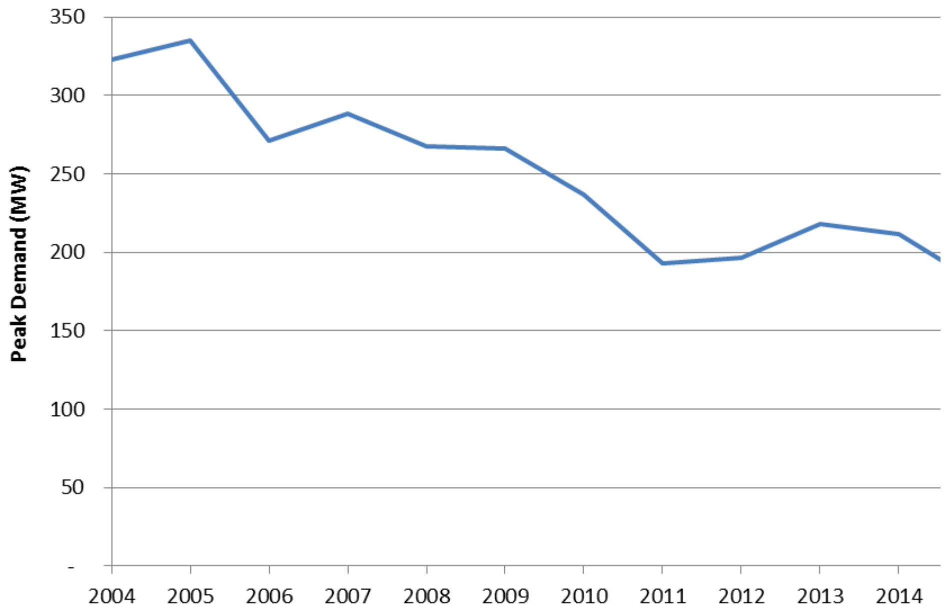
This section describes the development of the regional electricity demand forecast for the West of Thunder Bay Sub-region. Section 5.1 describes electricity demand trends in the sub-region from 2004 to 2014. Section 5.2 provides an overview of the demand forecast methodology used in this study, and Section 5.3 summarizes the various demand scenarios.

5.1 Historical Electricity Demand 2004-2014

The West of Thunder Bay Sub-region's peak electrical demand typically occurs during the evening in the winter. This is driven by a large electrical heating demand in the residential sector as access to natural gas in the area is limited.

In addition to the heating requirements from the residential sector, there are a number of large industrial customers in the pulp and paper and forestry sectors. These industrial customers consume a large amount of energy on a continuous basis; however, they are sensitive to changing economic conditions (e.g., commodity prices, changes in economic growth) which can have material impacts on annual energy demand. As shown in Figure 5-1, historical winter peak demand in the sub-region has decreased from a high of 335 MW in 2005 to a low of 210 MW in 2014. This decline in electrical load is primarily due to the closure of numerous large industrial customers in the pulp and paper sectors.

Figure 5-1: West of Thunder Bay Sub-region Historical Peak Demand (2004-2014)



5.2 Methodology for Establishing Planning Forecast Scenarios

Demand forecast scenarios were developed to assess reliability of the West of Thunder Bay electricity system over the planning period. For the purpose of regional planning, these demand scenarios take into consideration a number of components:

- Gross winter demand forecast scenarios for distribution-connected and transmission-connected customers,
- Estimated peak demand savings from meeting provincial energy conservation targets, and
- Expected peak capacity contribution from DG.

Gross demand forecast scenarios were developed based on the expected peak demand projections for distribution-connected and transmission-connected customers in the West of Thunder Bay Sub-region. For each scenario, these growth projections are modified to reflect the estimated peak demand savings from meeting provincial energy conservation targets and from existing and contracted DG.

Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts.

An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan accordingly.

The methodology and assumptions used for the development of the demand forecast scenarios are described in detail in Appendix A.

5.3 Development of Planning Forecast

5.3.1 Gross Demand Forecast Scenarios

The gross demand forecast is based on the gross electricity requirements for distribution-connected customers and transmission-connected customers in the sub-region.

Distribution-Connected Customers

The gross demand forecast for distribution-connected customers is provided by the five LDCs in the West of Thunder Bay Sub-region. Overall, the growth in electricity demand forecast from distribution-connected customers is expected to remain relatively modest. Most of the growth is attributed to requirements from small industrial customers, such as biomass pellet plants and saw mills, community development associated with the new gold mine near Rainy River and population growth in First Nations communities. Descriptions of the LDCs' forecast assumptions and methodology can be found in Appendix A.

Transmission-Connected Customers

The gross demand forecast for transmission-connected customers is developed based on information gathered from transmission-connected industrial customers. The IESO and Hydro One Transmission regularly communicate with existing and potential transmission-connected industrial customers to understand their electricity demand requirements and their operation and development status.

Over the planning period, the demand growth in the West of Thunder Bay Sub-region will be primarily driven by large, transmission-connected industrial customers, including gold mines near Rainy River and Dryden, and the proposed gas to oil pipeline development. New transmission-connected industrial customers could potentially add up to 300 MW of incremental electricity demand by 2034. As discussed, industrial customers are particularly sensitive to the changes in economic conditions. The timing, location and scale of industrial developments is uncertain and will depend on a number of external factors, such as the commodity price of the resource, the economic viability of the industrial project, and the ability to secure capital. Often these factors can lead to material increases or decreases in annual demand. For example, due to declining gold prices, the development of a prospective, large gold mine near Atikokan, with peak demand requirements of up to 125 MW, was suspended in 2014. Other developments, by contrast, are proceeding. For example, a new gold mine near Rainy River, with a peak demand requirement of up to 60 MW, is currently under construction and should be in operation by 2017.

Since these changes are often difficult to anticipate, a scenario based approach was used to ensure the sub-region's electricity system is able to adequately supply electricity to industries and communities under various assumptions and conditions. Three scenarios (Reference, High and Low) are described in Section 5.3.4.

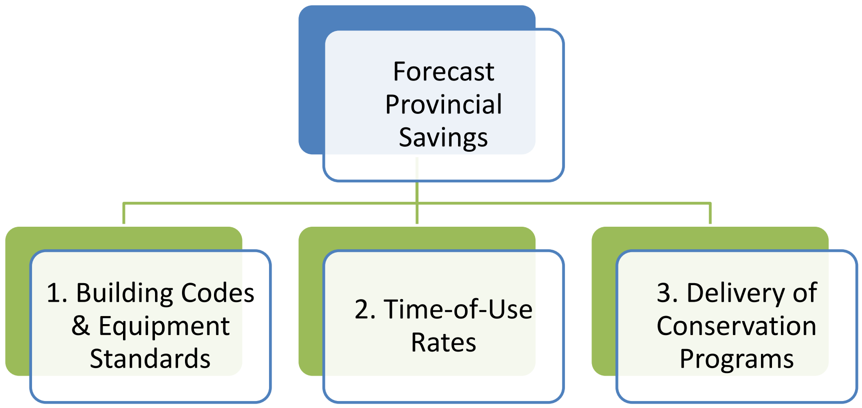
The specific forecasting methodology and assumptions for the gross demand forecast scenarios can be found in Appendix A.

5.3.2 Expected Peak Demand Savings from Provincial Conservation Targets

Conservation is the first resource considered in planning, approval and procurement processes. It plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. The conservation savings forecast for the sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.2), to determine the planning forecast for the sub-region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP") that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. A portion of this province-wide energy conservation target was allocated to the West of Thunder Bay Sub-region, and, as further described below, it was further converted to an estimated peak demand reduction for the sub-region. To estimate the impact of the conservation savings in the area, the forecast provincial savings were divided into three main categories, as shown in Figure 5-2:

Figure 5-2: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The 2013 LTEP committed to establishing a new 6-year Conservation First Framework ("CFF") beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near term, Ontario's LDCs have an aggregate energy reduction target of 7 TWh, as well as individual LDC specific targets. These targets are to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the CFF. In 2015, each LDC submitted a CDM plan to the IESO describing how the targets will be achieved. LDCs are also required to provide updates to their CDM plans.

As part of the Conservation First policy, the provincial government has adopted a broad definition of conservation that includes various types of customer action and behind-the-meter generation. This means that conservation includes any programs or mechanisms that reduce the amount of energy consumed from the provincial electricity grid. Conservation initiatives, including behind-the-meter generation projects and on-site generation, are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the sub-region. Conservation initiatives, including behind-the-meter generation projects and on-site generation, are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the sub-region.

For the purpose of this IRRP, the allocation of the 7 TWh of provincial energy savings target to the West of Thunder Bay Sub-region is estimated to offset approximately 14 MW of the forecast peak demand between 2015 and 2034. Savings from potential future demand response ("DR") resources are not included in the forecast. Instead, the development of locally targeted DR projects may be considered as potential solutions to address future needs.

The estimated annual peak demand savings from the provincial energy conservation targets in the West of Thunder Bay Sub-region are summarized in Appendix A.

5.3.3 Expected Peak Demand Contribution of Existing and Contracted Distributed Generation

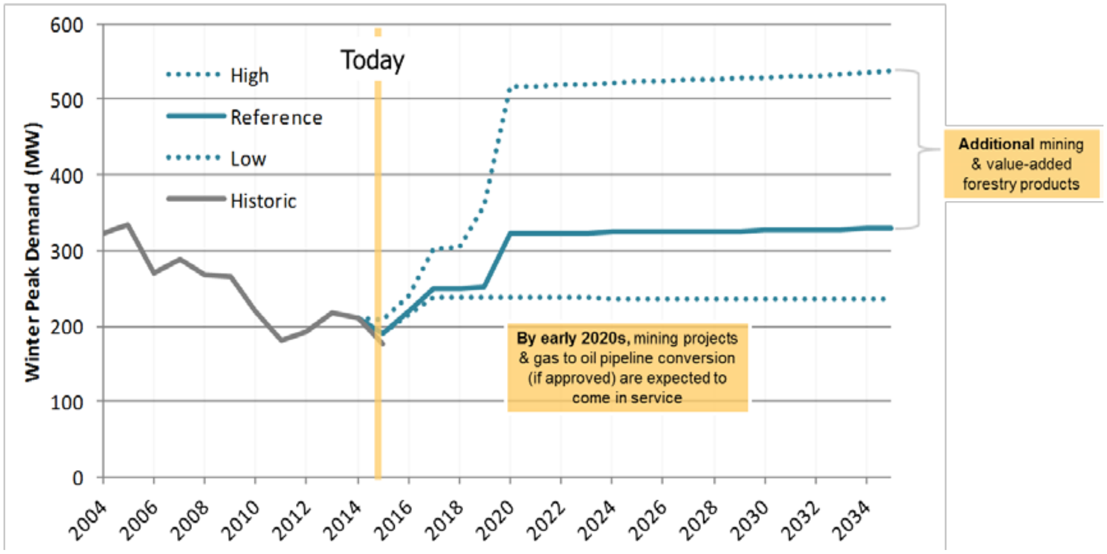
As of 2015, about 38 MW of DG was contracted in the West of Thunder Bay Sub-region. For the purpose of developing the planning forecast, contracted DG is expected to reduce the regional peak demand by about 1.5 MW over the next 20 years. Future DG uptake was, as noted, not included in the planning forecast and is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the West of Thunder Bay Sub-region can be found in Appendix A.

5.3.4 Planning Forecast

A scenario-based approach was used to account for the uncertainty in the demand forecast. Figure 5-3 shows planning demand scenarios for the West of Thunder Bay Sub-Region (2015 to 2034, using a base year of 2014). The scenarios represent plausible outcomes that must be considered in planning for the electricity needs of the sub-region. The demand forecast scenarios shown below take into consideration the gross demand forecast scenarios, estimated peak demand savings from provincial energy conservation targets, and existing and contracted DG.

Figure 5-3: Planning Forecast Scenarios [8]



Reference scenario

Under the Reference scenario, the winter peak electricity demand in the West of Thunder Bay Sub-region is expected to increase to 330 MW over the planning period. As shown in Figure 5-3, by the mid-2020s, the peak demand will be similar to 2004 levels. The growth includes two transmission-connected mining developments near the Dryden and Rainy River areas. Together, these developments could increase regional electricity demand by up to 70 MW.

For the purpose of regional planning, it is also assumed that the proposed gas to oil pipeline development will be approved and that four oil pumping stations will be supplied from the West of Thunder Bay transmission system under the Reference scenario. The pumping stations would each require approximately 15 to 18 MW of electricity supply by 2020.

High scenario

In addition to the growth identified in the Reference scenario, the High scenario assumes more transmission-connected mining developments and the recovery of the local pulp and paper industry, for example the restart of the mill in the Fort Frances area. The electricity demand from the proposed gas to oil pipeline development is expected to increase as a total of six oil pumping stations will be supplied from the West of Thunder Bay transmission system under

---

[8] West of Thunder Bay Sub-region demand forecast does not include growth in the North of Dryden Sub-region. The demand forecast for the North of Dryden Sub-region is discussed in Section 5.4.

this scenario. With these additional developments, the total demand could grow to 540 MW by the end of the study period.

Low scenario

Aside from the above-mentioned mining development in the River Rainy area, no additional mining development is expected to materialize under the Low scenario. It is assumed that the proposed gas to oil pipeline development will not proceed. This scenario results in a relatively flat electricity demand growth over the planning period.

Further details related to the demand forecast scenarios can be found in Appendix A.

5.4 Potential Growth in the North of Dryden Sub-region

The West of Thunder Bay electricity system is a major source of supply to the North of Dryden Sub-region, capable of transferring up to 85 MW via through the 115 kV line from Dryden to Ear Falls. In 2015, the winter peak demand in the North of Dryden area was about 68 MW.

Based on the North of Dryden IRRP published in 2015[9], up to 170 MW of additional demand growth could materialize in the North of Dryden Sub-region and would require supply from the West of Thunder Bay 230 kV bulk transmission system. Depending on the location, magnitude and timing of these potential developments in the North of Dryden Sub-region, this could have an impact on the 115 kV Dryden regional sub-system.

The North of Dryden IRRP recommends building a new 230 kV line to Pickle Lake to support the potential developments in the North of Dryden Sub-region including connection of 21 remote First Nation communities. With the new 230 kV line to Pickle Lake, up to 120 MW of incremental demand from new mining developments and remote communities north and northeast of Pickle Lake would be supplied directly from the 230 kV West of Thunder Bay bulk transmission system. The remaining growth in the Red Lake and Ear Falls area (up to 50 MW of incremental demand), which includes the remote communities north of Red Lake, would be supplied directly from the Dryden 115 kV sub-system. To ensure that the West of Thunder Bay electricity system has sufficient capacity to serve growth in the West of Thunder Bay and North of Dryden Sub-regions, the potential growth and development in the area north of Dryden is taken in to consideration in the development of this IRRP.

---

[9] http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf

6. Needs

This section outlines the needs assessment methodology and identifies regional electricity supply and reliability needs over the 20-year planning period. In addition, other electricity needs and considerations at the bulk, distribution and community levels are also discussed in this section.

6.1 Needs Assessment Methodology

The IESO's ORTAC,[10] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements (see Appendix B for more details).

Through the application of these criteria, three broad categories of needs can be identified:

- **Transformer Station Capacity** is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the load meeting capability ("LMC") of the step-down transformer stations in the local area, which is the maximum demand that can be supplied from the transformer stations based on their combined transformer station ratings.
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission line or sub-system, which is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See Appendix B for more details). Supply capacity needs are identified when peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** is the electricity system's ability to minimize the impacts of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

In addition, the needs assessment may also identify needs related to transmission service reliability performance, equipment end-of-life and planned sustainment activities. Service reliability performance describes the frequency and probability of major outages on an electricity system, which can be affected by various factors such as exposure to elements, age and maintenance of equipment, and length and configuration of the transmission or distribution networks. Equipment reaching the end of its life and planned sustainment activities may have an impact on the needs assessment and options development. Transmission assets reaching end-of-life are typically replaced with assets of equivalent capacity and specification. The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, or downsizing or even removing equipment that is no longer considered useful. Such instances may also present opportunities to enhance or reconfigure assets for infrastructure hardening to improve system resilience.

6.2 Regional Electricity Reliability Needs

For the purpose of regional planning, this IRRP focuses on identifying and addressing needs on the regional 115 kV sub-systems, as defined in Section 4.2.2. It is important to note that there may be a potential need for additional supply on the West of Thunder Bay 230 kV bulk system. This bulk system need is not within the scope of this IRRP, but for contextual reasons is discussed in Section 6.3.1.

Results from the needs assessment show all the regional 115 kV sub-systems are adequate over the planning period under Reference and Low scenarios. Under the High scenario, strong growth in the Dryden and North of Dryden Sub-region may exceed the Dryden 115 kV sub-system capacity over the planning period. End-of-life replacements, transmission service reliability and transformer station capacity needs were also identified in the West of Thunder Bay Sub-region. The following section describes these needs in more detail.

6.2.1 Potential Supply Capacity Need on the Dryden 115 kV Sub-system

The Dryden 115 kV sub-system can provide up to 240 MW of continuous supply to the Dryden area and North of Dryden Sub-region (Dryden 115 kV System LMC = 240 MW). Today, the Dryden 115 kV sub-system supplies 130 MW to the Dryden area and North of Dryden Sub-region. Under the Reference scenario, electricity demand supplied by the Dryden 115 kV sub-system is expected to grow to about 240 MW by 2034. There will be sufficient capacity on the existing system to support this growth over the planning period.

Under the High scenario, however, the electricity demand on Dryden 115 kV sub-system can potentially increase to about 290 MW. The existing Dryden 115 kV sub-system therefore does not meet the ORTAC supply capacity under this particular scenario. If the forecast demand growth materializes under the High scenario, 50 MW of additional supply capacity may be required on the Dryden 115 kV sub-system in the mid-2020s. Given that the timing, magnitude and location associated with potential developments in the Dryden area are uncertain, it is important to monitor these potential developments before proceeding with an investment decision. Section 7.1 will provide a high-level discussion of potential options to address these concerns under the High scenario.

Details related to the assessment can be found in Appendix B.

6.2.2 Transformer Station Capacity Needs in the Kenora area

The transformer station supplying the City of Kenora and surrounding areas ("Kenora MTS") can supply up to 25 MW at the time of peak. Today, this transformer station currently supplies up to 20 MW. There is therefore about 5 MW of supply margin remaining on the transformer station. Since the residential and commercial growth in the Kenora area is forecast to be modest over the planning period, the remaining margin will be adequate to support commercial and residential developments in the area.

Recently, a large industrial customer in the Kenora area that has historically been supplied from a local dam is looking to Kenora MTS for alternative supply. Depending on the needs of the industrial customer, the requirement for additional transformer station capacity may be triggered in Kenora over the next few years. Potential developments at the former Abitibi mill site may also require additional transformer station capacity in the Kenora area. However, the timing and magnitude of these developments are uncertain at this time. Kenora Hydro will monitor these developments closely to determine if and when a new transformer station will be required. If a new transformer station is required to supply the industrial customers, it may potentially provide a second source of supply to the City of Kenora and surrounding areas. As this is a customer-driven need, it is not expected to have major regional implications.

6.2.3 Transmission End-of-Life Replacements and Sustainment Activities

The Dryden TS 115 kV/44 kV transformers and Moose Lake 115 kV/44 kV transformers are due for end-of-life replacements within the next five years. The Dryden 115 kV/44 kV transformers are scheduled to be replaced in 2016, with assets of equivalent capacity and specification based on current standards. This sustainment decision was made prior to the initiation of this IRRP.

The Moose Lake 115 kV/44 kV transformers and associated 44 kV distribution lines are scheduled to be replaced in the early 2020s. The refurbished transformer station, with equally sized equipment and station reconfiguration, will improve the supply security to the customers and communities in Atikokan and the surrounding areas. As part of the IRRP, Atikokan Hydro and Hydro One Transmission examined potential sustainment options, including potential relocation of the transformer station, based on cost-benefit and cost allocation considerations. The details related to the end-of-life replacements for the Moose Lake 115 kV/44 kV transformers can be found in Appendix E.

Hydro One Transmission will be replacing wood pole structures on a number of aging 115 kV transmission lines in the Kenora, Sioux Lookout and Dryden areas and the 230 kV transmission lines in the Fort Frances and Atikokan areas. During the wood pole structure replacements, the electricity supply to local communities will be temporarily rerouted to other circuits. As a result, no service interruption is expected during construction. This sustainment decision was made prior to the initiation of this IRRP.

Going forward, the Working Group will need to better understand the timing and scope of upcoming sustainment activities in this sub-region, as sustainment activities may provide opportunities to replace these aging assets in a manner that also addresses broader regional needs.

6.2.4 Transmission Service Reliability and Performance

Many communities and customers in the sub-region are supplied by long transmission lines and rely on a single supply source. A few customers have expressed concerns regarding service reliability and performance. Service reliability and performance is measured based on customers' exposure to power outages on the distribution and transmission system, which is expressed in terms of *frequency* (i.e., number of outages a year) and *duration* (e.g., length of time before the power is restored). Transmission customer delivery point standards are used to measure the service reliability and performance of the electricity system in Ontario.

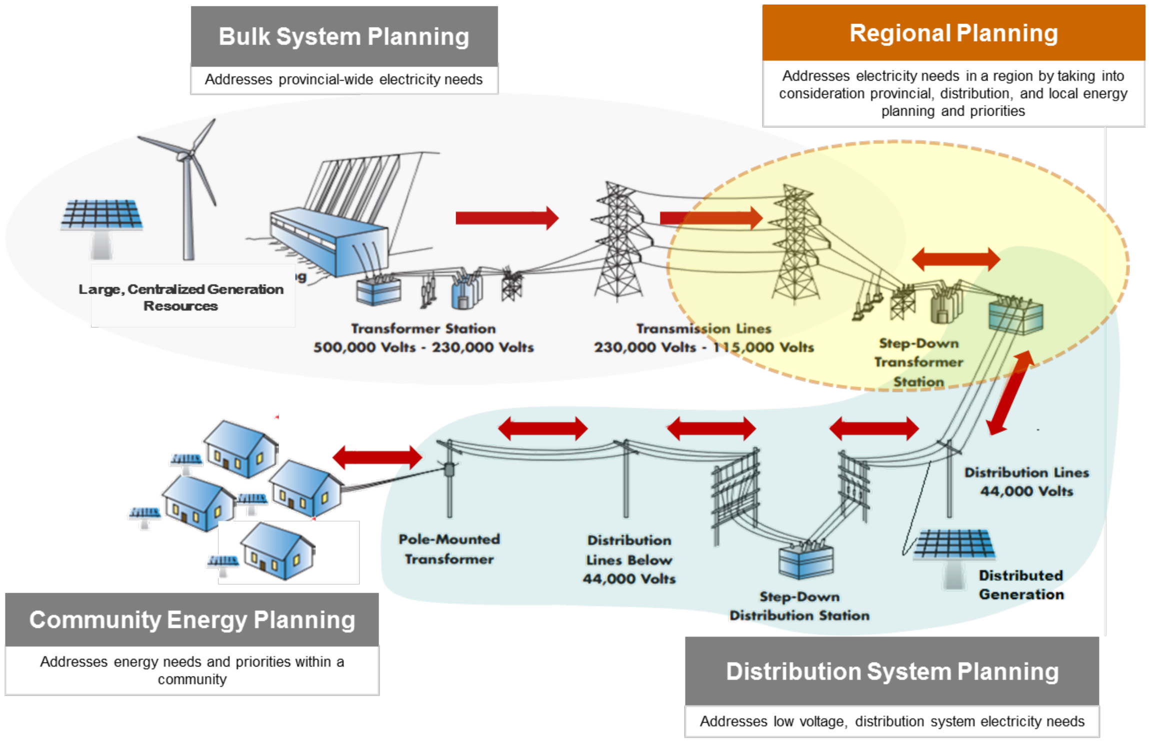
In response to service reliability and performance concerns raised by communities and LDCs, the Working Group assessed the reliability performance of the transmission system in the West of Thunder Bay Sub-region, in particular, the 115 kV sub-systems supplying Town of Sioux Lookout and Town of Fort Frances. These sub-systems are supplied by a single transmission supply and have recently experienced outages. Based on historical reliability performance statistics, the 115 kV transmission system supplying Sioux Lookout and Fort Frances is within the provincial service reliability and performance standards. However, Hydro One Transmission indicated that during a recent maintenance outage, switching equipment failure resulted in a prolonged outage for customers in the Fort Frances area. Customers and communities may work with Hydro One Transmission to explore options to avoid similar incidents in the future.

A summary of transmission reliability performance assessment can be found in Appendix C. Section 7.2 will discuss the potential opportunities to further improve transmission service reliability and the associated cost implications.

6.3 Other Electricity Needs and Considerations

As discussed in Section 3, electricity planning is conducted at various levels: bulk, regional, local, and community (Figure 6-1). In addition to regional planning, bulk, distribution and community energy planning activities are also underway in the West of Thunder Bay Sub-region. While these needs are beyond the scope of regional planning process, bulk, distribution and community energy needs were taken into consideration in the development of the plan.

Figure 6-1: Electricity Planning at the Bulk, Regional, Distribution and Community Levels

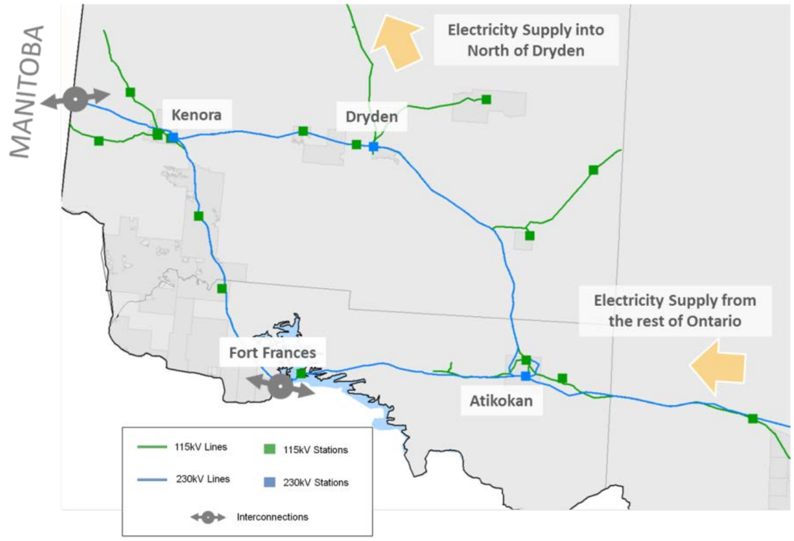


To provide the broader context, issues and considerations related to 230 kV bulk transmission system, the local distribution systems, and community energy planning activities and their implications on the West of Thunder Bay Sub-region will be discussed in the following sections.

6.3.1 230 kV Bulk System Needs

The 230 kV bulk transmission system supplying the West of Thunder Bay and North of Dryden Sub-regions is adequate today. As a result of potential industrial developments and remote community connections in the West of Thunder Bay and North of Dryden Sub-regions, the West of Thunder Bay 230 kV bulk transmission system may need to serve up to 500 MW of additional electricity demand over the planning period. The 230 kV bulk transmission system will require sufficient supply capacity to deliver power into the West of Thunder Bay and North of Dryden Sub-regions as shown in Figure 6-2.

Figure 6-2: 230 kV Supply into West of Thunder Bay and North of Dryden Sub-regions



12

Given the limited supply margin remaining on the 230 kV bulk transmission system, potential demand growth and changes in the regional supply mix may lead to bulk system reliability needs in the sub-region. These needs are discussed below:

- **230 kV supply into the Dryden area:** The existing 230 kV bulk transmission system can supply a total of 175 MW of load in Dryden area and North of Dryden Sub-region. There is 50-100 MW of additional capacity remaining to support growth in the Dryden area and North of Dryden Sub-region.

- **230 kV supply into the West of Thunder Bay Sub-region:** The existing 230 kV bulk transmission system is adequate today, assuming generation at Atikokan is available. Currently, there is approximately 150 MW of supply margin remaining to support growth in the West of Thunder Bay and North of Dryden Sub-regions. If the Atikokan generation is unavailable, either because of biomass fuel limitations or contract termination (in 2024), the supply margin may be further reduced.

A bulk transmission system study is currently underway to assess the reliability of the 230 kV bulk transmission system supplying the West of Thunder Bay and North of Dryden Sub-regions. As part of the study, the IESO is exploring potential supply options including generation, transmission and firm imports from Manitoba.

In order to maintain the viability of the transmission option, the IESO has issued a hand-off letter to Hydro One to undertake early development work. To facilitate the development work, Hydro One has been engaging Infrastructure Ontario in exploring ways to ensure that the project is developed and delivered in a cost-effective manner and results in value for Ontario electricity customers. The preliminary scope of the transmission option ("Northwest Bulk Transmission Line Project"[11]) consists of a new double-circuit 230 kV line between Thunder Bay and Atikokan and a single-circuit 230 kV line from Atikokan to Dryden. However, alternate routes may be considered as part of the development work.

6.3.2 Distribution System Needs

A number of distribution system needs were identified through engagement with communities and LDCs, including issues related to service reliability and performance, power quality and end-of-life replacements and sustainment activities. A summary of these issues is provided below. However, these needs will be formally addressed as part of the distribution planning process carried out by LDCs.

Distribution Service Reliability

In response to the service reliability and performance concerns raised by communities and LDCs, the Working Group assessed the reliability performance of the distribution systems in the West of Thunder Bay Sub-region. Results from the assessment show that the majority of distribution lines in this area perform well relative to other distribution lines in the province. However, there are two distribution lines supplying electricity to areas near Shabaqua and Margach that are performing below the provincial distribution system average. These distribution lines are three to four times longer than other distribution lines across the province. Long distribution lines typically exhibit lower levels of reliability because they are more exposed to tree and wildlife contact, and they sustain more damage from poor weather. Outages in rural areas with difficult terrain, also limits access by repair crews leading to increased restoration time. A summary of distribution reliability performance assessment can be found in Appendix D.

Section 7.2 will discuss the potential opportunities to further improve distribution service reliability and the associated cost implications.

---

[11] For more information on Northwest Bulk Transmission Line: http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/Bulk-Planning-Initiatives.aspx

Power Quality

Some industrial customers in the sub-region are experiencing issues related to power quality. Power quality issues are defined as disturbances to the customer's supply as a result of voltage-related issues. These voltage issues can be driven by a combination of customers' equipment and/or system voltage performances. The solutions and the cost responsibility of investments to address power quality issues may vary depending on the root causes of the problem. The Working Group agreed that there needs to be a better understanding of power quality issues in this sub-region and that they should be examined on a case-by-case basis by the LDCs, transmitter and customers.

End-of-Life Replacement and Sustainment Activities

Based on information provided by Hydro One Distribution, three distribution stations ("DS") were refurbished over the last couple of years: Nestor DS, Sioux Narrows DS, and Burleigh DS.

6.3.3 Community Energy Planning

A number of communities in the sub-region are in the process of developing community energy plans. At the time of this report, 16 of the 26 First Nations communities have received funding from the IESO through the Aboriginal Community Energy Plan program to develop community energy plans. The City of Kenora, City of Dryden and Town of Sioux Lookout have also expressed interest in developing community energy plans and some plans are in the early stages of development. The Municipal Energy Plan Program[12] administrated by the Provincial government supports municipalities in their efforts to develop a community energy plan.

Through community energy planning activities, communities will have a better understanding of their local energy needs and emissions footprint, will identify opportunities for energy efficiency and emissions reduction, and will develop plans to meet their goals in consideration of local economic development. These community energy plans examine broader energy needs, such as transportation, natural gas and electricity, and consider other objectives including net

---

[12] For more information on the Ministry of Energy MEP Program: http://www.energy.gov.on.ca/en/municipal-energy/

zero energy, electrification, and emissions reductions. The development of these plans is being led by communities.

Given the growing concern with climate change and the move toward a low carbon economy, a CEP may include recommendations to promote electrification and other forms of fuel switching, such as shifting from natural gas to electric-power heat pumps, to achieve a goal of reducing greenhouse gas ("GHG") emissions. As such, the outcomes from CEPs may drive additional requirements on the electricity system and should be monitored closely as part of the regional planning process. Furthermore, with the increased access to distributed energy resources, community energy plans may identify opportunities for community-based energy solutions, such as district energy, combined heat and power ("CHP"), or microgrids. Depending on the timing, location and magnitude of the needs, community-based energy solutions can be considered as potential options to address regional electricity needs.

6.4 Needs Summary

Table 6-1 provides a summary of the regional supply and reliability needs in the West of Thunder Bay Sub-region. These needs are within the scope of the regional planning process.

Table 6-1: Summary of Regional Supply and Reliability Needs

Regional Electricity Reliability Needs	Components	Status
Supply Capacity	Dryden 115 kV sub-system	50 MW of additional supply may be required around the mid-2020s under the High scenario
Transformer Station Capacity	The transformer station supplying the City of Kenora and surrounding areas (Kenora MTS)	Limited supply margin remaining on the transformer station. Additional capacity may be required in the next few years as a result of a distribution connection-request from industrial customers in the Kenora area.

Transmission Service Reliability	Transmission supply to Town of Sioux Lookout and Town of Fort Frances	Based on historical outage statistics, the regional transmission system is within provincial service reliability and performance standards. During a recent maintenance outage, switching equipment failure resulted in a prolonged outage for customers in the Fort Frances area.
End-of-Life Replacements and Sustainment Activities	Dryden 44 kV/115 kV transformers	Scheduled to be replaced in 2016
	Moose Lake 44 kV/115 kV transformers	Due for end-of-life replacements in early 2020s
	Aging 115 kV structures in Kenora, Fort Frances and Dryden area	These structures will be replaced within the next five years

Table 6-2 provides a summary of the issues and considerations related to 230 kV bulk transmission system, local distribution systems, and community energy planning activities in the West of Thunder Bay Sub-region. Although these issues are beyond the scope of the regional planning study, the Working Group will continue to monitor these needs closely and keep LAC members informed of bulk, distribution and community planning activities in the sub-region.

Table 6-2: Other Electricity Needs and Considerations in the area

Type	Needs	Status
Bulk	A potential need for additional supply on the 230 kV bulk system supplying the West of Thunder Bay and North of Dryden Sub-regions	Potential growth in the North of Dryden and West of Thunder Bay Sub-regions may exceed capability on the 230 kV bulk transmission system

Distribution	Reliability Performance	Majority of distribution lines in this area perform well relative to other lines in the province, with the exception of the two distribution lines supplying to areas near Shabaqua and Margach.
	Power Quality	Some industrial customers are experiencing power quality issues, which could be driven by a combination of customers' equipment and/or system voltage performances. This will need to be investigated on a case-by-case basis.
	End-of-Life and Sustainment Activities	Nestor DS, Sioux Narrows DS, and Burleigh DS were refurbished over the last couple of years
Community	Greater coordination is required	A number of communities have expressed interest and some plans are in the early stages of development.

7. Options to Address Potential Regional and Local Needs

In developing the 20-year plan, the Working Group considered a range of integrated solutions for addressing needs, including a mix of conservation, generation, transmission and distribution facilities, and other electricity system initiatives. When evaluating alternatives, the Working Group considers a number of factors, including technical feasibility, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs and options. Solutions that maximized the use of existing infrastructure were given priority, where they were otherwise determined to be cost effective.

Although investing in new electricity infrastructure, such as a new transmission line or a generation facility, can be a potential solution to address the electricity needs within a community, it requires substantial capital investment, has environmental/land-use impact and has a long-service life. As such, it is important to take into the consideration the longer-term cost implications, value and potential risks (e.g., stranded or underutilized assets) when recommending investment. Furthermore, these facilities typically require a long lead time to complete development, obtain approvals and complete construction. For this reason, commitment of these facilities must be made with sufficient lead time to ensure they are available when needed. When assessing the need for infrastructure investments, it is important to strike a balance between overbuilding infrastructure (e.g., committing to infrastructure when there is insufficient demand to justify the investment) and under-investing (e.g., avoiding or deferring investment despite insufficient infrastructure to support growth in the region). Typically, conservation solutions can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take five to seven years to come into service. The lead time for generation development is typically two to three years, but could be longer depending on the size and technology type.

Given the uncertainty with the location, timing and magnitude of the electricity demand growth in the West of Thunder Bay Sub-region, as discussed in Section 5, it is important to monitor development closely and create a flexible, comprehensive, integrated plan in anticipation of potential demand growth scenarios and varying supply conditions in the sub-region. At this time, early development work for major electricity infrastructure projects to address potential regional needs is not required. However, to lay the ground work for the next planning cycle, the Working Group has explored potential options to address the potential supply capacity needs on the 115 kV Dryden sub-system under the High scenario. There are opportunities for communities and customers to work with LDCs and Hydro One Transmission to explore opportunities to further improve transmission and distribution service reliability and to assess the associated cost implications. Finally, the Working Group, with input from the LACs, has identified areas to facilitate greater coordination between community energy planning activities and regional planning.

These options and the opportunities to address these local and regional needs are discussed in the following section.

7.1 Options to Address Supply Capacity Needs on Dryden 115 kV Sub-system under the High Scenario

As discussed in Section 6.2.1, about 50 MW of additional supply capacity will be required on the Dryden 115 kV sub-system under the High scenario. Given the uncertainty with the demand growth, early development work for major electricity infrastructure projects is not required at this time. However, it is important to continue to monitor demand closely to determine if and when an investment decision for the Dryden 115 kV sub-system is required.

To lay the groundwork for the next planning cycle, the Working Group examined three conceptual approaches to address potential supply capacity needs on the Dryden 115 kV sub-system: conservation and distributed energy resources, delivering provincial resources ("wires" planning); and, large localized generation. In practice, certain elements of electricity plans will be common to all three approaches, and some overlap may be necessary. It is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. The following section describes the attributes, benefits, risks and implementation requirements associated with each of the three approaches.

As discussed in Section 6.3.1, additional reinforcements may be required to address the 230 kV bulk transmission needs in the West of Thunder Bay Sub-region and will be addressed separately as part of the bulk transmission planning process.

7.1.1 Conservation and Distributed Energy Resources

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

However, within West of Thunder Bay Sub-region, the majority of the forecast load growth is anticipated to be driven by new industrial development, which is assumed to include relatively efficient equipment given the inherent economic benefits and the latest codes and standards. Conservation expected to be achieved through provincial targets, including time-of-use, codes and standards, and program delivery, has already been included in the planning forecast scenarios. Therefore, the potential for an additional amount of significant conservation that could address needs is limited.

Two of the available programs that transmission-connected industrial customers could be eligible for are the Industrial Conservation Initiative ("ICI") and the Industrial Accelerator Program ("IAP"). The ICI encourages Class A customers to reduce their peak demand contributions, by providing a means to reduce their Global Adjustment charges.[13] IAP is geared to reducing electricity consumption on the provincial system, and to helping companies become more competitive by providing financial incentives that encourage investment in innovative process changes and equipment retrofits.[14] Opportunities for energy savings will continue to be explored for new and existing transmission-connected customers in the West of Thunder Bay Sub-region.

7.1.2 Large, Localized Generation Resources

Siting localized generation based on the size and location of the electricity requirements can be an effective means for addressing major regional supply and reliability needs over the long term. While this approach is similar to distributed energy resources in that it shares the goal of providing supply locally, the emphasis is on large, transmission-connected generation facilities rather than smaller, distributed resources. In the context of the West of Thunder Bay Sub-region, a 50 MW generation facility connected to the Dryden 115 kV sub-system can address the potential supply capacity needs under the High scenario.

There are a number of factors that need to be considered when siting localized generation, and any decisions would need to align with the recommendations found in the August 2013 report

[13] More information on how Global Adjustment is calculated for Class A customers is available at http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx
[14] More information on IAP is available at: http://www.ieso.ca/Pages/Participate/Industrial-Accelerator-Program/default.aspx

entitled “Engaging Local Communities in Ontario’s Electricity Planning Continuum”[15] that was prepared for the Minister of Energy by the OPA and the IESO.

As the requirements in the West of Thunder Bay Sub-region are for additional capacity during times of peak demand, a large, transmission-connected generation solution would need to be capable of being dispatched when needed, and operate at an appropriate capacity factor. In some cases, additional transmission reinforcements may also be required. In addition, siting may be a challenge if the generation is to be located in populated or environmentally sensitive areas.

The cost of a large, localized generation resource depends on the size, fuel type, technology and the degree to which it can contribute to the local and provincial system capacity or energy needs. The fuel availability will also need to be taken in consideration. For example, there is limited natural gas storage capacity in northern Ontario, and the commitment timeframes for gas and electricity are not aligned. As such, procuring “firm” service in the northwest is expected to be more costly than in southern Ontario. The lead time for generation development is typically two to three years, but it could be longer depending on the size and technology type.

7.1.3 Delivering Provincial Resources (“Wires” Planning)

Delivering provincial resources, or “wires” planning, reflects the traditional regional electricity planning approach associated with the development of centralized electric power systems. This approach involves using transmission and distribution infrastructure to supply a region’s electricity needs by taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, along with generation sources typically located remotely from the region. Utilities, both transmitters and distributors, play a lead role in the development of this approach.

Installing an additional 115/230 kV autotransformer in the Dryden and surrounding area can enable more power to be delivered from the 230 kV bulk transmission system to the 115 kV Dryden sub-system. A 115/230 kV autotransformer typically costs in the range of $15 million to $20 million and the lead time to develop a transformer is typically three to five years. These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and utilities’ rate filings. The costs of “wires” solutions would depend not only on

[15] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

the specific infrastructure involved, but also on the cost of providing energy at the provincial system level. Cost responsibility for the transmission and distribution infrastructure would be determined as part of the regulatory application review process.

7.2 Opportunities to Further Improve Service Reliability

As discussed in Section 6.2.4 and Section 6.3.2, the reliability performance of the West of Thunder Bay Sub-region is generally within the provincial service reliability and performance standards. Communities and customers may consider working with LDCs and transmitter to explore opportunities to improve transmission and distribution service reliability and performance. Cost-benefit and cost allocation for investments will need to be considered.

At the distribution level, communities and customers may work with LDCs to identify mitigation measures to improve distribution service reliability, where applicable. Similarly, at the transmission-level, LDCs or transmission-connected customers may work with Hydro One Transmission to look at potential transmission improvements (e.g., switching facilities) to reduce the risk and impact of supply interruptions, especially during maintenance outages. Furthermore, many communities are interested in developing distributed energy resources. Communities may wish to explore opportunities for community-based solutions and emerging technologies, such as on-site generation and storage facilities, to minimize the impact of potential power outages.

Whether customers are looking at incremental distribution, transmission or community–based energy solutions to improve service reliability, consideration must be given to the cost–benefits and cost responsibility issues. According to the OEB's proposed "beneficiary pays" principle for cost-allocation, the responsibility to pay for higher reliability would likely be borne by the customers in the area. The issue of how much is appropriate to invest and who pays for the investments will need to be addressed.

The cost of improving service reliability varies depending on geography, the nature of the issue and the local system configuration. In the case of the West of Thunder Bay Sub-region, given the large geographical area and sparse population, solutions for improving system reliability performance may be very costly (e.g., a transmission line covering hundreds of kilometers), while the benefiting customer base may be relatively small. The Working Group has heard from communities and customers in this sub-region that below-average reliability is an impediment to economic development, while the investments necessary to improve the situation are not affordable. However, minor improvements, such as switches and outage mitigation and maintenance measures (e.g., tree trimming and relocations of off-road distribution lines), and distributed energy resources, may be more cost-effective alternatives. In any case, the cost-benefit and responsibility of investments to further improve service reliability will need to be examined on a case-by-case basis.

7.3 Potential Areas for Coordination: Community Energy Planning and Regional Planning Activities

As discussed in Section 6.3.3, a number of communities are currently in the process of developing community energy plans. Greater coordination between community energy planning and regional planning processes can help provincial system planners and local communities develop a common understanding of the growth and local developments, identify opportunities to develop community-based energy solutions and have an informed dialogue on related energy issues.

With the input from the LACs, the Working Group identified potential areas for greater coordination:

- Status of local growth and developments
- Local planning priorities
- Local energy planning activities (e.g., community energy plan)
- Impact of potential supply interruptions or outages
- Potential, feasibility and challenges of implementing community-based energy solutions in consideration of cost-benefit and cost responsibility

LAC meetings can be used as a forum to facilitate the discussion on these energy and planning issues at the community, distribution, regional and bulk system levels. More importantly, these meetings can provide an opportunity for communities to share lessons learned and best practices from community energy planning activities across a region.

A number of coordination efforts are underway in Ontario to facilitate the development of community energy planning, such as the Quality Urban Energy Systems of Tomorrow ("QUEST") initiative. Due to the unique energy planning challenges in the northwest, it would be helpful to identify initiatives to facilitate knowledge sharing and coordinate community energy planning activities in northern Ontario (e.g., a community energy planning webinar or workshop for communities in northern Ontario).

8. Recommended Actions

While specific solutions do not need to be committed to today, it is appropriate to begin work to gather information, monitor developments, continue to engage communities and develop alternatives to support decision-making for the next iteration of the IRRP for this sub-region. The plan sets out the actions required to ensure that options remain available to address future needs, if and when they arise.

Supply capacity needs on the Dryden 115 kV sub-system may emerge under the High scenario, but these potential needs do not require any immediate action. The Working Group will monitor demand growth closely to determine if and when an investment decision for the Dryden 115 kV sub-system is required. In the meantime, the Working Group will keep the communities informed about any developments at the bulk, regional and distribution levels. For communities and customers who are looking to further improve service reliability, they may consider working with LDCs and Hydro One Transmission to develop transmission, distribution and community-based solutions. However, cost-benefit and responsibilities will need to be taken into consideration. Communities in the West of Thunder Bay Sub-region have become increasingly involved in community energy planning activities. The results of early community energy planning initiatives, energy conservation initiatives, and achievable potential studies will be an important input to the next iteration of the plan for the West of Thunder Bay Sub-region. The LAC meetings can be an opportunity to help facilitate greater coordination between the local and regional electricity planning activities.

The recommended actions and deliverables for the plan are outlined in Table 8-1, along with the proposed timing and the parties assigned lead responsibility for implementation. The West of Thunder Bay Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the West of Thunder Bay Sub-region and track progress of these deliverables.

Table 8-1: Recommended Actions

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	Monitor electricity demand growth closely to determine if and when a decision on Dryden 115 kV sub-system is required	Review electricity demand growth in the West of Thunder Bay and the North of Dryden Sub-regions with the members of the LACs	Working Group	Annually
2	Ensure communities are informed of bulk and distribution planning activities in the West of Thunder Bay Sub-region	Provide a status update on bulk and distribution planning activities at LAC meetings	Working Group	On-going
3	Explore opportunities to further improve service reliability and power quality in consideration of cost-benefit and cost allocations	Examine cost benefit and cost responsibility of distribution, transmission and/or community-based energy solutions	Customers, local distribution companies, and transmitter	On-going
4	Coordinate regional and community energy planning activities	Use LAC meetings as an opportunity to share best practices and to coordinate regional and local energy planning activities Identify opportunities to facilitate knowledge sharing and to coordinate community energy planning activities in northern Ontario, such as webinars on community energy planning in northern Ontario	Working Group and Communities	On-going

9. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the West of Thunder Bay IRRP.

A phased community engagement approach was undertaken for the West of Thunder Bay IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the former OPA and the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Summary of the West of Thunder Bay Community Engagement Process

Creating Transparency: *Creation of West of Thunder Bay IRRP Information Resources*	• Dedicated West of Thunder Bay IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One Network Inc's website • Self-subscription service established for the Northwest Ontario planning region for subscribers to receive regional planning updates • Status: complete
Engaging Early and Often: *First Nation & Municipal Métis Outreach*	• Early engagement on regional planning and the draft Northwest Ontario Scoping Assessment Report (October - December 2014) • Meetings held with First Nations communities from across the planning region in Dryden, Fort Frances and Kenora (June - July 2015) • Group meetings held with municipalities from across the planning region in Dryden, Fort Frances and Kenora (June - July 2015) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: *Broader Community Outreach*	• West of Thunder Bay Local Advisory Committees (LACs) formed in fall 2015; dedicated West of Thunder Bay engagement page added to IESO website • Two LAC meetings held in November 2015 and April 2016 to discuss and obtain feedback on the development of the IRRP • General LAC meetings are open to the public and broadcast via live webinar; materials are posted to the engagement webpage • Status: begun in summer 2015; on-going

9.1 Creating Transparency

To start the dialogue on the West of Thunder Bay IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the West of Thunder Bay Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader Northwest Ontario planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the West of Thunder Bay IRRP were initiated in October 2014 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across northwest Ontario. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the Northwest Ontario Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation community members, Métis council members, federal and provincial representatives, electricity customers, Common Voice Northwest, transmission and generation project developers, and others.

9.2.1 Northwest Ontario Scoping Assessment Outcome Report

The draft Northwest Ontario Scoping Report was posted to the IESO website in December 2014 for comment. Following this comment period, the final scoping report was posted on January 27, 2015.

9.2.2 First Nation and Métis Community Meetings

Meetings with First Nation communities are one of the first steps in engagement for all regional plans. Initial meetings were held in Dryden, Fort Frances and Kenora in June and July 2015. The purpose of these meetings was to discuss the development of the IRRP and share the initial findings. During these meetings, community members indicated their participation in community energy planning as well as interest in local small renewable projects. Communities also gave information about developments in their community and the growing population. Concern was also raised about service outages and the cost of electricity.

On April 18, 2016, the IESO met with Dalles (Ochiichagwe'Babigo'Ining) Ojibway Nation to discuss the status of planning and the identified needs in the West of Thunder Bay area. The community also raised concerns about high electricity costs and the impact of hydroelectric power and other electricity infrastructure on their community.

The IESO invited all other local First Nations communities and Métis councils to similar meetings and remains open to further engagement on the plan.

9.2.3 Municipal Meetings

Meetings with area municipalities are also one of the first steps in engagement for all regional plans. In June and July 2015, the Working Group held group municipal meetings in Dryden, Fort Frances and Kenora to discuss the development of the IRRP as well as the findings to date. Attendees were generally pleased with the meetings and the opportunity to offer a local perspective, and they looked forward to the development of the LACs. During these meetings, many communities also indicated they were interested in developing community energy plans and wanted to find out more about how these plans and the IRRP could work together.

9.3 Bringing Communities to the Table

To continue the dialogue on regional planning, two LACs – a general LAC and a First Nations LAC - were established for the West of Thunder Bay regional planning area in fall 2015. The role of LACs is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. General LACs are comprised of Indigenous, municipal, environmental, business, sustainability and community representatives. First Nations LACs are comprised of representatives from the First Nation communities in the planning area. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's West of Thunder Bay engagement web page[16]. The general LAC meetings are also broadcast as live webinars to enable participation from across the planning region.

Development of the West of Thunder Bay general LAC was completed through a request for nominations process promoted by the following activities in July/August 2015: advertisements in local newspapers across the planning area and in Thunder Bay newspapers; localized digital advertising; emails sent to municipal representatives across the region; and an e-blast sent to the IESO's Northwest Ontario subscribers list. Two Métis Councils in the West of Thunder Bay area appointed a member to the general LAC. The development of the West of Thunder Bay First Nations LAC was established through a letter to the leadership of each First Nation in the

[16] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

West of Thunder Bay area inviting them to appoint a representative to the First Nations LAC. The First Nations LAC then appointed members to the general LAC.

The first meetings of the West of Thunder Bay LACs were held on November 18-19, 2015 in Dryden. The focus of these meetings was to introduce the regional planning process to the newly formed LACs, highlight key electricity supply issues and considerations in the West of Thunder Bay area, and determine the purpose and scope of the LACs. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.[17]

On April 19-20, 2016, the second general and First Nation LAC meetings were held in Dryden. The focus of these meetings was to provide an update on electricity planning activities in the area, review the draft outcomes of the West of Thunder Bay IRRP and determine key areas of focus for future LAC meetings. Material from the two LAC meetings and a web archive of the general LAC meeting can be accessed online.

Copies of the meeting summaries from the West of Thunder Bay general LAC meetings can be found in Appendix F.

Moving forward, the Working Group will present the final IRRP to both of the West of Thunder Bay LACs and discuss with members how they would like to continue the dialogue on regional planning in the area, as well as other electricity issues brought up by the LAC members, but that are outside the scope of regional planning.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website. Additional information on outreach activities for the West of Thunder Bay IRRP can be found on the IESO webpage and updates will continue to be sent to all Northwest Ontario Region email subscribers.

9.4 Additional Meetings and Presentations

The IESO recognizes Common Voice Northwest's unique mandate that includes investigating and making recommendations to the Northwest Ontario Municipal Association ("NOMA") on issues related to energy in the Northwest Ontario Region. The IESO continues to meet regularly

[17] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

with Common Voice Northwest to discuss the status of electricity planning for northwestern Ontario.

The IESO also presents regularly at the NOMA Spring Annual General Meeting and Fall Regional Conference, the Association of Municipalities of Ontario conference, as well as the Ontario Mining Association conference, among others. These presentations have included high-level status updates on the development of the West of Thunder Bay IRRP, along with other electricity topics.

10. Conclusion

This report documents the IRRP that has been carried out for the West of Thunder Bay Sub-region and fulfills the OEB's regional planning requirement for the sub-region. The IRRP identifies electricity needs in this sub-region over the 20-year period from 2015 to 2034.

Aside from the potential need for additional supply on the 230 kV bulk transmission system, there are no major regional needs identified in the West of Thunder Bay Sub-region under the Low and Reference scenarios. An additional 50 MW of supply may be required on the Dryden 115 kV sub-system under the High scenario. However, early development work for major electricity infrastructure projects is not required at this time given the uncertainty with the demand forecast. The Working Group will monitor demand growth closely to determine if and when an investment decision for the Dryden 115 kV sub-system is required. Although the transmission and distribution reliability performance of the West of Thunder Bay Sub-region is within the provincial service reliability and performance standards, communities and customers may consider working with LDCs and Hydro One to explore opportunities to further improve transmission and distribution service reliability with consideration given to cost-benefits and responsibility for investments. In the meantime, a number of communities in this sub-region are currently developing community energy plans. LAC meetings can be used as an opportunity to share best practices and to coordinate regional and local energy planning activities.

The West of Thunder Bay Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the sub-region, and will produce annual update reports that will be posted on the IESO website. To support development of the plan, a number of actions have been identified to develop alternatives, engage with the community, and monitor growth in the area, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the West of Thunder Bay Sub-region. The plan will be revisited according to the OEB-mandated 5-year schedule.

Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

December 22, 2015

hydro one

[This page is intentionally left blank]

Prepared and endorsed by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)

[This page is intentionally left blank]

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (“RIP”) WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE WINDSOR-ESSEX REGION.

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

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

This RIP provides a consolidated summary of needs and recommended plans for Windsor-Essex Region. No long-term needs (10 to 20 years) and associated plans have been identified.

This RIP is the final phase of the regional planning process and it follows the completion of the Windsor-Essex Region Integrated Regional Resource Plan (“IRRP”) by the IESO in April 2015 [1].

The major infrastructure investments planned, or being planned, for the Windsor-Essex Region over the near and medium-term identified in the various phases of the regional planning process are given in the table below.

No.	Project	I/S Date	Cost
1*	Supply to Essex County Transmission Reinforcement (SECTR TX) Project	June 2018	$77.4M
2*	Supply to Essex County Transmission Reinforcement (SECTR DX) Project	June 2018	$19.3M
3	Replacement of Keith end-of-life autotransformers	2020	$45M
4	Replacement of Kingsville end-of-life transformers	2018	$12M
5	230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	2018	$63M
6	Additional feeder position at Malden TS	TBD	TBD
7	Decommission of Tilbury TS	2019	TBD
8	Decommission of T1 Transformer at Keith TS	TBD	TBD

* These projects address the needs identified in the Windsor-Essex IRRP study for the region in the near and medium-term.

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. Should there be any new needs that emerge due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

[This page is intentionally left blank]

1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE WINDSOR-ESSEX REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) and documents the results of the joint study carried out by Hydro One, EnWin Utilities Ltd. (“EnWin”), Essex Powerlines Corporation, E.L.K. Energy Inc. (“E.L.K Energy”), Entegrus Inc. (“Entegrus”), Hydro One Networks Inc. (Distribution) (“Hydro One Distribution), and the Independent Electricity System Operator (“IESO”) in accordance with the regional planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Windsor-Essex Region comprises the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The map of the region is shown in Figure 1-1 below.

The Windsor-Essex area is supplied from a combination of generation located in the region and from the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations. The region peak electricity demand of about 800 MW is provided from three 230 kV and fourteen 115 kV step-down transformer stations.

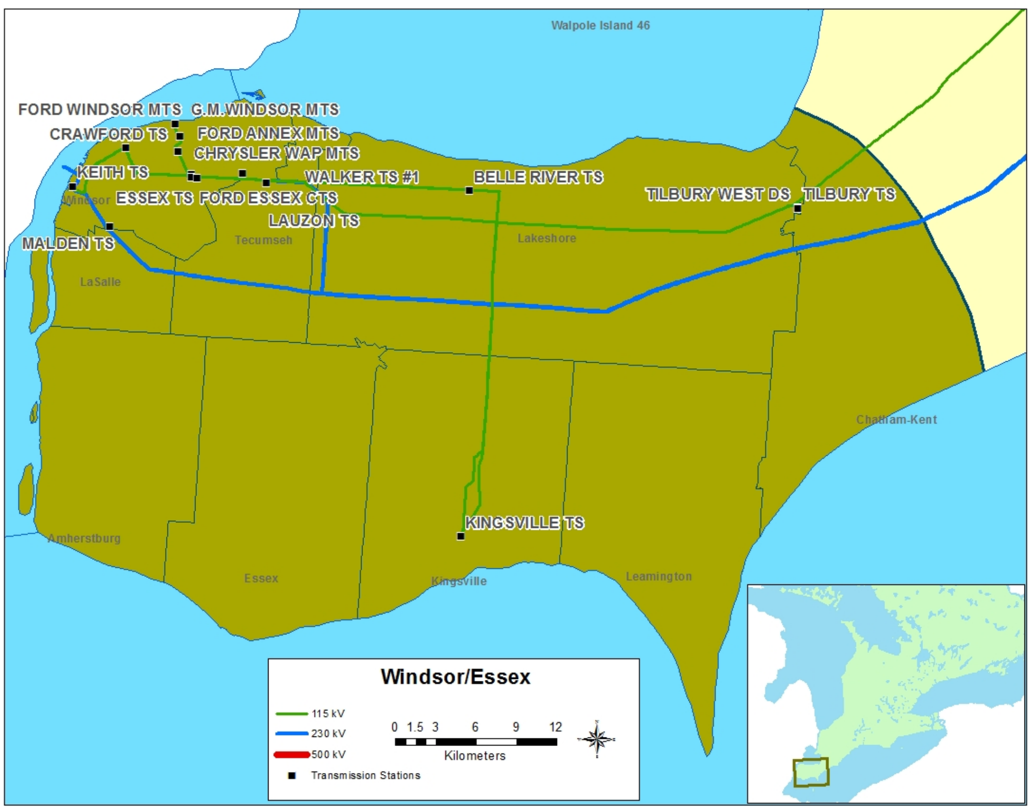


Figure 1-1 Geographical Map of Windsor-Essex Region

1.1 Scope and Objectives

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

Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete and the Windsor-Essex Region was identified as a "transitional" region. The planning status for the region was considered to be in the IRRP phase of the regional planning process. An IRRP for the region was completed in April 2015.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and mid-term needs (2015-2025) identified in previous planning phases (NA, SA, LP, and/or IRRP).
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Working Group.

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

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the region.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the regional needs.
- Section 7 provides a summary of regional plans.
- Section 8 provides summary of other projects.
- Section 9 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

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

[1] Also referred to as Needs Screening

need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. Since the Windsor-Essex Region was in transition to the new regional planning process, the IESO led IRRP engagement for this region was initiated after the completion of the IRRP.

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

The regional planning process specifies a 20 year planning assessment period for the IRRP. The RIP focuses on the wires options and, given the forecast uncertainty and the fact that adequate time is available to identify and plan new wire facilities in subsequent planning cycles, a study period of 10 years is considered adequate for the RIP. The exception would be the case where major transmission infrastructure investments are required. In these cases the RIP would review and assess longer term needs and develop a longer term plan.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- Participating in and conducting wires planning as part of the IRRP for the region.
- Working and planning connection capacity requirements with the LDCs.

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

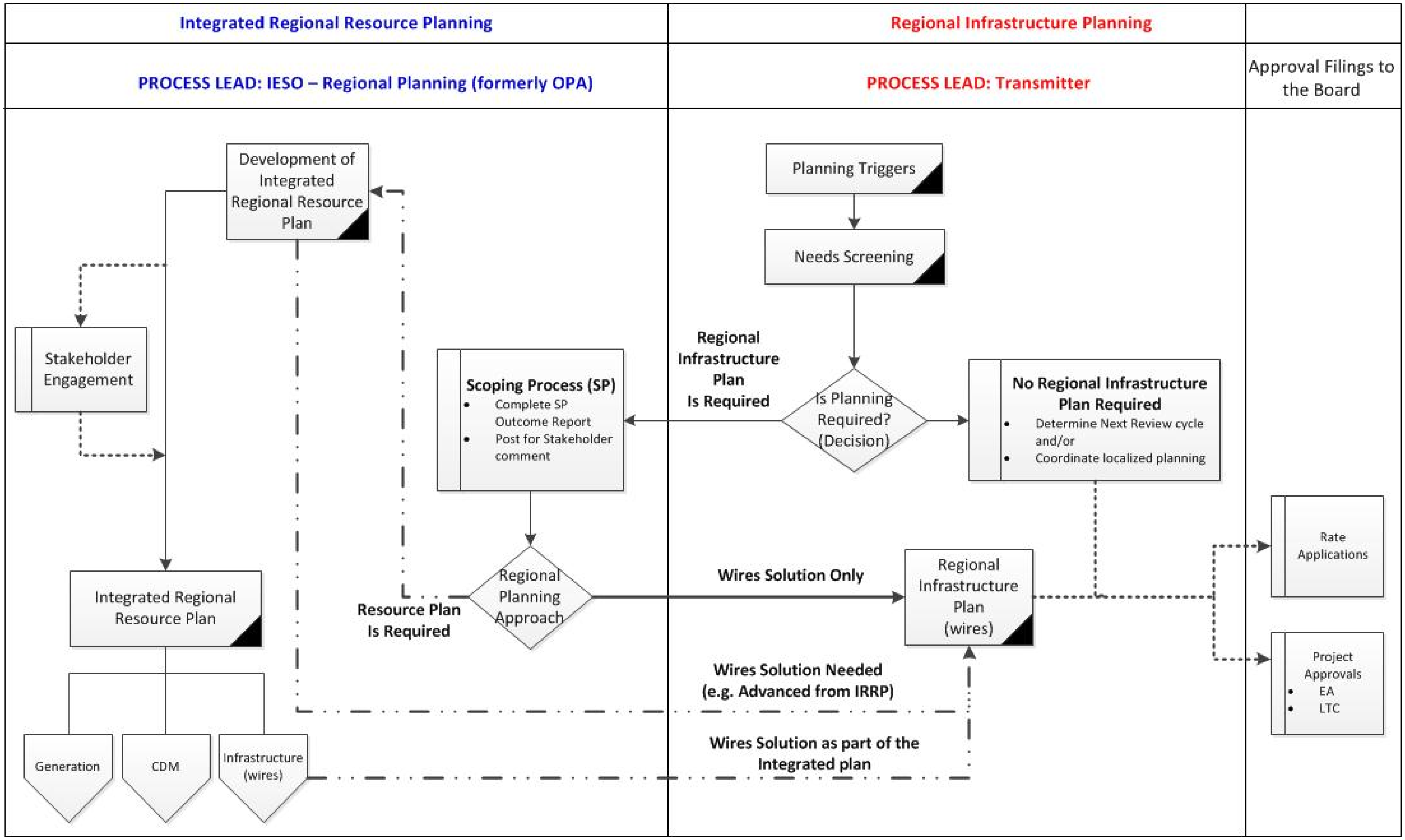


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP process is a four step process as shown in Figure 2-2 below.

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

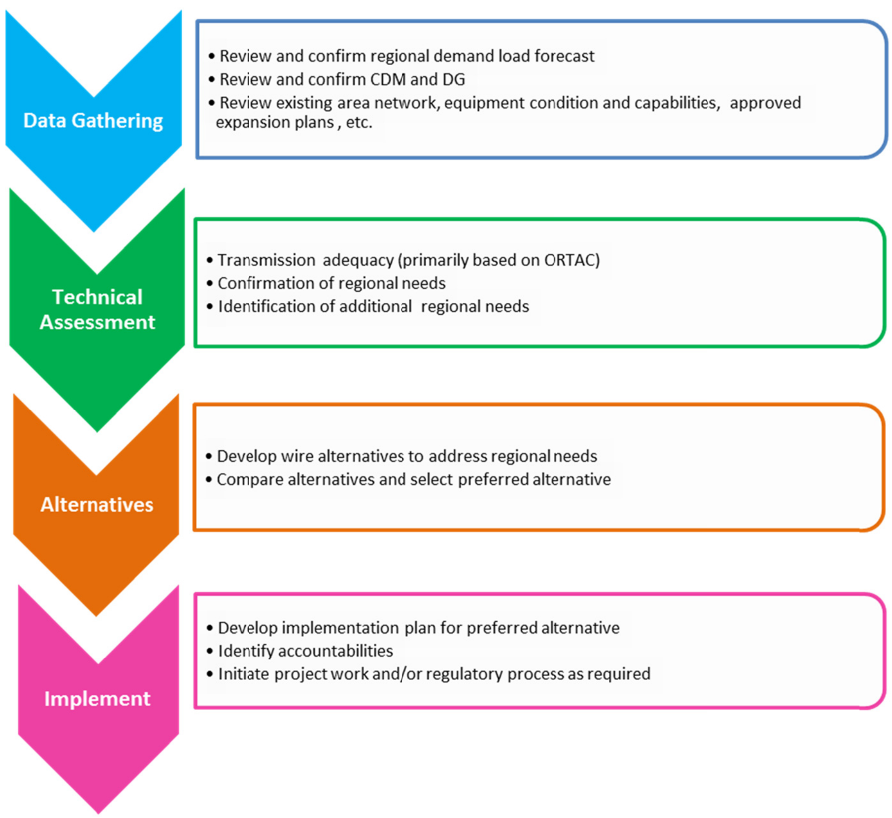


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION COMPRISES THE CITY OF WINDSOR, TOWN OF AMHERSTBURG, TOWN OF ESSEX, TOWN OF KINGSVILLE, TOWN OF LAKESHORE, TOWN OF LASALLE, MUNICIPALITY OF LEAMINGTON, TOWN OF TECUMSEH, THE WESTERN PORTION OF THE MUNICIPALITY OF CHATHAM-KENT AND THE TOWNSHIP OF PELEE ISLAND.

The region is served by five LDCs: EnWin, Essex Powerlines Corporation, E.L.K. Energy, Entegrus, and Hydro One Distribution, whose service territories are shown in Figure 3-1. EnWin and Hydro One Distribution are directly connected to the transmission system, while the three other LDCs have low voltage connections.

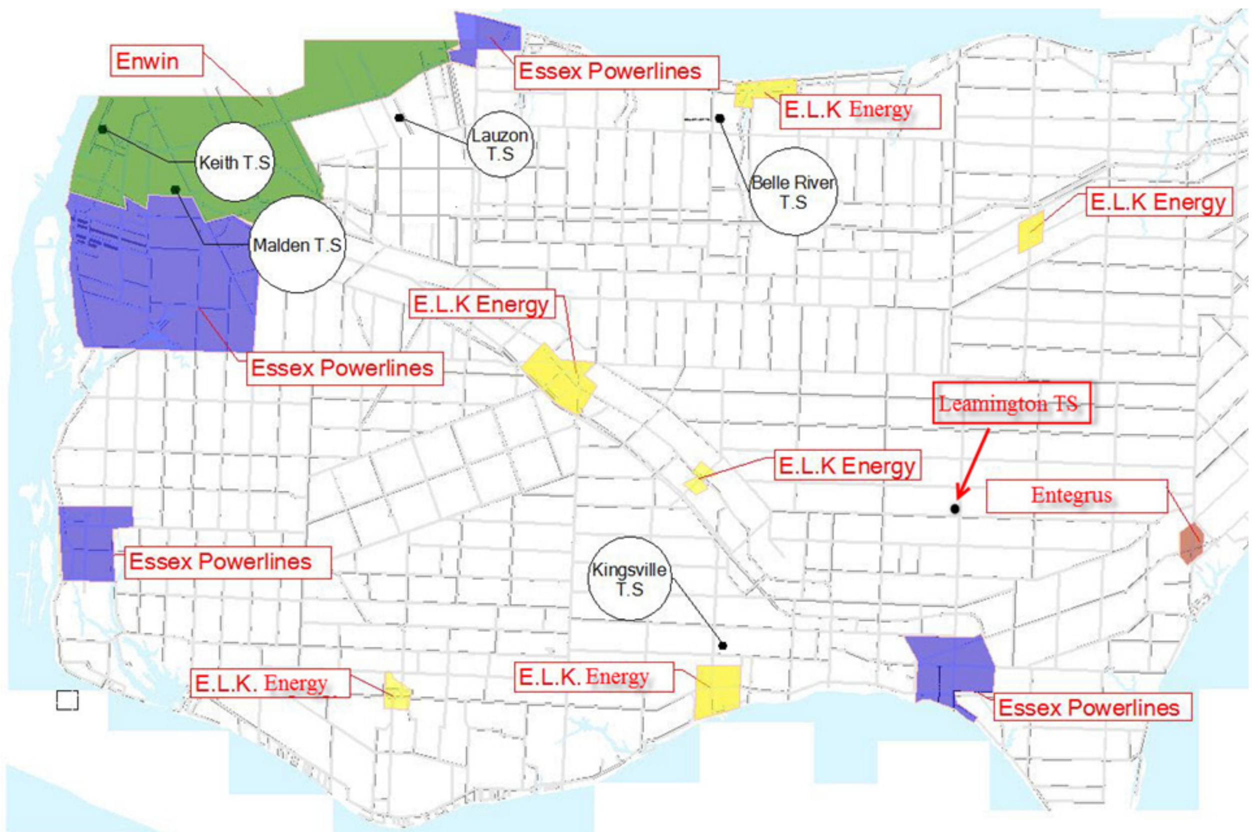


Figure 3-1 LDC Service Territories

The region peak electricity demand of about 800 MW is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 3-2 below.

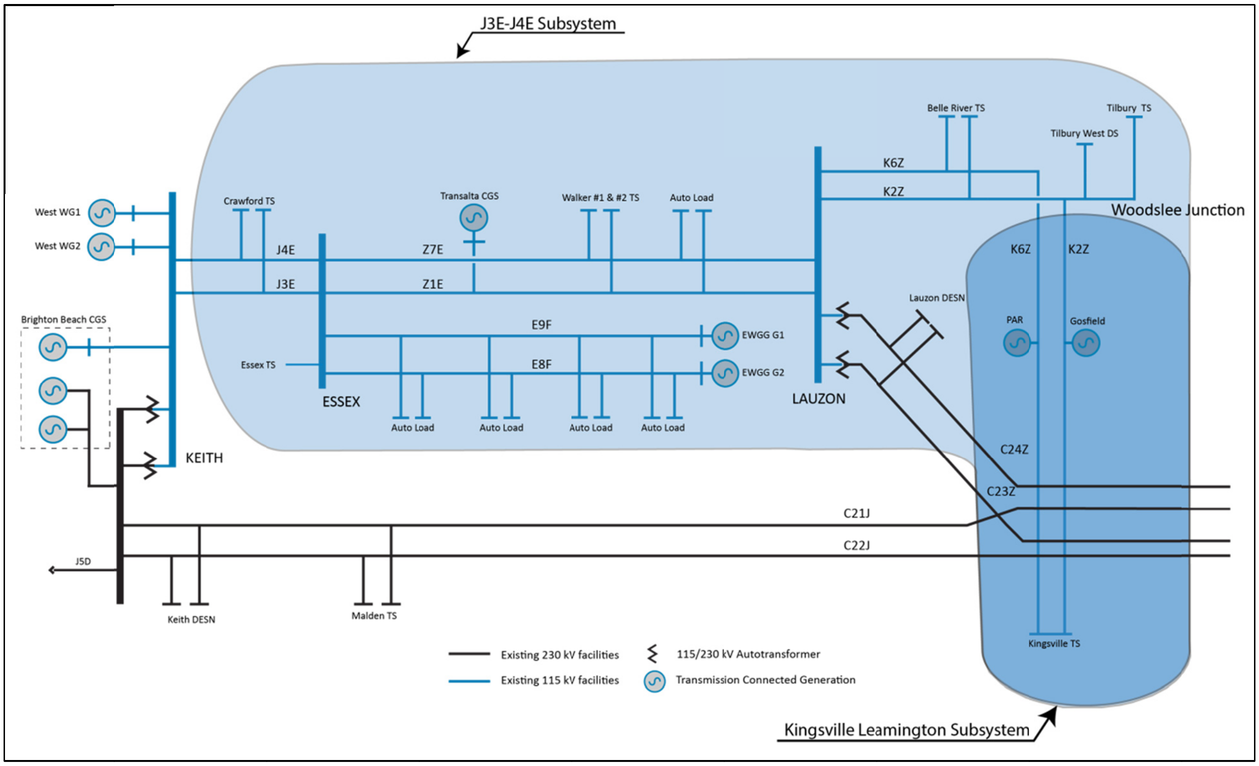


Figure 3-2 Windsor-Essex Area Subsystems/Single Line Diagram

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two auto-transformers in each station. About 65% of the area load is supplied by fourteen step-down transformers stations connected to the 115 kV network, while the balance is supplied by three step-down transformer stations connected to the 230 kV network. Table 3-1 lists the region's step-down transformer stations.

There are six customer-owned generating plants in the region connecting at the 230 kV and 115 kV levels with a combined contract capacity of 927 MW. In addition, the distributed generation connected at various locations to low-voltage ("LV") feeders in the region account for about 65 MW of effective capacity. Table 3-1 list the region's transmission connected generations.

The transmission system in the region can be divided into two "nested" sub-systems:

- The Kingsville-Leamington subsystem: customers supplied from Kingsville TS and
- The J3E-J4E subsystem: customers supplied from stations connected to the Windsor-Essex 115 kV system, as well as customers supplied from the 230/27.6 kV Lauzon DESN.

As can be noted in Figure 3-2 below, the Kingsville-Leamington subsystem is nested within the J3E-J4E subsystem. Therefore, increasing supply to the Kingsville-Leamington subsystem or transferring load from the existing Kingsville TS to a new 230 kV TS will impact the supply and demand balance in the J3E-J4E subsystem.

Table 3-1 Stations Included in the Windsor-Essex Region

Station (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customer(s)
Belle River TS (T1/T2)	115/27.6	K2Z/K6Z	Hydro One Distribution
Kingsville TS (T1/T2/T3/T4)	115/27.6	K2Z/K6Z	E.L.K. Energy Essex Powerlines Corp. Hydro One Networks Inc.
Lauzon TS (T5/T6/T7/T8)	230/27.6	C23Z/C24Z	EnWin Utilities Ltd. Hydro One Distribution
Tilbury West DS	115/27.6	K2Z	Hydro One Distribution
Tilbury TS (T1)	115/27.6	K2Z	Hydro One Distribution
Chrysler WAP MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Crawford TS (T3/T4)	115/27.6	J3E/J4E	EnWin Utilities Ltd.
Essex TS (T5/T6)	115/27.6	Z7E/	EnWin Utilities Ltd.
Ford Annex MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Ford Essex CTS	115/13.8	Z1E/Z7E	EnWin Utilities Ltd.
Ford Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
G.M. Windsor MTS	115/27.6	E8F/E9F	EnWin Utilities Ltd.
Keith TS (T1)	115/27.6	C21J/C22J	Brighton Beach Power LP West Windsor Power EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Keith TS (T22/T23)	230/27.6	C21J/C22J	
Malden TS (T1/T2)	230/ 27.6	C21J/C22J	EnWin Utilities Ltd. Essex Powerlines Corp. Hydro One Distribution
Walker MTS #2	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.
Walker TS #1 (T3/T4)	115/27.6	Z1E/Z7E	EnWin Utilities Ltd.

Table 3-2 Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	Dec. 31, 2024	Keith TS	541	526
Combined Heat and Power (CHP)	West Windsor Power	May 31, 2031	J2N (Keith TS)	128	107
	TransAlta Windsor	Dec. 1, 2031	Z1E	74	74
	East Windsor Cogeneration Centre	Nov. 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	Jan. 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	Dec. 5, 2031	K6Z	49	8

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED OR ARE UNDERWAY BY HYDRO ONE, AIMED AT IMPROVING THE SUPPLY TO THE WINDSOR-ESSEX REGION. A BRIEF LISTING OF THE COMPLETED PROJECTS OVER THE LAST 10 YEARS IS GIVEN BELOW:

- Belle River TS (May 2006): Built a new 2-25/33/42 MVA 115/27.6 kV transformer station in the Town of Lakeshore supplied from 115 kV circuits K2Z/K6Z. The station provides additional load supply capability to meet the load requirements of Hydro One Distribution customers in the Town of Lakeshore. The connection of new station required the untwining of K6Z to obtain two circuits (K2Z and K6Z) with K6Z on the north side of the towers. The new K2Z circuit section which only extends to Belle River TS was then connected to the then existing K2Z circuit just outside of Lauzon TS.

- Essex TS (October 2008): The station was refurbished with new 2-50/66/83 MVA 115/27.6 kV transformers. The 115 kV supply circuits were reconfigured to mitigate exposure to customer load loss for loss of a single transmission element under certain system conditions.

- Malden TS: Transformer T2 75/100/125 230/27.6 kV was replaced (July 2010) and T1 was replaced (December 2011).

- Keith TS: T23 transformer 50/67/83 MVA 230/27.6 kV was replaced (October 2008) and T22 transformer 50/67/83 MVA 230/27.6 kV was replaced (December 2013).

- Walker TS #1: Reactor installation for short circuit mitigation (June 2011).

- Kingsville TS: Reactor installation for short circuit mitigation (November 2011).

- Keith TS: Reactor installation for short circuit mitigation (April 2012).

- Lauzon TS: Three breakers were replaced: SC2Q (June 2012), SC3E (April 2012) and SC4J (April 2012).

- Keith TS: Six breakers were replaced: SC11K (May 2014), SC11SC (May 2014), SC1B (June 2014), T11P (August 2014), T12P (October 2014), SC2Y (January 2015).

The following projects are currently underway:

- Crawford TS: is a 115/28 kV, with two 50/67/83 MVA units in Windsor. It supplies the downtown Windsor area with a current peak load of 60 MW. The existing T3 transformer is at the end-of-life with leaky fittings and headboard. The T3 fire suppression system and separation wall also needs to be upgraded to current standards. The current plan is to replace T3 transformer and install neutral grounding reactors on the T3 and T4 transformer units. The project includes protection and control upgrades and relocation of battery, necessary spill containment facilities at Crawford TS. The project is under execution for $8.46 million with an in-service date of December 15, 2016. There are no cost implications for the LDCs. Once this project is complete the station will meet the current design standards.

5. LOAD FORECAST AND OTHER ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The peak demand in the Windsor-Essex Region has declined from a high of 1060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014.

Figure 5-1 shows the historical summer peak demand observed in the region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both contributed to a decline in electricity use in the region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the region's growth and electricity use. The five-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the region, including advanced manufacturing, tourism, and agri-business.

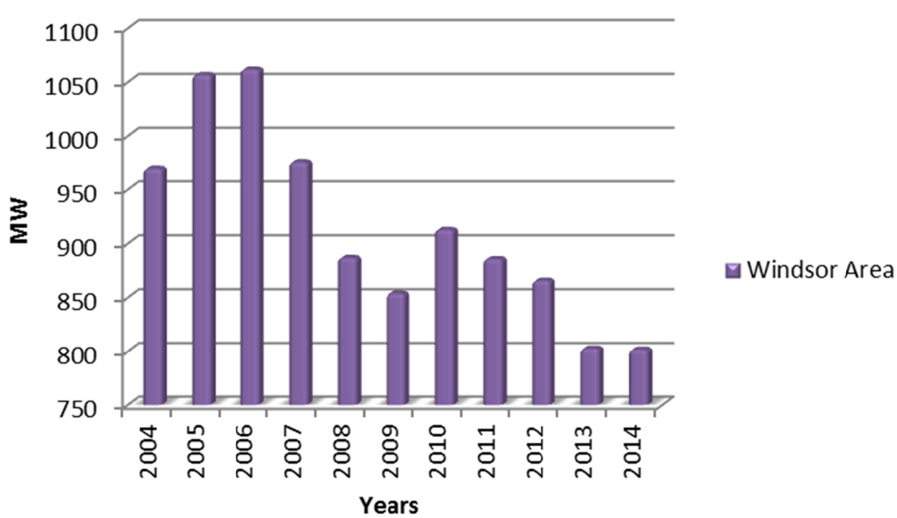


Figure 5-1 Historical Load Demand in Windsor-Essex Region

The peak demand in the Kingsville-Leamington area has also experienced fluctuations over the 2004-2014 period as shown in Figure 6-1.

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the Windsor-Essex Region:

a) First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
b) Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, and projected province-wide CDM programs. This information is provided by the IESO.
c) Lastly, a "planning forecast" is determined by reducing net demand by the contribution in the area from existing, committed and forecast DG. This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Summer peak gross non-coincident demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One Distribution, the two LDCs which are directly connected to the transmission system, for each of the transformer stations in the area. The forecasts from Hydro One Distribution include forecasts provided by the appropriate embedded LDCs.

The development of the load forecast for this RIP report followed a two-stage process:

(a) Using the forecast provided by the LDCs, the year by year growth rate for each station was first developed.
(b) The 2014 summer actual peak load, corrected for extreme weather, for each station was obtained.
(c) The growth rates from (a) were then applied to the 2014 summer peak load of (b) to obtain the gross load forecast for each station for extreme weather conditions.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. This load forecast reflects the following:

- A shift of load, commencing in 2016, from Walker TS #1 and #2 to Essex TS and GM MTS.
- Reduction in Kingsville TS load.
- Increase in loads at Keith TS, Crawford TS and Lauzon TS.

The gross load forecasts, for extreme weather conditions, by station and by subsystem are shown in Appendix A. Figure 5-2 is a graph of the Windsor – Essex Region extreme weather peak summer non-coincident load forecast. The overall region will experience an average annual growth rate of just less than 1%, while the Kingsville-Leamington area average growth rate would be about 1.6%.

Figure 5-2 also shows the load forecast from the IRRP report. The two forecasts are not materially different; hence the load forecast in this RIP report will not alter the conclusions of the IRRP.

The Reference Planning forecast (Appendix D) for each station is obtained by reducing the gross load forecast for the station by the amount of forecast conservation and DG. The conservation forecast (Appendix B) and the DG forecast (Appendix C) are the same as used in the IRRP report.

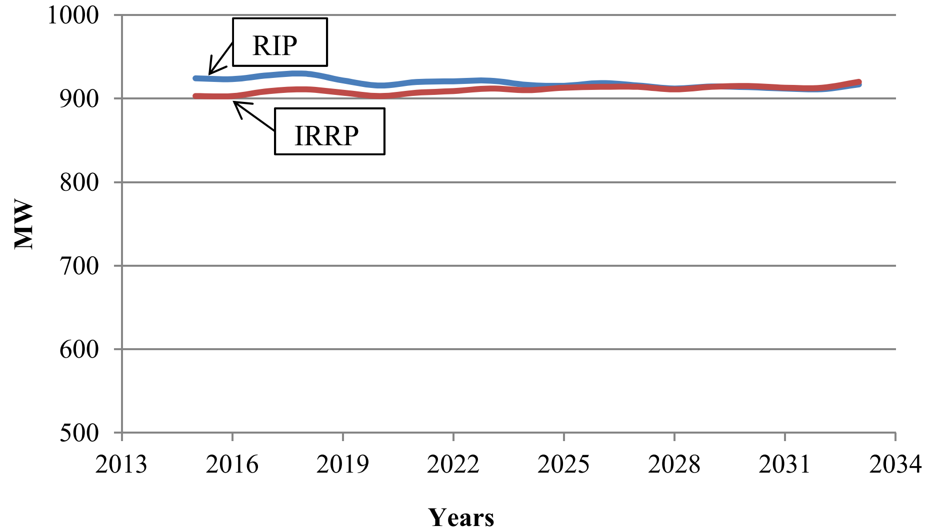


Figure 5-2 Reference Forecast in Windsor-Essex Region

5.4 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity. Load is assumed at 90% lagging power factor, unless known.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.

6. REGIONAL NEEDS

THIS SECTION SUMMARIZES THE WINDSOR-ESSEX REGION NEEDS OVER THE NEAR AND MID TERM. NO LONG TERM NEEDS HAVE BEEN IDENTIFIED.

Earlier studies by the IESO, ("Windsor-Essex Region Integrated Regional Resource Plan" - April 28, 2015, Supply to Essex County Transmission Reinforcement Project, January 2014) identified two near-term needs in the region. These needs are:

- **Minimize the Impact of Supply Interruptions in the J3E-J4E Subsystem:**
  The existing system lacks the capability to restore power to customers in the J3E-J4E subsystem in accordance with the ORTAC criteria, i.e., restoration of all loads within 8 hours. Based on current and forecast demand, up to 170 MW 0f the load interrupted cannot be restored by 2017.

- **Additional Supply Capacity in the Kingsville-Leamington Area:**
  Demand in the Kingsville-Leamington subsystem has already exceeded the load meeting capability of 120 MW in recent 3 years and is expected to continue to exceed the supply capacity over the forecast period. Figure 6-1 below shows the historical and forecast demand and supply capabilities in the Kingsville-Leamington subsystem after conservation and DG are taken into consideration.

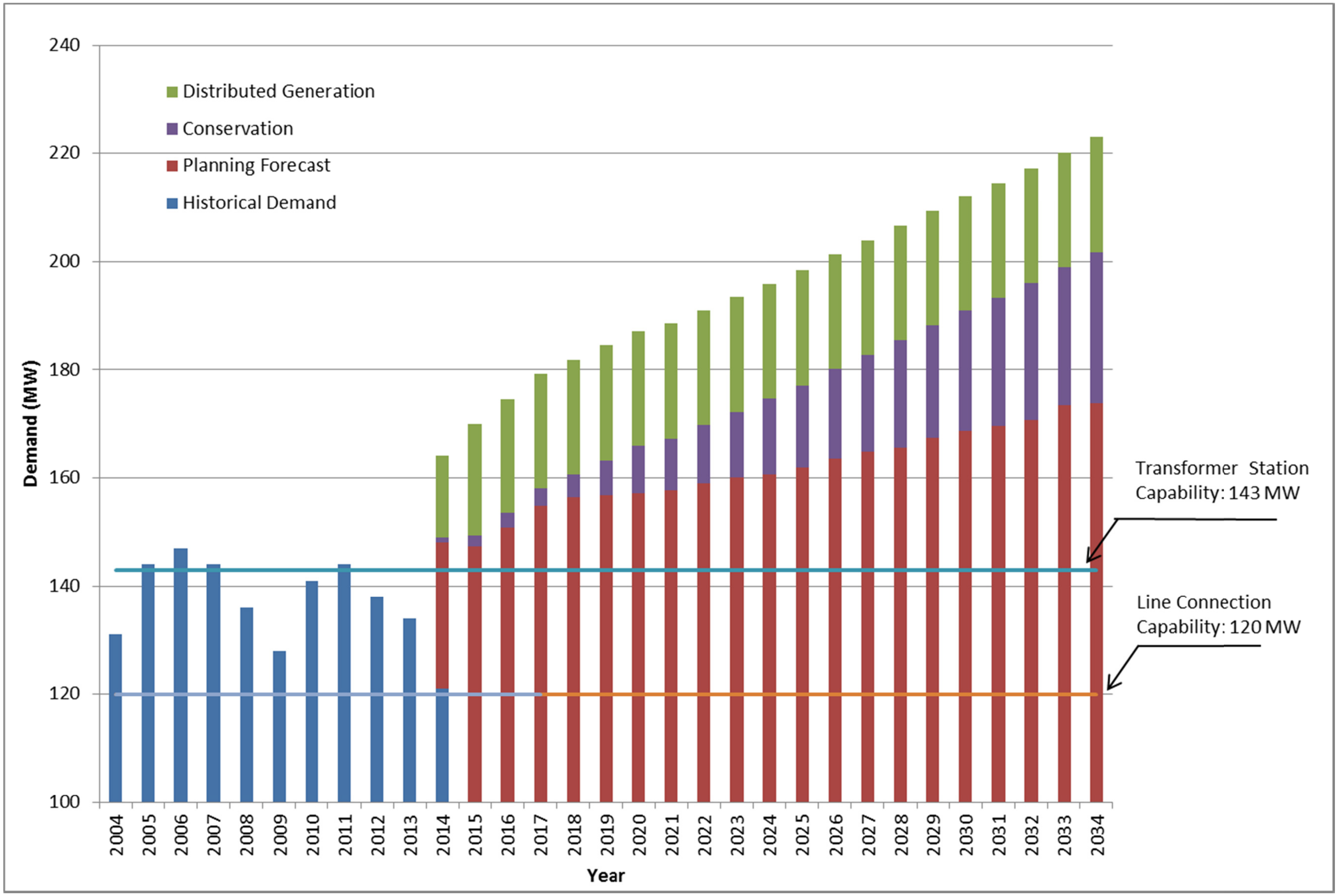


Figure 6-1 Historical and Forecast Demand of Kingsville-Leamington Subsystem

In addition, Hydro One has also identified infrastructure and major equipment which need replacement during the study period. The current plan is essentially a like-for-like replacement of 3 step-down transformers at Kingsville TS and 2 auto-transformers at Keith TS.

These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

Table 6-1 Summary of Needs

Type	Needs	Timeline	Process
Capacity to Meet Demand	Kingsville-Leamington Subsystem	2018	**IRRP**
Minimize the Impact of Interruption	J3E-J4E Subsystem	2018	**IRRP**
Aging Equipment Replacement	3 transformers at Kingsville TS are at end-of-life	Near-Term	**RIP**
Aging Equipment Replacement	2 autotransformers at Keith TS are at end-of-life	Near-Term	**RIP**

7. REGIONAL INFRASTRUCTURE PLANS

THIS SECTION PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE WINDSOR-ESSEX REGION.

7.1 Supply to Essex County Transmission Reinforcement (SECTR) Project

7.1.1 Description

The SECTR project as presented in the IRRP is an integrated solution to address both the J3E-J4E subsystem restoration need and the Kingsville – Leamington capacity need. As illustrated in Figure 7-1 the project consists of the installation of a new 230 kV supplied transformer station near Leamington connected to the existing C21J/C22J circuits via a new 13 km double-circuit 230 kV connection line on a new right-of-way.

The total cost of this project is $96.7M made up of:

(a) Build 230/27.6 – 27.6 kV 75/100/125 MVA Leamington TS with six LV breaker positions, plus other required switchgear: $32.1M
(b) Build a 13 km 2-circuit 230 kV line on a new right-of-way tapping into existing 230 kV circuits C21J/C22J plus Optical Ground Wire: $45.3M.
(c) Carry out distribution work for Leamington TS: $19.3M. Other additional distribution work includes two additional feeder positions at Leamington TS, and protection upgrades for in-service Kingsville DG transferred to Leamington TS.

With the establishment of Leamington TS, load will be transferred from Kingsville TS to the new station, such that the Kingsville TS load will be reduced to about 50 MW. As discussed in the IRRP report, this presents an opportunity to downsize the station from four transformers to two transformers, and would result in a combined supply capability in the Kingsville-Leamington area of 210 MW.

Figure 7-2 is a preliminary plan for the transfer of Kingsville TS feeders to Leamington TS. Feeders which are shown in blue will be completely transferred to Leamington TS, and the ones shown in green will be partially transferred to Leamington TS.

7.1.2 Recommended Plan and Current Status

Hydro One filed an application on January 22, 2014 with the OEB under Section 92 of the OEB Act for an order granting leave to construct approximately 13 km of new 230 kV transmission lines on steel lattice towers on a new right of way in the Windsor-Essex area and the installation of optic ground wire for system telecommunication purposes on existing C21J/C23Z towers near Leamington Junction and on new 230 kV towers. The application included a request for OEB approval of the methodology for allocating project cost to Hydro One Distribution, embedded LDCs and Sub-Transmission class customers.

On February 12, 2015, Hydro One filed an updated application that included the new 230/27.6 kV Leamington Transformer Station (Leamington TS). The OEB decided that the proceeding would be addressed in two phases. Phase 1 would only deal with the leave to construct application and Phase 2 of the proceeding would deal with cost allocation. Phase 1 of the SECTR S.92 proceeding has concluded and the "Leave to Construct" approval was granted by the OEB on July 16, 2015. The expected in-service date for the SECTR Project is June 2018. Phase 2 of the proceeding is continuing via an OEB policy review rather than the originally planned adjudicative process.

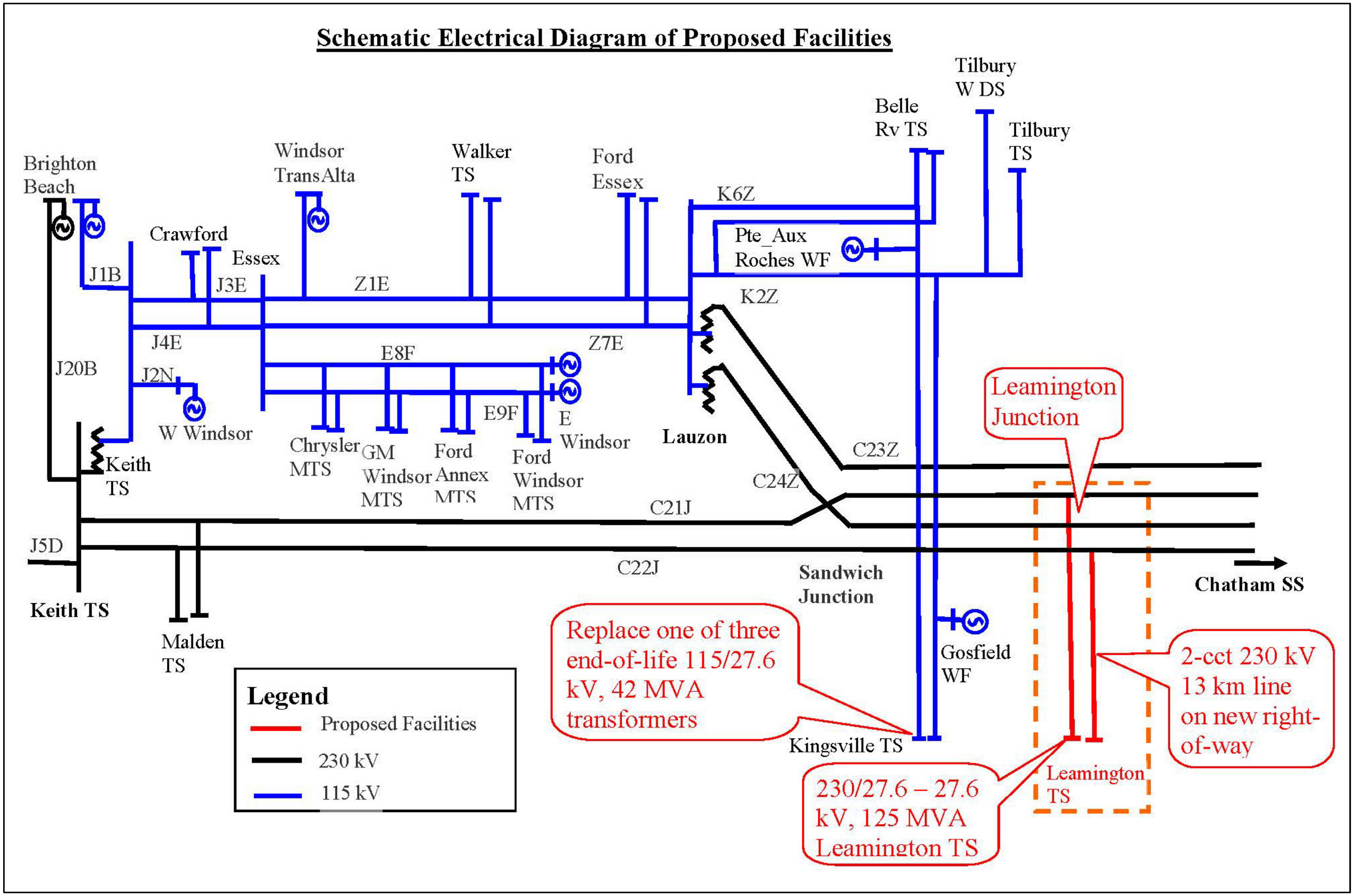


Figure 7-1 Schematic Electrical Diagram of the Proposed Facilities

Figure 7-2 Preliminary Distribution Feeder Plans for SECTR Project

7.2 Keith TS End-of-Life Auto-Transformer Replacement

7.2.1 Description

Keith TS is equipped with 2-230/115 kV 115 MVA autotransformers. These autotransformers are 1950's vintage and near end-of-life and require replacement.

7.2.2 Recommended Plan and Current Status

Due to SECTR project additional capacity will not be required and the end-of-life autotransformers at Keith TS will be replaced with equivalent like-for-like 125 MVA units. The expected in-service date is 2020. There are no cost implications for the LDCs.

7.3 Kingsville TS End-of-Life Transformer Replacement

7.3.1 Description

Kingsville TS is equipped with 4-115/27.6 kV 25/33/42 MVA transformers. One of these transformers was recently replaced, but the other three are 1950's vintage and will require replacement in the near future.

Due to SECTR project and the associated reduction in load at Kingsville TS, the station may be downsized and reconfigured as a two-transformer station. Hydro One Distribution is further reassessing to justify retaining the four-transformer arrangement if they receive additional request for connections at Kingsville area.

7.3.2 Recommended Plan

Hydro One Distribution to complete their connection capacity assessment as part of distribution system planning before Q3 2016 so that replacement and reconfiguration plan can be finalized by Hydro One in a timely manner.

7.4 Gordie Howe International Bridge (GHIB)

7.4.1 Description

The Gordie Howe International Bridge (GHIB) is a construction project under a bi-lateral agreement between the federal governments of Canada and the USA, and the governments of Ontario and Michigan, to construct a new border crossing between Windsor and Detroit. It will comprise a 12 km westerly extension of Hwy 401 to a site near Keith Transformer Station, where a new customs plaza and a new bridge over the Detroit River will be constructed. The highway will be extended by the Ministry of Transportation of Ontario (MTO), while the customs plaza and the bridge will be constructed by Transport Canada.

The GHIB project is multi-faceted in its impacts on Hydro One facilities and operations at Keith TS including: transmission lines, fiber lines and feeders relocation; insulation contamination due to salt spray effects from new bridge; relocation of access routes; possible security issues for staff accessing and working at the station; impacts on existing utilities (water/sewer/gas). In addition, the GHIB project will reduce the footprint of the station and encumber egress from the station. Consequently, this project will impact future expansion work at the station and possibly limit the extent to which the station can be developed relative to its ultimate plan development over the long term.

7.4.2 Recommended Plan and Current Status

In order to mitigate these impacts, as illustrated in Figure 7-3 below, additional real estate is required for future expansion to the north of McKee Rd. The existing transmission lines and feeders will also need to egress the station via underground cables so as not to interfere with the bridge operations.

The cost of this project will be fully recovered from the Windsor Detroit Bridge Authority (WDBA). A Transmission Assets Modification Agreement (TAMA) with the WDBA is expected to be finalized by early January 2016. Approvals for executing the project are expected by March 2016 for a planned in-service date by the end of 2018.

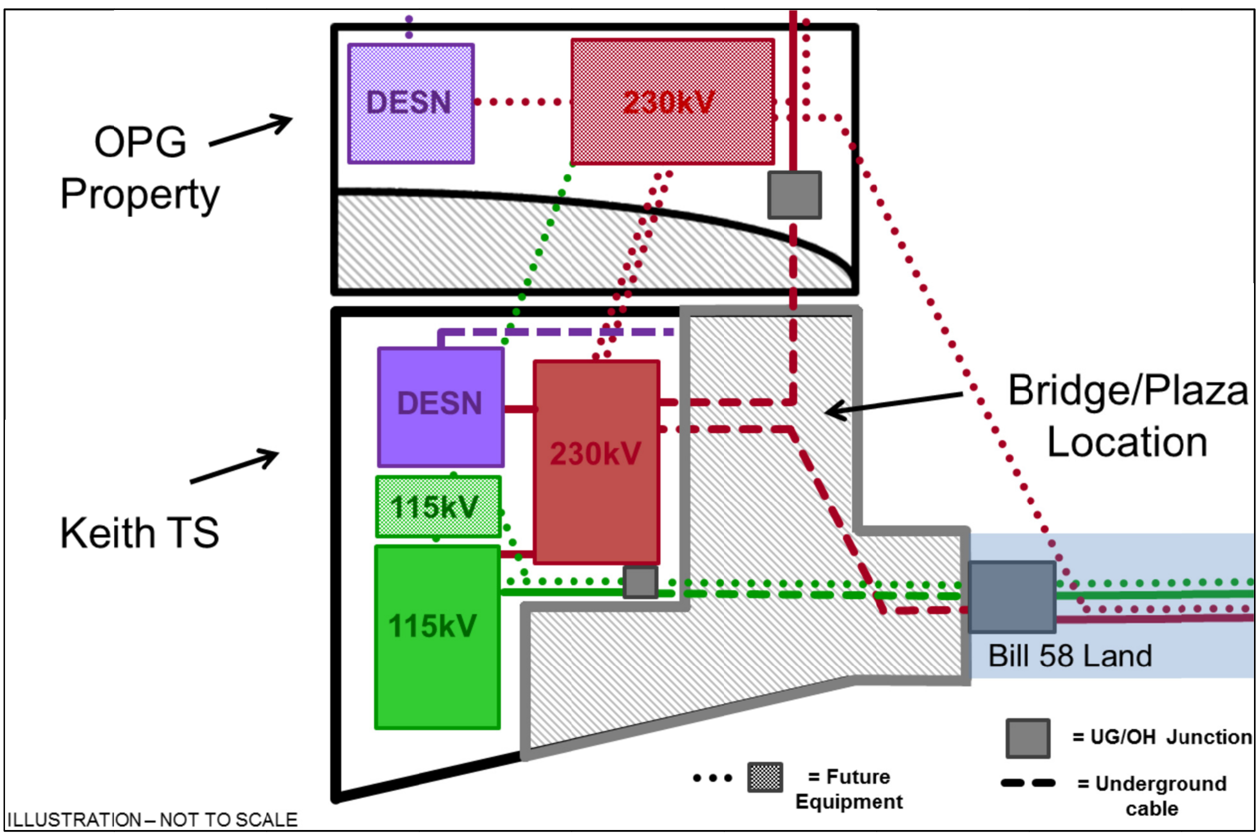


Figure 7-3 Gordie Howe International Bridge (GHIB) Project

8. OTHER PROJECTS

There are other wires projects that are currently under development and pending decision in the Windsor-Essex Region. These projects are local in nature and being planned and developed by Hydro One and relevant LDC as discussed below.

8.1 Malden TS Additional Feeder Positions

8.1.1 Description

Due to the load increase that's expected from the planned Detroit River International Crossing work and local highway construction, Essex Power has identified a need for two additional 28 kV feeder positions to be constructed at Malden TS.

The Malden transformer station is currently equipped with two 75/125 MVA transformers, 12 feeder positions and two capacitor banks and this plan involves expanding the station to 14 feeders. The two transformers at Malden TS were recently replaced, and there is additional capacity available at the station to meet the load requirement of the customer.

Based on a preliminary estimate the following will be the cost for the different layouts:

- Installation of two 28kV feeder breaker positions with feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $1.1M
- Installation of one 28kV feeder breaker position with no feeder tie with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $875k
- Installation of one 28kV feeder breaker position with a break before make connection to alternate bus with underground feeder egress to outside station fence by 1 meter. Estimated cost of about $925k

8.1.2 Recommended Plan and/or Current Status

The above options have been provided to Essex Powerlines Corp. Hydro One is awaiting its decision on the preferred option expected to be made in 2016.

8.2 Tilbury TS Transformer End-of-Life Replacement

8.2.1 Description

Tilbury West HVDS and Tilbury TS are both supplied from 115 kV circuit K2Z and are adjacent to each other. The two stations supply the Town of Tilbury and surrounding area. Tilbury West HVDS consists of 2 x 15/20/25 MVA, 115/27.6 kV transformers of 1980's vintage with two feeder positions; and Tilbury TS consists of 1 x 6/8 MVA 115/27.6 kV transformer of 1950's vintage with one feeder position. The

2014 peak load at Tilbury TS was 1.0 MW, and 16 MW at Tilbury West HVDS. The future load levels over the next 10 years at these stations are not expected to grow significantly.

Tilbury TS is near its end-of-life, and a decision to replace or retire should be made by 2017. Following three options are under consideration for Tilbury TS:

(1) Transfer Tilbury TS load (M1 feeder) to Tilbury West DS and decommission Tilbury TS at a cost of about $1.7M. This option is feasible as there is sufficient capacity at Tilbury West HVDS to accommodate both the Tilbury West HVDS forecast load and the Tilbury TS forecast load into the long term. Further, Tilbury West HVDS has sufficient capacity to accommodate its existing DG connections plus the existing 5 MW solar DG currently connected to Tilbury TS.

(2) Refurbish Tilbury TS at a cost of about $5M. This option would retain the supply capacity level and supply diversity that currently exists.

(3) Build a new DESN station at Tilbury TS with dual 115kV circuit supply from the K2Z and K6Z for an expected cost of about $20M. This would include building the 115kV line out from Tilbury Junction to the TS and a complete new station.

8.2.2 Recommended Plan and Current Status

Option 1 is the least cost alternative. It is recommended that Hydro One will have further discussions with the LDCs regarding these options and associated costs. These discussions are expected in 2016, and a decision is expected to be made by no later than 2017. Project construction is planned to commence in 2018 for an expected in-service in 2019. Depending on the option selected, costs may have to be recovered from the LDCs consistent with the TSC.

8.3 Keith TS T1 Transformer End-of-Life Replacement

8.3.1 Description

Keith TS transformer T1 (25/33/42 MVA 115/27.6 kV) is of 1950's vintage and it is approaching end-of-life. EnWin is the only LDC supplied from this Keith T1 and exclusively serves a single customer Nemak. The peak load was 8 MW in 2014. The load growth is expected to remain at this level in the long-term.

There is sufficient capacity at the Keith DESN station to accommodate both the forecast at Keith DESN load plus the forecast Keith TS T1 load over the next 10 years.

Following three possible options are considered to address the end-of life issue for Keith TS T1:

(1) Replace Keith TS T1.
(2) Transfer Keith TS T1 load to Keith T22/T23 DESN station.
(3) Resupply Nemak from another EnWin feeder connected to Keith T22/T23 DESN.

8.3.2 Recommended Plan and Current Status

It is recommended to develop cost estimates for each of the option. Following that Hydro One will initiate discussions with EnWin to review the options and decide on a preferred option.

Cost estimates are expected in Q1 of 2016 and selection of a preferred option is expected before the end of 2016. Discussions will then ensue with Hydro One and EnWin regarding planned construction dates.

9. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report provides a single consolidated source of information for infrastructure plans in the Windsor-Essex Region. It develops and outlines a plan for investments in transmission and/or distribution facilities to meet the electricity needs within the region. The RIP report was developed in collaboration of a Technical Working Group consisting of representation from the LDCs in the region, the IESO, and led by Hydro One consistent with the requirements set out in the TSC, DSC and the PPWG report.

This report highlights several near-term needs in the region for which implementation plans have already been developed and are planned for completion in the next five years. Table 9-1 provides a status of these projects along with their cost and timelines. Projects requiring further planning on scoping and pending decisions on the preferred alternative are provided in Table 9-2. Over the next five years, the total transmission and distribution investments associated with these projects is approximately $215M - $225M.

Table 9-1 Project Under Development

Project/Plan	Cost	I/S	Performed by
Supply to Essex County Transmission Reinforcement “SECTR TX”	$77.4 Million	March 2018	Hydro One
Supply to Essex County Transmission Reinforcement “SECTR DX”	$19.3 Million	March 2018 (first stage)	Hydro One Distribution
Replacement of Keith end-of-life autotransformers	$45 Million	2020	Hydro One
Replacement of Kingsville end-of-life transformers	$12 Million	2018	Hydro One
230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project	$63 Million	October 2018	Hydro One
Transformer replacement and station refurbishment at Crawford TS	$8.46 Million	December 2016	Hydro One

Table 9-2 Project Pending Decision

Project/Plan	Cost	I/S	Performed by
Additional feeder position at Malden TS	TBD	TBD	Hydro One
Replacement of Tilbury end-of-life transformer	TBD	2019	Hydro One
Keith TS end-of-life T1 Transformer	TBD	TBD	Hydro One

There are no long-term needs in this region that requires plans to be developed at this time. As with any region, the Windsor-Essex Region is monitored as part of Hydro One and LDC operations. Should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

10. REFERENCES

[1] Independent Electricity System Operator. "Windsor-Essex Region Integrated Regional Resource Plan". April 28, 2015.
http://www.ieso.ca/Documents/Regional-Planning/Windsor_Essex/2015-Windsor-Essex-IRRP-Report.pdf

APPENDIX A. GROSS FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
											Forecast										
Kingsville TS	158	133	137	141	145	146	147	148	149	150	151	152	153	155	156	157	158	159	160	161	162
Belle River TS	59	46	46	47	48	49	50	51	52	53	53	54	55	56	57	58	59	60	61	62	63
Tilbury West DS	34	17	17	17	17	18	18	18	18	18	19	19	19	19	19	19	19	19	19	20	20
Tilbury TS	10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Lauzon TS	225	191	193	195	197	199	201	203	204	206	208	209	211	213	215	217	219	221	223	224	226
Walker TS #1	99	71	79	76	77	77	78	78	79	79	80	80	81	81	82	82	83	83	84	84	85
Walker TS #2	99	95	111	92	92	93	93	94	94	95	96	96	97	97	98	99	99	100	100	101	102
Essex TS	116	55	63	73	73	74	74	75	75	76	76	77	77	78	78	78	79	79	80	80	81
Crawford TS	90	83	84	84	85	85	86	86	87	87	88	88	89	89	90	90	91	91	92	93	93
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**807**	**816**	**824**	**830**	**836**	**843**	**849**	**854**	**860**	**866**	**872**	**878**	**884**	**891**	**897**	**903**	**909**	**916**	**922**

Additional Stations in the Windsor-Essex Region Gross Demand (extreme weather)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
											Forecast										
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	67	67	67	67	67	67	68	68	68	68	68	68	68	68	68	69	69	69	69
Malden TS	200	117	118	119	120	120	121	122	124	124	125	126	127	127	128	129	130	131	131	132	133
Windsor Essex Total	**N/A**	**962**	**1000**	**1009**	**1019**	**1026**	**1033**	**1041**	**1048**	**1055**	**1061**	**1068**	**1074**	**1082**	**1089**	**1096**	**1104**	**1111**	**1118**	**1125**	**1133**

Kingsville-Leamington Sub-system Gross Demand (weather normal)	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
											Forecast										
Total	**N/A**	**155**	**160**	**165**	**169**	**172**	**174**	**177**	**178**	**181**	**183**	**186**	**188**	**191**	**193**	**196**	**199**	**201**	**204**	**206**	**209**

APPENDIX B. CONSERVATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Kingsville TS	158	1	2	3	3	4	6	9	10	11	12	14	15	16	18	20	21	22	24	25	26
Belle River TS	59	0	1	1	1	1	2	3	3	3	4	4	5	5	5	6	6	7	7	8	8
Tilbury West DS	34	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3
Tilbury TS	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lauzon TS	225	1	3	4	4	5	8	11	12	13	14	17	18	19	21	23	24	26	28	29	30
Walker TS #1	99	1	1	2	2	2	4	5	5	6	6	7	8	8	9	10	11	11	12	13	13
Walker TS #2	99	1	1	2	2	3	4	6	6	7	8	9	10	10	11	13	13	14	15	16	16
Essex TS	116	0	1	1	1	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	9
Crawford TS	90	1	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10	11	11
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**5**	**10**	**14**	**16**	**20**	**31**	**41**	**45**	**50**	**55**	**64**	**69**	**75**	**81**	**89**	**94**	**100**	**107**	**114**	**115**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Keith TS T1	54	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Keith TS T22/T23	114	0	1	1	1	1	2	3	3	3	3	4	4	5	5	6	6	7	7	8	8
Malden TS	200	1	2	2	3	3	5	7	7	8	9	11	11	12	14	15	16	17	18	19	19
Windsor Essex Total	**N/A**	**7**	**12**	**18**	**20**	**26**	**40**	**53**	**58**	**65**	**72**	**83**	**89**	**97**	**105**	**116**	**122**	**130**	**139**	**148**	**149**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation		*Forecast*																			
Total	**N/A**	**1**	**2**	**3**	**3**	**4**	**6**	**9**	**10**	**11**	**12**	**14**	**15**	**16**	**18**	**20**	**21**	**22**	**24**	**25**	**26**

APPENDIX C. DISTRIBUTED GENERATION ASSUMPTIONS BY SUBSYSTEM & STATION

J3E/J4E Sub-System Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Kingsville TS	158	15	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Belle River TS	59	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tilbury West DS	34	2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tilbury TS	10	2	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lauzon TS	225	8	16	18	19	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Walker TS #1	99	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Walker TS #2	99	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Essex TS	116	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crawford TS	90	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Chrysler	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Powerhouse	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Motors	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Annex	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ford Essex Engine Plant	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**N/A**	**35**	**59**	**64**	**66**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**

Additional Stations in the Windsor-Essex Region Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Keith TS T1	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keith TS T22/T23	114	21	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Malden TS	200	9	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Windsor Essex Total	**N/A**	**65**	**63**	**69**	**71**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**

Kingsville-Leamington Sub-system Distributed Generation	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
		Forecast																			
Total	**N/A**	**15**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**

APPENDIX D. REFERENCE PLANNING FORECAST BY SUBSYSTEM & STATION

J3E/J4E Sub-System	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		*Forecast*																			
Kingsville TS	158	133	114	117	121	121	120	118	118	118	118	117	117	118	117	116	116	116	115	115	115
Belle River TS	59	46	43	44	44	45	45	45	46	47	46	47	47	48	49	49	50	50	51	51	52
Tilbury West DS	34	17	7	7	7	8	7	7	7	7	8	7	7	7	7	7	7	7	6	7	7
Tilbury TS	10	1	-6	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Lauzon TS	225	191	174	173	174	174	173	172	172	173	174	172	173	174	174	174	175	175	175	175	176
Walker TS #1	99	71	76	72	73	73	72	71	72	71	72	71	71	71	71	70	70	70	70	69	70
Walker TS #2	99	95	109	89	89	89	88	87	87	87	87	86	86	86	86	85	85	85	84	84	85
Essex TS	116	55	62	71	71	71	70	71	70	71	70	71	70	71	70	70	70	70	70	70	71
Crawford TS	90	83	82	82	81	81	81	80	81	80	81	80	80	80	80	79	80	79	80	80	80
Chrysler	65	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Ford Powerhouse	65	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
General Motors	43	2	0	14	14	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
Ford Annex	43	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ford Essex Engine Plant	43	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Subtotal	**N/A**	**769**	**737**	**738**	**742**	**743**	**737**	**733**	**736**	**736**	**737**	**734**	**733**	**737**	**735**	**733**	**735**	**735**	**733**	**734**	**738**

Additional Stations in the Windsor-Essex Region	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (extreme weather)		*Forecast*																			
Keith TS T1	54	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Keith TS T22/T23	114	68	64	64	64	64	63	62	63	63	63	62	62	61	61	60	60	60	60	59	59
Malden TS	200	117	115	114	114	114	113	112	114	113	113	112	113	112	111	111	111	111	110	110	111
Windsor Essex Total	**N/A**	**962**	**924**	**923**	**928**	**930**	**922**	**916**	**920**	**921**	**921**	**916**	**915**	**919**	**916**	**912**	**915**	**914**	**912**	**911**	**917**

Kingsville-Leamington Sub-system	LTR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Demand (weather normal)		*Forecast*																			
Total	**N/A**	**155**	**147**	**151**	**155**	**156**	**157**	**157**	**158**	**159**	**160**	**161**	**162**	**164**	**165**	**166**	**167**	**169**	**169**	**171**	**173**

APPENDIX E. LIST OF ACRONYMS

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

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

NEEDS ASSESSMENT REPORT

Region: London

Date: April 1, 2015

Prepared by: London Area Study Team

London Area Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kennan Ip Jennifer Li Raymond Zeng
Independent Electricity System Operator	Phillip Woo Kun Xiong Jiya Shoaib
Entegrus Power Lines	Matthew Meloche
Erie Thames Power Lines Corporation	Chuck deJong Josh Smith Tim Collins
London Hydro Inc.	Bill Milroy Ismail Sheikh
St. Thomas Energy Inc.	Larry Martin
Tillsonburg Hydro Inc.	Stephen Gradish
Woodstock Hydro Services Inc.	Jay Heaman
Hydro One Networks Inc. (Distribution)	Alexander Hamlyn

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the London Area 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	London Area		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	February 2, 2015	**END DATE**	April 3, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the London Area 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 London Area 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 completed and has been initiated for Group 2 Regions. The London Area belongs to Group 2. The NA for the London Area was triggered on January 30, 2015 and was completed on March 31, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was conducted for 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 review 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 London Area. 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. In this region, asset utilization is at the capacity threshold even when LDCs CDM forecast is taken into account. Accordingly, further assessment is required to determine possible targeted CDM activities by feeders and station(s) to ensure CDM will meet load reduction forecasts. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the London Area 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 (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit.
- Under high eastwardly flows and or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

C. 115kV Transmission Lines

- The 115 kV circuit W8T reaches its continuous rating pre-contingency in 2014 based on the gross load forecast.
- The remaining 115 kV circuits supplying the London Area are adequate over the study period for the loss of a single 115 kV circuit.

D. 230 kV and 115 kV Connection Facilities

- Loadings at Aylmer TS, Strathroy TS and Wonderland TS exceed their transformer 10-Day Long Term Rating (LTR) in 2014 based on the net load forecast. The limitation at Aylmer TS will be addressed through the currently planned sustainment investment. Tillsonburg TS is forecasted to exceed its 10-Day LTR by the end of near term. Clarke TS is forecasted to exceed its 10-Day LTR in 2014 based on the gross load forecast, but is expected to be adequate to meet the net load forecast for the remainder of the study as planned CDM targets and DG contributions continue to offset the load growth.
- Historical data shows that Buchanan DESN power factor may be below Ontario Resource and Transmission Assessment Criteria under peak load conditions.

System Reliability, Operation and Restoration Review

Based on the net and gross load forecast, the 115 kV voltages at Tillsonburg TS were found to be less than minimum requirements under pre-contingency conditions in the near term.

Based on the gross and net load forecast, the loss of one element will not result in load interruption greater than 150MW in the London Region. The maximum gross and net 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 on the 230kV system, the gross and net load interrupted by configuration at peak conditions will exceed 150 MW and 250 MW.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

Aging Infrastructure / Replacement Plan

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

7. RECOMMENDATIONS

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

a) The following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or wires planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

b) No further regional coordination is required and following needs should be further assessed as part of local planning :

- Low power factor at Buchanan DESN

TABLE OF CONTENTS

List of Figures and Tables

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the London Area between 2014 – 2023. 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 London Area 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 London Area 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 London Area

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter, "Hydro One Transmission")
3.	Independent Electricity System Operator ("IESO")
4.	Entegrus Power Lines lnc.
5.	Erie Thames Power Lines Corporation
6.	London Hydro Inc.
7.	St. Thomas Energy Inc.
8.	Tillsonburg Hydro Inc.
9.	Woodstock Hydro Services Inc.
10.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the London Area 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 London Area belongs to Group 2. The NA for this area was triggered on January 30, 2015 and was completed on March 31, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the London Area 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 London Area Description and Connection Configuration

The London Area includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), City of St. Thomas. In addition, the facilities located in the London Region supply part of Norfolk County. The boundaries of the London Area are shown below in Figure 1.

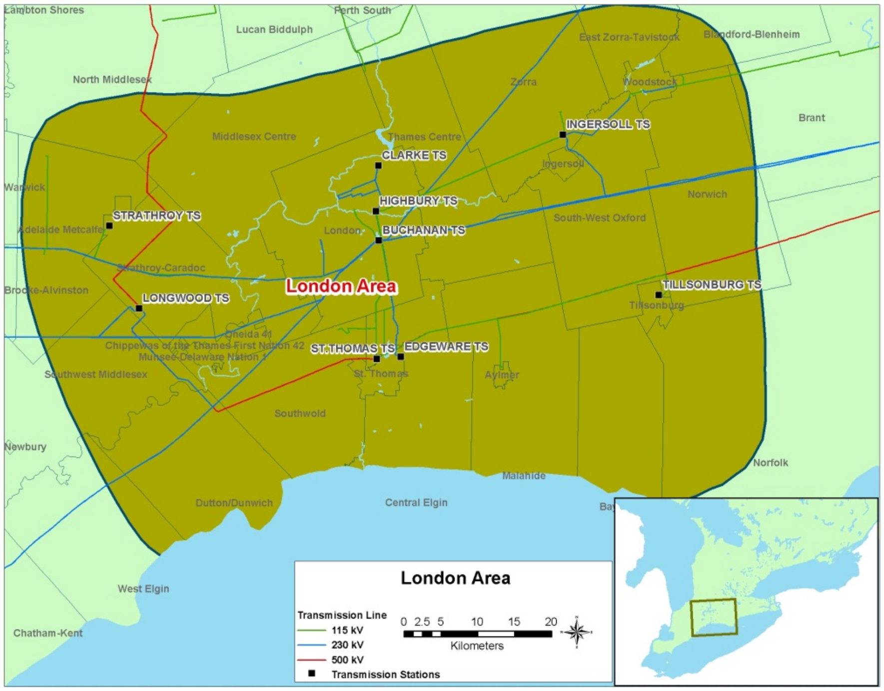


Figure 1: London Area Map

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 fourteen 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 existing facilities in the London Area 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. Also, although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham Area Regional Infrastructure Plan.

- 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.
- Fourteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll

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
    - Port Burwell 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

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

Table 2: Transmission Lines in 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 WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to ESWF JCT ESWF JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

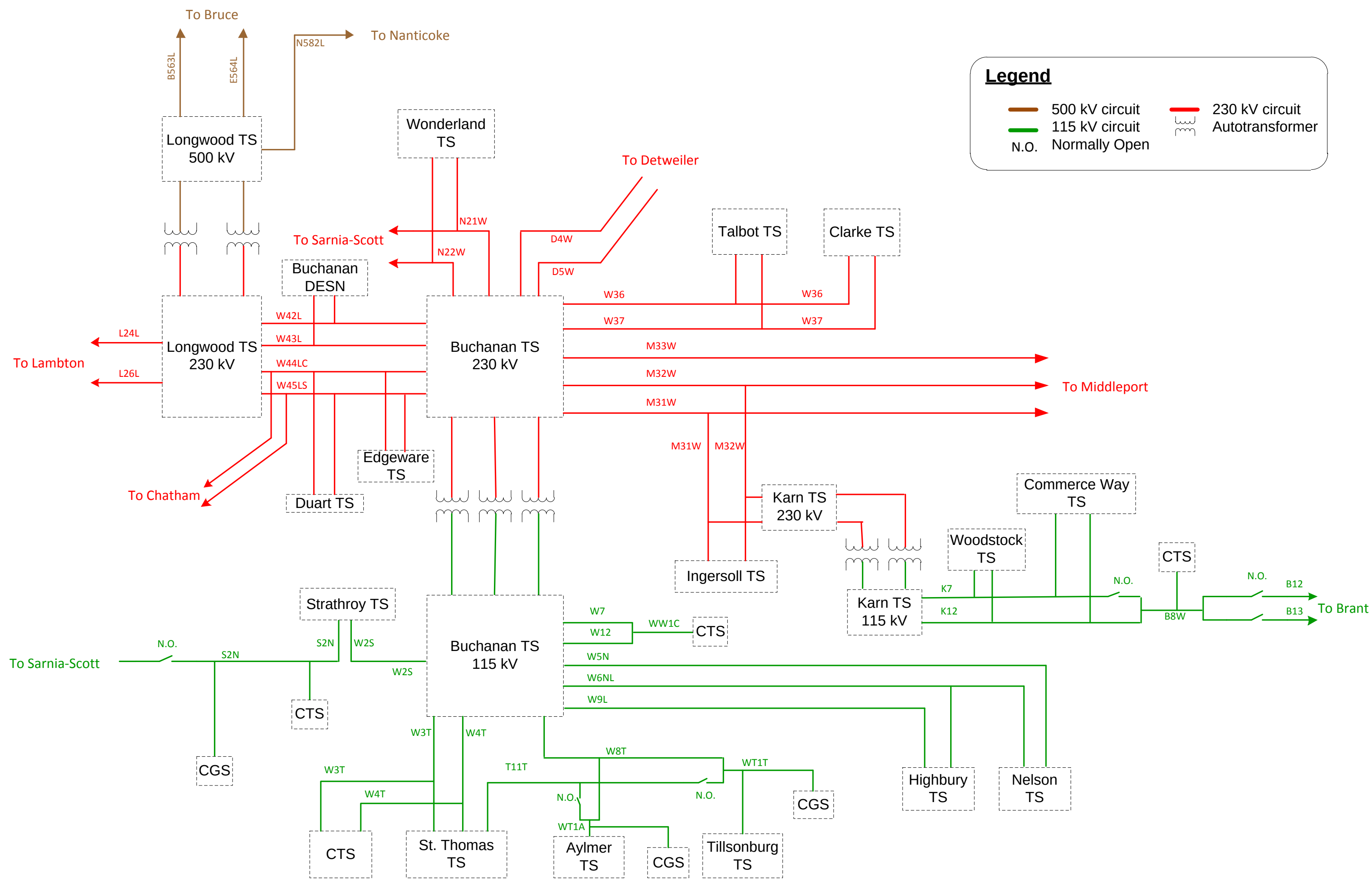


Figure 2: Single Line Diagram – London Area

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 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

The gross load forecast describes the total forecast electrical consumption in the area without considering the combined impact of CDM and DG. As per the data provided by the study team, the gross load in the London Area is expected to grow at an average rate of approximately 0.9% annually from 2014 – 2023.

4.2 Net Load Forecast

The net load forecast builds from the gross load forecast and includes the planned CDM targets and DG contributions. For the London Area, the net load is expected to grow 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 assessment is based on summer peak loads.

2. Load data for transmission connected industrial customers in the region was assumed to be consistent with historical peak loads.

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

4. Accounting for (2) and (3) mentioned 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 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.

5. Review impact of any on-going and/or planned development projects in the London Area 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).

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 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 London Area.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

6.1.2 230 kV Transmission Lines

Overall, the 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high eastwardly flows and/or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

6.1.3 115 kV Transmission Lines

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT reaches its continuous 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. In addition, the 115kV system is also restricted for any new DG connections at Tillsonburg TS because of capacity limitation.

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

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 in the London Area using the summer station peak load forecasts provided by the study team. The results are as follows:

Aylmer TS
Aylmer TS T2/T3 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 113% Summer 10-Day LTR in 2014).

Buchanan TS

Historical data shows that Buchanan DESN power factor is below ORTAC criteria under peak load conditions.

Clarke TS

Clarke TS T3/T4 exceeds its 10-Day LTR in 2014 based on the net load forecast (approximately 101% of Summer 10-Day LTR). Although based on the planned CDM targets and DG contributions, the station capacity for Clarke TS T3/T4 is adequate to meet the net forecasted demand over the remainder of the study period, loading at Clarke TS is above its LTR based on gross load.

Strathroy TS

Strathroy TS T1/T2 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 125% of Summer 10-Day LTR in 2014)

Talbot TS

Talbot TS T1/T2 and T3/T4 DESN is near its 10-Day LTR rating in the near term based on the net load forecast and is above its LTR based on gross load. The load forecast for Talbot TS increases significantly in year 2015 by 17MW based on the ongoing planning activities of the LDC to convert and transfer Nelson TS load to Talbot TS to accommodate the redevelopment plans of Nelson TS. The load transferred to Talbot TS in 2015 is temporary in nature, and will be transferred back to Nelson TS when the redevelopment is expected to be complete in 2019.

Tillsonburg TS

For the loss of T3, Tillsonburg TS T1 is forecasted to exceed its 10-Day LTR towards the end of the near term based on the net load forecast (approximately 102% of Summer 10-Day LTR in 2018) and is above its LTR based on gross load

Wonderland TS

For the loss of T6, Wonderland TS T5 is forecasted to exceed its 10-Day LTR 2014 based on the net load forecast (approximately 112% of Summer 10-Day LTR in 2014).

All the other TSs in the London Area are forecasted to remain within their normal supply capacity during the study period.

6.2 System Reliability, Operation and Restoration Review

Based on the net load forecast, the pre-contingency voltage at Tillsonburg TS 115kV is expected to be less than the minimum voltage level as established in Section 4.3 of the ORTAC.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

Based on the gross and net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW in the London Region. The maximum gross and net 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.

Based on the gross coincident load forecast at Buchanan TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit line W42L and W43L. 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.

Based on the gross and net coincident load forecast for Ingersoll TS and stations connected along the 115 kV circuits K7/K12/B8W, the load interrupted by configuration at peak will exceed 150 MW for the loss of double-circuit 230kV line M31W and M32W. Similarly, based on the gross and net coincident load forecast at Clarke TS and Talbot TS, the load interrupted by configuration will exceed 250 MW for the loss of double-circuit 230kV line W36 and W37. Furthermore, based on the gross and net coincident load forecast at Wonderland TS and Modeland TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit 230kV line N21W and N22W.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment and development initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. These sustainment plans do not affect the results of this NA study. During the study period:

- The existing Aylmer TS will be replaced with a new DESN with two 25/33.3/41.7 MVA transformer and four feeder positions and is scheduled to be completed in 2019. The replacement plan will address the transformer capacity need identified in section 6.1.4.
- The existing Nelson TS DESN will be redeveloped to maintain supply to the area. Final arrangement will depend on the ongoing discussions between the Hydro One and the LDC. This NA study assumes the LDC's plan to redevelop Nelson TS and convert the station LV from 13.8kV to 27.6kV.

- As part of the Burlington-Nanticoke Area Regional Infrastructure Planning, there is an ongoing plan to replace existing switches on B12/B13 with 115 kV breakers to address the voltage and capacity issue in the Brant area. This project will allow the existing normally-open points on B12/B13 to be operated normally-closed. The breakers cause no adverse impacts to the London Region. As the project is still in its planning phase, the ability to provide backup to the Woodstock area has not yet been confirmed.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that the following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or Wires Planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

The following need should be further assessed as part of local planning by Hydro One and relevant LDCs:

- Low power factor at Buchanan DESN

8 NEXT STEPS

IESO and Hydro One will initiate a SA and Local Planning process to address the relevant needs as per the recommendations 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
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
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 Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

hydro one

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

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

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	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Quyen Diep Sachna Bobal
Independent Electricity System Operator	Phillip Woo Jiya Shoaib
Veridian Connections Inc.	Craig Smith
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

TABLE OF CONTENTS

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.

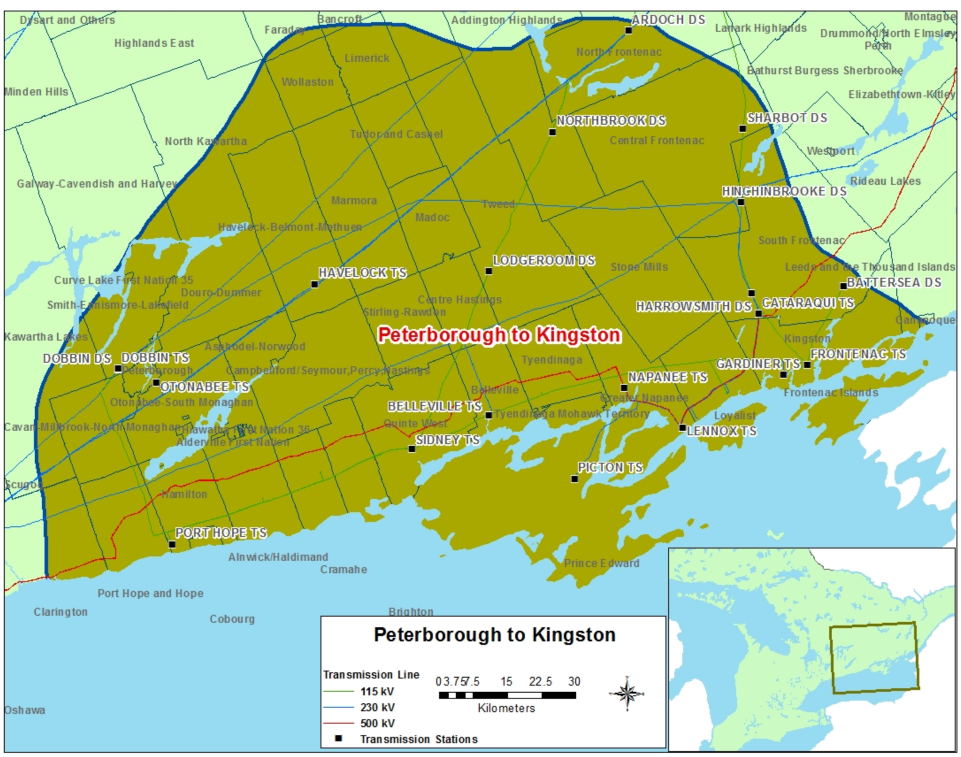


Figure 1: Peterborough to Kingston Region Map

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

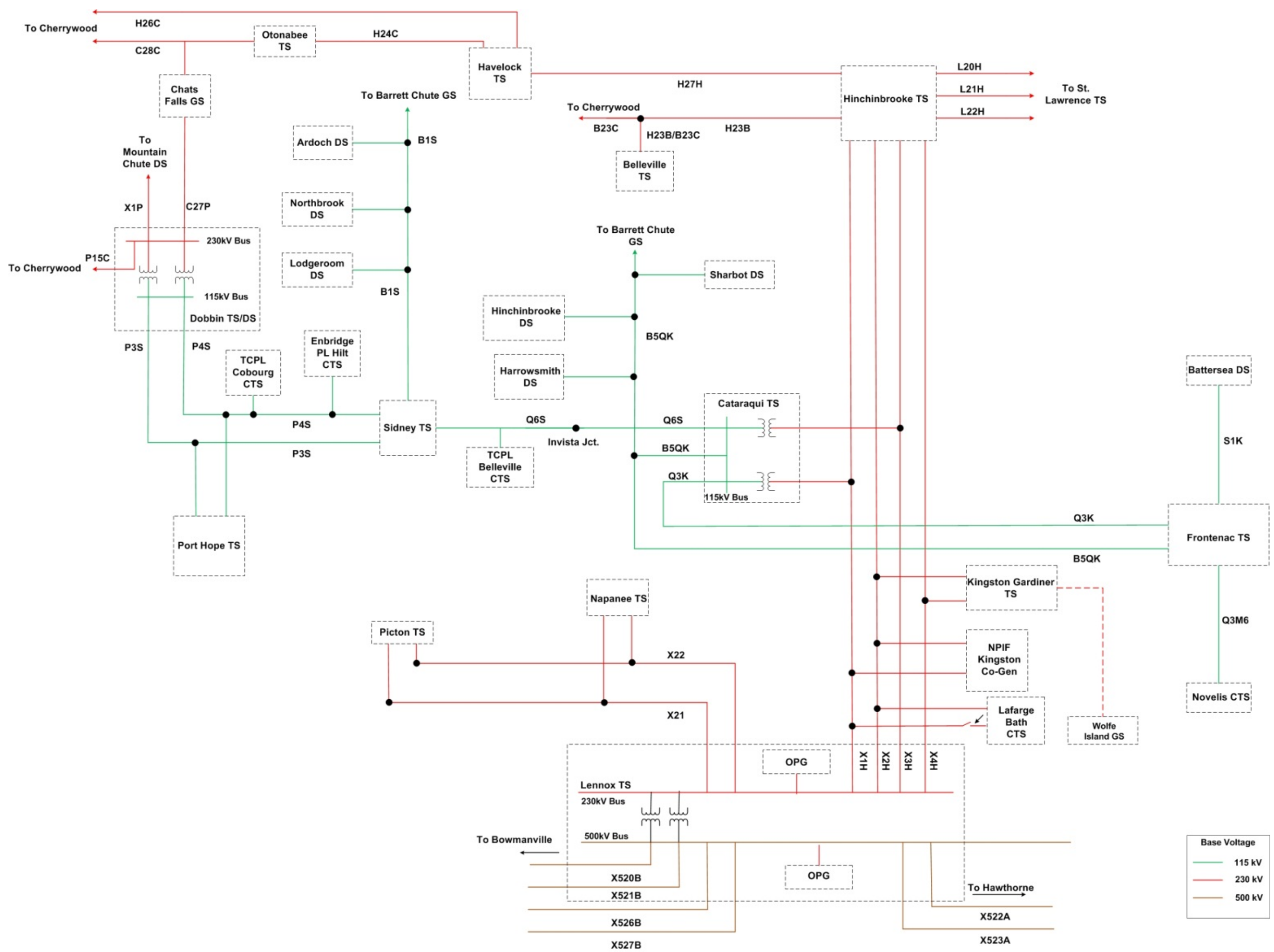


Figure 2: Single Line Diagram – Peterborough to Kingston Region

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

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

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.

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	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.

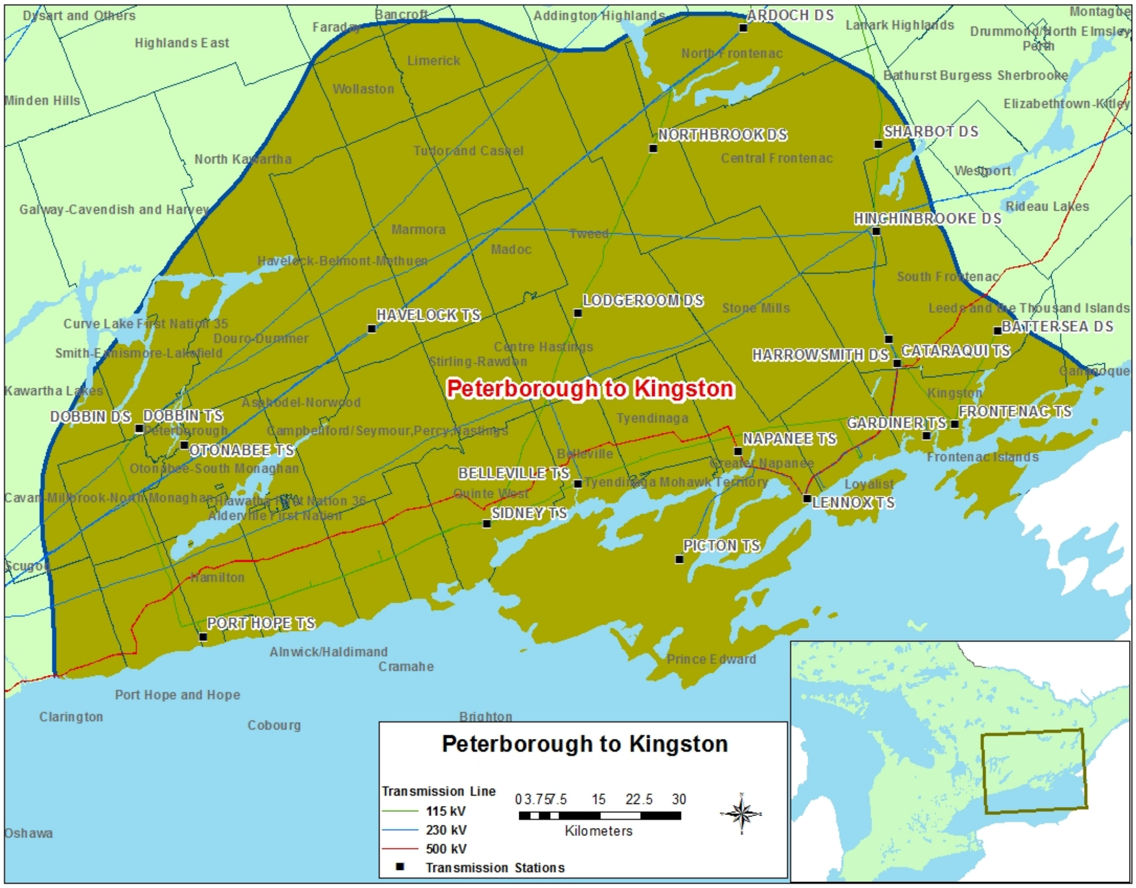


Figure 1: Peterborough to Kingston Region Map

5

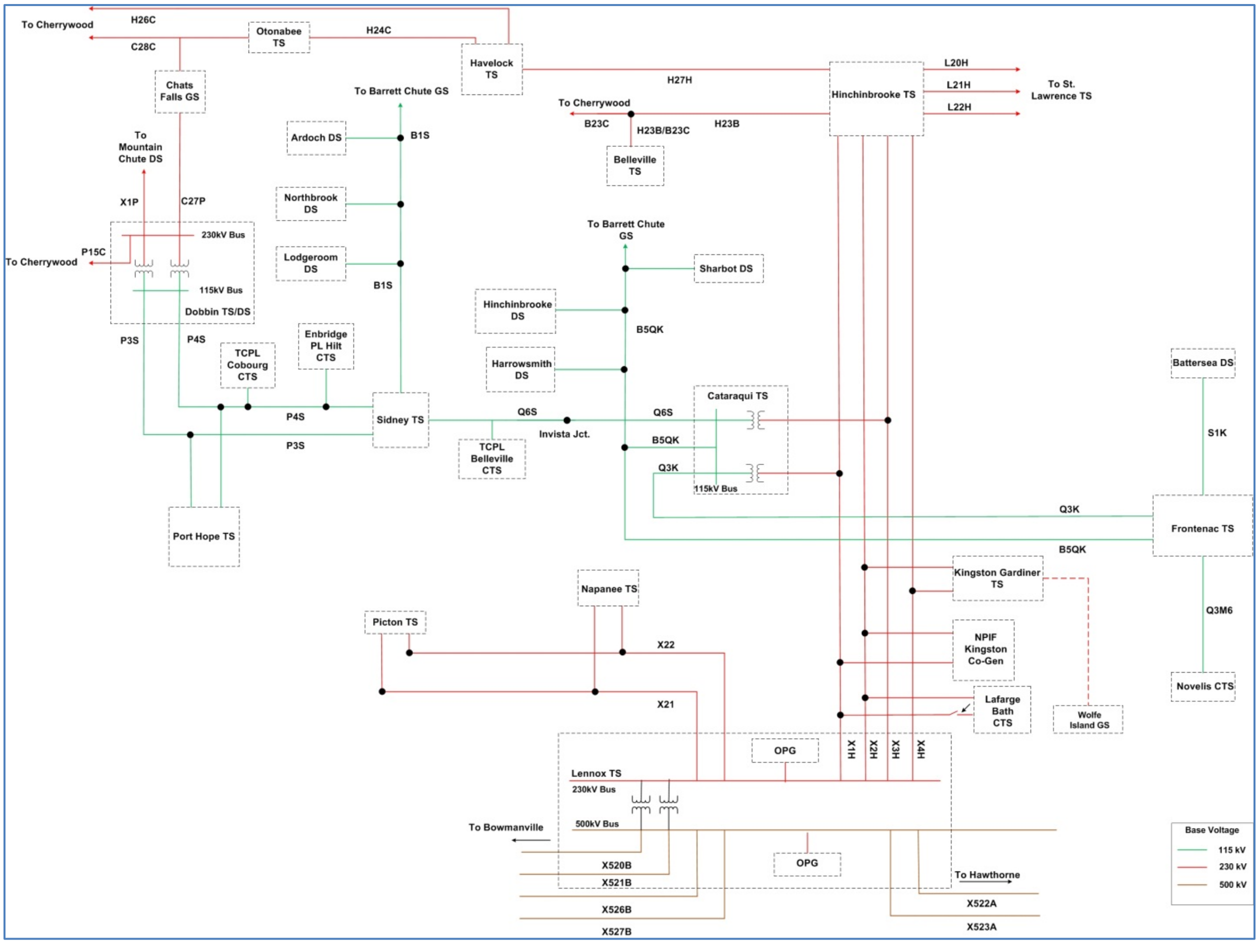


Figure 2: **Single Line Diagram – Peterborough to Kingston Region**

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

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

NEEDS ASSESSMENT REPORT

Region: South Georgian Bay/Muskoka

Revision: Final
Date: March 3, 2015

Prepared by: South Georgian Bay/Muskoka Region Study Team

South Georgian Bay/Muskoka Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Sacha Constantinescu Aleksandar Todic
Independent Electricity System Operator	Phillip Woo Nicole Hopper Bernice Chan
Hydro One Networks Inc. (Distribution)	Richard Shannon Ashley Lebel Charlie Lee
PowerStream Inc.	Michael Swift
Innisfil Hydro Distribution Systems Ltd.	Brenda Pinke
Orangeville Hydro Ltd.	Rob Koekkoek
Veridian Connections Inc.	Craig Smith

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the South Georgian Bay/Muskoka 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	South Georgian Bay/Muskoka Region		
LEAD	Hydro One Networks Inc.		
START DATE	January 2, 2015	**END DATE**	March 3, 2015

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the South Georgian Bay/Muskoka Region ("the 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 Networks Inc. (HONI) 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 Needs Assessment for the South Georgian Bay/Muskoka 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 Needs Assessment for Group 1 Regions is complete and has been initiated for Group 2 Regions. The South Georgian Bay/Muskoka Region belongs to Group 2 and the Needs Assessment for this Region was triggered on January 2, 2015 and was completed on March 3, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Needs Assessment 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 process, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This Needs Assessment included a study of transmission system and 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 HONI transmission provided information for the 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 of the report for further details.

5. 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 of the report for further details.

6. RESULTS

Transmission Capacity Needs

A. 115/230kV Transmission Lines and Auto-Transformers

- With the 230/115kV auto-transformer T1 or T2 at Essa TS out-of-service, the companion transformer is expected to exceed its summer 10-Day Limited Time Rating (LTR) during the study period based on gross summer demand forecast. T1 is expected to exceed its summer 10-Day LTR in the near-term and T2 in the medium-term. The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.
- With one element out of service, the 115 kV circuit E3B is expected to exceed its summer Long-Term Emergency (LTE) rating in the near-term based on gross summer demand forecast. The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.

B. 115/230kV Transmission Stations

- Barrie TS is a summer peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand forecast.
- Muskoka TS is a winter peaking station and will exceed its normal supply capacity in near-term based on both gross and net winter demand forecast.
- Parry Sound TS is a winter peaking station and currently exceeds its normal supply capacity based on both gross and net winter demand forecast.
- Midhurst TS T1/T2 DESN may exceed its normal supply capacity in the medium-term based on gross and net summer demand forecast if potential new commercial operations in the city of Barrie materialize.

System Reliability, Operation and Restoration Needs

Based on the gross and net coincident demand forecast, the loss of one element will not result in load interruption greater than the limit of 150MW. The loss of two elements will not result in load interruption greater than the limit of 600MW.

For the loss of two elements, based on gross and net region-coincident demand forecast the load interrupted by configuration may exceed 150MW and 250MW. The loss of 230kV circuits M6E+M7E may require some load to be restored within 4 hours and 30 minutes; the loss of 230kV circuits M80B+M81B may require some load to be restored within 4 hours; and the loss of 230kV circuits E8V+E9V may require some load to be restored within 4 hours during the study period. 230kV circuit M6E+M7E may not meet the 30 minutes restoration criteria. Further assessment is required.

Due to the increase generation within the Bruce Area, 115kV circuit S2S and Stayner T1 auto-transformer may be overloaded under pre-contingency conditions during high flow eastward from the Bruce Area. One possible solution would be to operate S2S open loop. This issue was identified by IESO as part of this assessment. Further assessment is required.

With Essa TS 500/230kV auto-transformer T3 or T4 out of service, the loss of the remaining 500/230kV Essa TS auto-transformer, may result in excessive post-contingency voltage declines under high loads conditions within the Essa area. This issue was identified by IESO as part of this assessment. Further assessment is required.

Aging Infrastructure / Replacement Plan

- Replacement of 115-44kV transformers (T1 and T2) at Barrie TS is scheduled for 2018.
- Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS is scheduled for 2019.
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS is scheduled for 2017.
- Ground clearance on several sections of the 230kV circuits M6E and M7E are planned to be increased in 2015. This may increase the current thermal rating of the lines.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows.

Study team recommends that a Scoping Assessment should be undertaken to address the near-term transmission and system reliability, operation and restoration needs as listed in Section 6, taking into consideration where appropriate the aging infrastructure/replacement plans identified.

These near-term needs require coordinated regional planning and development of a regional and/or sub-regional plan as soon as possible. The Scoping Assessment will determine whether the IESO-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken for one or more of these needs. The assessment may also recommend that local planning of wires only option between the transmitter and affected LDCs may be undertaken to address certain needs.

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a summary of needs that are emerging in the South Georgian Bay/Muskoka Region ("the Region") over the ten-year period from 2014 to 2023. 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 undertake an assessment of the South Georgian Bay/Muskoka 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 Networks Inc. (HONI), as transmitter, with Local Distribution Companies (LDCs) 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 South Georgian Bay/Muskoka Region Needs Assessment study team (Table 1) and led by the transmitter, HONI. The report captures the results of the assessment based on information provided by LDCs, the OPA and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for South Georgian Bay/Muskoka Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Hydro One Networks Inc. (Distribution)
4.	PowerStream Inc.
5.	Innisfil Hydro Distribution Systems Ltd.
6.	Orangeville Hydro Ltd.
7.	Veridian Connections Inc.

2 REGIONAL ISSUE/TRIGGER

The Needs Assessment for the South Georgian Bay/Muskoka Region was triggered in response to the OEB's RIP 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 Needs Assessment for Group 1 Regions is complete and has been initiated for Group 2 Regions. The South Georgian Bay/Muskoka Region belongs to Group 2. The Needs Assessment for this Region was triggered on January 2, 2015 and was completed on March 3, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the South Georgian Bay/Muskoka Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment 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 Needs Assessment.

3.1 South Georgian Bay/Muskoka Region Description and Connection Configuration

The South Georgian Bay/Muskoka Region is the area roughly bordered by 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 Grey Highlands to the west. The boundaries of the Region are shown in Figure 1 below.

Electrical supply to the Region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

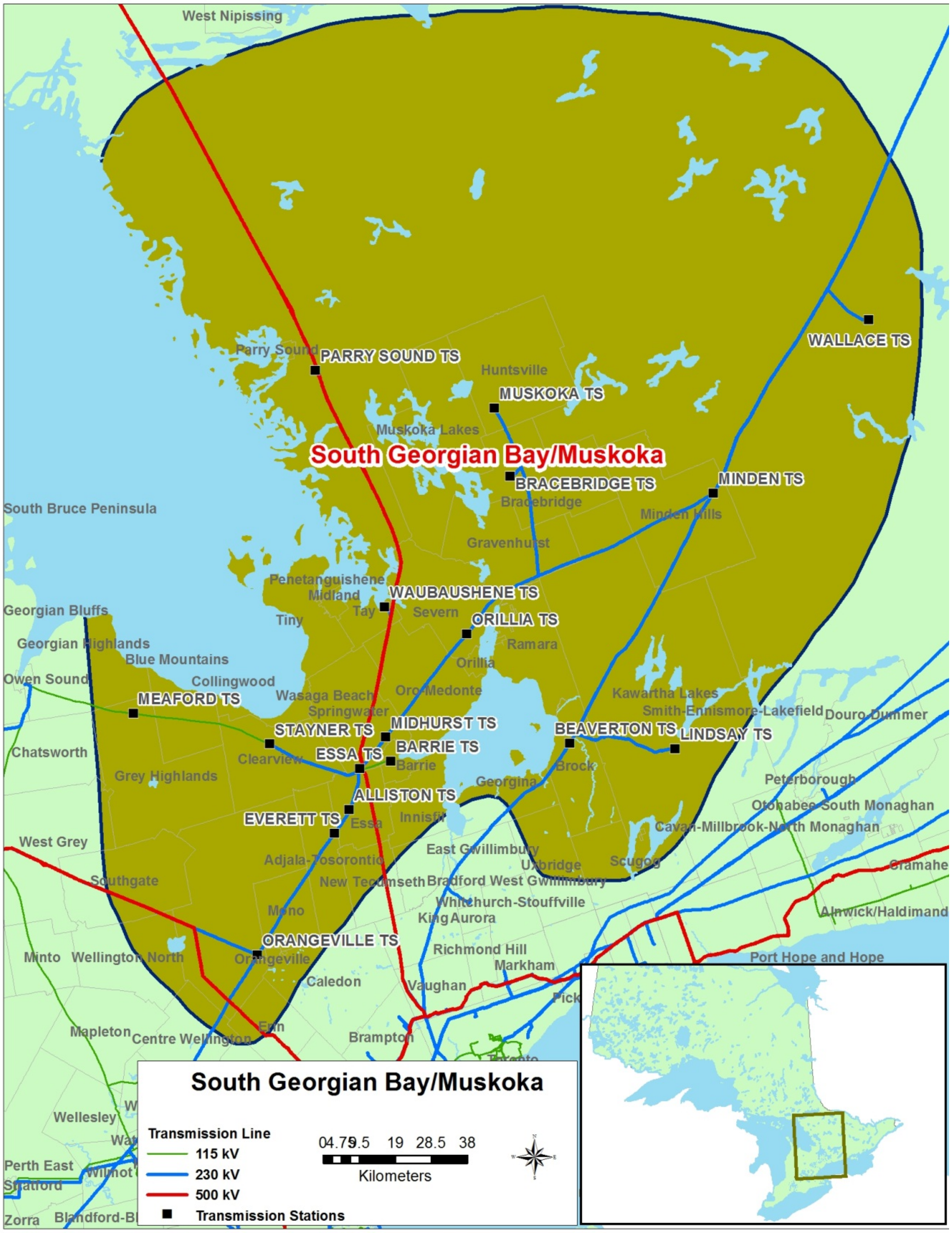


Figure 1: South Georgian Bay/Muskoka Region Map

The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.

- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.

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

- Essa TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230kV auto-transformers. Essa TS also supplies the 115kV system towards Barrie TS via two 230/115kV auto-transformers.

- Eleven step-down transformer stations supply load to the north and east areas of the Region (north and east of Essa TS): Barrie TS, Beaverton TS, Bracebridge TS, Lindsay TS, Midhurst TS, Minden TS, Muskoka TS, Orillia TS, Parry Sound TS, Wallace TS, and Waubashene TS.

- Five step-down transformer stations supply load to the south and west areas of the Region (south and west of Essa TS): Alliston TS, Everett TS, Meaford TS, Orangeville TS, and Stayner TS.

- Eight 230kV circuits (E8V, E9V, E20S, E21S, E26, E27, M6E, and M7E) radiating outward from Essa TS provide local supply to the Region. These circuits are essential to the Region and will be included in the study to ensure long-term reliability. Four 230kV circuits (D1M, D2M, D3M, and D4M) entering the region from the east are also a major supply path for the Region and will be analyzed in this study.

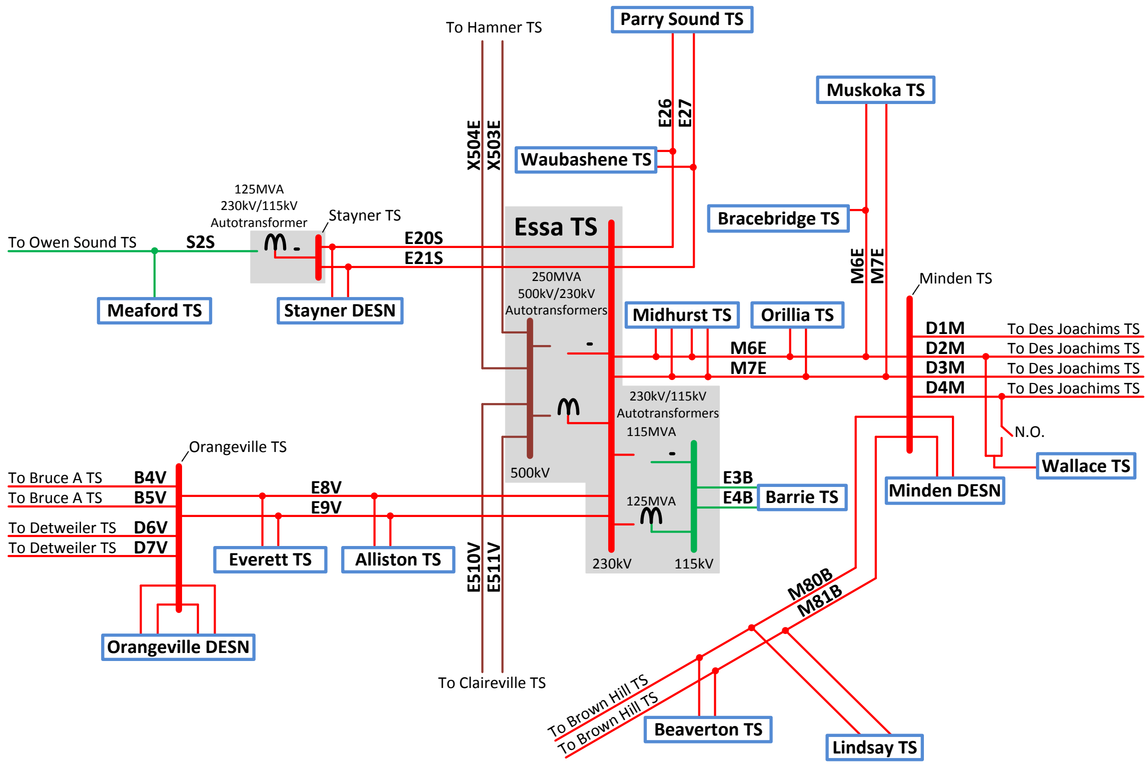


Figure 2: Single Line Diagram – South Georgian Bay/Muskoka Region

Table 2 below provides a list of LDCs in the South Georgian Bay/Muskoka Region.

Table 2: List of LDCs in the South Georgian Bay/Muskoka Region

Local Distribution Companies (LDCs)
Hydro One Networks Inc. (Distribution)
Powerstream Inc.
COLLUS PowerStream Corp.
InnPower Corp.
Lakeland Power Distribution Ltd.
Midland Power Utility Corp.
Orangeville Hydro Ltd.
Orillia Power Distribution Corp.
Parry Sound Power Corp.
Newmarket-Tay Power Distribution Ltd.
Veridian Connections Inc.
Wasaga Distribution Inc.

4 INPUTS AND DATA

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

- IESO provided:
    1. Historical 2013 regional coincident peak load and station non-coincident peak load
    2. List of existing reliability and operational issues
    3. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load and gross load forecast (2014-2023)
- HONI (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 load in the South Georgian Bay/Muskoka Region is expected to grow at an average gross rate of approximately 2% annually from 2014-2018 and 1.8% annually from 2019-2023.

Most of the load growth is attributed to the southern portion of the region, with the highest approximate annual growth rate occurring at the following stations: Barrie TS (4.1% from 2014-2018 and 5.9% from 2019-2023); Alliston TS (4.7% from 2014-2018 and 3.3% from 2019-2023); Midhurst TS (3.5% from 2014-2018 and 2.9% from 2019-2023) and Everett TS (3.2% from 2014-2018 and 2.9% from 2019-2023).

5 ASSESSMENT METHODOLOGY

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

1. 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.

2. Forecast winter/summer loads are provided by the Region's LDCs. There are no customer loads within this region.

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

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

5. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross demand 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 produced for both winter and summer and were used to perform the analysis for Section 6.1.2 of this report.

   A coincident region peak load forecast was used to perform the analysis for sections 6.1.1 of this report. A gross and net-region coincident peak load forecast was developed for winter conditions. As for summer conditions, only a gross coincident forecast was developed for conservatism but also due to the high load growth relative to CDM and DG in the summer peaking portion of the region. The gross summer coincident peak load forecast was developed based on projected percentages of the winter historical loading.

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 auto-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, 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/winter 10-Day Limited Time Rating (LTR).

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 considers, but is not limited to, the following criteria:
    - Region-coincident peak load forecast is used.
    - 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/winter 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC).
    - With one element out of service, no more than 150MW of load is lost by configuration. With two elements out of service, no more than 600MW 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.

6 RESULTS

This section summarizes the results of the Needs Assessment in the South Georgian Bay/Muskoka Region.

6.1 Transmission Capacity Needs

6.1.1 115/230kV Transmission Lines and Auto-Transformers

The 115/230kV transmission line and auto-transformer needs identified during the study period include, but may not be limited to the following:

- With the 230/115kV auto-transformer T1 or T2 at Essa TS out of service, the companion auto-transformer at Essa TS is expected to exceed its summer 10-Day LTR in the near-term based on gross summer demand forecast. T1 is expected to exceed its summer 10-Day LTR in the near-term (approximately 104% and 142% of summer 10-Day LTR by 2018 and 2023 respectively) and T2 in the medium-term (approximately 106% and 113% of summer 10-Day LTR by 2022 and 2023 respectively). The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.
- With one element out of service, the 115kV circuit E3B is expected to exceed its summer LTE rating in the near-term based on gross summer demand forecast (approximately 106% and 137% of summer LTE rating by 2019 and 2023

respectively). The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.

- With one element out of service, the voltage after tap-changer action at the Muskoka TS 230kV bus drops slightly below minimum continuous voltage limit in the medium-term based on gross winter demand forecast. With net winter demand forecast, the voltage remains within acceptable limits. This will be monitored and reassessed in the next regional planning cycle.
- With one element out of service, the voltage declines immediately following a contingency at Muskoka TS 44kV exceeds the limit of 10% after 2020 based on gross winter demand forecast. With the net winter demand forecast, the voltage remains within acceptable limits. This will be monitored and reassessed in the next regional planning cycle.

6.1.2 115/230kV Transformer Stations

The connection capacity needs identified during the study period include, but may not be limited to the following:

Barrie TS T1/T2 DESN (115-44kV):

- Barrie TS is a summer peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand forecast (approximately 103% and 150% of summer 10-Day LTR in 2014 and 2023 respectively).

Everett TS T1/T2 DESN (230-44kV):

- Everett TS is a summer peaking station and will exceed its normal supply capacity at the end of the study period based on the gross summer demand forecast. With the net summer demand forecast, the station remains below its normal supply capacity. This will be monitored and reassessed in the next regional planning cycle.

Minden TS T1/T2 DESN (230-44kV):

- Minden TS is a winter peaking station and will exceed its normal supply capacity in the near-term based on the gross winter demand forecast. With the net winter demand forecast, the station remains below its normal supply capacity until the end of the study period. This will be monitored and reassessed in the next regional planning cycle.

Muskoka TS T1/T2 DESN (230-44kV):

- Muskoka TS is a winter peaking station and will exceed its normal supply capacity in near-term based on both gross and net winter demand forecast (approximately 100% and 103% of winter 10-Day LTR in 2016 and 2023 respectively). The station capacity is currently limited by the low voltage current transformers (CTs). If this limitation is non-existent, the power transformer winter LTR would remain above the gross winter demand forecast for the study period.

Parry Sound TS T1/T2 DESN (230-44kV)

- Parry Sound TS is a winter peaking station and currently exceeds its normal supply capacity based on both gross and net winter demand forecast (approximately 117% and 119% of winter 10-Day LTR in 2014 and 2023 respectively). Using a historically more reasonable winter power factor of 0.95, the station still exceeds its normal supply capacity (approximately 111% and 113% of winter 10-Day LTR in 2014 and 2023 respectively).

Waubaushene TS T5/T6 DESN (230-44kV)

- Waubaushene TS is a winter peaking station and will exceed its normal supply capacity at the end of the study period based on the gross winter demand forecast. With the net winter demand forecast, the station remains below its normal supply capacity. This will be monitored and reassessed in the next regional planning cycle.

Several load customers are planning new commercial operations in the City of Barrie during the study period. The forecast used for capacity assessment is the 'median' load growth projection for the City of Barrie, which reflects the historical load growth. Using the 'high growth scenario', where new commercial operations may materialize and achieve their projected loading by 2018, the following additional capacity needs emerge:

Midhurst TS

- Both T1/T2 and T3/T4 DESN stations at Midhurst TS are summer peaking and remain within their normal supply capacity based on gross 'median' summer demand forecast.
- T1/T2 DESN may exceed its normal supply capacity in the medium-term based on both net and gross 'high growth scenario' summer demand forecast (approximately 102% and 104% of summer 10-Day LTR in 2021 and 2023 respectively).
- T3/T4 DESN may exceed its normal supply capacity in the medium-term based on gross 'high growth scenario' summer demand forecast. With the net forecast, the station remains within its normal supply capacity until the end of the study period. This will be monitored and reassessed in the next regional planning cycle.

6.2 System Reliability, Operation and Restoration Review

Based on the gross and net coincident demand forecast, the maximum load interrupted by configuration due to the loss of one element is below the load loss limit of 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW.

For the loss of two elements, the load interrupted by configuration may exceed 150MW and 250MW based on gross and net coincident demand forecast. The loss of 230kV circuits M6E+M7E may require some load to be restored within 4 hours and 30 minutes; the loss of 230kV circuits M80B+M81B may require some load to be restored within 4 hours; the loss of 230kV circuits E8V +E9V may require some load to be restored within 4 hours during the study period. 230kV circuit M6E+M7E may not meet the 30 minutes restoration criteria. Further assessment is required.

Due to the increase generation within the Bruce Area, 115kV circuit S2S and Stayner T1 auto-transformer may be overloaded under pre-contingency conditions during high flow eastward from the Bruce Area. One possible solution would be to operate S2S open loop. This issue was identified by IESO as part of this assessment. Further assessment is required.

With an Essa TS 500/230kV auto-transformer T3 or T4 out of service, the loss of the remaining 500/230kV Essa TS auto-transformer, may result in excessive post-contingency voltage declines under high load conditions within the Essa area. This issue was identified by IESO as part of this assessment. Further assessment is required.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

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

During the study period:

- Replacement of 115-44kV transformers (T1 and T2) at Barrie TS is scheduled for 2018.
- Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS is scheduled for 2019.
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS is scheduled for 2017.
- Ground clearance on several sections of the 230kV circuits M6E and M7E are planned to be increased in 2015. This may increase the current thermal rating of the lines.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows.

Study team recommends that a Scoping Assessment should be undertaken to address the following needs:

- Barrie TS 115kV transmission and transformation capacity – this includes the 230/115kV auto-transformer needs at Essa TS, the 115kV circuit E3B supplying Barrie TS (first three points of section 6.1.1) and the transformation capacity need at Barrie TS (first point of section 6.1.2). Coordination is also required with the existing sustainment initiative at Barrie TS.
- Muskoka TS T1/T2 DESN transformation capacity (fourth point of section 6.1.2).
- Parry Sound TS transformation capacity (fifth point of section 6.1.2).
- Midhurst TS T1/T2 DESN potential transformation capacity need based on 'high growth scenario'.
- System reliability, operation and restoration needs (section 6.2).

These near-term needs require coordinated regional planning and development of a regional and/or sub-regional plan as soon as possible. The Scoping Assessment (SA) will determine whether the IESO-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken for one or more of these needs. The assessment may also recommend that local planning of wires only option between the transmitter and affected LDCs may be undertaken to address certain needs.

8 NEXT STEPS

IESO will initiate a SA process for the region as soon as possible for the needs identified in the region.

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
iv) IESO System Impact Assessment Report for Dufferin Wind Farm (CAA ID: 2010-396)
v) South Simcoe Area Study: Adequacy of Transmission Facilities and Transmission Plan 2010-2024
vi) Minden, Essa and Parry Sound Area Supply Study (2010)

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
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
MTS	Municipal Transformer Station
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
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.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Orangeville TS End-of-Life Replacement
Region: South Georgian Bay / Muskoka

Date: May 27, 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 South Georgian Bay / Muskoka 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	South Georgian Bay / Muskoka (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 14, 2014	**END DATE**	May 27, 2016

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 South Georgian Bay / Muskoka Region dated March 3, 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 coordinated regional planning is required to address the majority of needs in the South Georgian Bay / Muskoka region. The NA report also indicated that there are end-of-life needs at Orangeville TS and it was determined that 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 LDCs.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

There are no capacity needs identified for Orangeville TS over the next ten years. Hydro One has identified that transformers and associated protection, control and telecom equipment at Orangeville TS will be reaching the end of their useful life over the study period. The replacement of this end-of-life equipment is a local area need and is 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 – Like-for-like replacement of non-standard end-of-life equipment at Orangeville TS.
Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN.

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time is Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN. See Section 4 for details.

5. NEXT STEPS

Hydro One will proceed with end-of-life replacement of non-standard equipment based on conditions assessment. Currently, it is planned to be replaced in 2023.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

The Needs Assessment (NA) for South Georgian Bay / Muskoka ("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 South Georgian Bay / Muskoka 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 South Georgian Bay / Muskoka Region Description and Connection Configuration

The South Georgian Bay / Muskoka Region is the area roughly bordered by 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 Grey Highlands to the west. The boundaries of the Region are shown in Figure 1 below.

Electrical supply to the Region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Table 1 below lists the major transmission circuits and Hydro One stations in the subject region. Figure 2 shows the single-line diagram of the transmission network in the Region.

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

- PowerStream Inc.
- Hydro One Networks Inc. (Distribution)

There are several other LDCs in this region embedded into the Hydro One Distribution system. Although invited, many of them opted not to directly participate as part of the Study Team. However, the interests of all embedded LDCs were communicated and considered through Hydro One Distribution as a host LDCs.

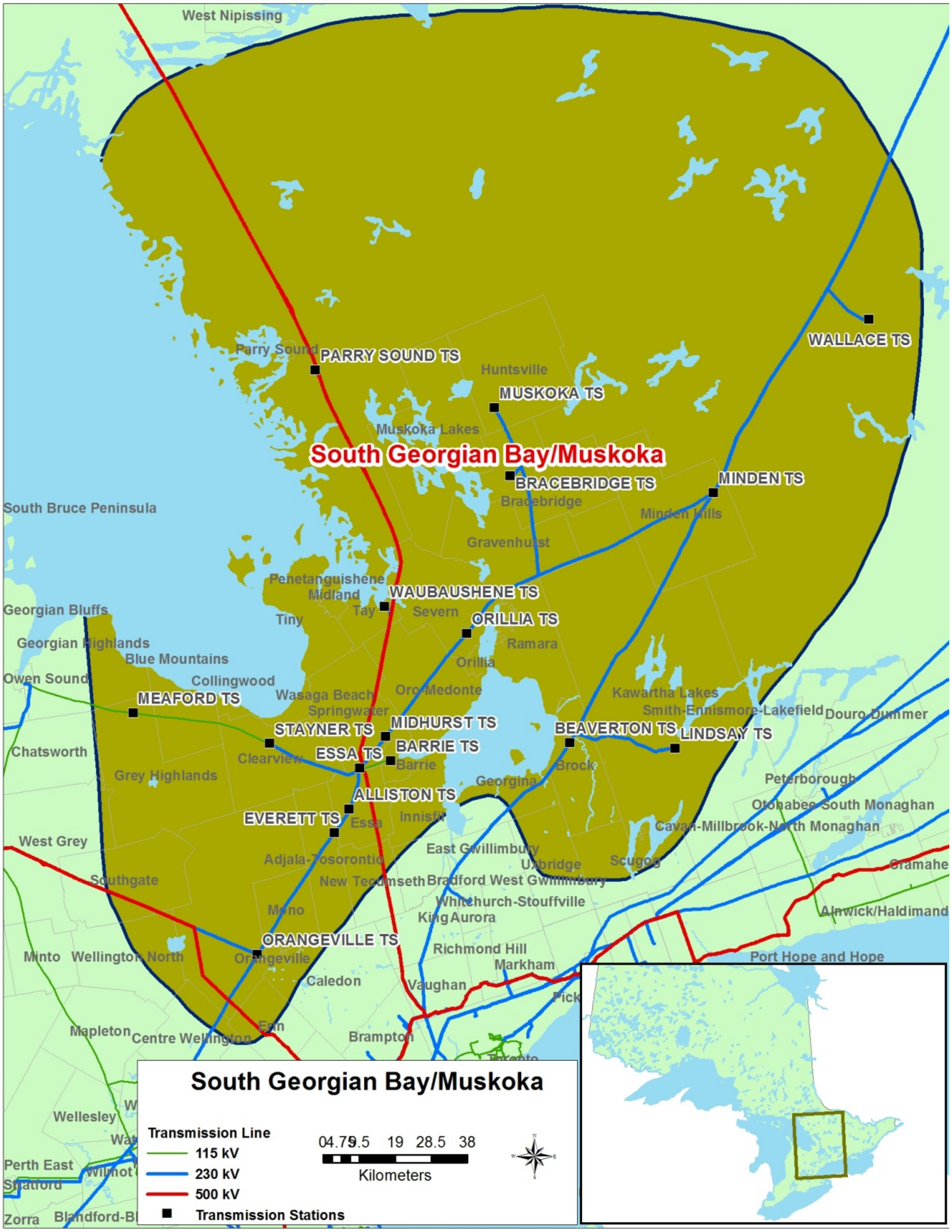


Figure 1: South Georgian Bay / Muskoka Region Map

Distribution connected loads of embedded LDCs in the South Georgian Bay / Muskoka region form a large percentage of the overall demand. Although these LDCs are not explicitly participating in the regional planning process, Hydro One considered their impact in this analysis.

Table 1: Transmission Lines and Stations in the South Georgian Bay / Muskoka Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
E3B, E4B, S2S	E8V, E9V, E20S, E21S, M6E, M7E, D1M, D2M, D3M, D4M, M80B, M81B, E26, E27	ALLISTON TS, BARRIE TS, BEAVERTON TS, BRACEBRIDGE TS, EVERETT TS, LINDSAY TS, MEAFORD TS, MIDHURST TS, MINDEN TS, MUSKOKA TS, ORANGEVILLE TS, ORILLIA TS, PARRY SOUND TS, STAYNER TS, WALLACE TS, WAUBAUSHENE TS

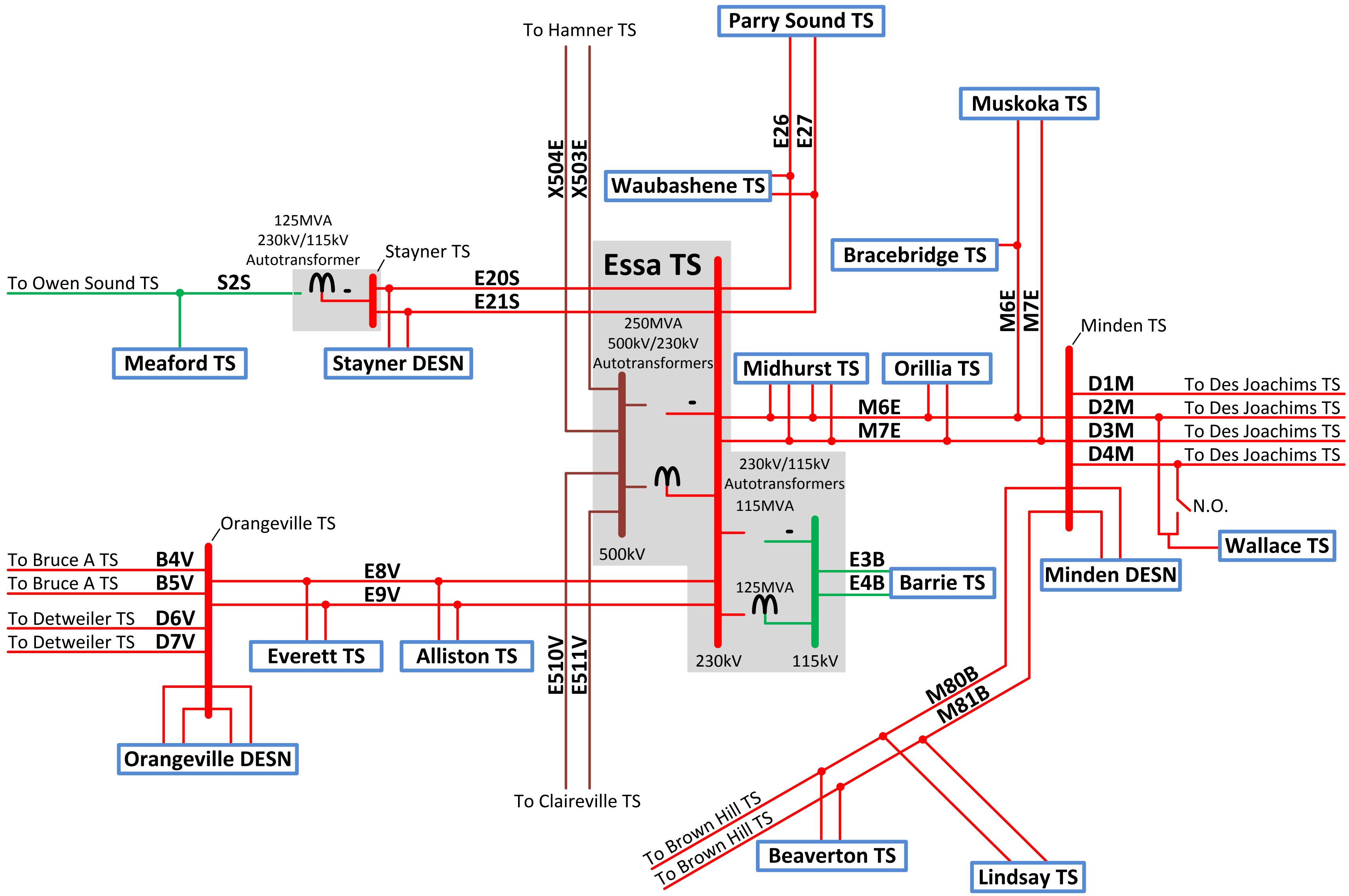


Figure 2: Single Line Diagram – South Georgian Bay / Muskoka Region

2 Area needs

2.1 South Georgian Bay / Muskoka Region Needs

As an outcome of the NA process, the study team identified six transformer stations with medium-term (5-10 years) capacity needs based on LDCs net load forecast which are not part of this Local Plan and will be addressed through the IRRP or RIP processes. It also identified a near-term end-of-life need at Orangeville TS in the South Georgian Bay / Muskoka Region to be addressed by developing a "Local Plan". To address this need, Hydro One Transmission undertook planning assessments with the impacted LDC, to address the need.

2.1 Needs Assessed by Hydro One Led Local Planning

- Orangeville TS End-of-Life Replacements – The 27.6 kV and 44 kV switchyards at Orangeville TS were placed in-service in late 1960s and several of the assets are at the end of their useful life. Previous assessments have identified that all four transformers T1, T2, T3, and T4 and associated equipment are candidates for replacement over the next few years. 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.

3 Alternatives Considered

Hydro One Transmission reviewed the above need and determined that Hydro One Distribution is the sole transmission-connected LDC impacted by the end-of-life replacements at Orangeville TS. Orangeville Hydro Limited (OHL), which supplies power to the Orangeville area, is an embedded LDC connected to the Hydro One-owned distribution system at Orangeville TS. OHL is also impacted by the end-of-life replacements and its interests were taken into consideration in determining the preferred alternative. Following options were considered to address the needs identified in Section 2.

Alternative 0 – Status Quo.

No further action taken at this time. Hydro One and LDC will monitor the aging equipment over the next three years and perform maintenance as issues arise. Further review will be undertaken in the next planning cycle or earlier and aging equipment will be replaced as failures arise.

Alternative 1 – Like-for-like replacement of non-standard end-of-life equipment at Orangeville TS

End-of-life transformers T1 and T2 will be replaced like-for-like by customized 75/125MVA transformers with non-standard 210-44-28kV three-winding configuration. A customized spare transformer would also be required in case T1 or T2 is removed from service for an extended period of time. End-of-life transformers T3 and T4 will be replaced like-for-like by standard 50/83MVA 220/44kV transformers. All associated end of life protection, control and telecom assets will be replaced as well as station service equipment. See figure 3 and figure 5.

Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN

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. All associated end-of-life protection, control and telecom assets will be replaced as well as station service equipment. See figure 4 and figure 6.

Table 2 provides a budgetary cost summary of a cost of all options.

Table 2: Budgetary Estimates for Alternatives

Options Considered	Cost
Alternative 0 – Monitor aging equipment over the next 3 years and perform maintenance as issues arise.	Will result in poor reliability not acceptable
Alternative 1 – Like-for-like replacement of non-standard end-of-life equipment at Orangeville TS.	$35-40M
Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN.	$30M

4 Preferred Alternative Selection

A recent station assessment has confirmed that transformers T1, T2, T3, T4 and associated equipment as well as associated end of life protection, control and telecom assets will be approaching end of their useful life. Integration of the replacement of multiple end-of-life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Orangeville Hydro Limited (OHL) has also expressed their intent to further increase their use of the 27.6 kV feeders supplied from Orangeville TS. Consequently, OHL also intends to reduce the number of customers and stations connected to the 44 kV feeders M3 and M5. Therefore, in an effort to standardize the configuration in the T1/T2 switchyard it can be reconfigured as a single 230-28 kV switchyard and the two existing 44 kV feeders, M45 and M46, relocated and supplied from the T3/T4 DESN. In this option, transformers T3 and T4 will be replaced, increasing capacity to maintain overall available capacity on the 44 kV network.

Hydro One Transmission and the LDCs reviewed all alternatives and concluded that Status Quo and Alternative #1 are not preferred options. It recommends to proceed with Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN.

The study team's recommendation to replace end-of-life equipment at Orangeville TS will also improve the level of reliability and quality of service. Currently, it is expected that the these equipment will be replaced in 2023. The cost of this investment is expected to be a transmission pool investment and LDCs are not expected to pay to replace the transmission equipment.

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
End-of-life replacements at Orangeville TS	• Alternative 2 – Replacement of non-standard end-of-life equipment at Orangeville TS with standard equipment, and reconfiguration of Orangeville DESN.	Hydro One Networks	Expected In- Service 2023

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] South Georgian Bay / Muskoka Needs Assessment Report

Appendix A: Diagrams

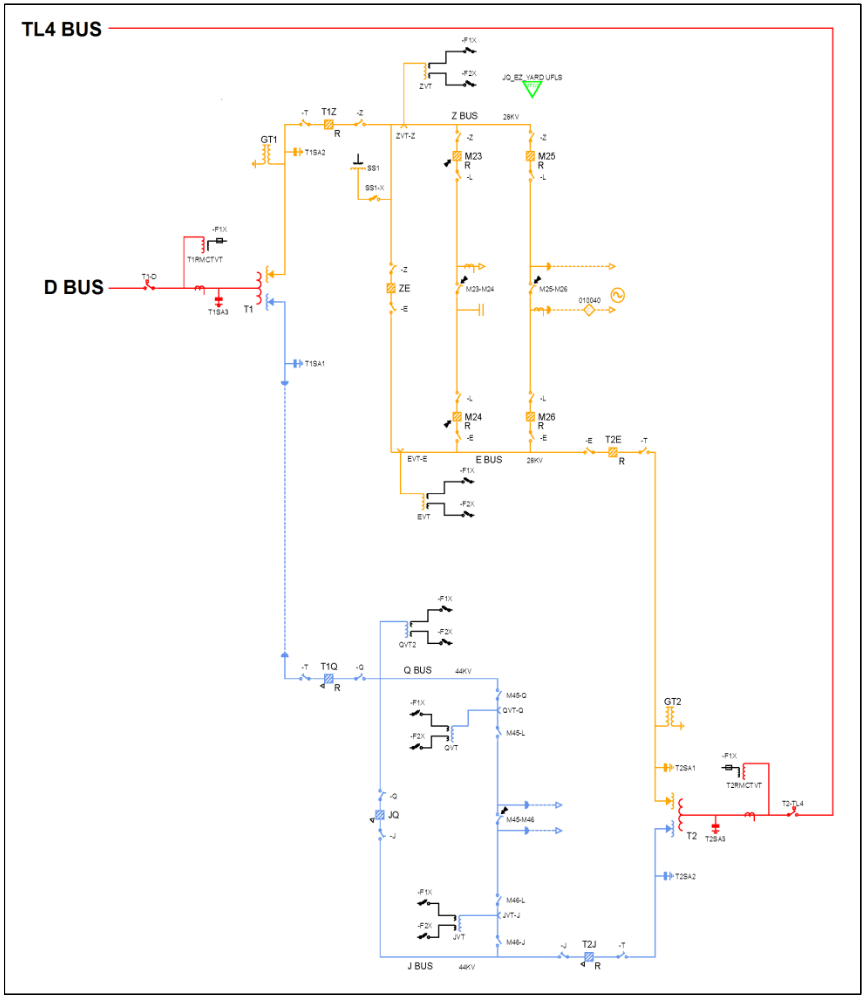


Figure 3: Orangeville T1/T2 DESN configuration after like-for-like replacement

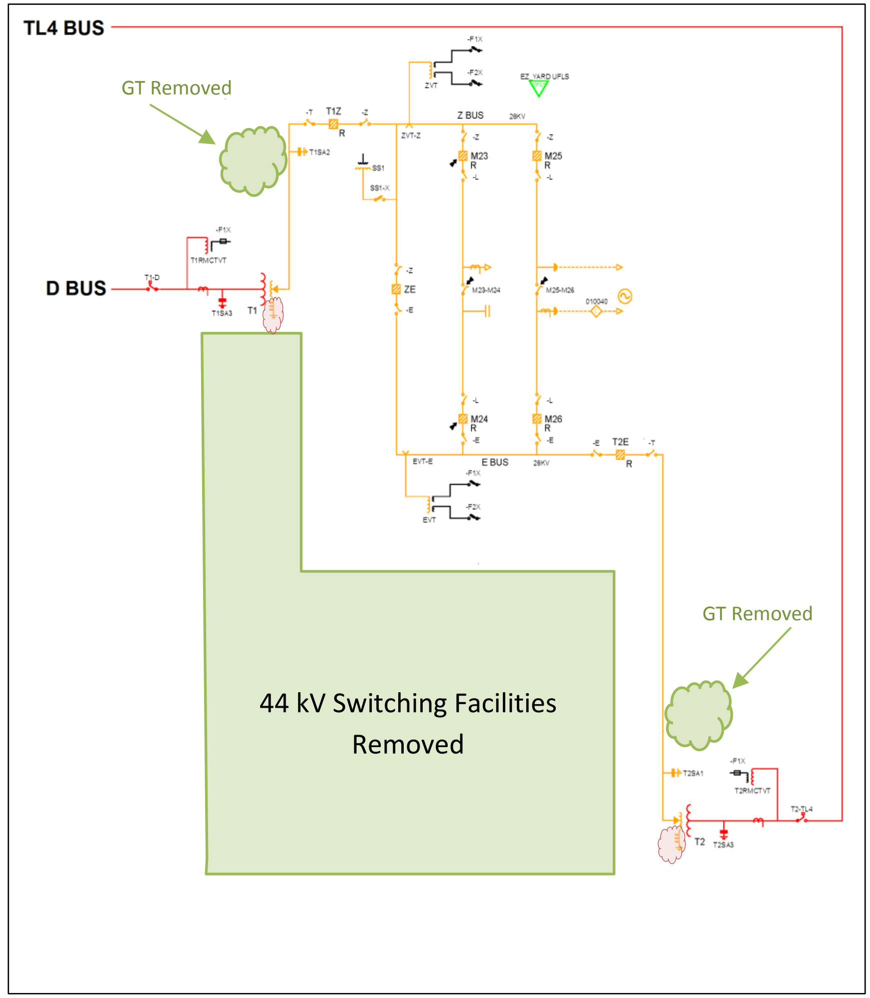


Figure 4: Orangeville T1/T2 DESN after Alternative 3 reconfiguration

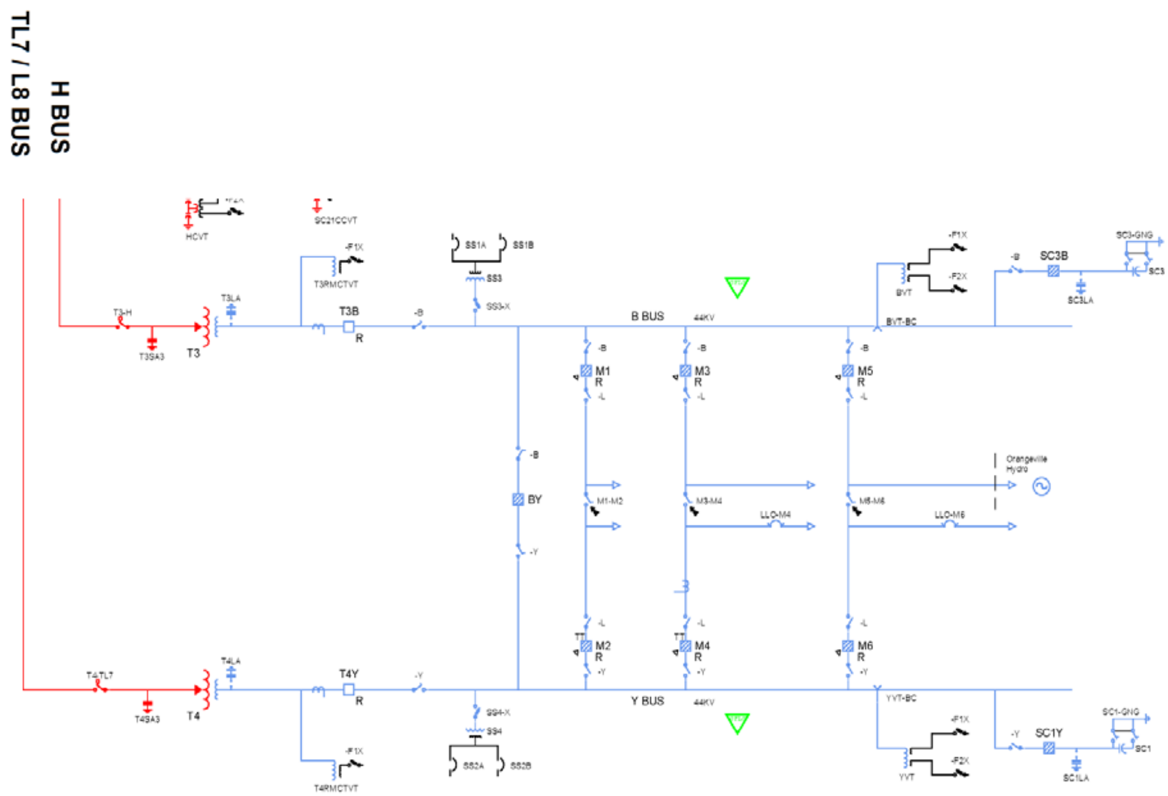


Figure 5: Orangeville T3/T4 DESN configuration after like-for-like replacement

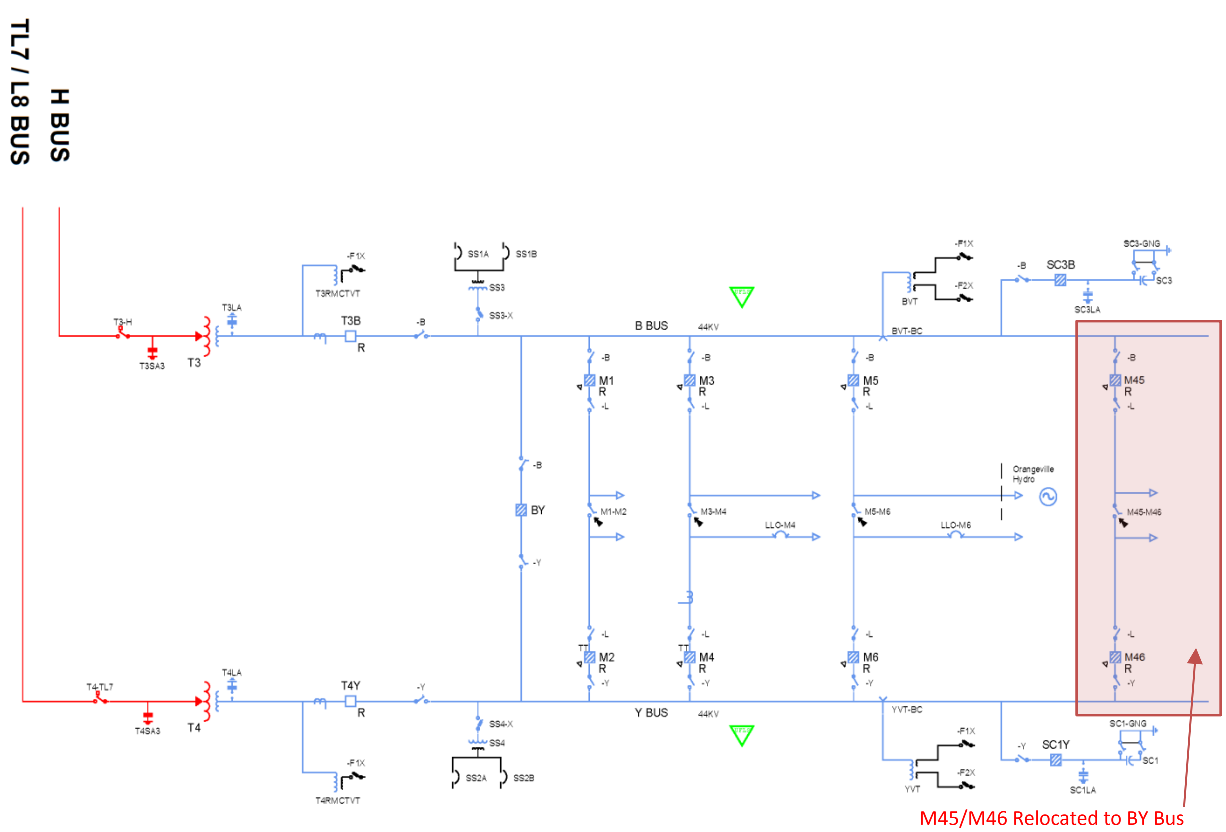


Figure 6: Orangeville T3/T4 DESN after Alternative 3 reconfiguration

Appendix B: Load Forecasts South Georgian Bay/Muskoka

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.6	0.8	1.3	1.7	1.8	2.1	2.3
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
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
	Coincidental Net	26.1	25.9	26.2	26.4	26.5	26.8	26.8	26.9	27.0	27.1	27.2
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
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.3	4.5	5.0	5.7	6.5
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
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
	Coincidental Net	55.1	54.1	61.2	63.5	66.0	68.2	69.8	71.1	73.0	74.8	76.6
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
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.3	3.1	4.9	6.9	8.0	9.4	10.9
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
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
	Coincidental Net	90.5	92.0	94.1	97.0	100.9	106.3	111.4	117.2	123.9	130.4	136.9
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
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.1	2.7	4.1	5.5	6.1	6.7	7.4
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
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
	Coincidental Net	89.2	90.6	91.0	91.4	91.5	92.0	91.9	91.7	91.9	91.8	91.7
Bracebridge TS	Non Coincidental Gross		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
LTR (MVA)	CDM (MW)		0.2	0.3	0.4	0.4	0.5	0.8	1.1	1.2	1.3	1.4
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
W: 93	Non Coincidental Net	20.0	19.9	19.7	19.6	19.6	19.5	19.2	18.9	18.8	18.7	18.6
	Coincidental Net	20.0	19.8	19.7	19.6	19.6	19.5	19.2	18.9	18.8	18.7	18.6

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Everett TS	Non Coincidental Gross		59.3	61.2	62.4	64.4	65.6	67.5	69.2	70.9	73.4	75.1
LTR (MVA)	CDM (MW)		0.4	0.8	1.2	1.4	1.8	2.8	3.7	4.2	4.7	5.3
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
W: 96	Non Coincidental Net	54.7	58.8	60.4	61.2	63.0	63.8	64.7	65.4	66.7	68.6	69.7
	Coincidental Net	55.1	59.2	60.8	61.7	63.4	64.2	65.2	66.0	67.3	69.2	70.3
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
LTR (MVA)	CDM (MW)		0.7	1.3	1.8	2.0	2.6	4.0	5.3	5.9	6.5	7.2
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
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
	Coincidental Net	84.1	84.1	85.1	85.6	85.6	86.4	86.6	86.6	87.0	87.3	87.6
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
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.7	0.9	1.3	1.8	1.9	2.2	2.4
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
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
	Coincidental Net	26.1	26.0	26.3	26.5	26.7	27.0	27.1	27.2	27.4	27.6	27.7
Midhurst TS (T1/T2)	Non Coincidental Gross		107.8	112.8	117.0	120.9	125.5	129.9	134.4	138.6	142.9	147.2
LTR (MVA)	CDM (MW)		0.8	1.5	2.2	2.6	3.4	5.3	7.3	8.1	9.2	10.5
S: 172	DG (MW)	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844
W: 194	Non Coincidental Net	101.6	106.1	110.4	113.9	117.5	121.2	123.7	126.3	129.6	132.8	135.9
	Coincidental Net	99.0	103.4	107.6	111.1	114.5	118.1	120.6	123.1	126.4	129.5	132.5
Midhurst TS (T3/T4)	Non Coincidental Gross		77.1	79.3	81.5	83.8	86.1	88.3	90.5	92.7	95.0	97.4
LTR (MVA)	CDM (MW)		0.6	1.1	1.5	1.8	2.4	3.6	4.9	5.4	6.1	6.9
S: 166	DG (MW)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
W: 192	Non Coincidental Net	75.0	76.5	78.2	79.9	82.0	83.7	84.7	85.6	87.3	88.9	90.5
	Coincidental Net	54.1	55.2	56.4	57.7	59.1	60.4	61.1	61.7	63.0	64.1	65.3
Minden TS	Non Coincidental Gross		56.2	56.7	57.3	57.8	58.3	58.8	59.3	59.9	60.4	61.0
LTR (MVA)	CDM (MW)		0.4	0.8	1.1	1.2	1.6	2.4	3.2	3.5	3.9	4.3

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
S: 59	DG (MW)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
W: 64	Non Coincidental Net	55.0	55.8	55.9	56.2	56.5	56.7	56.4	56.1	56.4	56.5	56.7
	Coincidental Net	45.0	45.7	45.8	46.0	46.3	46.4	46.2	45.9	46.1	46.2	46.3
Muskoka TS	Non Coincidental Gross		166.9	168.9	171.0	171.8	174.3	176.9	179.6	181.4	183.1	184.8
LTR (MVA)	CDM (MW)		1.3	2.3	3.2	3.7	4.8	7.2	9.7	10.6	11.8	13.1
S: 154	DG (MW)	0.452	0.452	0.452	0.452	0.452	0.452	0.452	0.452	0.452	0.452	0.452
W: 175	Non Coincidental Net	165.0	165.2	166.2	167.3	167.7	169.1	169.2	169.4	170.3	170.8	171.2
	Coincidental Net	145.4	145.6	146.4	147.4	147.7	149.0	149.1	149.3	150.0	150.5	150.8
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
	CDM (MW)		0.4	0.7	1.0	1.2	1.5	2.3	3.1	3.5	3.9	4.3
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
S: 104	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
W: 122	Coincidental Net	23.5	21.1	21.2	21.6	22.1	22.5	22.7	22.9	23.2	23.5	23.8
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
	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.0	1.4	1.6	1.7	1.9
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
S: 53	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
W: 58	Coincidental Net	23.5	22.8	23.1	23.4	23.6	23.9	24.1	24.3	24.5	24.7	24.9
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
LTR (MVA)	CDM (MW)		0.6	1.2	1.7	1.9	2.5	3.8	5.2	5.7	6.4	7.1
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
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
	Coincidental Net	82.6	83.4	84.5	85.6	86.3	87.6	88.2	88.8	89.8	90.6	91.3
Orillia TS	Non Coincidental Gross		126.2	128.2	130.7	131.5	133.9	136.5	139.5	141.1	143.0	144.9
LTR (MVA)	CDM (MW)		0.9	1.7	2.5	2.8	3.7	5.6	7.5	8.3	9.2	10.3
S: 165	DG (MW)	2.432	2.432	2.432	2.432	2.432	2.432	2.432	2.432	2.432	2.432	2.432
W: 186	Non Coincidental Net	122.4	122.8	124.0	125.8	126.2	127.8	128.5	129.5	130.4	131.3	132.2

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Coincidental Net	114.5	114.8	115.9	117.5	117.9	119.4	120.0	121.0	121.8	122.7	123.5
Parry Sound TS	Non Coincidental Gross		61.2	61.8	62.4	62.6	63.3	64.2	65.0	65.5	66.0	66.5
LTR (MVA)	CDM (MW)		0.5	0.8	1.2	1.3	1.7	2.6	3.5	3.8	4.3	4.7
S: 52	DG (MW)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
W: 57	Non Coincidental Net	57.5	60.7	61.0	61.2	61.2	61.6	61.6	61.5	61.6	61.7	61.8
	Coincidental Net	52.5	55.4	55.6	55.9	55.9	56.2	56.2	56.1	56.3	56.3	56.3
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
LTR (MVA)	CDM (MW)		1.0	1.9	2.7	3.1	3.9	6.0	8.0	8.7	9.6	10.7
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
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
	Coincidental Net	129.3	110.5	110.8	111.3	111.2	111.9	111.7	111.4	111.7	111.7	111.6
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
LTR (MVA)	CDM (MW)		0.3	0.5	0.8	0.9	1.1	1.7	2.3	2.5	2.8	3.1
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
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
	Coincidental Net	34.1	30.5	30.9	31.1	31.1	31.4	31.4	31.3	31.5	31.5	31.5
Waubaushene TS	Non Coincidental Gross		95.5	96.6	97.7	98.1	99.5	100.9	102.4	103.3	104.2	105.1
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.1	2.7	4.1	5.5	6.1	6.7	7.5
S: 100	DG (MW)	0.882	0.882	0.882	0.882	0.882	0.882	0.882	0.882	0.882	0.882	0.882
W: 110	Non Coincidental Net	94.1	93.9	94.4	95.0	95.1	95.9	95.9	96.0	96.4	96.6	96.8
	Coincidental Net	91.3	91.1	91.6	92.1	92.2	93.0	93.0	93.0	93.4	93.7	93.8

1. South Georgian Bay / Muskoka region is winter peaking
2. DG value (MW) is cumulative
3. DG value includes all distribution-connected generation, including MicroFIT

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
CDM allocation factor	0.75%	1.34%	1.90%	2.15%	2.74%	4.09%	5.40%	5.87%	6.46%	7.10%

CDM value is the percentage reduction applied to gross peak demand at each station

Appendix C: 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

Hydro One Network Inc.
483 Bay Street
6th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
ajay.garg@HydroOne.com

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.
483 Bay Street
Toronto, Ontario
M5G 2P5

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.

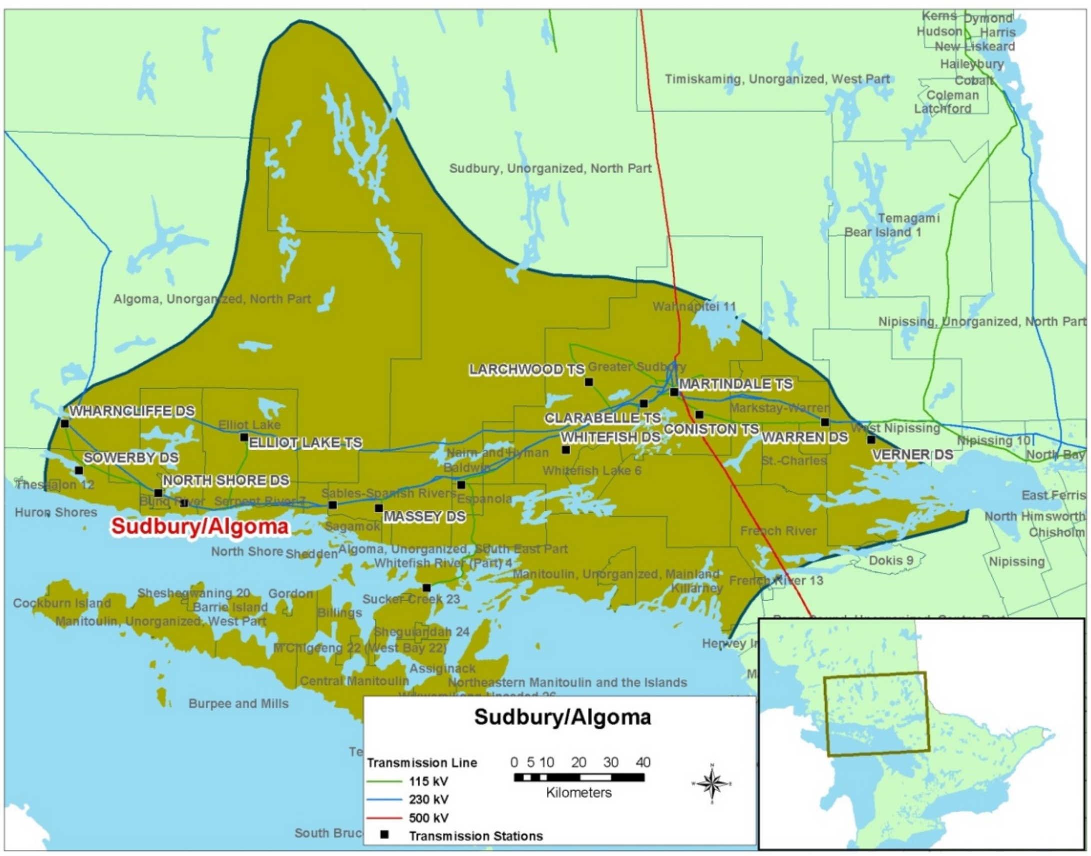


Figure 1: Sudbury to Algoma Region Map

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

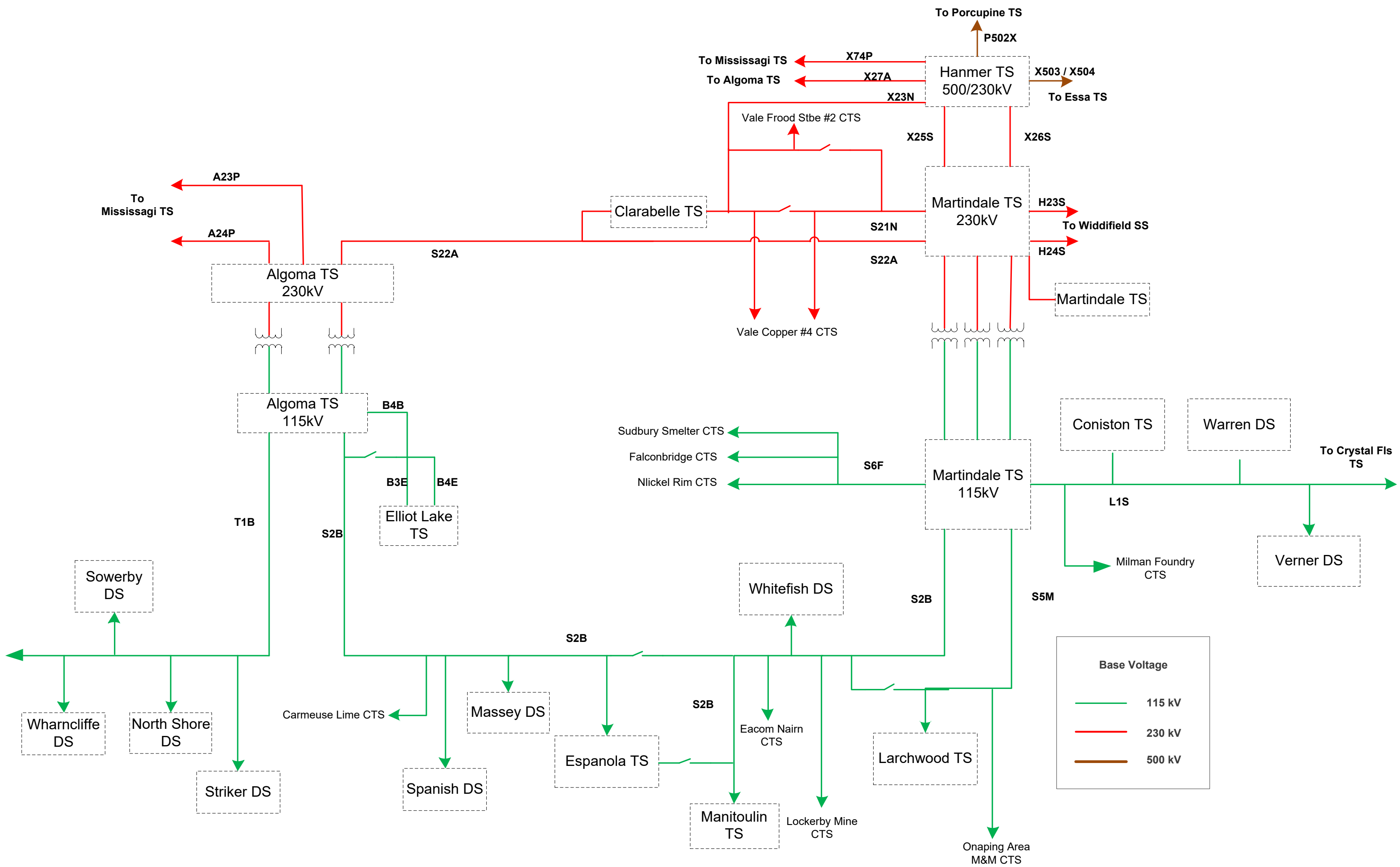


Figure 2: Single Line Diagram – Sudbury to Algoma Region

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

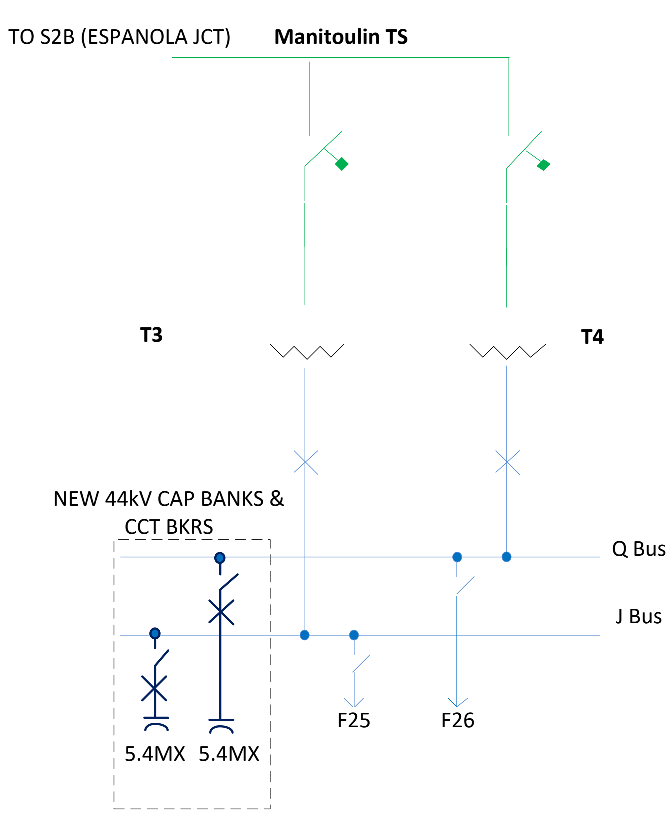


Figure 3 – New 44kV Capacitor Banks

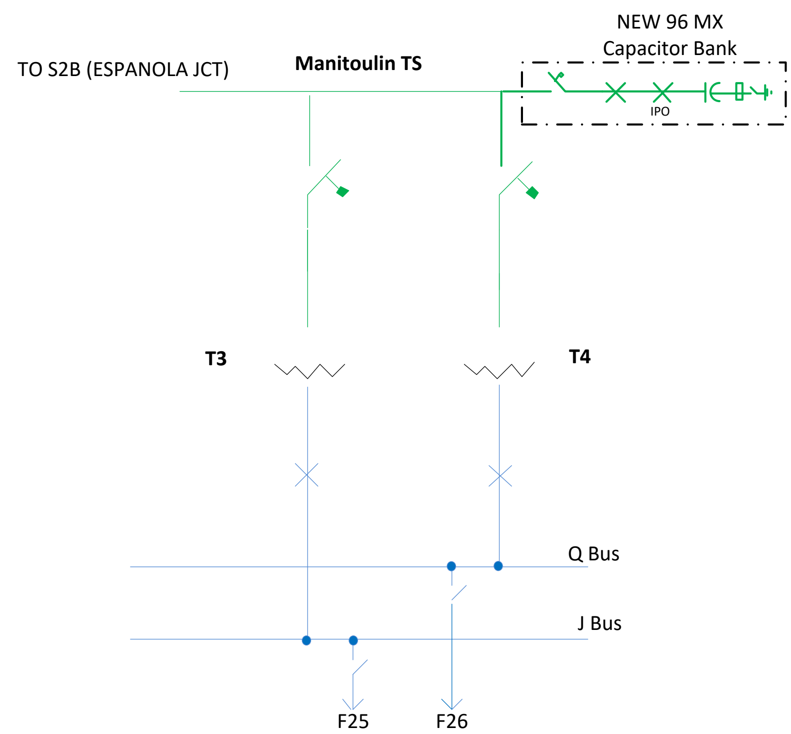


Figure 4 – 115kV Cap bank

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.
483 Bay Street
Toronto, Ontario
M5G 2P5

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.

TABLE OF CONTENTS

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.

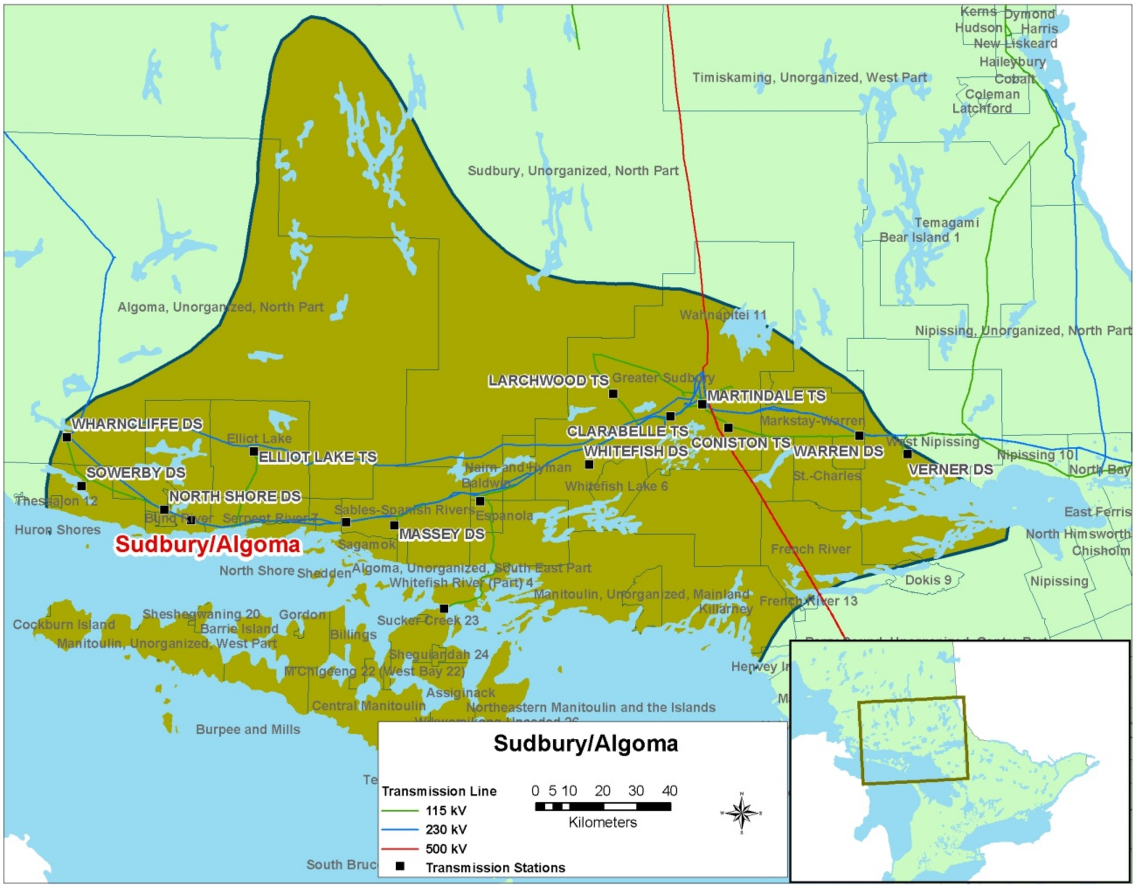


Figure 1: Sudbury to Algoma Region Map

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

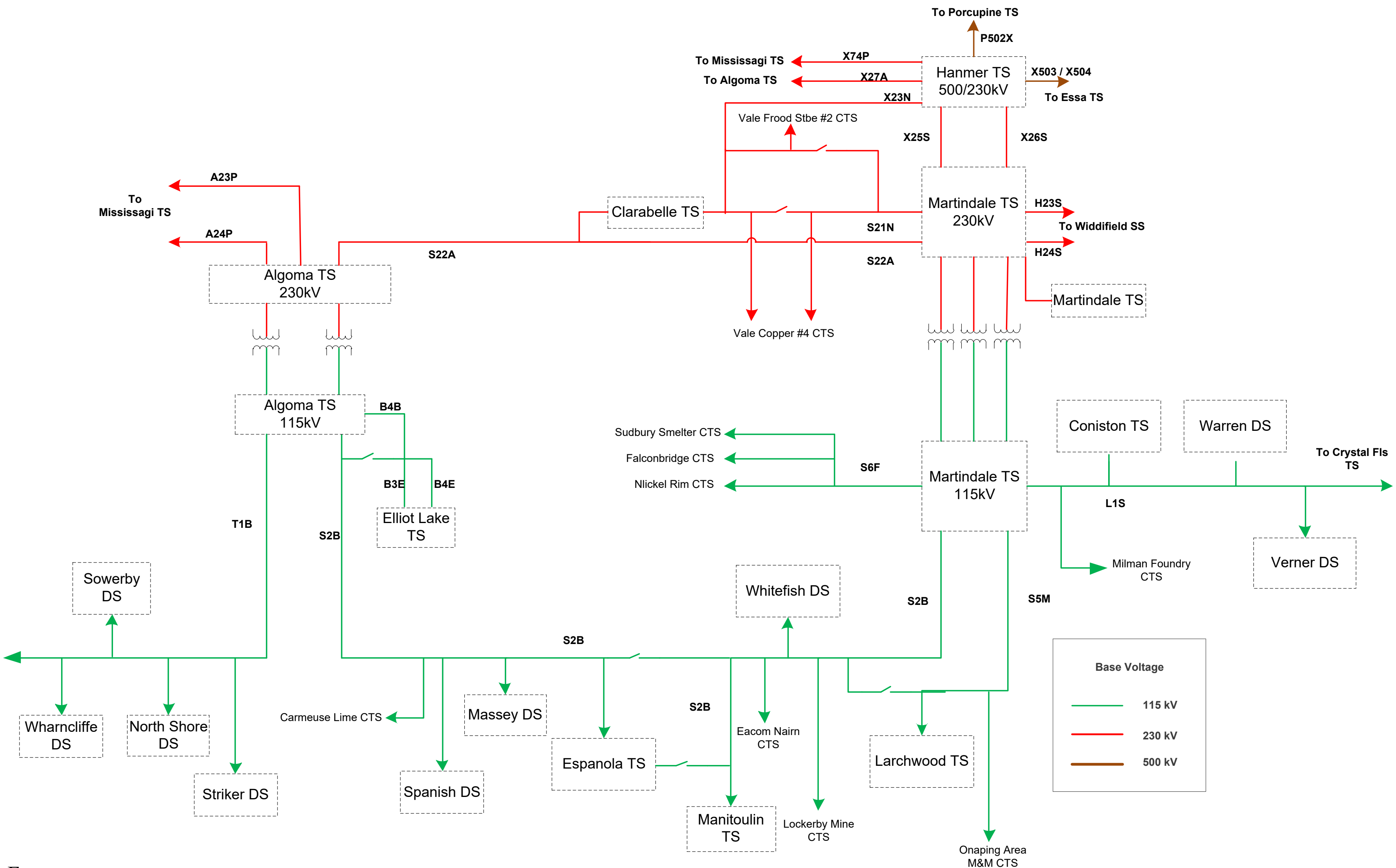


Figure 2: Single Line Diagram – Sudbury to Algoma Region

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

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

NEEDS ASSESSMENT REPORT

Region: Chatham-Kent/Lambton/Sarnia

Date: June 12, 2016

Prepared by: Chatham-Kent/Lambton/Sarnia Study Team

This report is prepared on behalf of the Chatham-Kent/Sarnia/Lambton regional planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Chatham-Kent/Lambton/Sarnia 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

NAME	Chatham-Kent/Lambton/Sarnia Study Team		
LEAD	Hydro One Networks Inc.		
REGION	Chatham-Kent/Lambton/Sarnia		
START DATE	April 13, 2016	**END DATE**	June 12, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Chatham-Kent/Lambton/Sarnia 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 Chatham-Kent/Lambton/Sarnia 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 Chatham-Kent/Lambton/Sarnia Region belongs to Group 3. The Needs Assessment for Chatham-Kent/Lambton/Sarnia Region was triggered on April 13, 2016 and was completed on June 12, 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 OEB.

The scope of the Needs Assessment includes a review of transmission system capability which covers transformer station capacity, transmission circuit thermal capacity, voltage performance and load restoration. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

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. If required, an IRRP will develop a 20-year strategic direction for the Region

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Chatham-Kent/Lambton/Sarnia Region. The information included: planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, system reliability performance, operational issues and 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 – 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformers capacity (Scott TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, 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. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, 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

- Loadings at Kent TS exceed their transformer 10-Day Long Term Rating (LTR) in 2016 based on the net load forecast.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at all transformer stations in the region meet Market Rule requirements.

D. Bulk Power System Performance in the Region

- Based on the assumed system study conditions, no bulk power system issue was identified in the Region. The IESO might undertake planning study to access the adequacy of the bulk power system with different system conditions.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at stations and several transmission circuits will take place. Further details of these investments can be found in Section 6.3 of this report.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends Hydro One transmission and the relevant LDCs to develop a local plan to address thermal overload of transformer T3 at Kent TS.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Chatham-Kent/Lambton/Sarnia (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 OEB.

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Chatham-Kent/Lambton/Sarnia 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 Chatham-Kent/Lambton/Sarnia Region Needs Assessment study team listed in Table 1. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1: Study team participants for Chatham-Kent/Lambton/Sarnia Region

No.	Organizations
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Bluewater Power Distribution Corporation
4.	Entegrus Power Lines Inc.
5.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The Needs Assessment for the Chatham-Kent/Lambton/Sarnia 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 began on April 13, 2016 and was completed on June 12, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Chatham-Kent/Lambton/Sarnia Region over an assessment period of 10 years, from 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuit thermal capacity, voltage performance and load restoration. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Chatham-Kent/Lambton/Sarnia Region Description and Connection Configuration

The region 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.
Figure 1 illustrates the approximate study area.

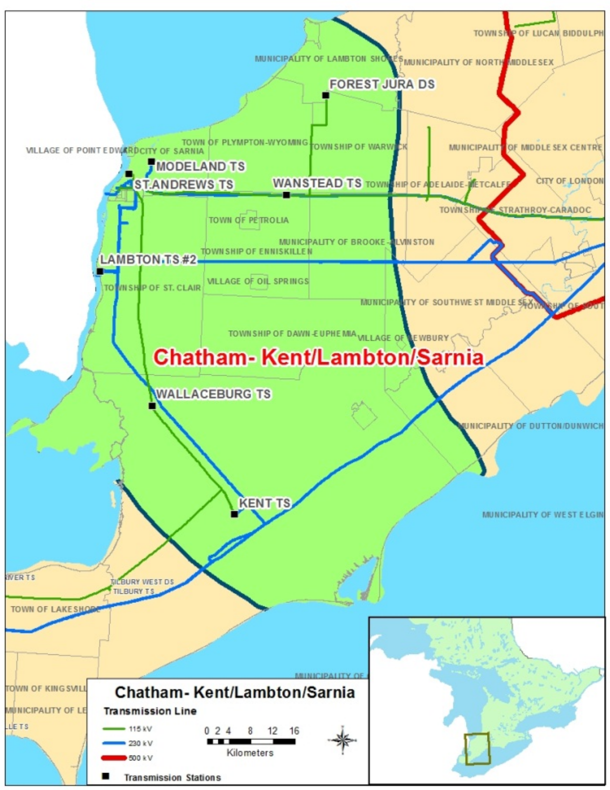


Figure 1: Map of Chatham-Kent/Lambton/Sarnia Region

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, W44LC and W45LS) towards Buchanan TS. This Region also contains a number of interconnections with neighboring Michigan State (B3N, L4D and L51D)

Listed in Table 2 and shown in Figure 2 are Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Table 2: Hydro One and customer assets in Chatham-Kent/Lambton/Sarnia Region

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
N1S, N4S, N6C, N7C, S2N, N5K, K2Z	N6S, N7S, V41N, V43N, L23N, L27V, L25V, L37G, L38G, L28C, L29C, C31, W44LC, W45LS, S47C, L24L, L26L, N21W, N22W	Scott TS, Lambton TS, Kent TS, Duart TS, Modeland TS, Wanstead TS, St. Andrew TS, Wallaceburg TS	Forest Jura HVDS, Customer CTS #1, Customer CTS #2, Customer CTS #3, Customer CTS #4, Customer CTS #5, Customer CTS #6, Customer CTS #7, Customer CTS #8

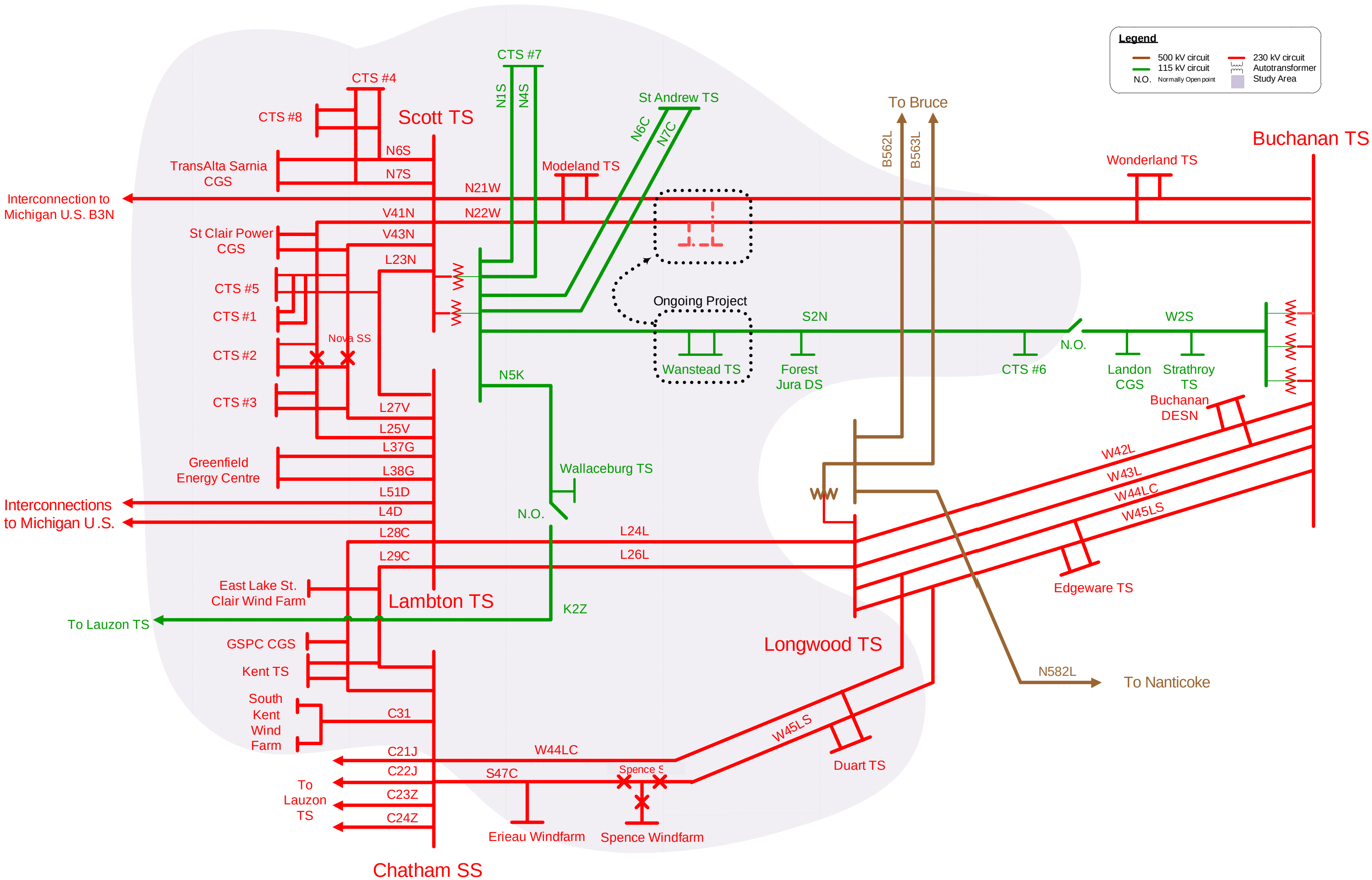


Figure 2: Single-Line diagram – Chatham-Kent/Lambton/Sarnia Region

4 INPUTS AND DATA

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

- LDCs provided historical summer (2012 – 2014) as well as summer gross load forecast (2015 – 2024)
- IESO provided:
  a. Historical regional coincident peak load and station non-coincident peak load
  b. List of existing reliability and operational issues
  c. Gas generation assumptions (See Table 3)
  d. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- Hydro One (Transmission) provided transformer, station and circuit ratings
- Hydro One (Transmission) provided existing reliability and operation issues
- Any relevant planning information, including planned transmission and distribution investments are provided by Hydro One (Transmission) and LDCs

Table 3 : Gas-fired generation output levels assumed for Needs Assessment

Gas Generators in Chatham-Kent/Lambton/Sarnia area	Maximum continuous summer outputs (MW)
Greenfield Energy Centre	1001
TransAlta Sarnia	435
St. Clair Power CGS	484
Greenfield South Power Corporation (GSPC)	283

Based on the historical information provided, Chatham-Kent/Lambton/Sarnia Region is a summer peaking region. As such, the Needs Assessment was conducted based on summer peak load and studies conditions. Further, as part of Hydro One's regular sustainment assessment, Wanstead TS has been identified as reaching end-of-life and is scheduled for a complete station rebuild. Prior to launch of the Needs Assessment study, LDCs connected to the existing Wanstead TS and Hydro One had committed to rebuilding the existing Wanstead TS from the current 115 kV supply to 230 kV supply. The project is currently being assessed by the IESO as part its System Impact Assessment process (CAA ID 2015-545). As such, the Needs Assessment assumed Wanstead TS will be converted to a 230 kV station. Please refer to Section 6.3 for more details about this conversion project.

4.1 Load Forecast

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 from 2015 – 2024. Factoring in the contributions of CDM and DG, the summer net coincident load in the Region is expected to grow at an average rate of approximately 0.2% annually from 2015 – 2024.

Please refer to Appendix A for the load forecasts utilized for this Needs Assessment.

5 Assessment Methodology

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

1. The assessment is based on summer peak loads.
2. Load forecasts are provided by the Region's LDCs using historical 2015 summer peak loads as reference points.
3. For the purpose of Needs Assessment, 2014 historical load levels were assumed for transmission connected industrial customers throughout the study period.
4. The historical peak loads at Hydro One's stations are adjusted for extreme weather conditions according to Hydro One methodology.
5. The LDC's load forecast is translated into load growth rates and is applied onto the historical, extreme weather adjusted, reference points.
6. Accounting for (2), (3), (4), and (5) above, a gross load forecast and a net load forecast are developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net forecast, which accounts for CDM and DG, is 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 sections 6.1.4
   - A gross and net regional coincident peak load forecast was used to perform the analysis for sections 6.1.1 to 6.1.3, 6.2.1, 6.2.2 and 6.2.4
7. Review impact of any on-going and planned development projects in the Region during the study period.
8. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as transformers, cables, and stations.
9. 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 10 – Day Limited Time Rating (LTR).

10. Transmission adequacy assessment is primarily based on the following criteria:
    - Regional load is set to the forecasted regional coincident peak load.
    - 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 10 – Day LTR.
    - All voltages must be within pre and post contingency ranges as per the Ontario Resource and Transmission Assessment Criteria (ORTAC).
    - The system to meet load security criteria as per the ORTAC, specifically, 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 timeframes as per the ORTAC.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Chatham–Kent/Lambton/Sarnia Region.

6.1 Transmission System Capacity Needs

6.1.1 230 kV and 115 kV Autotransformers

The 230/115 kV autotransformers (Scott 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 are adequate over the study period for the loss of a single 230 kV circuit in the Region.

6.1.3 115 kV Transmission Lines

The 115 kV lines supplying the Region are radial single circuit lines. These 115 kV circuits have adequate capacity over the study period.

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 transformer stations in the Region using the summer station non- coincident peak load forecasts.

Kent TS T3/T4 is forecasted to exceed its 10 – Day LTR in 2016 based on the net load forecast (approximately 119% Summer 10 – Day LTR in 2016).

All the other TSs in the Chatham-Kent/Lambton/Sarnia Region is forecasted to remain within their normal supply capacity during the study period.

6.2 System Reliability, Operation and Restoration Review

6.2.1 Load Security

Based on the gross regional coincident peak load forecast, with all transmission facilities in–service and coincident with an outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV–connected Greenfield Energy Centre unit on the 230 kV.

Based on the gross regional-coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Based on the gross regional coincident load forecast, the loss of two elements will not result in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Therefore, load security criteria for the Region are met.

6.2.2 Load Restoration

Based on the gross coincident load forecast at Modeland TS, Wanstead TS and Wonderland TS, by the end of study period, the load interrupted is expected to approach 240 MW for the loss of double-circuit 230 kV line N21W and N22W. Presently, N21W can be sectionalized and load can be restored from either Scott TS or Buchanan TS by use of existing switches on N21W. With the switching capabilities, magnitude of load loss can be reduced from the peak level of over 240 MW to less than 150 MW within 4 hours. The remaining load can be resupplied within the 4-8 hours timeframe by means of load transfers and/or switching alternate feeder supplies to neighbouring, unaffected transformer stations. Hydro One will continue to monitor load growth at stations connected to N21W/N22W and update the restoration plan on an ongoing basis as appropriate.

Based on the assumed load levels for the transmission-connected industrial customers connected to N6S and N7S, the load interrupted will exceed 150 MW for the loss of double-circuit 230kV line N6S and N7S. Hydro One crews located in Sarnia will be able to respond as quickly as possible to restore load to meet the 4 hours and 8 hours restoration criteria. It is the customer's accountability to ensure that there is onsite emergency supply for essential load or arrange for backup supply from other sources.

Therefore, load restoration criteria for the Region are met.

6.2.3 Voltage Performance

Under gross regional coincident peak load conditions, post-contingency voltage at all transformer stations in the region meet Market Rule requirements.

6.2.4 Bulk Power System Performance in the Region

Based on the study assumptions listed in Section 4, no issue was identified for bulk power system in the Region. It is noted that, however, there are a number of large scale combined-cycle gas plants in the Sarnia-Lambton area and gas-fired generation output could vary depending on broader system conditions such as expected load growth in the province or availability of other generation resources. Moreover, as previously noted in Section 3.1, the Chatham-Kent/Lambton/Sarnia Region is connected to the US market through interconnections in Sarnia and Lambton. Import and export generation levels on the interties have a significant impact on the bulk transmission system. Recognizing gas-fired generation output and import/export levels are important parameters for the bulk system performance for this Region, the IESO might undertake further study to assess the bulk system adequacy under different system conditions. At the launch of the said study, Hydro One will work with the IESO and solicit inputs from other entities such as large transmission connected industrial customers as required.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment and development initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. As mentioned in earlier section, the existing Wanstead TS will be refurbished, with standard 50/66/83 MVA transformers and is scheduled to be completed in 2018. Prior to launch of this study, the LDCs connecting to Wanstead TS and Hydro One had discussed and committed to converting the station from 115 kV to 230 kV connecting to 230 kV circuits N21W and N22W. The Needs Assessment study had included this committed project in the area network setup.

The following sustainment plans do not affect the results of this Needs Assessment study, but are included for completeness:

- The existing St Andrews TS will be refurbished with standard 50/66/83 MVA transformers and is scheduled to be completed in 2023.
- The existing Scott TS will be refurbished, autotransformer T5 will be replaced like-for-like with a 250MVA unit and is scheduled to be completed in 2022.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team agrees that Scoping Assessment is not required at this time.

For thermal overload of transformer T3 at Kent TS, considering there is adequate regional supply capacity to accommodate expected load growth, it is the study team's recommendation that no further regional coordination is required. Further, the study team recommends Hydro One transmission and the relevant distributors to develop a local plan ("Kent TS – T3 Capacity Limitation") for this need.

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

APPENDIX A: LOAD FORECASTS

As noted in Section 5, conservation and demand management (CDM) and distributed generation (DG) projects forecast information provided by the IESO were used to determine the net load forecast. The forecasted CDM achievement in the Chatham – Kent/ Lambton/Sarnia area is summarized in Table 4 and it represents the percentage reduction applied to gross peak demand at each station.

Table 4 : CDM forecast for the Chatham- Kent/Lambton/Sarnia Region

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CDM	0.96%	2.04%	2.74%	3.84%	4.86%	5.68%	6.25%	6.83%	7.22%	7.72%

The DG information shown in Table 5 and Table 6 reflects all generation contracts with the IESO in the Chatham – Kent/Lambton/Sarnia area: FIT, microFIT and CHPSOP. Further, the DG information represents the cumulative, effective capacity to meeting area peak demand.

Table 5: Chatham-Kent/Lambton/Sarnia regional coincidental load forecast

		Historical	Forecast									
Station	**Data**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	Coincidental Gross Load		14.66	14.87	15.09	15.30	15.52	15.74	15.97	16.20	16.43	16.66
	Coincidental CDM		0.14	0.30	0.41	0.59	0.75	0.89	1.00	1.11	1.19	1.29
	DG		0.07	0.07	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Coincidental Net Load	14.46	14.45	14.50	14.42	14.46	14.52	14.60	14.72	14.84	14.99	15.12
Forest Jura DS	Coincidental Gross Load		19.69	20.03	20.37	20.72	21.07	21.43	21.80	22.17	22.55	22.93
	Coincidental CDM		0.19	0.41	0.56	0.80	1.02	1.22	1.36	1.51	1.63	1.77
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Coincidental Net Load	19.36	19.49	19.60	19.80	19.91	20.03	20.20	20.42	20.64	20.90	21.14
Kent TS T1/T2	Coincidental Gross Load		71.05	72.70	74.38	76.11	77.88	79.70	81.56	83.46	85.42	87.42
	Coincidental CDM		0.68	1.48	2.04	2.92	3.78	4.53	5.10	5.70	6.16	6.75
	DG		0.53	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
	Coincidental Net Load	69.45	69.84	70.01	71.14	71.98	72.90	73.96	75.25	76.56	78.05	79.47
Kent TS T3/T4	Coincidental Gross Load		40.82	41.72	42.64	43.58	44.55	45.54	46.56	47.60	48.67	49.76
	Coincidental CDM		0.39	0.85	1.17	1.67	2.16	2.59	2.91	3.25	3.51	3.84
	DG		0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
	Coincidental Net Load	39.95	40.27	40.71	41.31	41.75	42.23	42.79	43.49	44.19	45.00	45.76
Lambton TS	Coincidental Gross Load		62.25	62.87	63.49	64.12	64.76	65.40	66.05	66.70	67.36	68.03
	Coincidental CDM		0.60	1.28	1.74	2.46	3.14	3.72	4.13	4.55	4.86	5.25
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Coincidental Net Load	61.64	61.66	61.59	61.75	61.66	61.61	61.68	61.92	62.15	62.50	62.78
Modeland TS	Coincidental Gross Load		82.93	83.27	83.61	83.96	84.30	84.65	84.99	85.34	85.69	86.04
	Coincidental CDM		0.80	1.70	2.29	3.22	4.09	4.81	5.32	5.82	6.18	6.64
	DG		0.02	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
	Coincidental Net Load	82.59	82.11	81.41	81.16	80.57	80.05	79.67	79.52	79.36	79.35	79.24
St. Andrews TS	Coincidental Gross Load		63.59	63.59	63.59	63.59	63.59	63.59	63.59	63.59	63.59	63.59
	Coincidental CDM		0.61	1.30	1.74	2.44	3.09	3.61	3.98	4.34	4.59	4.91
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Coincidental Net Load	63.59	62.98	62.29	61.84	61.14	60.50	59.97	59.61	59.25	59.00	58.68
Wallaceburg TS	Coincidental Gross Load		27.67	28.32	28.97	29.65	30.34	31.04	31.76	32.50	33.25	34.03
	Coincidental CDM		0.27	0.58	0.79	1.14	1.47	1.76	1.99	2.22	2.40	2.63
	DG		0.43	0.94	0.94	0.94	0.94	6.09	6.09	6.09	6.09	6.09
	Coincidental Net Load	27.05	26.98	26.80	27.24	27.57	27.93	23.18	23.68	24.19	24.76	25.31
Wanstead TS	Coincidental Gross Load		28.70	29.17	29.65	30.14	30.63	31.13	31.64	32.16	32.69	33.22
	Coincidental CDM		0.28	0.60	0.81	1.16	1.49	1.77	1.98	2.20	2.36	2.56
	DG		0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
	Coincidental Net Load	28.24	28.05	28.20	28.46	28.60	28.76	28.98	29.28	29.59	29.95	30.28
CTS #1	Transmission Connected Industrial Customer	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94
CTS #2	Transmission Connected Industrial Customer	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82
CTS #3	Transmission Connected Industrial Customer	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00
CTS #4	Transmission Connected Industrial Customer	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95
CTS #5	Transmission Connected Industrial Customer	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89
CTS #6	Transmission Connected Industrial Customer	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
CTS #7	Transmission Connected Industrial Customer	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89
CTS #8	Transmission Connected Industrial Customer	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71

Table 6 : Chatham-Kent/Lambton/Sarnia regional non-coincidental load forecast

		Historical	Forecast									
Station	Data	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Duart TS	Non-coincidental Gross Load		18.26	18.55	18.72	18.97	19.33	19.69	19.94	20.19	20.43	20.68
	Non-coincidental CDM		0.18	0.38	0.51	0.73	0.94	1.12	1.25	1.38	1.47	1.60
	DG		0.07	0.07	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Non-coincidental Net Load	14.46	18.01	18.10	17.96	17.99	18.14	18.32	18.44	18.56	18.71	18.83
Forest Jura DS	Non-coincidental Gross Load		22.58	23.05	23.29	23.70	24.19	24.75	25.09	25.50	25.82	26.22
	Non-coincidental CDM		0.22	0.47	0.64	0.91	1.17	1.41	1.57	1.74	1.86	2.02
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Non-coincidental Net Load	19.36	22.35	22.56	22.63	22.77	23.00	23.33	23.51	23.75	23.94	24.18
Kent TS T1/T2	Non-coincidental Gross Load		107.57	114.81	117.04	119.46	122.16	124.89	127.48	130.10	132.77	135.49
	Non-coincidental CDM		1.03	2.34	3.21	4.59	5.93	7.10	7.97	8.88	9.58	10.46
	DG		0.53	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
	Non-coincidental Net Load	69.45	106.00	111.26	112.63	113.66	115.02	116.58	118.30	120.02	121.98	123.83
Kent TS T3/T4	Non-coincidental Gross Load		61.87	65.59	66.79	68.11	69.62	71.14	72.55	73.98	75.42	76.90
	Non-coincidental CDM		0.59	1.34	1.83	2.62	3.38	4.04	4.54	5.05	5.44	5.93
	DG		0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
	Non-coincidental Net Load	39.95	61.11	64.08	64.80	65.33	66.08	66.93	67.85	68.76	69.82	70.81
Lambton TS	Non-coincidental Gross Load		71.39	72.21	72.55	73.18	74.29	75.37	76.00	76.60	77.15	77.72
	Non-coincidental CDM		0.69	1.47	1.99	2.81	3.61	4.28	4.75	5.23	5.57	6.00
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Non-coincidental Net Load	61.64	70.71	70.73	70.56	70.37	70.68	71.09	71.25	71.37	71.59	71.72
Modeland TS	Non-coincidental Gross Load		100.71	101.71	102.71	103.71	104.71	104.71	104.71	104.71	104.71	104.71
	Non-coincidental CDM		0.97	2.08	2.81	3.98	5.08	5.95	6.55	7.15	7.56	8.08
	DG		0.02	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
	Non-coincidental Net Load	82.59	99.72	99.48	99.74	99.57	99.47	98.60	98.00	97.40	97.00	96.47
St. Andrews TS	Non-coincidental Gross Load		62.74	62.74	62.74	62.74	62.74	62.74	62.74	62.74	62.74	62.74
	Non-coincidental CDM		0.60	1.28	1.72	2.41	3.05	3.57	3.92	4.28	4.53	4.84
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Non-coincidental Net Load	63.59	62.13	61.46	61.02	60.33	59.69	59.17	58.81	58.45	58.21	57.90
Wallaceburg TS	Non-coincidental Gross Load		41.86	42.84	43.86	44.80	45.82	46.95	48.10	49.19	50.28	51.40
	Non-coincidental CDM		0.40	0.87	1.20	1.72	2.23	2.67	3.01	3.36	3.63	3.97
	DG		0.43	0.94	0.94	0.94	0.94	6.09	6.09	6.09	6.09	6.09
	Non-coincidental Net Load	27.05	41.04	41.03	41.72	42.15	42.66	38.19	39.00	39.74	40.56	41.34
Wanstead TS	Non-coincidental Gross Load		34.10	34.68	35.29	35.68	36.22	36.99	37.75	38.30	38.83	39.34
	Non-coincidental CDM		0.33	0.71	0.97	1.37	1.76	2.10	2.36	2.61	2.80	3.04
	DG		0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
	Non-coincidental Net Load	28.24	33.40	33.59	33.95	33.94	34.08	34.51	35.01	35.31	35.65	35.93
CTS #1	Transmission Connected Industrial Customer	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94
CTS #2	Transmission Connected Industrial Customer	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82	20.82
CTS #3	Transmission Connected Industrial Customer	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00
CTS #4	Transmission Connected Industrial Customer	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95	112.95
CTS #5	Transmission Connected Industrial Customer	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89	30.89
CTS #6	Transmission Connected Industrial Customer	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
CTS #7	Transmission Connected Industrial Customer	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89
CTS #8	Transmission Connected Industrial Customer	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71	46.71

APPENDIX B: KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity
The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.

Coincident Peak Load
The electricity demand at individual facilities at the same point in time when the total demand of the region or system is at its maximum.

Contingency
The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM)
Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG)
Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load
Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR)
A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast
Prediction of the load or demand customers will make on the electricity system

Net Load
Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load
The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load
The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Weather Corrected Data
Load data that is adjusted to account for extreme weather conditions using an adjustment factor.

APPENDIX C: 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
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
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
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.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Greater Bruce – Huron

Revision: Final

Date: May 6, 2016

Prepared by: Greater Bruce-Huron Study Team

Distribution

Transmission

Greater Bruce-Huron Region Study Team Organization
Entegrus
Erie Thames Power
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Bruce-Huron 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	Greater Bruce-Huron Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	February 29, 2016	**END DATE**	April 28, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Greater Bruce-Huron 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 Greater Bruce-Huron 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 Greater Bruce-Huron Region belongs to Group 3. The Needs Assessment for this Region was triggered on February 29, 2016 and was completed on April 28, 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 OEB.

The scope of the Needs Assessment includes a review of transmission system capability which covers transformer station capacity, transmission circuit thermal capacity, and voltage performance. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

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. If required, an IRRP will develop a 20-year strategic direction for the Region.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Greater Bruce-Huron Region. The information included: planning activities already underway, historical load and power factor, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, system reliability performance, operational issues and 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 (2016 to 2025). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission System Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformer capacity (Seaforth TS, Hanover TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, 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. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, thermal limits for 115 kV circuit L7S between Seaforth Junction and Kirkton Junction will be exceeded in the near term (summer 2019) for the loss of 115 kV circuit D8S.
- Based on the net regional-coincident load forecast, the need date is expected to be deferred to the end of the study period.
- Due to the limited recorded effectiveness of CDM uptake in this Region, further study is required to identify an action plan.
  - The Need will be managed via Local Planning with the Region's study team.

D. 230 kV and 115 kV Connection Facilities

- Based on the gross non-coincident load forecast, the capacity of the 230 kV and 115 kV connection facilities in the Region are adequate over the study period.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Power Factor at Connection Facilities

- Historically, power factor at Wingham TS and Bruce HWP B TS do not meet Market Rule requirements.
  - The Need at Wingham TS will be managed via Local Planning between the transmitter and the affected LDCs.
  - The Need at Bruce HWP B TS will be managed via Local Planning between the transmitter

and the affected customer.

D. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result in poor end-of-feeder voltages (winter 2020/2021).
- Based on the net regional-coincident peak load forecast at Wingham TS, the need date may be deferred by 2 years.
- Due to the synergy between voltage performance and power factor, this voltage deficiency Need will be further studied in coordination with Wingham TS's power factor.
  - The Need will be managed via Local Planning between the transmitters and the affected LDCs

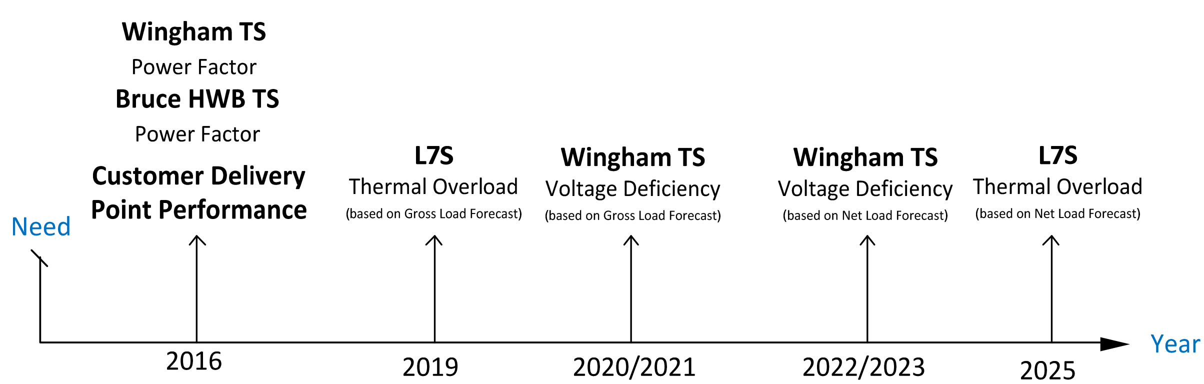
E. Customer Delivery Point Performance

- Based on a review of delivery point performance, several customer delivery points in the Region are below their historical measures.
  - Mitigation measures that align with Hydro One's OEB-approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

F. Bulk Power System Performance in the Region

- Based on a limited analysis of the bulk power system in the Region, 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is over its thermal limit near the end of the study period. This result is consistent with the KWCG Regional Infrastructure Plan (RIP) findings.
  - As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

Needs Timeline Summary



Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at ten stations and several transmission circuits will take place. The replacement of aged equipment may improve customer delivery point performance. Investigation into customer delivery point performance will take into consideration this replacement work.

Further details of these investments can be found in Section 6.3 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team recommendations:

1. Poor power factor and voltage deficiency at Wingham TS to be managed by Local Planning between Hydro One transmission and Hydro One distribution and may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS

2. Poor power factor at Bruce HWP B TS to be managed by Local Planning between Hydro One transmission and the transmission connected customer.

3. Mitigation of poor delivery point performance to several 115 kV connected customers to be managed according to Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers.

4. Thermal overload on circuit L7S to be managed by Local Planning between Hydro One transmission and the Region's study team.

TABLE OF CONTENTS

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 Greater Bruce-Huron 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 OEB.

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Greater Bruce-Huron 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 Greater Bruce-Huron Region Needs Assessment study team listed in Table 1. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1: Study Team Participants for Greater Bruce-Huron Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Entegrus
3	Erie Thames Power
4	Festival Hydro Inc.
5	Goderich Hydro - West Coast Huron Energy Inc.
6	Hydro One Networks Inc. (Distribution)
7	Independent Electricity System Operator
8	Wellington North Power Inc.
9	Westario Power Inc.

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Greater Bruce-Huron 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 February 29, 2016 and was completed on April 28, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Greater Bruce-Huron Region over an assessment period of 2016 to 2025. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuit 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 Greater Bruce-Huron Region Description and Connection Configuration

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. The boundary of the Greater Bruce-Huron Region is shown in Figure 1.

Figure 1: Greater Bruce-Huron Region Map

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 bulk of the electrical supply 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.

Listed in Table 2 and shown in Figure 2, are the transmission and transmission connected assets in the Greater Bruce-Huron Region.

Table 2: Hydro One and Customer Assets Bounded by the Greater Bruce-Huron Region

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
61M18, D8S, D10H, L7S, S1H	B4V, B5V, B22D, B23D, B20P, B24P, B27S, B28S, B81HW, B82HW	Bruce HWP B TS, Centralia TS, Douglas Point TS, Goderich TS, Hanover TS, Owen Sound TS, Palmerston TS, Seaforth TS, St. Marys TS, Stratford TS, Wingham TS	Constance DS, Festival MTS, Grand Bend East DS, Customer CTS #1, Customer CTS #2, Customer CTS #3, Customer CTS #4

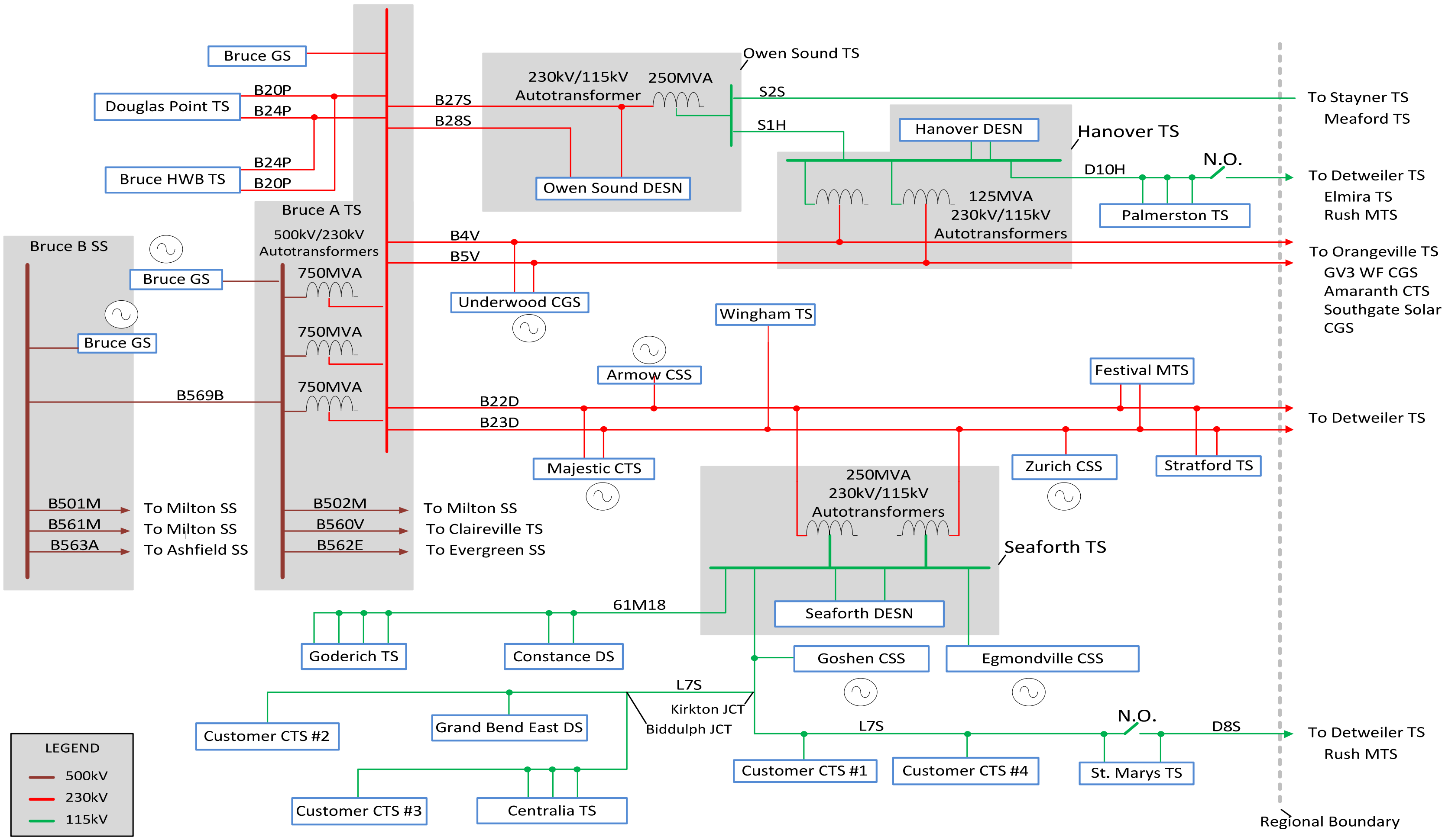


Figure 2: Single Line Diagram – Greater Bruce-Huron Region

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 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
  iv. Historical power factor data, MW and MVar for each station in the Region
- LDCs provided historical summer and winter net load (2013-2015) as well as summer and winter gross load forecast (2016-2025)
- Hydro One (Transmission) provided transformer, station and circuit ratings
- Hydro One (Transmission) provided existing reliability and operation issues
- Any relevant planning information, including planned transmission and distribution investments are provided by Hydro One (Transmission) and LDCs

4.1 Load Forecast

As per the data provided by the study team, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.1% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.0% from 2016-2025.

As per the data provided by the study team, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 0.5% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.3% from 2016-2025.

Based on historical load and on the load forecast, the Regions' winter coincident peak load is larger than its summer coincident peak load. As well, the majority of stations within the Region are winter peaking. The load forecasts utilized for this Needs Assessment are found in Appendix A: Load Forecasts.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. 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 this assessment is conducted for both summer and winter peak load.
2. Forecast loads are provided by the Region's LDCs using historical 2015 summer and historical 2014/2015 winter peak loads as reference points.
3. Forecast loads are provided by industrial customers in the Region. Where data was not provided, the load is assumed to be consistent with historical loads.
4. The historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
5. The LDC's load forecast is translated into load growth rates and is applied onto the historical, extreme weather adjusted, reference points.
6. Accounting for (2), (3), (4), (5) above, a gross load forecast and a net load forecast are developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net forecast, which accounts for CDM and DG, is analyzed to determine if the needs can be deferred.
    a. A gross and net non-coincident peak load forecast was used to perform the analysis for sections 6.1.4 and 6.2.3
    b. A gross and net regional-coincident peak load forecast was used to perform the analysis for sections 6.1.1 to 6.1.3 and 6.2.1 and 6.2.2 and 6.2.4
7. Review impact of any on-going and planned development projects in the Region during the study period.
8. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as transformers, cables, and stations.
9. 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.
10. Transmission adequacy assessment is primarily based on the following criteria:
    - Regional load is set to the forecasted regional-coincident peak load
    - 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 10-Day LTR.
- All voltages must be within pre and post contingency ranges as per the Ontario Resource and Transmission Assessment Criteria (ORTAC).
- The system to meet load security criteria as per the ORTAC, specifically, 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 timeframes as per the ORTAC.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Greater Bruce-Huron Region. The results are based on all 8 Bruce nuclear generating units in-service and no local/renewable generating units in-service in order to verify whether the transmission system has adequate capacity to supply the forecasted regional load.

6.1 Transmission System Capacity Needs

6.1.1 230 kV and 115 kV Autotransformers

The 230/115 kV autotransformers (Seaforth TS, Hanover TS, Detweiler TS, Owen Sound 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 lines supplying the Region are double circuit. The 230 kV circuits are adequate over the study period for the loss of a single 230 kV circuit in the Region.

6.1.3 115 kV Transmission Lines

The 115 kV lines supplying the Region are radial single circuit lines. These 115 kV circuits have adequate capacity over the study period.

115 kV circuit L7S that runs between Seaforth TS and St. Mary's TS is connected to 115 kV circuit D8S that runs between St. Marys TS and Detweiler TS, through the St. Marys TS low voltage bus-tie breaker. For the loss of D8S, L7S will exceed its short-term emergency (STE) and LTE ratings in the near term (summer 2019), under summer *gross*

peak load conditions. Under summer *net* peak load conditions, the flow on L7S decreases to ~97% of its emergency ratings at the end of the study period (summer 2025).

The sections of circuit explicitly over their ratings are: Seaforth Jct. x Goshen Jct., and Goshen Jct. x Kirkton Jct. The emergency ratings of these sections are limited by substandard clearances due to ground topology and a rural distribution line. Due to the limited recorded effectiveness of CDM uptake in this Region, this thermal overload Need will require further study and will therefore be managed by Local Planning with the Region's study team.

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 transformer stations in the Region using the winter and summer station non-coincident peak load forecasts. All stations in the Region have adequate supply capacity for the study period (2016-2025).

6.2 System Reliability, Operation and Restoration Review

6.2.1 Load Security

Based on the gross regional-coincident peak load forecast, with all transmission facilities in-service and coincident with an outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV-connected Bruce nuclear unit on the 230 kV system while on the 115 kV system Goshen wind farm is assumed out of service.

Based on the gross regional-coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Based on the gross regional-coincident load forecast, the loss of two elements will not results in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Therefore, load security criteria for the Region are met.

6.2.2 Load Restoration

Based on the gross regional-coincident peak load forecasts, with the use of existing transmission infrastructure, all load can be restored within approximately 8 hours depending on the severity of the contingency, the prevailing system conditions and the relative distance from the nearest field maintenance centre. Existing transmission infrastructure includes switches that can be operated from the Ontario Grid Control Centre (OGCC), Mid-Span Openers (MSOs) and other isolating devices that require a bucket truck and line crew to open and close.

The largest loss of load in the Region is 325 MW in winter 2024/2025 for the loss of the double circuit line B22D/B23D. By use of existing 61B22D-21 and 61B23D-26 switches at Seaforth TS, the OGCC can quickly resupply, within 30 minutes, approximately 218 MW from Bruce A TS or approximately 268 MW from Detwiler TS. The remaining load can be resupplied in 4-8 hours by opening existing bolted openers along the circuits.

Therefore, load restoration criteria for the Region are met.

6.2.3 Power Factor at Connection Facilities

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Wingham TS does not meet Market Rule requirements. Based on May 2014 to May 2015 historical data the power factor at Wingham TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point at least 60% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected LDCs.

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Bruce HWP B TS does not meet Market Rule requirements. Based on January 2014 to December 2015 historical data the power factor at Bruce HWP B TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point approximately 80% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected customer.

6.2.4 Voltage Performance

Under winter 2020/2021 gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result is poor end-of-feeder voltages. Under winter *net* regional-coincident peak load conditions, the need is deferred by two years to winter 2022/2023. This is a Need that requires mitigation via Local Planning between the transmitter and the affected LDCs.

6.2.5 Customer Delivery Point Performance

Based on a review of Hydro One's historical delivery point performance statistics, several customer delivery points in the Region are below their historical measures. The delivery points are those fed from the Region's 115 kV system. These statistics are consistent with those provided by IESO. Mitigation measures that align with Hydro One's OEB approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

6.2.6 Bulk Power System Performance in the Region

To bridge regional system planning with bulk system planning, a select number of bulk system planning contingencies within the Region are undertaken. With respect to the 230 kV circuits that supply regional load, breaker failure contingencies of these circuit's terminal breakers at BES and BPS station are analyzed to determine their impact. Gross regional-coincident peak load for the Greater Bruce-Huron region was used while a net regional-coincident peak load forecast for the KWCG region was used.

The results showed that 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is at its thermal rating at the end of the study period. This result is consistent with KWCG Regional Infrastructure Plan findings.

As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Table 3 lists Hydro One transmission sustainment initiatives that are currently planned for aging and End-Of-Life (EOL) infrastructure.

Table 3: Hydro One Transmission Sustainment Initiatives

Station/Circuit	Description of Work	Planning In-Service Date
Bruce A TS	230 kV breaker replacement	2019
	500 kV breaker replacement	2024
Bruce B SS	500 kV breaker replacement	2020
Goderich TS	Station refurbishment: replace existing 3 transformers (T1/T2/T3) with a typical 50/83 MVA 2 transformer DESN arrangement (T4/T5)	2017
Detweiler TS	Replace AC station service	2017
	Replace T2 and T4 autotransformers	2021
Centralia TS	Station refurbishment: replace existing 3 transformers with a typical 25/42 MVA 2	2018

	transformer DESN arrangement	
Palmerston TS	Station refurbishment: replace existing 3 transformers with a typical 50/83 MVA 2 transformer DESN arrangement	2018
Wingham TS	Station refurbishment	2022
Seaforth TS	Station refurbishment: to include autotransformers and DESN	2023
Hanover TS	Station refurbishment: to include DESN	2023
Stratford TS	Station refurbishment	2023
Circuit L7S	Replacement of 4 wood poles	2016
	Insulator replacements	As required
Circuit S1H	Replacement of shield wire	2016
	Replacement of 9 wood poles	2017
Circuits B4V & B5V	Insulator and U-bolt replacement	As required
Circuits B22D & B23D	Insulator replacements	As required
Circuits B27S & B28S	Insulator replacements	As required
Circuits B20P & B24P	Insulator replacements	As required

The replacement and/or refurbishment of equipment may improve the overall reliability performance at customer delivery points. Further investigation is required to verify.

6.4 Planned Transmission and Distribution Investments

Listed in Table 4 are planned transmission and distribution investments in the Region. Note that other than the currently planned refurbishment work in table 3, Hydro One transmission does not have additional planned investments within the Region other than connecting generation upon request.

Table 4: Planned Local Distribution Company Investments

LDC	**Investment Description**	**Planning In-Service Date**
Wellington North Power	Transfer ~50% of LDC's Mount Forest load fed from Hanover TS to Palmerston TS in 2016. A feeder extension (M2) from Palmerston TS will be used for this load transfer. This transfer has been incorporated into the Region's station load forecast.	2016

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

1. To mitigate poor power factor and to prevent against voltage deficiency at Wingham TS, Local Planning between Hydro One transmission and Hydro One distribution (this may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS) is recommended.

2. To mitigate poor power factor at Bruce HWP B TS, Local Planning between Hydro One transmission and the transmission connected customer is recommended.

3. To mitigate poor delivery point performance to several 115 kV connected customers, planning in accordance with Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers is recommended.

4. To prevent against thermal overload on circuit L7S, Local Planning between Hydro One transmission and the Region's study team is recommended.

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 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 FORECASTS

Table A1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.58	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.21	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.11	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	101.59	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	60.95	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS	33.27	33.44	33.65	33.78	33.97	34.22	34.47	34.64	34.80	34.95	35.10
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.48	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS	79.16	79.78	80.45	81.03	81.67	82.41	83.14	83.76	84.37	84.98	85.59
Wingham TS	48.21	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.47	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS	45.48	45.81	45.81	46.11	46.56	47.04	47.41	47.78	48.16	48.51	48.90
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	38.95	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.32	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.22	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	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	52.00	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS	30.53	30.68	30.77	30.91	31.14	31.35	31.50	31.63	31.14	31.90	32.03
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS	77.16	77.76	78.26	78.86	79.62	80.38	80.98	81.57	82.16	82.74	83.32
Wingham TS	37.69	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.05	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

* Summer 2014

** Summer 2013

Table A3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	18.63	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	40.95	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.63	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	102.64	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	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	4.63
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.48	68.03*	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS	33.69	34.75	34.96	35.10	35.29	35.55	35.81	35.99	36.15	36.31	36.47
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS	83.48	84.52	85.23	85.84	86.52	87.30	88.08	88.74	89.39	90.03	90.68
Wingham TS	57.06	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.69	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS	46.11	46.44	46.45	46.75	47.21	47.69	48.07	48.45	48.83	49.19	49.58
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	39.27	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.74	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	76.22	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	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	4.53
Owen Sound TS	100.01	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	52.32	54.71*	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS	30.53	31.00	31.09	31.24	31.46	31.68	31.83	31.96	31.47	32.24	32.37
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS	86.43	88.42	88.99	89.68	90.54	91.40	92.09	92.76	93.43	94.09	94.75
Wingham TS	50.74	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.42	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Load Transfer from Hanover TS to Palmerston TS

Table A5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.58	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.21	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.11	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.59	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	60.95	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS	33.27	33.24	33.26	33.06	32.98	32.98	33.02	33.02	33.06	33.06	33.07
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.48	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS	79.16	79.30	79.52	79.30	79.29	79.42	79.65	79.86	80.16	80.39	80.64
Wingham TS	48.21	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.47	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS	45.48	45.43	45.11	44.89	44.87	44.93	45.02	45.10	45.26	45.35	45.49
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.95	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	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	76.22	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	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.00	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS	77.16	77.10	77.05	76.77	76.70	76.76	76.87	76.97	77.20	77.33	77.49
Wingham TS	37.69	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.05	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

* Summer 2014

** Summer 2013

Table A7: Net – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.63	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.95	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.63	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.64	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	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	4.63
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.48	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS	33.69	33.66	33.68	33.48	33.39	33.40	33.44	33.44	33.47	33.47	33.49
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS	83.48	83.62	83.86	83.63	83.62	83.75	84.00	84.21	84.53	84.77	85.04
Wingham TS	57.06	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A8: Net – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.69	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	46.11	46.06	45.74	45.52	45.49	45.56	45.65	45.72	45.89	45.98	46.13
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.27	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.74	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	76.22	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	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	4.53
Owen Sound TS	100.01	100.41*	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.32	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.43	86.36	86.31	86.00	85.92	85.99	86.12	86.22	86.48	86.63	86.81
Wingham TS	50.74	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	6.42	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Load Transfer from Hanover TS to Palmerston TS

Hydro One Networks Inc.
483 Bay Street
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.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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.

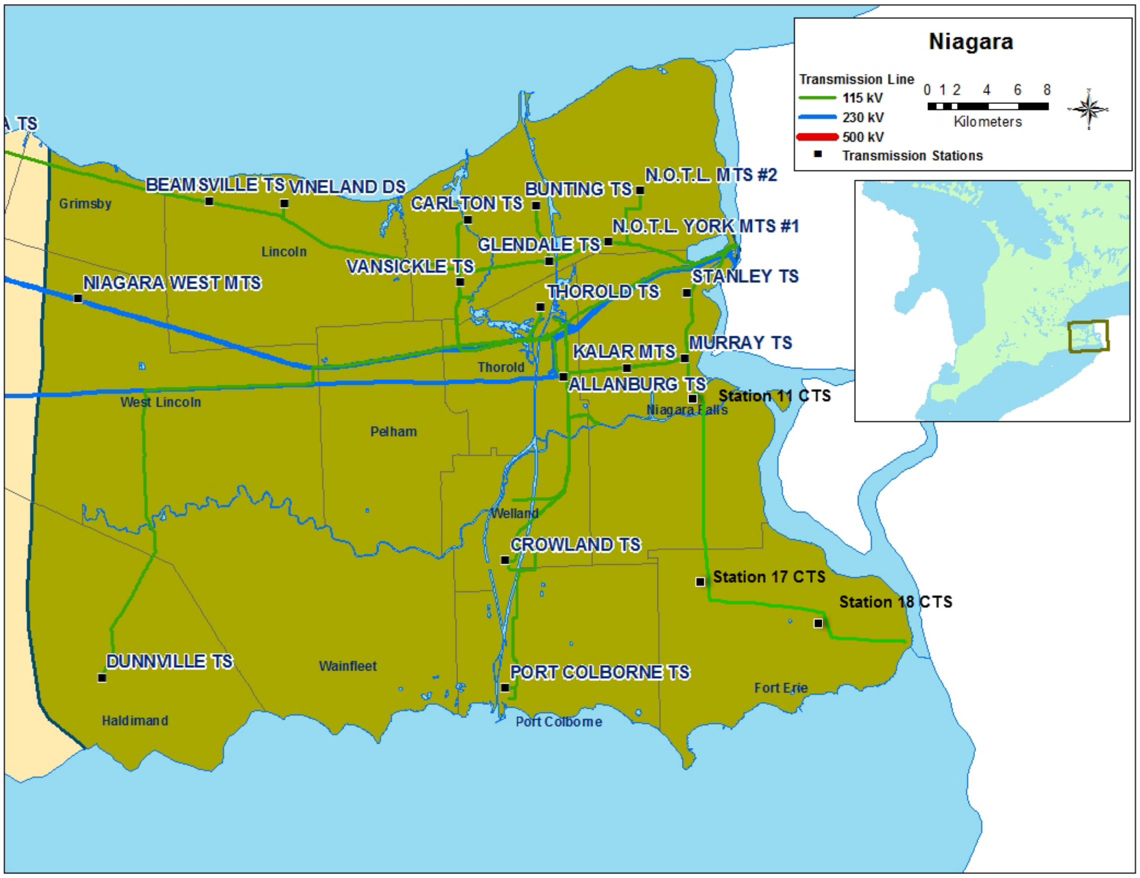


Figure 1: Niagara Region Map

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

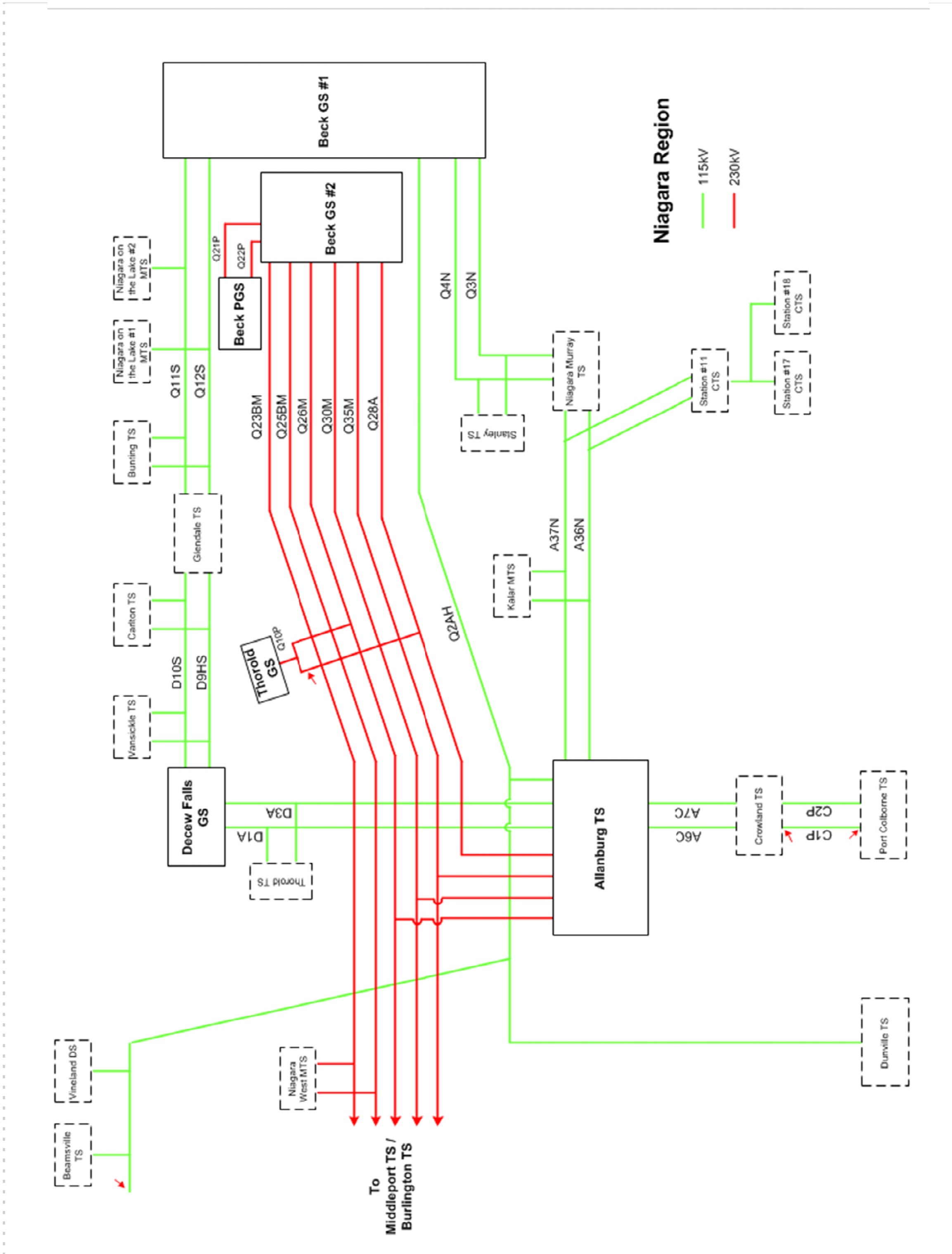


Figure 2: Simplified Niagara Regional Planning Electrical Diagram

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

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

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**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra Qasim Raza
Independent Electricity System Operator	Chris Reali Philip Woo
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.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the 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	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

TABLE OF CONTENTS

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.

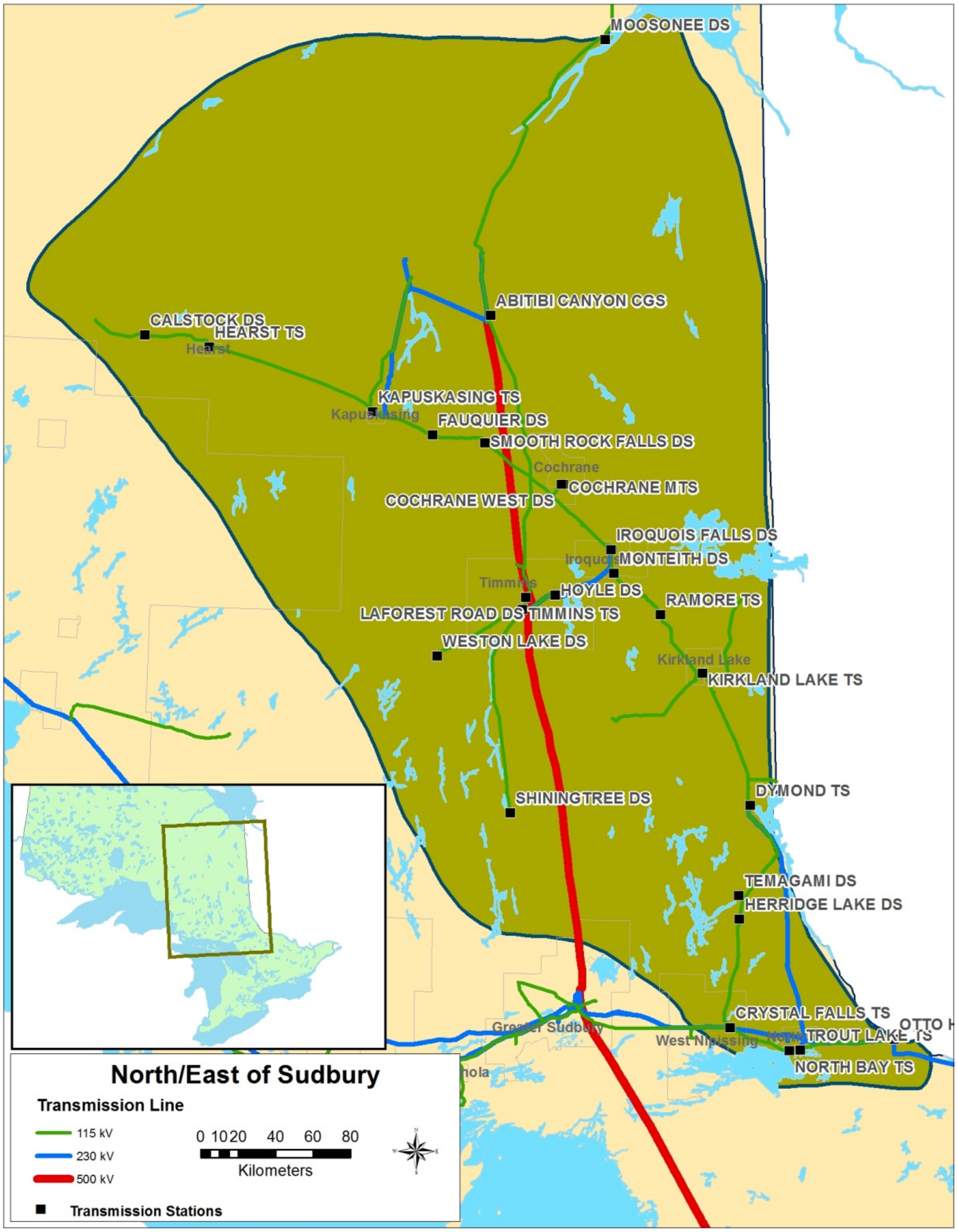


Figure 1: North & East of Sudbury Region Map

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

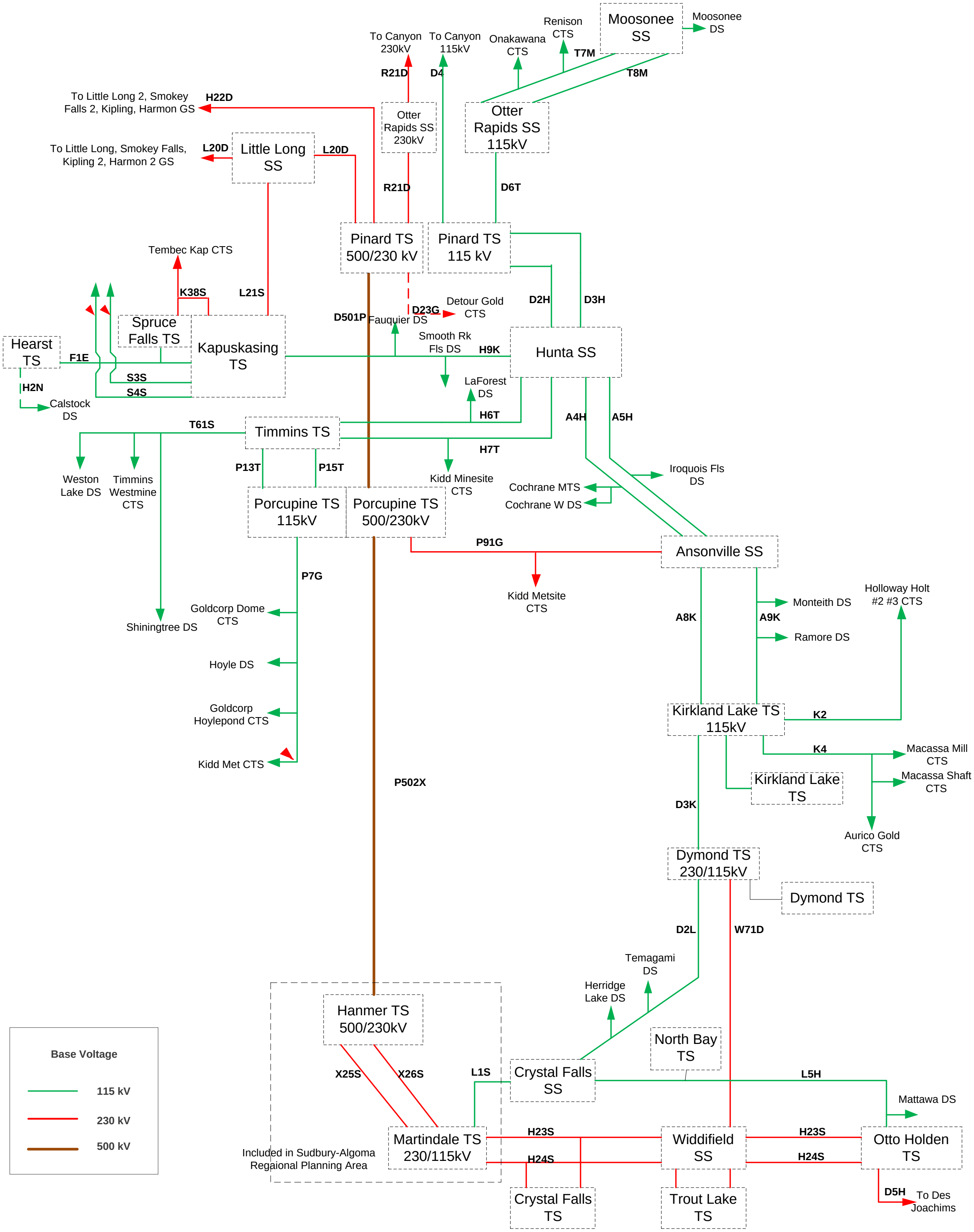


Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

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:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

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.
483 Bay Street
Toronto, Ontario
M5G 2P5

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.

TABLE OF CONTENTS

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.

.

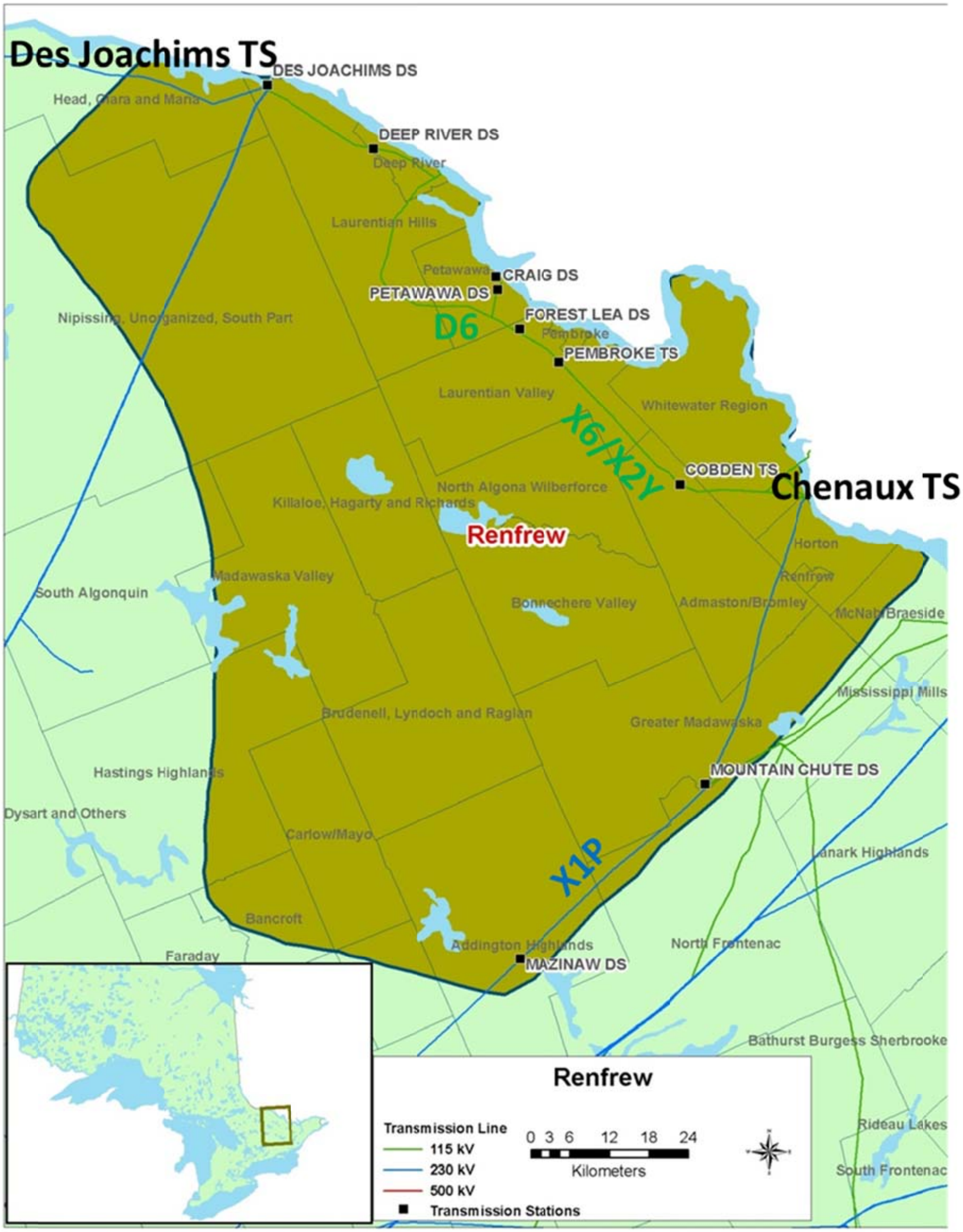


Fig. 1 Renfrew Region Map

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.

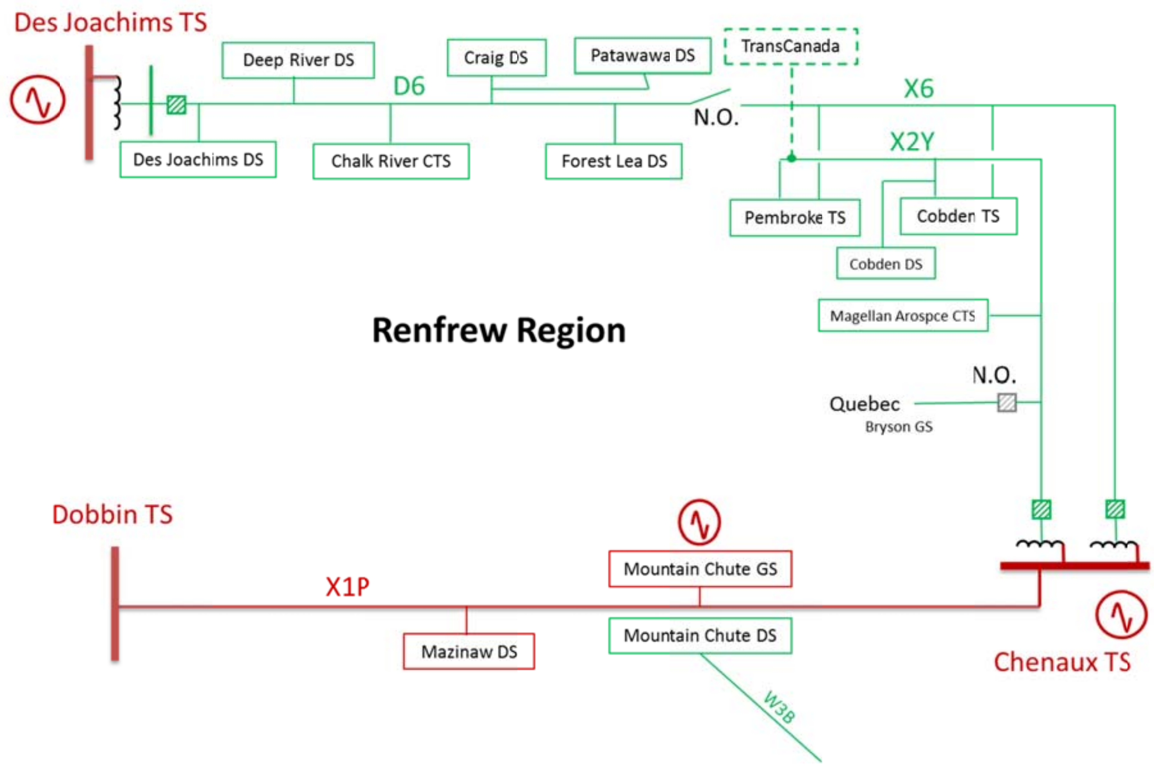


Fig. 2 Single Line Diagram – Renfrew Region

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.

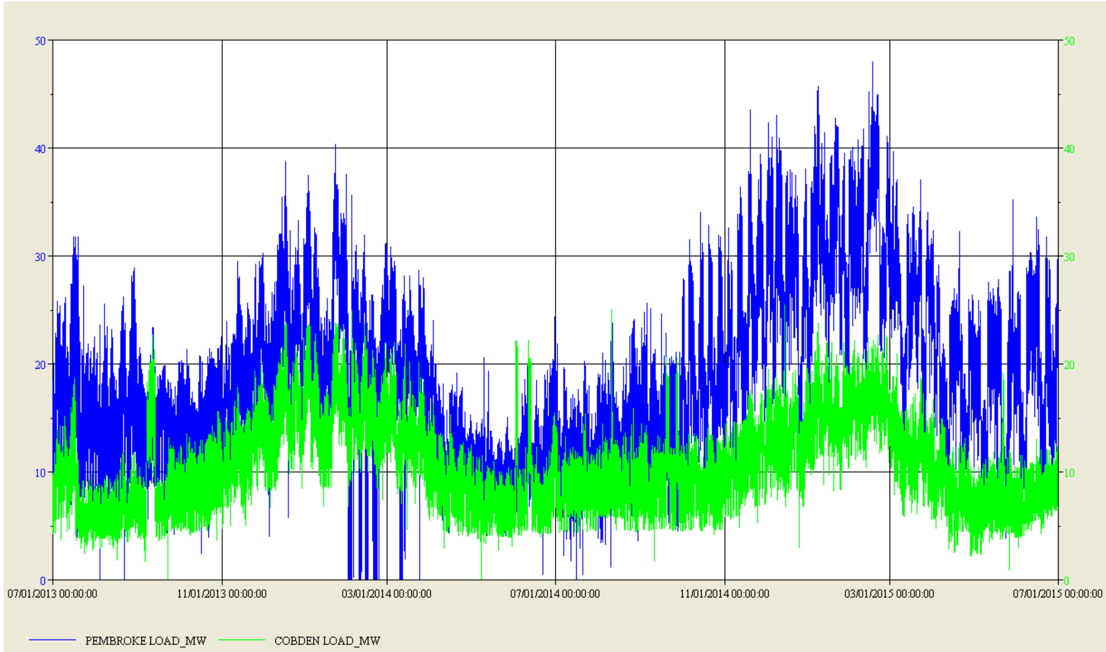


Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

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

Hydro One Network Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

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.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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.

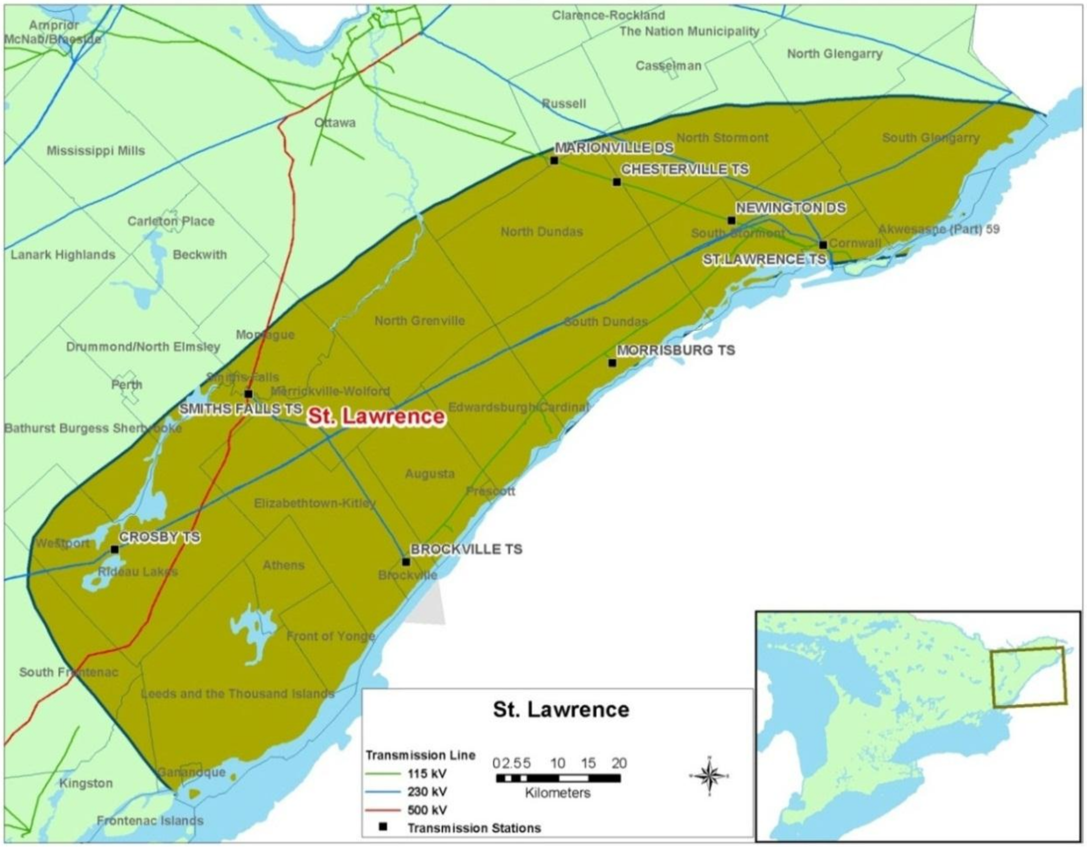


Figure 1 Map of St Lawrence Regional Planning Area

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.

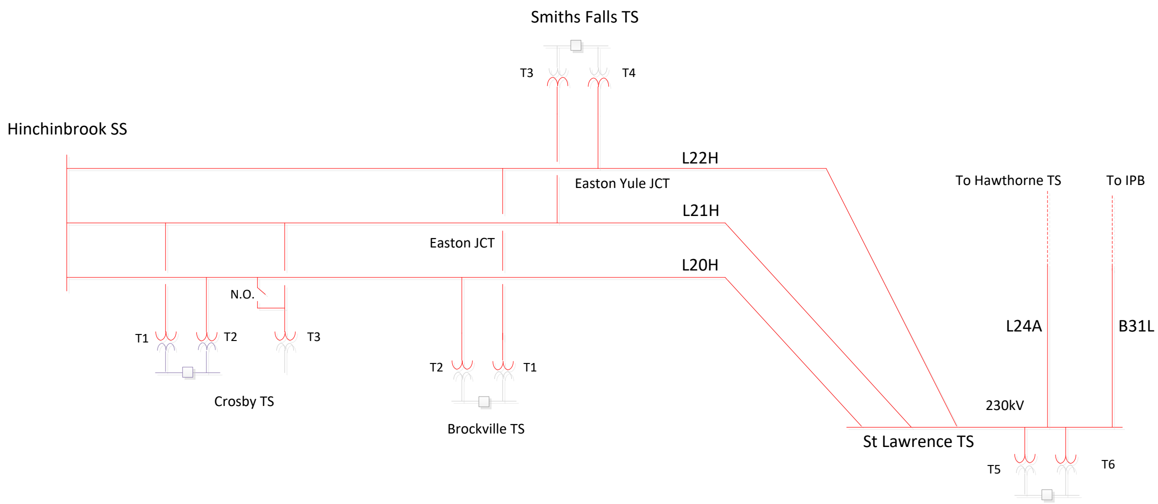


Figure 2 Single Line Diagram 230 kV St Lawrence Regional Planning Area

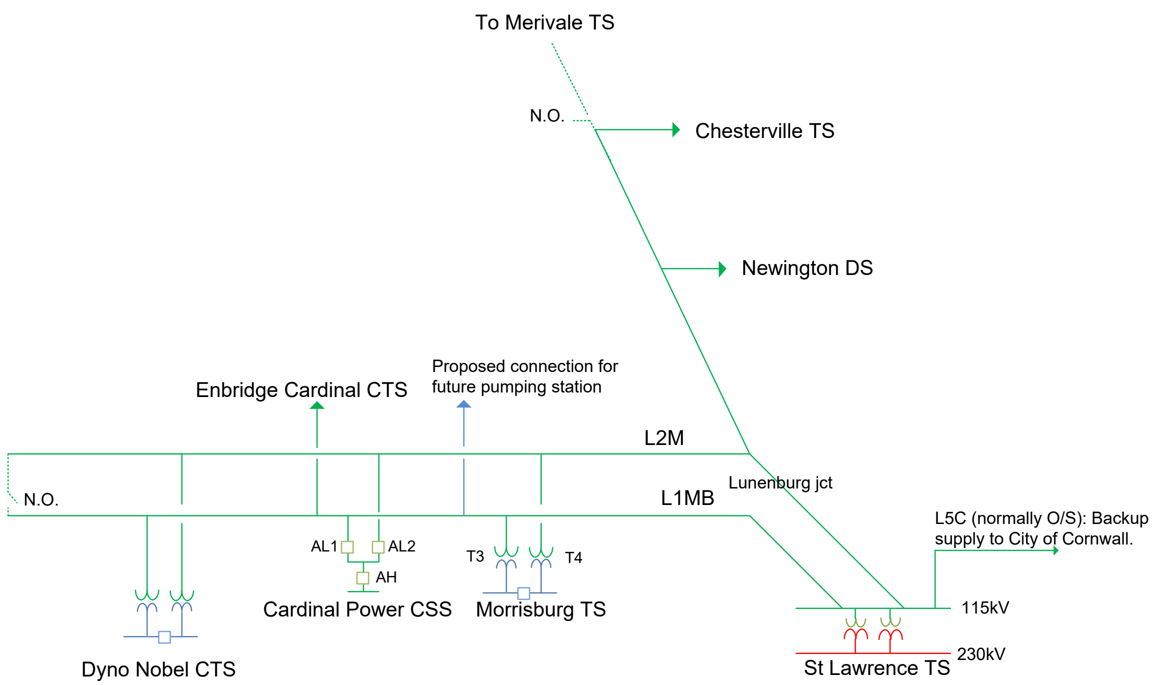


Figure 3 Single Line Diagram 115 kV St Lawrence Regional Planning Area

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

GTA East

REGIONAL INFRASTRUCTURE PLAN

January 9th, 2017

[This page is intentionally left blank]

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

With support from:

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

DISCLAIMER

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

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

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

[This page is intentionally left blank]

EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

TABLE OF CONTENTS

List of Figures

List of Tables

[This page is intentionally left blank]

1. INTRODUCTION

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

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

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

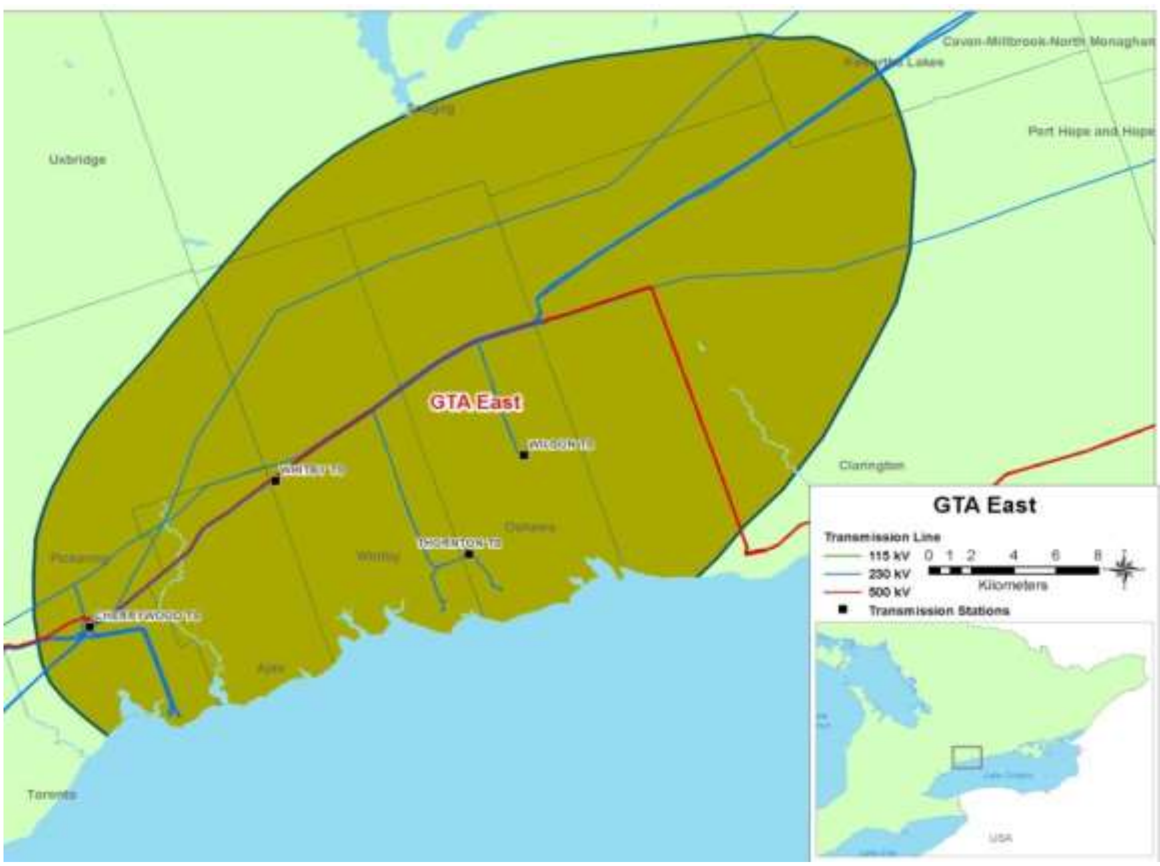


Figure 1-1 GTA East Region

---

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

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

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

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

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

---

[4] Also referred to as Needs Screening.

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

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

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

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

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

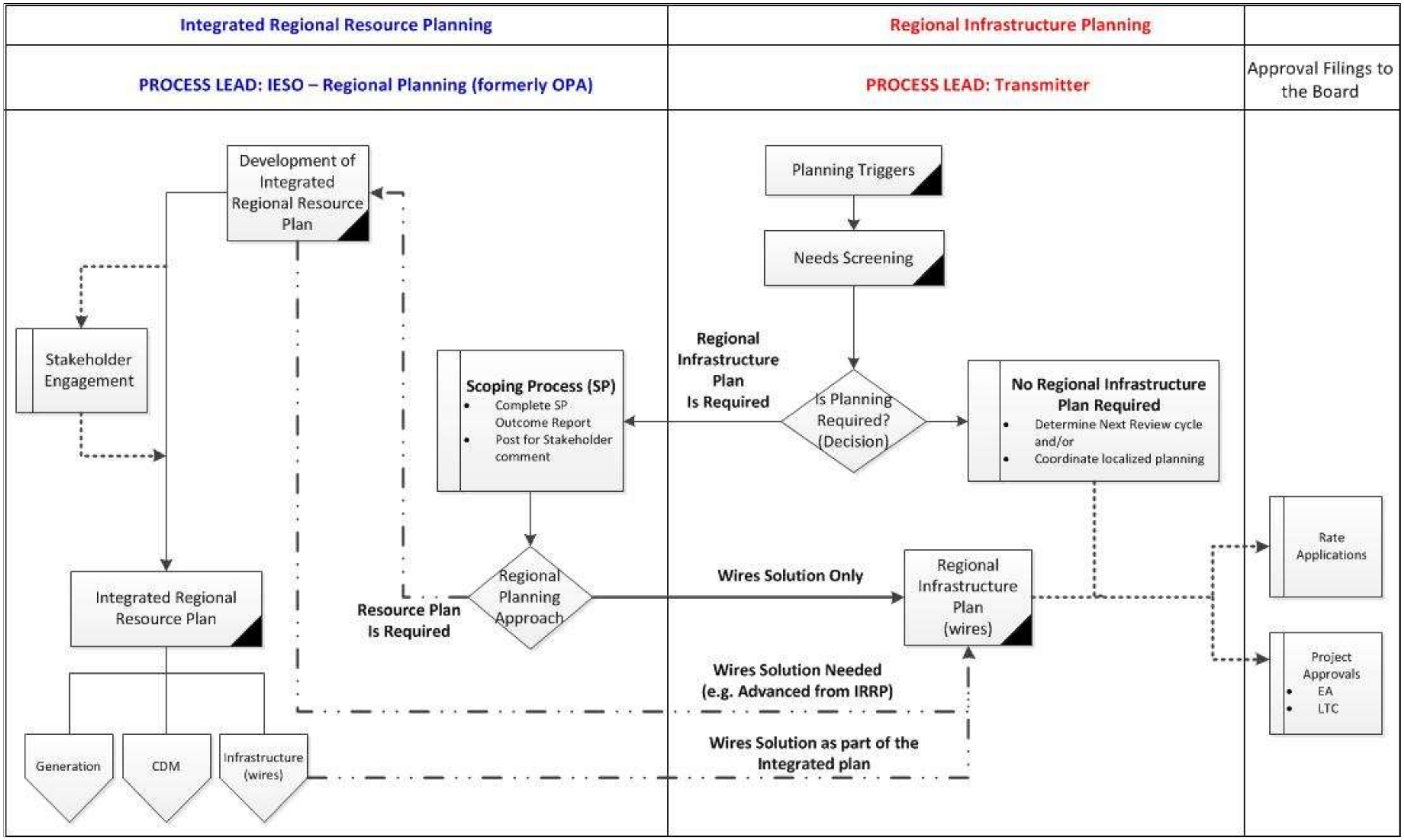


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

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

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

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

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

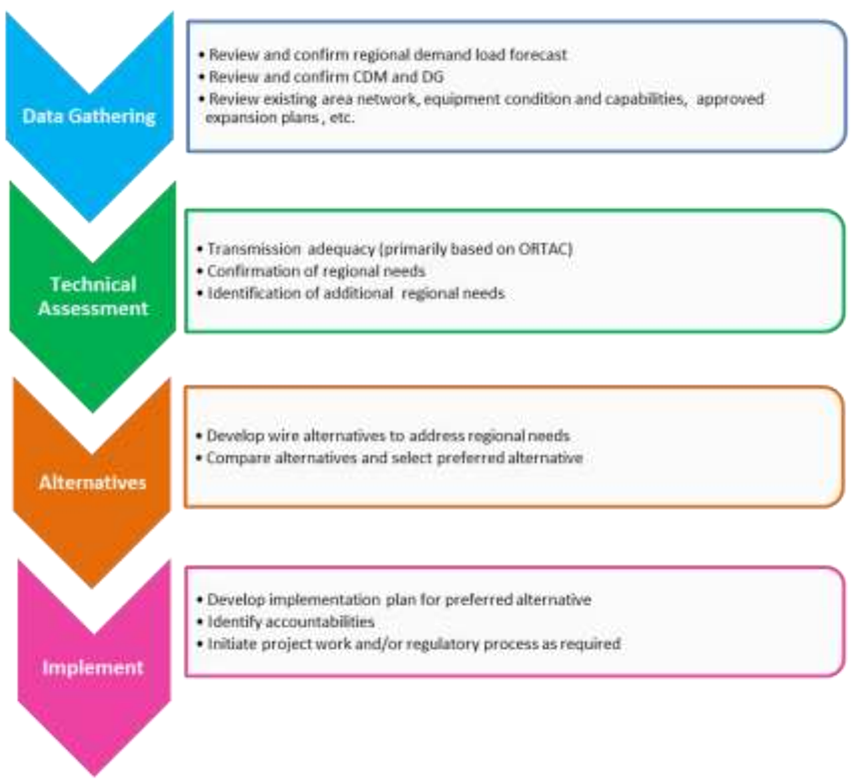


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

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

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

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

3.1 Pickering-Ajax-Whitby Sub-Region

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

3.2 Oshawa-Clarington Sub-Region

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

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

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

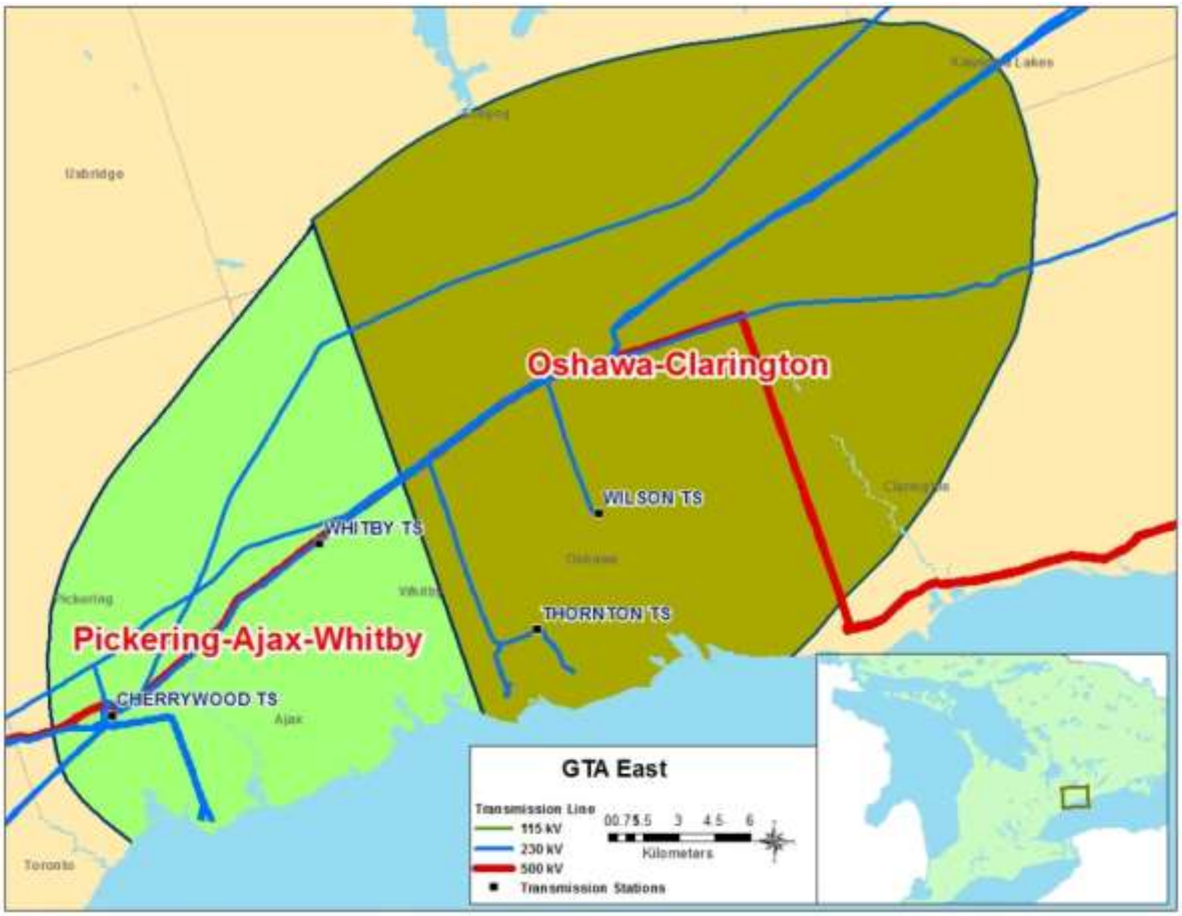


Figure 3-1 GTA East Region – Supply Areas

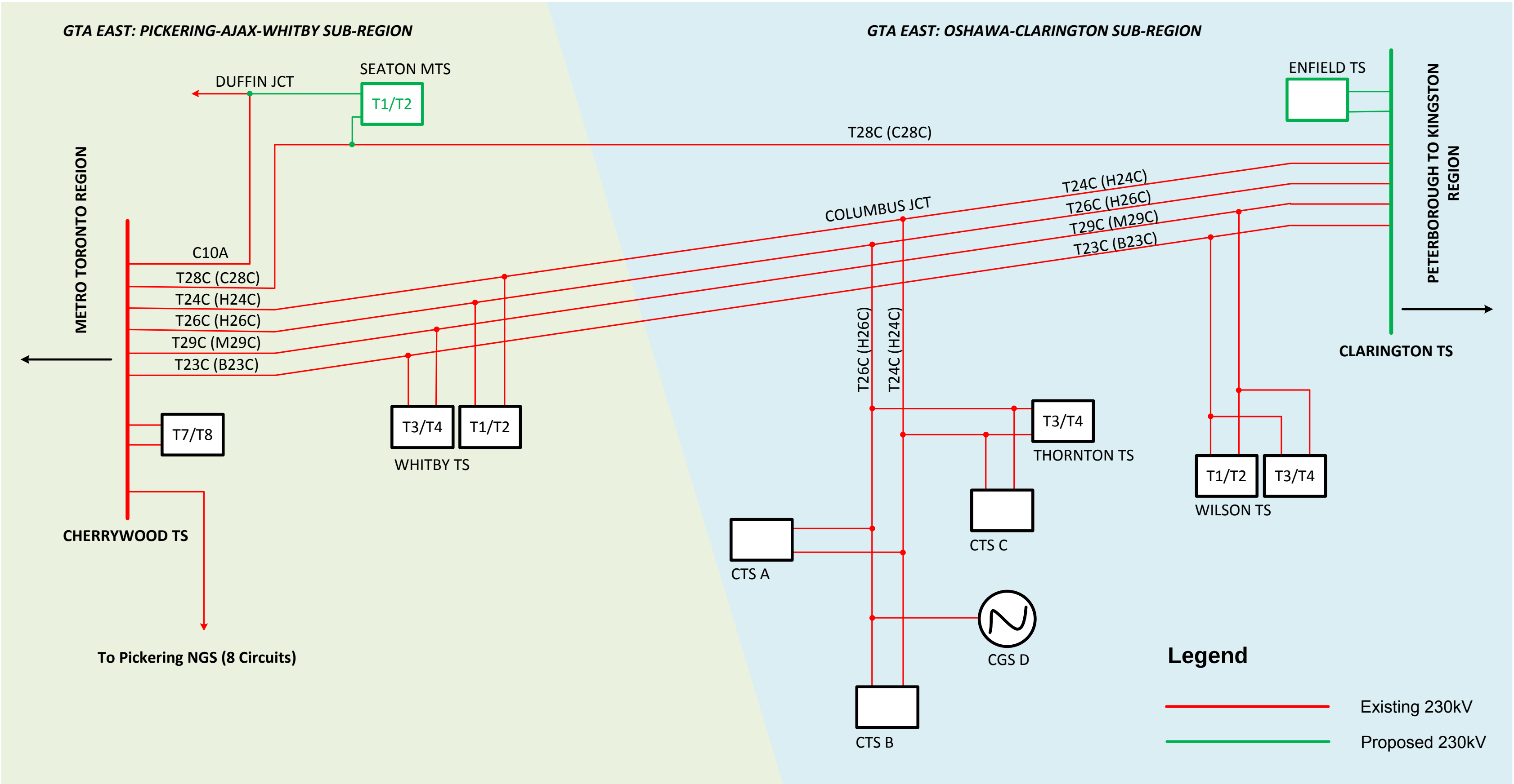


Figure 3-2 GTA East Region Single Line Diagram

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

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

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

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

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

- Installed LV neutral grounding reactors at Wilson TS T1/T2 DESN1 (2015) – to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 transformer replacements and install LV neutral grounding reactors (2016) – to replace end-of-life transformers and reduce line-to-ground short circuit fault levels to facilitate DG connections.

The following development projects are currently underway:

- Clarington TS (2018) – a 500/230kV autotransformer station at the Oshawa Area Jct. to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region. The thermal limits of the 230kV circuits supplying the Region will be upgraded and will be terminated at Clarington TS.

- Seaton MTS (2019) – a 230/27.6/27.6kV municipal transformer station to increase supply capacity in the Pickering-Ajax-Whitby Sub-Region and provide relief to Whitby TS 27.6kV following the development of new community of Seaton. The station will be serviced by two parallel 230kV circuits, C10A and C28C, emanating from Cherrywood TS. C10A will be extended eastward from Duffin Jct. to the site of the station.

- Enfield TS (2019) – a 230/44kV DESN to increase supply capacity in the Oshawa-Clarington Sub-Region and provide relief to Wilson TS. This station will be located at the Oshawa Area Jct. and will be directly connected to Clarington TS 230kV bus.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA East Region is expected to increase at an annual rate of approximately 2% between 2016 and 2025. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

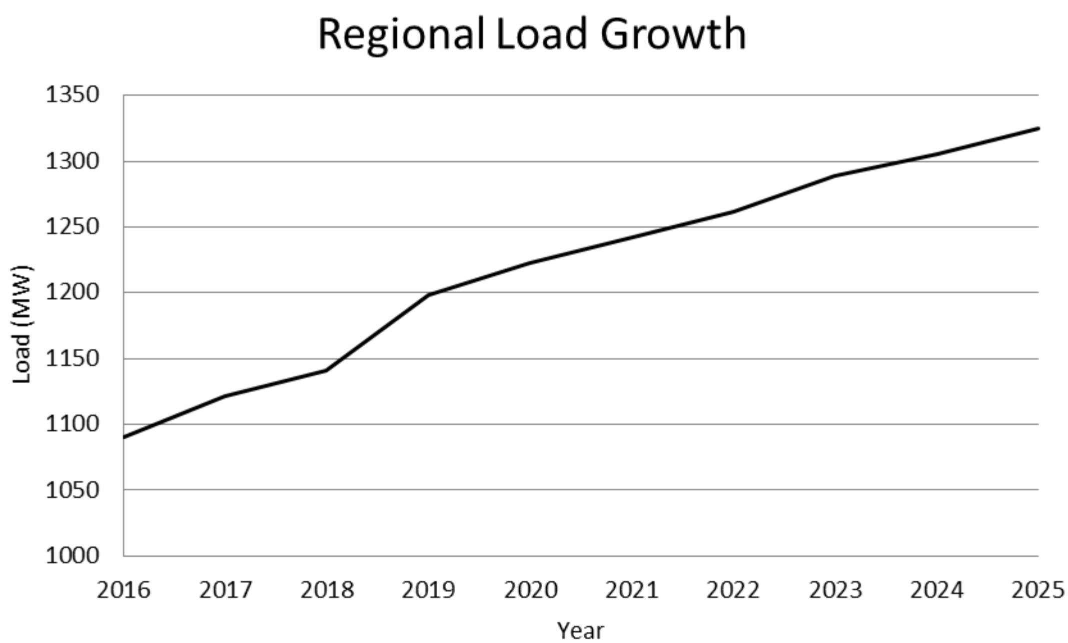


Figure 5-1 GTA East Region Coincident Net Load Forecast

Prior to the RIP's kick-off, the Working Group were asked to confirm load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for Pickering-Ajax-Whitby Sub-Region did not have a significant revision compared to the IRRP's load forecast. However, the revised forecasted non-coincident stations' peaks for Wilson TS and Thornton TS in the Oshawa-Clarington Sub-Region had a significant increase; therefore, the needs identified in previous assessments were reconfirmed.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2025.
- Pickering NGS is assumed to be out-of-service by 2024.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

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

Within the current regional planning cycle, three regional assessments have been conducted for the GTA East Region. The findings of these studies are input to the RIP:

1. IESO's Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan – June 30, 2016[1]
2. Hydro One's Oshawa-Clarington Sub-Region Local Planning Report – May 15, 2015[2]
3. Hydro One's GTA East Region Needs Assessment Report – August 11, 2014[3]

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

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the GTA East Region assuming Clarington TS will be in-service by 2018, Seaton MTS and Enfield TS by 2019, and Pickering NGS out-of-service between 2018 and 2024.

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

Table 6-1 Near and Mid-Term Needs in the GTA East Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
	7.2	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
Load Restoration	7.3	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
Short Circuit Constraint	7.4	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome

6.1 500kV and 230kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, B23C/M29C, H24C/H26C, and C28C, supplying both the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. Refer to Figure 3-2 for existing and proposed facilities to be operational in the Region in near future.

Bulk system planning is conducted by the IESO and is informed by government policy such as the long term energy plan ("LTEP"). The next LTEP is expected to be issued in 2017. Any outcomes from this level of planning that impact regional planning are expected to be integrated into the respective regions as necessary.

6.2 Pickering-Ajax-Whitby Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations in the Pickering-Ajax-Whitby Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Pickering-Ajax-Whitby Sub-Region

Station	DESN	Voltage Transformation
Cherrywood TS	T7/T8	230/44kV
Whitby TS	T1/T2	230/44/27.6kV
	T3/T4	230/44kV

Based on the LTR of these load stations, additional 27.6kV capacity is required at Whitby TS T1/T2 in 2019 which will be addressed by the proposed Seaton MTS (see details in Section 7.1). Cherrywood TS T7/T8 may be slightly overloaded initially, however, due to CDM and commissioning of Seaton MTS, the capacity need is expected to be eliminated by 2019. Forecast loads at Whitby TS T1/T2 44kV windings, and Whitby TS T3/T4 44kV windings are adequate over the study period.

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

Table 6-3 Transformation Capacities in the Pickering-Ajax-Whitby Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Cherrywood TS T7/T8 44kV	175	156	-
Whitby TS T1/T2 27.6kV	90	41	2019
Whitby TS T1/T2 44kV	90	56	-
Whitby TS T3/T4 44kV	187	161	-

6.3 Oshawa-Clarington Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations and four direct-connected customers in the Oshawa-Clarington Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Oshawa-Clarington Sub-Region

Station	DESN	Voltage Transformation
Wilson TS	T1/T2	230/44kV
	T3/T4	230/44kV
Thornton TS	T3/T4	230/44kV
Industrial Customer TS x4	-	-

Based on the LTR of these load stations, additional 44kV capacity is immediately required to provide relief to Wilson TS. Under certain conditions, overloading at Wilson TS T3/T4 was significant enough to plan for emergency rotating load shedding, if and when required. Plan to address this need is discussed further in Section 7.2. Thornton TS is adequate to meet the net demand over the study period.

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

Table 6-5 Transformation Capacities in the Oshawa-Clarington Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Wilson TS T1/T2 44kV	161	167	Immediately
Wilson TS T3/T4 44kV	133	146	Immediately
Thornton TS T3/T4 44kV	159	126	-

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

7. REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA East Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the Pickering-Ajax-Whitby Sub-Region and the NA and LP for the Oshawa-Clarington Sub-Region. Needs for which work is already underway are also included.

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

7.1 Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.1% annually.

Based on the DG and CDM forecasts in the Sub-Region, adequate 44kV transformation capacity is available at Cherrywood TS T7/T8 and Whitby TS to maintain reliable supply to meet the demand over the study period.

With the proceeding of a new residential and mixed use commercial area in the Sub-Region, called Seaton, significant increase in load demand is expected at 27.6kV level resulting in a shortage transformation capacity by 2019. The gross demand in the new development of Seaton is expected to be 88MW at the end of the study period (2025) and will continue to grow over long term period. The growth resulting from Seaton will have a significant impact on the 27.6kV transformation capacity in the Sub-Region.

Recommended Plan and Current Status

During the regional planning process, the Working Group considered multiple alternatives to address the transformation capacity in the Sub-Region. Preference was given to already existing facilities to ensure system's maximum capacity had been considered in line with the future demand. Other alternatives included CDM, local generation, and transmission & distribution facilities.

After considering estimated DG and CDM targets over the study period, the stations' capacities in the Sub-Region can be relieved to a certain extent. However, existing facilities alone will not be adequate to meet the future demand resulting from the new Seaton community load planned to be supplied at 27.6kV level.

As a result, an investment in wires infrastructure development in the Sub-Region is mandatory to connect and supply the development of Seaton via transmission/distribution facilities. Following the completion of the IRRP, the Working Group recommended Seaton MTS as the best solution to meet the transformation capacity need in the Sub-Region. Veridian Connections Inc. and Hydro One Networks Inc. have jointly submitted an EA application for the proposed station site and related 230kV transmission line work. Consistent with the regional planning studies, Veridian Connections Inc. is developing a plan for a new transformation station called Seaton MTS in northern Pickering. As confirmed by Veridian, the in-service timeline of this transformation station has been deferred to 2019 due to revised 2018 load forecast.

Class Environmental Assessment (EA) is in progress for the three potential construction sites for Seaton MTS illustrated in Figure 7-1.

Figure 7-1 Seaton MTS: Proposed Construction Sites

The project will have the following connection arrangement:

- From Duffin Jct, extend the circuit C10A east to proposed location under EA process
- Connect 2x75/125MVA, 230/27.6/27.6kV transformers to 230kV circuits; C10A and T28C[5]
- Supply 12x27.6kV feeders with a normally open tie-breaker configuration

The total cost of this project is estimated to be \$43M – \$48M. This estimate includes the cost of transmission as well as distribution investments which include the station’s construction, its connection

[5] T28C circuit nomenclature to replace C28C following Clarington TS (2018)

arrangements as defined above, feeder egress to the distribution risers outside of the station, and a spare transformer.

7.2 Increase Transformation capacity in Oshawa-Clarington Sub-Region

Description

The load forecast reflects an annual growth of 1.85% in Oshawa and Clarington area throughout the study period. Based on the 2015 historical demand and station's net demand forecast, Wilson TS T1/T2 and T3/T4 have already exceeded their respective normal supply capacities and will continue to do so over the study period. Overloading at Wilson TS T3/T4 has been significant enough that plans were put in place for emergency rotating load shedding, if and when required. Thornton TS may briefly exceed its transformation capacity in 2018 and 2019 but is adequate over the study period as well as long term period due to CDM contributions and distribution load transfer capability.

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

Recommended Plan and Current Status

To accommodate the load growth of Hydro One Distribution's and OPUCN's feeders at Wilson TS, a new transformer station, Enfield TS, is recommended to relief the transformation capacity. The proposed transformer options to be evaluated for the DESN are as follows:

1. 2x75/125MVA, 230/44kV transformers with 6x44kV feeder breaker positions, with space for future 2x44kV feeder positions and capacitor banks (Preliminary Cost Estimate: $23 million)
2. 2x75/125MVA, 230/44kV transformers with 8x44kV feeder breaker positions (Preliminary Cost Estimate: $27 million)

The Working Group recommends option 1 to address the transformation capacity need in the Sub-Region. Six feeders will be adequate to supply demand over the study period. Also, option 2 is not considered the best economic solution since option 1 will reserve extra space for 2x44kV feeder positions and capacitor banks for future, when required.

The new DESN, 2x75/125MVA 230/44kV transformers with 6x44kV feeder breaker positions with 2x44kV spare feeder positions, is proposed to be located at the Oshawa Area Junction in the municipality of Clarington. This junction is on the ROW of the Bowmanville and Cherrywood transmission line corridor illustrated in Figure 7-2. The property is already owned by HONI and it is also the site of the new 500/230kV autotransformer Clarington TS supplied by circuits B540C and B543C. The proposed in-service date for the new DESN has a preliminary cost estimate of $34M including feeders egress to the distribution risers outside the station and will be aligned with Clarington TS which is scheduled for 2018.

Figure 7-2 Enfield TS: Proposed Construction Site

Advantages in proceeding with this particular location are as follows:

- The land proposed has already been purchased as part of the property where Clarington TS will be situated resulting in one less station footprint in the Sub-Region.
- Class EA approval has been already obtained for the construction of new TS on Hydro One land at the Clarington TS site.
- The site is also near new development areas which results in minimizing the length of supply feeders from the station.

7.3 GTA East Load Restoration Assessment

Description

GTA East load restoration need was identified in the NA and IRRP reports as the Working Group recommended that further assessment was required to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria and requires further assessment.

Recommended Plan and Current Status

In collaboration with the Working Group, a detailed report[6] was completed to make a recommendation for the load restoration need identified in the Region. The Working Group's assessments in the report, attached in the Appendix F, concluded the following:

- The historical performance of the circuits over the last 15 years has been excellent with little or no impact on supply reliability and security.

- Working Group is recommending that further investment in motorized disconnect switch (MDS) at this time is not a feasible solution to the load restoration need because the risk and/or probability of loss of load is small based on past performances. Therefore, no further action is required at this time.

7.4 Short Circuit Constraint at Cherrywood TS T7/T8

Description

Currently, new DG is restricted from connecting to Cherrywood TS T7/T8 due to short circuit capacity constraints. Veridian Connections Inc., supplied by this station, has indicated that they have several customers that have expressed interest in connecting DG (over 5MW) to Cherrywood TS T7/T8 but are prevented due to the existing restriction. There is an existing 30MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the short circuit capacity restriction. This generating unit has been shut down and/or has not generated electricity now for more than one year.

Recommended Plan and Current Status

The short circuit capacity is currently held by an earlier landfill generation connection. Although the facility has not been generating and partially dismantled, there is an uncertainty about availability of the short circuit capacity. Hydro One and the IESO will continue to assess this issue to have this capacity reservation released.

[6] GTA East: Load Restoration, Transmission Planning Report, circulated within the Working Group on August 31, 2016

7.5 Long Term Regional Plan

As discussed in Section 5, the electricity demand in GTA East Region is forecasted to grow at 2% annually over the next 10 years. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1.3% annually from year 2026 to 2036. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the Pickering-Ajax-Whitby Sub-Region were identified in the IRRP. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades. As indicated in the IRRP, official plans by the municipalities expect the lakeshore area in the southern part of Pickering-Ajax-Whitby Sub-Region to grow due to development of high rise residential and commercial buildings. With Pickering NGS expected to retire by 2024, the 230kV transmission lines can be utilized along with a new step-down transformer station to address capacity needs in the southern part of the Sub-Region.

The current forecast did not consider future Pickering Airport which may have an impact on transformation capacity in the long term. Such potential needs will be monitored and system supply capability will be reviewed in the next planning cycle based on the official plans released by the municipalities.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will mainly provide relief to Wilson TS by supplying the excess load through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

Need ID	Needs	Timing
I	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
II	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
III	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
IV	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome
V	Additional transformation capacity for Oshawa-Clarington Sub-Region	Long term

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

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

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Seaton MTS and associated line work	Veridian and Hydro One	2019	$43M-$48M	I
2	Enfield TS	OPUCN and Hydro One	2019	$34M	II

GTA East load restoration need, Need ID III, has been reviewed in this Regional Planning cycle and “status quo/do nothing” course of action has been recommended (see Appendix F). Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

Hydro One is working with the IESO to explore the best course of action to relieve the short circuit constraint at Cherrywood TS, Need ID IV.

Additional transformation capacity for Oshawa-Clarington Sub-Region, Need ID V, will be reviewed as part of the next Regional Planning cycle.

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

9. REFERENCES

[1]. Independent Electricity System Operator, "Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan". June 30, 2016.
http://www.ieso.ca/Documents/Regional-Planning/GTA_East/2016-Pickering-Ajax-Whitby-IRRP-Report.pdf

[2]. Hydro One, "Local Planning Report – Wilson TS and Thornton TS Station Capacity Mitigation". May 15, 2015.
http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Local%20Planning%20Report%20-%20WilsonThornton%20-%2015_May_2015%20-%20Final.pdf

[3]. Hydro One, "Needs Screening Report, GTA East Region. August 11, 2014.
http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Needs%20Assessment%20Report%20-%20GTA%20East%20Region.pdf

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

[5]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

APPENDICES

Appendix A: Stations in the GTA East Region

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, Bus DK
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	H24C/H26C
Whitby TS T3/T4	230/44kV	B23C/M29C
Wilson TS T1/T2	230/44kV	B23C/M29C
Wilson TS T3/T4	230/44kV	B23C/M29C
Thornton TS T3/T4	230/44kV	H24C/H26C

Appendix B: Transmission Lines in the GTA East Region

Location	Circuit Designation	Voltage Level
Cherrywood TS to Whitby TS T3/T4, Wilson TS, and Clarington TS	B23C/M29C	230kV
Cherrywood TS to Whitby TS T1/T2, Thornton TS, and Clarington TS	H24C/H26C	230kV
Cherrywood TS to Clarington TS	C28C	230kV

Appendix C: Non-Coincident Load Forecast 2016-2025

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	Veridian	*T7/T8*	*BY (44kV)*	*175*	Gross Peak Load				180	180	180	180	180	180	180	180	176	176
					CDM				2	3	5	7	8	10	11	12	13	15
					Net Load Forecast	163	143	156	178	177	175	173	172	170	169	168	163	161
Whitby TS	Veridian	*T1/T2*	*BY (27.6kV)*	*90*	Gross Peak Load				61	76	80	90	90	90	90	90	90	90
	Whitby Hydro		*EZ (44kV)*	*90*	Gross Peak Load				54	55	56	57	57	58	59	60	61	62
					DG				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					CDM				2	3	4	6	7	8	9	10	12	13
					Net Load Forecast	77	88	97	113	128	132	141	141	140	140	140	139	139
Whitby TS	Veridian	*T3/T4*	*JQ (44kV)*	*187*	Gross Peak Load				70	70	74	74	74	74	74	74	74	74
	Whitby Hydro				Gross Peak Load				108	110	111	113	115	116	118	120	122	124
					DG				18	18	18	18	18	18	18	18	18	18
					CDM				2	3	5	6	8	9	11	13	15	17
					Net Load Forecast	175	161	162	159	160	163	164	163	164	164	164	163	163
Seaton MTS	Veridian	*T1/T2*	*(27.6kV)*	*153*	Gross Peak Load							5	16	27	40	60	75	88
					CDM								1	1	2	3	4	6
					Net Load Forecast	0	0	0	0	0	0	5	15	26	38	57	71	82
Wilson TS	OPUC	*T1/T2*	*BY (44kV)*	*161*	Gross Peak Load				156	161	167	148	145	142	140	140	140	140
	Hydro One				Gross Peak Load				30	31	35	35	41	41	41	41	41	41
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	157	174	167	184	189	197	176	177	173	170	170	169	168
Wilson TS	OPUC	*T3/T4*	*JQ (44kV)*	*134*	Gross Peak Load				25	26	27	25	25	25	25	25	25	25
	Hydro One				Gross Peak Load				150	151	152	152	153	154	155	156	157	158
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	166	133	146	173	174	174	171	170	170	170	170	170	170

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thornton TS	Whitby Hydro	*T3/T4*	*BY (44kV)*	*160*	Gross Peak Load				52	58	63	79	80.0	81	82	82	83	84
	OPUC				Gross Peak Load				100	101	103	95	88	86	84	80	80	80
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast	157	103	126	151	156	162	168	160	158	156	152	152	152
Enfield TS	OPUC	T1/T2	*(44kV)*	*153*	Gross Peak Load				0.0	0.0	0.0	38	57	71	84	98	108	118
	Hydro One				Gross Peak Load				0.0	0.0	0.0	26	33	34	35	36	37	38
					CDM							3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast				0	0	0	62	86	100	113	126	135	145
CTS A					Gross Peak Load				20.0	20.0	20.2	20.6	21.0	21.2	21.4	21.6	21.7	21.9
					Net Load Forecast			19.5	19.8	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.2	20.3
CTS B					Gross Peak Load				97.0	97.5	98.0	99.8	101.6	102.2	103.0	103.4	103.9	104.4
					Net Load Forecast			96.3	96.0	96.1	96.2	96.3	96.3	96.4	96.5	96.6	96.6	96.7
CTS C					Gross Peak Load				47.5	52.8	53.3	54.5	55.7	56.3	57.0	57.5	58.0	58.5
					Net Load Forecast			52	47.0	52.0	52.3	52.6	52.8	53.1	53.4	53.7	53.9	54.2
CGS D					Gross Peak Load				0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
					Net Load Forecast			0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Appendix D: Coincident Load Forecast 2016-2025

Stations	DESN ID	Historical (MW)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	T7/T8	156	173	172	170	168	167	165	164	163	158	156
Whitby TS (27.6kV)*	T1/T2	33	59	74	78	87	87	87	87	87	87	87
Whitby TS (44kV)*	T1/T2	39	52	53	54	55	56	56	57	58	59	60
Whitby TS	T3/T4	145	154	155	158	159	158	159	159	159	158	158
Seaton MTS	T1/T2	0	0	0	0	5	15	25	37	55	69	80
Wilson TS	T1/T2	128	179	184	192	172	173	169	166	166	165	164
Wilson TS	T3/T4	144	168	169	169	166	165	165	165	165	165	165
Thornton TS	T3/T4	125	146	151	157	163	155	153	151	147	147	147
Enfield TS	T1/T2	0	0	0	0	60	83	97	110	122	131	141
CTS A		19.5	19	19	19	19	19	19	19	20	20	20
CTS B		96.3	93	93	93	93	93	93	94	94	94	94
CTS C		52	46	50	51	51	51	51	52	52	52	53
CGS D		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

*DG/CDM contribution excluded from 2016-2036 coincident forecast

GTA East Coincident Load	**938.5**	**1091**	**1122**	**1141**	**1199**	**1223**	**1242**	**1262**	**1289**	**1306**	**1324**
Region's Annual Growth Rate		2%									

Appendix E: List of Acronyms

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

Appendix F: GTA East Load Restoration Report

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

TRANSMISSION PLANNING REPORT

GTA East: Load Restoration

Revision: Final
Date: August 31, 2016

Prepared by: Hydro One Networks Inc.

[This page is intentionally left blank]

Executive Summary

REGION	GTA East (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	August 31, 2016

1. INTRODUCTION

The purpose of this Transmission Planning (TP) report is to undertake a comprehensive assessment of the load restoration need identified in the Needs Assessment (NA) and Integrated Regional Resource Plan (IRRP) and develop a preferred recommendation. The recommendations of this TP report will become part of the Regional Infrastructure Plan (RIP) and is intended to facilitate the regional planning process as set out by Ontario Energy Board's (OEB) in the Transmission System Code (TSC) and the Planning Process Working Group (PPWG) report to the Board.

Based on Section 6 of the NA and IRRP report, the study team recommended that further assessment was required to address the load restoration need during peak load in the GTA East region. The NA and IRRP report indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration may exceed load restoration criteria and requires further assessment. The IESO led IRRP recommended this need be further assessed in the RIP, to be completed in Q4 2016. This report provides a detailed assessment along with options and the WG recommendation to be included in the RIP report.

2. REGIONAL NEED ADDRESSED IN THIS REPORT

The circuits M29C/B23C and H24C/H26C are on the same tower line in the GTA East Region 230kV corridor. The loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively.

3. OPTIONS CONSIDERED

Hydro One Transmission along with the WG members have considered the following options to addressing the load restoration need:

Option 1 – a) Status quo/Current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

See Sections 4 & 5 for detailed assessment.

4. PREFERRED SOLUTION

At this time, B23C, M29C, H24C, and H26C are approximately 120km-300km long and the historical performance since 2000 has been excellent with no relevant outages. With the new Clarington TS in 2018, the line exposure in the region will reduce to only 46km including tap sections. The assessment concluded that

a) The annual carrying cost of the switches is not justified compared to the annual outage cost, and
b) The installation of Motorized Disconnect Switches will not result in significant enhancement to the reliability of the system after the Clarington TS is in service in 2018.

Option 1 is the preferred solution recommended by the WG at this time. Further details of the assessment and justification are provided in Sections 4 & 5.

5. NEXT STEPS

There are no further actions required at this time.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Region Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham Region.

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Region. Whitby TS DESN2, Thornton TS, and other CTS in the Region are supplied by H24C/H26C while Whitby TS DESN1 and Wilson TS are supplied by B23C/M29C.

A new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is expected to be in service by 2018. The assessments in this report evaluate the reliability impact of Clarington TS in the region as well as the installation of Motorized Disconnect Switches (MDS). The new Clarington TS will provide additional load meeting capability in the Region and will eliminate any overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 1[1].

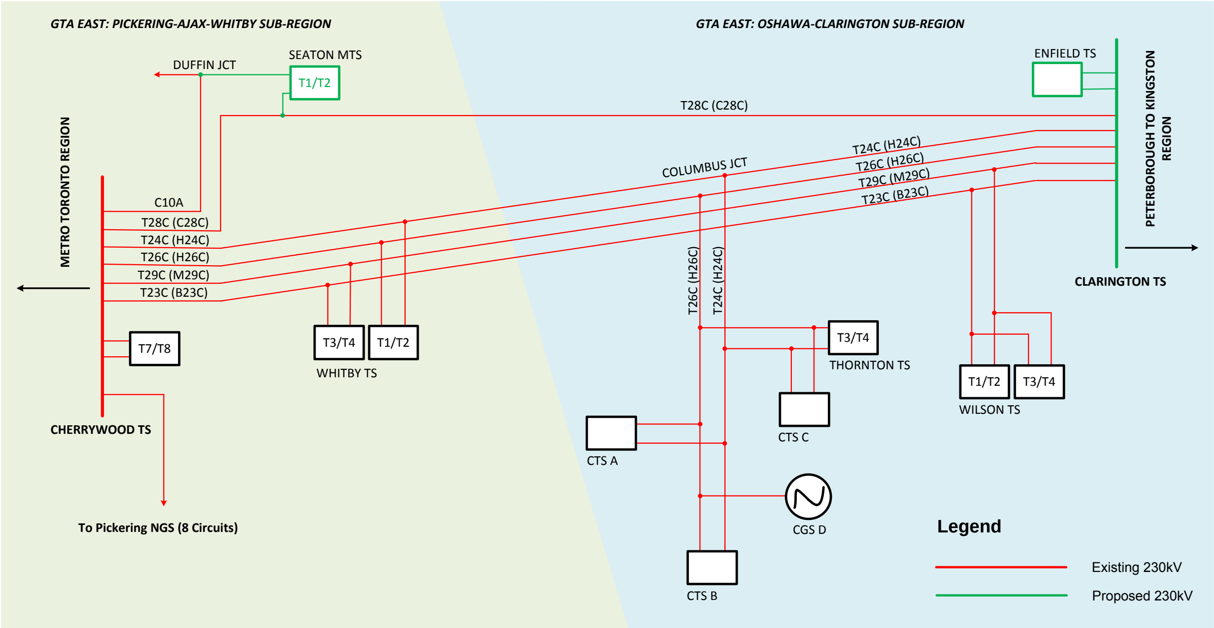


Figure 1 **GTA East Region - Single Line Diagram**

[1] Circuits' nomenclature is shown following the commissioning of Clarington TS (2018) with current convention in parentheses

2 Identified Need

2.1 Load Restoration Criteria

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

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

In addition, ORTAC also provides a provision for exemption from the above restoration criteria on a case-by-case basis.

Figure 2 illustrates the load restoration timelines as discussed above.

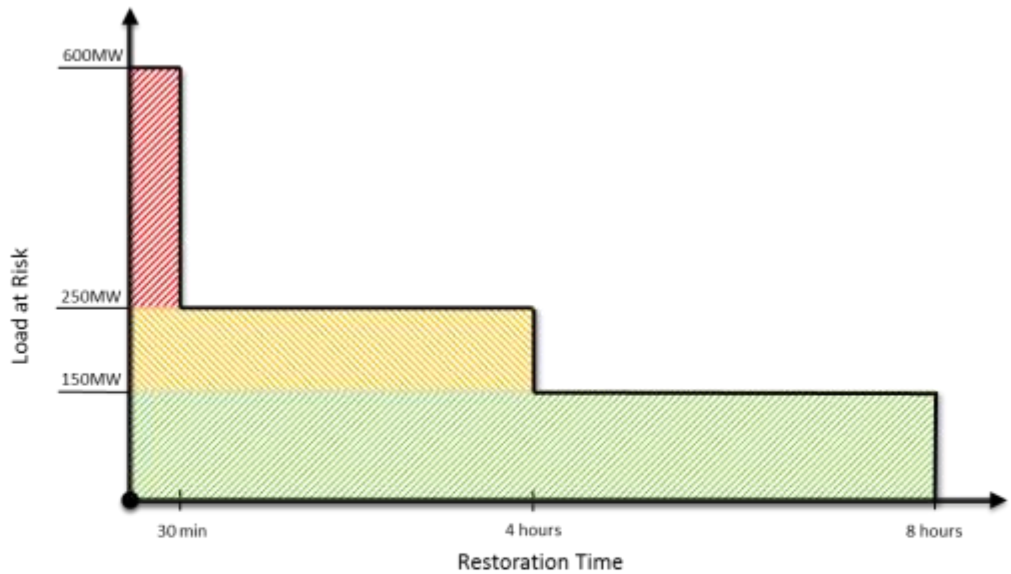


Figure 2 **Load Restoration Criteria**

2.2 Shortfall Need

In 2015, H24C/H26C and M29C/B23C supplied a coincident peak demand of approximately 366MW and 417MW, respectively.

It is expected and assumed that all loads can be restored within 8 hours. However, consistent with the NA and IRRP reports, during peak load periods all loads cannot be restored in the region subsequent of a double circuit contingency between Cherrywood TS and Clarington TS within 30 minutes to 4 hours.

Further findings from the Local Distribution Companies (LDC) in the Region and as reported in the IRRP[2], up to 57MW and 142MW can be restored for customers supplied by H24C/H26C through distribution transfers within 30 minutes and 4 hours, respectively. This leaves the maximum shortfall of 59MW after 30 minutes, and 74MW after 4 hours to be restored from these circuits.

Similarly, for the M29C/B23C, up to 105MW can be restored through distribution transfers within 30 minutes and 257MW within 4 hours for customers supplied by these circuits under the current supply arrangement. This leaves the maximum shortfall of 62MW after 30 minutes, and 10MW after 4 hours to be restored from these circuits.

Table 1 summarizes the 2015 peak demands for each pair of circuit and differentiates between restorable load and the shortage load for 30-minutes and 4-hour periods as discussed above.

Table 1 **Load Restoration/Shortfall in 2015**

2015 Coincident Peak					
Load Pocket	**Actual Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	366	57	59	142	74
M29C/B23C: Whitby TS DESN2, Wilson TS	417	105	62	257	10

By the end of 2025, the load that cannot be restored increases due to load growth in the region illustrated in Table 2.

Table 2 **Load Restoration/Shortfall in 2025[3]**

2025 Coincident Peak (Net Forecast)					
Load Pocket	**Forecast Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	445	57	138	142	153
M29C/B23C: Whitby TS DESN2, Wilson TS	425	105	70	257	18

[2] Published in June, 2016
[3] Load forecast is subject to change

2.3 Options considered

An option to build a new 26km of line would have resulted in a cost of more than $75M, obtaining new right-of-way and was not further considered. Following options were further assessed:

Option 1a is status quo and option 1b includes Clarington TS to be in-service by 2018. Accordingly, following two options are further evaluated against each other:

Option 1 – a) Status quo/current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

A conceptual configuration of the switches (marked by the red X) is shown for Option 2 in Figure 3.

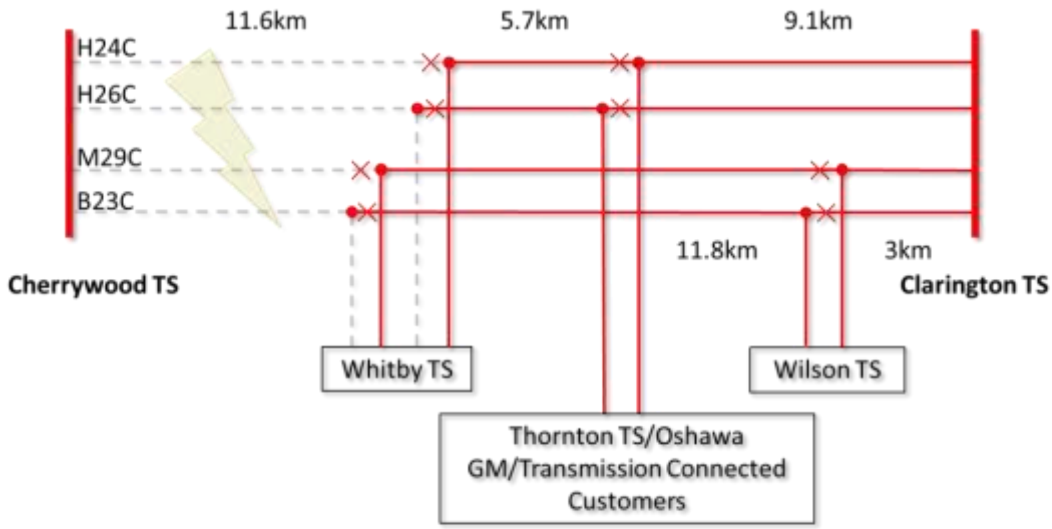


Figure 3 **MDS: Conceptual Configuration**

Similar cases can be shown to isolate faults on other sections of the corridor to restore the loads. It must be noted that although the corridor is protected using 8 MDSs as shown above, the tap offs will still remain unprotected. Further, a common mode fault (refer to section 4) at the tap off line sections will cause an outage regardless of installed switches. With the use of 8 MDS, the optimal locations of the switches are the junction points and 2 switches per circuit as shown in Figure 3.

3 Evaluation Method & Assumptions

The options identified in the previous section were evaluated from the reliability and cost points of view. The reliability indices for overlap outages were evaluated with the help of the AREP Program (Area Reliability Evaluation Program). The reliability for each option is expressed in terms of the frequency and duration of supply interruptions to customers.

Two cost components, one representing the capital cost and one representing the outage cost were evaluated for each option. The two annual costs are given as follows:

Annual cost of carrying charge = C*R,

Where: C – Capital cost of the switches
R – Annual discount rate

The annual outage cost (or risk cost) = F*P*I,

Where: F – Annual duration of load interruption in hours
P – Average kW interrupted including load factor
I – Customer interruption cost ($/KWh)

The following assumptions were made in the assessments:

1. All MDSs are assumed to be perfect (100% reliable).
2. Outages on line tap sections are excluded in common mode outages assessment in section 4.
3. All customer loads are restored within 8 hours for Option 1 and within 30 minutes for Option 2.
4. In case of overlap outages, switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour.
5. Faults do not occur on lines section where MDSs are located.

The assessment data used in the benefit/cost analysis for all options is provided in Table 3.

Table 3 **Data Used in Reliability Studies**

Assessment Data	
No. of circuit pairs on same towers	27
Total circuit length	551.347km
Circuit years in service	26 years
Distance between Cherrywood TS and Clarington TS	26km
2015 Peak load supplied from B23C and M29C, P	417MW
2015 Peak load supplied from H24C and H26C, P	366MW
Load factor for all load stations	0.6
Customer interruption cost, I	\$10–\$30/kWh[4]
Load restoration time without switches	8 hours
Load restoration time with switches	30 minutes
Cost of one switch (x4 per pair, C)	\$3 Million (\$12 Million)
Annual discount rate, R	5%

[4] Known as Value of Lost Load (VOLL), range is consistent with a Canadian Regulatory Application conducted in 2006 after considering customer composition and provincial GDP – IRRP (2016)

4 Impact of Common Mode Outages

A common mode outage is defined as an event involving two or more outages with the same initiating cause and where the outages are not consequences of each other and occur nearly simultaneously.

4.1 Line Outage Data

The historical common mode outage data for all 230 kV circuits on same structures and east of Cherrywood TS from 1990 to 2015 was used to compute the frequency and duration of common mode line outages. A summary of the common mode line outage events, along with the duration, over the period of 25 years is given in Table 4.

Table 4 **Common Mode Outage Events (from 1990 to 2015)**

Event #	Circuits Involved	Year	Outage Duration	Outage Cause
1	X3H and X4H	1992	927.6h	High winds toppled 16 towers
2	D5A and B5D	1998	0.15h or 9m	Electrical storm
3	B23C and M29C	2008	2.02h	Human error, relay settings
4	L21H and L22H	2011	0.08h or 5m	Relay problems

Only 4 common mode outages have been recorded in eastern Ontario in the last 25 years, of which, only one event is of relevance for this assessment. Hence, Event # 1, in Table 4 is the only one used in calculating the frequency of common mode line outages. This event occurred in November 1992 where adverse weather toppled multiple towers. The other outage events are not relevant to common mode outages because either the outage duration is less than 30 minutes (time assumed for switches to restore power supply to customers) or the outage was preventable or both.

NOTE: Event #1 has never occurred on the GTA East 230kV corridor which is the scope of this assessment but used as a proxy for assessment.

4.2 Reliability Results

The annual frequency of line common mode outages for 230 kV circuits east of Cherrywood TS was calculated by dividing the number of common mode line outages in 25 years by the product of the number of circuit in service years and the total circuit km over the 25 years period. The annual frequency was found to be **0.00007 outages/km** for all of eastern Ontario's 230kV transmission circuits. A low reliability index indicates the circuits in eastern Ontario have performed exceptionally well.

The commissioning of Clarington TS, Option 1b, does not affect the reliability indices for the common mode line outages because of the location of the station at the Oshawa Area Junction. All four 230 kV circuits currently emanate east on single towers from Cherrywood TS to the Oshawa Area junction point. From there on, B23C disperses south towards Belleville TS while the remaining three circuits emanate east on individual towers towards eastern Ontario. Therefore, a common mode line outage on these circuits cannot occur east of Oshawa Area

Junction, future site for Clarington TS.

It is also emphasized that the MDS would have no impact on the frequency of supply interruptions to customers. However, depending upon the location of a permanent fault, the switches can reduce the duration of interruption to customers by isolating the faulted section of the line and restoring the load from the alternative path.

The frequency and duration indices for all options are given in Table 5. The 8 hour restoration time for Option 1a and 1b, without switches, is in accordance with the standard outlined in ORTAC.

Table 5 **Reliability Indices, Common Mode Line Outages**

Options	Annual Frequency of Loss of Supply to any Customer	Duration of loss of Supply in Hours per Occurrence	Annual Duration of Supply Interruptions, F
Option 1a or 1b	0.00182	8	0.01456h or 52.4s
Option 2	0.00182	0.5	0.00091h or 3.3s

4.3 Cost Results

The capital cost and outage cost components were evaluated for all options using the formulae stated earlier. Table 6 shows the results for Circuits B23C and M29C while Table 7 shows the results for Circuits H24C and H26C.

Table 6 **Cost Results, Common Mode Line Outages (B23C/M29C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$36.43-$109.29	$36.43-$109.29
Option 2	$600.00	$2.28-$6.84	$602.28-$606.84

Table 7 **Cost Results, Common Mode Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$31.97-$95.92	$31.97-$95.92
Option 2	$600.00	$2.00-$6.00	$602.00-$606.00

The reliability and cost benefit assessment for the common mode line outages is based on the past 25 years of historical performance of 230kV circuits in eastern Ontario. Based on these findings, the annual reliability index for the GTA East region is only 0.00182 outages. As stated earlier, the installation of switches will not have an impact on the frequency index of events. Rather, as seen in Table 5, the duration of an event is the only dependent variable where the annual duration of an outage is reduced from 52.4s to 3.3s with the installation of switches.

The cost analysis in each option is dependent on the reliability index and is calculated using the assessment data provided in Table 3. Using the cost calculation formulas in Section 3, annual carrying cost of the switches and annual outage costs are calculated for B23C/M29C and

H24C/H26C. The annual carrying cost of the 4 switches per circuit pair is based on the minimum operating period of 20 years while the annual outage costs are based on the duration of outages, calculated from the reliability index, with and without the installation of switches.

The annual cost for just common mode line outages for each pair in the region is approximately $32k-$109k while the annual carrying cost of switches, including cost of outages, for each pair is nearly 5-19 times more, $602k-$607k. Also, the annual outage cost due to a common mode line outage is calculated on a very small probability of an event occurring. The annual frequency of loss of supply to any customer in the region is only 0.00182 outages, 1 in over 549 years, with or without switches as MDS have no impact on the frequency of supply interruptions.

As shown, the annual reliability and cost benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The installation of switches improves the outage duration, if occurred, from 52.4s to 3.3s for a certain annual investment of over $1.2M for both pairs of circuits. The annual benefits will still be lower than the carrying costs even if higher values are used for the frequency of common mode line outages. In addition, MDS are assumed to be 100% reliable in this assessment while they introduce a weak link on the system. The reliability and cost analysis show that the installation of MDS is not justifiable.

5 Impact of Overlap Outages

An overlap outage is referred to an event where two or more components are out of service at the same time. The outage initiating causes are different and outages can start at different time. The overlap outage may occur as one of two types; Forced-Forced or Planned-Forced.

5.1 Line Outage Data

The historical outage data from 1990 to 2014 was used to compute the frequency and duration of H24C/H26C line sections and line terminal indices due to forced and planned outages. A reliability model was developed using Area Reliability Evaluation Program (AREP) for both options. The reliability indices were then used to calculate the annual frequency and annual duration of loss of supply to customers. It is expected that circuits B23C/M29C will have similar reliability indices, if not better, due to comparable characteristics and load as circuits H24C/H26C.

5.2 Reliability Results

Currently, the four circuits collectively supply eastern Ontario for 120–300km. In spite of this long distance, the reliability and security of the transmission lines in this part of the province has been exceptional based on the historical performances. Given that these 230kV circuits will now be terminating at Clarington TS, the exposure will reduce to 26km, the region's security and reliability is expected to improve substantially. Table 8 illustrates the reliability indices for the loss of supply to customers considering both types of overlap events: Forced-Forced and Planned-Forced.

Table 8 **Reliability Indices, Overlap Line Outages**

Options	Annual Frequency of Loss of Supply	Annual Duration of Supply Interruptions
Option 1a	0.01	0.12h or 7.02m
Option 1b	0.0008	0.007h or 26.60s
Option 2, Whitby TS DESN 1	0.0001	0.0003h or 1.26s
Option 2, Thornton TS/CTSs	0.0004	0.002h or 8.47s

For each reliability index above, two sets of reliability indices were considered: one due to the overlap of forced outages (Forced-Forced) only and one with the overlap of planned and forced outages (Planned-Forced). In the course of the overlap outages' assessment, it was observed that the Planned-Forced type outages had the dominant impact on the final reliability indices when compared to Forced-Forced type outages.

Further, two types of outages in each set, namely the permanent outages and the switching outages, were computed. In the permanent outage, the supply to customers is restored after repairing the failed components while in the switching outage; the supply to customers is restored by switching off the failed components and restoring the healthy ones to service. The switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour except in the case of Option 2 where MDSs are expected to operate within 30 minutes.

It is observed in Table 8 that with the commissioning of Clarington TS in 2018, the reliability improves by over 92% while an additional investment in MDSs of over $24 million yields another increment of only 7% to the system reliability. With Clarington TS in service, Option 1b, the reliability indices improve significantly when compared to the reliability of the existing supply system. Also, the annual duration of supply interruption is reduced to just 26.6 seconds from 7 minutes with Clarington TS in the region.

5.3 Cost Results

The capital (carrying) cost and outage cost components were evaluated for the both options using the formulae stated earlier and the results are shown in Table 9. These costs are mainly dependent on the annual duration of supply interruption in Table 8. Since the annual duration of supply interruption in the region is expected to be reduced to merely 26.6s with Clarington TS soon to be in service, the annual expected outage cost has dropped by almost 94%.

Table 9 illustrates that the annual benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The performance of H24C/H26C is expected to be exceptionally good following the commissioning of Clarington TS with an expected annual cost of $15.37k-$46.12k, a very well improvement from the current system and at least 13 times more economical than the annual cost with the switches. With the inclusion of Clarington TS by 2018, the system is projected to be most cost-effective and reliable.

Table 9 **Cost Results, Overlap Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a	$0.00	$263.52-$790.56	$263.52-$790.56
Option 1b	$0.00	$15.37-$46.12	$15.37-$46.12
Option 2	$600.00	$3.66-$10.97	$603.66-$610.97

6 Conclusion

6.1 Common Mode Outages

The following concluding remarks can be made regarding the impact of the common mode outages:

i) All options have the same frequency of supply interruptions to customers.
ii) Only one common mode outage, relative to this assessment, has occurred in the eastern Ontario in the past 25 years. This event occurred in 1992 due to high winds toppling multiple towers.
iii) The reliability and cost analysis show that it is not justifiable to invest $24M for marginal improvement.

6.2 Overlap Outages

The following concluding remarks can be made regarding the impact of overlap outages:

i) A significant improvement in reliability is observed after the commissioning of Clarington TS in 2018, Option 1b. However, the installation of MDS, Option 2, does not result in a substantial improvement in the reliability indices for an additional cost of approximately $24M.
ii) The result of reliability/cost analysis for circuits B23C/M29C is expected to be similar to H24C/H26C due to similar regional characteristics and loading conditions, therefore, same conclusion can be drawn for both pairs.

6.3 Summary

Based on historical data and a technical analysis on how outages impact the loads supplied by the GTA East 230kV corridor currently, post-Clarington TS, and with MDS, Table 10 illustrates that Clarington TS alone improves the reliability in the region by 77.8% while with additional investment of $24M in MDS, further reliability improvement is insignificant (less than 4%).

Table 10 **Summary of Results**

Options	Total Annual Cost ($k)	Annual Frequency of Interruption	% Reliability Improvement
Option 1a, Current System	$632.16-$1,896.49	0.02364	-
Option 1b, post Clarington TS	$101.28-$303.87	0.00524	77.8%
Option 2, MDS post Clarington TS	$1,211.47-$1,234.37	0.00444	81.2%

In conclusion, the performance of all 4 circuits has been very good over the last 20 years. With Clarington TS in service in 2018 the risk exposure on these circuits will be significantly less; therefore, it is not justifiable to further invest $24M.

Finally, these costs will have to be recovered from the customers or rate payers consistent with the TSC. Furthermore, MDS were considered to be ideal and 100% reliable in the course of this assessment but in reality introduce a weak link in the system.

WG is recommending that based on this assessment, Option 1b is considered to be the most economical and reliable state of the system. No further action is required at this time.

7 Next Steps

Hydro One will continue with the Clarington TS and keep the LDCs informed of any delays with the project. The finding of this study will be included in the GTA East RIP report expected to be completed in Q4 2016.

8 References

[1] Line Switches Reliability Study by Gomaa HAMOUD, Hydro One – May, 2016
[2] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May, 2013
[3] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
[4] GTA East Needs Assessment Report – April, 2013
[5] GTA East Integrated Regional Resource Plan (IRRP) Report – June, 2016

PARRY SOUND / MUSKOKA SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Parry Sound/Muskoka

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board electricity licence, EI-2013-0066.

This IRRP was prepared on behalf of the Parry Sound/Muskoka Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Lakeland Power Distribution Ltd.
- Midland Power Utility Corporation
- Newmarket-Tay Power Distribution Ltd.
- Orillia Power Distribution Corporation
- PowerStream Inc.
- Veridian Connections Inc.

The Working Group assessed the reliability of electricity supply to customers in the Parry Sound/Muskoka Sub-region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Parry Sound/Muskoka Sub-region; and developed recommended actions, while maintaining flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviations	Descriptions
CCAP	Climate Change Action Plan
CDM or Conservation	Conservation and Demand Management
CEP	Community Energy Plans
CFF	Conservation First Framework
CHP	Combined Heat and Power
DG	Distributed Generation
DR	Demand Response
FIT	Feed-in Tariff
GHG	Greenhouse Gas
Hydro One	Hydro One Networks Inc. (Distribution and Transmission)
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
Lakeland Power	Lakeland Power Distribution Ltd.
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
Midland PUC	Midland Power Utility Corporation
MW	Megawatt
Newmarket-Tay Power	Newmarket-Tay Power Distribution Ltd.
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
Orillia Power	Orillia Power Distribution Corporation

Abbreviations	Descriptions
ORTAC	Ontario Resource and Transmission Assessment Criteria
OWA	Ontario Waterpower Association
PowerStream	PowerStream Inc.
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt-Hours
Veridian Connections	Veridian Connections Inc.
Working Group	Technical Working Group for Parry Sound/Muskoka Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") for the Parry Sound/Muskoka Sub-region addresses the electricity needs for the sub-region over the next 20 years from 2015 to 2034 ("study period"). The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group (the "Working Group") for the Parry Sound/Muskoka Sub-region composed of the IESO, Hydro One Distribution and Hydro One Transmission[1], Lakeland Power Distribution Ltd. ("Lakeland Power"), Midland Power Utility Corporation ("Midland PUC"), Newmarket-Tay Power Distribution Ltd. ("Newmarket-Tay Power"), Orillia Power Distribution Corporation ("Orillia Power"), PowerStream Inc. ("PowerStream") and Veridian Connections Inc. ("Veridian Connections").

The area covered by the Parry Sound/Muskoka IRRP is a Sub-region of the South Georgian Bay/ Muskoka Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process. This sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. This sub-region is characterized by:

- **Diverse communities**: In addition to the "unorganized areas"[2] in the Parry Sound District, there are eight First Nation communities and 35 municipalities located in this sub-region, all of which are listed in Section 4.1. The communities have different local priorities and electricity needs. Some communities are engaging in community energy planning activities.

- **Large geographical area:** A mix of long and expansive 230 kilovolt ("kV") transmission, 44 kV sub-transmission and low-voltage distribution infrastructure are required to deliver electricity supply to the various communities and customers across this sub-region. The geography and sparsely populated areas make it challenging and costly to develop and maintain infrastructure.

- **Use of Electric Space and Water Heating:** Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. In addition to electricity, some customers also rely on other fuel types, such as wood, to meet their heating requirements.

---

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc. ("Hydro One"), respectively.
[2] Unorganized areas are parts of the province where there is no municipal level of government. Services in these unorganized districts are typically administered by local services boards.

- **Modest Growth:** While relatively slower growth is expected in the manufacturing sector, growing First Nation communities, developments in the tourism and retail sector, and potential local economic development could contribute to higher electricity demand in the sub-region. Seasonal population driven by tourism and recreational activities may also increase electricity requirements over the longer term.

This IRRP fulfills the requirements for the sub-region as required by the IESO's OEB electricity licence. IRRPs are required to be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. This IRRP will be revisited in 2021, or earlier if significant changes occur relative to the current forecast.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Parry Sound/Muskoka Sub-region is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Parry Sound/Muskoka Sub-region and the study scope are discussed in Section 4;
- Demand forecast and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in the Parry Sound/Muskoka Sub-region are presented in Section 6;
- Options to address regional and local needs are addressed in Section 7;
- Recommended actions are set out in Section 8;
- A summary of community, Indigenous and stakeholder engagement to date is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Parry Sound/Muskoka IRRP addresses the sub-region's electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP was developed in consideration of a number of factors, including reliability, cost, technical feasibility, flexibility and also the diverse needs and unique characteristics of the sub-region.

The needs and recommended actions are summarized below.

2.1 Need to Minimize the Frequency and Duration of Power Outages

Customers and communities in the Parry Sound/Muskoka Sub-region experience more frequent and prolonged power outages relative to other communities and electricity customers in the province. Any outage along the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines can interrupt the electricity supply to the communities and customers. Results from the service reliability performance assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below provincial average[3] in terms of frequency and duration of outages. Long 44 kV sub-transmission lines and off-road facilities are the main causes for frequent and prolonged outages for this sub-region. Lengthy distribution lines also typically exhibit lower levels of reliability because of increased exposure to trees and wildlife, and they sustain more damage from poor weather. Limited access to off-road facilities makes it difficult for repair crews to detect early signs of equipment failures, do preventative maintenance and restore power in a timely manner.

While major 230 kV transmission outages have been relatively infrequent in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system has limited ability to restore power in a timely manner and minimize the number of customers impacted in the event of a major 230 kV transmission outage and does meet Ontario's planning criteria.

The Working Group has recommended a set of actions to minimize the frequency and duration of 44 kV related power outages and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

---

[3] On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less.

Recommended Actions

1. **Inform communities and Local Advisory Committee ("LAC")[4] members of the 44 kV sub-transmission system service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region.**

   Hydro One Distribution will examine options to improve the reliability performance on the 44 kV sub-transmission system as part of their planning process. Hydro One Distribution will provide an update on measures to improve 44 kV sub-transmission system service reliability performance including any proposed capital plans. This update will be provided by end of 2017.

   The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

2. **Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**

   Hydro One Distribution, Lakeland Power and Veridian Connections will examine various options to improve service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas, including the option to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from an alternate transformer station. The cost-benefit and cost responsibility of these options will be considered. The affected LDCs will discuss their assessment and decision with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results will be shared with LAC members and affected communities.

[4] A LAC for the Parry Sound/Muskoka Sub-region was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions.

3. **Install two 230 kV motorized switches at Orillia TS**

To restore power to customers in a timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at the Orillia Transformer Station ("TS"). The IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS in 2017. Based on typical development timeline of switching facilities, the project is expected to be in-service by the end of 2020.

4. **Explore opportunities to improve resilience and service reliability at the community level**

Some communities are engaged in community energy planning activities and interested in developing distributed energy resources. The IESO can facilitate discussions with First Nation communities, municipalities and LAC members on the opportunities to improve system resilience and service reliability through community energy planning and distributed energy resources and the cost-benefit of these opportunities.

2.2 Need to Provide Adequate Supply to Support Growth

Despite the relatively slow growth in this sub-region, the transformers supplying the Parry Sound and Waubaushene areas are approaching their maximum capacity in the near term. Additionally, the electricity demand on the 230 kV transmission system supplying the Orillia and Muskoka area may exceed capacity over the longer term.

Actions need to be taken to ensure that the regional electricity system has adequate supply to support growth in this sub-region over the planning period.

Recommended Actions

1. **Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**

The electricity demand at the Parry Sound TS has already exceeded the transformers' capacity. To manage the near-term demand growth in the area, about 6 Megawatts ("MW") at Parry Sound TS will be resupplied from Muskoka TS. In order to re-supply these customers, it is recommended that Hydro One Distribution seek approval to construct a new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS. The siting and routing of these facilities will be determined as part of the project development process.

Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020.

The electricity demand at Waubaushene TS is approaching it's transformer's capacity limits. To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS will be resupplied from Orillia TS by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required.

Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in the Waubaushene area from Midhurst TS could impact the timing and need for a new transformer station in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil Sub-region.

2. **Determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments in the Parry Sound/Muskoka Sub-region**

With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted local conservation and demand management, distribution-connected generation and/or other distributed energy resources to defer major capital investments that might otherwise be required (e.g., transformer upgrades at Parry Sound TS and Waubaushene TS, reinforcements on the Muskoka-Orillia Sub-system).

The Working Group will initiate a local achievable potential study in the Parry Sound/Muskoka Sub-region to determine the cost and feasibility of using distributed energy resources and local demand management options to defer those major capital investments. A range of distributed energy resources and local demand management options may be suitable, including focused marketing and/or incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. These options will be considered as part of the study. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the study.

The Working Group will also work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency programs in First Nation communities and municipalities.

3. **Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**

The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970's and therefore these transformers could be reaching end-of-life in the early 2030s. On an annual basis, Hydro One Transmission will provide updated information on the condition of aging equipment at the Parry Sound TS and Waubaushene TS. This information will be shared with the LAC and the Working Group. The IESO will continue to monitor the demand growth at Parry Sound TS and Waubaushene TS to determine whether it is cost effective to advance the end-of-life replacement and to replace aging assets with upgraded/upsized facilities. This need will be revisited in the next iteration of the plan.

4. **Monitor electricity demand growth closely to determine the timing of any investment decisions relating to the Muskoka-Orillia 230 kV sub-system**

On an annual basis, the IESO will review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with the Working Group and members of the LAC. This information will be used to determine if and when an investment decision for the Muskoka-Orillia 230 kV is required. This need will be revisited in the next iteration of the plan.

3. Development of the Integrated Regional Resource Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[5] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence were to become the responsibility of the new IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and

---

[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a more limited "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that a RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

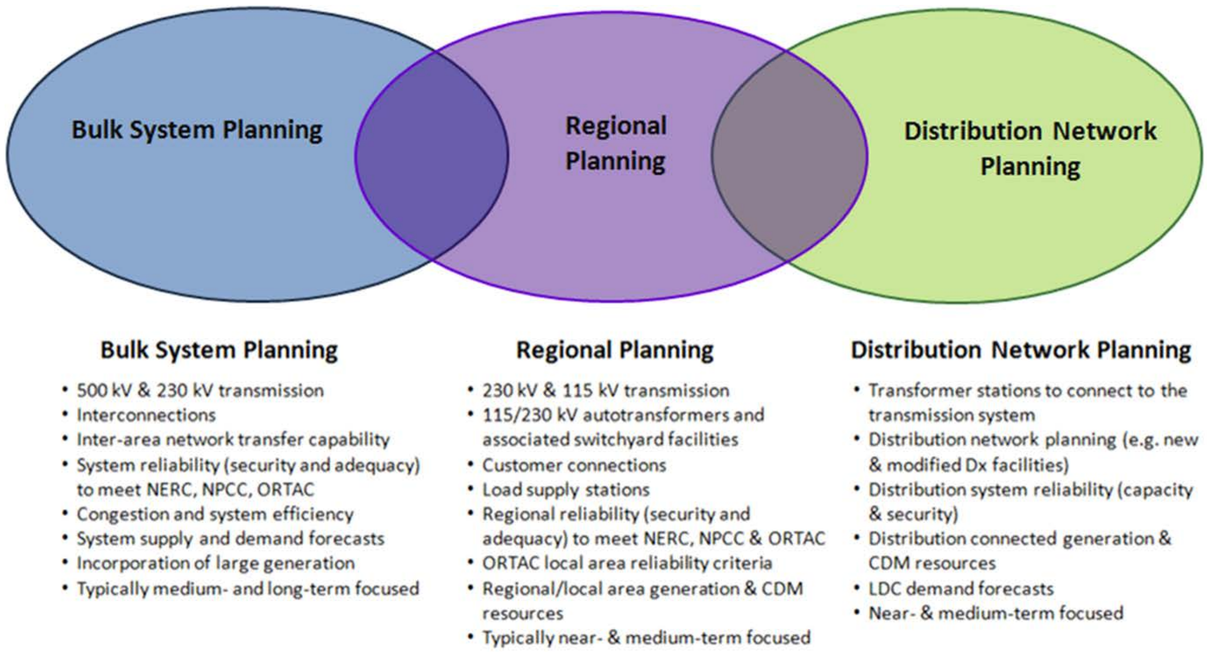


Figure 3-1: Levels of Electricity System Planning

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

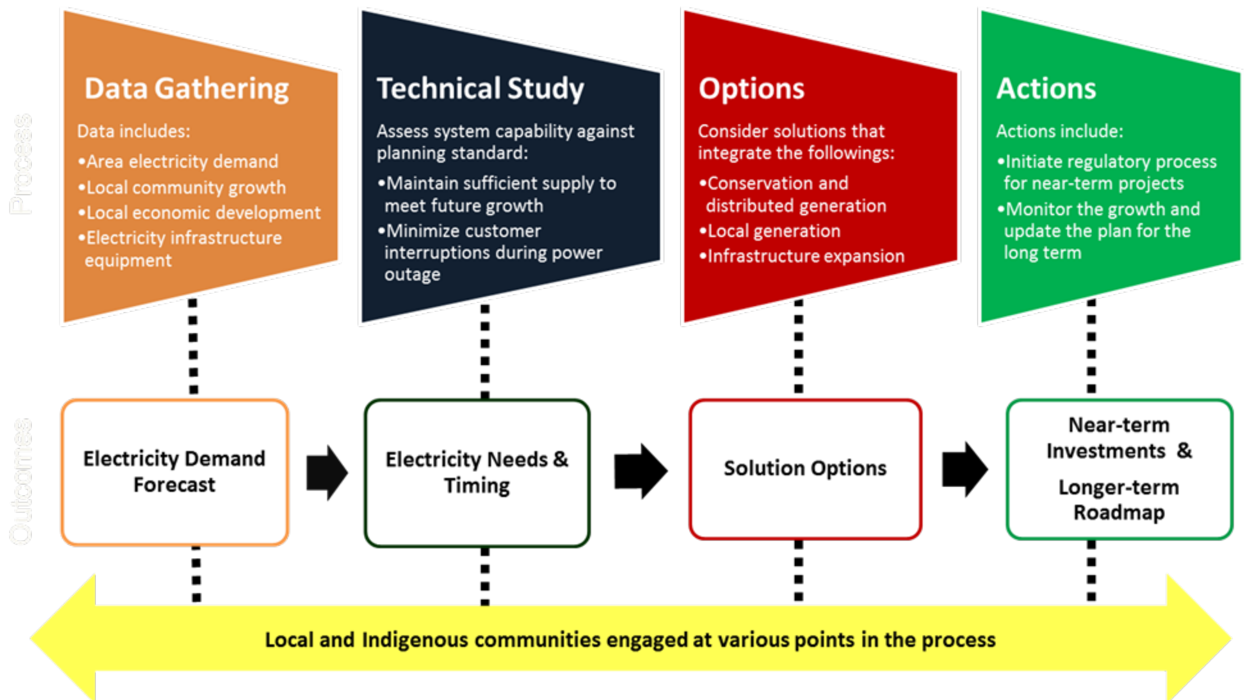
3.2 The IESO's Approach to Integrated Regional Resource Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

The IRRP describes the Working Group's recommendations for system enhancements based on different scenarios. The Working Group also recommends staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with large individual customers. The IRRP seeks to ensure flexibility is maintained such that changing long-term conditions may be accommodated.

In developing this IRRP, the Working Group followed a number of steps. These steps included: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Parry Sound / Muskoka Sub-region Working Group and IRRP Development

In 2014, the lead transmitter – Hydro One Transmission – initiated a Needs Screening process for the South Georgian Bay/Muskoka planning region. The South Georgian Bay/Muskoka Needs Screening study team determined that there was a need for coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

The South Georgian Bay/Muskoka Scoping Assessment Outcome Report [6] was finalized on June 22, 2015 and identified two sub-regions for coordinated regional planning: Parry Sound/Muskoka and Barrie/Innisfil. The two sub-regions are shown in Figure 3-3.

[6] South Georgian Bay/Muskoka Region Scoping Assessment Outcomes report (see IESO website: whttp://www.iemo.com/Documents/Regional-Planning/South-Georgian-Bay-Muskoka/SGBM-Scoping-Process-Outcome-Report-Final-20150622.pdf)

Figure 3-3: South Georgian Bay/Muskoka Region and Sub-regions

Subsequently, the Working Groups were formed to carry out the IRRP for the Parry Sound/Muskoka and Barrie/Innisfil Sub-regions. According to the OEB regional planning process, the Working Groups had 18 months to develop the IRRP.

In addition to the formation of the Working Groups, a LAC for the Parry Sound/Muskoka was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions. Further detail regarding community and stakeholder engagement activities is provided in Section 9.

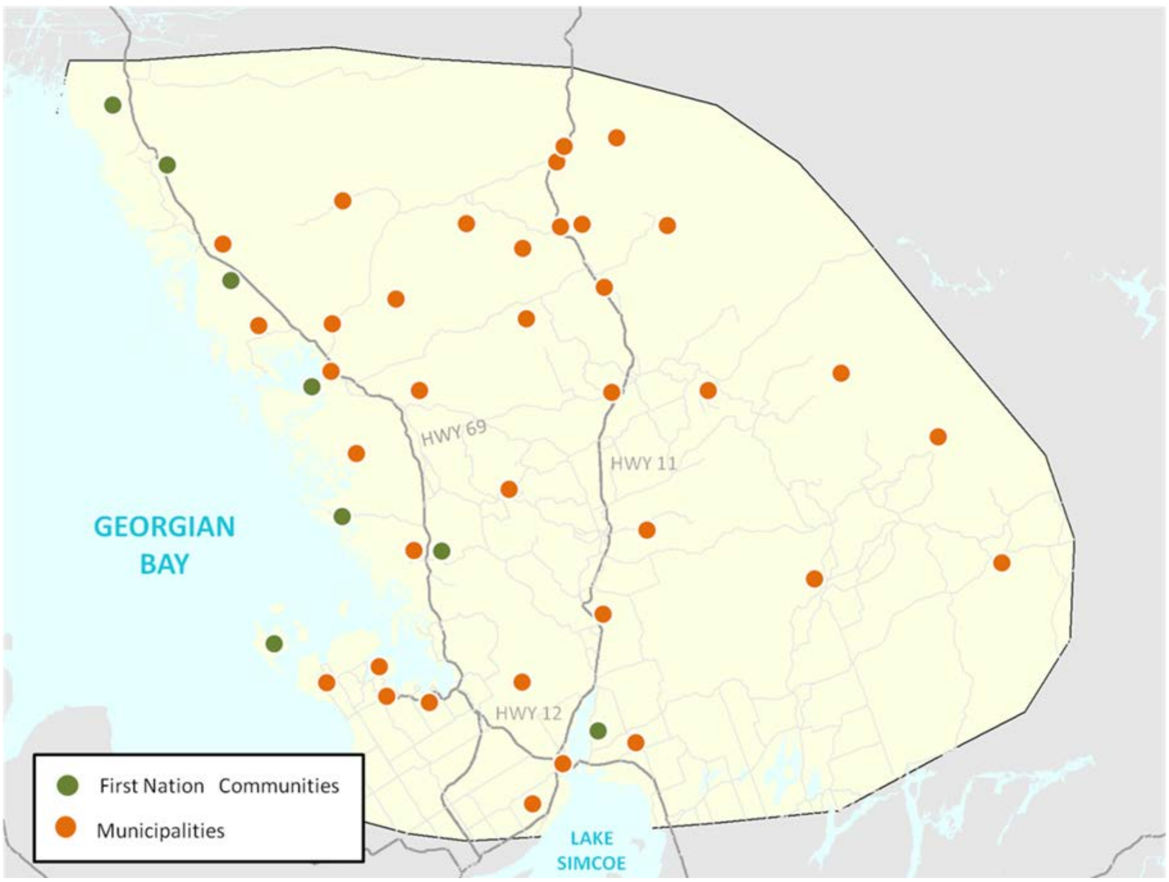
4. Background and Study Scope

The study scope of the IRRP is described in Section 4.1. Section 4.2 describes the electricity system supplying the Parry Sound/Muskoka Sub-region.

4.1 Parry Sound / Muskoka - Study Scope

The Parry Sound/Muskoka Sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. The approximate geographical boundaries of the sub-region are shown in Figure 4-1.

Figure 4-1: Geographical Boundaries of the Parry Sound/Muskoka Sub-region



The Parry Sound/Muskoka Sub-region includes the following First Nation communities:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

The sub-region also includes the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan
- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin

- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

In addition, there are a number of unorganized areas in the District of Parry Sound.

The Parry Sound/Muskoka IRRP assesses the reliability and adequacy of the regional electricity system supplying the Parry Sound/Muskoka Sub-region and identifies integrated solutions for the 20-year period from 2015 to 2034. The electricity system supplying the Parry Sound/Muskoka Sub-region is described in more detail in Section 4.2.

It is important to note that connection assessments of generation resources procured under programs, such as the Feed-in-Tariff, are beyond the scope of this IRRP. Generation projects participating in procurement programs will be assessed according to the rules and specifications of those programs. However, the peak demand contribution from generation resources already contracted through such programs are taken into account in the demand forecast as described in Section 5.3.3.

4.2 Electricity System Supplying Parry Sound / Muskoka Sub-region

The electricity system supplying the Parry Sound/Muskoka Sub-region consists of local generation resources, 230 kV regional transmission, 44 kV sub-transmission and low voltage distribution networks. Local generation resources provide important sources of electricity supply to the communities and customers in this sub-region. However, local generation sources are not sufficient and are supplemented with power delivered to the sub-region from the rest of the province through the 230 kV transmission system. From the 230 kV transmission system power is delivered to communities and customers through the 44 kV sub-transmission and low-voltage distribution networks. The following sub-sections discuss these components in more detail.

4.2.1 Local Generation Resources

Local generation in the Parry Sound/Muskoka Sub-region is primarily hydroelectric and solar. The total installed capacity of local generation is approximately 126 MW comprised of approximately 28 MW hydroelectric, 97 MW solar, and 1 MW combined heat and power ("CHP").

In Ontario, the electricity system is designed to meet regional coincident peak demand – i.e., the one-hour period each year when total demand for electricity in the region is the highest. While hydroelectric and solar resources are potential sources of energy, only a portion of their generation capacity can be relied upon at the time of peak due to the variable nature of these resources. In the Parry Sound/Muskoka Sub-region, electricity demand typically peaks during the evening in the winter season. For the purpose of infrastructure planning, the installed capacity of distributed and variable generation is accordingly adjusted to reflect the reliable power output at the time of the local winter peak.

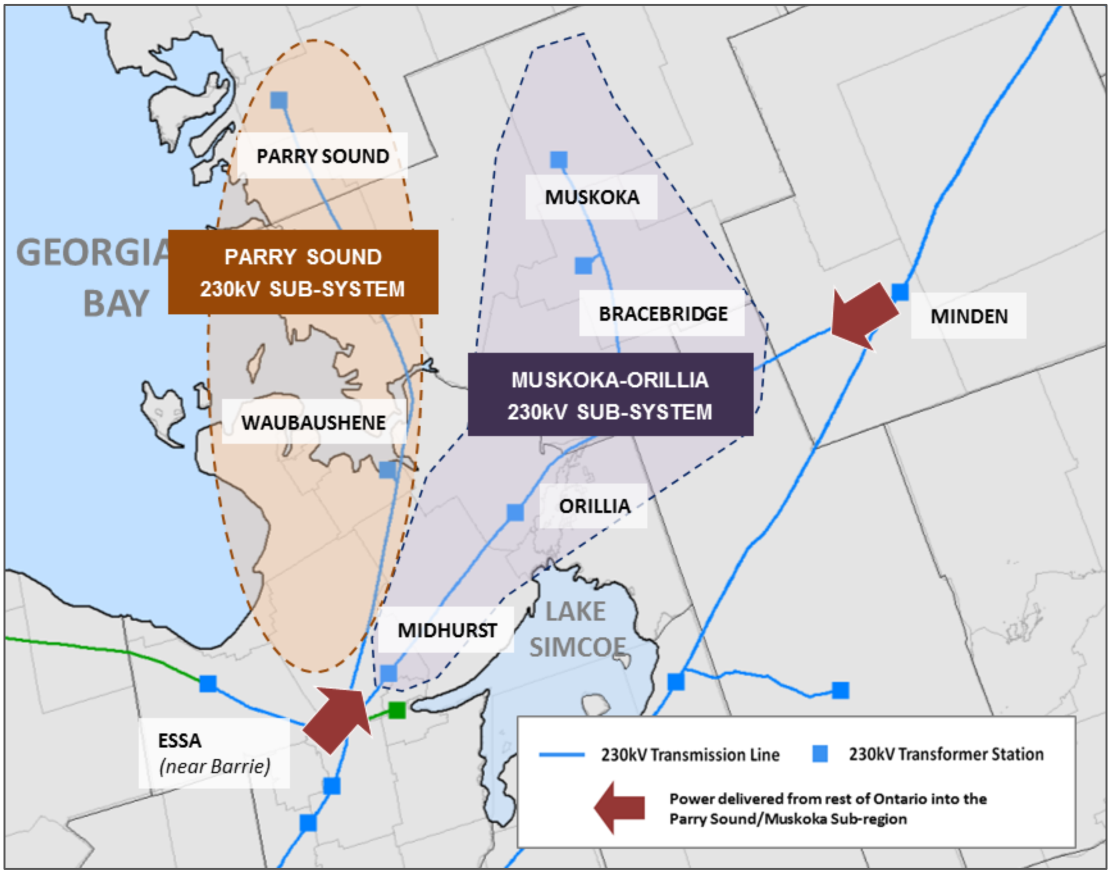
Hydroelectric facilities in the area are relatively small, generally less than 2 MW, however there are a couple facilities as large as 10 MW. The output of these facilities also depends on the availability of water resources and the operation of the facilities. To determine the dependable level of output at the time of peak, historical performance data of the hydroelectric generation facilities in the sub-region were used. The results are an assumed 34% capacity contribution from these resources.

Similarly, the solar facilities in the sub-region are also relatively small, with most being less than 0.5 MW, however there are a couple facilities as large as 10 MW. While the installed capacity of solar is high in the region, there is limited availability of solar power during the time of local peak, which occurs during the evening in the winter. It is assumed that solar would not provide any capacity at the time of local peak.

4.2.2 230 kV Transmission System

Power is delivered from the rest of the province into the Sub-region through the 230 kV transmission system at Essa (near Barrie) and Minden. As shown in Figure 4-2, the 230 kV transmission system supplies seven customers and utility-owned transformer stations. For the purpose of regional planning, the sub-region is further sub-divided into two regional 230 kV sub-systems: Muskoka-Orillia 230 kV sub-system and Parry Sound 230 kV sub-system.

Figure 4-2: Parry Sound/Muskoka Sub-region – 230 kV Transmission System

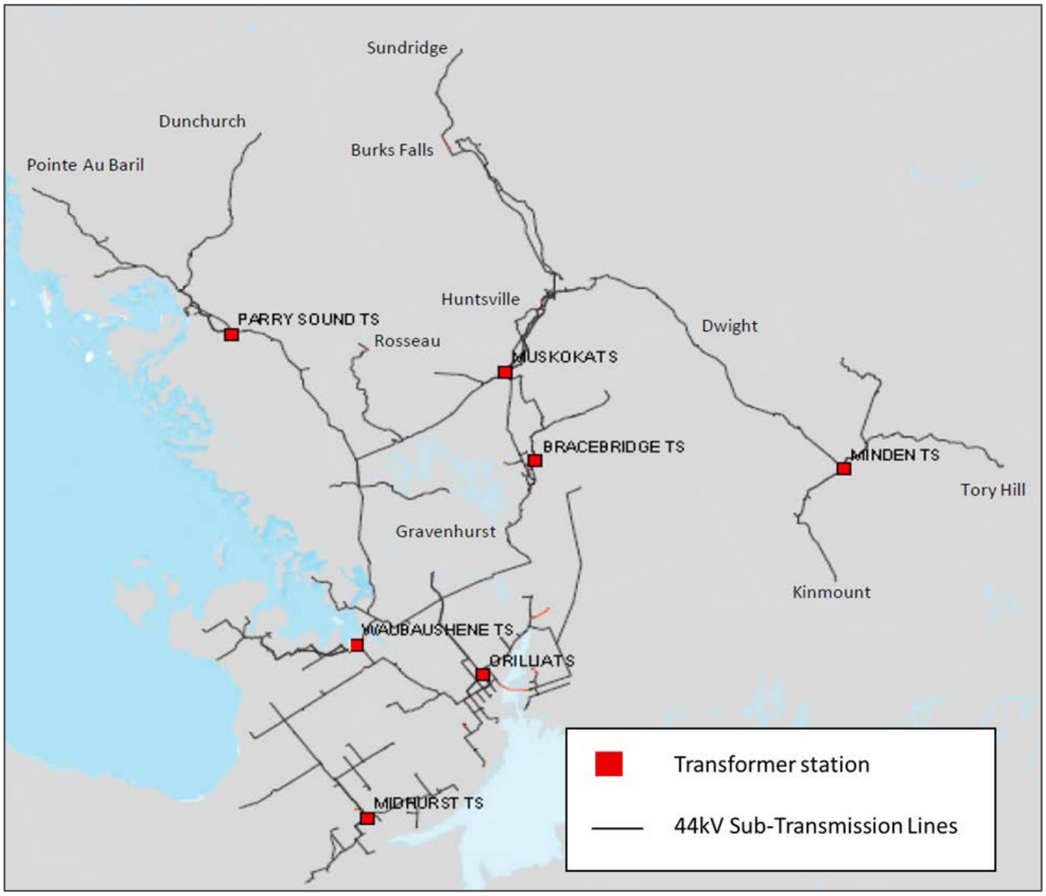


Since Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region, it is considered within the scope of the Barrie/Innisfil IRRP. However, Midhurst TS is supplied by the Muskoka-Orillia 230 kV sub-system and could impact the electricity supply to the Parry Sound/Muskoka Sub-region. Therefore, when assessing the reliability and adequacy of the Muskoka-Orillia 230 kV sub-system, the electricity demand growth at Midhurst TS needs to be considered in this IRRP.

4.2.3 44 kV Sub-transmission and Low-Voltage Distribution System

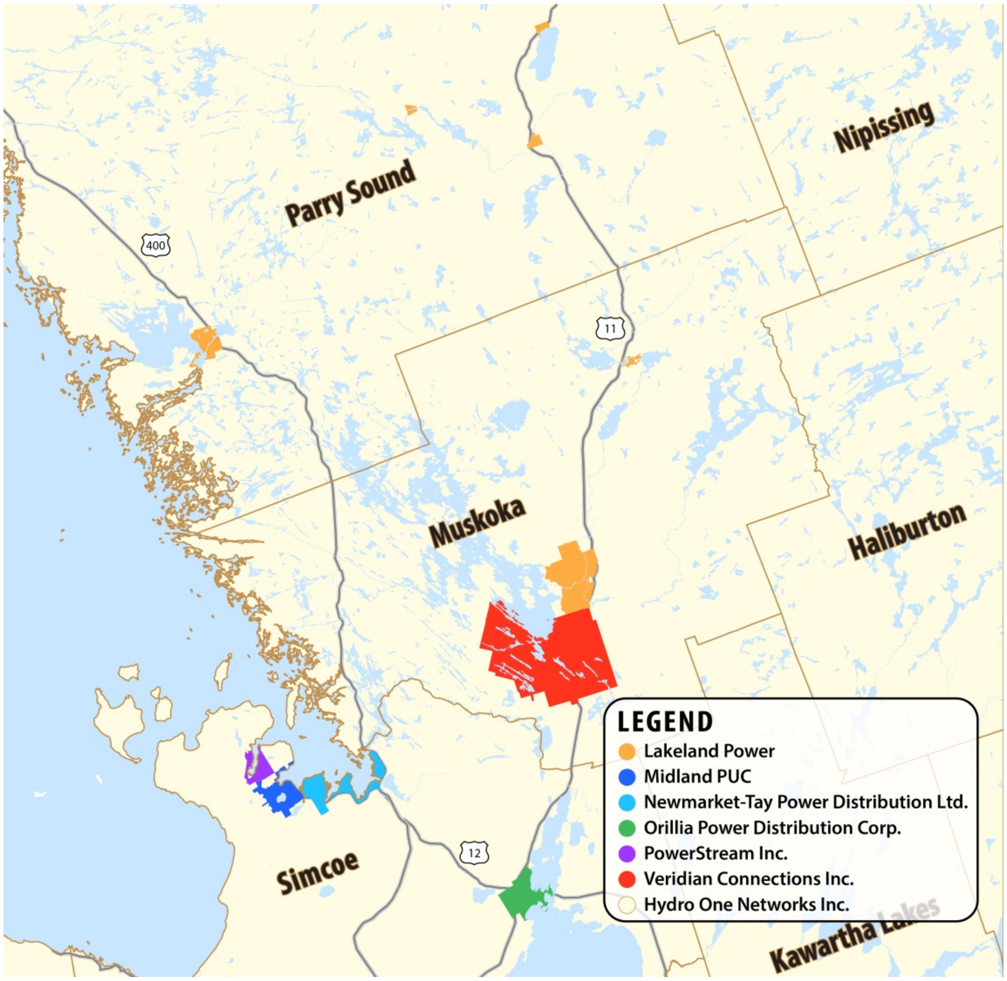
From the 230 kV sub-systems, power is delivered through transformer stations to the 44 kV sub-transmission system majority of which is operated by Hydro One Distribution in the Parry Sound/Muskoka Sub-region. As illustrated in Figure 4-3, given the large geography and sparsely populated areas, many communities and customers in this Sub-region are supplied by long 44 kV sub-transmission lines and a single source of supply.

Figure 4-3: 44 kV Sub-transmission System in the Parry Sound/Muskoka Sub-region



From the 44 kV sub-transmission system, power is delivered to the low voltage distribution network, which supplies various communities across the sub-region. The low-voltage distribution system is managed and operated by seven LDCs: Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, and Hydro One Distribution, as shown in Figure 4-4.

Figure 4-4: Local Distribution Companies Service Areas



Distribution system planning is beyond the scope of the regional planning process. Issues related to the distribution system may be discussed in this IRRP for context, but will be addressed through the local distribution planning process led by the Local Distribution Companies ("LDCs").

Details regarding the characteristics of the LDC service areas can be found in Appendix A.

5. Demand Forecast

Regional electricity systems in Ontario are designed to meet regional coincident peak demand – the one-hour period each year when total regional demand for electricity is the highest.

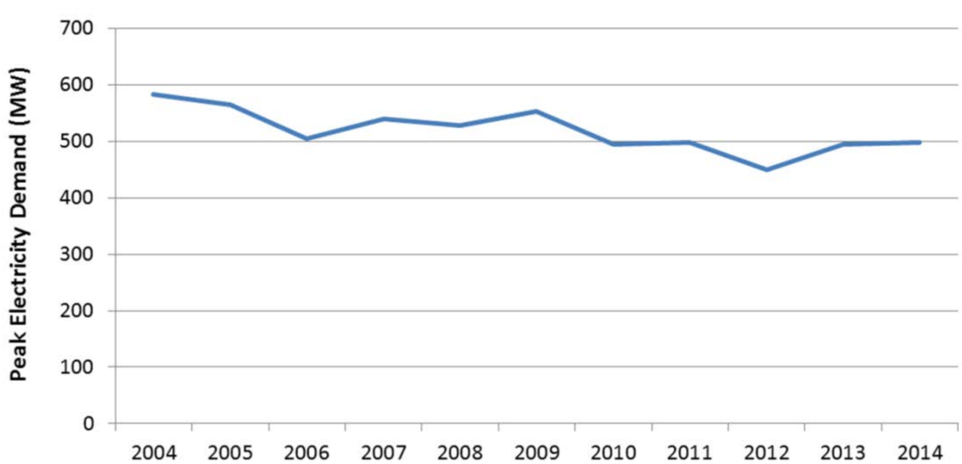
This section describes the development of the regional electricity demand forecast for the Parry Sound/Muskoka Sub-region. Section 5.1 describes historical electricity demand trends in the sub-region from 2004 to 2014. Section 5.2 provides an overview of the demand forecast methodology used in this study, and Section 5.3 summarizes the planning forecast for the sub-region.

5.1 Historical Electricity Demand 2004-2014

Electricity demand in this sub-region is primarily driven by residential and commercial customers. Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. As such, the electricity demand in this sub-region typically peaks during the winter months. This sub-region also supports a mix of economic activities including tourism, retail, healthcare and manufacturing industries. Seasonal population driven by tourism and recreation activities also contributes to the electricity demand requirements in this sub-region.

Demand has declined slightly between 2004 and 2010 but has been relatively stable since then at around 500 MW, as shown in Figure 5-1. The historical demand shown below was adjusted to account for weather-related impacts.

Figure 5-1: Historical Peak Demand - Parry Sound/Muskoka Sub-region (2004-2014)



5.2 Methodology for Establishing Planning Forecast

A planning forecast was developed to assess reliability of the Parry Sound/Muskoka Sub-region electricity system over the planning period (2015 to 2034). For the purpose of regional planning, the planning forecast considers the following components:

- Gross winter demand forecast scenarios for distribution-connected and transmission-connected customers,
- Estimated peak demand savings from meeting provincial energy conservation targets, and
- Expected peak demand capacity contribution from DG.

The gross demand forecast was developed based on the expected peak demand projections for distribution-connected and transmission-connected customers in the Parry Sound/Muskoka Sub-region. To develop the planning forecast, the gross demand forecast was modified to reflect the estimated peak demand savings from meeting provincial energy conservation targets and from existing and contracted DG.

Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs and, adapting the plan accordingly.

The methodology and assumptions used for the development of the planning forecast are described in detail in Appendix A.

5.3 Development of Planning Forecast

5.3.1 Gross Demand Forecast

The gross demand forecast was provided by the seven LDCs in this sub-region, based on customer connection requests, local economic development and growth assumptions outlined in Ontario's *Places to Grow Act, 2005*, which are reflected in municipal and regional plans.

A modest increase in electricity demand is forecast in this sub-region over the next 20 years. While slower growth is expected in the sub-region's manufacturing sector, growing Indigenous communities, new residential and commercial developments, seasonal population and potential local economic development such as the Parry Sound Airport Development and

Rama Road Corridor Economic Employment District, will contribute to growing electricity demand in the sub-region. Electric space and water heating requirements from communities, and aforementioned new residential and commercial developments will continue to be a major driver of peak electricity demand in this sub-region. Based on the information provided by the LDCs, gross demand is expected to grow 1.1% annually over the planning period.

Given the diverse communities and geography of this sub-region, electricity demand growth is not uniformly distributed across the sub-region. Only a small increase in electricity demand is expected in the northern Simcoe County, Minden and Parry Sound. Most of the electricity growth is forecast to be concentrated in Muskoka, Orillia and surrounding areas. For example, in Orillia, additional planned developments, including condominium and waterfront development and new retail, commercial, industrial and institutional customers may materialize within the 20-year planning period resulting in as much as an additional 20-22 MW of peak demand. For the purpose of regional planning, this potential load was considered as part of the sensitivity analysis.

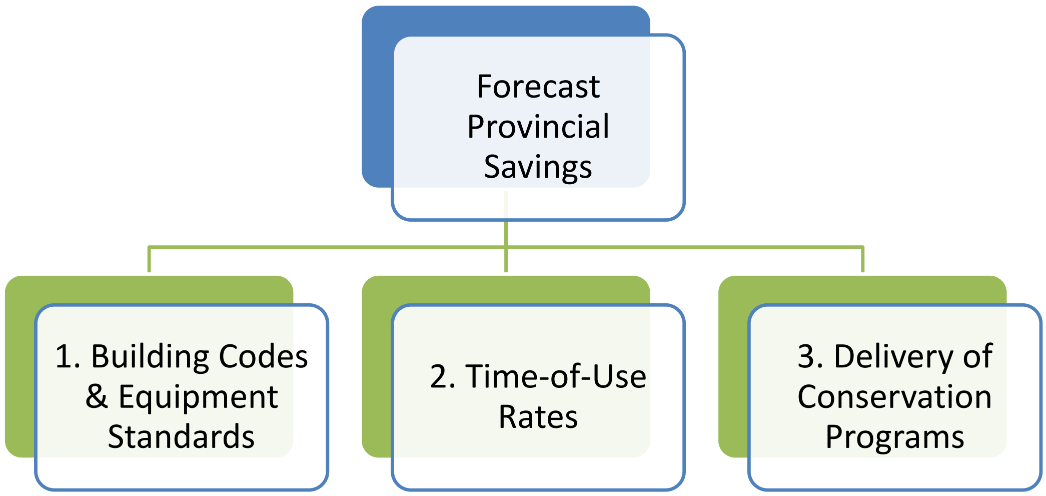
The specific forecasting methodology and assumptions for the gross demand forecast can be found in Appendix A.

5.3.2 Expected Peak Demand Savings from Provincial Conservation Targets

Conservation is incented and achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. The conservation savings forecast for the Parry Sound/Muskoka Sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.2), to determine the planning forecast in this sub-region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP") that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. The expected peak demand savings from meeting this target were estimated for the Parry Sound/Muskoka Sub-region. To estimate the impact of the conservation savings in the sub-region, the forecast provincial savings were divided into three main categories, as illustrated in Figure 5-2.

Figure 5-2: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The impact of estimated savings for each category was further broken down for the Parry Sound/Muskoka Sub-region by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Parry Sound/Muskoka Sub-region, LDCs were requested to provide breakdowns of their gross demand forecast, and electrical demand by sector for the forecast at each transformer station. For each transformer station where the LDC could not provide gross load segmentation, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors was used to help estimate the breakdown of demand. Once sectoral gross demand at each transformer station was estimated, the next step was to estimate peak demand savings for each conservation category: building codes and equipment standards, time-of-use rates, and delivery of conservation programs. The estimates for each of the three savings groups were done separately due to their unique characteristics and available data. The final estimated conservation peak demand reduction, 35 MW by 2034, was then applied to the gross demand to create the planning forecast.

Additional conservation forecast details are provided in Appendix A.

5.3.3 Expected Peak Demand Contribution of Existing and Contracted Distributed Generation

As of 2015, about 123 MW of DG was contracted and/or existing in the Parry Sound/Muskoka Sub-region. The majority of the contracted and installed capacity is solar projects. The sub-region also has several hydroelectric power facilities and one CHP facility.

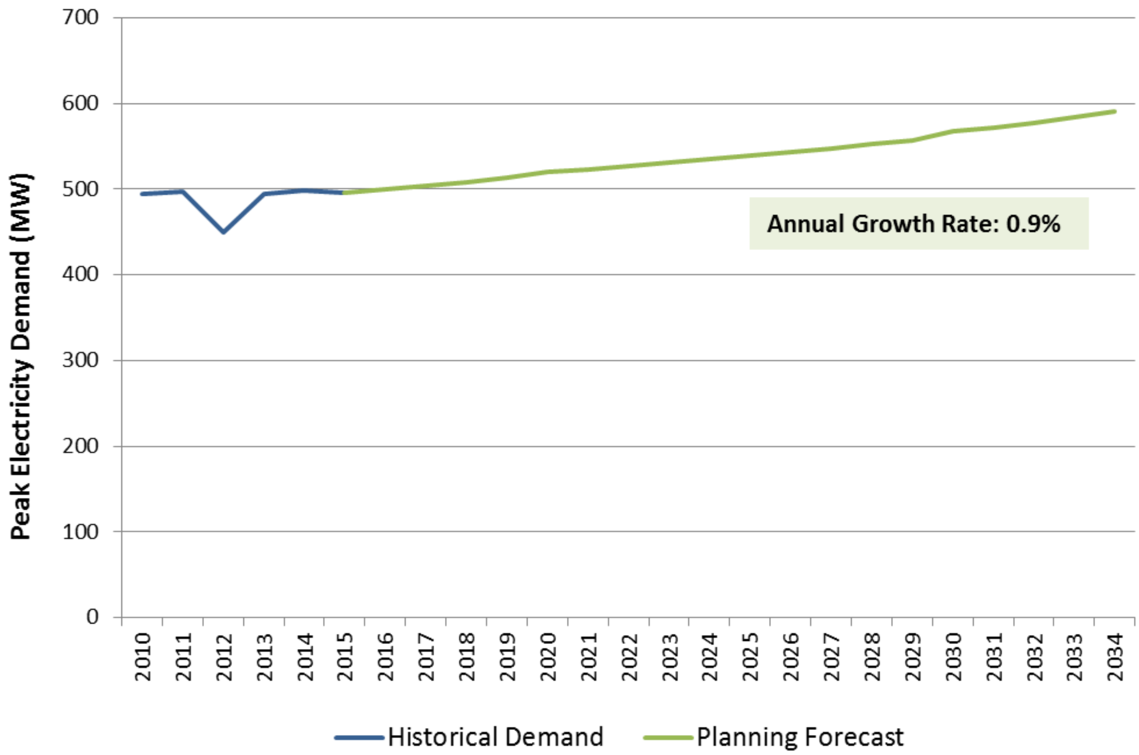
As the peak for the sub-region tends to occur during the winter evening hours, solar resources do not provide capacity contribution, however the other DG resources do have an impact on the peak. For the purpose of developing the planning forecast, contracted DG is expected to reduce the regional peak demand by as much as 11 MW over the next 20 years. Future DG uptake was, as noted, not included in the planning forecast and is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the Parry Sound/Muskoka Sub-region can be found in Appendix A.

5.3.4 Planning Forecast

Figure 5-3 shows the planning forecast for the Parry Sound/Muskoka Sub-region for the planning period from 2015 to 2034 (using a base year of 2014). The planning forecast takes into consideration the gross demand forecast scenarios, estimated peak demand savings from provincial energy conservation targets, and existing and contracted DG. Based on the planning forecast, the electricity demand in the sub-region is expected to grow 0.9% annually, with an incremental peak demand growth of 100 MW over the planning period.

Figure 5-3: Parry Sound/Muskoka Sub-region Planning Forecast (2015-2034)



As discussed in Section 4.2.2, Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region. As a result, the Parry Sound/Muskoka Sub-region demand forecast shown above does not include electricity demand from Midhurst TS.

Further details related to the demand forecast scenarios can be found in Appendix A.

6. Needs

This section outlines the needs assessment methodology and identifies regional electricity supply and reliability needs over the 20-year planning period.

6.1 Needs Assessment Methodology

The IESO's ORTAC,[7] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability (see Appendix B for more details).

Through the application of these criteria, three broad categories of needs can be identified:

- **Transformer Station Capacity** is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the load meeting capability ("LMC") of the step-down transformer stations in the local area, which is the maximum demand that can be supplied from the transformer stations based on equipment rating and outage conditions.
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission line or sub-system, which is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See Appendix B for more details). Supply capacity needs are identified when peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** is the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

[7] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

In addition, the needs assessment may also identify needs related to service reliability performance, equipment end-of-life and planned sustainment activities. Service reliability and performance is measured based on customers' exposure to power outages on the distribution and transmission system, and is expressed in terms of frequency (i.e., number of outages a year) and duration (e.g., length of time before the power is restored). Equipment reaching the end of its life and planned sustainment activities may impact the needs assessment and options development. Transmission assets reaching end-of-life are typically replaced with assets of equivalent capacity and specification. The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, or downsizing or even removing equipment that is no longer considered useful. Such instances may also present opportunities to enhance or reconfigure assets for infrastructure hardening to improve system resilience.

6.2 Regional and Local Electricity Reliability Needs

Through the needs assessments, the Working Group has identified the need: (1) to minimize the frequency and duration of power outages and (2) to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region. The following sections further describe these needs.

6.2.1 Need to Minimize the Frequency and Duration of Power Outages

As discussed in Section 4.2, while there is local generation in this sub-region, communities and customers primarily rely on the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines to deliver power from the rest of the province into the Parry Sound/Muskoka Sub-region. Outages along any of these lines (i.e., 230 kV, 44 kV, low voltage distribution lines) could interrupt the electricity supply to communities and customers in the Parry Sound/Muskoka Sub-region.

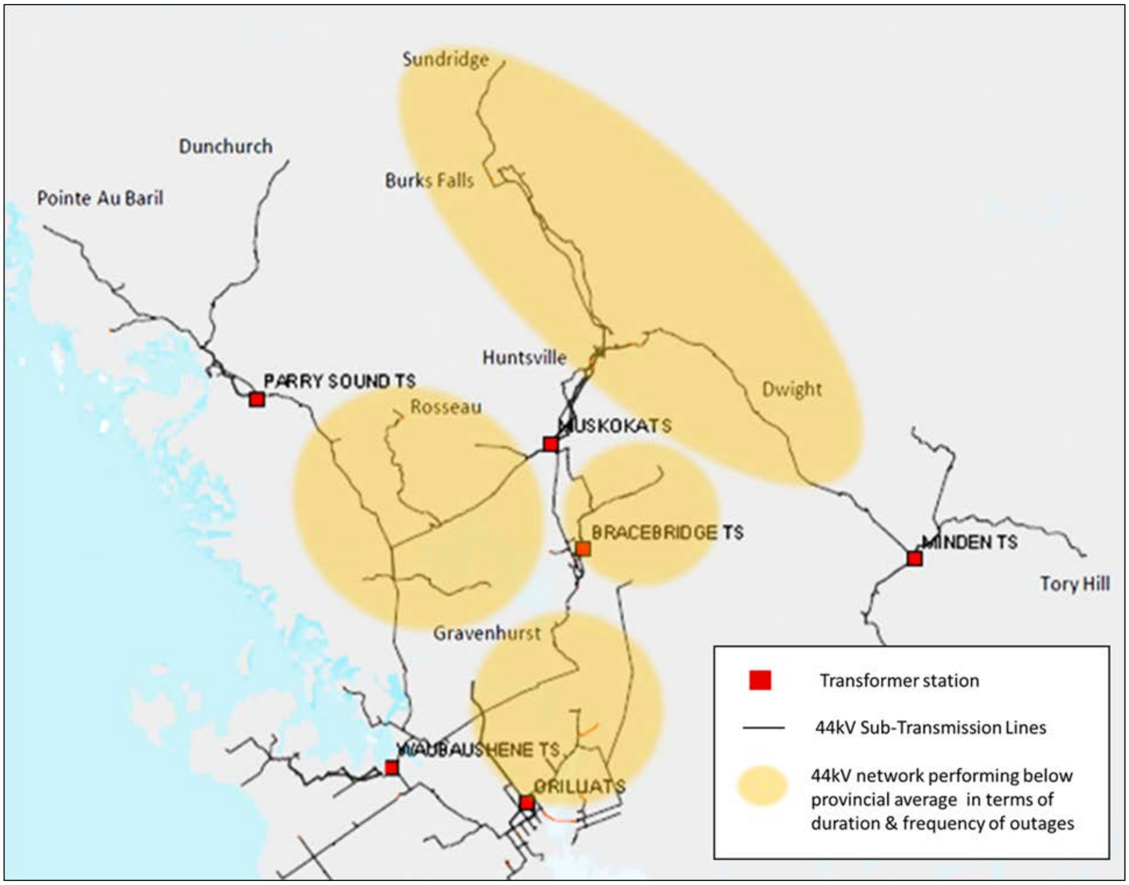
In this sub-region, customers and communities experience more frequent and prolonged power outages in comparison to customers and communities in other areas of the province. The consequences of extended power outages can have impacts for customers and society at large. For example, the Working Group has heard from communities and customers in this sub-region that below-average reliability is an impediment to economic development.

To better understand the causes of these power outages, the Working Group examined the service reliability and performance of the 44 kV sub-transmission system, and the load restoration capability and security of the 230 kV transmission line supplying the Parry Sound/Muskoka Sub-region. The results from the needs assessments are summarized below.

44 kV Sub-Transmission Service Reliability and Performance

In response to community and customers' concerns regarding power outages in this sub-region, the Working Group examined historical service reliability and performance of the 44 kV sub-transmission system over the last five years. Results from the assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below average in terms of frequency and duration of outages (as shown in Figure 6-1). On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less. Based on the historical service reliability and performance data over the last five years, the outages for many of the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region are almost double the provincial average in terms of frequency and duration.

Figure 6-1: 44 kV sub-transmission systems that are performing below provincial average in terms of frequency and duration of outages in the Parry Sound/Muskoka Sub-region



The service reliability and performance of the 44 kV sub-transmission system is impacted by a number of factors, including a facility's exposure to various elements, age and maintenance of equipment, length and configuration of the network, and the repair crew's accessibility to facilities. Lengthy 44 kV sub-transmission lines and off-road facilities are the main reasons for frequent and prolonged outages in the Parry Sound/Muskoka Sub-region.

- **Lengthy 44 kV sub-transmission lines:** As a large and sparsely populated geographical area, this sub-region is supplied by 44 kV sub-transmission lines that are typically longer than other 44 kV sub-transmission lines in Ontario. The average length of a 44 kV sub-transmission line in Ontario is about 45 km. Most of the 44 kV sub-transmission systems in the Parry Sound/Muskoka Sub-region range from 40 to 100 km in length. Long sub-transmission lines typically exhibit lower levels of reliability because of increased exposure to trees and wildlife. Tree contact has been identified as one of the major causes of 44 kV sub-transmission outages in this sub-region. Furthermore, with longer

44 kV sub-transmission lines, repair crews require additional time to identify and isolate causes of any outages.

- **Off-Road Facilities:** Many of the 44 kV sub-transmission systems are located off-roads. Due to limited access to off-road facilities, repair crews have difficulty detecting early signs of equipment failure, performing preventative maintenance and restoring power in a timely manner.

The detailed summary of the reliability performances of these 44 kV sub-transmission systems can be found in Appendix C.

Load Restoration and Security on the 230 kV Transmission System

Outage statistics from Hydro One Transmission indicate that have been three major outages involving the loss of both 230 kV transmission circuits in the sub-region since 1990. These outages lasted no more than 2-3 hours. While major 230 kV transmission outages have been relatively infrequent and short in duration in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system supplying the Orillia and Muskoka area has limited ability to restore power in a timely manner and minimize the number of customers interrupted in the event of a major 230 kV transmission outage. As discussed in Section 6.1, the 230 kV transmission system should be designed in accordance with the load restoration and security criteria outlined in ORTAC (see Appendix B).

Based on the needs assessment, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC load restoration criteria and may violate the load security criteria over the longer term depending on the electricity demand growth in the area. The Muskoka-Orillia 230 kV sub-system is a 171 km double-circuit 230 kV transmission line (M6/7E) between Barrie and Minden. This system currently supplies four transformer stations and supplies about 465 MW of peak demand.[8] In the event of a major outage involving the loss of both transmission circuits on the Muskoka-Orillia 230 kV sub-system, all customers supplied by this transmission line would be interrupted. The existing system cannot restore any power to customers within 30 minutes. As

---

[8] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

a result, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC 30 minute load restoration criteria.

Based on the planning forecast, the winter demand on the Muskoka-Orillia 230 kV sub-system is expected to increase to 621 MW by 2034. According to ORTAC load security criteria, no more than 600 MW of electricity supply can be interrupted following a major outage. Depending on the electricity demand growth, the Muskoka-Orillia 230 kV sub-system may violate the load security criteria over the longer term.

Action is required to improve the load restoration and security for the Muskoka-Orillia 230 kV sub-system and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

6.2.2 Need to Provide Adequate Supply to Support Growth

To ensure there is an adequate and reliable source of electricity supply for the customers and communities in the Parry Sound/Muskoka Sub-region, the electricity system will need to have sufficient supply to support forecast electricity demand growth and to comply with ORTAC. Results from the needs assessment indicate that transformers at Waubaushene TS and Parry Sound TS are at, or nearing capacity and will be in violation of ORTAC in the near term. Over the longer term, electricity demand growth could also exceed the supply capability of the Muskoka-Orillia 230 kV sub-system. The following sections further discuss these near- and longer-term supply capacity needs.

Demand Exceeds Capability at Parry Sound TS and Waubaushene TS in the Near-Term

The transformers supplying the Town of Parry Sound and surrounding areas can supply up to 52 MW at the time of local peak (Parry Sound TS LMC = 52 MW). The electricity demand in the area has already exceeded the capability of these transformers over the last couple of years. For example, during the winter of 2015, these transformers supplied up to 61 MW at the time of local peak, exceeding the LMC of Parry Sound TS by about 9 MW. Near-term action is required to ensure that the electricity system in the area has adequate supply to support growth. Over the planning period, the electricity demand supplied by Parry Sound TS is forecast to grow less than 1 MW per year so that by 2034 Parry Sound TS would need to supply about 74 MW.

Similarly, Waubaushene TS, supplying Waubaushene and the surrounding area can supply up to 99 MW at the time of local peak (Waubaushene TS LMC = 99 MW). Today, Waubaushene TS supplies about 96 MW of electricity demand. The transformers at this station are nearing capacity and electricity demand growth is expected to exceed capability by 2017. Near-term action is required to ensure that the electricity system has adequate supply to support future growth. The electricity demand supplied by Waubaushene TS is expected grow modestly at less than 1 MW per year. Based on the planning forecast, Waubaushene TS is expected to supply about 111 MW of electricity demand by 2034.

Demand may exceed the capability of Muskoka-Orillia 230 kV sub-system over the longer term

The Muskoka-Orillia 230 kV sub-system can supply up to 600 MW at the time of peak (Muskoka-Orillia 230 kV sub-system LMC = 600 MW). Today, the Muskoka-Orillia 230 kV sub-system supplies up to 454 MW.[9] Given the modest electricity demand growth in this area, electricity demand is not expected to exceed its capability until the early 2030s based on the planning forecast.

Given the uncertainty associated with the long-term electricity demand forecast, it is sufficient to monitor demand growth before proceeding with an investment decision. Section 7.2.2 provides a high-level discussion of options to address this potential need over the longer term.

6.3 Other Electricity Needs and Considerations

In addition to the regional and local electricity reliability needs outlined in Section 6.2, the Working Group identified other electricity needs and considerations that could impact the regional electricity supply. These issues are discussed in more detail below.

6.3.1 End-of-Life Replacements and Sustainment Activities

The Minden 230/44 kV transformers are scheduled for end-of-life replacements within the next five years. Hydro One is preparing a plan to replace all the aging equipment at Minden TS in the next few years. The aging 25/42 MVA transformers are to be replaced with 50/83 MVA transformers to address the capacity needs at the station. This sustainment decision was made prior to the initiation of this IRRP.

[9] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst TS is considered as part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and has an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

In addition to the near-term sustainment activities, the Working Group also identified potential assets that could be reaching end-of-life over the planning period. The expected service life of a transformer is about 60 years. The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970s and therefore these transformers could be reaching end-of-life in the early 2030s. There may be opportunities to align end-of-life facility replacements with solutions to address longer-term needs in the sub-region.

6.3.2 Community Energy Planning

A number of communities in the sub-region are in the process of developing community energy plans ("CEP(s)"). At the time of this report, seven of the eight First Nation communities have received funding from the IESO through the Aboriginal Community Energy Plan program to develop CEPs. The Municipal Energy Plan Program[10] administrated by the provincial government supports municipalities in their efforts to develop CEPs.

Through community energy planning activities, communities will have a better understanding of their local energy needs and emissions footprint, be able to identify opportunities for energy efficiency and emissions reduction, and develop plans to meet their goals in consideration of local economic development. These CEPs examine broader energy needs, such as transportation, natural gas and electricity, and consider other objectives including net zero energy, electrification, and emissions reductions.

On June 8, 2016, the Ontario government released Ontario's Climate Change Action Plan ("CCAP"), which outlines policy to reduce the use of fossil fuel and to encourage the move toward a low carbon economy. In response to this policy direction, a CEP may include recommendations to promote electrification and other forms of fuel switching, such as shifting from natural gas to electric-power heat pumps and from gasoline to electric vehicles, to achieve a goal of reducing greenhouse gas ("GHG") emissions. As such, the outcomes from CEPs may drive additional requirements on the electricity system and should be monitored closely through the regional planning process. Furthermore, with the increased access to distributed energy resources, CEPs may identify opportunities for community-based energy solutions, such as district energy, CHP, or microgrids. Depending on the timing, location and magnitude of the

---

10 For more information on the Ministry of Energy MEP Program: http://www.energy.gov.on.ca/en/municipal-energy/

needs, community-based energy solutions can be considered as potential options to address regional electricity needs.

6.3.3 Power Quality

A large customer in the sub-region is experiencing issues related to power quality. Power quality issues are defined as disturbances to the customer's electricity supply as a result of voltage. Voltage issues can be caused by customers' equipment and/or system voltage performance. The solutions and cost responsibility of investments to address power quality issues may vary depending on the root causes of the problem. The Working Group agreed that power quality issues need to be better understood and should be examined on a case-by-case basis by the area LDCs, transmitter and customers.

6.4 Needs Summary

Table 6-1 provides a summary of the regional supply and reliability needs in the Parry Sound/Muskoka Sub-region.

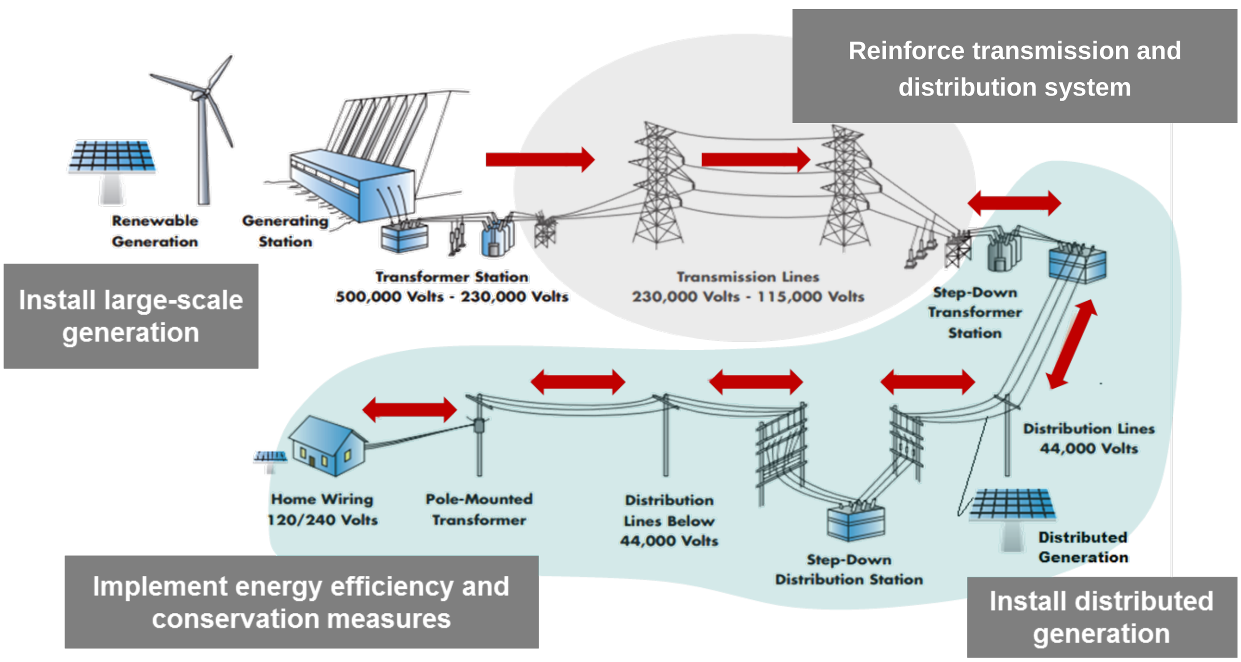
Table 6-1: Summary of Regional and Local Reliability Needs

Local and Regional Electricity Reliability Needs	Components	Status
Need to Minimize the Frequency and Duration of Power Outages	44 kV sub-transmission systems	Performing below provincial average in terms of frequency and duration of 44 kV sub-transmission outages
	Muskoka-Orillia 230 kV sub-system	Limited ability to restore power to customers in a timely manner in the event of a 230 kV transmission outage involving the loss of both transmission circuits. The sub-system does not meet the ORTAC load restoration criteria
		Electricity demand growth may exceed 600 MW and could violate the ORTAC load security criteria in the early 2030s
Provide Adequate Supply to Support Growth	Parry Sound TS	Electricity demand growth already exceeds system capability today
	Waubaushene TS	Electricity demand growth forecast to exceed system capability in 2017
	Muskoka-Orillia 230 kV sub-system	Electricity demand growth could exceed system capability in the early 2030s

7. Options to Address Regional and Local Electricity Needs

As shown in Figure 7-1, traditionally power has been generated from large, centralized generation sources. To provide electricity supply to the various communities across Ontario, power has been delivered through transmission and distribution infrastructure. To address regional and local electricity needs, one approach is therefore to reinforce the transmission and distribution infrastructure supplying the local area. However, in recent years, communities and customers have been exploring opportunities to reduce their reliance on the provincial electricity system by meeting their electricity needs with local, distributed energy resources and community-based solutions. This approach includes a combination of emerging technologies and conservation programs, such as targeted DR and conservation programs, DG and advanced storage technologies, micro-grid and smart-grid technologies, and more efficient and integrated process systems combining heat and power.

Figure 7-1: Options to Address Electricity Needs



Options Evaluation

When evaluating alternatives, the Working Group considered a number of factors, including technical feasibility, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs and options. Solutions that maximized the use of existing infrastructure were given priority.

Investing in new electricity infrastructure, such as a new transmission line or a generation facility requires substantial capital investment, has environmental/land-use impacts and has a long-service life. As such, it is important to take into the consideration the longer-term cost implications, value and potential risks (e.g., stranded or underutilized assets) when recommending an investment. Furthermore, these facilities typically require long lead times to obtain approvals and complete construction. For these reasons, decisions on new facilities must take into account these considerations and be made with sufficient lead time to ensure they are available when needed.

When assessing the need for infrastructure investments, it is important to strike a balance between overbuilding infrastructure (e.g., committing to infrastructure when there is insufficient demand to justify the investment) and under-investing (e.g., avoiding or deferring investment despite insufficient infrastructure to support growth in the region). Typically, demand management and energy efficiency programs can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take five to seven years to come into service. The lead time for generation development is typically two to three years, but could be longer depending on the size and technology type.

Finally, the issue of how much is appropriate to invest and who pays needs to be addressed. In regional planning, depending on the type and classification of assets, the costs may be shared by all provincial ratepayers or recovered only by the specific customers they serve (e.g., LDC, industrial customers). In some cases, a combination of cost-sharing may occur when there are both provincial and local benefits. Notably, the Working Group has heard concerns from communities about affordability. Given the high cost of electricity, it is important consider how investments impact local ratepayers.

<u>Near-Term Actions and Long-Term Planning Considerations</u>

For the near and medium term, the IRRP identifies specific actions and investments for immediate implementation. This ensures that necessary resources will be in-service in time to address more pressing needs. For the long term, the IRRP identifies potential options to meet needs that may arise in 10-20 years. It is not necessary to recommend specific projects at this time (nor would it be prudent given forecast uncertainty and the potential for technological change). Instead, the long-term plan focuses on developing and maintaining the viability of long-term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, actions need to be taken to (1) minimize the frequency and duration of power outages, and (2) ensure that the regional electricity system has adequate supply to support growth. In developing the 20-year plan, the Working Group examined a wide range of integrated solutions to address these local and regional needs. These options are discussed in the following section.

7.1 Minimize the Frequency and Duration of Power Outages

To minimize the frequency and duration of power outages, the Working Group examined options to improve service reliability and performance on the 44 kV sub-transmission system and to address load restoration and security needs on the 230 kV transmission system.

7.1.1 Options to Improve Service Reliability and Performance on the 44 kV Sub-transmission System

44 kV Sub-Transmission Maintenance and Outage Mitigation Initiatives

Hydro One Distribution owns and operates the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region. Currently, Hydro One Distribution has a number of on-going maintenance and outage mitigation initiatives, including vegetation management, line patrols and grid modernization, to help reduce the frequency and duration of outages on the 44 kV sub-transmission system. These initiatives are summarized in Table 7-1.

Table 7-1: Status of Current Maintenance and Outage Mitigation Initiatives in the Parry Sound/Muskoka Sub-region

Initiatives	Status
Vegetation Management Program	▪ Vegetation management was last completed in these areas in 2015/2016 ▪ Full clearing for these areas is planned for 2021/2022 ▪ Hydro One has committed $20 million in 2016 in the districts of Muskoka and Parry Sound to reduce tree-related outages for its customers
Line Patrols	▪ Data is collected to help identify and prioritize the need to replace distribution poles and/or potentially defective equipment ▪ Last line patrolling cycle for these priorities areas occurred between 2010-2012 ▪ The next line patrolling cycle is scheduled for 2016 to 2021

Mid-cycle Hazard Tree Program	▪ Visual inspection to identify potential risk of tree-related contact ▪ This program will be conducted in this sub-region in 2018/2019
Distribution Management System & Grid Modernization	▪ Distribution management system will be implemented in this sub-region by the end of 2016 and will enable operators to have greater grid visibility and to respond to outages in a timely manner ▪ A broader grid modernization initiative is underway to identify opportunities for distribution automation (e.g., remote fault indicators, automated switches), which can help operators diagnose the sources of the outages and respond in a timely manner

In addition to these on-going maintenance programs and initiatives, Hydro One Distribution may take additional measures to further improve service reliability and performance on the 44 kV sub-transmission systems. These include:

- Install distribution automation and fast-acting switching devices to restore power in a timely manner
- Relocate "Off-Road" 44 kV sub-transmission system lines to roadside to facilitate access for maintenance crews
- Strengthen ties within the 44 kV sub-transmission system to allow adjacent 44 kV lines to serve as a back-up supply in the event of an outage

The cost, feasibility and effectiveness of these measures depend on the solution type, geography and nature of the 44 kV sub-transmission system and will need to be examined on a case-by-case basis. Hydro One Distribution will assess these options through the distribution planning process and will provide an update to the communities and LACs on plans to improve 44 kV sub-transmission system service reliability performance, including any proposed capital plans, by the end of 2017. The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

<u>Option to Resupply Customers from Bracebridge TS</u>

Currently, the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and the Township of Seguin are supplied by lengthy 44 kV sub-transmission system lines (60-100 km in length) from Muskoka TS and Orillia TS. To reduce 44 kV sub-transmission line exposure, new 44 kV sub-transmission lines can be built (~ up to 15 km) to resupply these areas from Bracebridge TS. These new 44 kV sub-transmission lines to Bracebridge TS cost about $3 to $6 million.

Today, Bracebridge TS supplies one industrial customer. The electricity demand from this industrial customer has decreased significantly over several years. Over the longer term, there should be sufficient capacity at Bracebridge TS to supply some of the customers in the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and surrounding areas.

As discussed in Section 6.2.1, outages on the transmission system or transformer stations are relatively infrequent in this sub-region. However, due to the current system configuration at Bracebridge TS,[11] all power being supplied by the Bracebridge TS will be interrupted in the event of an outage at the TS or on the 230 kV transmission line.

Operational measures could help mitigate customers' exposure to outages on the 230 kV transmission system supplying Bracebridge TS. In the event of an outage on the 230 kV system, customers could rely on the Muskoka TS or Orillia TS as a backup supply and vice versa. In addition, a second TS and/or a combination of switching facilities could be installed to minimize the impact of potential 230 kV transmission system outages. The cost of these transmission reinforcements could range from $5 to $30 million.

Going forward, Hydro One Transmission, Hydro One Distribution, Lakeland Power and Veridian Connections will examine the cost-benefit and cost-responsibility of options to improve the service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas and will discuss these findings with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results from these discussions will be shared with LAC members and affected communities.

[11] In Ontario, most transformer stations are designed to have two transformers to provide redundancy during outages on the transmission system. In the event that one transformer is out-of-service, the remaining TS could still provide a continuous supply to the customers. Because Bracebridge TS was originally designed to serve the needs of the specific industrial customer, the station only has a single transformer.

7.1.2 Options to Improve Load Restoration and Security on the Muskoka-Orillia 230 kV Transmission System

Distribution Option

One option to restore electricity supply to customers following a major outage on the Muskoka-Orillia 230 kV sub-system is to resupply these customers from neighbouring 230 kV transmission system (e.g., Parry Sound 230 kV sub-system) using the distribution network. The extent to which these customers can be resupplied through the distribution network is highly variable and depends on various factors such as load level at neighbouring stations, distance between stations, voltage of neighbouring distribution systems, time of day and operating procedures in place on the distribution system. Based on information provided by the LDCs, only about 20 to 30 MW can be resupplied from neighbouring stations within 30 minutes following a major outage on the Muskoka-Orillia 230 kV sub-system. In order to meet the ORTAC load restoration at today's demand level, the system will need to restore at least 200 MW within 30 minutes following the transmission outage. As such, this option is not sufficient to meet the ORTAC load restoration criteria.

Transmission Option

In the event of a 230 kV transmission outage, fast-acting isolating devices can be installed to minimize the impact of supply interruption to customers. There are two types of fast-acting isolating devices: (1) motorized switches and (2) breakers.

Motorized switches can be used to isolate sections of the transmission line within 30 minutes following a major transmission outage and would enable power to be restored to customers in a timely manner. This is particularly important in remote areas, where repair crew may have limited access to the infrastructure. Grid operators can operate these switches remotely to isolate sections affected by an outage in a timely manner. The cost of these switches ranges from $5 to $7 million.

As an alternative solution, breakers can immediately isolate sections of the transmission line that are not directly impacted by the outage. Since breakers can reduce the total number of customers that would be affected by a transmission outage, it can be an effective solution to address the longer-term load security needs on Muskoka-Orillia 230 kV sub-system. Since additional infrastructure and protection and control systems are required for breakers, the cost of breakers is usually 3-4 times more than for motorized switches ($20 to $25 million). Given the uncertainty of the demand forecast over the longer term and the substantial cost of installing breakers, the Working Group agreed that installing breakers on the Muskoka-Orillia 230 kV sub-system is not required at this time. A summary of options to improve load restoration and load security on Muskoka-Orillia 230 kV sub-system can be found in Appendix E.

In consideration of the cost-benefit of these options, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at Orillia TS. With these switches, about 50% of the electricity supply to customers on the Muskoka-Orillia 230 kV sub-system could be restored within 30 minutes in the event of an outage on the 230 kV transmission system, meeting the ORTAC 30 minute load restoration criteria.

To bring the 230 kV transmission system in compliance with Ontario's planning standard, the IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS. Based on project development timeline for switching facilities, the project is expected to be in-service by the end of 2020.

7.1.3 Opportunities to Use Community-Based Solutions to Improve Resilience and Service Reliability

In addition to the transmission and distribution options discussed above, there may be opportunities to improve system resilience and service reliability at the community level using distributed energy resources and emerging technologies, such as residential solar-storage technology, micro-grids and on-site generation. Many of the community-based solutions are still in the early stages of development. The Working Group needs to better understand the cost and feasibility of these options. Depending on the interest from First Nation communities, municipalities and the LAC, the Working Group can facilitate discussions on the cost-benefit of opportunities to improve system resilience and the service reliability through community-based solutions. A good opportunity for these discussions may be through community energy planning activities.

7.2 Provide Adequate Supply to Support Growth

To ensure that the regional electricity system has adequate supply to support growth, the Working Group examined options to address the near-term needs at Parry Sound TS and Waubaushene TS and the longer-term supply capacity needs on the Muskoka-Orillia 230 kV sub-system.

The following section discusses these options in more detail.

7.2.1 Options to Provide Additional Transformer Station Capacity at Parry Sound TS and Waubaushene TS

Distribution Option

To free up supply capacity at Parry Sound TS and Waubaushene TS, some customers in the Parry Sound and Waubaushene areas can be resupplied from neighbouring transformer stations using existing and/or new 44 kV sub-transmission facilities.

To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS can be resupplied from Orillia TS using the existing 44 kV sub-transmission infrastructure by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required. This option would address the needs at Waubaushene TS over the planning period at minimal cost and would maximize the use of existing facilities. Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in Waubaushene from Midhurst TS could have an impact on the timing and need for a new TS in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil areas.

Similarly, to manage the near-term growth in the area, about 6 MW at the Parry Sound TS can be resupplied from Muskoka TS. There is sufficient capacity at Muskoka TS to supply these customers over the planning period. To resupply these customers, Hydro One will need to seek approval to construct a new 44 kV sub-transmission line (estimated cost of about $7 million). The siting and routing of these facilities will be determined as part of the project development process. Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020. These reinforcements would substantially address the near-term supply needs at Parry Sound TS and would also improve service reliability for the Townships of Muskoka Lakes and Seguin.

In the near term, the Working Group recommends resupplying some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations. This option will fully address the supply needs at Waubaushene TS over the planning period and will help manage near-term demand at Parry Sound TS at a minimal cost. Even after implementing these near-term measures, about 16 MW of additional supply will still be required to address the supply needs at Parry Sound TS over the planning period. As such, other options will need to be considered to address the supply needs at Parry Sound TS over the planning period.

Transmission Option

Transformers at the existing Parry Sound TS and Waubaushene TS can be upgraded to enable more power to be delivered to the Parry Sound and Waubaushene areas. This option costs about $25 to $30 million for each transformer station upgrade.

Transmission-Connected Generation Facilities

Since the need is at the transformer station level, transmission-connected generation facilities would not address the need. The Working Group therefore did not consider it.

Community-Based Solution: Local Demand Management and Distributed Energy Resources

With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted conservation and local demand management, distribution-connected generation and/or other distributed energy resources to defer the transformer upgrade at Parry Sound TS and Waubaushene TS. In order to defer the transformer upgrades, LDCs would need to reduce the electricity demand by about 1 MW annually at each of these transformer stations. Based on economic analysis, the LDCs can save about $2 million for every year of deferred capital. More details related to the capital deferral analysis can be found in Appendix D.

Through discussions with the LDCs and communities, the Working Group has identified a number of potential community-based solutions to address supply needs in the Parry Sound and Waubaushene areas. For example:

- **Heating efficiency:** As discussed in Section 5.1, the electricity demand peak in this sub-region is driven by electric space and water heating. There may be opportunities to reduce the peak demand by improving heating efficiency in the area.

  While a large portion of the communities in this sub-region rely on electric heating, some customers also rely on other fuel types, such as wood, to meet their heating requirements. In some cases, communities may have some access to natural gas infrastructure. Through initiatives, such as home energy audits, retrofit programs and community energy planning activities, the Working Group can work with communities to better understand the heating requirements and energy baseline (e.g., heating fuel, housing insulation) and identify opportunities to improve heating efficiencies in the Parry Sound/Muskoka Sub-region.

- **Local hydroelectric potential:** Based on information provided by the Ontario Waterpower Association ("OWA"), there is about 38 MW of hydroelectric potential in the Parry Sound District. As discussed in Section 4.2.1, many of the hydroelectric resources are run-of-the-river facilities with limited storage capability. As such, only a portion of their installed capacity can be relied upon at the time of local peak. Furthermore, much of these potential hydroelectric resources are located far from existing transmission and distribution infrastructure. To access this potential, additional transmission and distribution infrastructure may be required. More details related to these hydroelectric potential can be found in Appendix F.

- **Pilots and emerging technologies:** Many LDCs are engaging in pilots and studies to better understand the costs and feasibility of community based solutions and **e**merging technologies, such as residential solar-storage technology, microgrids, and thermal energy storage. These emerging technologies can potentially help reduce a community's reliance on the provincial grid during the time of local peak.

At this time, the Working Group has limited information on the cost and feasibility of distributed energy resources and local demand management. More work is needed to determine whether it is cost effective and feasible to rely on these solutions to address the local need. To better understand the cost and feasibility of implementing distributed energy solutions and demand management in the Parry Sound/Muskoka Sub-region, the Working Group recommends initiating a local achievable potential ("LAP") study for the Parry Sound/Muskoka Sub-region in early 2017. The study will examine the cost and feasibility of a range of distributed energy resources and local demand management options including incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. The study may also examine options to manage new demand from increased electrification that may result from Ontario's CCAP. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the LAP study.

As well, the Working Group will work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency opportunities in First Nation communities and municipalities.

End-of-Life Replacement Considerations

As discussed in Section 6.3.1, transformers at Parry Sound TS and Waubaushene TS could be reaching their end-of-life in the early 2030s. Depending on the electricity demand growth, it may be cost effective to advance the end-of-life replacement of these aging assets with upgraded/upsized facilities.

To determine if there is an opportunity to align the end-of-life facility replacement with solutions to address supply need at Parry Sound TS and Waubaushene TS, the Working Group will actively monitor and assess the conditions of these transformers and electricity demand growth. The Working Group will revisit this need in the next iteration of the plan.

7.2.2 Options to Provide Additional Supply Capacity on Muskoka-Orillia 230 kV sub-system over the Longer Term

As discussed in Section 6.2.2, about 20 MW of additional supply capacity will be required on the Muskoka-Orillia 230 kV sub-system in the early 2030s. Given the uncertainty with the demand growth and the fact that the need does not arise until late in the planning period, early development work for major electricity infrastructure projects is not required at this time. However, it is important to continue to monitor demand closely to determine if and when an investment decision for the Muskoka-Orillia 230 kV sub-system is required. To lay the ground work for the next planning cycle, the Working Group has explored potential options to address the longer-term needs on Muskoka-Orillia 230 kV sub-system.

Distribution Option

To free up supply capacity on the Muskoka-Orillia 230 kV sub-system, one option is to supply some of customers on the Muskoka-Orillia 230 kV sub-system from the transformer stations on the Parry Sound 230 kV sub-system using existing and/or new 44 kV sub-transmission facilities. However, as discussed in Section 6.2.2 , electricity demand at Parry Sound TS and Waubaushene TS has already exceeded the TS capacity and would not have sufficient capacity to supply additional customers. This option was therefore ruled out by the Working Group.

Transmission Options

Installing switching facilities or upgrading sections of the transmission lines can enable more power to be delivered into the Muskoka-Orillia 230 kV sub-system. These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and utilities' rate filings. The lead time to develop these facilities is typically three to five years.

The costs of these transmission reinforcements range from $20 to $30 million depending on the reinforcements requirements. Cost responsibility for the transmission reinforcements would be determined as part of the regulatory application review process.

This option should be considered and revisited in the next iteration of the plan.

Transmission-Connected Generation Option

Siting transmission-connected generation facilities can be effective for addressing supply capacity on Muskoka-Orillia 230 kV sub-system. A 20 MW generation facility connected to Muskoka-Orillia 230 kV sub-system can address the potential supply capacity needs arising in the early 2030s.

There are a number of factors that need to be considered when siting localized generation, and any decisions would need to align with the recommendations found in the August 2013 report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[12] prepared for the Minister of Energy by the former OPA and the IESO.

As the requirements in the Parry Sound/Muskoka Sub-region are for additional capacity during times of peak demand, a large, transmission-connected generation solution would need to be capable of being dispatched when needed, and operate at an appropriate capacity factor. In some cases, additional transmission reinforcements may also be required.

The cost of a large, localized generation resource depends on the size, fuel type, technology and the degree to which it can contribute to the local and provincial system capacity or energy needs. The fuel availability will also need to be taken into consideration. The lead time for generation development is typically two to three years, but it could be longer depending on the size and technology type.

---

[12] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

This option should be considered and revisited in the next iteration of the plan.

Community-Based Solutions: Local Demand Management and Distributed Energy Resources

With the modest electricity demand growth in this sub-region, there is an opportunity to use targeted local demand management, distribution-connected generation and/or other distributed energy resources to manage demand on the Muskoka-Orillia 230 kV sub-system and to defer major capital investments and infrastructure development over the longer term. As discussed in Section 7.2.1, the Working Group will initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local demand management options to defer major capital investments (e.g., transmission reinforcements). In conjunction with the study, the Working Group will continue to work closely with communities to coordinate community-energy planning activities and to identify opportunities for targeted CDM opportunities in First Nation communities and municipalities.

This option should be considered and revisited in the next iteration of the plan.

8. Recommended Actions

The recommended actions to minimize the frequency and duration of power outages and to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region over the planning period are outlined in Tables 8-1 and 8-2, along with the proposed timing and the parties that will lead the implementation.

The Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the sub-region and to track progress toward these deliverables and this information will be shared and discussed with the LAC.

Table 8-1: Recommended Actions to Minimize Frequency and Duration of Power Outages

	Recommendations	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Inform communities and LAC members of the 44 kV sub-transmission service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region**	Provide an update to communities and LAC members on the 44 kV sub-transmission service reliability performance improvements including any proposed capital plans The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.	Hydro One Distribution	End of year 2017
2	**Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**	Discuss findings and decision with the Working Group through the regional planning process Share the results with LAC members and affected communities	Hydro One Distribution, Lakeland Power and Veridian Connections	To be completed by Q4 2017

3	**Install two 230 kV motorized switches at Orillia TS to restore power to customers in timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system**	Prepare a letter to Hydro One Transmission to initiate project development work	IESO	Early 2017
		Design, develop and construct two 230 kV motorized switches	Hydro One Transmission	In-service by end of 2020
4	**Explore opportunities to improve resilience and service reliability at the community level**	Facilitate discussions with First Nation communities, municipalities and LAC members on the cost-benefit and opportunities to improve system resilience and service reliability through community energy planning	IESO	On-going

Table 8-2: Recommended Actions to Provide Adequate Supply to Support Growth

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**	Seek approval to construct a new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS	Hydro One Distribution	In-service by 2020
		Transfer up to 4 MW from Waubaushene TS to Orillia TS Transfer up to 6 MW from Parry Sound TS to Muskoka TS	Hydro One Distribution	Prior to 2020
		Transfer up to 7 MW from Waubaushene TS to Midhurst TS (if required)	Hydro One Distribution	Early 2020s upon completion of Barrie Area

				Transmission Reinforcement
		Coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage demand growth in the Waubaushene and Barrie/Innisfil areas	IESO	On-going
2	**Determine the cost and feasibility of using distributed energy resources and local CDM options to defer major capital investments in the Parry Sound/Muskoka Sub-region**	Initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments (e.g., transmission reinforcements)	IESO to assist and provide funding LDCs to carry out the study	Initiate study in early 2017
		Work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and demand management opportunities in First Nation communities and municipalities.	IESO	On-going
3	**Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**	Review electricity demand growth at Parry Sound TS and Waubaushene TS with LAC members	IESO	Annually
		Monitor and provide updated information on the condition of aging equipment at Waubaushene TS and Parry Sound TS to the LAC and the Working Group	Hydro One Transmission	Annually

		Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities.	IESO	Annually
4	**Monitor electricity demand growth closely to determine if and when an investment decision on the Muskoka-Orillia 230 kV sub-system is required**	Review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with LAC members	IESO	Annually

9. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the Parry Sound/Muskoka IRRP.

A phased community engagement approach was undertaken for the Parry Sound/Muskoka IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Parry Sound/Muskoka Community Engagement Process

Creating Transparency:

Creation of Parry Sound/Muskoka IRRP Information Resources

- Dedicated Parry Sound/Muskoka IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page created on Hydro One website
- Self-subscription service established for the South Georgian Bay/Muskoka planning region for subscribers to receive regional planning updates
- Status: complete

Engaging Early and Often:

Municipal and Indigenous Outreach

- Early engagement on regional planning and the South Georgian Bay/Muskoka Scoping Assessment Report (September 2015)
- Group meetings held with municipalities from across the planning region held in Huntsville and Parry Sound (September 2015)
- Meetings held with First Nation communities in Rama (September 2015)
- Status: initial outreach complete; dialogue continues

Bringing Communities to the Table:

Broader Community Outreach

- Parry Sound/Muskoka LAC formed in spring 2016; dedicated Parry Sound/Muskoka engagement web page added to IESO website
- Two LAC meetings held in June and September 2016 to discuss and obtain feedback on the development of the IRRP and draft recommendations
- LAC meetings are open to the public; materials are posted to the engagement webpage
- Status: begun in spring 2016; on-going

9.1 Creating Transparency

To start the dialogue on the Parry Sound/Muskoka IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the Parry Sound/Muskoka Sub-region, the IRRP terms of reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader South Georgian Bay/Muskoka planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the Parry Sound/Muskoka IRRP were initiated in September 2015 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across the Parry Sound/Muskoka Sub-region. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the South Georgian Bay/Muskoka Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation community members, and local industrial customers.

9.2.1 South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

The draft South Georgian Bay/Muskoka Region Scoping Report was posted to the IESO website in May 2015 for comment, and a final version was posted on June, 22, 2015. The report was led by the IESO, and developed in collaboration with regional participants, including Hydro One Networks, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, and Veridian Connections.

9.2.2 First Nation Community Meetings

On September 24, 2015 the IESO met with Chief Denise Restoule and Councillor Roger Restoule of Dokis First Nation, Chief Barron King of Moose Deer Point First Nation, Chief Warren Tabobondung of Wasauksing First Nation and community representatives. The feedback received focused on the concern that any necessary future infrastructure be planned so that environmental disturbance is minimized and traditional land and space considerations for each community be respected during the planning process. Community members also expressed the preference to have meetings with communities and municipalities at the same time to ensure that everyone is engaged in the same dialogue. Feedback was also shared that communities would like distributed generation proponents to have the same strong relationship with First Nation communities as they do with municipalities to provide communities with a firsthand opportunity to present and protect their needs.

The IESO remains open to additional meetings to support further engagement of the IRRP.

9.2.3 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In September 2015, the Working Group held municipal meetings in Huntsville and Parry Sound to discuss findings for the South Georgian Bay/Muskoka Region and next steps in the process, including identifying potential options to strengthen reliability in the area, increase supply capacity and replaced aging electricity infrastructure nearing end-of-life. Attendees provided insight on population forecasting, challenges with reliability in the area, and the importance of public and community engagement as the planning process develops. It was also indicated that there was a preference for a LAC for each of the two sub-regions instead of one committee for the larger South Georgian Bay/Muskoka Region.

9.3 Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the Parry Sound/Muskoka Sub-region in spring 2016. The role of the LAC is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. There is currently one general LAC in the planning area, which includes First Nation and Métis representation. The possibility of also forming a First Nation LAC, comprised of representatives from the First Nation communities in the planning area remains, should First Nation communities request an additional forum for community discussions. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's Parry Sound/Muskoka engagement webpage.[13]

Development of the Parry Sound/Muskoka LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across the planning area; digital (website) advertising in communities throughout the planning area; emails sent to municipal representatives across the region; letters to the Chiefs of the First Nation communities in the area inviting them to appoint a representative to the LAC, and an e-blast sent to the IESO's South Georgian Bay/Muskoka subscribers list.

On June 20, 2016, the Working Group held the inaugural LAC meeting in the Town of Gravenhurst. The focus of the meeting was to introduce the regional planning process to the newly formed LAC, provide an overview of the electricity infrastructure supplying the area, and touch upon key electricity needs and issues in the Parry Sound/ Muskoka Sub-region to be discussed in greater detail at subsequent LAC meetings.

The second LAC meeting was held on September 26, 2016 in the Town of Dwight. LAC members were presented with the draft IRRP recommendations, and had the opportunity to provide their feedback following the meeting to help inform the final report. Materials from both meetings can be accessed online on the IESO's website.[14]

Copies of the meeting summaries from the Parry Sound/Muskoka LAC meetings can be found in Appendix G.

At the September 2016 meeting, the members of the Parry Sound/Muskoka LAC expressed their interest in continuing to meet on a regular basis following the posting of the IRRP. As a result, the LAC will continue to meet until the start of the next planning cycle in 2018. Information about LAC meetings will continue to be posted on the IESO Parry Sound/Muskoka Sub-region engagement webpage and email notifications of meetings will continue to be sent to the broader South Georgian Bay/Muskoka email subscriber list.

---

[13] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

[14] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

10. Conclusion

This report documents the regional planning process that has been carried out for the Parry Sound/Muskoka Sub-region and fulfills the OEB's regional planning requirement for the sub-region. The IRRP identifies electricity needs in this sub-region over the 20-year period from 2015 to 2034 and recommends a set of actions to minimize the frequency and duration of power outages and to ensure that the regional electricity system has adequate supply to support growth.

The Parry Sound/Muskoka Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the sub-region, and will produce annual updates that will be posted on the IESO website[15]. To support development of the plan, a number of actions have been identified to develop alternatives, engage with communities, and monitor growth in the area. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the Parry Sound/Muskoka Sub-region. The plan will be revisited according to the OEB-mandated 5-year schedule.

---

[15] IESO website (http://www.iemo.com/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/default.aspx)

BARRIE / INNISFIL SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

Integrated Regional Resource Plan

Barrie/Innisfil Sub-region

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Barrie/Innisfil Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- PowerStream Inc.
- InnPower Corporation
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Barrie/Innisfil Sub-region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Barrie/Innisfil Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions, subject to obtaining all necessary regulatory and other approvals.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviations	Descriptions
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
CT	Current Transformer
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IAP	Industrial Accelerator Program
Innisfil Hydro	Innisfil Hydro Distribution Inc.
InnPower	InnPower Corporation
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LAP	Local Achievable Potential
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MS	Municipal Substation
MVA	Mega Volt Amp
MW	Megawatt
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PowerStream	PowerStream Inc.

Abbreviations	Descriptions
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
TOU	Time-of-Use
TPS	Traction Power Station
TS	Transformer Station
TWh	Terawatt-Hours
Working Group	Technical Working Group for Barrie/Innisfil Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Barrie/Innisfil Sub-region over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the technical Working Group composed of the IESO, PowerStream Inc. ("PowerStream"), InnPower Corporation ("InnPower"), Hydro One Distribution and Hydro One Transmission.[1]

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB's regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for 21 electricity planning regions at least once every five years. The Barrie/Innisfil Sub-region is within the South Georgian Bay/Muskoka planning region, one of the OEB's 21 identified areas (Figure 1-1).

Figure 1-1: Map of the South Georgian Bay/Muskoka Region

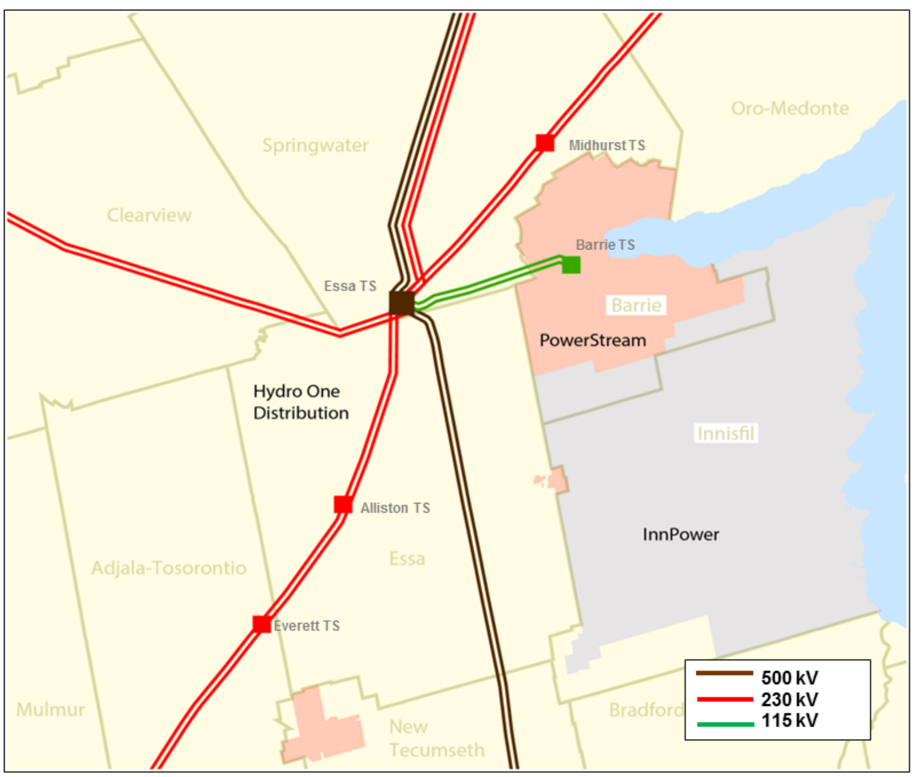
[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc. ("Hydro One"), respectively.

The Barrie/Innisfil Sub-region roughly encompasses the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

The study is focused on addressing the forecast load growth in south Barrie and the Town of Innisfil; however, it considers other needs throughout the sub-region. The study area is shown in Figure 1-2, along with the service area of each local distribution company ("LDC") in the sub-region.

Figure 1-2: Map of Barrie/Innisfil Sub-region



This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies immediate investments that are required to meet near- and medium-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for long-term options and does not recommend specific investments or projects at this time. Instead, the long-term plan identifies near-term actions to consider alternatives, engage with the community, and gather information to lay the groundwork for determining options for future analysis. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results can inform decisions should any be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for the Barrie/Innisfil Sub-region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Barrie/Innisfil Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions, are described in Section 5;
- Electricity needs in the Barrie/Innisfil Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Sections 7 and 8;
- A summary of engagement to date and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Barrie/Innisfil Sub-region IRRP provides recommendations to address the sub-region's forecast electricity needs over the next 20 years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies forecast electricity needs in the sub-region over the near term (up to five years, or 2015 through 2019), medium term (six to 10 years, or 2020 through 2024) and longer term (11-20 years, or 2025 through 2034). These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. The IRRP was developed based on consideration of planning criteria, including reliability, cost, feasibility and flexibility; and, in the near term, it seeks to maximize the use of existing electricity system assets.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions. This IRRP also identifies possible long-term electricity needs. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to recommend specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time.

The Barrie/Innisfil IRRP includes a near-term project to rebuild Barrie Transformer Station ("TS"). Given the timing of the need, the Working Group issued a hand-off letter in December 2015 to request that Hydro One begin development work on this project.[2] The need and rationale for this near-term project are outlined in Section 6.2.1. The full near-, medium-, and long-term plans are summarized below.

2.1 Near-Term and Medium-Term Plan (2015-2024)

The plan to meet the near- and medium-term needs of electricity customers in the Barrie/Innisfil Sub-region was developed to maximize the use of the existing electricity system in consideration of planning criteria such as reliability, cost, and feasibility, as outlined earlier in

[2] http://www.ieso.ca/Documents/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil_IESO-letter-to-HydroOne-20151207.pdf

Section 2. The near-term plan was also developed to be consistent with the long-term development of the sub-region's electricity system.

To address the near-term end-of-life and capacity needs at Barrie TS, the aforementioned new transmission project to rebuild Barrie TS is underway. The near- and medium-term plan also includes a load transfer to be completed by PowerStream to relieve Barrie TS, and a feeder relocation and expansion project, to be carried out by InnPower and Hydro One Distribution, to increase InnPower's feeder supply capacity from Barrie TS. The elements of the plan are outlined in further detail below.

Recommended Actions

1. Rebuild and Uprate Barrie TS and E3/4B to 230 kV

To mitigate challenges posed by both Barrie TS and related 115 ("kilovolt") kV supply infrastructure reaching end-of-life, and to address the near-term capacity needs at Barrie TS, Hydro One is developing the "Barrie Area Transmission Reinforcement" project. The project will rebuild the existing Barrie TS and uprate its existing supply from 115 kV to 230 kV, increasing the supply capacity to the area. A Class Environmental Assessment ("EA") process is currently underway. The existing Barrie TS site is well situated for supplying the near- and medium-term forecast load growth in the south Barrie and Innisfil areas. The targeted in-service date for the project is the end of 2020.

2. PowerStream Load Transfer – From Barrie TS to Midhurst TS

PowerStream is planning to transfer up to 27 ("megawatt") MW of load from Barrie TS to Midhurst TS by 2020, assuming full data centre load growth. This will increase the incremental capacity available at Barrie TS and provide additional transfer points between Barrie TS and Midhurst TS. This will address near-term capacity needs and provide additional reliability benefits during emergency situations.

3. Relocate and Expand InnPower Feeder Supply from Barrie TS

Currently, Hydro One Distribution is allocated one feeder from the existing Barrie TS, the 13M3 feeder, which is used solely to supply their embedded LDC InnPower. The capacity of this feeder is forecast to be exceeded in 2020. The rebuilt Barrie TS will include one additional feeder position, which can be used to address this need. Additionally, the existing InnPower supply uses an idle Hydro One Transmission right-of-way ("ROW"). The use of this ROW for sub-transmission purposes limits future long-term options for new transmission facilities in the south Barrie and Innisfil area. It is recommended that Hydro One Distribution and InnPower develop a plan to build new 44 kV feeders to support InnPower's forecast growth and enable the existing 13M3 feeder to be relocated out of the Hydro One Transmission corridor. The proposed in-service date for the new feeders is the end of 2020.

2.2 Longer-Term Plan (2025-2034)

In the long-term, the Barrie/Innisfil Sub-region's electricity system is expected to reach its capacity. This is based on the IRRP planning forecast presented in Section 5.6, which is consistent with municipal growth plans and the province's *Places to Grow Act, 2005*. Beginning in the mid to late 2020s, there is a forecast need for new transformer station capacity, particularly in the south Barrie and Innisfil areas. The capacity of the upgraded Barrie TS and the existing Everett TS are forecast to be exceeded in 2026 and 2027, respectively. Transformer station capacity in the Barrie area is forecast to be exceeded in 2031, and the sub-region's transformer capacity is forecast to be exceeded by the end of the study period in 2034. Additionally, in 2034, there is a need for supply capacity for the broader South Georgian Bay/Muskoka Region based on the ratings of the 230/500 kV autotransformers at Essa TS. Any plans to address the station capacity needs must be coordinated with a plan to address this long-term transmission system needs at Essa TS, as they are interrelated.

A number of alternatives are possible to meet the sub-region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP.

This IRRP sets out near-term actions required to ensure that options remain available to address future needs, if and when they arise.

Recommended Actions

1. Implement Conservation and Distributed Generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key near-term action of the Barrie/Innisfil Sub-region's long-term plan. In developing the demand forecast, peak demand impacts associated with meeting provincial targets were assumed before identifying the residual needs; this is consistent with the province's Conservation First policy.[3] Meeting provincial conservation targets amounts to approximately 37 MW, or 19%, of the forecast demand growth, during the first 10 years, and a total of 82 MW, or 23% of the total forecast demand growth, by the end of the study period.

To ensure these savings materialize, it is recommended that the LDCs' conservation efforts be focused as much as possible on measures that will contribute to meeting the Conservation First energy targets while also maximizing peak demand reductions. The monitoring of conservation success will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the sub-region and assessing potential for additional conservation.

Provincial programs that encourage the development of DG can also contribute to reducing peak demand in the sub-region; these will, in part, depend on local interest and opportunities for development. The LDCs and the IESO will continue their activities to support these initiatives and monitor their impacts.

2. Barrie TS Local Achievable Potential Study

Due to the long-term capacity need forecast for the south Barrie and Innisfil areas, PowerStream and InnPower, with support from the IESO's conservation fund, will be undertaking a Local Achievable Potential ("LAP") study for the Barrie TS service area. This study aims to determine demand savings potential through conservation and demand management ("CDM" or "conservation") for the Barrie TS area, above and beyond what is attributed to the LTEP targets already accounted for in the planning demand forecast. The study will also help determine options for acquiring this potential (e.g., incentives and adders to existing CDM programs, new programs, behind-the-meter generation, energy storage, etc.). The study will provide a better understanding of the costs and feasibility of conservation and demand management measures to address capacity needs in the area to better inform options for the next planning cycle. The study may also examine options to manage new demand from increased electrification that may result from Ontario's Climate Change Action Plan.

---

[3] Conservation First: A Renewed Vision for Energy Conservation in Ontario: http://www.energy.gov.on.ca/en/conservation-first/

3. Undertake Community Engagement

Broad community and public engagement, including discussions with local Indigenous communities, is essential to develop the long-term plan. It is recommended that engagement involve several phases addressing: public education/awareness of electricity issues, planning, technologies, and regulatory requirements; fostering an understanding of community growth and its relationship to electricity needs; understanding the pros and cons of various alternatives to meeting long-term needs; and obtaining input on community preferences for various approaches to meeting longer-term needs.

To obtain input and advice on the engagement plans for the Barrie/Innisfil Sub-region, the Working Group will establish a Local Advisory Committee ("LAC") consisting of community representatives and stakeholders.

4. Increase the Limited Time Rating of Everett TS

The existing ratios of the current transformers[4] ("CT") at Everett TS are causing a limitation beyond the limited time rating[5] ("LTR") of the station transformers. Since the minimum station load has increased sufficiently, Hydro One can update the CT ratios, allowing the full LTR of the existing transformers to be utilized. Everett TS is forecast to exceed its existing de-rated LTR in 2027; the Working Group will monitor the station load and request that Hydro One take action to change the CT ratios if necessary before the next regional planning cycle.

5. Explore Conversion of the 13M3 115 kV Corridor to 230 kV

Metrolinx has applied for connection to the transmission system in the Barrie area. They will connect to the new 230 kV transmission lines created as part of the Barrie Area Transmission Reinforcement project. It is recommended that Hydro One works to ensure the development work for the Metrolinx connection project will allow for future expansion of the transmission system south toward Innisfil. The Working Group will monitor the need for additional development work for the corridor between planning cycles.

---

[4] Current transformers are instrument transformers used for measurements for metering/loading data or for generating signals for protective devices. Since the current on the actual system is usually too high to be either economically or practically measured or to supply a signal to a protective device, the current transformer lowers the current to an acceptable level. The ratio between these two current values is the "CT ratio".

[5] The limited time rating is a property of an individual transformer, representing its ability to withstand the thermal stress of short duration use (10 days) at the given capacity, above its standard rating, without experiencing any degradation in asset condition as a result.

6. Develop Community-Based Solutions

There is the potential for emerging technologies and innovative solutions to address the long-term needs in the Barrie/Innisfil Sub-region. These could include combinations of conservation, district heating, local generation, storage, off-grid solutions, and other emerging technologies. However, before such technologies can be relied upon to address regional capacity needs, it is necessary to identify the opportunities available in the Barrie area, test the performance of these technologies, and demonstrate how these technologies can be "bundled" to provide firm capacity resources at the local level. In addition, the cost responsibility and payment mechanisms for these options still need to be assessed.

PowerStream has implemented a pilot project in their southern service territory to study the benefits and economics of aggregated customer-side generation and storage. The results of this study can be used to inform future discussion and the development of non-wires solutions for the long-term needs in the sub-region for the next planning cycle.

7. Monitor Demand Growth, Conservation Achievement and Distributed Generation Uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial distributed generation projects, and actual demand growth in the Barrie/Innisfil Sub-region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on conservation and DG is also a useful input into the ongoing development of non-wires options as potential long-term solutions.

8. Initiate the Next Regional Planning Cycle Early, if Needed

Along with the indices outlined in point 7 above, the Working Group will monitor changes in growth targets, progress in servicing greenfield lands, transit electrification in the area, results of the LAP study for Barrie TS, and any significant changes in the area's forecast growth. If monitoring activities determine that area growth is on pace with the high forecast scenario, it may be necessary to initiate the next iteration of the regional planning process earlier than 2020 given the lead time for the long-term supply options.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[6] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence were to become the responsibility of the new IESO

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine what type of planning is required for each region. A Scoping Assessment explored whether a

---

[6] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two week public comment period prior to finalization.

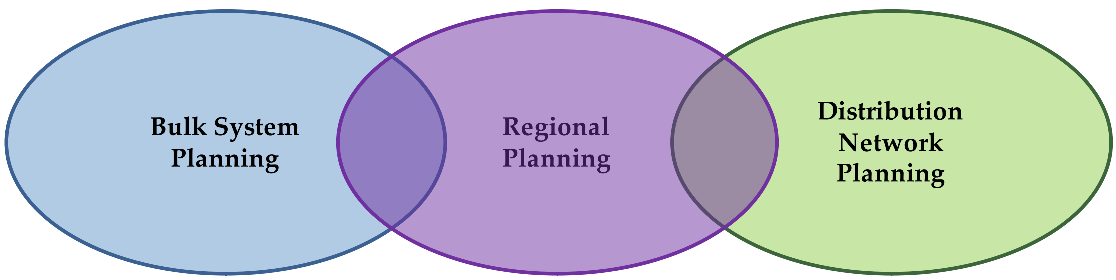
The final IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capabilities
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- and medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified DX facilities)
- Distribution system reliability (capacity and security)
- Distribution connected generation and CDM resources
- LDC demand forecasts
- Near- and medium-term focused

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

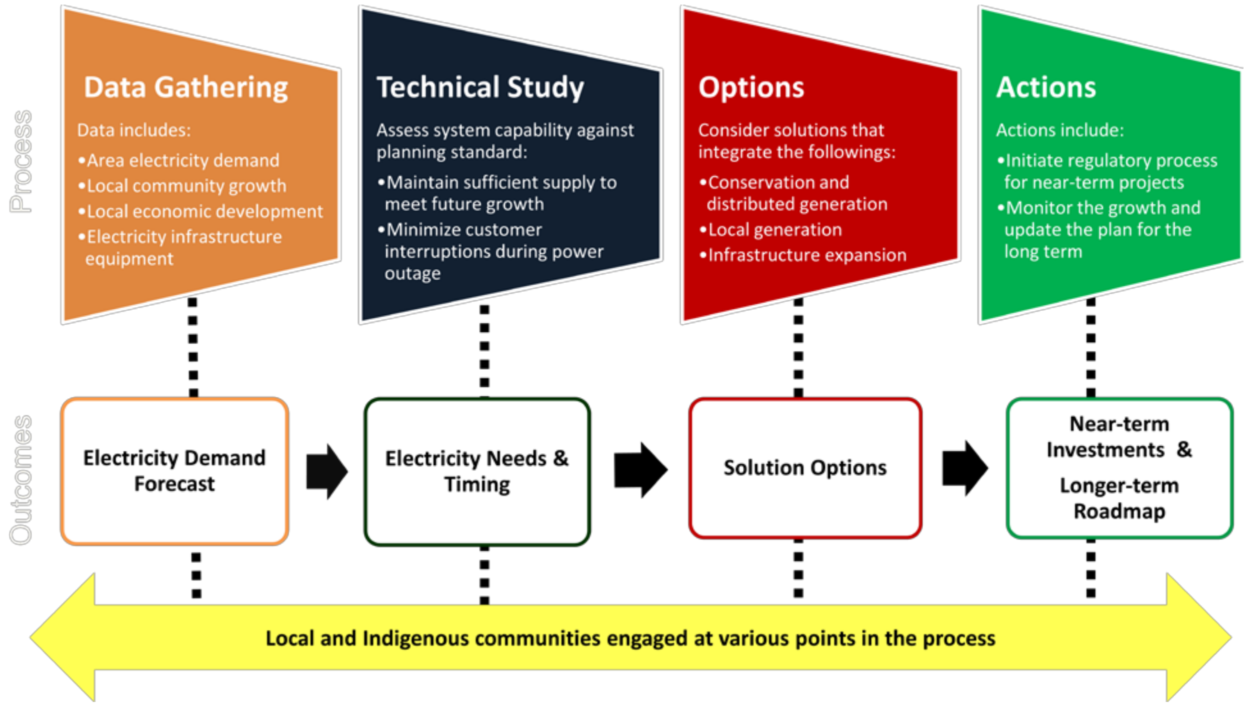
3.2 The IESO's Approach to Regional Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near and medium term—as compared to the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead-time to develop electricity infrastructure, near-term electricity needs require prompt action to implement the specified solutions. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead-time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and the Working Group carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and Indigenous communities who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2, below.

Figure 3-2: Steps in the IRRP Process



The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

3.3 Barrie/Innisfil Sub-region Working Group and IRRP Development

The process to develop the Barrie/Innisfil IRRP was initiated in 2015 with the release of the Needs Assessment report for the South Georgian Bay/Muskoka Region. This product was prepared by Hydro One Transmission with participation from the IESO, PowerSteam, Innisfil Hydro Distribution Inc. ("Innisfil Hydro"),[7] Orangeville Hydro Ltd., Veridian Connections Inc. and Hydro One Distribution. The Needs Screening process was carried out to identify needs

[7] Innisfil Hydro Distribution Inc. became InnPower Corporation on November 4, 2014. This was reflected the OEB's amendment to the licensee name on their electricity distribution licence on December 4, 2014 (EB-2014-0297).

that may require coordinated regional planning in the South Georgian Bay/Muskoka Region. The subsequent Scoping Assessment Report produced by the IESO recommended that the needs identified for the Barrie/Innisfil Sub-region should be further pursued through an IRRP owing to the potential for coordinated solutions and significant assets reaching end-of-life.

In 2015 the Working Group was formed to develop Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the sub-region, and recommend the near- and medium-term actions.

4. Background and Study Scope

Two planning studies have been conducted in the South Simcoe area – now referred to as the Barrie/Innisfil Sub-region – in the last 12 years.

First, in November 2003, a joint utility planning study was initiated by six LDCs in Simcoe County, one large industrial customer, and Hydro One Transmission, to assess the supply and reliability needs of Simcoe County. The study recommended the implementation of two transmission projects to supply forecast growth in the Meaford/Collingwood and South Simcoe areas: the addition of Everett TS, which came into service in 2007 and the Southern Georgian Bay Transmission Reinforcement, which involved upgrading the 115 kV Essa-to-Stayner line to 230 kV and installing a 230/115 kV autotransformer at Stayner TS, which came into service in 2009.

Second, in 2010, Hydro One Transmission initiated a regional supply planning study of the South Simcoe area. Together with the OPA (now merged with the IESO), PowerStream, Innisfil Hydro, and Hydro One Distribution, Hydro One Transmission prepared a study report in 2011 that recommended the installation of low voltage capacitors at Midhurst TS and Orillia TS, completed in 2012, and recommended that Innisfil Hydro (now InnPower) make a formal request to Hydro One for additional transformation capacity.

Building on these past regional studies and taking into account updates to activities in the region and LDCs' load forecasts, this report presents an IRRP for the Barrie/Innisfil Sub-region for the 20-year period from 2015 to 2034. To set the context for this IRRP, the scope of the planning study and the sub-region's existing electricity system are described in Section 4.1.

4.1 Study Scope

This IRRP develops and recommends options to meet the supply needs of the Barrie/Innisfil Sub-region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, CDM, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, and generation uptake through the Feed-in Tariff ("FIT") and other province-wide programs.

This IRRP addresses regional needs in the Barrie/Innisfil Sub-region, including adequacy, security, and relevant end-of-life asset considerations.

The following transmission facilities were included in the scope of this study:

- 230/115 kV autotransformers at Essa TS
- Stations—Barrie TS, Midhurst TS, Alliston TS, and Everett TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa to Midhurst section)

The Barrie/Innisfil Sub-region is supplied from the two 500/230 kV autotransformers at Essa TS. These transformers form part of the bulk transmission system, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. Specifically, the autotransformers are impacted by bulk power system flows on the north-south transmission interface, driven by changing generation and load patterns in northern and southern Ontario. Accordingly, the Essa autotransformers were assessed through a separate bulk planning study by the IESO. However, results of the bulk study that have regional implication are discussed in this IRRP.

The Barrie/Innisfil Sub-region and its supply infrastructure are shown in Figure 4-1 and Figure 4-2.

Figure 4-1: Regional Transmission Facilities

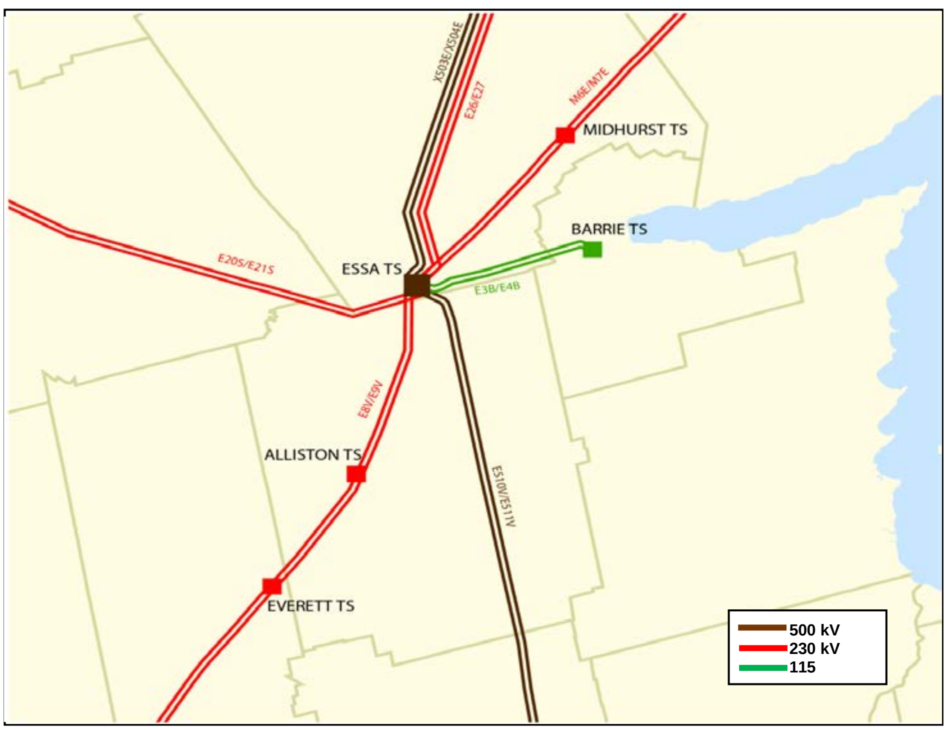
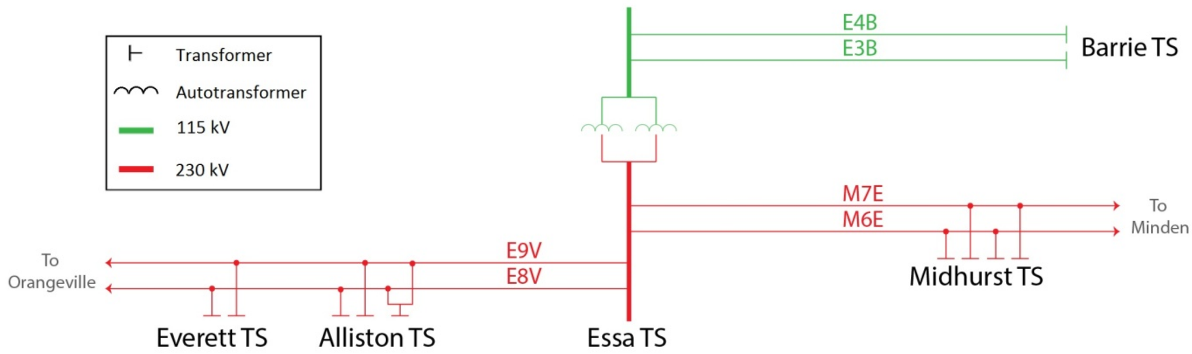


Figure 4-2: Barrie/Innisfil Sub-region Electrical Sub-systems



The Barrie/Innisfil IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the load meeting capability ("LMC") and reliability of the existing transmission system supplying the Barrie/Innisfil Sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC.
- Establishing feasible integrated alternatives to address needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using decision-making criteria that include: technical feasibility, cost, reliability performance, flexibility, environmental and social factors.
- Developing and communicating findings, conclusions and recommendations.

5. Demand Forecast

This section outlines the forecast of electricity demand within the Barrie/Innisfil Sub-region. It highlights the assumptions made for peak demand load forecasts, and the contribution of conservation and DG to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is referred to as “coincident peak demand”. Typically this represents the time when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station’s individual peak, regardless of whether each station’s peaks occur at a different time than the area’s overall peak.

Within the Barrie/Innisfil Sub-region, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the air conditioning loads of residential and commercial customers. The Working Group determined the co-incident and non-coincident area peaks for the sub-region are fairly equivalent since they correspond with this weather-related peak. Hence, the non-coincident peak for each station was used as the basis of the load forecast starting point.

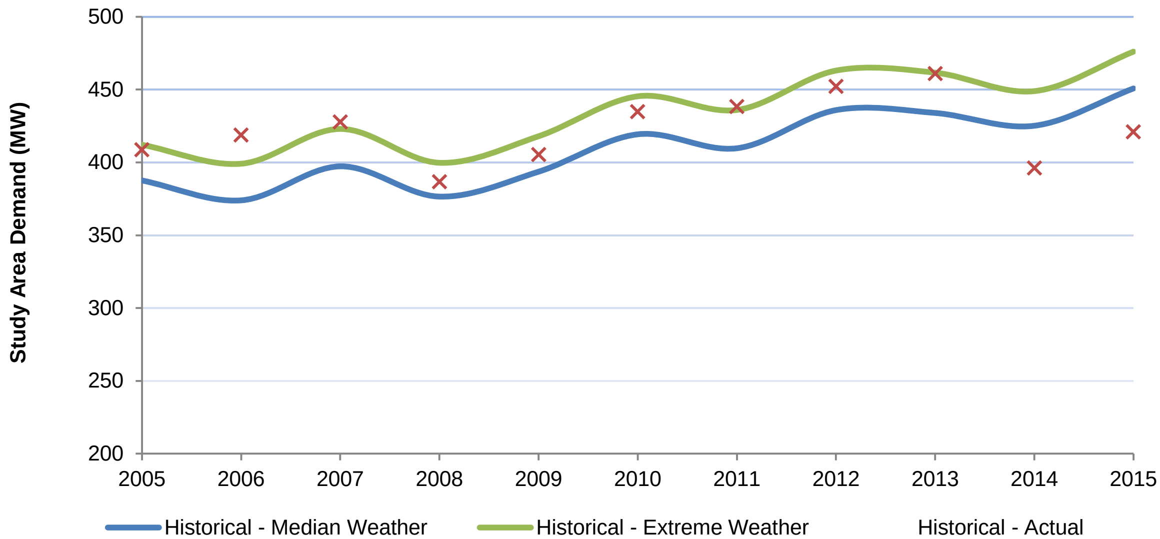
Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2015. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The coincident peak electrical demand for the Barrie/Innisfil Sub-region is shown in Figure 5-1. The historical data (in red) shows the coincident peak demand for the year.

The historical demand adjusted for extreme and median weather (in green and blue, respectively) shows the demand at the same hour, but adjusted to reflect the expected behaviour under the applicable weather conditions. Correction factors between historical, median and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

Figure 5-1: Historical Peak Demand in the Barrie/Innisfil Sub-region



The weather corrected peak shows that demand has been generally increasing since 2005. However, the data for the summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments (i.e., as required for the summers of 2014 and 2015).

5.2 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs at the regional level.

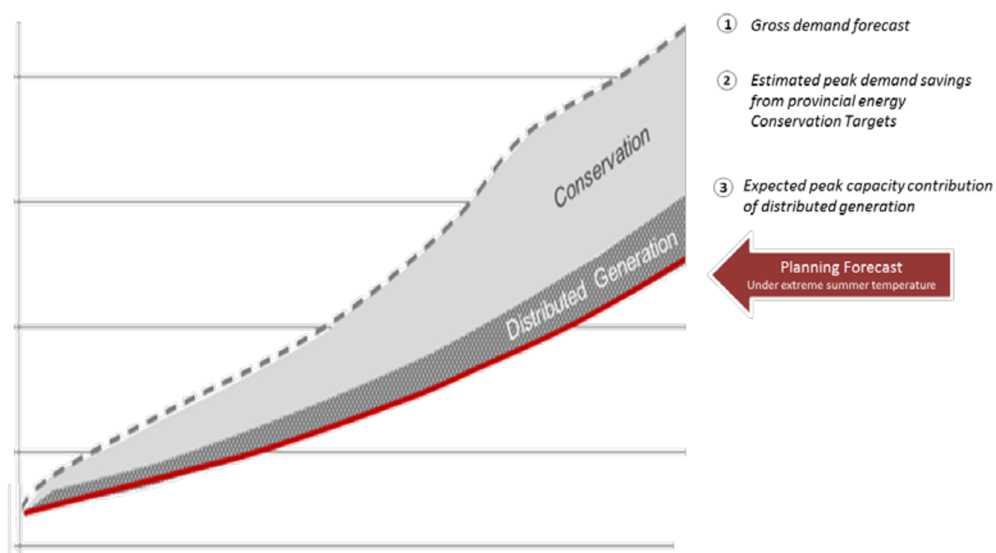
Regional electricity needs are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak demand requirements. Regional planning therefore typically focuses on the growth in regional-coincident peak demand.

The 20-year planning forecast is divided notionally into three timeframes. The near term (0-5 years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions as other methods (i.e., DG or CDM) are still being tested to determine if their lead-times will be suitable to meet near-term timelines. The medium term (5-10 years), however, provides more lead time to develop and incorporate DG and CDM options.

The long-term forecast covers the 10-20 year period and has the lowest degree of certainty. It is used for the identification of potential longer-term needs, and for the consideration and development of integrated solutions (including CDM, DG, and major transmission upgrades). To address the relative uncertainty of long-term needs, a high and a low forecast scenario were created. Early identification of potential long-term needs and potential solutions makes it possible to begin engagement with the local community and all levels of government long before the need is triggered. This provides the greatest opportunity to gain input on decision making, and to ensure local planning can account for new infrastructure.

The regional peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in each LDC's service territory. The LDC forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Growth Plan for the Greater Golden Horseshoe, 2006, as amended. These forecasts were then modified to produce a planning forecast (i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets, DG contracted through provincial programs such as FIT and microFIT, and to reflect extreme weather conditions). The planning forecast was then used to assess any growth-related electricity needs in the region.

Figure 5-2: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, it also assumes that the targets will be met and that the targets, which are energy-based, will produce corresponding local peak demand reductions. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the area LDCs and, as necessary, adapting the plan. Additional details related to the development of the demand forecast are provided in Appendix A.

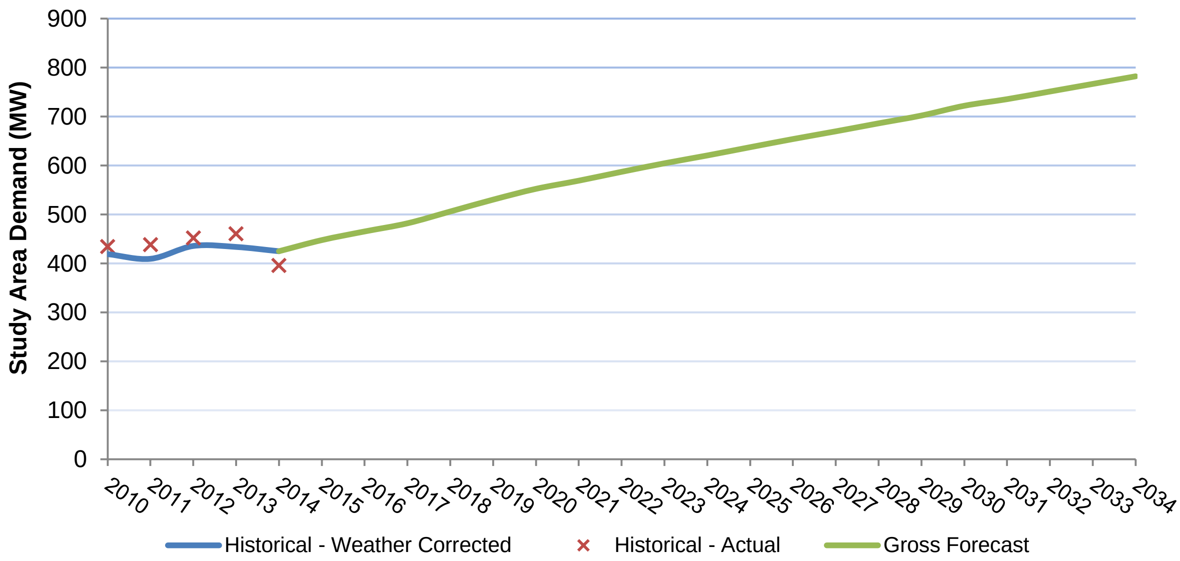
5.3 Gross Demand Forecast

Each participating LDC in the Barrie/Innisfil Sub-region prepared gross demand forecasts at the transformer station level, or at the bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development, but they do not account for the impact of new conservation measures such as codes and standards or demand response ("DR") programs. However, LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, which is termed "natural conservation".

LDCs have the best information on customer and regional growth expectations in the near and medium term since they have the most direct involvement with their customers. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. More details on the LDCs' load forecast assumptions can be found in Appendix A.

The graph below shows the gross demand forecast information provided by LDCs for the Barrie/Innisfil Sub-region, with historical data points provided for comparison. The gross forecast provided by the LDCs, shown in Figure 5-3, is for median weather conditions.

Figure 5-3: Barrie/Innisfil Sub-region Gross Forecast



Total annual growth averages 3% per year for the study area over the 20-year planning horizon. Growth is highest in the first 10 years at an average of 3.7% per year, before reducing to an average of 2.3% per year for the following 10 years. Although the forecast is shown for the entire study area, individual stations are forecast to experience different growth rates.

To address development uncertainty in the area, the LDCs also produced a forecast for both a high and a low growth scenario. While the needs assessment was conducted based on the reference load growth scenario, the high and low forecasts were used for evaluating the robustness of different medium- and long-term options. The regional gross growth rate ranges from 2.2% per year in the low scenario to 3.9% per year in the high.

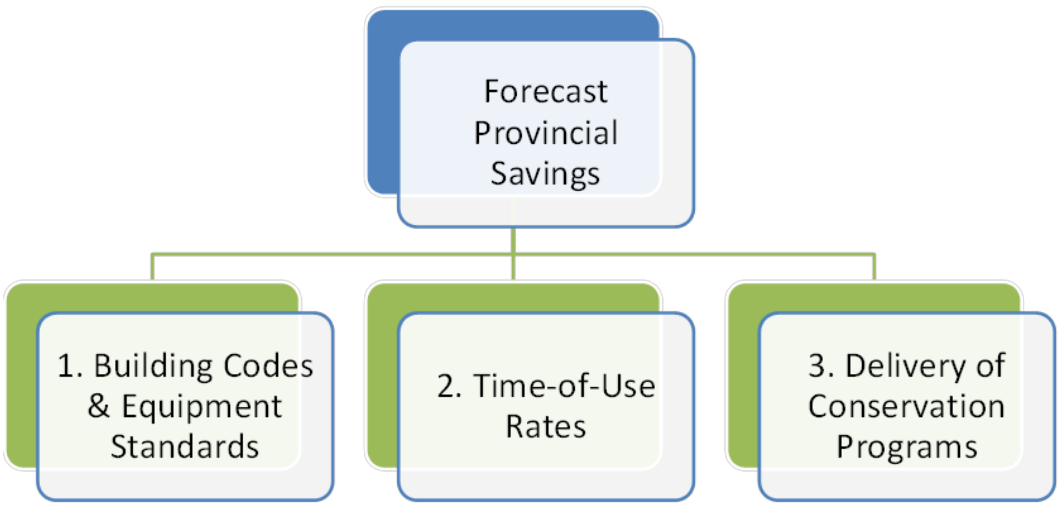
The forecasts were provided based on best available information and, as appropriate, will be updated going forward. The gross demand forecasts by station for the reference, high and low scenarios are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's growth, helping to keep demand within equipment capability. The conservation savings forecast for the Barrie/Innisfil Sub-region have been applied to the gross peak demand forecast for median weather, along with DG resources (described in Section 5.5), to determine the net peak demand for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. To estimate the impact of the conservation savings in the sub-region, in terms of impact to peak demand, the forecast provincial savings were divided into three main categories:

Figure 5-4: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate Structures*
3. *Savings due to the delivery of Conservation Programs*

For the Barrie/Innisfil Sub-region, the impacts of the estimated savings for each category were further broken down by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by these three customer sectors. This provides a better resolution for the forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Barrie/Innisfil Sub-region, LDCs were requested to provide both their gross demand forecast and a breakdown of electrical demand by sector for each TS. Once sectoral gross demand at each TS was estimated, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rates, and conservation programs. The estimate for each of the three savings groups was done separately due to their unique characteristics and the available data. The final estimated conservation peak demand reduction, 82 MW by 2034, was applied to the gross demand to create the planning forecast. Table 5-1 provides the conservation peak demand savings for a selection of the forecast years.

Table 5-1: Peak Demand MW Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032
Savings (MW)	5	12	19	28	37	48	60	73	80

Additional conservation forecast details are provided in Appendix A.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Barrie/Innisfil Sub-region is also forecast to offset peak demand requirements. The introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's FIT program, has increased the significance of distributed renewable generation in Ontario. This renewable generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

After applying the conservation savings to the demand forecast as described above, the forecast is further reduced by the expected peak contribution from contracted, but not yet in-service, DG in the sub-region. The effects of projects that were already in-service prior to the base year of the forecast were not included as they are already embedded in the actual demand, which is the starting point for the forecast. Potential future (but uncontracted) DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of June 2015, new DG projects are expected to offset an incremental 3.2 MW of peak demand within the Barrie/Innisfil Sub-region by 2018. Most distribution connected contracted generators included in the forecast are small-scale solar projects (< 500 kW); however, there are some larger FIT (< 10 MW) solar projects connecting at Midhurst TS. A capacity contribution of 22%, to the regional peak, has been assumed to account for the expected output of the local solar resources during summer peak conditions.

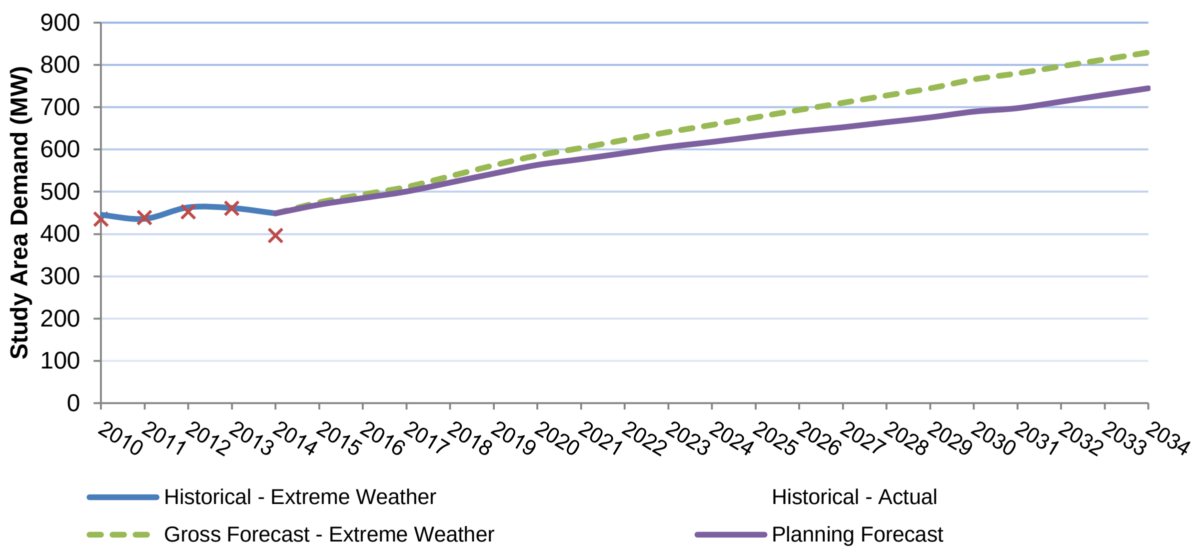
Additional details of the regional demand reductions from province-wide DG programs are provided in Appendix A.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced.

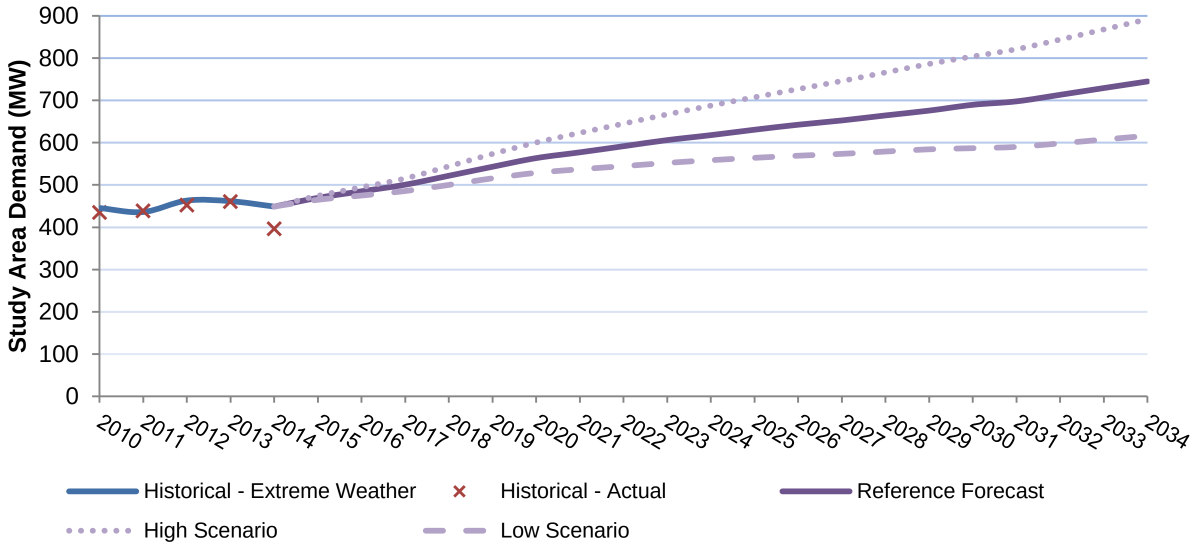
Figure 5-5 below illustrates the planning forecast, along with historic demand in the area. Note that the planning forecast has been adjusted for extreme weather conditions. For comparison in Figure 5-5 the gross forecast has also been adjusted for extreme weather conditions. Further details of the planning forecast scenarios are provided in Appendix A.

Figure 5-5: Barrie/Innisfil Sub-region Planning Forecast



The net forecast for the high, low and reference scenarios are shown in Figure 5-6. Further information on the high and low scenarios and each of the LDC's load forecast assumptions can be found in Appendix A.

Figure 5-6: Barrie/Innisfil Sub-region High and Low Demand Forecast Scenarios



6. Needs

Based on the planning forecasts, system capability, and application of provincial planning criteria, the Barrie/Innisfil Sub-region Working Group identified electricity needs in the near, medium, and long term. This section describes the identified needs for these three time horizons in the Barrie/Innisfil Sub-region.

6.1 Needs Assessment Methodology

ORTAC,[8] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements (see Appendix B for more details).

By applying these criteria, two broad categories of needs have been identified for the Barrie/Innisfil Sub-region IRRP:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by the station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer(s) under the assumption that the largest transformer is out of service.[9]
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission supply to the area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix B for more details). Supply capacity needs are identified when the peak demand for the area exceeds the LMC.

The needs assessment also identifies requirements related to equipment end-of-life and planned sustainment activities. Equipment reaching end-of-life and planned sustainment activities have

---

[8] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

[9] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low voltage bus, high voltage circuits, etc.) are undersized relative to the transformer rating. LTR is further defined on page 8.

a significant impact on the needs assessment and option development for the Barrie/Innisfil Sub-region.

6.2 Local Electricity Supply and Reliability Needs

The needs assessment for the Barrie/Innisfil IRRP focused on identifying needs for local transformer stations and related supply infrastructure. The impact of all three demand forecast scenarios (reference, high, and low – see Section 5.6) on the local transmission infrastructure was evaluated. Near-, medium-, and long-term capacity needs were identified for the south Barrie and Innisfil areas for the reference scenario, along with a long-term capacity need at Everett TS. End-of-life infrastructure needs were also identified in the area.

6.2.1 Near- and Medium-Term Needs

The near- and medium-term needs identified for the Barrie TS service area were considered together since the infrastructure impacted is common to all identified needs. The near- and medium-term needs are summarized in Table 6-1.

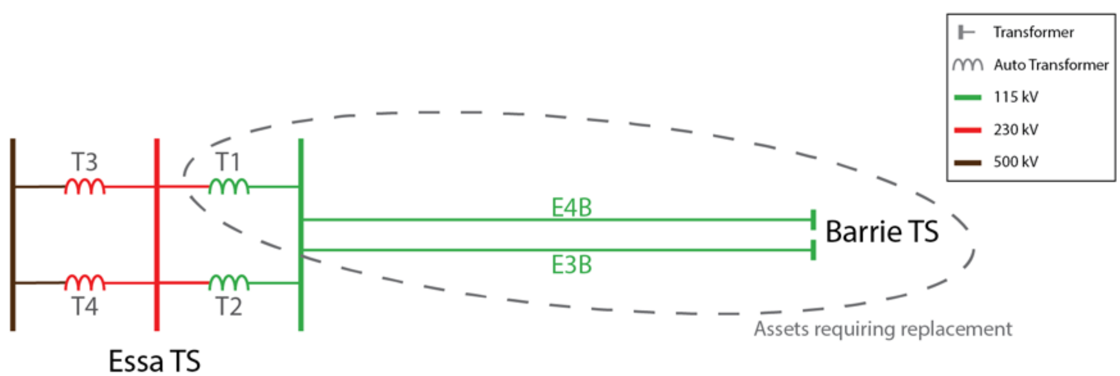
Table 6-1: Barrie/Innisfil Sub-region Near- and Medium-Term Electricity Needs

Need	Description	Timing
End-of-Life	Hydro One has identified Barrie TS and components of its 115 kV supply infrastructure to be nearing their end-of-life.	2020
Transformer Station Capacity	Net demand growth in the southern portion of the City of Barrie and in the Town of Innisfil is forecast to exacerbate the existing transformer station capacity need at Barrie TS. Barrie TS also lacks additional feeder positions to accommodate future growth in Innisfil.	Today
Supply Capacity	The net demand growth is forecast to exceed the LMC of the 115 kV supply to Barrie TS (E3/4B).	2019

Hydro One Transmission identified existing sustainment initiatives at Barrie TS driven by the 115/44 kV station transformers reaching end-of-life, along with the 44 kV switchgear, circuit breakers, disconnect switches and other station equipment.

Barrie TS was placed in-service in 1962. The 44 kV switchyard assets at Barrie TS have been identified by Hydro One as being in need of replacement in the near term. Barrie TS is currently supplied by the 230/115 kV autotransformers at Essa TS via the Essa 115 kV switchyard and 115 kV circuits E3/4B. These assets were built in the 1950s, with many of them already exceeding their expected life and in need of replacement in the near and medium term. Figure 6-1 depicts the significant assets that Hydro One has identified as requiring replacement in the near term.

Figure 6-1: Single Line Diagram Detailing Existing Supply of Barrie TS and Assets Requiring Replacement



The timing and replacement options for Barrie TS were discussed among the Working Group members. It was agreed that based on the existing and forecast station demand, that Barrie TS and E3/4B should be rebuilt to 230 kV, with 75/125 Mega Volt Amp ("MVA") 44/230 kV transformers. This means that the end-of-life replacement of Barrie TS will add approximately 50 MW of incremental supply capacity in the south Barrie and Innisfil area. Details of the alternatives considered by the Working Group can be found in Appendix B.

Barrie TS is forecast to experience the highest average yearly growth rate of any TS in the study area over the 20 year planning period, for all load growth scenarios. This is driven by the large amount of growth set out in the local municipal plans and in the province's Growth Plan for the Greater Golden Horseshoe, 2006, as amended, which identify the City of Barrie as an urban growth centre.

Effective January 1, 2010, the City of Barrie annexed approximately 5,700 acres of land from the Town of Innisfil to accommodate its forecast growth. These annexed lands are within the Barrie TS service area, and their development contributes to a large portion of the station's forecast growth. Barrie TS growth is also influenced by the recent and continued development of data centres in the City of Barrie, and forecast growth in the Town of Innisfil, including the proposed industrial and commercial development of Innisfil Heights near Highway 400.

Barrie TS is currently utilized by two LDCs, PowerStream and InnPower.

Figure 6-2: Forecast Summer Demand for Barrie TS - Reference Scenario

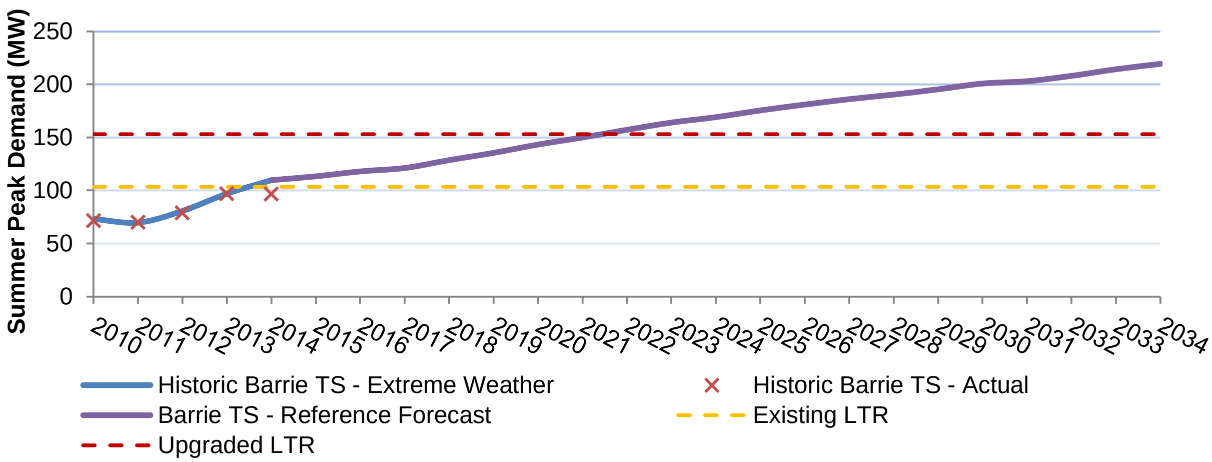


Figure 6-2 shows the forecast load growth for Barrie TS under the assumptions from the reference scenario, along with the existing LTR of Barrie TS and the future LTR of the uprated Barrie TS. Based on the forecast provided by the LDCs, Barrie TS would have exceeded its existing LTR by 2015 and will exceed the uprated LTR by 2022. By the end of the study period, there is approximately 66 MW of forecast capacity need that cannot be supplied by the uprated Barrie TS.

Currently all seven existing 44 kV feeder positions available at Barrie TS have been allocated to an LDC. Six of these feeders are used to supply PowerStream customers and one to supply InnPower. Based on the normal operating rating of the 44 kV feeder supplying InnPower, there will be a need for additional feeder capacity and a new feeder position by 2020 for the reference forecast scenario. The uprated Barrie TS will have a total of eight feeder positions, meaning there will be an additional position available as an option to supply future load growth in both south Barrie and Innisfil.

In addition to the limitation posed by the transformers at Barrie TS, the existing upstream 115 kV transmission supply is forecast to exceed its limit. The 115 kV circuits that supply Barrie TS are E3/4B. E3B is expected to exceed its LMC in 2019. These 115 kV circuits are supplied by two 230/115 kV autotransformers at Essa TS. The most limiting of these transformers is expected to exceed its LTR in 2020. By upgrading the Barrie TS supply to 230 kV, it ensures that future load growth at Barrie TS, up to its new LTR, can be accommodated, and there will be remaining line capacity to accommodate future load customers in the area at 230 kV.

6.2.2 Long-Term Capacity Needs

Long-term capacity needs were identified at both the transformer station level and the sub-area/sub-region level. Two different sub-system levels were defined based on both the ability to transfer load on the distribution system, and on the overall electrical supply to the area. The two areas defined for the purpose of the needs assessment are the "Barrie Sub-area" – defined below – as well as the established "Barrie/Innisfil Sub-region".

In the long term, transformer capacity needs arise for Everett TS and for the broader Barrie Sub-area. At the end of the study period, both a transformer capacity need and a supply capacity need arise for the broader Barrie/Innisfil Sub-region. These needs, along with their timing and influencing factors, are discussed in more detail below.

Everett TS

The transformer station capacity need at Everett TS is a long-term need. Everett TS is a relatively new transformer station, which came into service in late 2007 to address capacity needs in the South Simcoe area, relieving Alliston TS. Everett TS is forecast to supply load growth in the Town of New Tecumseth, primarily Alliston and the surrounding area.

Figure 6-3: Forecast Summer Demand for Everett TS - Reference Scenario

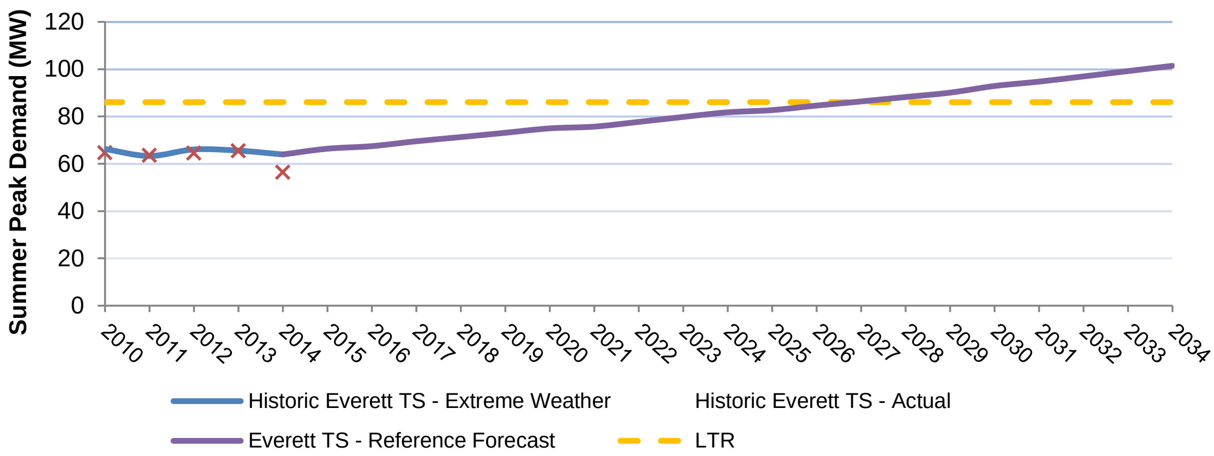


Figure 6-3 shows the forecast load growth for Everett TS under assumptions from the reference scenario. Based on the forecast provided by the LDCs, Everett TS will exceed its current LTR in 2027. By the end of the study period, there is approximately 15 MW of forecast capacity need that cannot be supplied by Everett TS.

A capacity need at Everett TS was identified in both the 2011 South Simcoe study and in the latest Needs Assessment completed by Hydro One for this regional planning cycle. Both studies outlined that this capacity need can be addressed by changing the CT ratios, which are currently limiting the station LTR, once the station's minimum load exceeds 8 MVA. Since 2011, the minimum load at Everett TS has surpassed 8 MVA meaning the CT ratios can now be changed whenever the additional capacity is required. This would defer the capacity need at Everett TS beyond the study period.

Barrie Sub-area

The Barrie Sub-area is defined as the area serviced by both Midhurst TS and Barrie TS, recognizing geographical overlap in their service areas. Ties exist between the stations for emergency load transfers, and there is potential for permanent load transfers or for a choice between the two stations when servicing new load.

The LMC of the Barrie Sub-area is defined as the combined LTRs of Midhurst TS and Barrie TS. The ability to fully utilize this firm capacity, however, is constrained by the feasibility or cost effectiveness of any load transfers or optimization of the distribution system. The available capacity in the Barrie Sub-area is also increased by the uprating of Barrie TS discussed in Section 6.2.1.

Figure 6-4: Summer Demand Forecast for the Barrie Sub-area - Reference Scenario

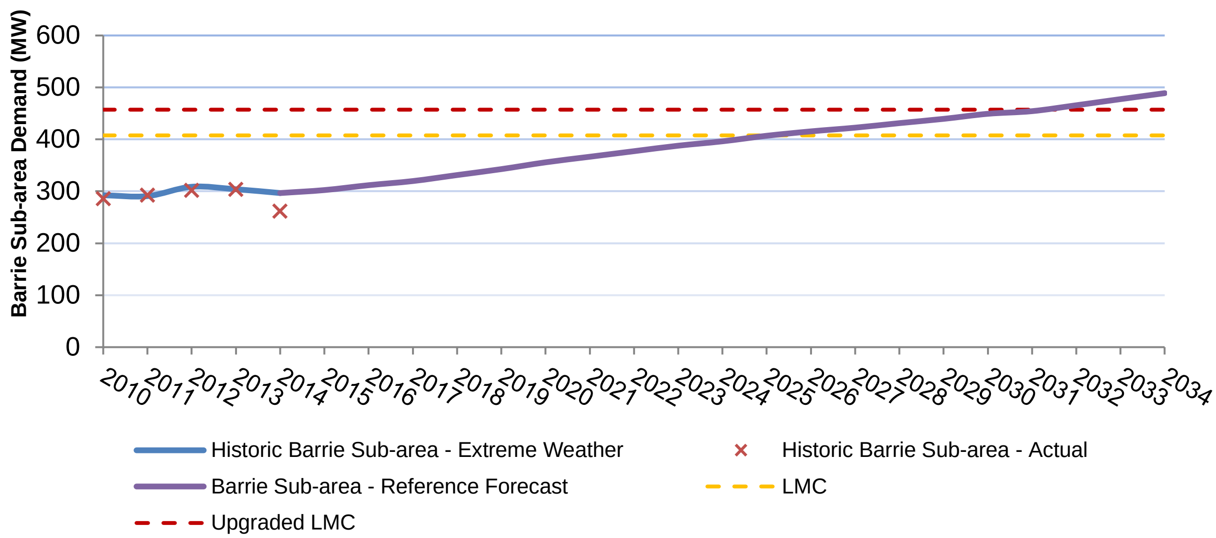


Figure 6-4 shows the forecast load growth in the Barrie Sub-area under assumptions for the reference scenario. Based on the forecasts provided by the LDCs, the Barrie Sub-area will exceed the combined capacity of Midhurst TS and uprated Barrie TS by 2031. By the end of the study period there is approximately 32 MW of forecast capacity need that cannot be supplied in the Barrie Sub-area assuming optimum load sharing between Midhurst TS and Barrie TS.

Barrie / Innisfil Sub-region

The Barrie/Innisfil Sub-region is defined in Section 4.1 as the area supplied by Midhurst TS, Barrie TS, Alliston TS and Everett TS. This area is supplied primarily by the bulk system, via the 500/230 kV autotransformers at Essa TS. Based on the forecast load growth, the region is primarily limited by the combined transformer capacity of Midhurst TS, Barrie TS, Everett TS and Alliston TS. This recognizes the existing ties used for emergency load transfers and the potential to implement permanent load transfers throughout the area.

Figure 6-5: Summer Demand Forecast Barrie/Innisfil Sub-region - Reference Scenario

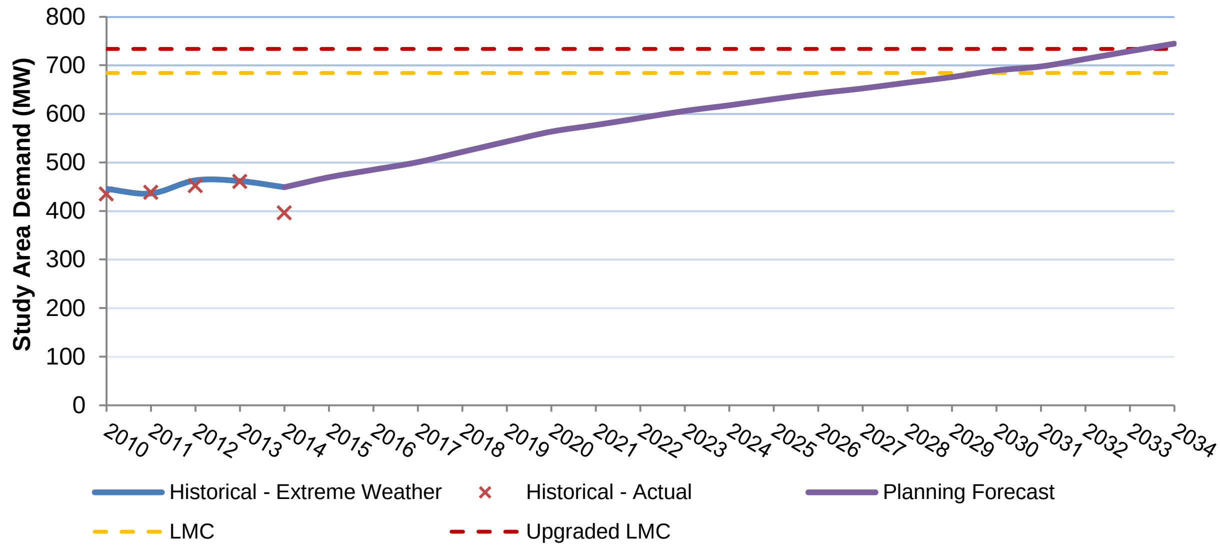


Figure 6-5 shows the forecast load growth in the Barrie/Innisfil Sub-region under assumptions for the reference scenario. Based on the forecasts provided by the LDCs, the Barrie Sub-region will exceed the combined capacity of the transformer stations in the region (accounting for the uprated Barrie TS) by 2034. By the end of the study period there is approximately 14 MW of forecast capacity need that cannot be supplied in the Barrie/Innisfil Sub-region, assuming optimum load sharing between all transformer stations.

The upstream transmission limitation for the sub-region is the 500/230 kV autotransformers at Essa TS. The loading of the autotransformers is also impacted by the load in the Parry Sound/Muskoka Sub-region and, to a certain degree, by the bulk system flow on Ontario's north-south transmission interface. The IESO has studied the impact on the Essa TS autotransformers under different bulk flow conditions and the load forecasts from both the Barrie/Innisfil IRRP and the Parry Sound/Muskoka IRRP. Based on these assumptions, a forecast capacity need, based on the loss of one autotransformer, does not arise until 2034.

In addition to the growth included in the planning demand forecast, the Metrolinx most recent electrification plan has indicated a preference for connecting to the new 230 kV supply extension via the uprated Barrie TS for their traction power station for the Barrie line. This connection could advance the need date for the supply capacity due to the Essa autotransformer limitations. Therefore, this project should be monitored closely by both the IESO (since it has implications for the bulk system) and the Working Group.

6.3 Needs Summary

The majority of needs in the Barrie/Innisfil Sub-region concern various loading limits on Barrie TS, along with the need to address the risk posed by the end-of-life infrastructure at the station.

With the Barrie Area Transmission Reinforcement project, which Hydro One has begun development work for at the request of the IESO and the Working Group, the near-term end-of-life need and the existing capacity need at the station can be addressed. Over the medium and long term, additional capacity needs arise in the area, including InnPower's need for additional 44 kV feeder capacity, additional transformer capacity needs at Everett TS and in the Barrie area, and a need for additional transformer and supply capacity for the sub-region by the end of the study period.

The table below provides a brief summary of needs that will be considered during the development of options for the plan.

Table 6-2: Summary of Needs in Barrie/Innisfil Sub-region

Area	Need	Description	Need Date
Barrie TS	Barrie TS transformer capacity need	There is an existing transformer capacity need at Barrie TS. The incremental capacity provided by the Barrie Area Transmission Reinforcement project should address a large portion of the near- and medium-term capacity need at Barrie TS.	Today
	Barrie TS supply capacity need	The 115 kV circuits currently supplying Barrie TS are forecast to exceed their LMC. By uprating these circuits to 230 kV, the Barrie Area Transmission Reinforcement project addresses this need.	2019

Area	Need	Description	Need Date
	End-of-life for Barrie TS 115/44 kV transformers and station equipment	Significant station components, both at and supplying Barrie TS are nearing end-of-life and require replacement by 2020. The Barrie Area Transmission Reinforcement project should address this need.	2020
	InnPower distribution/feeder supply capacity	Currently InnPower is only allocated one feeder from Barrie TS which is forecast to exceed its normal operating rating in the near to medium term.	2020
	Medium-term transformer capacity need	The uprated Barrie TS is forecast to exceed its new LTR in the medium term, based on the expected load growth in south Barrie and Innisfil.	2022
Everett TS	Everett TS transformer capacity need	Everett TS is forecast to exceed its limited LTR in the long term.	2027
Barrie Sub-area	Transformer capacity need	Load in the Barrie area is forecast to exceed the combined transformer capacity of Midhurst TS and the uprated Barrie TS in the long term, primarily driven by load growth at Barrie TS.	2031

Area	Need	Description	Need Date
Barrie/Innisfil Sub-region	Transformer and supply capacity need	In the long term, the load in the Barrie/Innisfil Sub-region is forecast to exceed both the combined transformer capacity of Barrie TS, Everett TS, Midhurst TS and Alliston TS, and the LMC of the Essa autotransformers.	2034

7. Near- and Medium-Term Plan

The plan to address the near- and medium-term needs identified for the Barrie TS service area is already underway. As described in Section 6.2.1, there are end-of-life and existing station capacity needs at Barrie TS that need to be addressed today. The near-term plan has been developed by the Working Group, with a project to rebuild and uprate Barrie TS (the Barrie Area Transmission Reinforcement project) formally handed off to Hydro One in December 2015. The hand-off letter was issued to ensure that facilities could be in-service in time to meet the identified needs, given the typical lead-time of five to seven years for a transmission project. The rebuild of Barrie TS and E3/4B is currently undergoing the development work (e.g., EA process, Leave to Construct).

This section describes the alternatives considered by the Working Group in developing the near- and medium-term plan for the Barrie/Innisfil Sub-region; provides details of, and rationale for, the recommended plan; and outlines the implementation plan.

7.1 Alternatives for Meeting Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated options. The Working Group further considered technical feasibility, cost and consistency with long-term needs and options in the Barrie/Innisfil Sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were given priority.

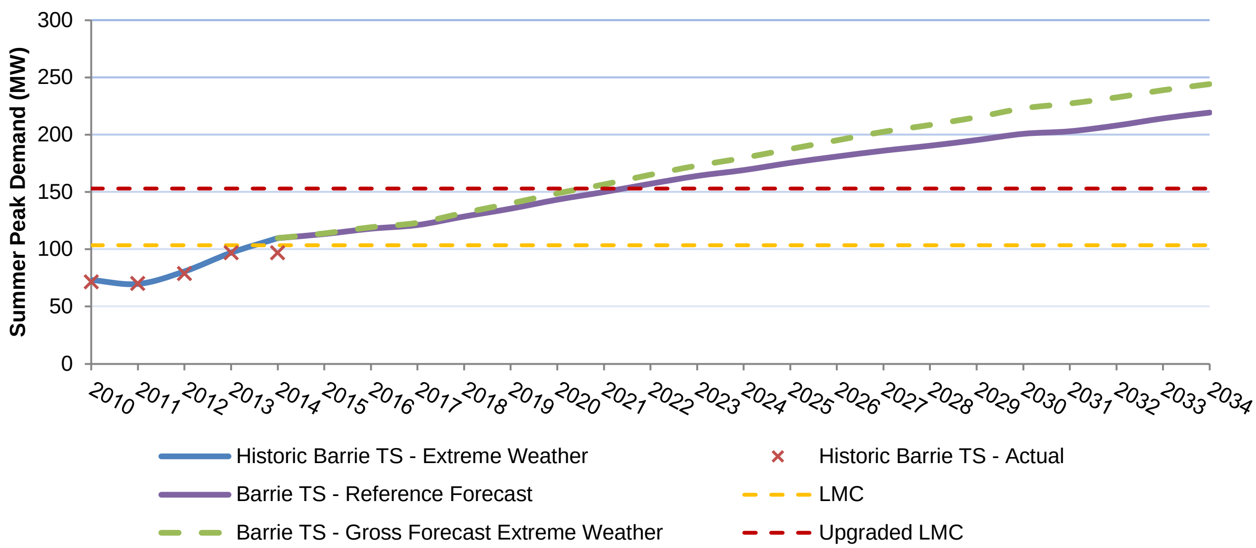
The following sections detail the alternatives considered and evaluates them against the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak demand impact of the provincial conservation targets as described in Section 5.4. In the Barrie TS area, the LTEP energy reduction targets account for approximately 10 MW, or 17% of the forecast demand growth during the first 10 years of the study. This is forecast to defer the Barrie TS capacity need by one year from 2021 to 2022.

In Figure 7-1, Barrie TS load is shown under both the gross and net planning (accounts for expected conservation and contracted DG) forecasts. Both forecasts are adjusted for extreme weather conditions.

Figure 7-1: Effect of Conservation Targets on Barrie TS Peak Load



Most conservation targets are energy targets (measured over an entire year). Transmission needs, on the other hand, are triggered based on peak demand (single highest observation of hourly demand in a year). As a result, in order to reduce, defer, or otherwise address needs, conservation programs must have an impact during the hour of peak demand. In the case of the Barrie/Innisfil Sub-region, this typically means late afternoon on the hottest weekdays of summer.

The net planning forecast includes an estimate of how meeting the mostly energy based conservation targets translates into peak demand reductions. There is, however, uncertainty in both meeting energy conservation targets and determining how meeting those targets will translate into peak demand savings. As such, there is a wide range of potential demand impacts that could be experienced (both higher and lower than forecast), while still achieving full conservation targets. Therefore, LDCs are encouraged to focus their Conservation First Framework ("CFF") funding towards measures and programs that can also reduce peak and overall demand–particularly in areas where needs have been identified through regional planning.

As part of the implementation of this plan, the Working Group will annually review actual peak demand, including the impact of conservation. The IESO will support the LDCs in exploring the full potential of conservation for addressing long-term needs, discussed further in the long-term plan in Section 8.

7.1.2 Local Generation

Large transmission-connected generation and small-scale distribution-connected DG options were ruled out as viable alternatives for meeting near-term needs in the Barrie/Innisfil Sub-region. This was primarily due to the end-of-life issues at Barrie TS, which must be addressed now and could not be solved using local generation, since approximately 100 MW of existing customer load would be left without supply if the infrastructure was not replaced at end-of-life.

In addition, because local generation contributes to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered when assessing options for near- and medium-term needs. Currently, Ontario has a surplus of generation capacity and no new capacity is forecast to be needed until the mid-2020s at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," solutions were considered by the Working Group to meet the near-term needs. "Wires" infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including lines, stations, or related equipment. These solutions are often characterized by high upfront capital costs, but have high reliability over the lifetime of the asset.

7.1.3.1 Transmission-based Solution to Address Near-Term Need

To address the end-of-life need at Barrie TS, the Working Group investigated different transmission-based solutions. Based on the assessment of these options along with the system needs, the rebuild and uprating of Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers was chosen as the preferred option. A description of the alternatives considered by the Working Group can be found in Appendix B.

7.1.3.2 Distribution-based Solutions to Address Medium-Term Need

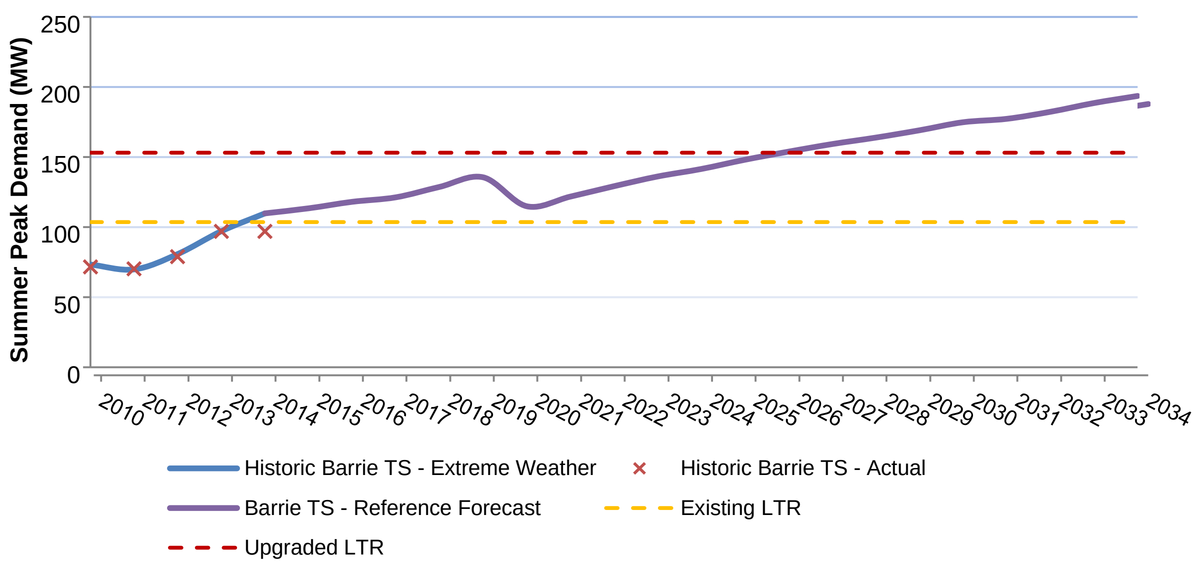
To address the medium-term transformer station and feeder capacity needs at Barrie TS, different distribution-based solutions were investigated. These included load transfers from Barrie TS to Midhurst TS, and new 44 kV feeders from the rebuilt Barrie TS to InnPower's service territory. These are described in more detail below.

Load Transfers

Due to the proximity of Barrie TS and Midhurst TS, and since PowerStream has an existing supply from both stations, load transfers are a feasible option to relieve Barrie TS. By building additional supply feeders from Midhurst TS, PowerStream can transfer up to 27 MW of load from Barrie TS assuming full data center load growth. This load transfer makes use of new feeders PowerStream already planned to construct, primarily due to data center expansion in the area. The available load transfer capacity is based upon normal operating conditions; during feeder outage situations the transfer amount may vary based on the redundancy needs of key customers.

The load transfer defers the capacity need at the uprated Barrie TS from 2022 to 2026 and also provides PowerStream with additional transfer capability between Barrie TS and Midhurst TS during emergency conditions. Figure 7-2 shows the reference scenario demand forecast for Barrie TS accounting for PowerStream's load transfer.

Figure 7-2: Barrie TS Reference Demand Forecast Load with PowerStream 2020 Load Transfer



With PowerStream's load transfer in place, by the end of the study period there is approximately 40 MW of forecast capacity need that cannot be supplied by the uprated Barrie TS.

PowerStream's existing ability to perform temporary load transfers for emergency purposes will also help manage the Barrie TS current capacity need both leading up to the completion of the Barrie Area Reinforcement project and throughout its construction staging. However, depending on Hydro One's contingency plan for the period of construction PowerStream may need to install additional distribution switches to meet their load security requirements during the rebuild of Barrie TS.

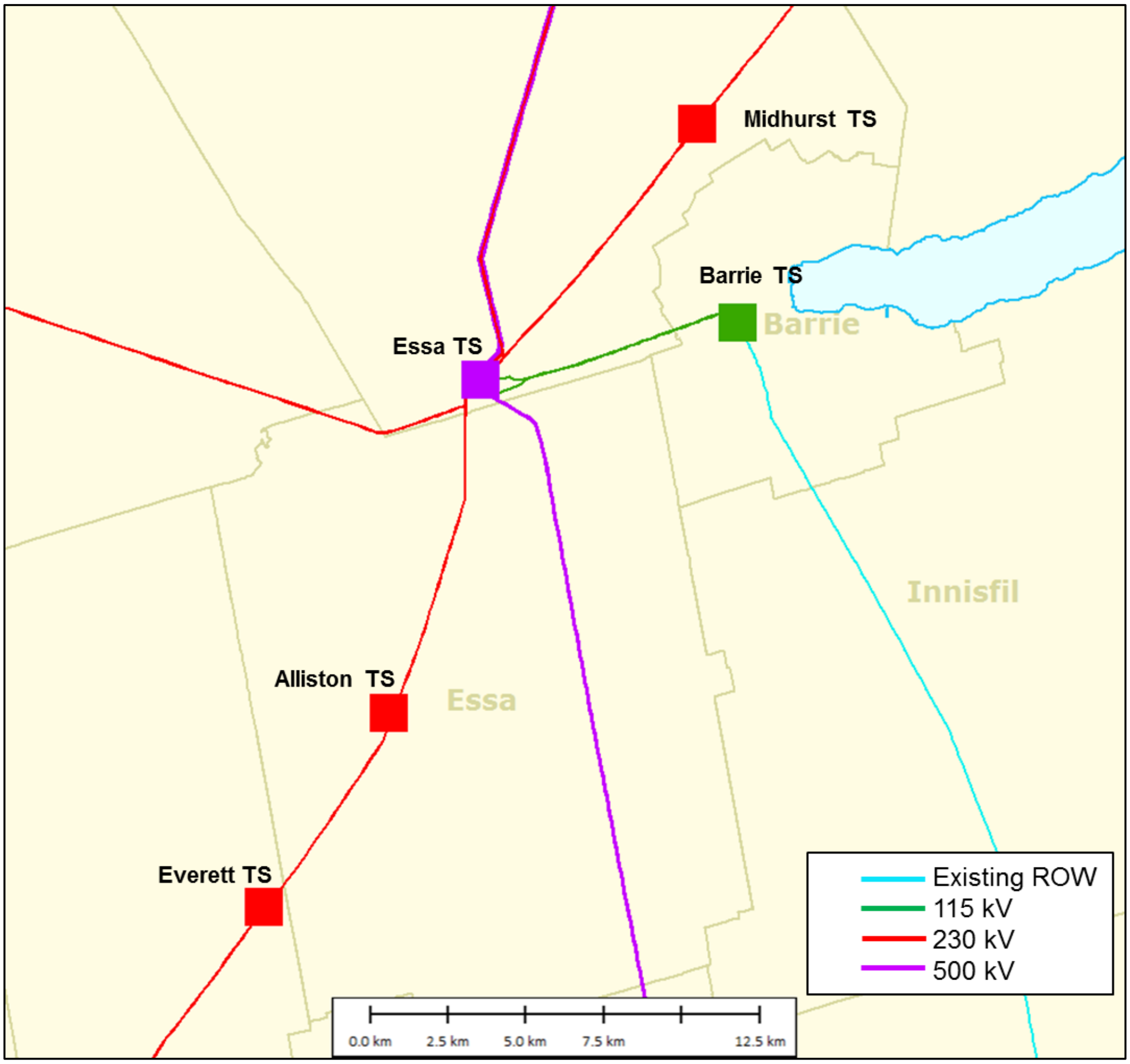
44 kV Feeder Expansion & Relocation

Currently, InnPower is supplied with one feeder from Barrie TS, operated at 44 kV and is considered an embedded customer to Hydro One Distribution. Up until the demarcation point in the Town of Innisfil, the feeder that supplies InnPower, 13M3, is an idle 115 kV line owned by Hydro One Transmission and operated at 44 kV to supply InnPower. The ROW for this 115 kV line extends south, past the existing supply points to InnPower.

This existing feeder can supply approximately 25 MW of capacity, which InnPower is forecast to exceed in 2020. The new Barrie TS will accommodate one additional 44 kV feeder, which can be used by InnPower when their capacity need arises. The additional feeder will require a new route south to Innisfil to service InnPower load.

It is recommended that, when building the new feeder, the line be built as a two circuit 44 kV feeder line and that the 13M3 feeder be relocated to this new line. This will leave the 115 kV ROW idle and will maintain a future option for addressing the long-term capacity needs in the south Barrie and Innisfil areas.

Figure 7-3: Map of the Barrie Area Including the 13M3 115 kV Corridor



Currently, Metrolinx has indicated an interest in utilizing this corridor to extend the 230 kV supply from the uprated Barrie TS to their proposed traction power station site, which sits just south of Barrie TS, adjacent to the ROW. InnPower is also interested in future use of the ROW, recognizing that long-term capacity needs in their service territory may require additional transformer station capacity in the long term.

7.1.3.3 Alternative Transmission Solution to Address Medium-Term Need

To address the need for new transformer station capacity at Barrie TS in 2022 – assuming no PowerStream load transfer – a new station supplied at 230 kV via the 13M3 corridor to south Barrie or Innisfil could provide approximately 150 MW of additional transformer station capacity to the area. This additional capacity would also service the long-term transformer station capacity needs for the Barrie Sub-area and overall Barrie/Innisfil Sub-region.

In this case, the distribution solution (the PowerStream load transfer) is the more cost-effective option and maximizes the use of existing infrastructure, deferring the capacity need to 2026. The lead-time for a new transformer station is five to seven years, so no commitment is needed today to begin development work. The need for new transformer station capacity will be monitored while all options for additional long-term capacity are further explored, as outlined in the long-term plan in Section 8.

7.2 Recommended Near- and Medium-Term Plan

The Working Group recommends the actions described below to meet the near- and medium-term electricity needs of the Barrie/Innisfil Sub-region. Successful implementation of these actions, in addition to achievement of targeted conservation measures, is expected to address the sub-region's electricity needs until the late 2020s /early 2030s.

Rebuild and Uprate Barrie TS and E3/4B to 230 kV

To mitigate challenges posed by both Barrie TS and its 115 kV supply infrastructure reaching end-of-life, and to address the near-term capacity needs at Barrie TS, Hydro One is developing the Barrie Area Transmission Reinforcement project. The project will rebuild the existing Barrie TS and uprate its existing supply from 115 kV to 230 kV, increasing the supply capacity to the area. The existing Barrie TS site is well situated for supplying the near- and medium-term forecast load growth in the south Barrie and Innisfil areas. A Class EA process is currently underway. The targeted in-service date for the project is the end of 2020.

PowerStream Load Transfer – From Barrie TS to Midhurst TS

PowerStream is planning to transfer up to 27 MW of load from Barrie TS to Midhurst TS by 2020 assuming full data centre load growth. This increases the incremental capacity available at Barrie TS, addressing near- and medium-term needs, while providing the reliability benefit of additional transfer points between Barrie TS and Midhurst TS for emergency situations. The PowerStream load transfer allows the need for additional capacity at the uprated Barrie TS to be deferred from 2022 to 2026 under reference case assumptions.

Relocate and Expand InnPower Feeder Supply from Barrie TS

Currently Hydro One Distribution is allocated one feeder from the existing Barrie TS which is used to service InnPower. The capacity of this feeder is forecast to be exceeded in 2020. The rebuilt Barrie TS will include one additional feeder position, which can be used to address this need. Additionally, the existing InnPower supply uses an idle Hydro One Transmission ROW. The use of this ROW for sub-transmission purposes limits future long-term options for additional transmission facilities in the south Barrie and Innisfil areas. It is recommended that Hydro One Distribution and InnPower develop a plan to build a new two circuit 44 kV feeder line to support InnPower's forecast growth and to relocate the InnPower supply to outside of the Hydro One Transmission corridor. The proposed in-service date for these feeders is the end of 2020. The two feeder supply from Barrie TS is forecast to supply InnPower's forecast demand at Barrie TS until 2026 under reference case assumptions.

7.3 Implementation of Near- and Medium-Term Plan

To ensure that the near-term electricity needs of the Barrie/Innisfil Sub-region are addressed, it is important that the plan recommendations be implemented as soon as possible. The specific actions and deliverables are outlined in Table 7-1, along with the recommended timing.

Table 7-1: Summary of Needs and Recommended Actions in Barrie/Innisfil Sub-region

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
- Barrie TS is at end-of-life and requires replacement - Barrie TS has reached its firm capacity	Rebuild and upgrade Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers	Hydro One	In-service by end of 2020
- The uprated Barrie TS has a medium-term capacity need	Transfer up to 27 MW of load from Barrie TS to Midhurst TS assuming full data centre load growth	PowerStream	In-service by 2020 at the latest[10]

[10] PowerStream's 2016-2020 Custom Incentive Rate filing states a proposed in-service date of 2018 based on additional distribution needs their project addresses in the Barrie area. If the project is in-service prior to 2020 it will provide additional ability to mitigate the near-term Barrie TS capacity need until the Barrie Area Transmission Reinforcement project comes in-service.

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
- Load growth in south Barrie will require additional feeder capacity for InnPower from Barrie TS - The existing corridor used to supply InnPower is required for future infrastructure development	InnPower will work with Hydro One to relocate out of the 115 kV corridor, constructing two new 44 kV feeders from Barrie TS to Innisfil	InnPower & Hydro One Distribution	Proposed in-service for end of 2020

To implement the recommended near-term actions in a timely manner, a RIP should be initiated for the broader South Georgian Bay/Muskoka planning region upon IRRP completion. This process will allow for detailed design and study of the transmission and distribution infrastructure expansion required to complete the recommended actions. The outcome of the RIP will be a more detailed development plan, including a refined estimate of expected costs and benefits to customers.

8. Long-Term Plan

In the long term, the outlook for the Barrie/Innisfil Sub-region depends on assumptions made in the forecast. Under the low growth scenario, the sub-region has no need for additional transformer station capacity until the end of the study period. Under the reference scenario, the need for new transformer station capacity arises in the mid to late 2020s. With the aggressive load growth assumptions in the high scenario, any new transformer station constructed in the area to address needs throughout the study period would be reaching its LTR by the end of the study period. These three scenarios represent the uncertainty associated with long-term forecasts and are an example of why a different approach is required for long-term versus near- and medium-term planning.

For needs appearing in the long term, there is an opportunity to develop and explore a broader set of options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Due to the long-term capacity need forecast for the Barrie and Innisfil areas, PowerStream and InnPower will be undertaking a LAP study for the Barrie TS service area, with support from the IESO's Conservation Fund. This study will help determine the conservation potential, specifically for the Barrie TS area, beyond the LTEP targets already accounted for in the planning demand forecast (e.g., additional incentives and adders to refocus existing CDM programs, new programs, behind-the-meter generation, energy storage, etc.). The study will provide a better understanding of the associated costs and feasibility of CDM measures to address the identified capacity needs in the area, better informing options for the next planning cycle.

PowerStream has also implemented a pilot project in their southern service territory to study the benefits and economics of aggregated customer side generation and storage. The results of this study can be used to inform further discussion and development of non-wires solutions for the long-term needs in the Barrie/Innisfil Sub-region for the next planning cycle.

Broad community and public engagement, including with local Indigenous communities, is essential to develop the long-term plan. It is recommended that engagement involve several phases: addressing public education/awareness of electricity issues, planning, technologies, and regulatory requirements; fostering an understanding of community growth and its relationship to electricity needs; understanding the pros and cons of various alternatives to meeting long-term needs; and obtaining input on community preferences for various approaches to meeting needs.

To provide input and advice on engagement plans for the Barrie/Innisfil Sub-region, the Working Group will establish a LAC consisting of community representatives and stakeholders.

8.1 Recommended Actions and Implementation

A number of alternatives are possible to meet the sub-region's long-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

For some needs, such as the transformer station capacity need at Everett TS, the solution is straightforward (changing the CT ratios) and can be easily implemented by the transmitter when required. For other needs, such as the transformer station capacity needs in the south Barrie and Innisfil areas, the recommended actions focus on monitoring and information gathering, community engagement, and more detailed options development for non-wires solutions prior to the next planning cycle.

The recommended actions and deliverables for the long-term plan are outlined in Table 8-1, along with their recommended timing, and the parties with lead responsibility for implementation.

Table 8-1: Recommended Near-Term Actions for Addressing Long-Term Needs

Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
Formation of a LAC.	IESO	To be formed early 2017

Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
Conduct a LAP study to determine cost and feasibility of CDM measures to address capacity needs in the Barrie TS service area.	PowerStream & InnPower	Study to be completed by end of 2017
Coordinate the development work for the Metrolinx traction power station supply to maintain the future supply option for south Barrie and Innisfil utilizing the same corridor.	Hydro One	To be monitored
Change the CT ratios at Everett TS when required.	Hydro One	To be monitored – pre 2027
Monitor, and prepare an annual update to the Working Group, on demand, conservation and DG trends and achievement in the area.	IESO	Annually

The Working Group will work with the local communities to monitor leading indicators for growth in the Barrie/Innisfil Sub-region. This includes monitoring changes to growth targets, the composition and location of specific customer segments (residential, commercial, industrial), and electricity impacts from implementation of community energy plans. If these or other factors affect service reliability or the capacity of the local electricity delivery systems a new IRRP process may be initiated ahead of the five year planning cycle. Examples of developments that could trigger revisiting the plan prior to the next cycle include:

- Critical PowerStream customers reaching 95% of their projected load
- InnPower's expanded feeder supply from Barrie TS reaching 95% of its firm capacity
- Innisfil completing the servicing of their development lands
- Detailed design and development work proceeds for the Metrolinx electrification plans and requires further coordination with the Working Group
- Significant changes to the study area's forecast growth

The Working Group will continue to meet at regular intervals during the implementation phase of this IRRP to monitor developments in the sub-region, progress towards the deliverables in Table 8-1, and developments that would trigger an early return to the IRRP process.

9. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the Barrie/Innisfil IRRP.

A phased community engagement approach is being undertaken for the Barrie/Innisfil IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of Barrie/Innisfil Community Engagement Process

Creating Transparency:

Creation of IRRP Information Resources

- Dedicated Barrie/Innisfil IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page created on Hydro One website
- Self-subscription service established for the South Georgian Bay/Muskoka planning region for subscribers to receive regional planning updates
- Status: complete

Engaging Early and Often:

Municipal and Indigenous Outreach

- Posting of South Georgian Bay/Muskoka Scoping Assessment Report for feedback (May-June 2015)
- Group and individual meetings held with municipalities from across the planning region in Barrie, Innisfil, Simcoe County and Springwater (August - November 2015); follow-up meetings held to discuss the draft IRRP recommendations prior to posting the IRRP (November 2016)
- Meeting held with Indigenous communities from across the South Georgian Bay/Muskoka planning region.
- Status: initial outreach complete; dialogue continues

Bringing Communities to the Table:

Broader Community Outreach

- Barrie/Innisfil LAC to be formed in early 2017; dedicated Barrie/Innisfil engagement web page to be added to IESO website
- LAC meetings to discuss longer-term needs in the sub-region, and broader community engagement to help inform the next planning cycle
- LAC meetings will be open to the public; materials will be posted to the engagement webpage
- Status: beginning in early 2017; on-going

9.1 Creating Transparency

To start the dialogue on the Barrie/Innisfil IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated Barrie/Innisfil web page[11] was created on the IESO website including information on why an IRRP was being developed for the Barrie/Innisfil Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader South Georgian Bay/Muskoka planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the Barrie/Innisfil IRRP included posting the South Georgian Bay/Muskoka Region Scoping Assessment document for comment and undertaking meetings with communities in the planning area to discuss the development of the plan and obtain early input and feedback.

9.3 South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

The draft South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was posted to the IESO website in May 2015 for comment, and a final version was posted on June 22, 2015. The Scoping Report identified the need for an IRRP for the Barrie/Innisfil Sub-region and presented the Terms of Reference for the development of the plan.

9.4 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In August through November 2015, the Working Group held individual and group municipal meetings in Barrie, Innisfil, Simcoe County, and Springwater to initiate discussions on the IRRP. Key discussion topics included: the regional planning process and findings in the South Georgian Bay/Muskoka Scoping Report, the need for an IRRP for the Barrie/Innisfil area, municipal growth plans and electricity growth forecasts, the identified electricity needs in the area and future engagement activities. Attendees provided insight on updated municipal growth plans, reinforced the importance of community engagement for project/infrastructure siting, and expressed an interest in having a LAC as a forum to bring local municipalities to the table and engage in a singular dialogue.

---

[11] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil.aspx

9.5 Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC[12] will be established for the Barrie/Innisfil Sub-region in early 2017. The role of the LAC will be to provide advice and recommendations on the development of options to meet the longer-term electricity needs in the area, as well as to provide input on broader community engagement. LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information and materials will be posted on the Barrie/Innisfil engagement webpage.

Development of the Barrie/Innisfil LAC will be carried out through a request for nominations process promoted by the following activities: advertisements in local newspapers and digital (website) advertising in communities throughout the planning area; emails sent to municipal representatives across the region; meetings with Indigenous communities for the broader region; and an e-blast sent to the IESO's South Georgian Bay/Muskoka subscribers list. Information will also be posted to the dedicated Barrie/Innisfil IRRP webpage.[13]

Meetings were also held with the area municipalities in November 2016 prior to the posting of the IRRP to discuss the recommendations included in the plan as well as future engagement activities such as the development of a LAC.

---

[12] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

[13] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil.aspx

10. Conclusion

This report documents an IRRP that has been carried out for the Barrie/Innisfil area, a sub-region of the OEB's South Georgian Bay/Muskoka planning region. The IRRP identifies electricity needs in the Barrie/Innisfil Sub-region over the 20-year period from 2015-2034, identifies preferred "wires" solutions to address near-term needs, and lays out actions to monitor, defer, and address needs that may arise in the long term.

Implementation of the near-term plan is already underway. Hydro One is developing the Barrie Area Transmission Reinforcement project, and LDCs are continuing to implement their existing CDM plans. PowerStream and InnPower have also initiated a LAP study for the Barrie TS, which will be used to inform the long-term options discussion for the next planning cycle and discussion with the future LAC.

To further refine and implement the preferred near-term "wires" solutions, it is recommended that an RIP be initiated. The RIP for the broader South Georgian Bay/Muskoka Region is to be led by Hydro One Transmission. For recommendations relating to Barrie/Innisfil, the RIP process should include PowerStream and InnPower as working group members. The IESO will continue to provide support throughout the RIP process, and assist with any regulatory matters that may arise during plan implementation.

To support the development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community, and monitor load growth in the sub-region. Responsibility for these actions has been assigned to the appropriate members of the Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for the Barrie/Innisfil Sub-region.

The Barrie/Innisfil Sub-region Working Group will continue to meet at regular intervals to monitor developments in the sub-region and track progress toward the plan deliverables. In particular, the actions and deliverables associated with peak demand reducing initiatives will require annual review of system demand and program achievement to determine whether new initiatives are required. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the OEB-mandated 5-year schedule.

1.3 (5.2.2) COORDINATED PLANNING WITH THIRD PARTIES - CUSTOMER ENGAGEMENT

The Renewed Regulatory Framework (RRF) is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. One of the main outcomes is *Customer Focus*: services are provided in a manner that responds to identified customer needs and preferences[1]. Hydro One understands that its services are a major driver of long-term success of the Company and its customers and therefore uses various means to obtain feedback from its customers. This feedback is then incorporated into the investment planning process and to inform Hydro One's Business Plan

Customer Engagement was and remains critical to the planning decisions and process that Hydro One follows. Including this information in this chapter demonstrates the up-front commitment to focus on customers and their requirements.

1 Ontario Energy Board, *Renewed Regulatory Framework for Electricity*, October 2012, Page 2

1.3.1 (5.2.2 A) HOW CUSTOMER NEEDS ARE DETERMINED

Hydro One has a three-pronged approach to engaging its distribution customers:

1. formal customer engagement;
2. stakeholder engagement; and
3. other ongoing forums for Hydro One to interact with customers.

Hydro One worked with a consultant to design a formal customer engagement process to assist in engaging customers through a series of meetings to hear their concerns, priorities and preferences. This feedback informed the investment plan that is the basis of this rate application. This customer engagement process is discussed in Section 1.3.2 of this Exhibit.

Hydro One uses a stakeholder engagement process to approach industry stakeholders and OEB staff to receive input from special interest groups and associations that represent Hydro One distribution customers. A total of four stakeholder sessions were held in relation to this Application. They are discussed further in Section 1.3.2.4 of this Exhibit.

Other ongoing initiatives include:

Customer Surveys

Surveys are used to gauge the current satisfaction levels of the distribution customer groups (e.g., residential, local distribution companies, small business, commercial and industrial) and identify issues. Some of these surveys are annual and others are transactional. Transactional surveys are issued after a customer has had direct contact with a Hydro One representative either from the Customer Call Centre or with a field trade group such as Provincial Lines or Forestry.

Focus Groups

Sessions are conducted by a third party on behalf of Hydro One whereby pre-screened groups of people are approached and asked questions about Hydro One and its current practices. The questions can target specific areas of interest for Hydro One and allow for detailed questions.

Direct Personal Contact

Large Distribution Account ("LDA") and Embedded Local Distribution Companies ("LDC") have regular interactions with Hydro One. Zone Superintendents are aligned with LDA customers and Key Account Executives are aligned with Embedded LDCs to better communicate the more complex needs of larger customers.

Call Centre Contact

For Residential and Small Business customers, Hydro One receives ongoing feedback regarding its current performance through its call centre, fax, e-mail, and/or online.

These initiatives are discussed further in Exhibit A, Tab 4, Schedule 1, Customer Service Strategy.

1.3.2 (5.2.2 A) CUSTOMER ENGAGEMENT PROCESS

When the Hydro One investment program is developed, it is guided by the RRF that states that utilities must, "…demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate engagement…[2]".

Ipsos, an established vendor of record with Hydro One was selected to work on the Distribution Customer Engagement initiative based upon their previously demonstrated ability to deliver the work required and their ability to meet the timelines in support of this Distribution Rate Application. Ipsos is a global independent market research company, ranked third worldwide among research firms, managed and controlled by research professionals through offices in eighty-seven countries.

Ipsos was commissioned by Hydro One, "…to assist with the design, execution, documentation, and analysis of feedback for the customer engagement and engagement process. By engaging Ipsos, a third-party research firm, the Company set out to establish an engagement process that ensured the facilitation, development of research and questions, and report writing provided an unbiased, unvarnished, evidence-based engagement report to support the filing. As a key element of its application for distribution rates, the outcome of this engagement process helped to determine Hydro One's electricity distribution rate application for a five-year period between 2018 and 2022."[3] See Attachment 1 for the Ipsos Report.

The objectives for the distribution customer engagement were to:

---

2 Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 2012, Section 2.5

3 Ipsos, Distribution Customer Engagement Report, August 2016, p.20.

- Establish the process, vehicles, and conditions for effective engagement that captures the feedback of all distribution customer segments;
- Provide every customer with an opportunity to participate;
- Adopt a research-based approach to engagement to gather the data necessary to support an informed and representative view;
- Contribute to unbiased analysis of customer input by engaging external research professionals; and
- Demonstrate flexibility and provide tangible evidence of Hydro One's willingness to listen, learn and establish plans that reflect and respect the needs of its customers.[4]

To achieve these objectives, Ipsos led several efforts on Hydro One's behalf to obtain an impartial understanding of the issues faced today by Hydro One distribution connected customers. Some of the means by which Ipsos approached Hydro One customers to understand their needs and preferences were:

- Phone Surveys - Telephone survey of random and representative sample of Residential and Small Business Hydro One customers;
- On-line Surveys accessing an Ipsos Panel of respondents. An online workbook was used to survey a representative sample of Residential and Seasonal customers drawn from an on-line panel sample;
- Focus Groups for Residential and Small Business customers;
- Open Link Online Survey for Residential/Seasonal, Small Business, Commercial & Industrial customers. For customers who did not wish to complete the survey online, there was an option to complete the survey by phone or a paper copy;
- On-line Survey for Large Distribution Accounts, Local Distribution Companies; and
- In-person Workshops for Large Distribution Accounts, Local Distribution Companies, Commercial & Industrial customers facilitated and recorded independently by Ipsos.

4 Ipsos, Distribution Customer Engagement Report, August 2016, p.5.

1.3.2.1 PRINCIPLES AND DESIGN

The following principles and objectives guided the engagement design and implementation:

- Hydro One entered into the engagement process in good faith with a view to facilitating and streamlining future OEB proceedings related to the application;
- Hydro One received and considered all submissions but retained control over the process of developing its application;
- All engagements were carried out on a without-prejudice basis;
- An independent facilitator documented and reported the discussions and any agreements reached with all or some participants; and,
- Agreements reached are submitted to the OEB as part of the evidence for this application.

The overall goal for the sessions was to create a forum for participants and Hydro One to discuss issues related to the Hydro One Distribution Rate Application and to identify areas of agreement and concern to shape the pre-filed evidence. To further this mandate, participants were asked to:

- Represent the various views of their customers/constituencies; and
- Assist Hydro One to understand their goals and issues through participation in a process of open dialogue and submissions.

The specific objectives for stakeholder engagement included:

- Inform and update key stakeholders about Hydro One’s Distribution business, and the approaches and methodology used to determine revenue requirement and rate design;
- Give stakeholders a range of opportunities to provide input and feedback on aspects of the Application;
- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application;
- Act as a forum for the exchange of information and views;

- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences; and
- Clarify and scope as many issues as possible prior to the Hydro One submission to the OEB.

1.3.2.2 WEBSITE

As part of the engagement process, Hydro One created links to the 2018-2022 Distribution Custom Incentive Rate Application on its Distribution Rates Applications web page on its external website. The intent is to provide interested stakeholders the opportunity to monitor the engagement process and to provide input throughout the engagement.

The web page (http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx) is updated regularly and contains meeting agendas, presentations made available at the stakeholder sessions and the meeting notes. Hydro One stakeholders were advised by email about the sessions, agendas, and how to participate or follow the proceedings via the regulatory website if they could not attend.

1.3.2.3 CUSTOMER PARTICIPATION

To ensure that as many customers as possible had the opportunity to participate, Hydro One used the following methods to notify customers of its engagement process:

- two press releases;
- bill inserts;
- newspaper advertisements;
- earned media; radio ads;
- eBlasts (English and French);
- posters to MPPs’ offices;
- targeted social media (FaceBook, Twitter);

- printed invitations to participate in the on-line survey (Commercial & Industrial); and
- e-mail invitations with follow-up calls (LDA, LDC/DG).

There were 19,861 residential and small business customer responses through focus groups, an online workbook (Ipsos panel), or by telephone survey. There were also 201 medium and large business customer responses through in-person workshops held in seven locations across the province or on-line workbooks.

Table 7 - Customer Meeting Details

#	Date	Location	Customers	Emerging Themes on Customer Needs and Preferences
1A	June 8, 2016	Hamilton	LDC LDA	• Outage Communication • Power Quality
1B	June 8, 2016	Hamilton	Commercial Industrial	• Awareness of tools and resources • Outage Communication • Customer Service and Relationship • Power Quality • Rate Increase vs. Reliability
2	June 9, 2016	Collingwood	LDC LDA Commercial Industrial	• Planning • Cost Reduction and Efficiencies • Company Culture • Role of Utility • Local Needs
3	June 13, 2016	Timmins	LDA LDC Commercial Industrial	• Cost • Reliability • Capacity and Expansion • Customer Service • Efficiency

#	Date	Location	Customers	Emerging Themes on Customer Needs and Preferences
4	June 14, 2016	Thunder Bay	LDA LDC Commercial Industrial	• Cost • Efficiencies and Optics • Power Quality
5A	June 16, 2016	London	LDA LDC	• Outage Communication • Overall Communication of concerns • Power Quality • Rates • Responsibility to rate payers vs. shareholders
5B	June 16, 2016	London	Commercial Industrial	• Billing • Future of the Grid • Rate Increases and Efficiencies
6	June 17, 2016	Windsor	LDA LDC Commercial Industrial	• Capacity • Power Quality
7	June 24, 2016	Kingston	LDA LDC Commercial Industrial	• Regional Concerns • Sharing of Expertise

See Attachment 2 in Section 1.3.5 for the executive summaries of the customer meetings.

1.3.2.4 STAKEHOLDER SESSION SUMMARY

In the Hydro One Networks Inc. 2015-2019 Distribution Rates Application Decision, dated March 12, 2015, for proceeding EB-2013-0416, the OEB directed Hydro One to perform several productivity studies to be filed with Hydro One's next Distribution Rates application.

Hydro One sought stakeholder feedback on the proposed approach and framework for four separate OEB-directed distribution productivity studies: (i) Vegetation Management Program Study; (ii) Total Factor Productivity Study; (iii) Pole Replacement Program Study and (iv) Distribution Station Refurbishment Program Study.

Hydro One's experience has been that early involvement with stakeholders is critical to developing a submission that reflects the broad interests and concerns of the Ontario Energy Board ("OEB") and Hydro One Distribution's constituencies. Stakeholder groups including intervenors from previous Hydro One rate proceedings, OEB staff, embedded LDCs and large distribution accounts were invited to participate in all of the stakeholder sessions via an invitation letter and a follow-up e-mail. Approximately, forty groups were invited to participate in the stakeholder sessions either in person or via teleconference. Hydro One believes that those invited were representative of the interests of the majority of its stakeholders.

Those stakeholders that were not able to attend were invited to monitor the process through the company's website and to provide input throughout the process. Funding was available to eligible intervenors consistent with the current OEB's Practice Direction on Cost Awards.

Hydro One held four stakeholder sessions in association with this distribution rate application; two sessions addressed the undertaking and preliminary results of four distribution productivity studies; one session to discuss key findings of the Total Compensation Study and how customer feedback and productivity was incorporated into the distribution system plan; and one session was to obtain feedback on the key issues and challenges with Hydro One's 2018 to 2022 Distribution Rate Application.

The overall goal of the stakeholder sessions was to improve the quality and comprehensiveness of the productivity studies and pre-filed evidence and to minimize the issues to be addressed at the OEB hearing. The engagement sessions consisted of presentations to stakeholders followed by facilitated discussions on the issues raised. The presented information and notes of meeting were also made available through Hydro One Networks' website for those stakeholders that could not attend the sessions. In addition, Hydro One staff was available for informal dialogue with stakeholders throughout the process.

All stakeholder sessions were held in accordance with the principles, objectives, participation format, and engagement format described in Section 1.3.2.1.

Session #1 – Productivity Study Proposed Methodology

Session #1 was held on October 22, 2015 at the DoubleTree Hotel in Toronto using Swerhun Facilitation to facilitate the session and produce the minutes of the meeting. Eighteen participants attended, representing eleven stakeholder groups, and OEB staff. In this session, CN Utility Consulting (Vegetation Management Program Study), Power System Engineering Inc. (Total Factor Productivity Study), Navigant Consulting, and First Quartile Consulting (Pole Replacement Program and Distribution Station Refurbishment Program Studies) presented and sought participant feedback on an overview of their respective proposed study methodology, benchmarking approach, peer group selection criteria, and metric selection.

Session #2 – Productivity Study Preliminary Results and Findings

Session #2 was held on October 5, 2016 at the DoubleTree Hotel in Toronto with Hardy Stevenson and Associates Limited acting as the facilitator and scribe for the meeting minutes. Fourteen stakeholders attended, representing eleven stakeholder organizations, and OEB staff. In this session, Power System Engineering Inc., CN Utility, Navigant Consulting and First Quartile Consulting presented and sought participant feedback on preliminary findings and recommendations resulting from their respective studies.

Session #3 – Total Compensation Study, Customer Engagement, Performance Metrics and the Distribution System Plan

Session #3 was held on November 30, 2016 at the DoubleTree Hotel in Toronto with The Fixers Communications Group Inc. acted as facilitator and scribe for the meeting minutes. Fourteen stakeholders attended, representing eleven stakeholder organizations, and OEB staff. In this session:

- Mercer Canada presented the methodology and findings of a comprehensive compensation cost benchmark study, the fourth in a series of such benchmark studies performed by Mercer Canada on behalf of Hydro One (2008, 2011, 2013, and 2016). The Total Compensation Studies are to provide useful and reliable information concerning Hydro One's compensation costs, and how these costs compare to those of other regulated distribution utilities in North America.

- Ipsos Reid presented high-level findings of quantitative and qualitative stakeholder research that they undertook for Hydro One Networks in the summer of 2016. The overall objective of Hydro One's customer engagement process was to obtain a deeper understanding of customer needs and preferences to facilitate the building and managing of strong productive relationships with customers now and in the future.

- Hydro One staff presented the existing and the proposed performance metrics submitted as part of this distribution rate application to demonstrate its commitment to continuous improvement in the areas of productivity and cost efficiency and alignment with the Renewed Regulatory Framework outcomes in the areas of Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. Hydro One was seeking input to ensure the metrics chosen would allow OEB staff and Intervenors to monitor key outcomes and Hydro One's commitment to its distribution system plan.

- Lastly, Hydro One staff delivered a presentation on how the results of the customer engagement process informed Hydro One's DSP and how the proposed metrics would measure and monitor the success of Hydro One's investments and expenditures.

Session #4 – Application Details

Session #4 was held on February 8, 2017 at the DoubleTree Hotel in Toronto with Ehl Harrison Consulting Inc. acting as facilitator and scribe for the meeting minutes. Discussion topics included:

- **2018 to 2022 Custom IR Application Framework –** An overview of the distribution rate application framework. The application is aimed at balancing competing priorities, those being asset needs, customer needs and preferences, and rate impacts. The topic included a review of the 5-year revenue requirements, the estimated rate changes over the period and the contributing factors.

- **Econometric Benchmarking of Total Costs –** This topic included the findings of an econometric study presented by Steve Fenrick of Power Systems Engineering Inc. It included identification and recommendation of an appropriate stretch factor.

- **Distribution Cost Allocation / Rate Design -** A presentation of Hydro One's methodology to forecast load for 2018 to 2022, allocate costs between customer classes, determine customer classes, and implement OEB-approved rate design changes. It includes Hydro One's plan to integrate the acquired utilities with

- respect to rates. The presentation also included the associated bill impacts based upon typical consumption levels.

- **Capital and OM&A Core Work Program -** An overview of the components of the OM&A expenditures; specifically, sustaining, development, operating and customer service details. The primary goal in the management of distribution assets is centred on sound investment strategies to keep costs low and minimize rate impacts. Hydro One demonstrate that the proposed core work projects and programs have been developed to address customer preferences and outcomes.

Detailed notes from the four stakeholder sessions are included in Attachment 3 in Section 1.3.5.

1.3.2.5 FIRST NATIONS ENGAGEMENT SUMMARY

Hydro One serves eighty-eight First Nations communities. A First Nations Engagement Session was held on February 9 and 10, 2017. The main objectives of the discussion session were to hear First Nations' priorities and to solicit feedback on the upcoming Distribution Rates submission to the OEB. To provide the best environment for the engagement session with the First Nations, Hydro One consulted with Hunter Courchene for advice on the logistics to include in the sessions and to create the invitation and contact the First Nations participants on behalf of Hydro One. Hunter Courchene provided the note taking for the sessions. Phil Goulais was hired to act as facilitator. Mr. Goulais has experience with First Nations and is often called upon by First Nations to chair their meetings.

The presentations included an overview of the key features of the distribution system and the rate setting approach for the 2018 to 2022 application This included the general characteristics of the application and the associated rate impacts. There was also a discussion on the approvals sought in the application along with how Hydro One incorporated customer preferences, cost efficiencies and productivity into the application. Hydro One outlined its value proposition for customers that governs the delivery of safe, reliable and affordable service. Additionally, presentations were made on Hydro One's new Customer Care approach and on Hydro One's operations reliability measures.

Session reports from both days of the engagement are provided in Attachment 4 to this Exhibit.

1.3.2.6 METIS DISCUSSION SUMMARY

An engagement session, similar to the First Nations session, was held on May 13, 2017 with representatives of the Métis Nation of Ontario. Hunter Courchene provided the note taking for the session. This discussion included the same topics that were delivered at the First Nations' discussion sessions along with additional information on Hydro One's employment, training and procurement program initiatives.

A session report was not available at the time of filing.

1.3.2.7 CUSTOMER ENGAGEMENT PROCESS SUMMARY

Hydro One's customer and stakeholder engagement process meets the objectives described in Section 1.3.2. Hydro One believes customers and stakeholders have a better understanding of its operations and business practices. More importantly, Hydro One improved its understanding of customer needs and stakeholder issues and concerns through the engagement process. Hydro One has shaped its investment plan and distribution rate application accordingly – by aligning customer preferences, responsible stewardship of assets and impact of rates.

1.3.3 SUMMARY OF CUSTOMER NEEDS AND PREFERENCES

As a result of the customer outreach, Ipsos analyzed the results and wrote a report detailing the results of each of the outreach methods (e.g., open link surveys, phone surveys) by segment, to guide Hydro One distribution investment decisions.

As there were several customer segments involved in the engagement sessions for Hydro distribution-connected customers, the key themes varied by customer segment. The Ipsos report showed the following:

- Cost is definitely the top priority for Residential and Small Business customers, and is one of the top priorities for Large Customers. This preference is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. Many customers believe that total electricity costs are approaching an unaffordable level.

- Maintaining reliable electricity service is consistently second, in terms of priority, compared to cost. Residential and Small Business customers expressed the view that Hydro One should maintain existing levels of power reliability and quality. For Large Customers, improving power quality and reducing the number and duration of sustained outages is a top priority along with cost.

- Willingness to accept a rate increase to maintain and improve service level is limited. The majority of residential and small business customers are unwilling to accept higher rate impacts for better reliability.

- Large customers are more concerned with the reliability of service they currently receive than residential and small business customers and accept that investments are needed. However, although this group of customers is more inclined to value better reliability, it is not willing to entertain the corresponding rate impact.

- Customer service improvements above existing levels are not something for which customers are willing to pay higher rates.

- For large customers, power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, are the primary concern. Some customers have capacity challenges and want more access to power in order to grow their enterprises.

- All large customer segments prioritize the renewal program that focuses on replacing equipment that affects reliability ahead of other options for improving reliability. Other options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages.

- Commercial and Industrial customers welcomed the opportunity to participate in engagements and are looking for a more active relationship with Hydro One,

- Several Large Customers spoke about a need for greater capacity and want Hydro One to more strongly advocate and support their requests for capacity.

- Large Customers want improved outage customer communications with more accurate estimates of power restoration.

- There is a low awareness of Hydro One's role in the energy industry and negative views of the electrical industry and current government also perform a role.

- Large Customers wanted a greater transparency of Hydro One operations and administration, to include planned investments.[5]

5 Ipsos, Distribution Customer Engagement Report, August 2016, pp. 144-145.

1.3.4 (5.4.1 F) HOW THE PLAN REFLECTS CUSTOMER NEEDS AND PREFERENCES

Hydro One's Distribution System Plan is designed to reflect customers' needs and preferences. Highlights of the specific measures being taken to address the customer engagement information are listed below.

1. Customers indicated that keeping rates low was a priority. Many customers, especially residential customers, asserted that reliability performance is a second priority compared to rates.

Response: Hydro One has deliberately deferred some 2018 capital spending in order to pace investments in such a way as to minimize rate impacts and offset the effects of a reduced load forecast. This includes managing rate of replacement and, where appropriate, accepting short-term, small scale, reliability impacts in order to reduce or defer capital spending requirements and minimize rate impacts.

2. Customers asked that Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases.

Response: Hydro One has implemented a number of productivity initiatives to reduce unit and operational costs and the associated rate impacts. These productivity initiatives are detailed in Section 1.5.

3. Residential and Small Business customers requested that Hydro One maintain its existing level of reliability.

Response: To sustain reliability performance across the Province, Hydro One has assessed the condition of its key assets and has developed an investment plan that properly paces renewal investments to achieve this outcome. Supporting this are System Renewal projects and programs such as the Pole Replacement Program, Distribution Station Refurbishment Projects, and Line Renewal Projects.

The pole replacement program will be replacing 77,400 poles over the planning period to manage the volume of poles which have been assessed to be in poor condition. Similarly, the number of distribution stations that are refurbished has been established to sustain the condition of the fleet. Reliability performance of specific feeders that have outlier performance will be addressed by correcting the root cause of reliability on a case by case basis. Some feeder performance improvements will be accomplished through remote monitoring and control of switches and breakers as well as fault locating technology and additional protective devices.

4. A top priority for Large Customers is to improve power quality.

Response: Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue that they are experiencing. In addition, a capital power quality program has been incorporated into the plan. This program will install power quality meters, install surge arresters, and/or improve grounding where needed to assist in power quality investigations. Approximately $200k per year has been allocated to this work. Hydro One has also increased the funding for reliability enhancement projects to specifically target LDA and mid-size industrial customers. These projects are selected to improve system reliability where concerns have been raised by Hydro One’s LDA and mid-size industrial customers that a performance issue exists with the network. A lack of action would see existing reliability levels deteriorate. Investments may include installing lightning arrestors, new switches, automatic sectionalizing devices, or creating feeder ties to improve restoration time. The funding for these investments will increase by approximately $3M, starting in 2018, from the current funding level of approximately $1.5M per year.

The investment plan reflected in this Application seeks to meet customers' needs regarding reliability and power quality, in a manner that controls costs. Hydro One recognises that customers are sensitive to the total delivered price of power. Increased investments in the distribution system result in increased cost to customers. As such, Hydro One's focus will be on executing cost control and driving productivity across the organization, as discussed in Section 1.5, in order to align customer preferences, work programs and rate impacts. Ongoing communications with customers to provide information regarding these facts will be another area of focus for Hydro One during the test years in this Application.

1.3.5 ATTACHMENTS: CUSTOMER ENGAGEMENT

Attachment	Name
1	Ipsos Distribution Customer Engagement Report
2	Customer Meeting Summaries
3	Stakeholder Session Summaries
4	First Nations Engagement Reports

DISTRIBUTION CUSTOMER ENGAGEMENT REPORT

DEVELOPMENT OF DISTRIBUTION INVESTMENT PLAN

AUGUST 2016

Prepared for:
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2P5

hydro one

Ipsos

DISTRIBUTION CUSTOMER ENGAGEMENT REPORT

DEVELOPMENT OF DISTRIBUTION INVESTMENT PLAN

AUGUST 2016

This report has been prepared by Ipsos for Hydro One Networks Inc. The conclusions drawn and opinions expressed are those of the authors.

Ipsos
160 Bloor Street East, #300
Toronto, ON M4W 1B9
Tel: 416.324.2900
Fax: 416.324.2865
www.ipsos.ca

TABLE OF CONTENTS

EXECUTIVE SUMMARY

BACKGROUND AND CONTEXT

Hydro One Networks Inc. (Hydro One) engaged Ipsos to assist with the design, execution, documentation and analysis of feedback from distribution-connected customers for its customer engagement process. Ipsos was engaged to facilitate, to develop research questions, and to provide a resulting report that is unbiased, unvarnished and evidence-based. The views contained in this report are the views of Ipsos, based on analysis of research results and views expressed by Hydro One customers.

This report documents and summarizes the feedback and insight from that engagement, and will be considered by Hydro One as it develops its investment plan to support its Distribution Revenue Requirement and Rate Application for 2018–2022. This application is to be submitted to the Ontario Energy Board (OEB) in early 2017.

Hydro One's customer engagement process contemplates the enhanced engagement between utilities and their customers as described in the OEB's Renewed Regulatory Framework for Electricity (RRFE). The RRFE holds the expectation that utilities, "… demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has

been informed by appropriate consultation…" The expectation therein, that utilities provide an overview of associated customer engagement and outreach activities in their applications and that they demonstrate how customers' feedback and needs have been reflected and considered, further shaped Hydro One's approach.

By engaging Ipsos, the company set out to establish a best-in-class customer engagement process. The multi-segmented and multi-channel approach undertaken by Hydro One over a period of approximately three months, provided the opportunity for all segments of the company's distribution-connected customers across the province to participate in the process. As a result, 19,904 Hydro One customers provided their input into this process.

CUSTOMER ENGAGEMENT GOALS

- Establish a comprehensive, best-in-class approach to customer engagement.
- Establish an inclusive, accessible, verifiable, and transparent process to secure the input/feedback necessary to prepare an investment plan and Distribution Rate Application that considers Hydro One's customers' needs and preferences.
- Ensure the associated customer and stakeholder research and feedback meets the spirit and the intent of the RRFE.

CUSTOMER ENGAGEMENT OBJECTIVES

- Establish the process and conditions for effective customer engagement that captures the feedback of all distribution customer segments.
- Ensure every customer has the opportunity to participate.
- Take a research-based approach to customer engagement to gather the data necessary to support an informed and representative view.
- Contribute to unbiased analysis of customer input by engaging external research professionals.
- Demonstrate flexibility and provide tangible evidence of Hydro One's willingness to listen, learn and establish plans that reflect and respect the needs of its customers.

OTHER CONSIDERATIONS FOR CUSTOMER ENGAGEMENT

- Hydro One's customers are geographically dispersed, so it is important to reflect this in a multi-channel communications strategy to reach and encourage as many customers as possible to participate.
- Customer engagement should take place as early as possible to build trust and awareness of the process, and more importantly, to ensure time to develop investment plans based on customer input.
- The process must be professional, well-executed and conducted in a manner that clearly and consistently states the aims, rules, process for all involved.
- While investment scenarios were developed for the customer engagement process with Large Customers, the company does not have a recommended scenario, nor will it ask customers to choose from scenarios presented.
- Customer views and input will be reflected in a resulting investment plan.

GLOSSARY OF TERMS

The following terms are used throughout the report.

TERM	MEANING
Directional differences	Refers to comparisons between sub-groups of customers where the differences cannot be said to be statistically significant
'Informed' Customers	Refers to customers who were provided with additional information about Hydro One's network/business
Large Customer	Refers to the aggregate of the following Large Customer segments: Commercial and Industrial (which will be referred to as C&Is), Large Distribution Accounts (which will be referred to as LDAs), Local Distribution Companies (which will be referred to as LDCs), Connected Distributed Generators (which will be referred to as DGs)
Local Distribution Companies (LDCs) and Distributed Generators (DGs)	Throughout the report, the Local Distribution Companies (LDCs) and Connected Distributed Generators (DGs) (>10 kW) have been managed as one segment; both are supported by the same Key Account Executives
Residential and Small Business Customer (R&SB)	Refers to the aggregate of Residential, Seasonal and Small Business customer segments
Small Business Customer	Refers to General Service customers (<50 kW peak demand and 50 to <500 kW peak demand)
'Uninformed' Customers	These customers did not receive the additional information that 'Informed' Customers did

SUMMARY OF FINDINGS

The following summary is based on the collective feedback of 19,904 distribution customers who provided 20,062 responses through the various customer engagement activities. A full detailing of the customer engagement activities are provided in the Methodology section of this report. Detailed findings from each distribution customer segment are also provided in later sections of this report.

The findings of the engagement process are grouped thematically:

1. Costs
2. Customer priorities
3. Level of reliability customers expect
4. Types of reliability improvements customers value
5. Willingness to accept a rate increase to maintain and improve service levels

1. COSTS

Keeping costs as low as possible is customers' top priority. This was evident across most of Hydro One's distribution customer segments, with the exception of local distribution companies who place a greater priority on receiving reliable service, both in terms of the number and duration of interruptions.

"If there is a way to improve both [service and cost], obviously that is ideal, but if I'm going to weigh one over the other, then I'm going to choose the cost."

Among R&SB customers, the preference for keeping costs low is influenced by three factors:

1. The majority of customers indicate that the current level of reliability and service they receive from Hydro One is in line with their expectations, and therefore there is not a strong desire for improved service, particularly if it means raising rates.

"The service is consistent with very few outages."

"I would rather the company not worry about improving the other areas and instead concentrate on keeping costs low for customers."

2. The preference for keeping costs low, for some customers, is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. There is a perception among some customers that Hydro One has not demonstrated this in the past, and thus some customers do not accept that rate increases are necessary.

"If Hydro [One] had ever been well-managed, they would have known years ago that the equipment needed to be dealt with and would have been looking towards that and doing that every year so that their equipment did not become outdated and go beyond its life expectancy. So, now they're saying all this needs to be done and dealt with and they're already in debt and they're already gouging us with hydro rates. And now they're saying this all has to get fixed. This is how they're trying to justify the extra increase so they can deal with this, but why wasn't this dealt with years ago?"

"I think it's unreasonable honestly because I know the company's net assets have increased 13% since 2012, and something like 4,000 employees have made the Sunshine List, earning over $100,000 a year on the public dime. So, I think it's a little unreasonable to be dipping into the customer's pocket to sustain the level of outages that I personally feel is a little unreasonable."

3. The final factor is that for some customers, electricity costs represent a financial challenge, and are approaching being unaffordable. These customers feel that they simply can't afford an increase in rates. The reference to rates is in relation to the overall bill, rather than a specific comment about the distribution delivery rate charge. This was heard primarily in focus groups and in Workshop feedback from C&I customers, rather than arising from survey responses.

"…some months, I have problems paying my hydro bills. So, because of the rates of hydro and all the additional delivery charges and all of that other stuff that comes on your bill, I actually had to go to equal billing in order to be able to pay my hydro, and that's crazy."

"…electricity prices are certainly surpassing my wage [increases]. So, I always think of it that way that I'm definitely paying more out of pocket in proportion to my income."

2. CUSTOMER PRIORITIES

For those who identify cost as their top priority, maintaining reliable electricity service is consistently their second priority. Many Large Customers, particularly C&I businesses, are facing reliability challenges. For many of them, power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, is their primary concern and many express that improvements are needed for their businesses to remain competitive and grow. Other customers are facing capacity challenges and want more access to power in order to grow their enterprises.

Customer service improvements, while desired particularly among Large Customers, are not something for which customers are willing to pay higher rates. However, it is clear that customer service issues for C&I and Small Business customers need to be better addressed for these customers to feel heard. The customer service issues raised by these customers during the customer engagement range from those with relatively specific and potentially simple solutions, such as improving the way in which Hydro One communicates with Large Customers during outages/interruptions and doing a better job explaining the charges (such as Global Adjustment) on the bill, as well as correcting outstanding billing errors, to more complex issues such as the need for greater and more prompt support for capacity expansion applications, as well as for incentive programs.

The sentiments expressed by customers indicate that there is a significant opportunity for Hydro One to improve its communication and overall interaction with Large Customers, specifically C&I customers. The customer engagement activities also exposed several areas where customers, both large and small, lack a sufficient level of awareness or have misconceptions of what is within Hydro One's purview, what is mandated by the OEB, what is the responsibility of the Independent Electricity System Operator (IESO), and what is the role of government in setting policy and directing the IESO on the province's fuel mix, the price of electricity, and cost attribution.

3. THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

As outlined in the Methodology section of this report, Hydro One and Ipsos sought to compare the needs and preferences of R&SB customers in two contexts:

- One representing the average 'uninformed' customer (who received no additional information prior to providing input, as noted below); and,
- One representing customers who prior to answering questions have been informed about Hydro One, its service territory, its performance in terms of the average number and length of power outages and why outages occur. This group of customers is referred to as 'informed' customers throughout the report.

'Uninformed' R&SB customers took part in the Telephone Survey, and were not provided with the informational Workbook about Hydro One, unlike 'informed' customers.

The exercise found several similarities between 'informed' and 'uninformed' customers including that both groups indicate that keeping costs low is their top priority and that reducing the number and duration of power outages that they experience today is their second priority. The level of reliability that customers expect appears to be one of the areas where the views of 'informed' customers differ from that of 'uninformed' customers. 'Informed' customers are directionally more likely to say the current number and average length of outages they experience are worse than they expect.

The majority of 'uninformed' R&SB customers indicate that the level of reliability they currently experience is in line with their expectations or better. Residential and Small Business (non-Seasonal) customers report experiencing an average of roughly three outages of at least one minute in duration in the past 12 months, with Seasonal customers averaging about two outages. The largest share of 'uninformed' customers, 48% of Residential and 55% of Seasonal, indicate that this level of reliability (number of outages) is about what they expect. Only 16% of Residential and 17% of Seasonal customers indicate the number of outages they experienced is worse than they expect. Comparatively, among the 'informed' customer group, more customers (25% of Residential and 35% of Seasonal customers) indicate the number of outages they experienced is worse than they expect. This group is also directionally more likely to say the average length of outages is worse than they expect.

Large Customers as a group are much more concerned with the reliability of service they currently receive than represented in the views of R&SB customers. Under the illustrative scenarios presented by Hydro One in Large Customer Workshops, they are much more inclined to value better reliability, but are not willing to entertain the corresponding rate impact.

4. THE TYPES OF RELIABILITY IMPROVEMENTS THAT CUSTOMERS VALUE

Large Customers were provided with six various investment options that Hydro One could prioritize and asked to rank each of them in order from one to six, where one represents the item that would have the greatest positive impact on their organization and where six represents the item that would have the least positive impact. All Large Customer segments, to a lesser extent C&I, prioritize the Renewal Program that focuses on replacing equipment that affects reliability ahead of other options for improving reliability. Other options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages.

Views on secondary and tertiary priorities vary somewhat. LDA customers place the second greatest priority on the Smart Grid, that is, using technology to reduce their chances of losing power. They place this slightly ahead of increased tree-trimming and grid strengthening. LDC/DG customers place tree-trimming in the second position – in fact nearly as many of these customers feel this would have the greatest positive impact on them as those favouring the Renewal Program. C&I customers actually place as much of a priority on grid strengthening as the Renewal Program and then place investments in Smart Grid as their tertiary choice.

When it comes to ranking other service-related options, of which there were seven to rank, all Large Customer segments prioritize providing more accurate estimates of when power will be restored. But, this is followed closely by power quality – that is, monitoring and reducing the number of power quality issues (e.g., your lights flickering). LDA customers actually place this slightly ahead of more accurate power restoration estimates.

5. WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

A majority of R&SB customers who offer an opinion are willing to accept the rate impact shown during the customer engagement activities – roughly an additional 1% of the total monthly bill each year for five years – that would maintain the current reliability and service levels. 'Informed' customers – particularly among the Seasonal customer segment – are directionally more willing to accept the rate impacts that would maintain the current number and average length of outages than the average 'uninformed' customer. The majority of R&SB customers are unwilling to accept higher rate impacts for better reliability regardless of whether they are 'informed' or 'uninformed'.

Hydro One's Large Customers generally accept that investments are needed to address the company's aging infrastructure and distribution system. However, they expect Hydro One to exhaust all operational efficiencies before raising rates. As such, at present there is limited acceptance of any of the illustrative rate impact scenarios, even to maintain the current levels of reliability and service. Directionally, between the three scenarios posed – one each for improving, maintaining and degrading reliability – Large Customers are more likely to accept larger rate impacts to maintain and improve reliability than smaller rate impacts for declining reliability.

Rate increases are difficult for many Large Customers to accept as they have concerns and need more information about Hydro One's operational efficiencies and its ability to effectively manage costs. Further, they need to be assured the company has sufficiently explored other options. The opinions of some are influenced by negative experiences they have had in the past that they associate with Hydro One's poor decision-making. This is particularly true of those who struggle with their electricity supply, either in terms of reliability and/or capacity, as well as those who have had billing problems and/or difficulty getting the answers they feel they need from the company.

"I do think you have not been efficient in the last 20 years and I think there's a lot of costs you can cut…what do you think is acceptable, 2.5% or 4% increase...How efficient have you become in the last 5 years, do you have that?"

Negative experiences with and poor perceptions of Hydro One have bled into their view of the company's ability to make prudent, cost-efficient investment decisions. They question Hydro One's current operational effectiveness, and believe that maintaining and improving the system can be achieved by managing costs more effectively rather than increasing rates. As well, because customers perceive that Hydro One is a monopoly in its service area, they are reluctant to believe that the company has the desire to get better.

For some Large Customers, the current high cost of electricity means that a rate increase of any size and on any line item of their bill is unaffordable, and a direct threat to the viability and the competitiveness of their businesses in Ontario. Unfavourable comparisons to prices in other jurisdictions were made several times, as participants perceive that Ontario has one of the highest costs of electricity of any jurisdiction in North America. A rate increase by Hydro One needs to include customer-facing, public details on operational efficiencies, as well as information as to how the company has effectively managed costs to date. The investment plan should detail tangible benefits to the customers who struggle most with reliability — addressing power quality concerns and regional concerns. The plan should also detail how Hydro One can address those with additional capacity needs.

"Good for Hydro One. They've been under the radar, [but it is] very brave of [them] to come out and do these sessions."

"How can we see a rate increase of this magnitude in general, but particularly for decreasing service? Why are there seemingly no attempts to maintain service but to reduce YOUR operating costs?"

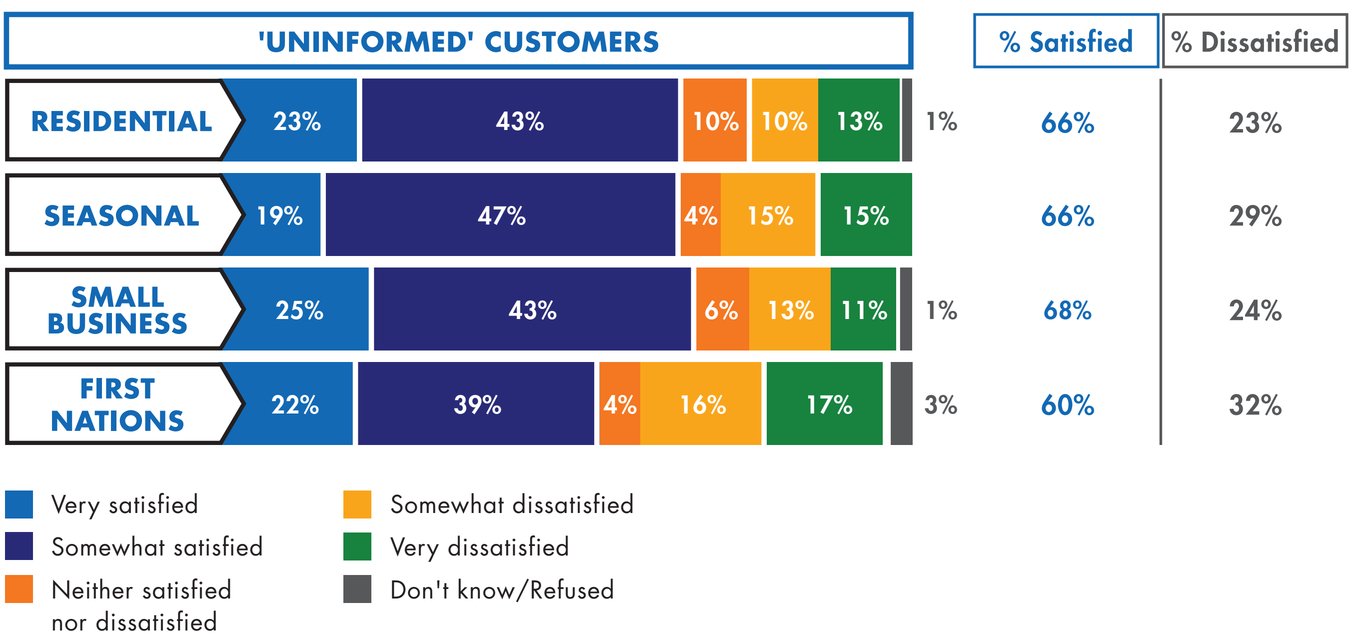
"[I] would have liked to see some slides on what Hydro One is doing internally to identify opportunities to create operational efficiencies and reduce costs internal to the organization."

Overall, as evidenced by the comments and questions raised during the in-person Workshops, the Distribution Customer Engagement was successful in raising awareness of Hydro One's past investment planning and performance, in receiving a wide variety of detailed feedback from all its customer segments, and in positively affecting perceptions of the company by making an effort to engage and listen.

KEY THEMES

Satisfaction with Hydro One does not vary significantly between 'uninformed' customer segments. There is more variation between the 'informed' customer segments including between Large Customer segments. 'Informed' Residential customers report lower satisfaction than 'uninformed' customers.

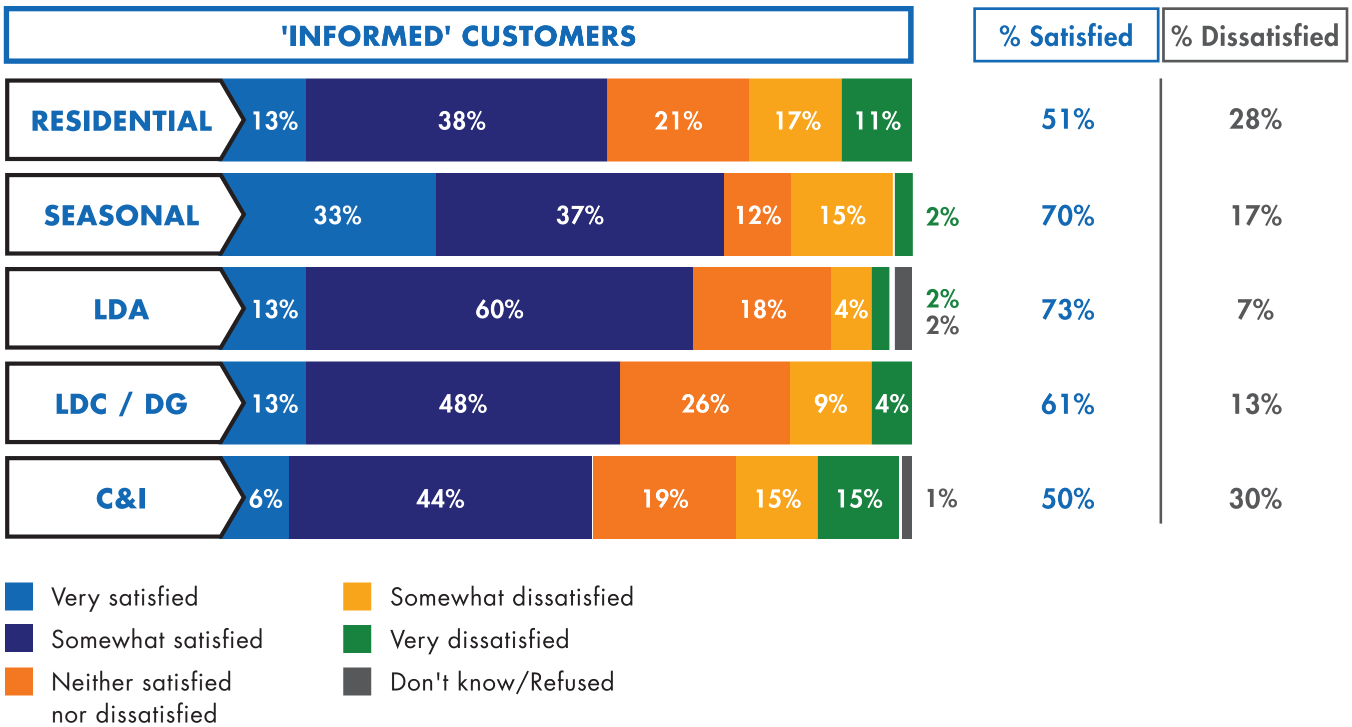
ALL CUSTOMER SEGMENTS
OVERALL SATISFACTION WITH HYDRO ONE



As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Telephone Survey: Residential (n=243), Seasonal (n=68), Small Business (n=159), First Nations (n=204)

ALL CUSTOMER SEGMENTS

OVERALL SATISFACTION WITH HYDRO ONE



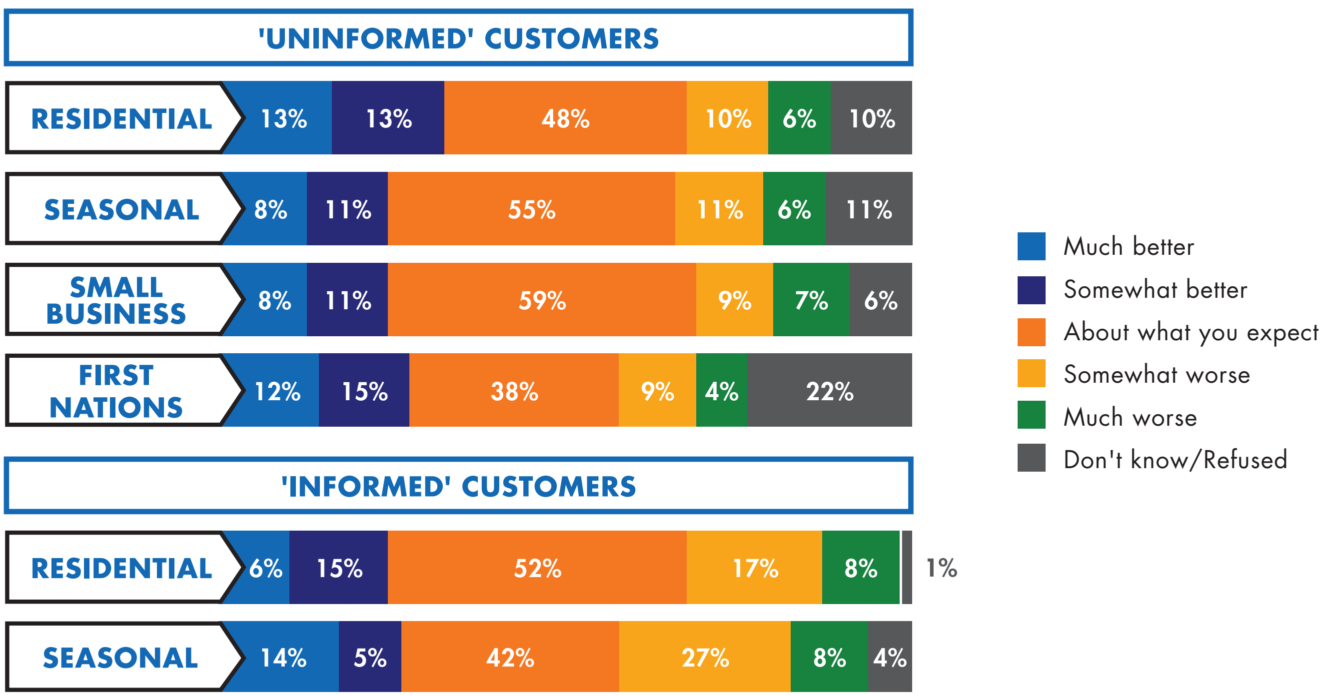
As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Online Workbook: Representative Sample: Residential (n=1384), Seasonal (n=98) / Large Customers: LDA (n=45), LDC/DG (n=23), C&I (n=133)

The largest share of 'uninformed' customers indicate that the current number and average length of outages they experience is about what they expect. 'Informed' customers are directionally more likely to indicate it is worse than they expect.

TELEPHONE SURVEY + ONLINE WORKBOOK REPRESENTATIVE SAMPLE

RELIABILITY EXPECTATIONS

NUMBER OF OUTAGES

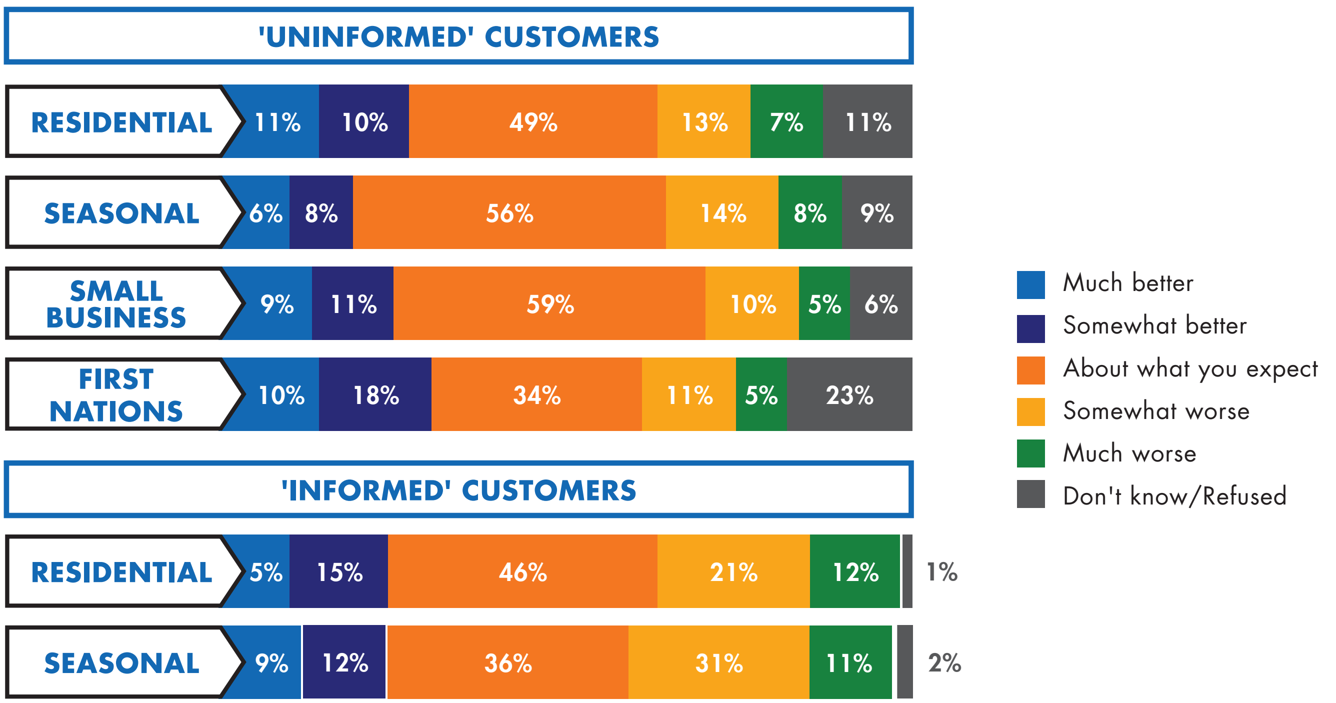


Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66) Small Business (n=144), First Nation (n=217). Informed: Residential (n=977), Seasonal (n=52)

TELEPHONE SURVEY + ONLINE WORKBOOK REPRESENTATIVE SAMPLE

RELIABILITY EXPECTATIONS

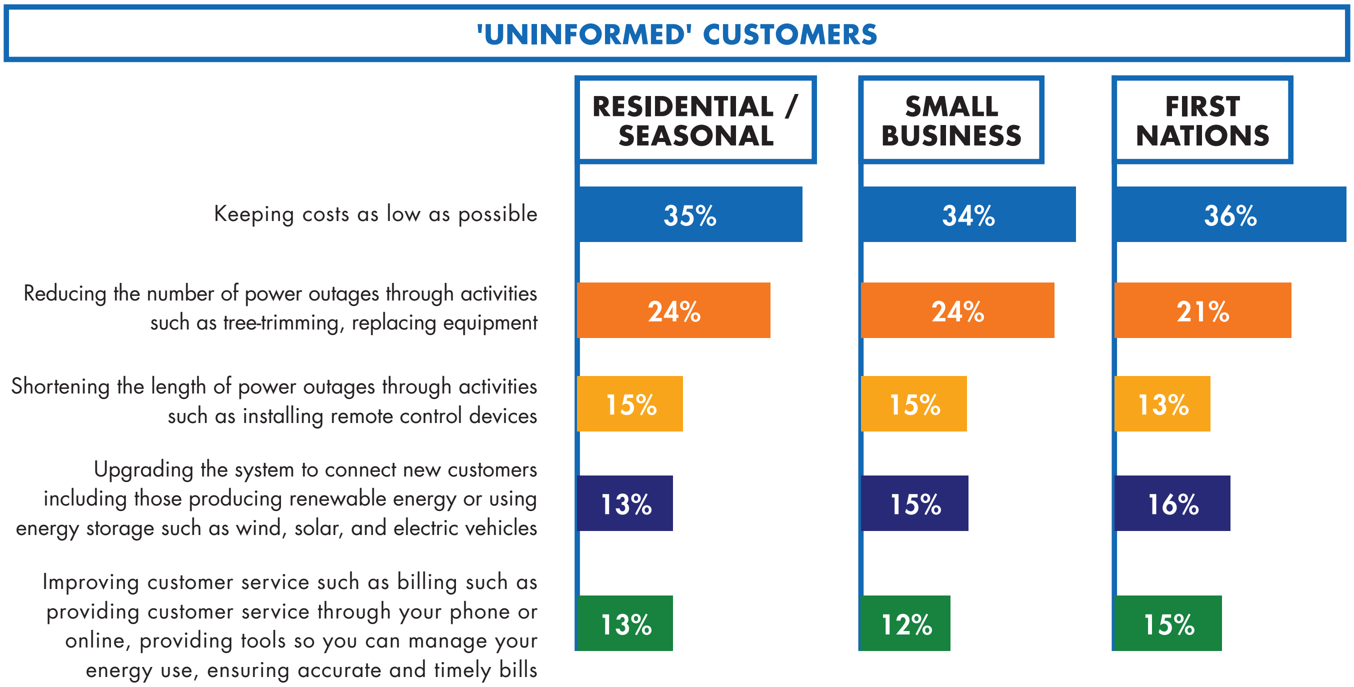
LENGTH OF OUTAGES

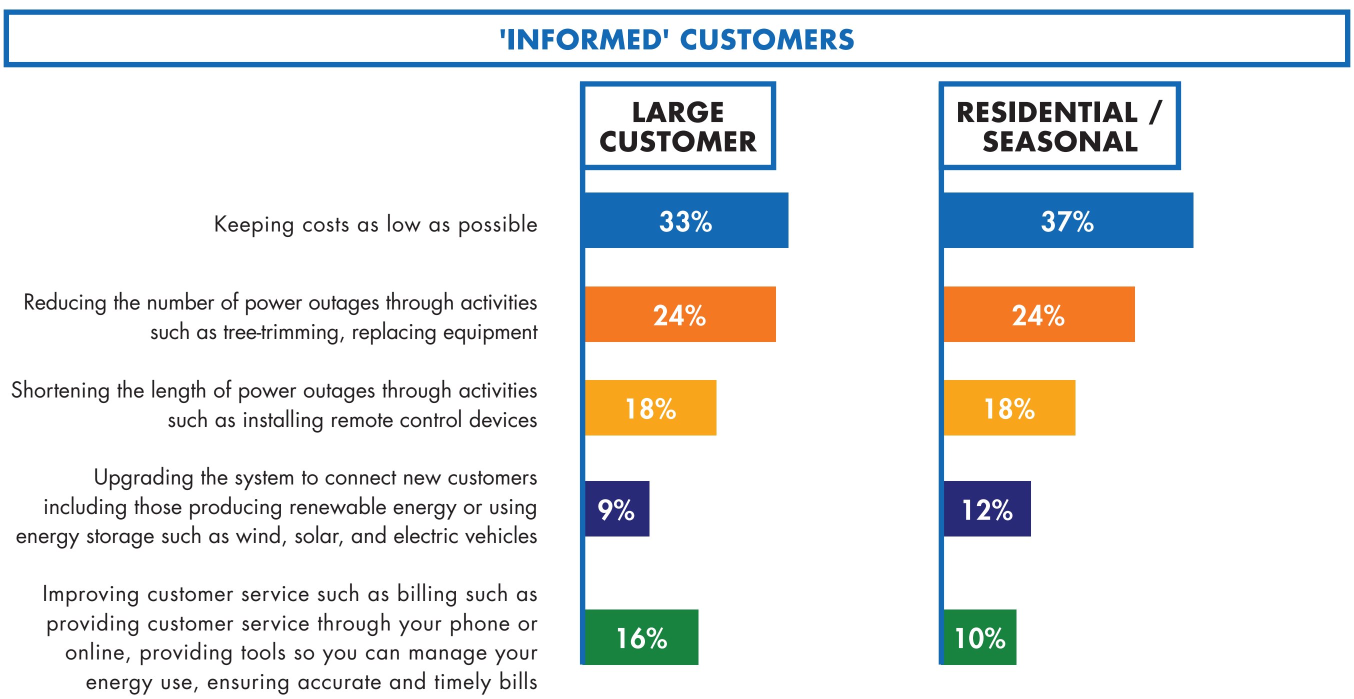


Q10. In general, when you think about the average length of the power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66) Small Business (n=144), First Nation (n=217) Informed: Residential (n=977), Seasonal (n=52)

All customer segments prioritize keeping costs as low as possible over improvements in other areas. Reducing the number of power outages is consistently the second priority among customers.

ALL CUSTOMER SEGMENTS
CUSTOMER PRIORITIES



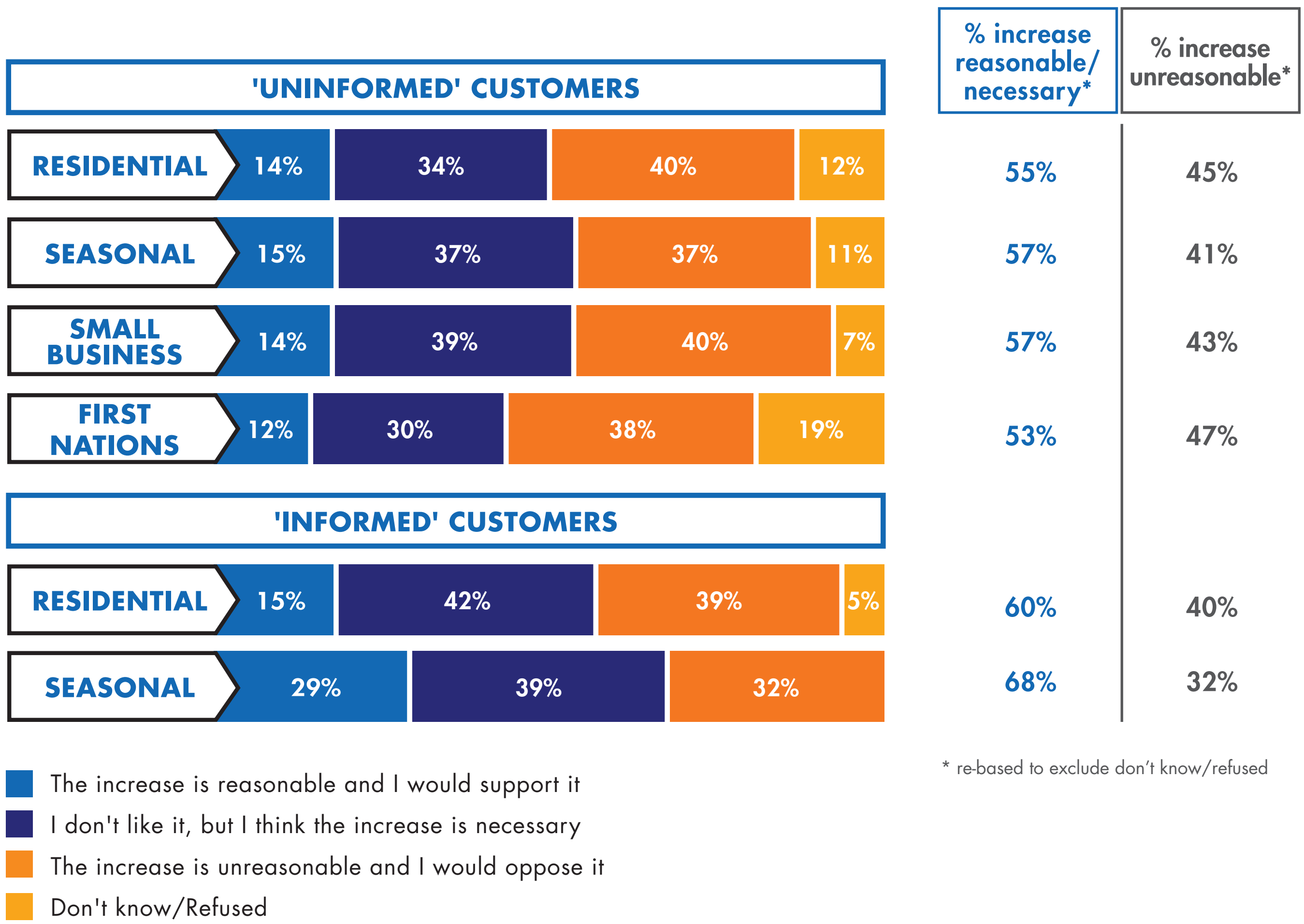


Q5. Hydro One would like to better understand what is important to you as a [insert] customer. [Below is /I am going to read] Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Paired choice preferences relative to other options. Base: Uninformed - Residential/Seasonal (n=499). One respondent opted not to answer, Small Business (n=199). One respondent opted not to answer Q5., First Nations (n=300). Informed - Large Customers (n=87). Base: Residential/Seasonal (n=1604).

When posed with a roughly 1% rate increase on the total monthly bill, per year for five years, acceptance varies from 53% to 57% among 'uninformed' customers who had an opinion (i.e., excluding don't know/refused) and from 60% to 68% among 'informed' customers.

TELEPHONE SURVEY + ONLINE WORKBOOK REPRESENTATIVE SAMPLE

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



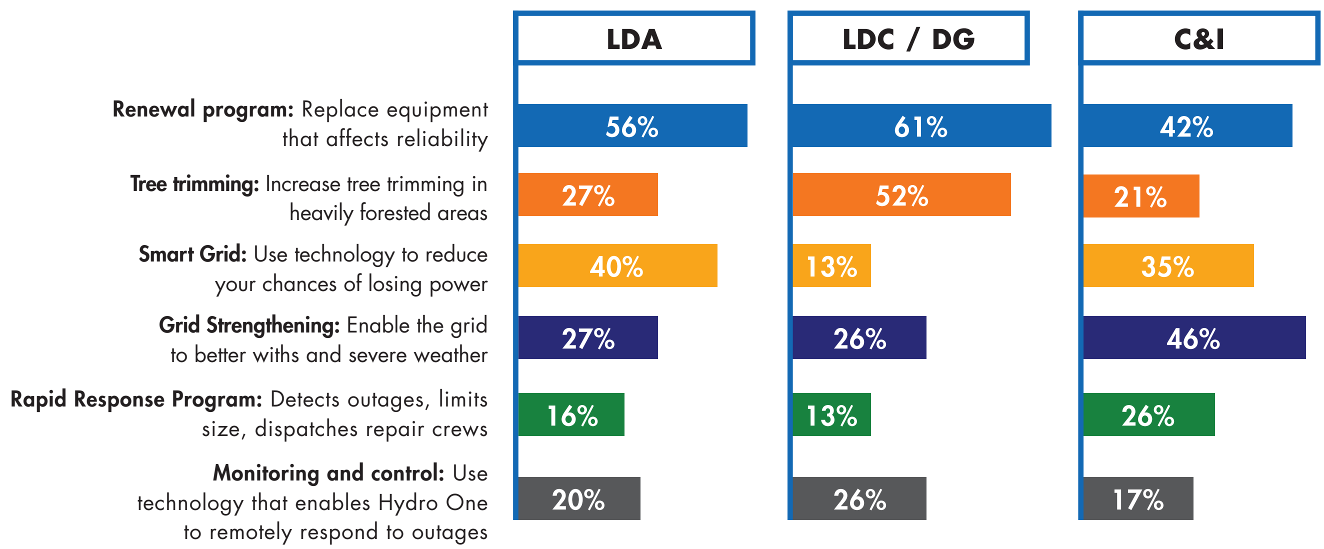
Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [residential or seasonal / small business] customer's total monthly bill will need to increase by [IF residential or seasonal 1.1% or the equivalent of $2.00 / IF small business 1% of the equivalent of $5.20]. The increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF residential or seasonal $10.00 / IF small business $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Note that for the Telephone Survey, this question was posed as Which of the following is closest to your point of view? Base: Uniformed -Residential (n=400), Seasonal (n=100), Small Business (n=200), First Nations (n=300). Informed - Residential (n=1502), Seasonal (n=102)

All Large Customer segments, but to a lesser extent C&I, prefer that Hydro One focuses on replacing equipment that affects reliability ahead of other reliability improvement efforts. LDA customers place the second greatest priority on the Smart Grid, that is using technology to reduce their chances of losing power. They place this slightly ahead of increased tree-trimming and grid strengthening. LDC/DG customers place tree-trimming in the second position – in fact nearly as many of these customers feel this would have the greatest positive impact on them as those who favour the Renewal Program. C&I customers actually place as much of a priority on grid strengthening as the Renewal Program and then place Smart Grid as their tertiary preference.

ONLINE WORKBOOK/WORKSHOP SURVEY BOOKLET

CUSTOMER PREFERENCES FOR WAYS TO IMPROVE RELIABILITY

Percentages shown represent % who ranked the item in the first or second position.



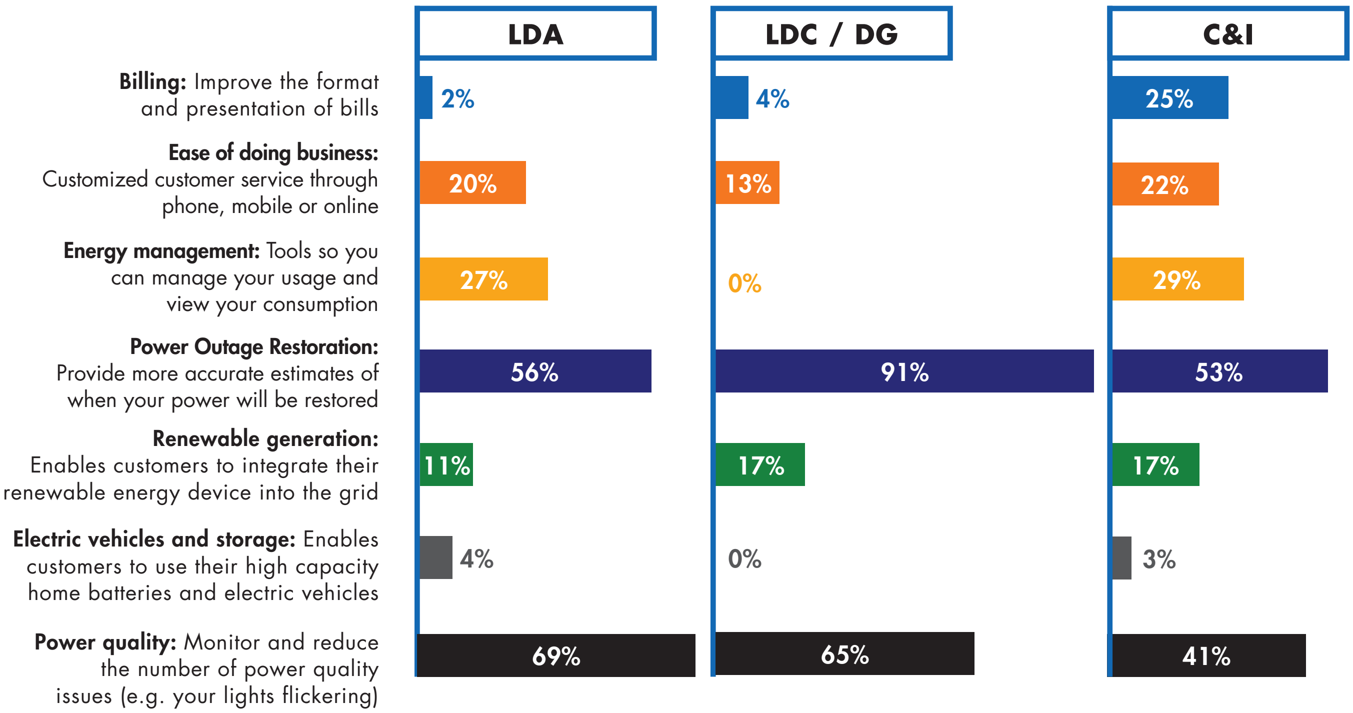
Q11. Please rank the RELIABILTIY items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 6 represents the least positive impact. Base: LDA (n=45), LDC/DG (n=23), C&I (n=133)

When it comes to ranking other service-related options, the top two preferences are more accurate estimates of when power will be restored and for better power quality – that is, monitoring and reducing the number of power quality issues (e.g. your lights flickering).

ONLINE WORKBOOK/WORKSHOP SURVEY BOOKLET

CUSTOMER PREFERENCES FOR WAYS TO IMPROVE SERVICE

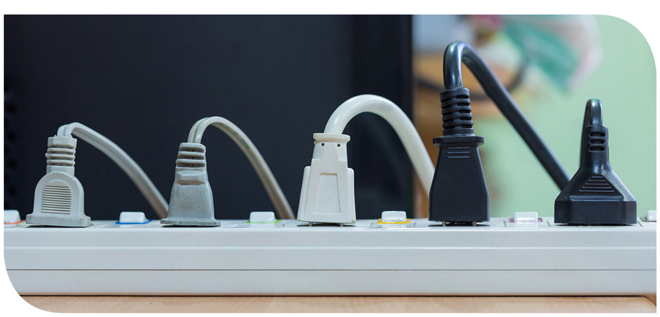
Percentages shown represent % who ranked the item in the first or second position.



Q12. Please rank the SERVICE items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 7 represents the least positive impact? Base: LDA (n=45) , LDC/DG (n=23) , C&I (n=133) Note: for the online workbook, Billing was worded as - Ensure you receive timely and accurate bills, Ease of doing business was worded as - Seamless customer service through phone, mobile or online

CONTEXT AND BACKGROUND

Hydro One's Distribution Customer Engagement process contemplated the enhanced engagement between utilities and their ratepayers as described in the Ontario Energy Board's (OEB) *Renewed Regulatory Framework for Electricity* (RRFE). The RRFE holds the expectation that utilities "…demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation…" The expectation therein for utilities to provide an overview of associated customer engagement and outreach activities in their application, and to demonstrate how customer feedback/needs have been reflected and considered, further shaped Hydro One's approach. This is in-line with Hydro One's approach and desire to provide customers with the opportunity to provide input into key activities that affect customer service, product offerings and future initiatives.



Ipsos was commissioned by Hydro One to assist with the design, execution, documentation, and analysis of feedback for the customer engagement process. By engaging Ipsos, a third-party research firm, the company set out to establish a best-in-class customer engagement process by ensuring that facilitation, the development of research and questions, and the report writing provided an unbiased, unvarnished, evidence-based report to support the filing. As a key element of its application for distribution rates, the outcome of this customer engagement process will help to determine Hydro One's electricity distribution rate application for a five-year period between 2018 and 2022.

The role of the customer engagement process is to ensure Hydro One's distribution investment plan is informed by customer needs, preferences and priorities.

Customer engagement is critical for the Hydro One Distribution filing with the Ontario Energy Board. To ensure the strongest approach, Hydro One:

- Leveraged lessons learned from its recent Transmission-Connected Customer engagements to create an approach tailored to the unique needs of Hydro One's distribution customers;
- Engaged a third-party vendor to ensure research methodologies and Workshop facilitation were unbiased and thorough;
- Focused the scope of the Workbooks and Workshops such that investment plans can readily incorporate customer input where advisable;
- Used several different approaches to obtain qualitative and quantitative information from customers of all distribution segments (where possible);
- Took advantage of the customer engagement process to begin a conversation with customers about issues and concerns that matter most to them; and,
- Took the necessary steps to ensure the overall process was accessible and transparent.

Further, Hydro One's application filing must demonstrate that services are provided "in a manner that responds to identified customer preferences."

As such the customer engagement objectives were to obtain customer feedback on their following:

- Customers' level of satisfaction with Hydro One and desired improvements;
- Customer expectations of reliable electricity distribution;
- How customers prioritize or trade-off spending on reliability, customer service, upgrades to the system to connect renewable energy customers, and keeping costs low as possible;
- The types of reliability improvements that customers value; and,
- Willingness to accept rate impacts to maintain and/or improve reliability and service levels.

[1] Ontario Energy Board, *Renewed Regulatory Framework for Electricity*, October 2012, Section 2.5

DESCRIPTION OF HYDRO ONE'S DISTRIBUTION CUSTOMER SEGMENTS

As the largest electric distribution utility in Ontario, Hydro One serves several different residential and business segments:

- Residential & Small Business (R&SB) – about 1.3 million customers
- Commercial & Industrial (C&I) – about 8,000 customers
- Large Distribution Accounts (LDA) – 92 customers
- Local Distribution Companies (LDC) – 59 customers (distribution connected)
- Connected Distributed Generators (DG) – 966 connected Hydro One DG projects (projects greater than 10 kW)

RESIDENTIAL & SMALL BUSINESS (R&SB)

At 1.3 million strong, this is Hydro One's largest customer segment by number of accounts, although they are outnumbered by the number of poles that support them (1.6M). Representing 42% of distribution power being used, this segment includes homes, small shops, and local farms. Through previous commissioned research, Hydro One indicates that this customer segment is characterized by the following, relative to the Ontario average:

- Customers are slightly older than the Ontario average;
- They are more likely to own their homes, rather than rent;
- These homes are relatively older, with 18% built before 1946;
- There are fewer homes with central air conditioning;
- More reside in single-detached homes; and,
- Customers spend more, on average, for electricity than the rest of Ontario, with approximately 180,000 using electric heat.

COMMERCIAL & INDUSTRIAL CUSTOMERS

This segment has approximately 8,000 customers and represents 13% of distribution power used (that is, distribution load consumed). This segment includes hospitals, grocery store chains, and other businesses. The Business Customer Centre (BCC) supports this group of customers for billing and business questions. According to Hydro One, historically this customer segment's priorities have been around costs, reliability, billing, and customer service.

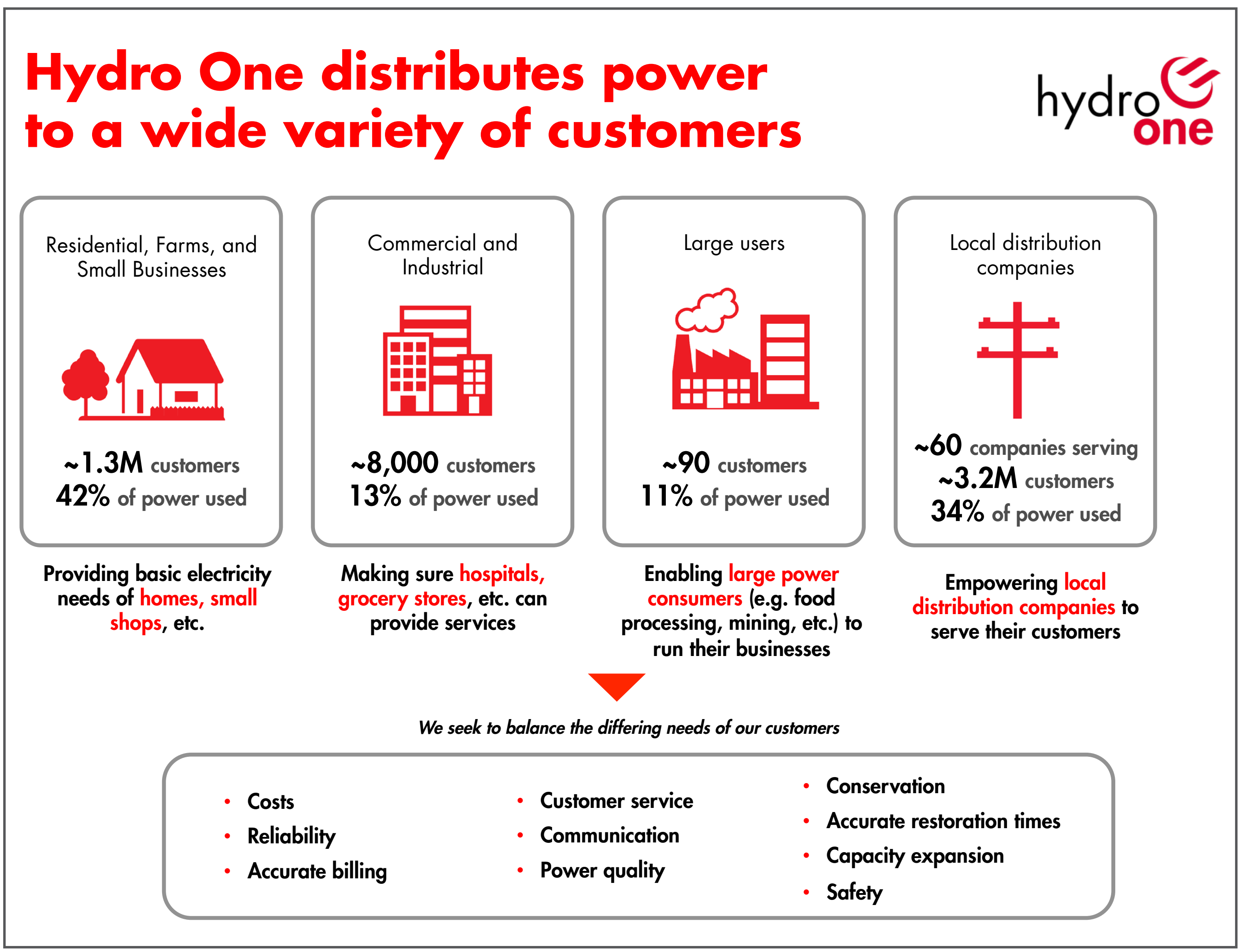
Environics Analytics, EA & Demostats 2016
2 Ibid, Section 1.0

LARGE DISTRIBUTION ACCOUNTS (LDAs)

This segment has 92 customers and represents 11% of all distribution power used. This segment includes food processing plants, automotive and related industries, mining, and other large businesses. The relationship with this customer segment is supported by Hydro One's Zone Superintendents across Ontario. According to Hydro One, historically, this customer segment's priorities have been around communication with Hydro One, conservation and demand management incentives, costs, reliability, power quality, billing, and customer service.

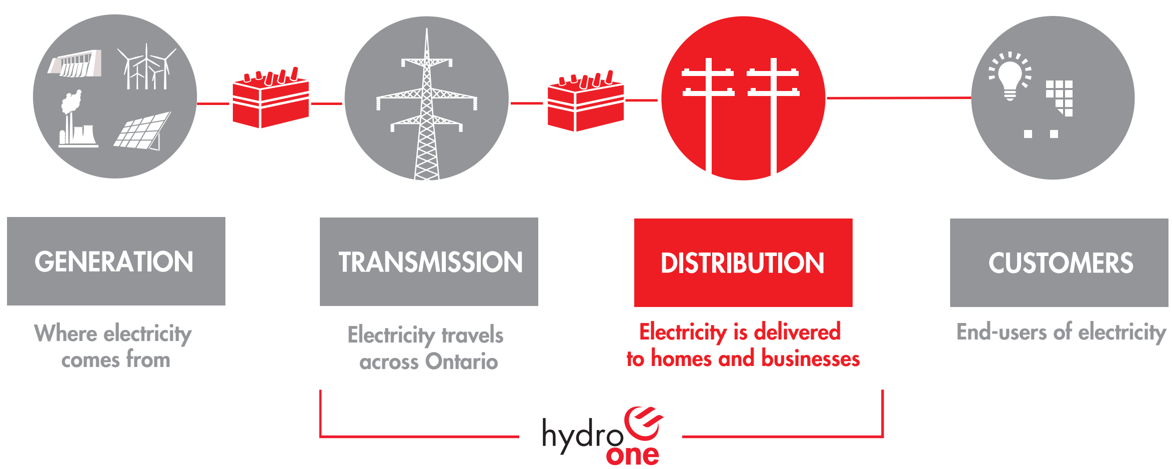
LOCAL DISTRIBUTION COMPANIES (LDCs)

This segment has 59 companies and represents 34% of all distribution power used. This segment represents the utilities connected to Hydro One's distribution system and according to Hydro One, historically, this customer segment's priorities have been around rates, reliability, and capacity expansion. This customer segment is supported by Hydro One Key Account Executives. Hydro One Key Account Executives also support DGs (>10 kW) which are smaller scale energy providers with plants close to the point of energy consumption (e.g., solar, thermal, wind).



DESCRIPTION OF HYDRO ONE'S DISTRIBUTION BUSINESS

Hydro One's operations cover more than 600,000 kilometres and some of the most challenging and diverse geography in Canada. Hydro One's system transmits electricity from generation sources to transmission-connected customers, and indirectly through them, to distribution customers. The Distribution Customer Engagement only addressed the Distribution portion of Hydro One's operations.



GENERATION

- Electricity is produced by generators including Ontario Power Generation, Bruce Power, NextEra and other generators.

TRANSMISSION

- **Transmission assets** convey electricity from generators to distributors and large consumers.
- Hydro One operates 96% of transmission in Ontario

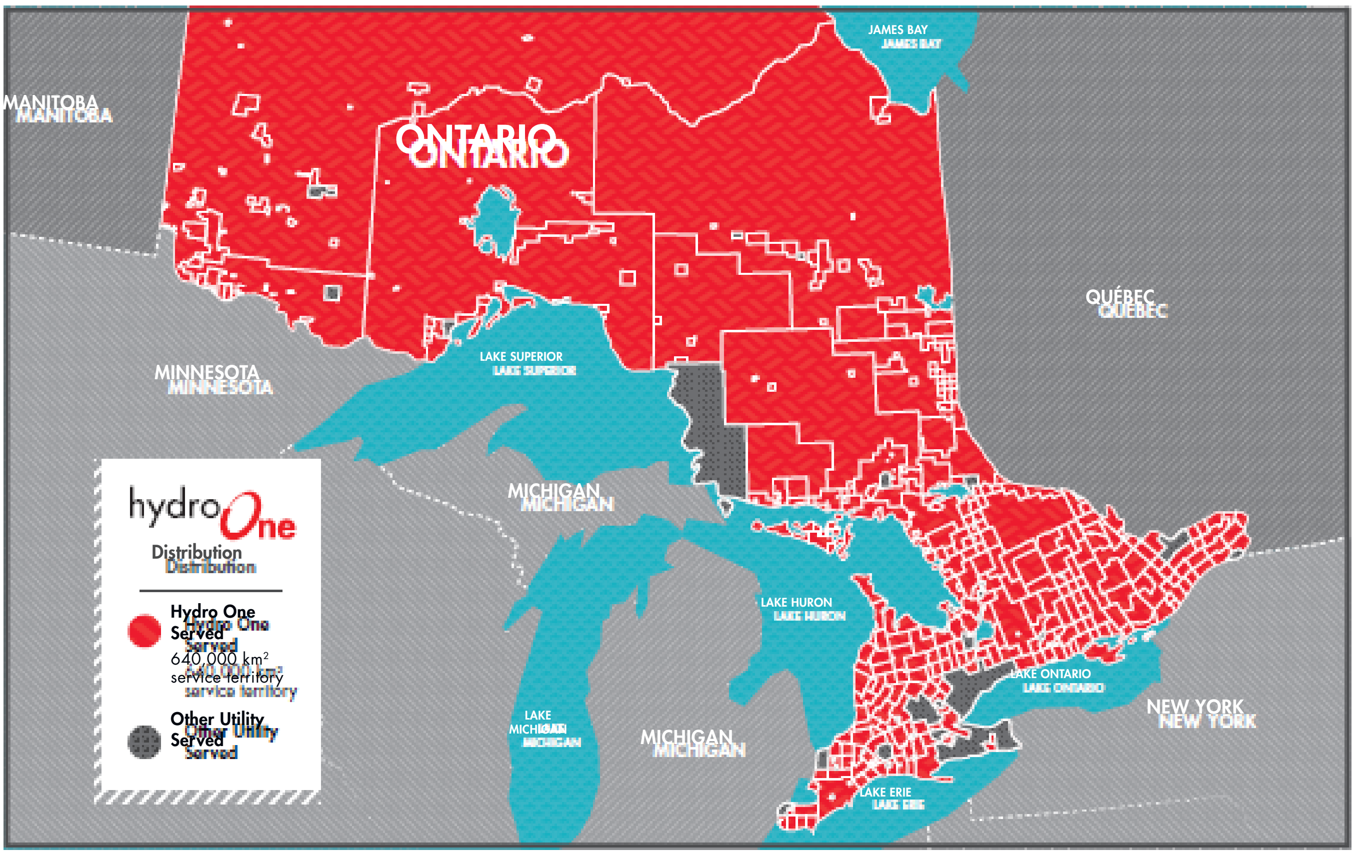
DISTRIBUTION

- **Distribution assets** convey electricity to customers.
- Hydro One distributes electricity to 25% of Ontario's population

CUSTOMERS

- **Residential**
- **Commercial and Industrial**
- **Large Consumers**
- **Other Distributors**

Hydro One's distribution assets include 123,000 kilometres of distribution power lines and approximately 1,000 distribution and voltage regulating stations. Hydro One is accountable to plan, operate, build and maintain an affordable, robust and flexible distribution system that serves Ontario's energy needs.



According to Hydro One, its investment plan will identify, prioritize, and determine pacing of the investments made in their system. On this basis, Hydro One has stated that it aims to create value by:

- Ensuring its investment plan considers and reflects the needs and preferences of its customers by achieving a balance between managing risk, service and cost, while recognizing its customers' needs and maintaining a high standard of quality;
- Recognizing that every dollar spent comes at a cost to its customers and the people of Ontario;
- Making prudent, cost-effective, short and long-term investments in the distribution system so that the electricity needs of Ontario are met now and into the future;
- Addressing emerging risks to the system, and always looking for ways to economically extend the life of existing distribution assets; and,
- Being innovative by adapting new/proven technologies, equipment and processes that contribute to the efficiency of the operation.

CUSTOMER ENGAGEMENT METHODOLGY

A COMPREHENSIVE APPROACH INVOLVING MULTIPLE METHODS OF ENGAGEMENT

In collaboration with Hydro One, Ipsos set out to design a comprehensive customer engagement methodology that is based on scientific method, by ensuring the rules of statistical validity and reliability are followed, and at the same time, is inclusive of any customer seeking the opportunity to voice their opinion. The methodology included both qualitative approaches in the form of Focus Groups and Workshop sessions and quantitative approaches including a Telephone Survey and Online Workbook.

- The qualitative components are useful to uncover the reasons behind customer needs and preferences. These components allow customers to provide open-ended feedback and provide examples to a greater degree than what is possible in a survey format.
- The Online Workbook and Telephone Survey components allow us to quantify opinions, so that Hydro One has a representative and reliable measurement of the magnitude of customer needs and preferences.

AN OPPORTUNITY TO COMPARE AND CONTRAST THE NEEDS AND PREFERENCES OF AN 'INFORMED' CUSTOMER WITH AN 'UNINFORMED' CUSTOMER

Ipsos and Hydro One also sought to explore the extent to which the needs and preferences of R&SB customers differ, if at all, when R&SB customers are provided with information about the energy sector and Hydro One. Understanding the extent to which 'informed input' from customers varies from 'uninformed input' is valuable for a few reasons:

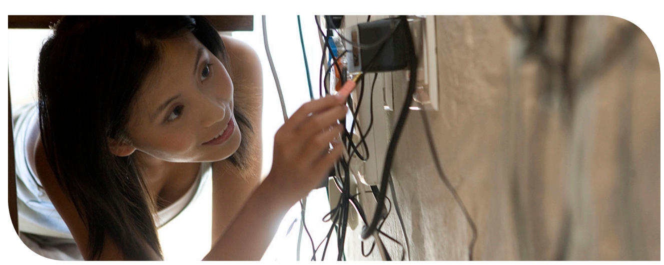
- It improves customer engagement by ensuring that the views Hydro One takes into consideration include the view of customers who are more informed about underlying issues;
- It also provides useful insight to help improve how Hydro One communicates with its customers; and,
- The findings from this approach can inform future customer engagement activities that Hydro One, other utilities, and the OEB may conduct.

Hydro One designed two informative Workbooks to share with customers – one geared toward Residential, Seasonal, and Small Business customers and one geared toward Large Customers. The goal of both Workbooks was to provide customers with background information regarding Hydro One, its service territory, its performance in terms of the average number and length of power outages, and why outages occur. The content of the Workbooks varied between R&SB and Large Customers to ensure that the illustrative examples were reflective of their respective rate classes. Unlike the R&SB customers, where one group of customers did not receive the information, all Large Customers were provided with a Workbook. This Workbook contained detailed, technical information on the ways in which Hydro One currently manages reliability and service, and the ways in which it could approach improving reliability and service for these customers. The creation of the Workbook was handled primarily by Hydro One, who had the final say on its content and design. The questions posed to customers were embedded in the Workbook and followed the relevant information being provided for context for the question. A copy of both the R&SB and Large Customer Workbooks is provided in the Appendix.

As will be described in the following sections, the Online Workbook for R&SB customers was used with two groups of R&SB customers – those who were engaged through Ipsos' online panel and those who were engaged through an Open-Link where any R&SB customer could participate. The former group was recruited to reflect a representative sample of 'informed' R&SB customers and thus could be compared to the representative sample of 'uninformed' R&SB customers who were randomly selected to participate in a Telephone Survey. The sample of customers who completed the Telephone Survey were not provided with the Workbook, and thus represent the 'uninformed' perspective.

WHO WE HEARD FROM AND HOW AND WHEN THEY GAVE THEIR FEEDBACK

Customer engagement process was conducted across all of the Hydro One's distribution customer segments. In total, 19,904 customers participated in the customer engagement. A total of 20,062 responses were received. Please note that customers responding to the Online Workbook Open-Link could answer twice if they are both a Residential/Seasonal and Small Business customer. With respect to Large Customers, some customers sent more than one representative to attend the workshop sessions, resulting in more than one response per customer. A methodology overview and total number of customers from each distribution customer segment who participated in each of the customer engagement components are shown on the next page.



WHO PARTICIPATED

	RESIDENTIAL, SEASONAL AND SMALL BUSINESS CUSTOMERS				LARGE CUSTOMERS		TOTAL NUMBER OF RESPONSES
	Focus Groups	Online Workbook (Representative sample)	Online Workbook (Open-link)	Telephone Survey (Representative sample)	In-person Facilitated Workshop†	Online Workbook	
RESIDENTIAL CUSTOMERS	32	1,502	15,689	400			17,623
SEASONAL CUSTOMERS		102	1,106	100			1,308
SMALL BUSINESS CUSTOMERS	24		406	200			630
FIRST NATIONS CUSTOMERS				300			300
LDA					40	5	45
LDC OR DG					20	3	23
C&I					54	79	133
TOTAL	56	1,604	17,201*	1,000	114	87	20,062

†One-on-one meetings were undertaken with two customers (1 LDC and 1 C&I) *A total of 148 customers who responded to the open-link survey completed the survey twice – once as a residential or seasonal customer and once as a small business customer. Therefore, the total number of responses to the open-link is 17,201 (17,053 unique respondents + 148). A total of 19,904 unique customers participated across all of the consultation components. For Large Customers the numbers provided represent the number of responses received through the Workshop booklet or the Online Workbook, not the number of organizations. Some organizations had more than one person attend the Workshops and not all participants at the Workshop completed the booklet. A total of 129 participants, representing 104 customers attended the Workshops, of which 114 completed the booklet in-person at the session.

The following section describes each customer engagement component in detail. Ipsos was responsible for collecting all of the feedback from the various activities, conducting an analysis of the feedback and writing the report. Ipsos followed its standard internal quality control protocol for data tabulation, analysis and validation to ensure the accuracy of the data. Hydro One was not involved in the data tabulation, analysis or validation process.

PARTICIPATION METHODS

RESIDENTIAL, SEASONAL AND SMALL BUSINESS CUSTOMERS

INFORMED SAMPLE (online workbook)

- A representative sample of n=1,604 Residential and Seasonal customers drawn online panel sample
- An Open-Link of n=17,201 responses representing 17,053 R&SB customers

INFORMED SAMPLE (focus groups)

- Eight online Focus Groups with 56 R&SB customers

UNINFORMED SAMPLE (telephone survey)

- These results are based on a statistically valid and reliable survey and can be projected to broader customer population
- Telephone survey of random and representative sample of n=500 residential and seasonal customers
- Telephone survey of a random and representative sample of n=200 Small Business customers (demand and non-demand)
- Telephone survey of a random and representative sample of n=300 First Nations customers

LARGE CUSTOMERS: LDA, LDC, DG AND C&I

LARGE CUSTOMERS

- Nine in-person Workshop sessions were conducted in seven cities (Collingwood, Windsor, Hamilton, Kingston, London, Thunder Bay and Timmins). A total of 129 people attended representing 104 customers.* In addition to verbal feedback, participants were provided with a Workbook to complete.
- An Online Workbook was completed by 87 customers who did not attend the in-person Workshop sessions.**

*Two one-on-one meetings were conducted with large customers in lieu of attending a Workshop session. In both cases, an Ipsos note-taker was present to record the conversation. ** The Online Workbook presented the same information that was shared at the Workshop and posed nearly identical questions. The only difference in the questions was that the Online Workbook used a statistical technique called paired-choice to quantitatively measure the relative importance customers place on various aspects of service. This technique could not be replicated in hard-copy, thus the Workshop survey booklet used a "pick the most important" approach instead.

DETAILED CUSTOMER ENGAGEMENT FINDINGS

DESCRIPTION OF THE ENGAGEMENT WITH RESIDENTIAL/SEASONAL, SMALL BUSINESS CUSTOMERS

R&SB customers were consulted using both qualitative and quantitative approaches. There were three quantitative components and one qualitative component:

1. **Telephone Survey: Representative Sample.**
   A representative Telephone Survey of Residential, Seasonal, Small Business, and First Nations customers, the results of which can be generalizable to the broader customer base. This sample was not provided with the informational Workbook and thus represents the 'uninformed' view.

2. **Online Workbook: Representative Sample.**
   A representative sample of Residential/Seasonal customers completed an Online Workbook which involved the same questions that were asked in the Telephone Survey, but what makes it a Workbook is that customers were provided with information prior to answering the questions. This sample represents an 'informed' view. The sample was drawn from Ipsos' online panel.

3. **Online Workbook: Open-Link Sample.**
   A publicly available version of the Online Workbook that was distributed broadly through public channels for interested customers subject to qualification rules described in a later section. To distinguish the results of this component from the Online Workbook conducted with the representative sample, it will be referred to as the 'Open-Link' sample.

4. **Focus Groups:**
   Finally, Focus Groups were conducted with R&SB customers to drill down into greater detail on some of the findings from the Telephone Survey.

A full description of each of these components is provided below.

1. TELEPHONE SURVEY: REPRESENTATIVE SAMPLE

Often times public consultations attract the strongest advocates or detractors of a particular policy or initiative and a broad, representative Telephone Survey allows us to put those results in context, reflective of the entire population and not only those who volunteer. By conducting a representative survey, we can have greater confidence that the feedback reflects the broader customer base.

The Telephone Survey was conducted with a random and representative sample of:

- n=500 Residential and Seasonal customers (n=400 Residential and n=100 Seasonal)
- n=200 Small Business customers
- n=300 First Nations residential customers

A stratified, random sampling approach was used to pull each of these from Hydro One's customer database and screened to ensure the respondent was the person in the household or business with primary or shared responsibility for paying the electricity bill.

They also needed to pay the bill directly to Hydro One (as opposed to their landlord or property manager if renting or leasing their home or business property). The table on the next page shows the margin of error associated with each of these samples. The margin of error has been calculated at the 95% confidence level. This means if the survey is repeated 20 times, 19 of those times the results of the survey will be the same within the margin of error. The margin of error will be larger for sub-groups.

TELEPHONE SURVEY: REPRESENTATIVE SAMPLE

	Sample Size	Margin of error (95% confidence level)	Fielding dates	Screening	Quotas	Weighting Variables	Survey length (minutes)	Response Rate
RESIDENTIAL CUSTOMERS	400	±4.9%	June 2–17, 2016	Bill payer, pay to Hydro One	Region, Density	Density (urban, medium, low)	17	13%
SEASONAL CUSTOMERS	100	±9.8%	June 2–17, 2016	Bill payer, pay to Hydro One	Region	None	17	13%
SMALL BUSINESS CUSTOMERS	200	±6.9%	June 2–17, 2016	Bill payer, pay to Hydro One	Region	Region, Demand/ Non-Demand	13	11%
FIRST NATIONS CUSTOMERS	300	±5.7%	June 2–17, 2016	Bill payer, pay to Hydro One	Region and within region urban/rural	None	18	13%

The table also describes any statistical weighting that was applied to the samples to ensure the composition reflects the true proportions in the customer database. Also shown in the table are the interviewing fielding dates, the average survey length and response rate. For all samples, the response rate was calculated using the Marketing Research and Intelligence Association's recommended response rate formula. The survey was available to all respondents in both official languages. A total of two respondents opted to complete the survey in French.

First Nations customers were included as part of the customer survey and over-sampled relative to their size within the total customer base to ensure we reliably captured the needs and preferences of this important customer group.

In some instances, responses to survey questions may total to greater than 100% due to rounding or because respondents were permitted to provide more than one response, such as in open-ended questions. This is in keeping with standard research practice.

2. ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

The primary purpose of conducting the Online Workbook with a representative sample of Residential and Seasonal customers is to have an understanding of the opinions of a representative sample of customers who have been informed about Hydro One, its service territory, its performance in terms of the average number and length of power outages its customers experience, and why outages occur prior to answering questions. A total of n=1,502 Residential customers and n=102 Seasonal customers completed the Online Workbook. The sample was drawn from the Ipsos' online panel. The data was weighted by Residential vs. Seasonal and region/urban/rural customers. A breakdown of the regional/urban/rural sample composition and a copy of the questionnaire is provided in the Appendix.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

	Sample Size	Fielding dates	Screening	Quotas	Weighting Variables	Survey length (minutes)
RESIDENTIAL CUSTOMERS	1,502	June 2–23, 2016	Bill payer, pay to Hydro One	Region	Region/ urban/rural	15
SEASONAL CUSTOMERS	102	June 2–23, 2016	Bill payer, pay to Hydro One	Region	Region/ urban/rural	10

The table above describes any statistical weighting that was applied to the samples to ensure the composition reflects the true proportions of Hydro One's customers. Also shown in the table are the interviewing fielding dates and the average survey length. In keeping with industry standards, it is not appropriate to quote a margin of error for non-probability based, opt-in surveys and thus we have not reported a margin of error on the Online Workbook results. The survey was available to all respondents in both official languages. A total of 15 respondents opted to complete the survey in French.

As noted previously, in some instances, the percentages reported may total to greater than 100% due to rounding or because respondents were permitted to provide more than one response, such as in open-ended questions. This is in keeping with standard research practice.

3. ONLINE WORKBOOK: OPEN-LINK SAMPLE

The primary purpose of offering an Open-Link version of the Online Workbook was to provide an avenue by which R&SB customers of Hydro One who were not randomly selected to participate in the Telephone Survey could participate and have their opinions heard.

Since the results contained within this section of the report are based on self-selected or volunteered participation, the results should not be interpreted as a representative sample of Hydro One customers. Further, the Online Workbook was designed to inform customers about Hydro One, its service territory, its performance in terms of the average number and length of power outages, and why outages occur prior to answering questions. This is information to which the average customer would not necessarily have equal access. For both of these reasons, the results of the Online Workbook cannot be said to represent or be generalizable to the opinions of the broader Hydro One customer base. Nonetheless, it is valuable to have feedback from a large volume of interested and now informed customers. Therefore, this section should be given consideration in Hydro One's decision-making. As it is not appropriate to quote a margin of error for non-probability based, opt-in surveys, we have not reported a margin of error on the Online Workbook results.

Respondents who indicated that they are both a Residential or Seasonal customer and a Small Business customer of Hydro One were provided with the opportunity to complete the Online Workbook twice. Those who decided to answer twice count as two responses. Because of this overlap the data in this section is based on the total number of responses, rather than the number of respondents.

PUBLISHING THE WORKBOOK ONLINE

The Open-Link Online Workbook was available in both official languages and was hosted by Ipsos on its secure server at **www.ipsosresearch.com/hydroone**. Upon arriving at the landing page, respondents were able to choose to complete the survey in English or French.

PROMOTING THE SURVEY

The Online Workbook was extensively promoted to customers to encourage as many customers as possible to participate. The objective of Hydro One's communications strategy was to drive maximum customer participation of the Open-Link across customer segments by targeting audiences across multiple channels. A 1-800 in-bound phone number was also promoted across all channels for customers who preferred to participate over the phone. Customers calling in could also request a hard copy of the Workbook be mailed to them (a pre-paid business reply envelope was provided for customers to return the Workbook directly to Ipsos). The call-in line was manned 11 hours a day between 11 a.m. and 10 p.m. EST Monday to Friday, and was available in both official languages. Readers should note that customers requesting to participate over the phone received the Telephone Survey that was used with the representative sample of customers. As such, they were not exposed to the informational Workbook that the customers who responded online would have. There were no requests for a hard copy. A call-back protocol of three call attempts was in place on the in-bound line. For any individual who left a voicemail on the in-bound line if, for example, the line was busy when they called or they were calling off hours, three attempts were made to contact the individual to complete the survey before the number was disposed of as unreachable.

The key messages of the communications strategy were informational in nature:

- Hydro One is looking for feedback from customers to inform the development of tomorrow's electricity system
- Hydro One is looking to learn and understand the level and type of service that customers expect from the company
- Customers' feedback will be considered as Hydro One develops its plan, which in turn will determine electricity delivery rates

The strategy involved two waves of marketing communication which allowed the company to determine the most effective channels for communicating informational messaging. The company was able to determine that the traditional forms of marketing – print and radio – were ineffective in driving participation. The second wave of communications – which was focused on digital media – was more effective, increasing participation by 40%.

Wave One:

- Bill inserts
- Paid traditional advertising: print and online newspaper and radio
- Paid Tweets

Wave Two:

- Facebook ads
- eBlasts

The full channel strategy included the following tactics:

- **Hydro One direct-managed channels:**
  - Link on **www.HydroOne.com** landing page throughout the duration of the campaign
  - Link on **www.HydroOne.com/MyAccount**, which is the authenticated customer portal
  - Use of the company's Twitter account: **@hydroone**
  - Employees to encourage customer participation during customer interactions
  - Bill inserts
  - eBlasts sent directly by Hydro One to customers
- **Earned media**
  - Two press releases
- **Paid advertising**
  - Radio advertisements in local markets
  - Print advertisements in local newspapers
  - Online newspaper advertisements
  - Social media
    - Facebook ads
    - Paid tweets on Twitter
- **Stakeholder engagement**
  - Notification to MPP offices
    - Posters sent to MPP offices
  - Notification to key stakeholder groups

A summary of the total promotional efforts is provided on the next page. The multi-channel strategy garnered more than four million impressions.

R&SB ONLINE WORKBOOK PROMOTION

	CHANNEL	METRICS	TARGET	ACTUAL	DURATION
PAID MEDIA	BILL INSERTS	Number sent	650K	893K	June 3 – July 11
PAID MEDIA	RADIO	Impressions # stations # ad plays	693K 27 3,240	693K 27 3,240	June 6 – June 27
PAID MEDIA	LINK ON WEBSITE	Impressions Page views Unique views	1.2M N/A N/A	 *1,469* 17,745	June 8 – July 18 on website Additionally, three R&SB email blasts were conducted July 7, 8 and 11
PAID MEDIA	SOCIAL MEDIA	Impressions # posts # comments	1.0M N/A N/A		Facebook ads: June 22 – July 5 Paid Tweets: June 8 – July 16
PAID MEDIA	PRINT NEWSPAPER	Impressions # papers # notices	1.9M 41 123	1.9M 41 123	June 8 – June 24
PAID MEDIA	ONLINE NEWSPAPER	Impressions # clicks	1.0M N/A		June 8 – June 24
EARNED MEDIA	EARNED MEDIA	Impressions # articles # interviews # requests	N/A N/A N/A N/A	425K 4 1 0	June 8 – July 16
EARNED MEDIA	SOCIAL MEDIA	Impressions # Twitter link clicks # FB posts	N/A N/A N/A	54 17,614 0	June 8 – July 16

TOTAL RESPONSE

A total of 18,718 responses were received to the publicly available Open-Link Online Workbook and 379 responses were received over the phone. The phone responses were combined with the online responses for a total of 19,097 responses. On average it took customers 18 minutes to complete the Workbook/Survey. A total of 364 responses were received in French. After removing invalid responses, the final number of valid responses is 17,201. A description of how responses were validated is provided below.

VALIDATING CUSTOMER RESPONSES

Those wishing to participate in the Open-Link Online Workbook were required to self-identify themselves as a R&SB customer. Respondents were also required to indicate that they had at least some responsibility for paying the electricity bill in their household/business and that they pay directly to Hydro One and not through a landlord or property manager. Respondents were also required to enter their postal code to verify their residential, seasonal or business addresses falls within Hydro One's service territory. Any respondent who provided an invalid postal code was removed from the final sample. This removed 703 responses.

Upon closing the survey, the data was scrubbed to accept only one complete per IP address unless the IP was duplicated because the respondent answered the survey twice as they indicated that they are both a Residential/Seasonal and a Small Business customer, and they wanted the opportunity to answer as both. This removed 791 responses. Respondents who indicated that they or someone in their household works for a public relations or market research company, media, a company that provides electricity, an energy regulator or holds an elected office or staff position were also removed from the final sample. This removed 402 responses.

Please note that Ipsos does not ever link to the personal information submitted on the website. All responses are kept anonymous and confidential.

4. R&SB FOCUS GROUPS

Finally, focus groups were conducted following the Telephone Survey. The purpose of the Focus Groups was primarily to dive deeper and probe into more detail the reasons behind why some customers are willing to accept a rate increase and why others are not. Specific customer service and reliability options were probed to understand the level of interest there is among customers for various ways in which Hydro One could improve in these areas.

A series of eight Focus Groups with Residential and Small Business customers of Hydro One were conducted via conference call and using Ipsos' Ideation Exchange online research platform. A total of 31 Residential and 25 Small Business customers attended these sessions. These took place on June 27 & 28, and July 5 & 6. Residential participants received an honourarium of $75 for their participation, and Small Business participants received $150. Providing an honourarium for participation is a standard practice for this type of research.

Residential participants were recruited using a third-party database and Small Businesses were recruited from Hydro One's customer list. Participants in all sessions were the person in their household or business who is primarily or jointly responsible for dealing with paying utility bills. All groups were a mix of gender, age, working status/business type, income, and education levels.

During recruitment, customers were asked their overall perception of Hydro One on a five-point scale. Individuals that selected either end of the scale – either very positive or very negative – were screened out to avoid participants with overly strong views one way or the other from dominating the session.

Participants were able to dial into the conference as well as log in to the platform from their homes or businesses. All sessions were hosted by Ipsos moderators and conducted from Ipsos' Toronto office at 160 Bloor Street East, Suite 300. All were audio recorded for transcription.

A schedule and breakdown of Focus Group session dates, markets, and segments is as follows:

	Residential	Small Business
GTA / HORSESHOE	Monday, June 27, 5:30 p.m.	Tuesday, July 5, 5:30 p.m.
SOUTHWESTERN ONTARIO	Monday, June 27, 7:00 p.m.	Tuesday, July 5, 7:00 p.m.
SOUTHEASTERN ONTARIO	Tuesday, June 28, 5:30 p.m.	Wednesday, July 6, 5:30 p.m.
NORTHERN ONTARIO	Tuesday, June 28, 7:30 p.m.	Wednesday, July 6, 7:00 p.m.

LARGE CUSTOMERS

Hydro One set out to engage as many Large Customers as possible in the customer engagement. In order to maximize participation, customers were provided two methods by which to participate. Feedback was obtained primarily through two qualitative formats:

1. Facilitated, in-person Workshops
2. Online Workbook

In addition to these methods, one-on-one meetings were held with two customers to gather feedback – one with a major grocery chain and one with a Connected Distributed Generator. Ipsos provided a note-taker at both meetings to record the conversation and feedback.

The table below outlines the breakdown of the number of Large Customers that were invited to participate and the number who participated.

BREAKDOWN OF LARGE CUSTOMERS

	LDA	LDC	DG	C&I	TOTAL
Total number of Large Customers	92	59	966	~8,000	~9,117
IN-PERSON FACILITATED WORKSHOPS					
Total number invited to attend an in-person Workshop	81	59	27	881	1,039
Total number who sent back an RSVP	43	18	6	70	137
Total number who attended a Workshop	33	14	3	53	103
ONLINE WORKBOOK					
Total number who were sent the URL to the Online Workbook	46	41	22	5,226	5,335
Total number who completed the Online Workbook	5	3		79	87
CUSTOMERS NOT INVITED					
Did not attend a Workshop and were not sent a survey	11	4	2	2,721	17

Hydro One was responsible for Workshop invitations, and for the outreach and distribution of the Online Workbook URL to Large Customers, the details of which are described next.

LARGE DISTRIBUTION ACCOUNTS (LDAs)

All LDAs were invited to participate in the Workshop sessions through a personalized e-mail which contained an invitation letter from Hydro One's President and CEO Mayo Schmidt requesting their participation. These personalized e-mails were sent out on May 12. Phone calls were made by Hydro One's Zone Superintendents to their customers after May 25, providing information about the purpose of the Workshop as well as the venue and timing for each. After May 25, follow-up calls, visits or e-mails were made to all LDA customers.

For a copy of the invitation e-mail and letter, please refer to the Appendix.

LOCAL DISTRIBUTION COMPANIES (LDCs) AND CONNECTED DISTRIBUTED GENERATORS (DGs)

All LDCs were invited to participate in the Workshop sessions via e-mail sent through a centralized mailbox for RSVP tracking purposes. The initial 'Save the Date' e-mail, inviting customers to attend a Hydro One Workshop location, was sent to all LDCs and a sub-set of Distributed Generators on May 12. A second e-mail which included a registration button with the list of Workshop venues and times (excluding Windsor, which was initially C&I focused), was sent out on May 20, with a reminder sent out again to 33 LDC and DG customers who had not already RSVP'd by June 6. Phone calls were also made by the respective

Key Account Executives to each of the LDC and DG customers that had yet to respond as way of follow-up. On June 17, Hydro One sent out the online Workshop invitations and unique passwords to 41 LDCs who had not been able to participate in the Workshops.

Twenty-two DG customers were invited to participate in the Workshops. The customers selected accounted for a mix of DG types, with input from the Key Account Executives who advised who should be included from their key accounts. Of those, two DG customers participated in the Workshops and the remaining 20 were provided PINs to participate in the online survey.

For a copy of e-mail messages and invitations to participate in the Workshops and Online Survey, please refer to the Appendix.

COMMERCIAL & INDUSTRIAL (C&I) CUSTOMERS

Of Hydro One's total pool of about 8,000 C&I customers, an initial group of 335 customers were selected to be invited to attend one of the Workshops. These C&I customers were selected to ensure there was balanced input accounting for:

- The largest sub-sectors, as well as those known to have specific concerns;
- Representation across zones;
- Representation across size segments; and,
- Customer contact information availability.

Of this initial group of 335 customers, it was determined that Hydro One was able to locate e-mails for 300 of them and these customers were invited to the Workshops. For the remaining 35, the breakdown of additional follow-up for these customers is as follows:

- Left voicemail and did not receive a further response – **9**
- Refused to receive an e-mail and wanted the invitation by mail – **9**
- No answer or unable to find the right person to confirm an email – **17**

An additional 71 customers in Northern Ontario were contacted, for better coverage of these areas in the Workshops. As well, all of Thunder Bay and many Timmins customers were contacted in order to improve participation rates in these markets – 122 and 57 respectively for a total of 179.

To further boost Workshop participation, Hydro One reviewed call logs from the past two years, to source customers likely to be interested in providing feedback at a Workshop. As a result, a total of 150 invitations were sent.

At the beginning of this initiative, Hydro One had spoken with the first person who answered the phone when dialing the number on file. Hydro One staff learned that when they asked to speak with those directly involved with how their company used electricity, they achieved better Workshop acceptance rates. This change in approach to get the 'right' person on the phone resulted in obtaining better targeted contact information for 110 customers, to whom Hydro One then sent a Workshop invitation. As the dates for the workshop were approaching, Hydro One reached out to another 71 customers who were sent invitations, which further improved Workshop participation rates.

In total, 881 C&I Customers were invited by phone and/or e-mail to participate in the Workshops, of which there were 50 customers who participated.

1. FACILITATED, IN-PERSON WORKSHOPS

The Workshop sessions were conducted with LDA, LDC, DG, and C&I customers. The Workshops sought to identify the needs and preferences of these Large Customers. Hydro One was responsible for sending out the invitations as well as the follow-up, reminders and other communication outreach with a broad cross-section of its Large Customers for the Online Workbook. Hydro One's efforts to invite and encourage as many of these customers as possible to the in-person sessions has been documented above.

A total of nine Workshop sessions were conducted in seven locations across Ontario. The locations were chosen by Hydro One in collaboration with Ipsos based on what would be the most convenient and accessible for customers.

Hydro One executives and representatives were present to greet and interact with participants, and to provide local context. Hot breakfast and lunch meals were provided during morning sessions, with a light lunch and refreshments provided during afternoon sessions. In advance of each session, attendees who confirmed their attendance were emailed an advance copy of Hydro One's presentation. Customers who did not RSVP, but showed up on the day of the workshop, did not receive a copy of the presentation in advance.

The Workshop dates, location and times are described in the table below:

LOCATION & DATE	LDA & LDC	C&I
Hamilton: Wednesday, June 8, 2016 Crowne Plaza Hotel and Conference Centre	9:30 a.m. – 12:00 p.m.	2:00 p.m. – 5:00 p.m.
Collingwood: Thursday, June 9, 2016 Blue Mountain Resorts	Combined workshop - 9:30 a.m. – 12:00 p.m.	
Timmins: Monday, June 13, 2016 Cedar Meadows Resort and Spa	Combined workshop - 9:30 a.m. – 12:00 p.m.	
Thunder Bay: Tuesday, June 14, 2016 Thunder Bay Art Gallery	Combined workshop - 9:30 a.m. – 12:00 p.m.	
London: Thursday, June 16, 2016 Four Points by Sheraton	9:30 a.m. – 12:00 p.m.	2:00 p.m. – 5:00 p.m.
Windsor: Friday, June 17, 2016 St. Clair College Centre for the Performing Arts	Combined workshop - 9:30 a.m. – 12:00 p.m.	
Kingston: Friday, June 24, 2016 Delta Kingston Waterfront Hotel	Combined workshop - 9:30 a.m. – 12:00 p.m.	

WORKSHOP AGENDA

Prior to the start of each Workshop, survey booklets were distributed to participants according to their segment (LDA, LDC, DG or C&I), so that they could be filled out during the course of the session. A bound presentation deck was also distributed to each participant to take notes if desired, and to take away with them after the session. The deck included two market-specific slides:

1. Reliability by location within the province, where frequency and duration by local market was provided; and,
2. Examples of improvement projects in the local region were provided.

This presentation was also projected on screen during each Workshop to follow the information as it was presented. An Ipsos note-taker was present at each session, and each session was audio recorded.

Hydro One representatives presented information on the company, and an Ipsos moderator led group discussions after each section of the presentation.

The workshop was conducted in four parts:

1. Introduction: Who we are and what we do

A description of Hydro One, its distribution area, its assets and its customers was provided. Hydro One's role in the electricity system including transmission and delivery was shown, and the purpose of the Workshop focusing on distribution was clarified. The commitment to balance needs of customers, as well as understand previous feedback from Large Customers was also described. A detailed breakdown of a typical customer's monthly bill and a description of line items was provided and disseminated, and it was explained that Hydro One's distribution business only makes a profit through distribution delivery charges. Further, a breakdown of what these charges pay for was shown.

2. Review: Current system performance

Details of Hydro One's previous system performance and historical reliability were shown to participants. A breakdown of reliability by location within Hydro One's service area was provided, including frequency and duration of outages in local markets. Comparison to other distributors with an explanation of Hydro One's mostly rural customer base, as well as reliability variations from customer to customer, were introduced. Causes of equipment failure and reliability challenges faced by Hydro One and other utilities were also shown.

3. Context: Investing in the system

Current efficiencies and productivity, the factors that influence investment decisions, 2016 expenditures, and the current program to maintain reliability were all described during this portion of the Workshops. Regional initiatives to improve reliability and service were also shown.

4. Discussion: What's best for you

Candidate areas for potential improvement for reliability and for service were shown, followed by an introduction to the illustrative investment scenarios. These included three scenarios:

- **Scenario 1:** Maintaining performance scenario
- **Scenario 2:** Declining performance scenario
- **Scenario 3:** Improving performance scenario

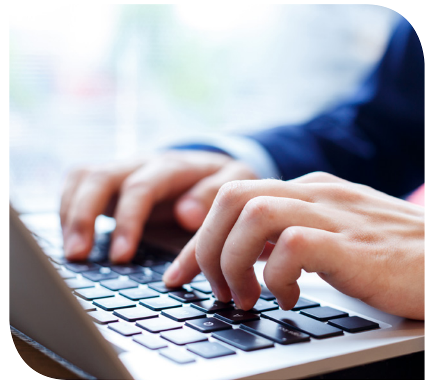
Each Scenario contained information on investment levels, including capital and OM&A expenditures. A summative slide including distribution delivery rate increases was shown, along with reliability and customer service impacts for each Scenario.

Finally, targeting investments to offer differentiated reliability and service to Large Customers, and the metrics to measure reliability performance, were explained to close the Workshops.

2. ONLINE WORKBOOK/ SURVEY BOOKLET

Those invited customers that were not invited to, or were unable to attend, one of the Workshop sessions were e-mailed or mailed the Online Workbook. As with the in-person Workshops, Hydro One was responsible for sending out the invitations as well as the follow-up, reminders and other communication outreach with a broad cross-section of its Large Customers for the Online Workbook.

LDA, LDC, and DG customers received a unique ID to access the Workbook, thus ensuring that once it was completed the customer could not go in and complete it a second time. Because of the size of the C&I customer base that was invited to complete the Online Workbook (5,226), an Open-Link of the Online Workbook was e-mailed or mailed to each customer.



C&I customers were not given a unique ID. IP capture was in place to ensure that only one "complete" per computer was accepted, but it is possible that customers could participate twice since they also attended one of the Workshop sessions.

The Online Workbook presented the same information shared at the Workshops and posed nearly identical questions. The only difference in the questions was that the Online Workbook used a statistical technique called paired-choice to quantitatively measure the relative importance customers place on various aspects of service. This technique could not be replicated in hard-copy, thus the Workshop survey booklet used a, "pick the most important" question in place of the paired-choice question.

A total of 87 customers completed the Online Workbook. This data was merged together with the survey booklets that were completed by 104 participants in the Workshops. As with the R&SB survey results, the percentages reported on this data may total to greater than 100% due to rounding or because respondents were permitted to provide more than one response, as in the case of open-ended questions.

RESIDENTIAL AND SEASONAL CUSTOMERS

SUMMARY

While opinions are mixed, the largest share of Residential and Seasonal customers feel the current number and average length of power outages they experience is in line with their expectations. A majority of Residential and Seasonal customers who offer an opinion are willing to accept the proposed roughly 1% increase on their total monthly bill to maintain the current number and average length of outages, but are not willing to pay more for better reliability.

While on most questions the needs and preferences of Residential and Seasonal customers do not vary greatly regardless of whether they are 'informed' or 'uninformed,' some differences emerge:

- *'Informed' customers are directionally more likely to say the current number and average length of outages they experience is worse than they expect; and,*
- *'Informed' customers, particularly among the Seasonal customer segment, are directionally more willing to accept the rate impacts proposed to maintain the current number and average length of outages than the average 'uninformed' customer.*

TELEPHONE SURVEY

As outlined in the methodology section of this report, the following results are based on a Telephone Survey of a random and representative sample of n=400 Residential and n=100 Seasonal customers. A stratified, random sampling approach was used to pull the sample Residential and Seasonal customers from Hydro One's customer database. With a sample of this size, the results are considered accurate to within ± 4.9 percentage points, 19 times out of 20 for Residential and ± 9.8 percentage points for Seasonal, of what they would have been had all Residential and Seasonal customers been surveyed. That means that if the survey is repeated 20 times, 19 of those times the results of the survey will be the same within the margin of error. The margin of error will be larger within sub-groupings of the survey population. These data were statistically weighted by density (urban, medium, low, seasonal) to ensure the sample composition reflects the true proportions in the customer database. The data was not weighted by region or rural/urban because the unweighted proportions closely match the true proportions.

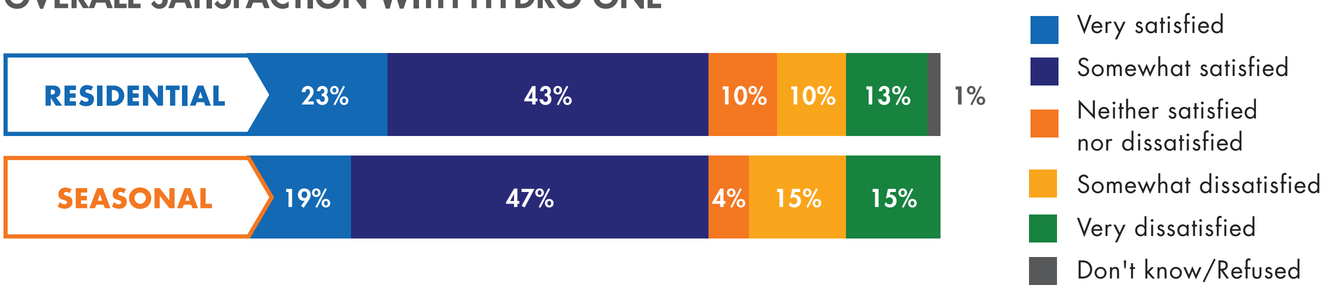
For more information on the survey methodology refer to the Customer Engagement Methodology section of the report. A full breakdown of the sample composition and a copy of the questionnaire are provided in the Appendix.

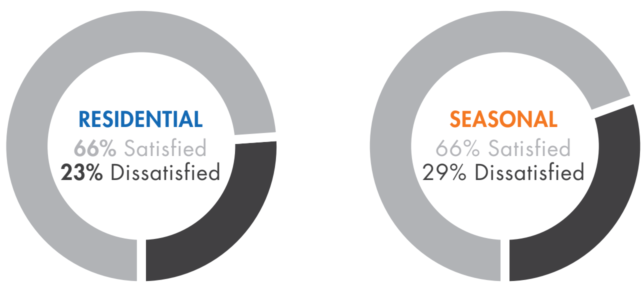
CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Two-thirds (66%) of Residential and Seasonal customers report that they are satisfied with Hydro One overall, one-in-ten (10%) hold a neutral opinion, while one-quarter (23%) are dissatisfied. When asked on an unaided basis what Hydro One can do to improve its service to them, the most frequent answer customers give is to reduce their monthly bills. Some customers mention this in the context of lower prices or lower rates, while others just simply say lower cost.

TELEPHONE SURVEY

OVERALL SATISFACTION WITH HYDRO ONE



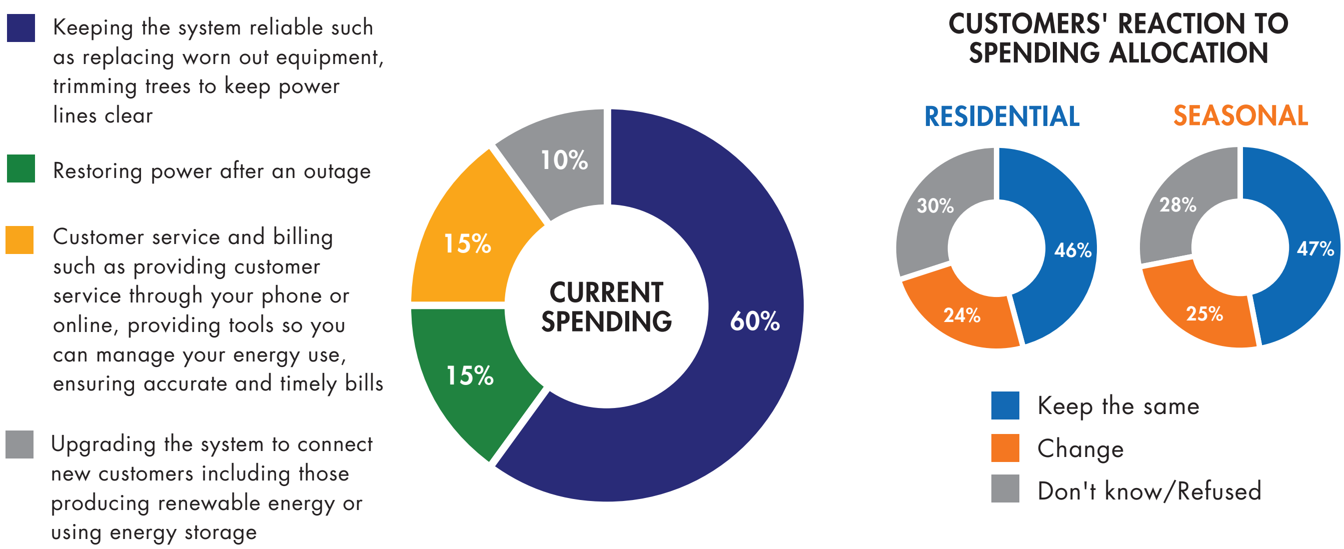


As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. Please think about Hydro One as I have just described it to you. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Residential (n=243), Seasonal (n=68)

Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, the majority that offer an opinion (excluding Don't Know/Refused) indicate that they would not change how the money is currently allocated.

TELEPHONE SURVEY

OPINIONS ON CURRENT ALLOCATION OF SPENDING



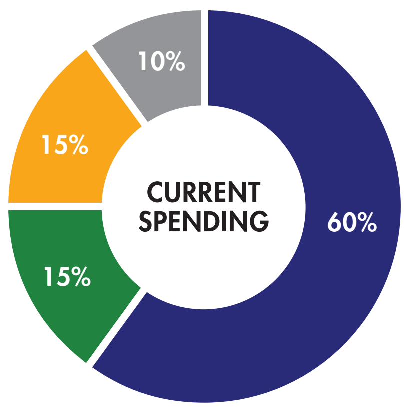
Q3. Please listen carefully as I will be reading out a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments and will be asking your opinion about the breakdown. Hydro One currently spends [READ LIST]… If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base: Residential (n= 400) , Seasonal (n=100)

One-quarter of both Residential customers and Seasonal customers indicate that they would change how the money is allocated. In general, these customers allocate more money to restoring power after outages and less money to keeping the system reliable.

TELEPHONE SURVEY

PREFERRED ALLOCATION OF SPENDING

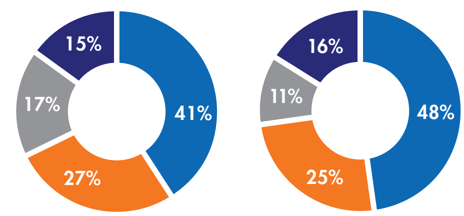
- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage



CUSTOMERS' PREFERRED ALLOCATION OF SPENDING

RESIDENTIAL

SEASONAL



- Keeping the system reliable
- Restoring Power
- Customer Service
- Upgrading the system to connect new customers

Q4. Of the 4 distribution investments you just heard, what percentage would you allocate to.. [READ LIST]? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100 % (Residential = n=79) , Seasonal (n=23)

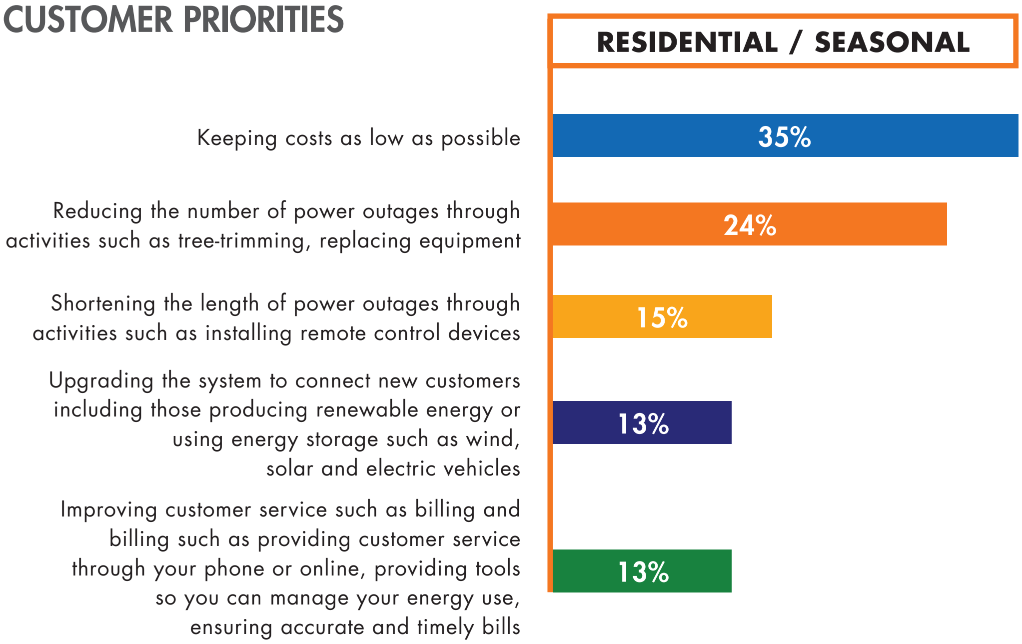
CUSTOMER PRIORITIES

A paired-choice exercise was used to identify customer priorities in order to help Hydro One better tailor its services. Paired-choice is an analytical technique designed to draw out the extent to which respondents prefer each option in relation to every other option. It works by pairing options off so that they are essentially 'competing' against one another. A series of these pairs are presented to respondents, who are asked to choose which of the two options they prefer. Respondents are forced to choose an option and cannot give a 'don't know' answer.

In our survey, there were 10 possible pairs of the five options being evaluated, and each respondent was shown five separate pairs. The rotational design was built by Ipsos' research science team. The results of the exercise are presented as relative preference scores. Relative preference scores reflect the share of total preference each option has, which means we have to imagine that there is a pool of total preference to be allocated across each of the options. Essentially, relative preference reflects a collective strength of feeling towards a particular option in relation to the others – the higher the percentage, the more strongly it is preferred among respondents. For more information on paired-choice, refer to the Appendix.

The chart below shows that keeping costs as low as possible has a relative preference score of 35% among Residential and Seasonal customers, and that this is the largest preference score of the options presented. This indicates that customers prioritize keeping costs as low as possible above the other options (reducing the number of outages, improving restoration times, improving customer service, or upgrading the system to connect new customers). It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is the next more preferred option.

TELEPHONE SURVEY
CUSTOMER PRIORITIES



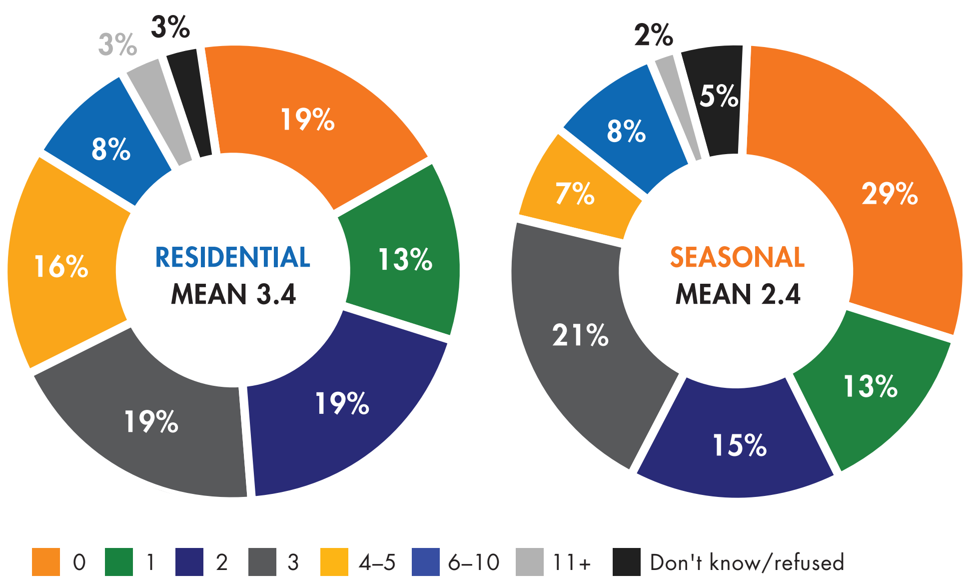
Q5. Hydro One would like to better understand what is important to you as a [Residential or Seasonal customer]. I am going to read Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Paired-choice preferences relative to other options. Base: Residential/ Seasonal (n=499) One respondent opted not to answer Q5.

THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate that the level of reliability that they currently experience is in line with their expectations. Residential customers report experiencing an average of roughly three outages of at least one minute in length in the past twelve months, Seasonal customers average about two outages. The largest share of customers – 48% of Residential and 55% of Seasonal – indicate that this level of reliability (number of outages they experienced) is about what they expect. Only 16% of Residential and 17% of Seasonal customers who experienced at least one outage indicate the number of outages they experienced is worse than they expect.

TELEPHONE SURVEY

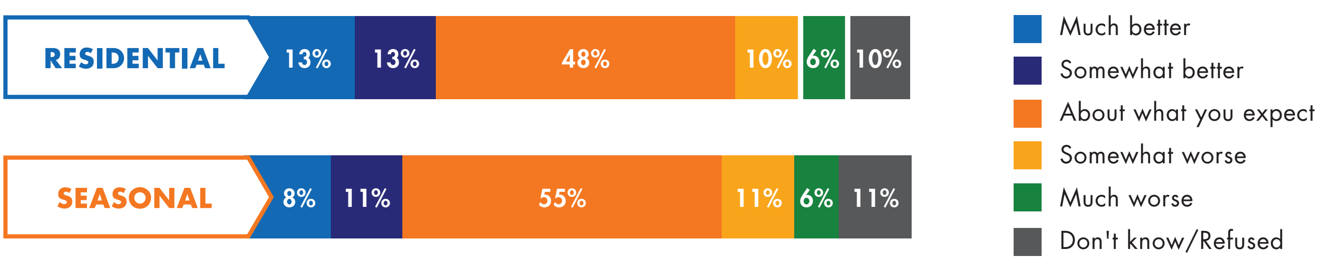
AVERAGE NUMBER OF OUTAGES



Q7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did you experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. Base: Residential (n=400), Seasonal (n=100)

TELEPHONE SURVEY

CUSTOMER EXPECTATIONS

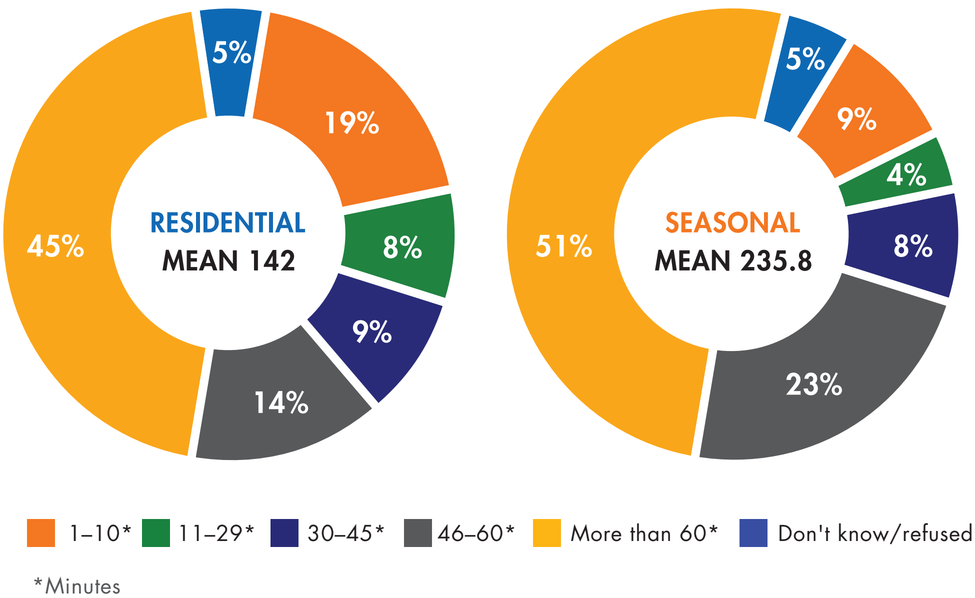


Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66)

When it comes to length of outages, Residential customers estimate that the outages that they experience last an average of roughly two hours, while Seasonal customers estimate an average of roughly four hours. Similar to opinions of frequency of outage, the largest share of customers indicate that this is about what they expect. Twenty percent say this is worse than they expect.

TELEPHONE SURVEY

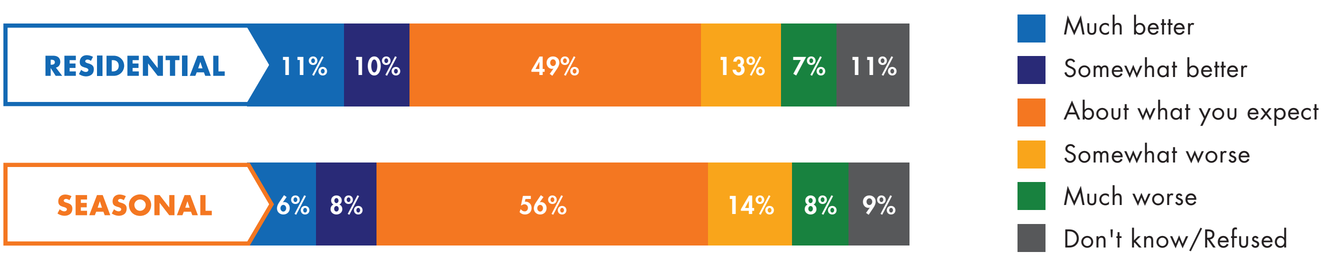
AVERAGE LENGTH OF OUTAGES



Q9. On average, how long did these unplanned outages last? Please answer in minutes. Your best guess is fine. Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66)

TELEPHONE SURVEY

CUSTOMER EXPECTATIONS



Q10. In general, when you think about the average length of the power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66)

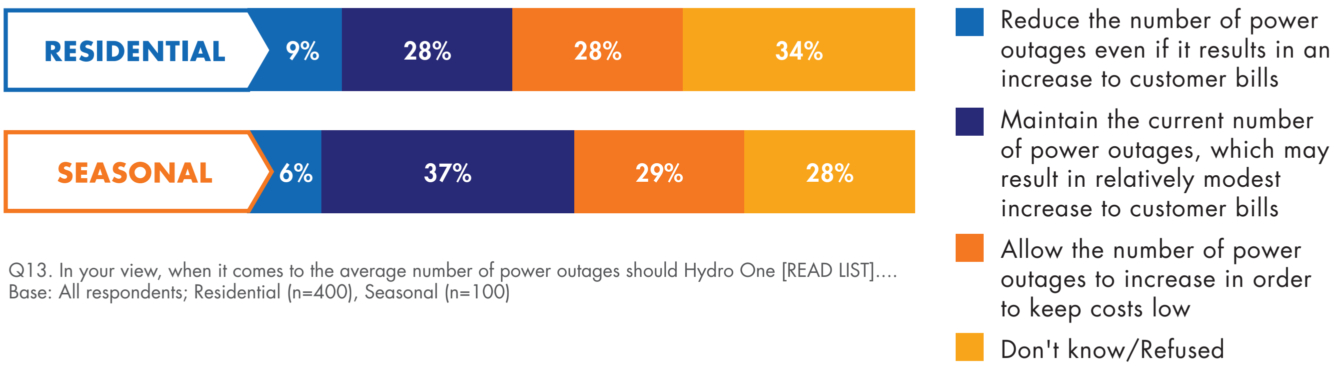
HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

When asked what Hydro One should do on the topic of the number and length of outages, opinions are mixed and a reasonably large minority of customers do not offer an opinion (34% of Residential customers indicate they don't know or refuse to provide an opinion on number of outages and 32% on duration, and 28% and 29% of Seasonal customers respectively). Of those who offer an opinion, 42% of Residential customers would trade off an increase in their monthly bill to keep number of outages to the current level, but 43% would allow the number of power outages to increase in order to keep costs low. Less than two-in-ten customers (14%) would like to reduce the number of outages and would be willing to accept a potential increase in their monthly bill to achieve it.

TELEPHONE SURVEY

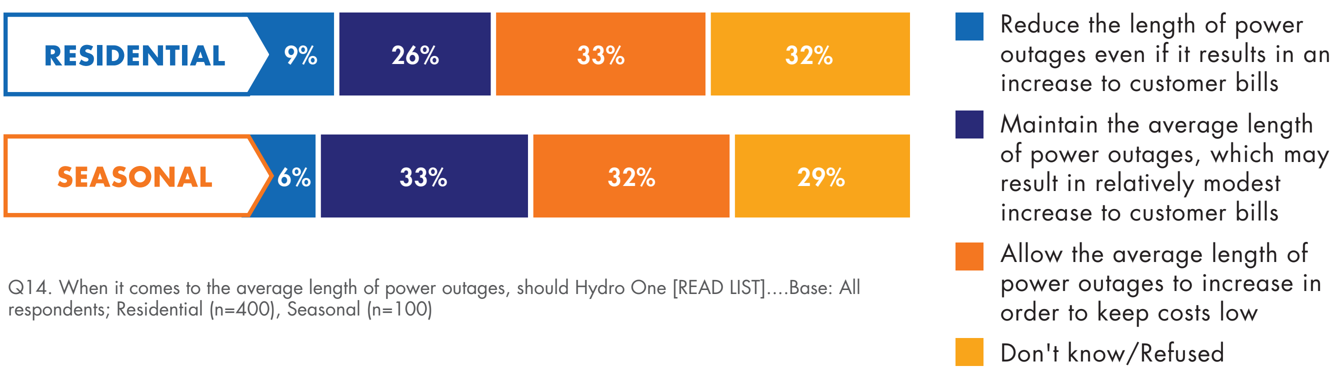
RELIABILITY TRADE-OFF PREFERENCES

NUMBER OF POWER OUTAGES



Q13. In your view, when it comes to the average number of power outages should Hydro One [READ LIST].... Base: All respondents; Residential (n=400), Seasonal (n=100)

LENGTH OF POWER OUTAGES



Q14. When it comes to the average length of power outages, should Hydro One [READ LIST]....Base: All respondents; Residential (n=400), Seasonal (n=100)

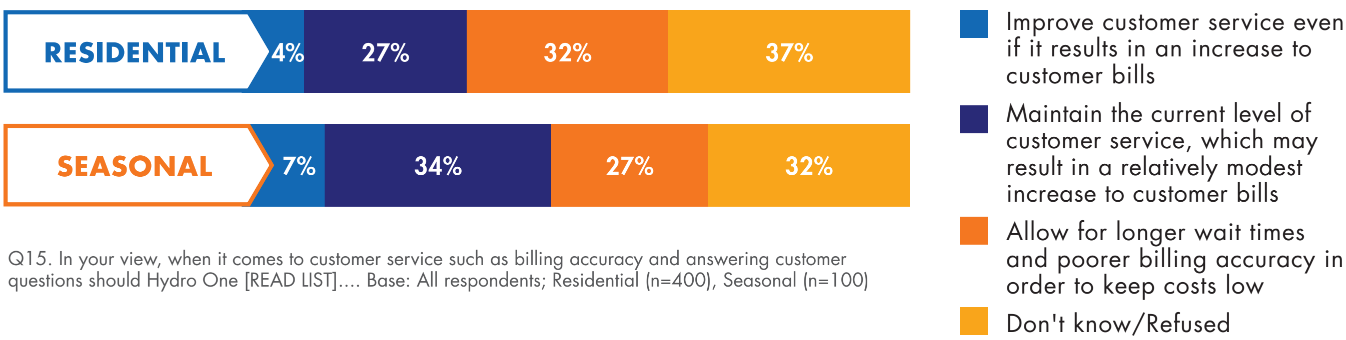
As shown in the chart above, customer opinions on the number of outages break out very similarly when it comes to preferences on how to address both the length of outages that they experience as well as the level of customer service they receive. The percentage of Residential customers who would accept a rate increase in order to maintain the status quo is about even with the percentage of customers that would accept worsening levels (including allowing the length of outages to increase or allow for longer wait times and poorer billing accuracy) in order to keep costs low.

There is greater consensus among customers when it comes to their level of interest in upgrades to the system to connect new customers including those producing renewable energy or energy storage. While roughly one-third do not offer an opinion, a majority (65%) of Residential customers with an opinion indicate that given the choice they would prefer to allow a slowdown in Hydro One's ability to connect renewable energy customers, in order to keep costs low.

TELEPHONE SURVEY

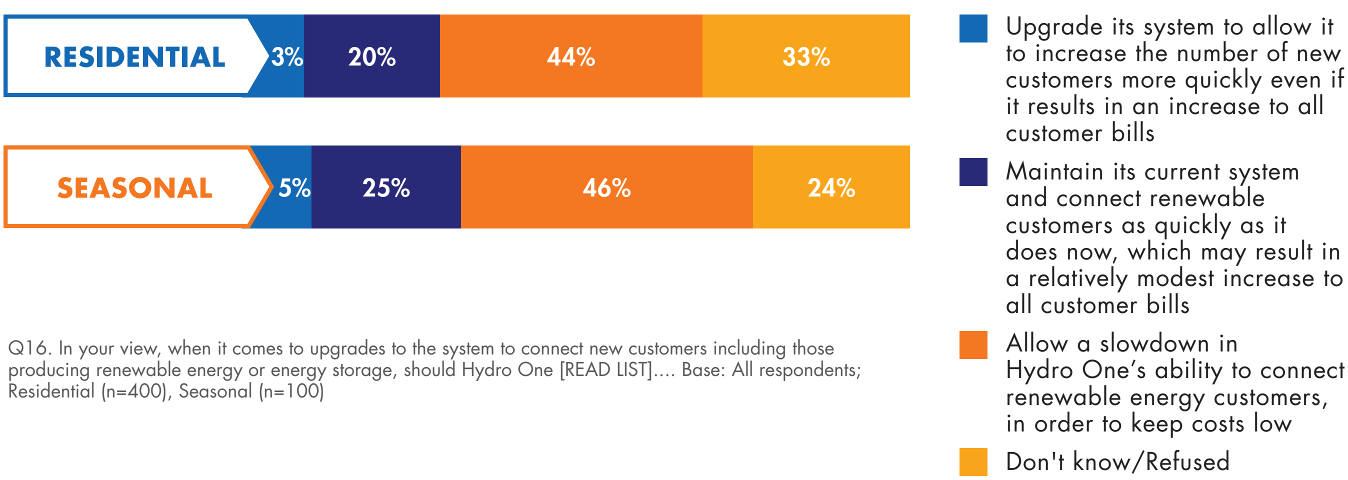
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One [READ LIST]…. Base: All respondents; Residential (n=400), Seasonal (n=100)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



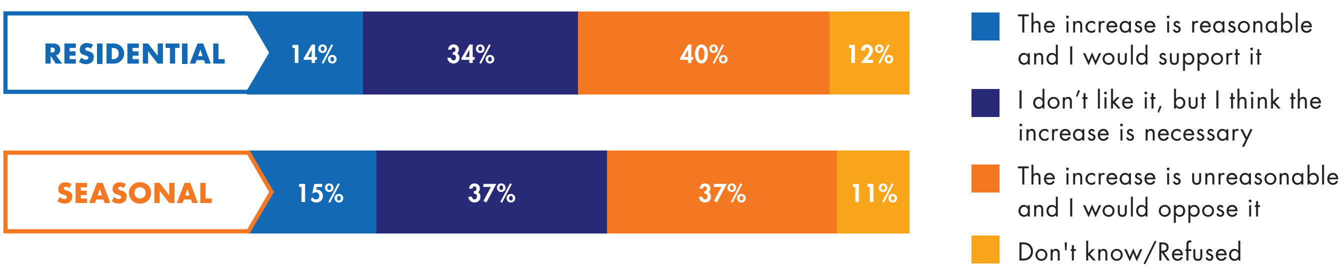
Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One [READ LIST]…. Base: All respondents; Residential (n=400), Seasonal (n=100)

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to at least maintain the level of reliability and customer service it currently provides, a typical Residential or Seasonal customer's **total monthly bill** will need to increase by 1.1% or the equivalent of $2.00, half of Residential (48%) and Seasonal (52%) customers are willing to accept it, roughly 40% of both segments are opposed, and the remaining 10% do not offer an opinion. Prior to answering this question, customers were informed that the increase of $2.00 would be applied each year for the next five years, and that by the fifth year a typical monthly bill will be roughly $10.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside the control of Hydro One.

TELEPHONE SURVEY

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [Residential or Seasonal customer's total monthly bill will need to increase by [1.1% or the equivalent of $2.00]. The increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF RESIDENTIAL OR SEASONAL $10.00 / IF BUSINESS: $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Which of the following is closest to your point of view [READ LIST]? Base: All respondents; Residential (n=400), Seasonal (n=100)

This takes into consideration the percentage of customers that do not provide an answer. When these percentages are re-based on only those who offered an opinion, acceptance increases to 55% among Residential customers and 57% among Seasonal customers.

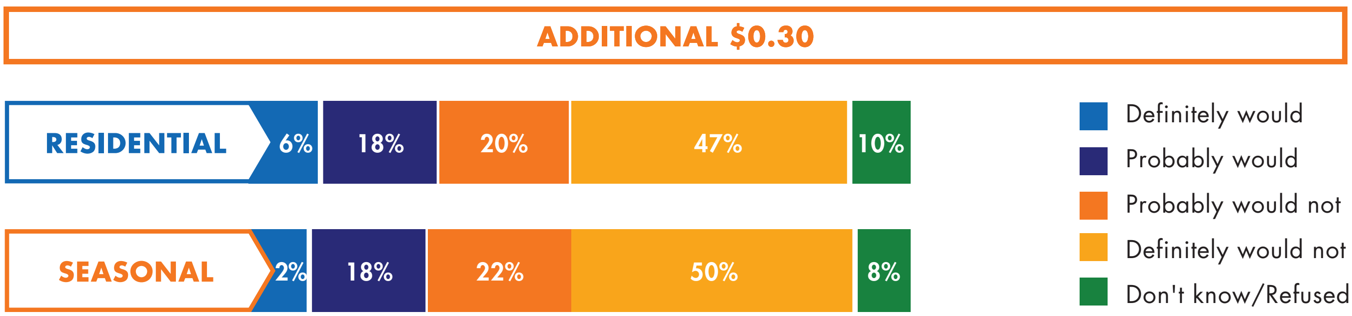
Not surprisingly given the majority of customers feel the current level of reliability falls within their expectations, relatively few customers are willing to pay more for improved reliability or service. Only one-in-ten customers indicate that they would be willing to pay more than the $2.00 (1.1%) increase in order to have **better reliability** than today. An additional 15% of Residential customers and 20% of Seasonal customers would consider it (selecting 'maybe' as their response). Sixty percent would not pay anything more. There is even less interest in paying for an improved level of customer service – only 8% of Residential and 6% of Seasonal customers say that they would be willing to pay extra for improved customer service.

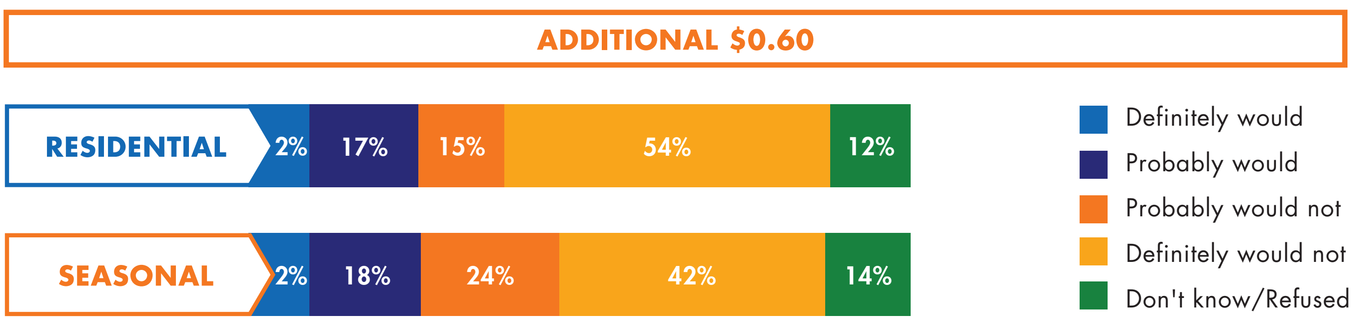
And lastly, customers were asked their level of interest in a 10% reduction in the number and length of future outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $.30 per month, or at total of $2.30 more on their monthly bill, and the other half was asked to consider a rate increase of $.60 per month for a total of $2.60 more on their monthly bill.

Only 6% of Residential customers say they definitely would prefer to pay $2.30 more (or $11.50 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 18% say they probably would. Only 2% of Residential customers say they definitely would prefer to pay $2.60 more (or $13.00 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 17% say they probably would.

TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS





Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30 / OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30 /$2.60] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50 / $13.00] higher than it is now? [READ LIST] Base: SPLIT SAMPLE (Residential n=200), Seasonal (n=50)

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

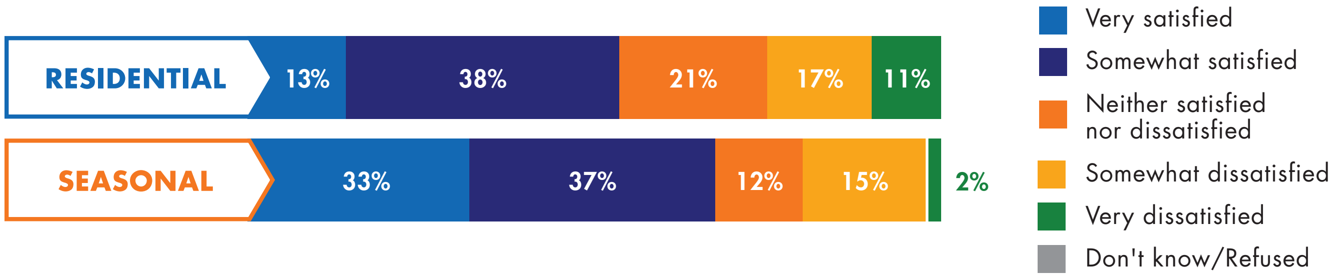
The primary purpose of conducting the Online Workbook with a representative sample of Residential and Seasonal customers is to have an understanding of the opinions of customers who have been informed about Hydro One through the Workbook (the same Workbook that was provided to those responding to the Open-Link). A total of n=1,502 Residential customers and n=102 Seasonal customers completed the Online Workbook. The sample was drawn from Ipsos' panel.

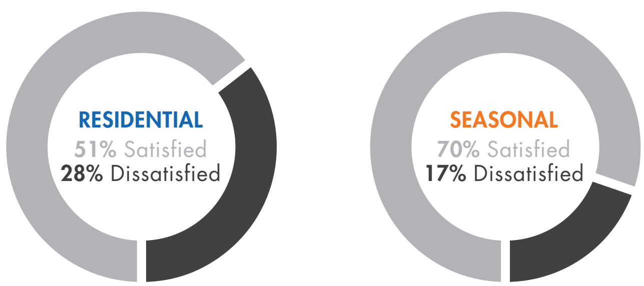
CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Whereas 66% of the representative sample of 'uninformed' Residential customers surveyed by telephone report being satisfied with Hydro One, satisfaction is lower among the 'informed' sample. Only half (51%) of Residential customers are satisfied. Two-in-ten (21%) hold a neutral opinion, while nearly three-in-ten (28%) are dissatisfied. Notably, Seasonal customers report similar levels of being satisfied regardless of being 'informed' or 'uninformed.'

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

OVERALL SATISFACTION WITH HYDRO ONE



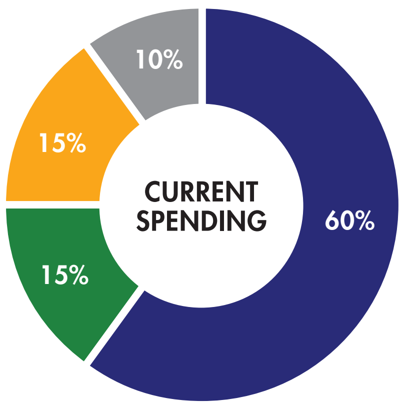


As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Residential (n=1,384, Seasonal (n=98)

Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, 41% of Residential customers and 56% of Seasonal customers would keep the current spending breakdown the same as it is now. Twenty-seven percent of Residential and 24% of Seasonal indicate that they would change how the money is currently allocated. These results are similar to those of the 'uninformed' telephone sample.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

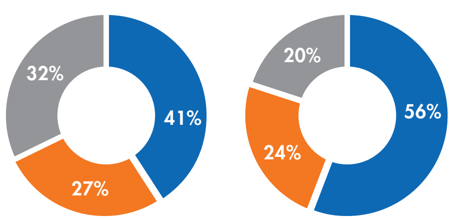
PREFERRED ALLOCATION OF SPENDING



- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage

OPINION ON CURRENT ALLOCATION OF SPENDING

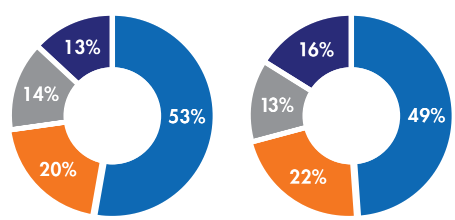
RESIDENTIAL SEASONAL



- Keep the same
- Change
- Don't know/Refused

CUSTOMERS' PREFERRED ALLOCATION OF SPENDING

RESIDENTIAL SEASONAL



- Keeping the system reliable
- Restoring Power
- Customer Service
- Upgrading the system to connect new customers

Q3. The pie chart above shows a rough estimate of what Hydro One currently spends on each of its major electricity distribution investments. If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base Residential (n=1,502), Seasonal (n=102)
Q4. What percentage would you allocate to...? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% Base: Residential (n=408), Seasonal (n=25)

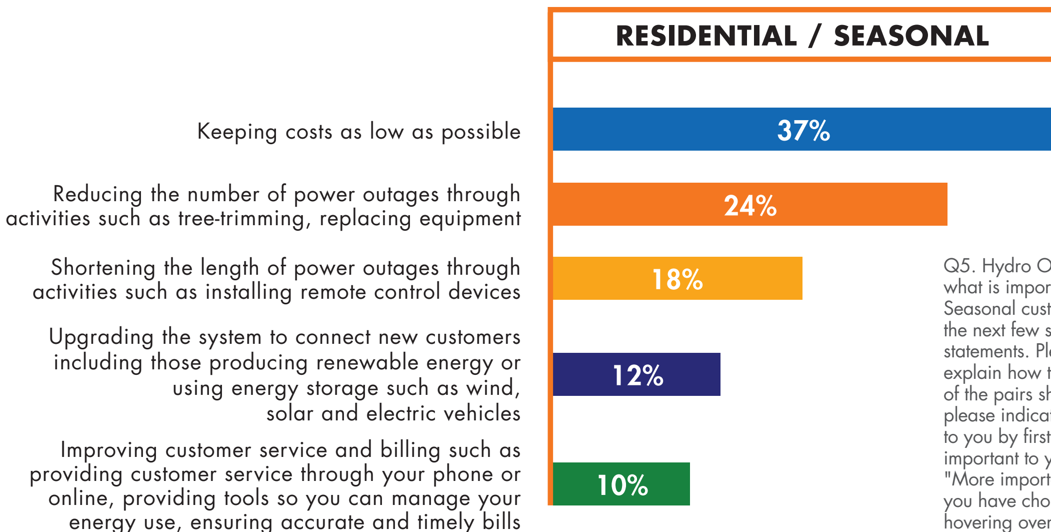
In general, these customers allocate more money to restoring power after outages and less money to keeping the system reliable. This too is consistent with the results of the 'uninformed' Telephone Survey among these customer segments.

CUSTOMER PRIORITIES

As noted in earlier sections, a paired-choice exercise was used to identify customer priorities in order to help Hydro One better tailor its services. For more information on paired-choice refer to the Appendix.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

CUSTOMER PRIORITIES



Q5. Hydro One would like to better understand what is important to you as a [Residential or Seasonal customer]. On this screen, as well as the next few screens, you will see rotating pairs of statements. Please read the instructions below that explain how to make your choice between each of the pairs shown. For each of the pairs below, please indicate the one that is more important to you by first clicking the statement that is more important to you and then clicking on the words "More important'. You should see the statement you have chosent with the words 'More important' hovering over it. This indicates the statement that you feel is the more important of the two. Then please click the next button to move to the next screen with the next pair. Base: Residential/ Seasonal (n=1,604). One respondent opted not to answer Q5.

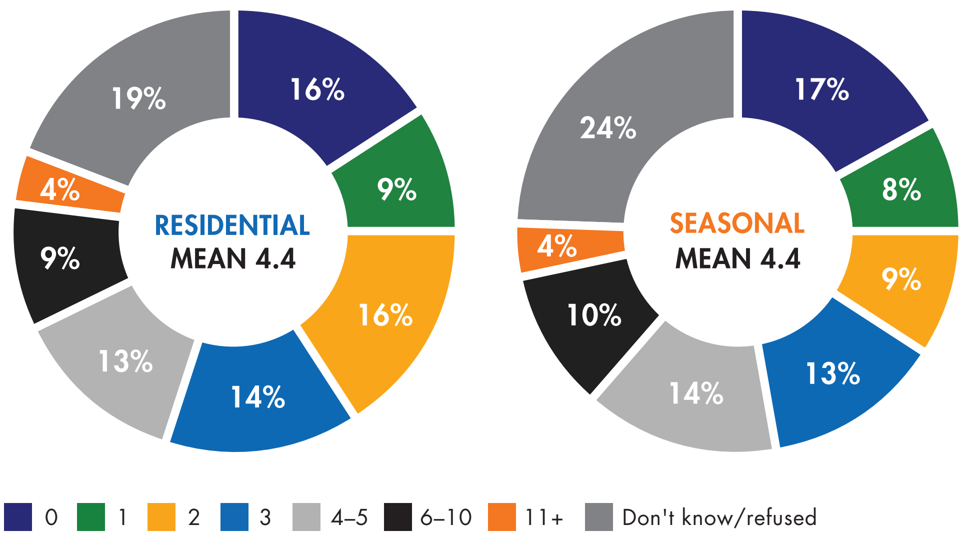
The chart above shows that keeping costs as low as possible has a relative preference score of 37% among Residential and Seasonal customers, and that this is the largest preference score of the options presented. This indicates that customers prioritize keeping costs as low as possible above the other options – reducing the number of outages, improving restoration times, improving customer service, or upgrading the system to connect new customers. It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is next more preferred option.

THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate that the level of reliability they currently experience is in line with their expectations. Residential customers report experiencing an average of roughly 4.4 outages of at least one minute in duration in the past 12 months, Seasonal customers average about the same at 4.4 outages. The largest share of customers – 52% of Residential and 42% of Seasonal – indicate that this level of reliability (number of outages they experienced) is about what they expect. One-quarter of Residential and 35% of Seasonal customers who experienced at least one outage, say it is worse than they expect, comparatively two-in-ten of both Residential and Seasonal customers say it is better than they expect.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

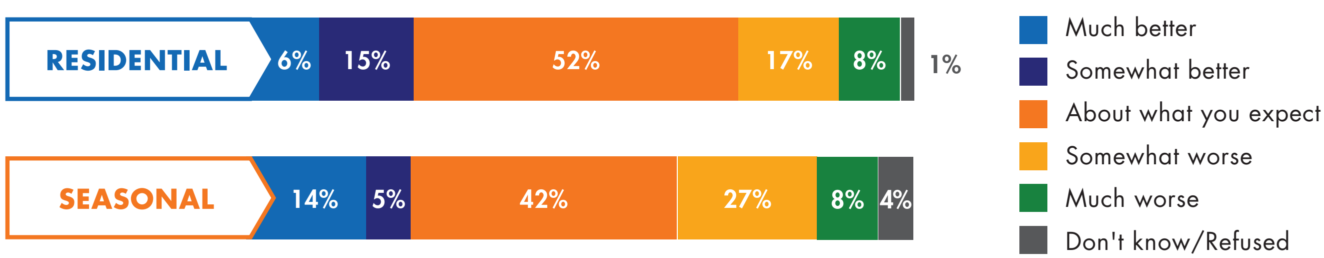
AVERAGE NUMBER OF OUTAGES



Q7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did you experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine.
Base: Residential/ Seasonal customer; Residential (n=1,502), Seasonal (n=102)

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

CUSTOMER EXPECTATIONS

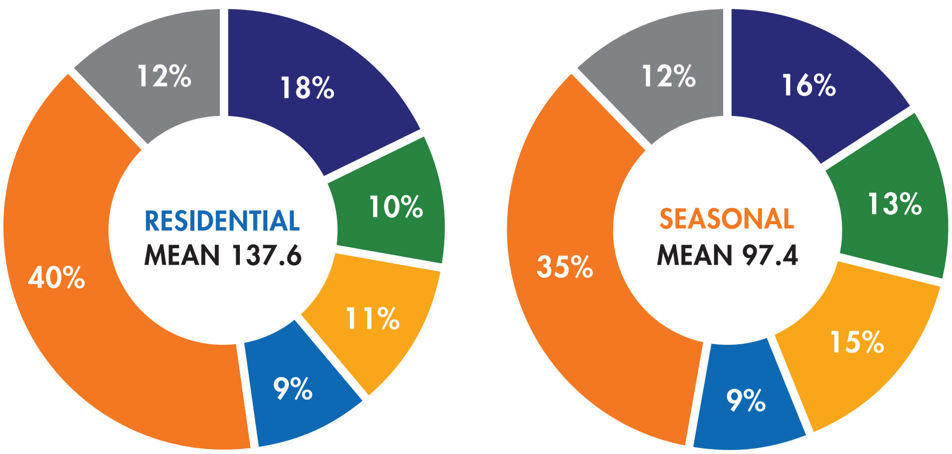


Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations?
Base: Residential/Seasonal customer who sustained power outages in the past 12 months; Residential (n=977), Seasonal (n=52)

When it comes to length of outages, Residential customers estimate the outages that they experience last an average of 2.3 hours, while Seasonal customers estimate an average of 1.6 hours.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

AVERAGE LENGTH OF OUTAGES



Q9. On average, how long did these unplanned outages last? Please answer in minutes. Your best guess is fine. Base: Residential/ Seasonal customer who sustained power outages in the past 12 months; Residential (n=977), Seasonal (n=52)

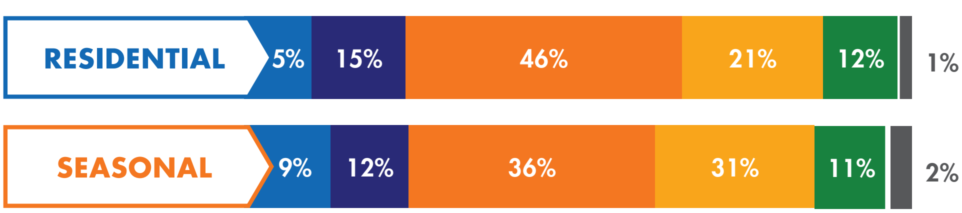
1–10* | 11–29* | 30–45* | 46–60* | More than 60* | Don't know/refused

*Minutes

Customers are less likely to say that their current average length of outages is about what they expect compared to the frequency of outages. One-third (33%) of Residential and 42% of Seasonal customers who experienced at least one outage, feel the current length of outages they experience is worse than they expect.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

CUSTOMER EXPECTATIONS



	% Better	% Worse
Residential	19%	33%
Seasonal	20%	42%

Much better | Somewhat better | About what you expect | Somewhat worse | Much worse | Don't know/Refused

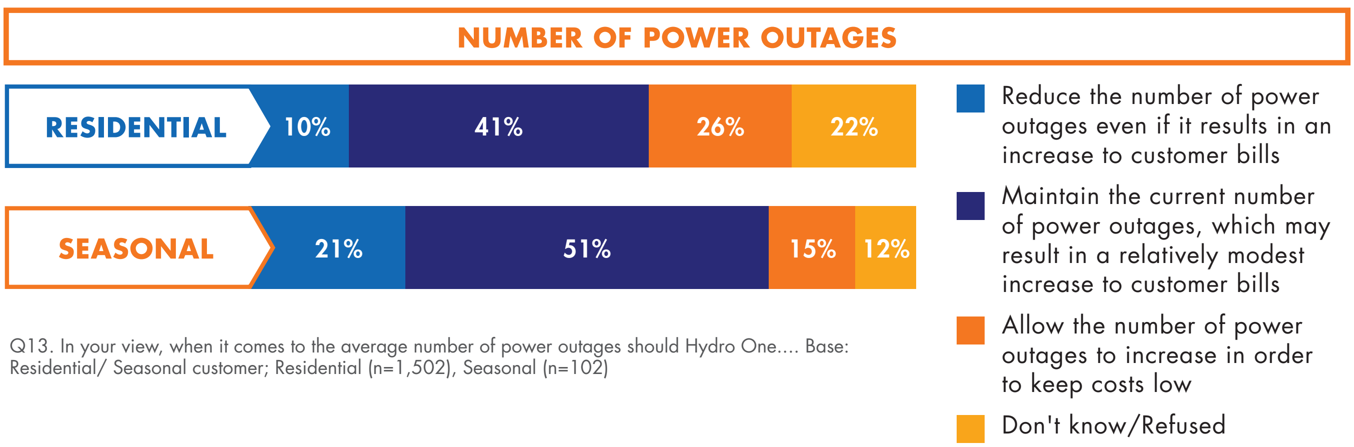
Q10. In general, when you think about the average length of the power outages you experienced over the last 12 months how did it compare to your expectations? ? Base: Residential/ Seasonal customer who sustained power outages in the past 12 months; Residential (n=977), Seasonal (n=52)

HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

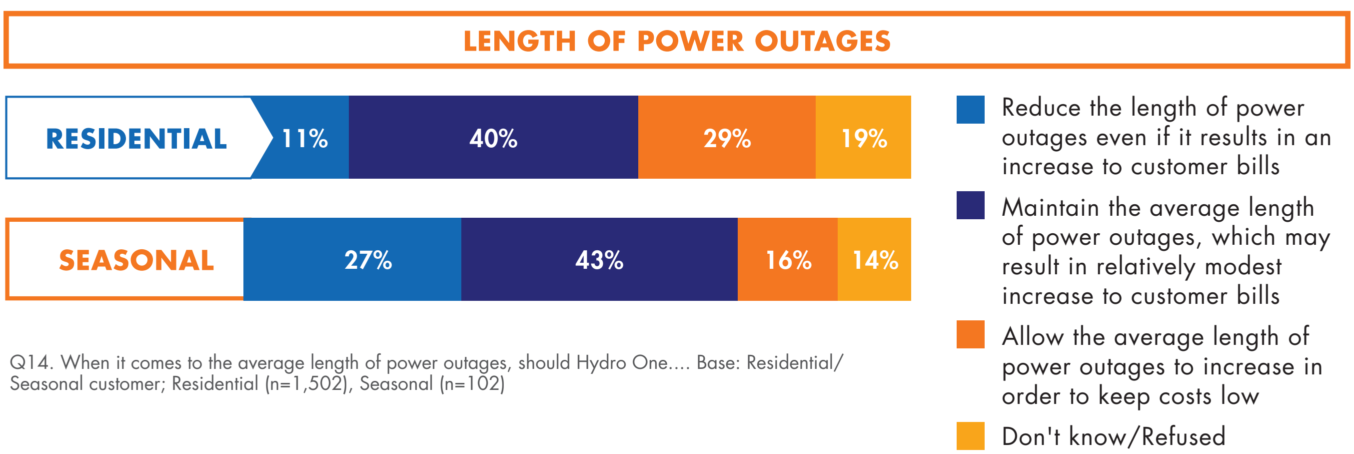
When asked what Hydro One should do on the topic of the number and length of outages, opinions are mixed. Fifty-one percent of Residential customers would trade off an increase in their monthly bill to maintain or reduce the current number of outages, and the same percentage would trade off an increase to maintain or improve the current length of outages. Seasonal customers are much more willing to accept a rate increase to maintain or improve the current number and length of outages (72% will accept an increase to maintain or improve the current number of outages, 70% would accept an increase to maintain or improve the current length of outages).

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

RELIABILITY TRADE-OFF PREFERENCE



Q13. In your view, when it comes to the average number of power outages should Hydro One.... Base: Residential/ Seasonal customer; Residential (n=1,502), Seasonal (n=102)



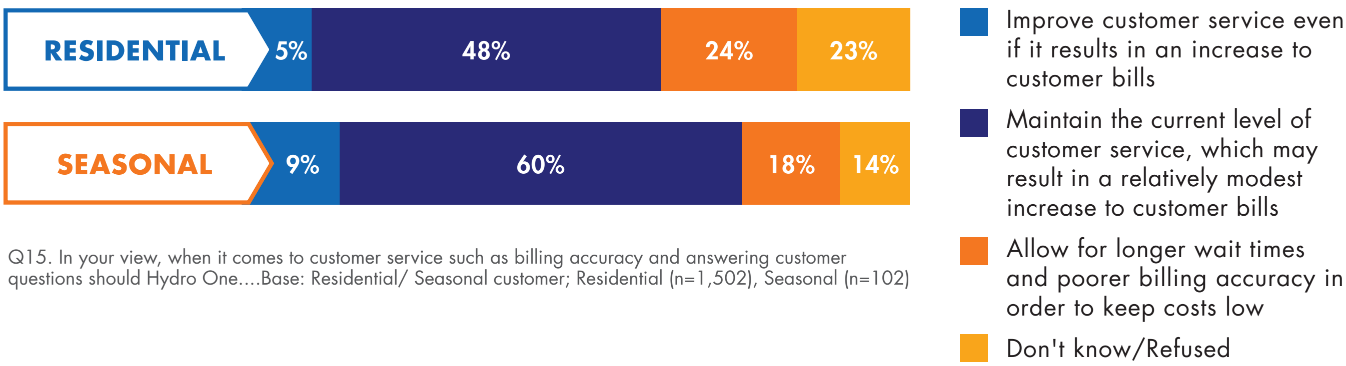
Q14. When it comes to the average length of power outages, should Hydro One.... Base: Residential/ Seasonal customer; Residential (n=1,502), Seasonal (n=102)

Fewer customers are willing to accept a rate increase for system upgrades in order to increase the number of new customers, including those producing renewable energy or energy storage.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

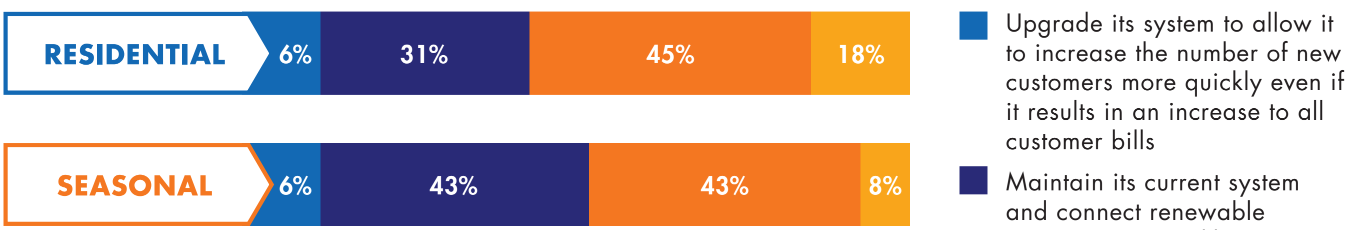
PREFERENCE FOR OTHER TRADE-OFFS

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One....Base: Residential/ Seasonal customer; Residential (n=1,502), Seasonal (n=102)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



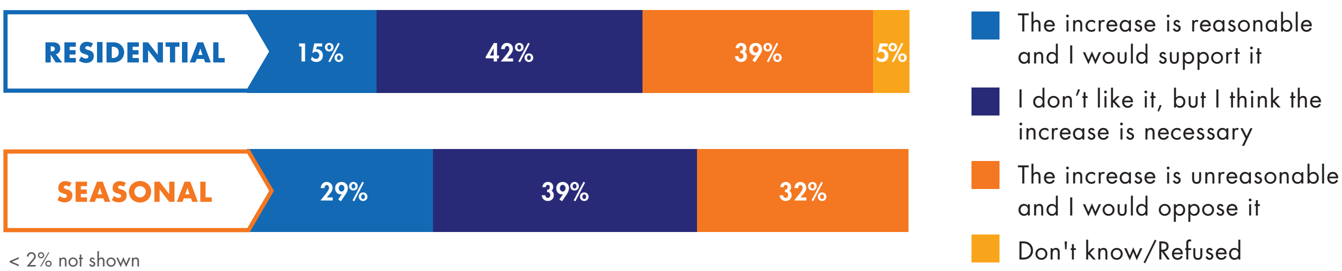
Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One… Base: All respondents; Residential (n=1,502), Seasonal (n=102)

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND TO IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Residential or Seasonal customer's **total monthly bill** will need to increase by 1.1% or the equivalent of $2.00, nearly six-in-ten residential (57%) and nearly seven-in-ten Seasonal (68%) customers are willing to accept it. This is directionally higher than the results of the 'uninformed' telephone sample. Prior to answering this question, customers were informed that the increase of $2.00 would be applied each year for the next five years, and that by the fifth year a typical monthly bill would be roughly $10.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside of Hydro One's control.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



< 2% not shown

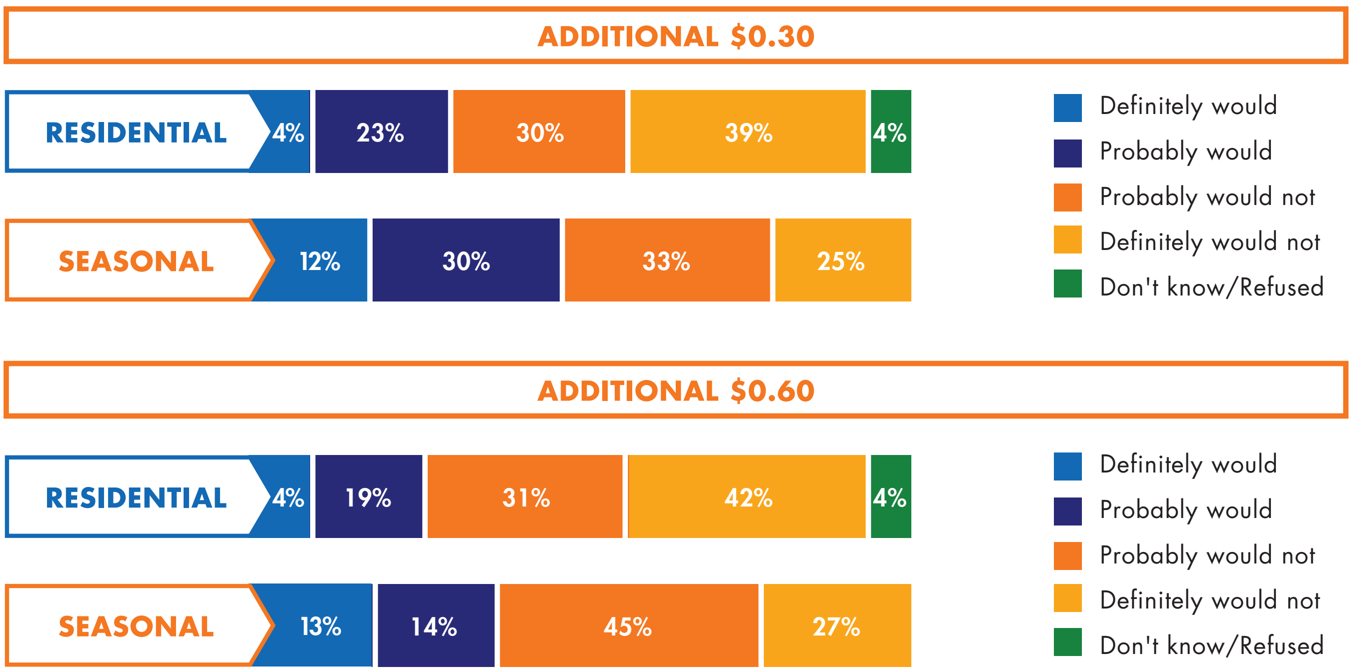
Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical residential or seasonal customer's total monthly bill will need to increase by [1.1% or the equivalent of $2.00/1% or the equivalent of $5.20]. This increase will be applied each year for the next five years. By the fifth year, a typical monthly bill will be roughly $10.00 higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Base: Residential (n=1,502), Seasonal (n=102)

Customers were asked about their level of interest in a 10% reduction in the number and length of future power outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $0.30 per month, or a total of $2.30 more on their monthly bill, and the other half was asked to consider a rate increase of $0.60 per month for a total of $2.60 more on their monthly bill.

Only 4% of Residential customers say they would definitely prefer to pay $2.30 more (or $11.50 by the fifth year) instead of the $2.00 (or $10.00 by the fifth year) and 23% say they probably would. Only 4% of Residential customers say they definitely would prefer to pay $2.60 more (or $13.00 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 19% say they probably would. Interest is directionally higher among Seasonal customers.

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

WILLINGNESS TO PAY FOR IMPROVED LEVELS



Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30/OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30/$2.60 more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50/$13.00] higher than it is now? Base: Residential/ Seasonal customer; Residential (split n=756/n=746), Seasonal (split n=50/n=52)

ONLINE WORKBOOK: OPEN LINK

The primary purpose of offering an Open-Link version of the Online Workbook was to provide an avenue by which R&SB customers of Hydro One who were not randomly selected to participate in the Telephone Survey could participate and have their opinions heard.

Since the results contained within this section of the report are based on self-selected or volunteered participation, the results should not be interpreted as a representative sample of Hydro One customers. Further, the Online Workbook was designed to inform customers, prior to answering the survey, about Hydro One and its role within the provincial electricity system such as Hydro One's service territory, reliability, customer service benchmarking, and the challenges it is facing in the future. This is information that the average customer would not necessarily have equal access to. For both of these reasons, the results of the Open-Link survey cannot be said to represent or to be generalized to the opinions of the broader Hydro One customer base.

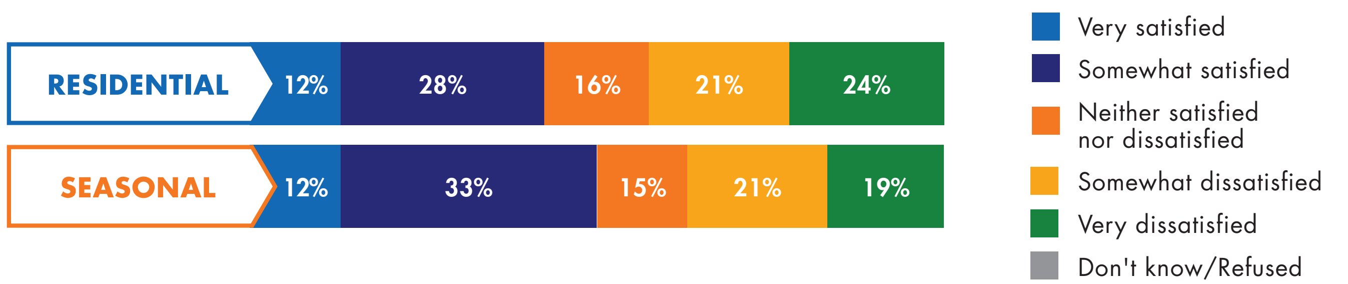
A hard copy of the Online Workbook and Survey is provided in the Appendix. As noted in the Customer Engagement Methodology section of this report, the Online Workbook was extensively promoted to customers to encourage as many customers as possible to participate. A total of 17,201 valid responses were received.

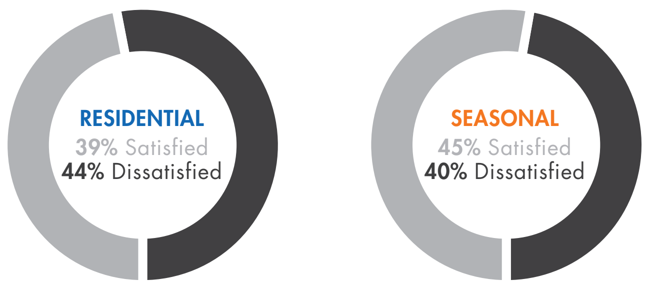
CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Whereas 66% of the representative sample of 'uninformed' Residential customers surveyed by telephone report being satisfied with Hydro One, and half of the 'informed' representative sample report being satisfied, only 39% of those who responded to Open-Link were satisfied. At 45%, satisfaction among Seasonal customers who responded to the Open-Link is also lower than the representative samples (Telephone or Online Workbook).

ONLINE WORKBOOK OPEN-LINK

OVERALL SATISFACTION WITH HYDRO ONE



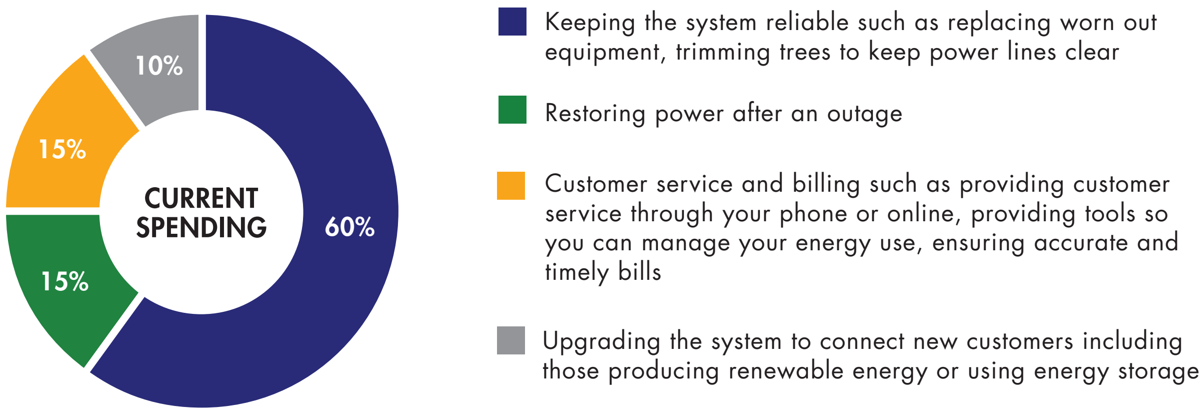


As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; - Residential (n=15,226), Seasonal (n=1,097)

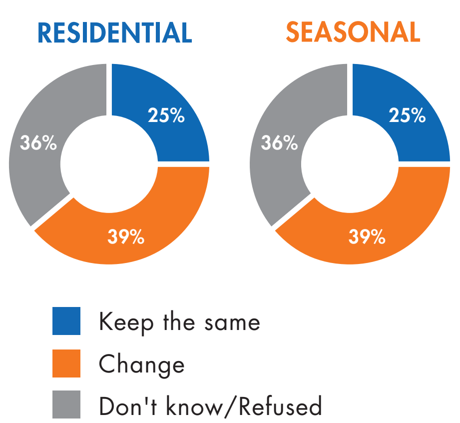
Given the opportunity to review a rough breakdown of how much Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is spent, 25% Residential and Seasonal customers would keep the current spending breakdown the same as it is now. This is much lower than found in the 'uniformed' Telephone Survey and the 'informed' Online Workbook sample. Four-in-ten indicate that they would change how the money is currently allocated.

ONLINE WORKBOOK OPEN-LINK

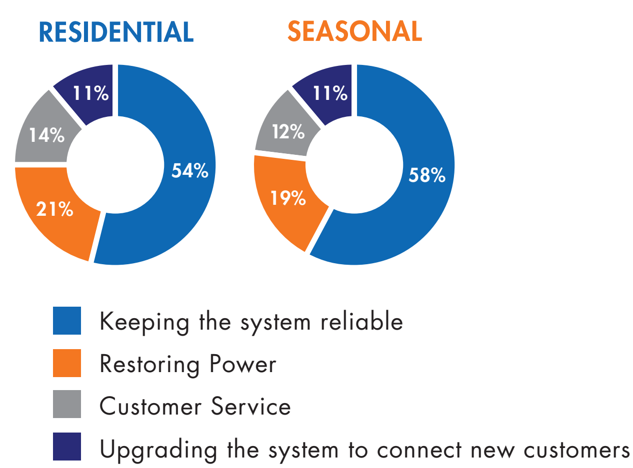
PREFERRED ALLOCATION OF SPENDING



OPINION ON CURRENT ALLOCATION OF SPENDING



CUSTOMERS' PREFERRED ALLOCATION OF SPENDING



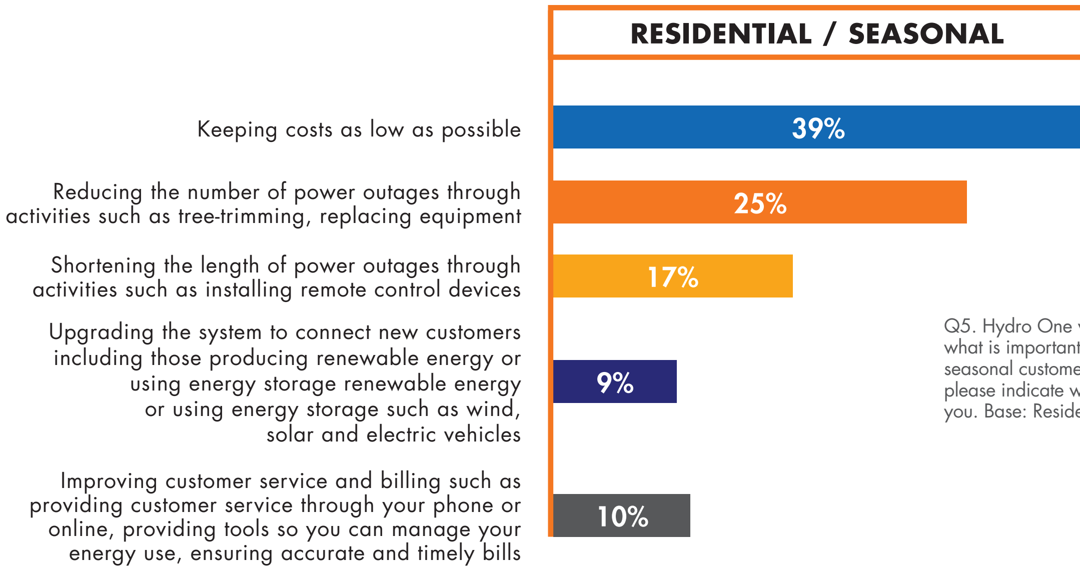
Q3. The pie chart above shows a rough estimate of what Hydro One currently spends on each of its major electricity distribution investments. If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base Residential (n=15,689), Seasonal (n=1,106)
Q4. Of the 4 distribution investments you just heard, what percentage would you allocate to...? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% Base: Residential (n=6,095), Seasonal (n=427)

Similar to the results of the other methods, these customers allocate more money to restoring power after outages and less money to keeping the system reliable.

ONLINE WORKBOOK OPEN-LINK

CUSTOMER PRIORITIES

As noted in earlier sections, a paired-choice exercise was used to identify customer priorities in order to help Hydro One better tailor its services. For more information on paired-choice, refer to the Appendix.



Q5. Hydro One would like to better understand what is important to you as a [residential or seasonal customer]. For each of the pairs below, please indicate which one is more important to you. Base: Residential/Seasonal (n=16,675).

The chart above shows keeping costs as low as possible has a relative preference score of 39% among Residential and Seasonal customers, and this is the largest preference score of the options presented. This indicates that customers prioritize keeping costs as low as possible above the other options, such as reducing the number of outages, improving restoration times, improving customer service, or upgrading the system to connect new customers. It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is the next more preferred option.

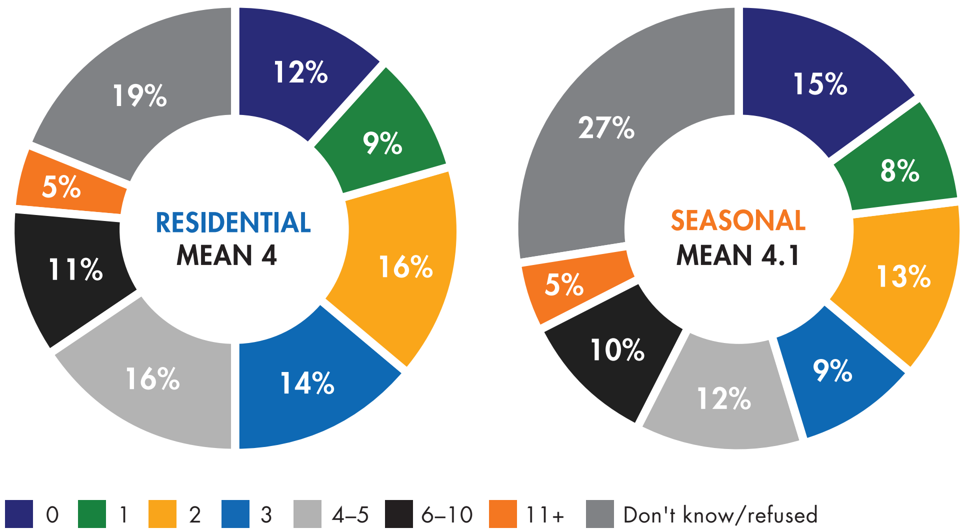
THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

While still the largest share of customers indicate that the number of power outages they experienced in the past 12 months is in line with their expectations, twice as many customers from the 'informed' Open-Link sample indicate the number of outages is worse than they expect compared to those from the 'uninformed' Telephone Sample (Residential customers: 30% Open-Link versus 16% Telephone/Seasonal customers: 34% Open-Link versus 17% telephone).

Both the 'informed' samples from the Online Workbook (Open-Link and representative sample) report they experienced a higher number of power outages in the past 12 months (Residential: 4.4 online representative sample, 4.0 online Open-Link) than those in the Telephone Survey (3.4). The average number of outages is higher among responses from rural customers than those from urban customers (4.4 vs 3.5).

ONLINE WORKBOOK OPEN-LINK

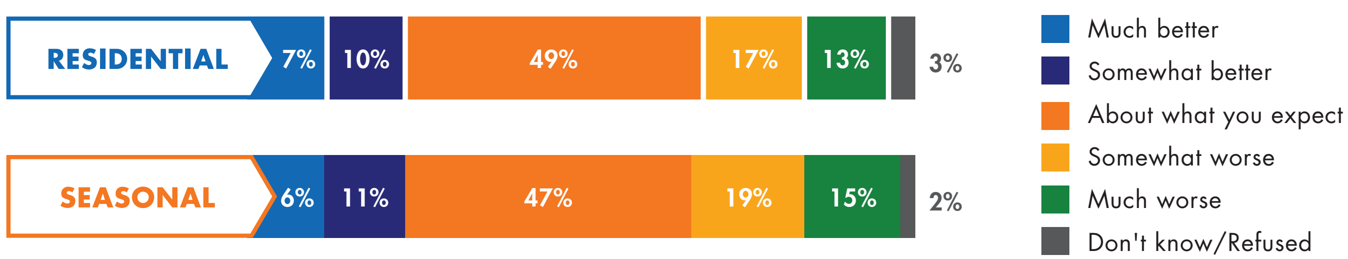
AVERAGE NUMBER OF OUTAGES



Q7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did you experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. Base: Residential (n=15,689), Seasonal (n=1,106)

ONLINE WORKBOOK OPEN-LINK

CUSTOMER EXPECTATIONS



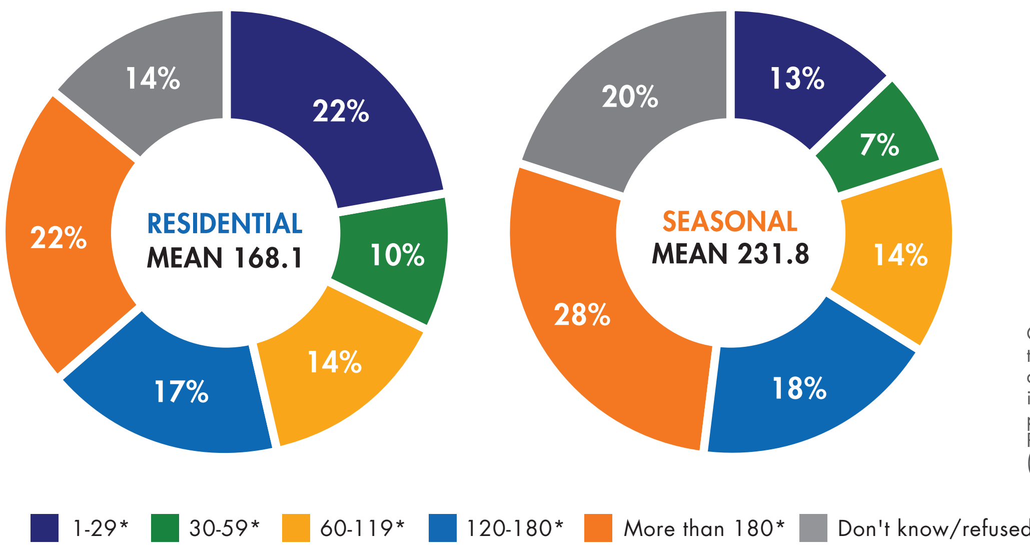
Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations? Base: One or more sustained power outages in the past 12 months. Residential (n=10,912), Seasonal (n=638)

When it comes to length of outages, 'informed' Residential and Seasonal customers who took the Open-Link survey were twice as likely to say that the average length of outages they experienced is worse than they expect (Residential: 35% versus 20%; Seasonal: 41% versus 22%).

Residential customers who responded to the Open-Link estimate that the average length of the outages they experienced is 2.8 hours, compared to 2.4 hours among the Telephone sample. The estimated average between Seasonal customers to the Open-Link and Telephone are more consistent (3.8 hours and 3.9 hours respectively).

ONLINE WORKBOOK OPEN-LINK

AVERAGE LENGTH OF OUTAGES

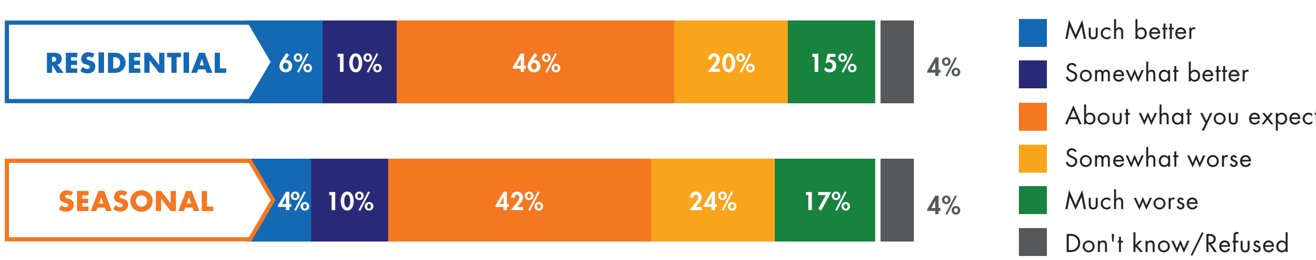


Q9. On average, how long did these unplanned outages last? Please answer in minutes. Your best guess is fine. Base: One or more sustained power outages in the past 12 months. Residential (n=10,912), Seasonal (n=638)

*Minutes

ONLINE WORKBOOK OPEN-LINK

CUSTOMER EXPECTATIONS



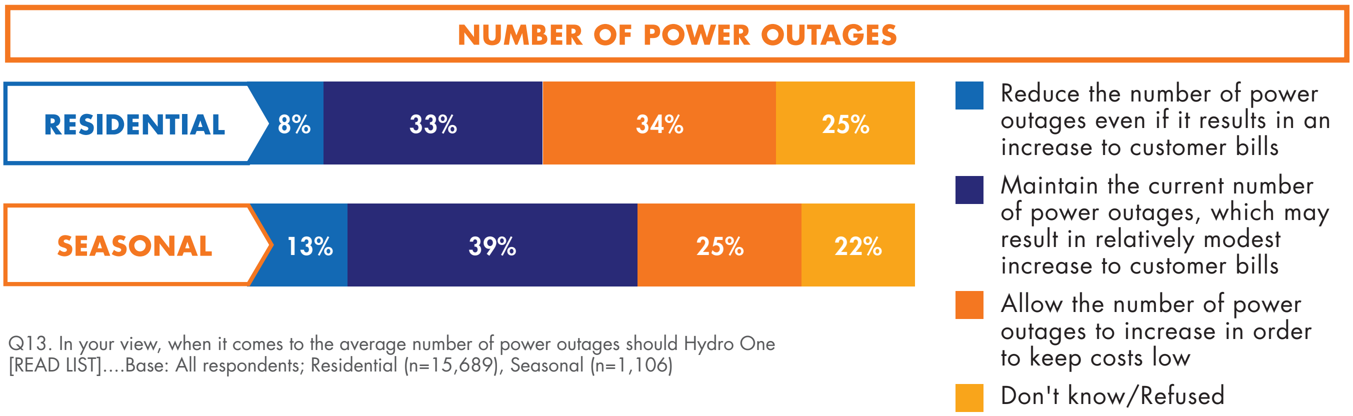
Q10. In general, when you think about the average length of the power outages you experienced over the last 12 months how did it compare to your expectations? Base: One or more sustained power outages in the past 12 months; Residential (n=10,912), Seasonal (n=638)

HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

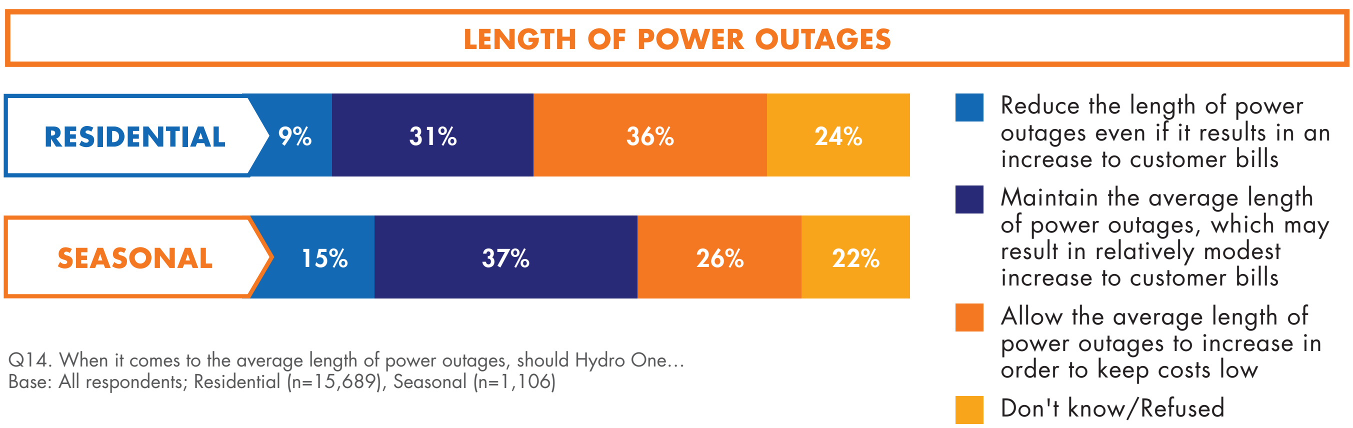
When asked what Hydro One should do on the topic of the number and duration of outages – that is, maintain current levels, improve upon current levels or allow the levels to degrade – opinions are mixed. A reasonably large minority of customers did not offer an opinion (25% of Residential customers indicated they don't know or refused to provide an opinion on the number of outages and 24% on duration, and 22% of Seasonal customers).

ONLINE WORKBOOK OPEN-LINK

RELIABILITY TRADE-OFF PREFERENCE



Q13. In your view, when it comes to the average number of power outages should Hydro One [READ LIST]....Base: All respondents; Residential (n=15,689), Seasonal (n=1,106)



Q14. When it comes to the average length of power outages, should Hydro One…
Base: All respondents; Residential (n=15,689), Seasonal (n=1,106)

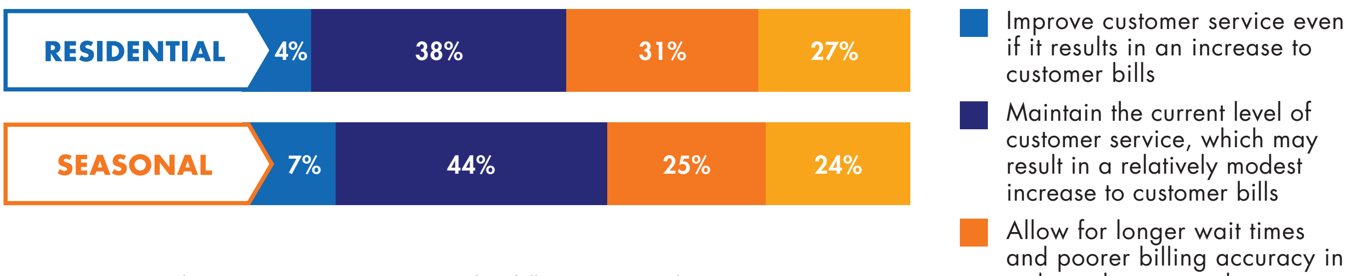
Of those who offer an opinion on the number of outages, 44% of Residential customers would trade off an increase in their monthly bill to keep number of outages at the current level, but 45% would allow the number of power outages to increase to keep costs low. One-in-ten customers (11%) would like to reduce the number of outages and would be willing to accept a potential increase in their monthly bill to achieve it. This is consistent with the results of the Telephone Survey. Customers' opinions on the number of outages break out very similarly when it comes to preferences on how to address both the duration of outages as well as the level of customer service.

Customers were asked what they would prefer when it comes to upgrades to the system to connect new customers, including those producing renewable energy or energy storage. While roughly two-in-ten do not offer an opinion, a majority (68%) of those with an opinion indicate that given the choice they would prefer to allow a reduction in Hydro One's ability to connect renewable energy customers in order to keep costs low.

ONLINE WORKBOOK OPEN-LINK

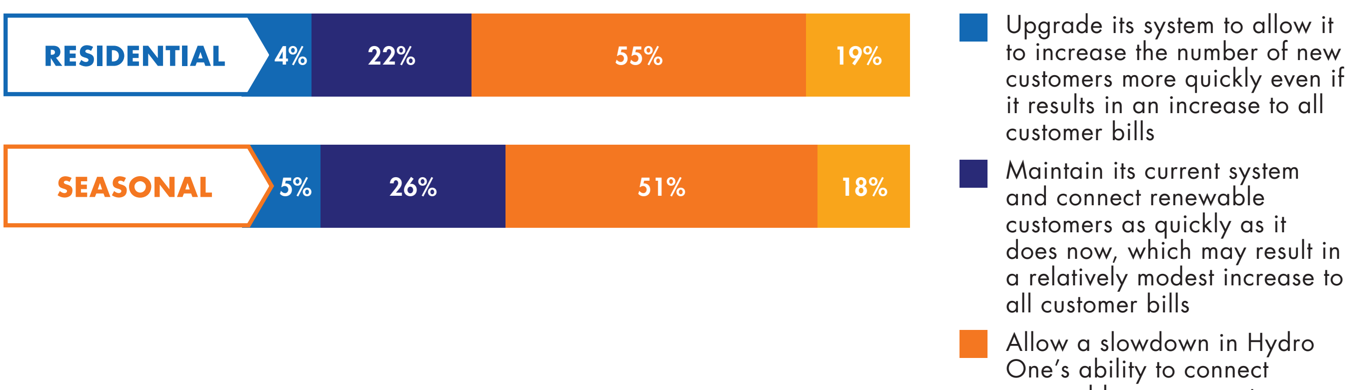
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One… Base: All respondents; Residential (n=15,689), Seasonal (n=1106).

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One [READ LIST].... Base: All respondents; Residential (n=15,689), Seasonal (n=1,106)

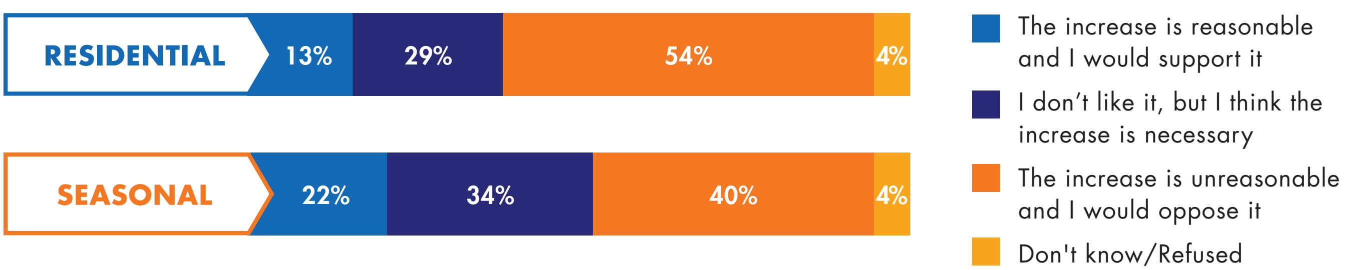
Once re-based on only those who offered an opinion, acceptance increases to 44% among Residential customers and 58% among Seasonal customers. These results are on par with the 'uninformed' Telephone Survey, which was directionally lower than the results of the 'informed' representation sample.

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Residential or Seasonal customer's **total monthly bill** will need to increase by 1.1% or the equivalent of $2.00, less than half of Residential (42%), but over half of Seasonal (56%) customers are willing to accept it, while half (54%) of Residential and 40% of Seasonal customers are opposed. The remaining 4% respectively do not offer an opinion. Prior to answering this question, customers were informed that the increase of $2.00 would be applied each year for the next five years, and that by the fifth year a typical monthly bill will be roughly $10.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside of Hydro One's control.

ONLINE WORKBOOK OPEN-LINK

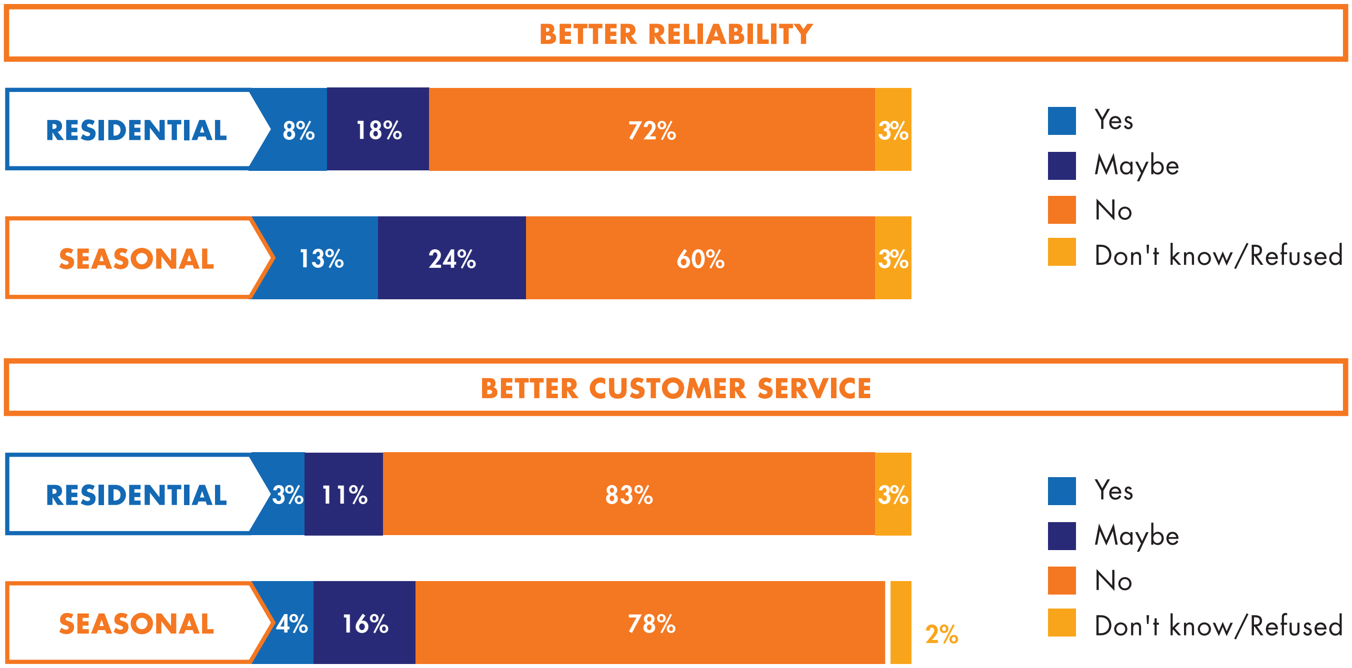
ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [Residential or Seasonal] customer's total monthly bill will need to increase by 1.1% or the equivalent of $2.00. The increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF RESIDENTIAL OR SEASONAL $10.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Base: All respondents; Residential (n=15,689), Seasonal (n=1,106),

ONLINE WORKBOOK OPEN-LINK

WILLINGNESS TO PAY FOR IMPROVED LEVELS



Q18. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have better reliability than you have now? Base: Residential (n=15,689), Seasonal (n=1,106) Q19. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have better customer service than you have now? than you have now? Base: Residential (n=15,689), Seasonal (n=1,106)

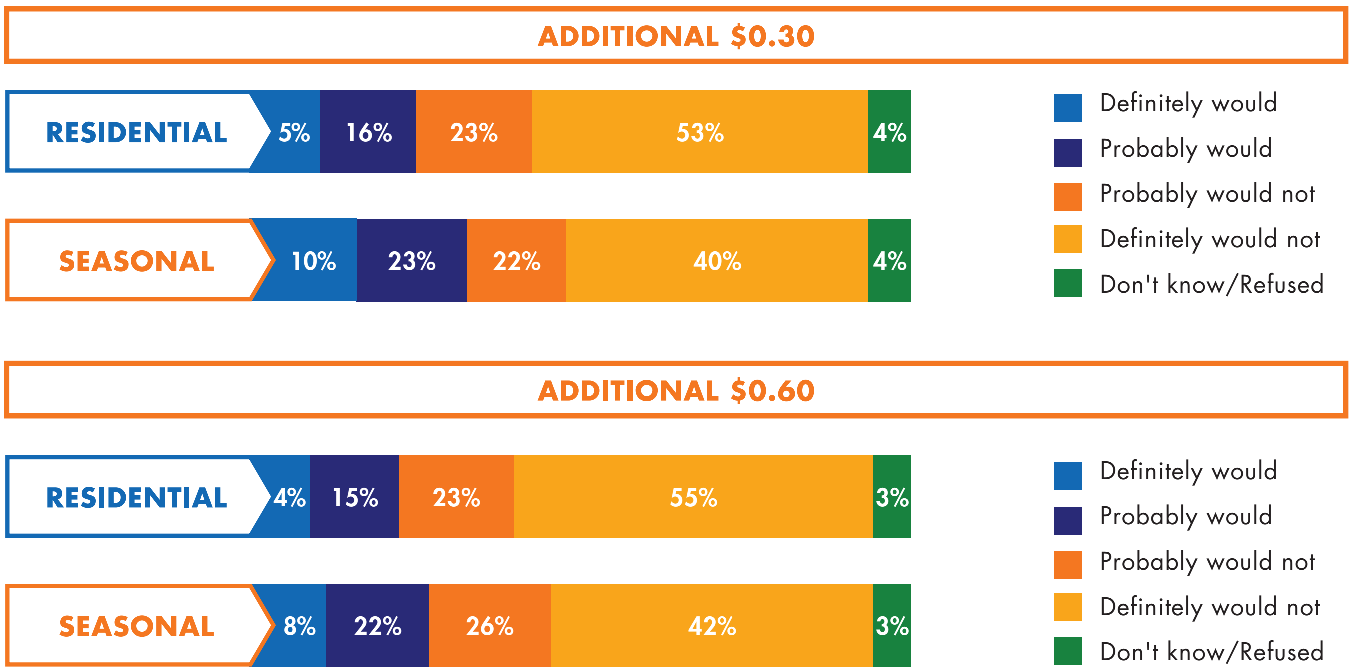
Only one-in-ten Residential customers indicate that they would be willing to pay more than the $2.00 (1.1%) increase in order to have better reliability than they have now. An additional 18% of Residential customers would consider it (selecting 'maybe' as their response) and 72% would not pay anything more. There is even less interest in paying for an improved level of customer service – only 3% of Residential customers are willing to pay more for improved customer service.

Lastly, customers were asked their level of interest in a 10% reduction in the number and length of future outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $.30 per month, or a total of $2.30 more on their monthly bill, and the other half was asked to consider a rate increase of $.60 per month for a total of $2.60 more on their monthly bill.

Only 5% of Residential customers say they definitely would prefer to pay $2.30 more (or $11.50 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 16% say they probably would. This is on par with the telephone sample. Only 4% of Residential customers say they definitely would prefer to pay $2.60 more (or $13.00 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 15% say they probably would. Willingness to pay the additional cost associated with improved levels is higher among Seasonal customers where 33% definitely or probably would pay the additional $0.30 and 30% would pay the additional $0.60.

ONLINE WORKBOOK OPEN-LINK

WILLINGNESS TO PAY FOR IMPROVED LEVELS



Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30/OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30/$2.60] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50/$13.00] higher than it is now? Base: Residential/Seasonal customer; Residential (split n=7,854/n=7,835), Seasonal (split n=567/n=539)

FOCUS GROUPS

A series of four focus groups with Residential customers were conducted to further flesh out early learnings and findings from the Telephone Survey. In particular, understanding the reasons in more detail for why some customers accept and others do not accept rate impacts, were of interest. Furthermore, they were designed to understand general needs and preferences, to provide information about Hydro One and its operations, and to ascertain reaction to this information.

SUMMARY

Residential customers generally had positive overall experiences with and perceptions of Hydro One, as they have satisfactory or high levels of customer service and reliability. For some customers, cost and affordability was the biggest area of concern. Most were unaware that Hydro One only makes a profit on delivery charges.

A distribution rate increase received mixed support, with the majority of customers stating that they didn't like the increase but that they understood why it is necessary. For those who opposed an increase, they disliked the idea in principle. For some this was driven by an information gap as to what the additional funds would be used for, with others citing their negative perceptions of Hydro One and its ability to use the funds wisely.

Opinions were mixed as to what degree Hydro One should be preparing the grid for future needs. While some believed in the forward-looking, long-term benefits of items such as an increase in renewable energy, others stated these types of initiatives would only benefit a select group of individuals and that the cost of these benefits should not be borne by all customers.

Because they do not currently struggle with reliability, seeing this area maintained was of interest, but having it further improved was of little interest. Power restoration during outages was highly satisfactory, with the ability to receive or seek accurate and timely restoration information being of appeal.

Based on the information presented during the Focus Groups, participants stated they had a better understanding of the need to invest in Hydro One's distribution delivery infrastructure, with a few stating their dissatisfaction with its current pace of maintenance and renewal based on the information provided.

Residential participants are the least engaged with and informed about Hydro One and the energy sector. However, they were open and receptive to receiving more information about both their current bill and any future rate increases, which in turn would likely engender a positive influence on their views of Hydro One. Hearing credible information from Hydro One about ways to conserve energy and ideas to save on electricity costs were also of interest to this group. There were multiple channels listed as to how residents would like to hear from Hydro One. Hearing information about planned outages and power restoration, and any rate increase and the reasons for it, through all of these channels were of interest.

DETAILED FINDINGS

COSTS AND RATE INCREASES

The cost of electricity emerged as a theme of concern to many Residential Focus Group participants. There were mentions of issues with the perceived high cost/price of electricity rates and bills, with some participants expressing a desire for overall lower bills or a decrease in rates. A few organic mentions were made of electricity costs being much lower in other jurisdictions.

"Prices could be considerably lower."

"I'm not happy with the overall cost."

> *"Hydro bills are through the roof and it is becoming very unaffordable. Not sure why the States can offer electricity SO much cheaper than Canada."*

Some Residential participants perceive that rate increases are higher than inflation and/or the cost of living. A few who struggle with the cost of electricity state that it is unaffordable and that they are currently unable to pay their electricity bills, with others raising a deep concern that a continued rise in prices would mean being unable to pay their electricity bills in the future.

"…electricity prices are certainly surpassing my wage [increases]. So, I always think of it that way, that I'm definitely paying more out of pocket in proportion to my income."

"…some months, I have problems paying my hydro bills. So, because of the rates of hydro and all the additional delivery charges and all of that other stuff that comes on your bill, I actually had to go to equal billing in order to be able to pay my hydro, and that's crazy."

When it was explained that Hydro One only makes a profit on the transmission, distribution, and delivery charges on an electricity bill, and that other charges on the bill are pass-through only, most participants in the groups were unaware of this. For a few, this positively affected their view of Hydro One, while others stated that their views remain unchanged.

"I guess if the rates seem high I don't have to be mad at Hydro One."

A few mentions were made of delivery charges being billed without having actually used any electricity during that period — participants were puzzled as to the reasons for this.

"[There] hasn't been any electricity or hydro used, and yet they're still got a bill with a delivery charge on it…"

One participant stated her belief that privatization would result in an increase in rates/costs to the ratepayers, as she has observed with other companies who have been privatized.

"I just know that without certain regulation that was in place before, prices of businesses that have moved towards privatization have risen, and that's kind of been the track record in the past, so that's really what I'm basing my prediction on."

When asked about a residential rate increase of 1.1% or $2.00 per month for the average customer:

- Most indicated they don't like the increase, but think that it is necessary
- Several stated that the increase is unreasonable and were opposed to it
- Several indicated they did not know if they support an increase
- Some stated that the increase is necessary and were supportive

Those who indicated that an increase is necessary or supported a rate increase stated they recognize that it is needed to maintain service and reliability levels while others were resigned to rising prices and cost of living.

> *"I actually thought Hydro One was taking much more, but this clarifies a lot. I actually feel more positive towards them now if anything."*

"I feel it does need to be done to sustain maintenance and make sure the power doesn't go out more frequently. Do I like it? No. Because it's going to go up and nobody likes that. But we don't really have a choice, we need the reliability."

"If I see a high quality of reliability over costs I am fine with paying the extra amount."

"Well, the cost of living is going up. Nothing stays at the same rate. Just as your salary is going up, everything else will go up, too. So you can imagine that the bill is going to go up. So nothing to do about that."

For those who were opposed to a rate increase, their opposition was generally not due to a lack of affordability. To them, they opposed it in principle for reasons including:

- A general desire to keep costs low, regardless of maintaining/improving reliability and service
- Skepticism about the "average" amount being $2.00
- A lack of information as to where and how funds are currently used, and how a rate increase would be used
- A perception that funds are currently or will not be used wisely by Hydro One

"I would rather the company not worry about improving the other areas and instead concentrate on keeping costs low for customers."

"If there is a way to improve both [service and cost], obviously that is ideal, but if I'm going to weigh one over the other, then I'm going to choose the cost."

"…the only thing I'd like to see is a decrease in my bill...As far as the bill, I can't think of what they would say that would make me feel an increase at this point in time for anything would be reasonable, because like I said, I honestly feel they should be decreasing our bills."

"…if they increase our percentage on our delivery charge — so yes, maybe our bill will go up maybe $2.00 a month on our delivery charge, but it's not taking into account that our electricity [has] always gone up as well. So, it would be far more of an impact than $2.00…So, having it go up another $2.00 at this point, hypothetically $2.00, is not it. It's going up by 1.1% of whatever the delivery percentage is that they're charging on the electricity they've delivered."

"…I'm unclear on my costs as it is. I pay an awful lot, like everybody else, every year, and I just can't imagine why we need to pay more to maintain reliability…I just don't understand that. So, if I could better understand where the costs are going now, I may have a different answer to this question later."

"…part of that is I see their service trucks sitting on the side of the road for hours on end and their service people taking two-hour lunch breaks all the time…."

"I think it's unreasonable honestly because I know the company's net assets have increased 13% since 2012, and something like 4,000 employees have made the Sunshine List, earning over $100,000 a year on the public dime. So, I think it's a little unreasonable to be dipping into the customer's pocket to sustain the level of outages that I personally feel is a little unreasonable."

One participant stated that she did not understand the relationship between increasing rates, and how it affects outages.

"I just have a hard time understanding how rate increase has to do with power outages, like the length of time or whatever…I mean, do we have to pay money to have a better response time to power outages? I don't understand. So if we pay less, we'll have more frequent power outages or if we pay more, when we have a power outage it will be resolved quicker? I don't understand."

For many participants including those who opposed and those who didn't know whether or not they supported a rate increase, having more information on how the rate would be spent was of interest. Some participants indicated an interest in having this information represented using charts, illustrations or graphics. Some stated that Hydro One should proactively push the information out to its customers via multiple channels, while others indicated they would seek the information out themselves in the event of a rate increase.

"I would like information on why they're going to do a $2.00 increase per month on my bill. So, it could be just something in the mail along with my bill, just to say briefly what it's about and when it would be happening, not that it just appears on my bill."

"I would prefer…a text where it notifies me about the change and where it would lead me to a website where I could find out more information if this is my interest."

"Even a simple pie chart, showing the different areas where they're investing in new infrastructure or maybe even development or their disaster recovery plan, however the money falls out, that would be nice to see. Like a budget."

CURRENT AND FUTURE ASSET MANAGEMENT, AND ASSOCIATED COSTS

Based on the information on Hydro One provided during the Focus Groups, many participants expressed their surprise at the breadth of service the company provides, and stated that it positively affected their view of Hydro One and/or a potential rate increase. Others indicated that the information was new, but did not change their view of Hydro One either positively or negatively.

"More trust. The breakdown helps. We don't normally see what's happening in the background. Helps build confidence in paying that extra amount to them."

"…I had no idea. I definitely have no issues with the increase after seeing this information."

"It improves my view overall of Hydro One."

"This is the kind of information that Hydro One should be sharing with customers so that we better understand the situation."

A few customers expressed their concern and dismay as to the current condition and number of aged assets. They also expressed concern that this would mean an increase in rates in order to fix these issues.

"This impacts my view of Hydro One negatively. I didn't realize the company was so behind on updating their system…"

"These are upgrades that they knew were coming for years and should have budgeted for, not expected the consumer to have to take on additional cost."

Residential participants were polarized as to what degree Hydro One should proactively plan for and manage the grid for future needs. Some participants stated it is Hydro One's responsibility to both proactively plan for items such as renewable energy and energy storage that take the evolution of the grid into account; however, they state costs should be kept low and advocated for a balanced, steady approach to managing these changes. A few stated that although there might be a short-term increase in costs and rates, there would be long-term economic and environmental benefits.

"I think it is important to stay on top of the updates, if we fall behind it could be expensive."

"I believe that Hydro [One] should be continually investing in newer and more reliable ways of delivering and sustaining power overall. I would like Hydro [One] to begin using solar for their own stores of electricity generation."

"…I think it's good to stay on top of the technology, so when it comes to your electric cars and stuff, that finally becomes the thing to have, it's not all at once we end up with a great big fee. Maybe slowly introducing things might be a smarter idea than us being hit with some other kind of fee on top of our regular hydro."

"…it does need to remain a balance between infrastructure improvement and affordability."

"There needs to be progress in all areas, but I think to have sole focus or a disproportionate focus is only going to in the long run not pay the dividends and it's going to spike cost, it's going to potentially focus on areas that may not in the long run pan out to be the definitive answer."

The advantages of having customers and small generators send power back to the grid were also debated, with one participant citing net metering as a positive program/benefit.

"Hydro One needs to improve access to allow small renewable energy producers (households) to flow their electricity back into the electrical system. We had considered installing solar but there was almost no capacity to do so in our area. Considering there are not a lot of rooftop solar panels in our area, I don't see why capacity is so low."

Those who are opposed to proactively preparing the grid state this is a low priority area that should be of concern only to those who are directly benefiting, or as the need arises in future. They stated that Hydro One should not be responsible for passing these costs to other customers, as they perceive only a small group would benefit — for example, only those who drive electric vehicles, or those who can afford to install solar panels on their roofs.

"I feel it's a personal choice…Why does everybody have to pay for the very, very small percentage of people who [own] electric vehicles, renewable energy at their own home, and making adjustments to their homes and their power systems that Hydro One is then going to pass on to everybody who doesn't have any of that. That would really upset me."

RELIABILITY AND POWER RESTORATION

Most Residential customers stated they do not have issues with reliability and experience an expected/acceptable number of outages. They understand the reasons for outages and state that Hydro One provides great service in restoring power in a timely way. Participants in remote areas were more likely to experience more frequent outages.

"The service is consistent with very few outages."

"I am satisfied with Hydro One because they are always there. For example, when we had the ice storm. They were working 24/7 to make sure everyone's needs were met."

"We are in a fairly remote area, and I would say our power is out maybe once every one or two months, and sometimes it's for a significant period of time, like this week, it was out for three hours, three and one half hours."

Several participants stated they do not believe customers should have to accept a trade-off in terms of choosing reliability versus keeping costs low, and that they should not have to choose one over the other. They stated it is Hydro One's role as a utility to balance reliability and cost.

"…it does need to remain a balance between infrastructure improvement and affordability."

"…I don't think that I would be willing to accept an increase in price for a decrease in outages. I feel as a distributor of electricity, that's kind of Hydro One's responsibility to ensure that people have access to electricity for an agreed upon price. When outages still occur, I don't get a refund on my bill, so I don't feel that I should be charged a premium to reduce outages."

Many participants indicated that because they do not experience a high number of or any outages, they could not comment on power restoration. For those who did experience outages, they reported mixed satisfaction with power restoration — many were satisfied with restoration times, with others stating that they experience longer outages. Impacts were minimal and mostly considered a minor inconvenience.

"We recently had one [power outage] about a month ago due to weather conditions. The outage lasted for about five minutes tops. Swift resolution. I was very impressed."

"I'm pretty happy with the reliability, but when it does happen, it's like four days sometimes, and it's kind of unfortunate."

Most participants call in to the number on their bill or visit Hydro One's website for restoration information. Others rely on news sources or neighbours for information. The information provided by Hydro One on restoration times was often not timely or accurate. Having restoration information proactively pushed out to them by Hydro One was of interest, particularly in the event of longer outages.

"I think communication during an outage could be improved. Often, a customer has to look to secondary news sources to find out [an] ETA for restoring power."

"Hydro One seems to have a delay in posting affected areas on their website, so that information is not always up-to-date."

"Communication during the outage could be improved in the event that power has been out for several days."

Awareness of Hydro One's outage app was low, with some expressing interest in it — particularly for nimble, timely and accurate outage restoration information. One participant mentioned being able to track their usage on the app as being of interest.

"I think it should probably have a specific explanation in terms of which zone is being affected, or maybe just a quick update on what the developments are, minute-by-minute or so of what they are actively doing or working on, on-the-go."

"…how much is my bill [going to be], basically, at the end of the day? …if I can track my own expenses biweekly or whatever."

CUSTOMER SERVICE AND BILLING

Residential customers are generally satisfied with Hydro One's customer service, and most are able to receive satisfactory closure on any issues they have with Hydro One. Having little to no need for contact with Hydro One is considered a positive, as it means that the customer is not having any issues or outages. For many, their monthly bill is their main point of interaction.

"Their customer service is always wonderful, and I can honestly say I have not had an encounter with them where I was not fully satisfied."

"[I am] very satisfied with Hydro One, as they are very prompt with their services — answering questions and onsite visitation."

"…they called back. They [said] they would call back when I phone to say that we lost power here. I phoned them. They phoned right back…They said we'll call you by this time. They called when they were supposed to call. They showed up when they said they were going to show up. And the problem was fixed, so no complaints at all."

"I've lived in my apartment for over a year and I've never once had any outages or had to contact Hydro One for anything. I've been pretty lucky."

Wait times on the phone when calling into the customer service centre was the main area of dissatisfaction for Residential participants — they would like to have wait times minimized. However, this was not an area participants believed should require more investment/ higher costs. While phone is still a preferred contact option for many participants, some also expressed interest in contacting Hydro One in other ways — such as a live chat option on its website — as participants believe this would minimize wait times.

"…recently I had a customer service experience through a direct chat window from the company's website…So, it might be nice just for a quick question that doesn't require a lot of explanation to have a chat window on [Hydro One's] website."

"I think live chat would de-clog lines, so we don't have to spend so much time waiting on a line for a customer rep."

Billing is a satisfactory area for most participants. A few participants indicated that they find their bills confusing, and wished to receive clarity around charges. For some, this meant a more simplified bill while for others it was more information, or information in a more graphic or illustrative format. The ability to see information separate from the bill — either through an insert, or online — were also mentioned as being of interest. One participant mentioned the desire to see digital bills move away from e-post.

"…there is a lot of information on the bills and it seems like the comparative usage and rates and the price and per unit and all that stuff…that might be something that you could go drill down to online through an online account versus all on the bill every month…"

"I always think that when you want to show something visually, graphics always help… It's better than straight numbers."

COMMUNICATION AND AWARENESS

As a group, Residential customers are less aware of the energy sector in general and are the least actively engaged with Hydro One. As a result, they are receptive to hearing more information and less likely than other segments to have negative perceptions.

Some participants indicated their interest in having

Hydro One provide ideas and information on ways to save and conserve energy and ultimately, the cost of their electricity bill. This might be through programs, coupons, or simply being able to track their detailed usage between bills. Having this information come directly from Hydro One would lend credibility to the information. A few customers spoke of positive experiences with energy/cost saving programs with Hydro One, with others stating that they are unable to get recommendations and information on programs.

"I think in a sense they would be a great vehicle to inform their customers how to save…for them to offer their customers suggestions on how to be more efficient users, interesting, unique strategies, I think goes hand in hand. In my opinion, I would value them even more by offering this as opposed to other individuals or companies saying you can do better by using energy in other ways that…I have not been able to do myself."

The means through which Hydro One can effectively communicate with its customers was discussed during the Focus Groups. Relevant information to include in any communication includes planned outages, rate increases, and service restoration.

Participants expressed interest in a number of different channels and some indicated that they would like to hear from/about Hydro One via multiple channels, including:

- Directly on the bill
- Bill inserts
- App
- Social media
- Separate letter
- E-mail
- Advertising
- Texts
- Website

Seeing more information during the groups had an overall positive impact on perceptions of Hydro One. Hearing directly from Hydro One is of high interest and would instill confidence and trust in Residential participants as to Hydro One's efficacy as a service provider.

"The visuals gave me a new understanding of Hydro One and the challenges that they face. They should be sharing this with their customers…"

"What they are doing in more detail. Maybe a breakdown of what each thing cost and is not just maintaining but before more effective in the long run."

"A letter from upper management and an explanation with graphics would be great to assume confidence and trust from our side."

SUMMARY

In general, compared to Residential customers, Small Business customers indicate they are more inclined to accept some type of an increase in their monthly bill to see a reduction in the number and average length of outages, but back track at the size of the increase in rates that is required. When posed with a 1% increase on their total monthly bill to ***maintain*** *the current level of reliability and service they receive, 57% of those who offer an opinion would accept it (53% across all Small Business customers surveyed). This is on par with the response of Residential customers. When posed with higher increase for a reduction in the number of outages, Small Business customers react more negatively than Residential customers.*

TELEPHONE SURVEY

As outlined in the methodology section of this report, the following results are based on a Telephone Survey of a random and representative sample of n=200 Small Business customers. A stratified, random sampling approach was used to pull the sample Small Business <50 kW peak and 50 to <500 kW peak customers from Hydro One's customer database. With a sample of this size, the results are considered accurate to within ±6.9 percentage points, 19 times out of 20, of what they would have been had all Small Business customers been surveyed. That means that if the survey is repeated 20 times, 19 of those times the results of the survey will be the same within the margin of error. The margin of error will be larger for sub-groups of the population. The data was statistically weighted by Demand/ Non-Demand and by region to ensure the sample composition reflects the true proportions in the customer database.

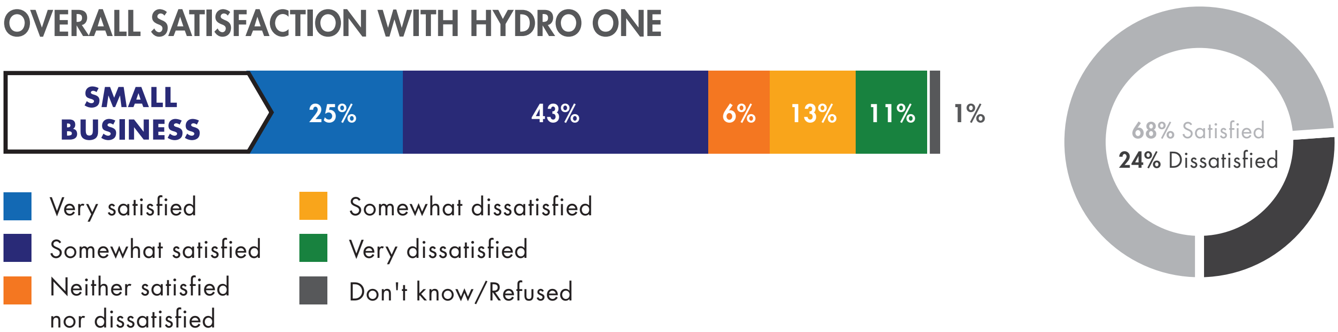
For more information on the survey methodology refer to the Customer Engagement Methodology Section of the report.

CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Roughly two-thirds (68%) of Small Business customers report they are satisfied with Hydro One overall, while one-quarter (24%) are dissatisfied. When asked on an unaided basis what Hydro One can do to improve its service to them, the most frequent answer customers give is to reduce their monthly bills. Some customers mention this in the context of lower prices or lower rates, while other just simply say lower cost.

TELEPHONE SURVEY

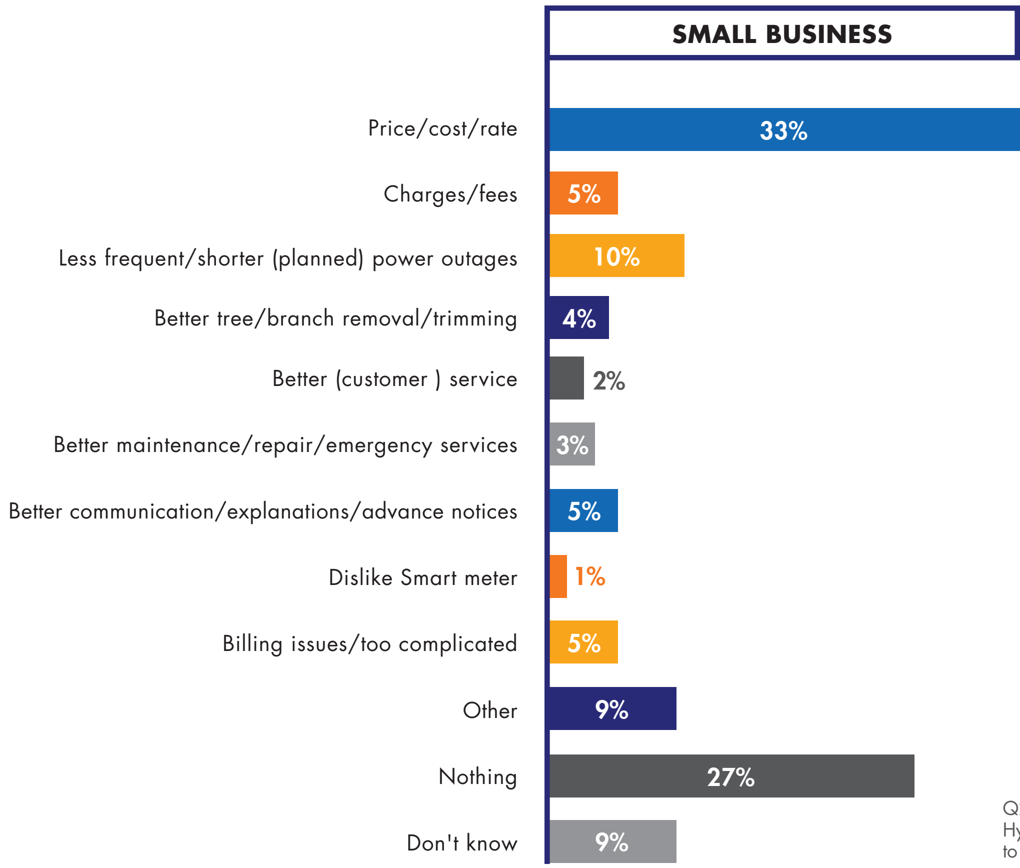
OVERALL SATISFACTION WITH HYDRO ONE



As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. Please think about Hydro One as I have just described it to you. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Small Business (n=159)

TELEPHONE SURVEY

HOW HYDRO ONE CAN IMPROVE ITS SERVICE

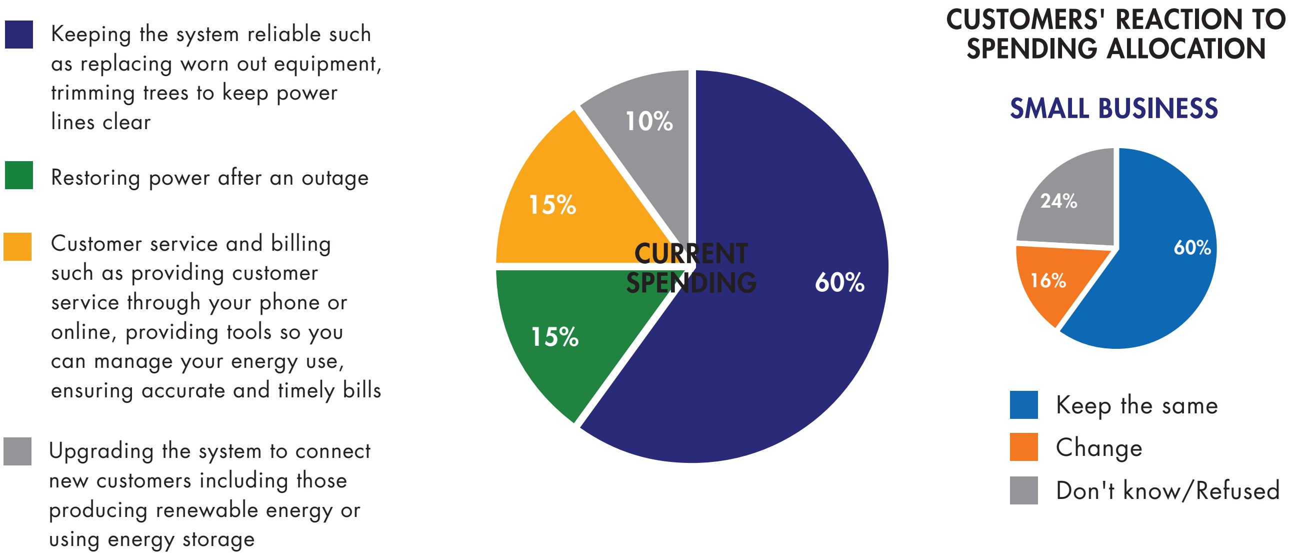


Q2. Is there anything in particular that Hydro One can do to improve its service to you? Base Small Business (n=200)

Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, the majority (60%) indicate that they would not change how the money is currently allocated. Sixteen percent of customers indicate that they would change how the money is allocated. In general, these customers allocate more money to restoring power after outages (increasing the current amount by about two-thirds) and money for upgrading the system to connect new customers including those producing renewable energy (by about 50%) and less money to keeping the system reliable (about 20% less).

TELEPHONE SURVEY

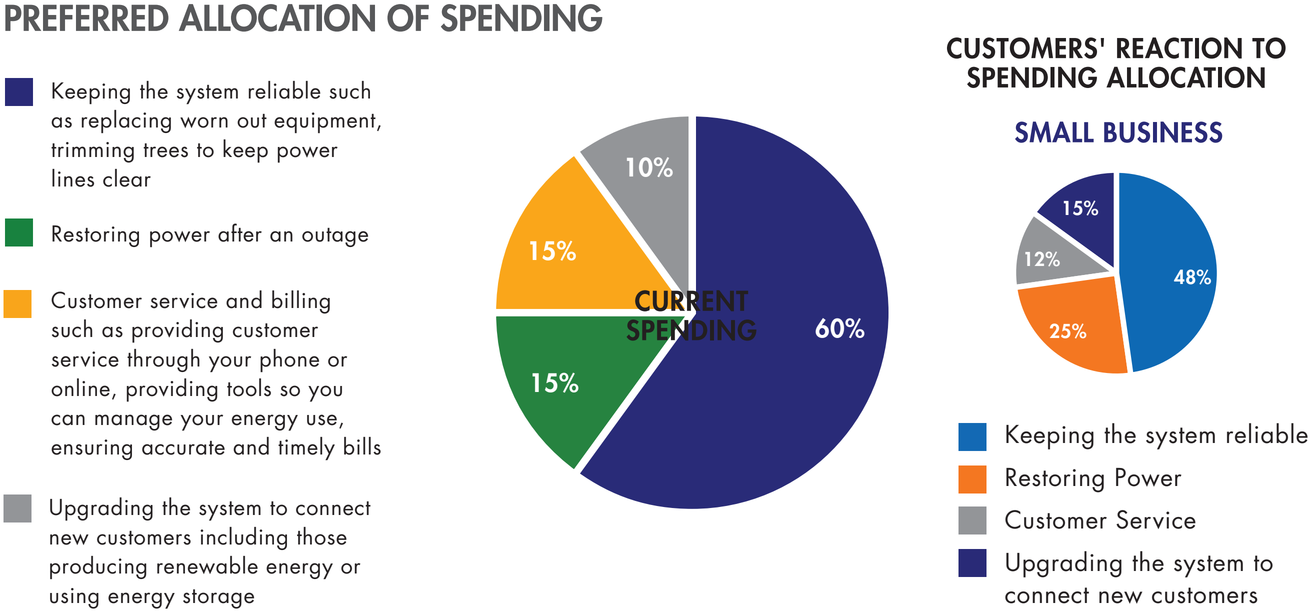
OPINIONS ON CURRENT ALLOCATION OF SPENDING



Q3. Please listen carefully as I will be reading out a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments and will be asking your opinion about the breakdown. Hydro One currently spends [READ LIST]… If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base: Small Business (n= 200)

TELEPHONE SURVEY

PREFERRED ALLOCATION OF SPENDING



Q4. Of the 4 distribution investments you just heard, what percentage would you allocate to…? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% (Small Business n=26)

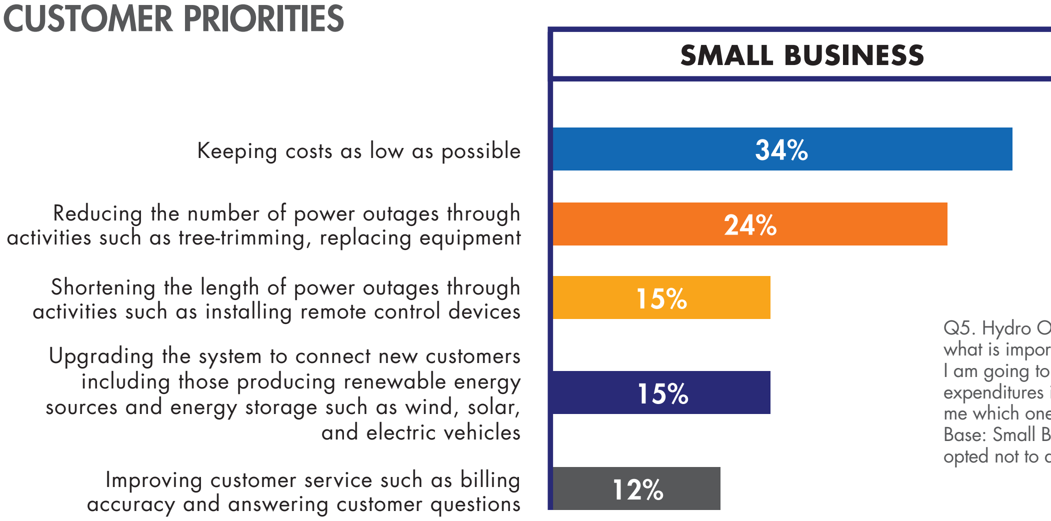
CUSTOMER PRIORITIES

A paired-choice exercise was used to identify customer priorities in order to help Hydro One better tailor its services.

The chart below shows that keeping costs as low as possible has a relative preference score of 34% among Small Business customers, which is the largest preference score of the options presented. This indicates that customers prioritize keeping costs as low as possible above the other options – reducing the number of outages, improving restoration times, improving customer service, or upgrading the system to connect new customers. It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is the next most preferred option.

TELEPHONE SURVEY

CUSTOMER PRIORITIES



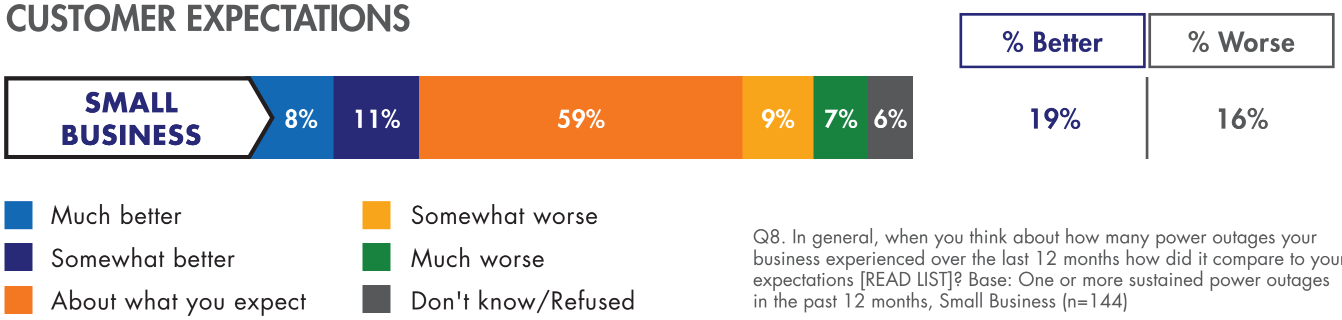
Q5. Hydro One would like to better understand what is important to you as a customer. I am going to read Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you.
Base: Small Business (n=199). One respondent opted not to answer Q5.

THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate that the level of reliability that they currently experience is in line with their expectations. Small Business customers report experiencing an average of roughly three outages of at least one minute in duration in the past 12 months. The largest share of customers – 59% – indicate that this level of reliability (number of outages they experienced) is about what they expect. Only 16% of customers who experienced at least one outage indicate the number of outages they experienced is worse than they expect.

TELEPHONE SURVEY

CUSTOMER EXPECTATIONS

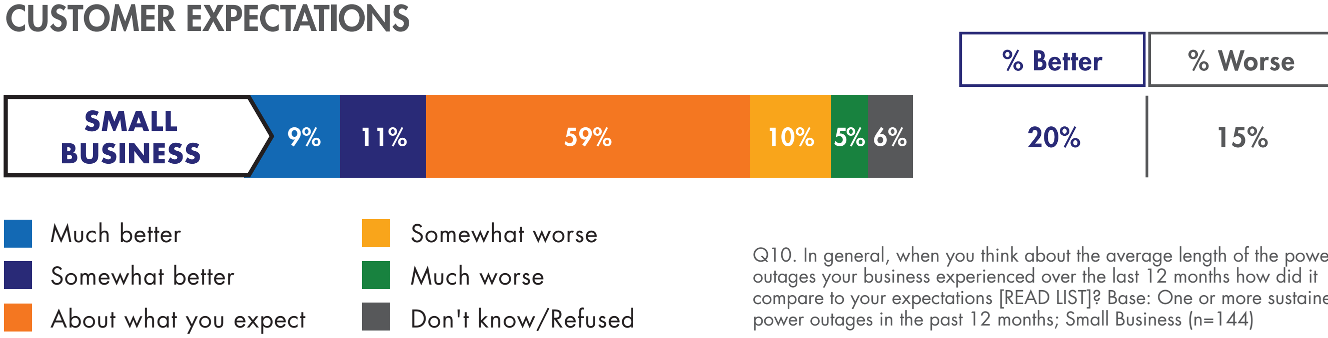


Q8. In general, when you think about how many power outages your business experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months, Small Business (n=144)

When it comes to length of outages, Small Business customers estimate the outages they experience last an average of two hours. Similar to opinions of frequency of outage, the largest share of customers indicate that this is about what they expect. Fifteen percent of those who experienced at least one outage say this is worse than they expect.

TELEPHONE SURVEY

CUSTOMER EXPECTATIONS

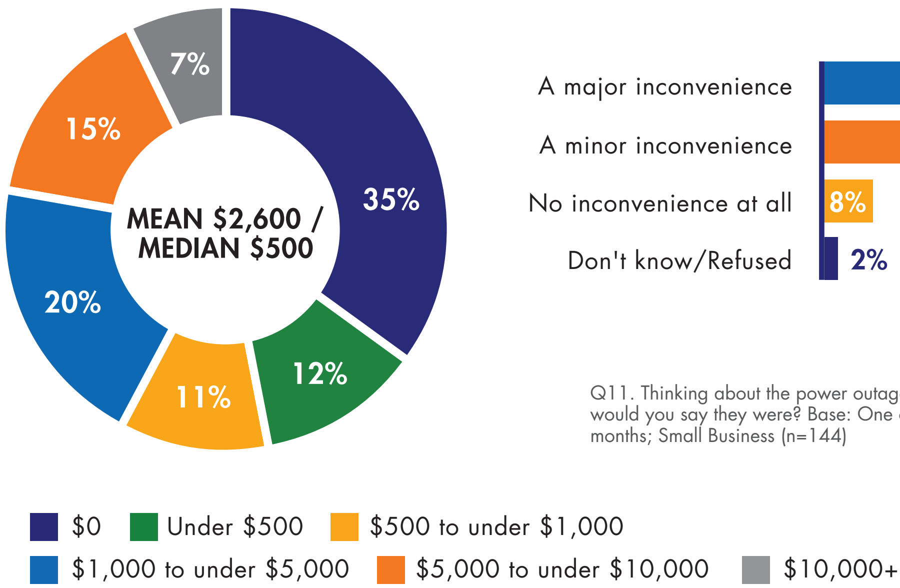


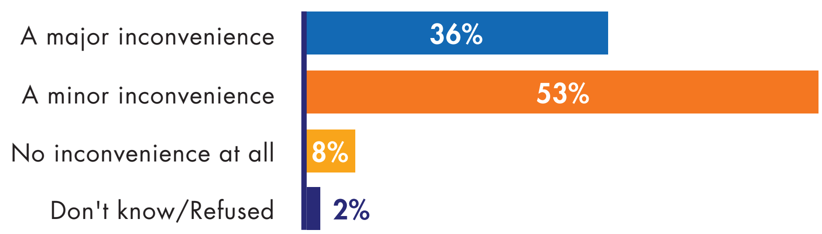
Q10. In general, when you think about the average length of the power outages your business experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Small Business (n=144)

Half (53%) of Small Business customers who have experienced an outage in the past 12 months indicate that the outage(s) were a minor inconvenience and nearly four in 10 (36%) describe the impact as being a major inconvenience. On average, customers indicate that these outage(s) cost their business $2,600.

TELEPHONE SURVEY

IMPACT OF POWER OUTAGES ON BUSINESS





Q11. Thinking about the power outages your business experienced in the past 12 months, would you say they were? Base: One or more sustained power outages in the past 12 months; Small Business (n=144)

Q12. How much, if any, would you say the outages your business experienced in the past 12 months collectively cost your business? Please answer in whole dollars, do not include cents. Base: Those who faced a major and minor inconvenience in business due to power outages in past 12 months, don't knows excluded (n=117)

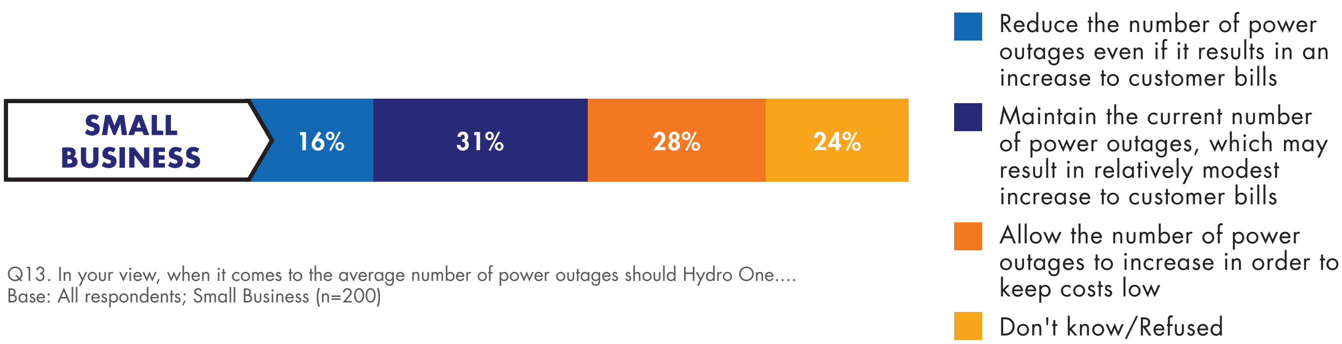
HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

Small Business customers are significantly more likely than Residential/Seasonal customers to support a rate increase in order to reduce the number of outages. More Small Business customers offer an opinion than Residential customers (24% don't know or refuse vs. 34% among Residential), and of those, 22% would like to reduce the number of outages and would be willing to accept a potential increase in their monthly bill to achieve it compared to only 14% among Residential customers. The largest share of Small Business customers (31%) would trade off an increase in their monthly bill to keep number of outages to the current level (41% among those that offer an opinion). Nearly four-in-ten (37%) would allow the number of power outages to increase in order to keep costs low. Customers' opinions on the number of outages break out very similarly when it comes preferences on how to address the length of outages they experience.

TELEPHONE SURVEY

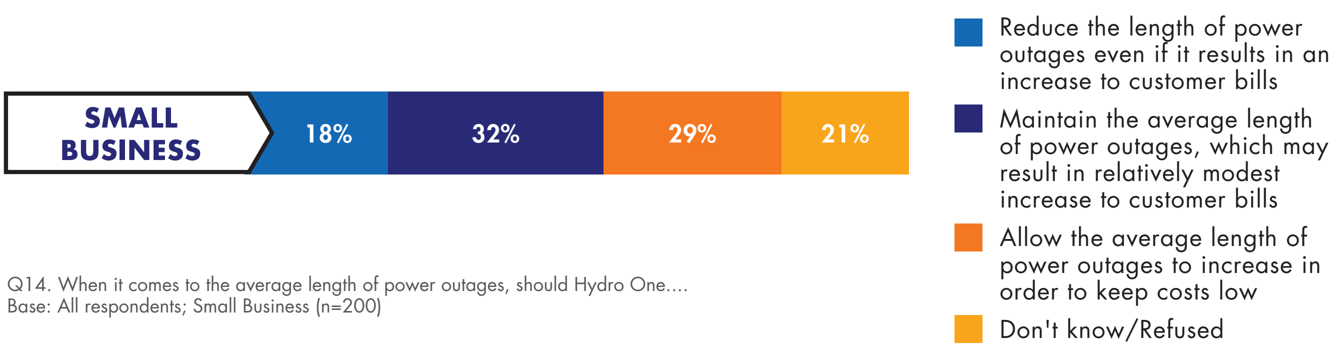
RELIABILITY TRADE-OFF PREFERENCE

NUMBER OF POWER OUTAGES



Q13. In your view, when it comes to the average number of power outages should Hydro One....
Base: All respondents; Small Business (n=200)

LENGTH OF POWER OUTAGES



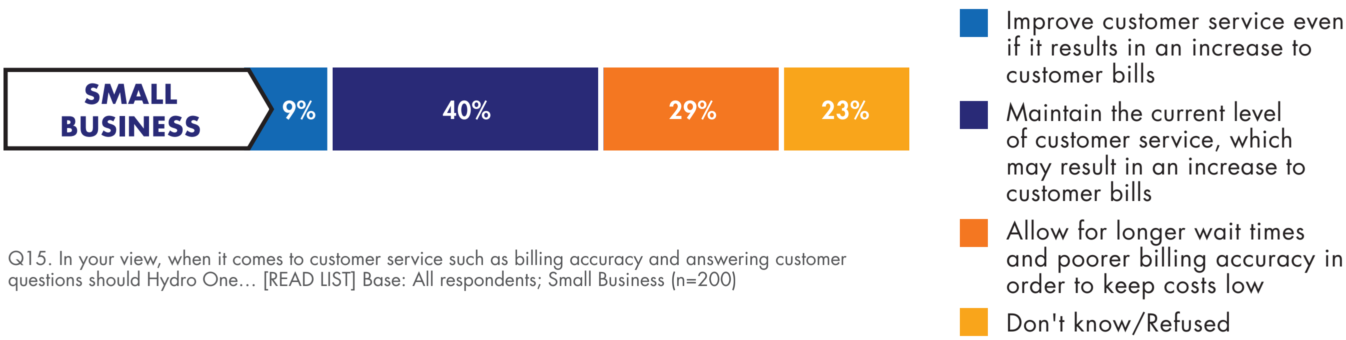
Q14. When it comes to the average length of power outages, should Hydro One....
Base: All respondents; Small Business (n=200)

While roughly two-in-ten (18%) do not offer an opinion, of those with an opinion half (56%) indicate that given the choice they would prefer to allow a reduction in Hydro One's ability to connect renewable energy customers, in order to keep costs low.

TELEPHONE SURVEY

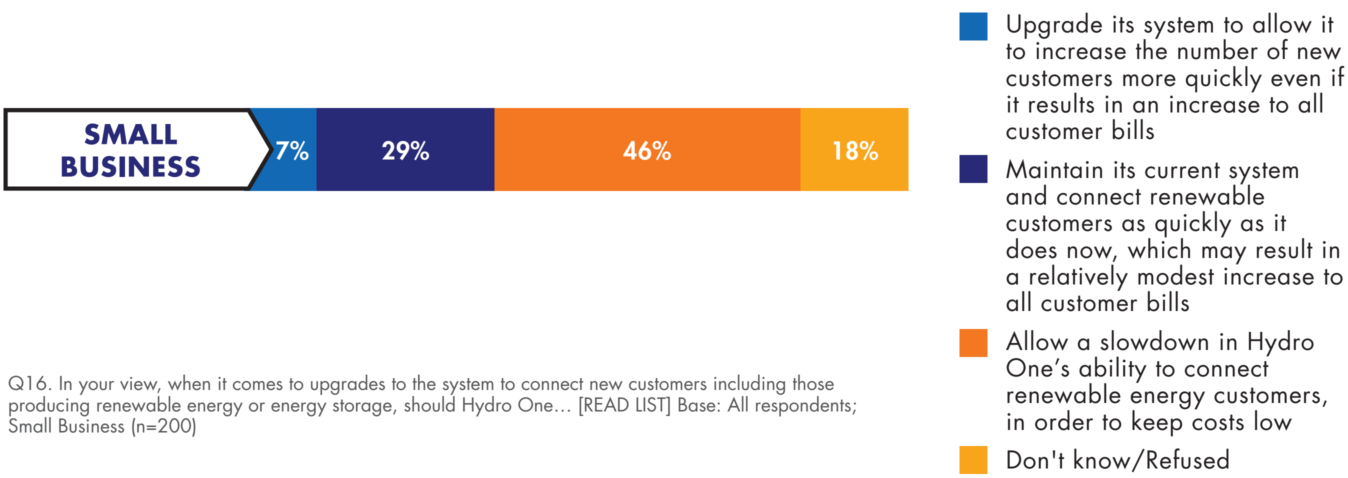
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One… [READ LIST] Base: All respondents; Small Business (n=200)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



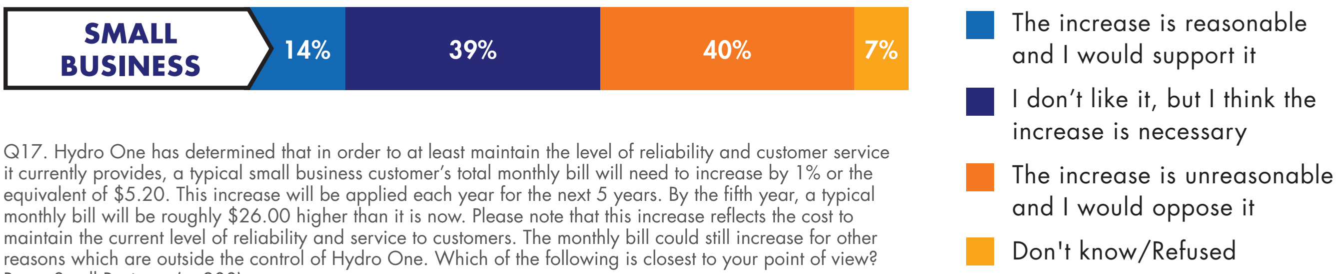
Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One… [READ LIST] Base: All respondents; Small Business (n=200)

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Small Business customer's **total monthly bill** will need to increase by 1% or the equivalent of $5.20, half (53%) of customers are willing to accept it, roughly 40% are opposed and the remaining 7% do not offer an opinion.

TELEPHONE SURVEY

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical small business customer's total monthly bill will need to increase by 1% or the equivalent of $5.20. This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly $26.00 higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Which of the following is closest to your point of view?
Base: Small Business (n=200)

Prior to answering this question, customers were informed that the increase of $5.20 would be applied each year for the next five years, and that by the fifth year a typical monthly bill will be roughly $26.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside of Hydro One's control.

Despite being initially more inclined to pay more for better reliability as compared to Residential/Seasonal customers, Small Business customers are less willing to pay what is required to achieve it. Few customers are willing to pay more for better reliability. Only one in 10 customers indicate they would be willing to pay more than the $5.20 (1%) increase in order to have better reliability than they have now. An additional 13% would consider it (selecting 'maybe' as their response). Seventy-three percent (73%) would not pay anything more. There is even less interest in paying for an improved level of customer service – only 6% say that they would be willing to pay extra for improved customer service with 82% saying they would not.

Lastly, customers were asked about their level of interest in a 10% reduction in the number and length of future power outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $0.80 per month, or a total of $6.00 more now (or $30.00 by the fifth year) on their monthly bill, and the other half was asked to consider a rate increase of $1.60 per month for a total of $6.80 more now (or $34.00 by the fifth year) on their monthly bill.

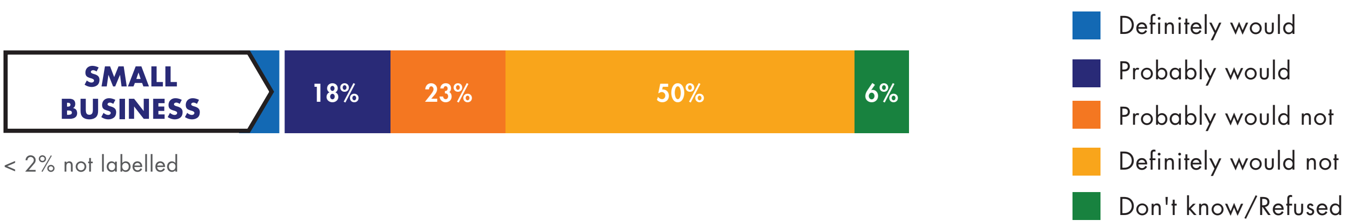
Of those who were asked about paying an additional $0.80, only 20% of customers say they would prefer to pay more, whereas 73% say they would not, including half who say they 'definitely' would not.

Of those who were asked about paying an additional $1.60, only 14% of customers say they would pay and 77% say they would not.

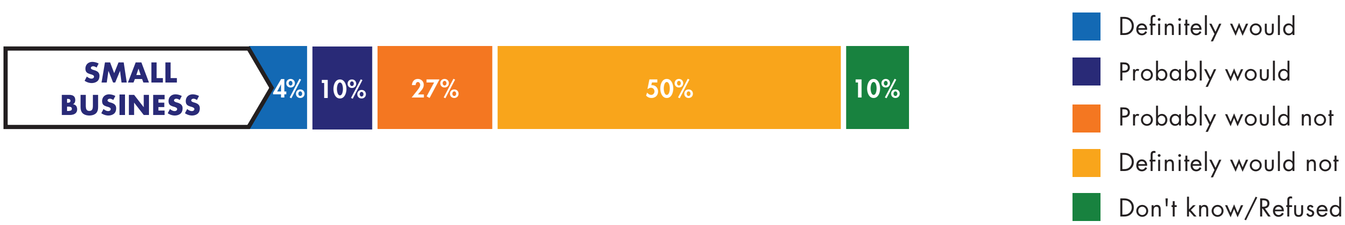
TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS

ADDITIONAL $0.80



ADDITIONAL $1.60



20B. Would you be willing to pay an additional [HALF OF RESPONDENT SHOW $0.80/OTHER HALF SHOW $1.60] per month over and above the $5.20 which would be approximately [SPLIT SAMPLE $6.00 /$6.80] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$30.00/$34.00] higher than it is now. Base: SPLIT SAMPLE (Small Business n=100)

Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, the largest share of customers would change how it is spent (42%). This compared to only 16% from the 'uninformed' Telephone Survey. In general, these customers allocate more money to restoring power after outages, but how much more customers would spend on this is fairly marginal (up to 19%), particularly compared to how much the 'uninformed' sample, who would allocate up to 25% of the total.

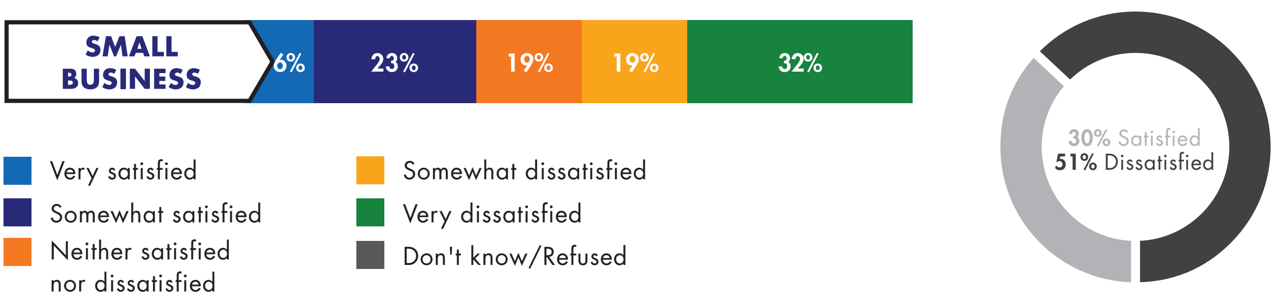
ONLINE WORKBOOK: OPEN-LINK

CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Thirty percent of Small Business customers who responded to the Online Workbook Open-Link report they are satisfied with Hydro One overall, while 51% are dissatisfied. This is lower than the levels of satisfaction reported by Residential and Seasonal customers who responded to the Open-Link.

ONLINE WORKBOOK OPEN-LINK

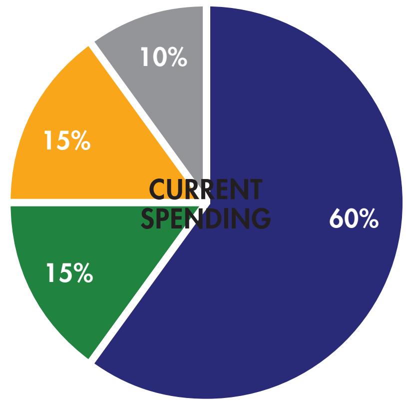
OVERALL SATISFACTION WITH HYDRO ONE



As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.
Q1. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Small Business (n=394)

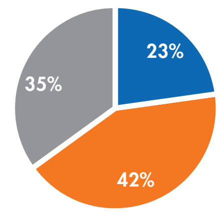
ONLINE WORKBOOK OPEN-LINK
OPINIONS ON CURRENT ALLOCATION OF SPENDING

- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing (Providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)
- Connecting new customers including those producing renewable energy or using energy storage



CUSTOMERS' REACTION TO SPENDING ALLOCATION

SMALL BUSINESS

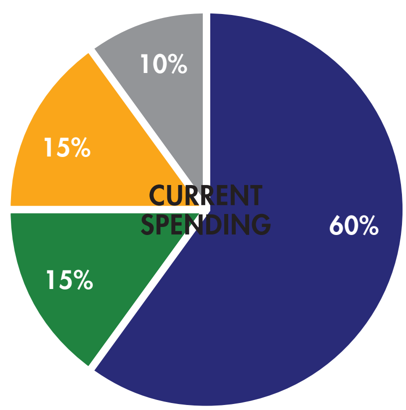


- Keep the same
- Change
- Don't know/Refused

Q3. The pie chart above shows a rough estimate of what Hydro One currently spends on each of its major electricity distribution investments. If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base: Small Business (n=406)

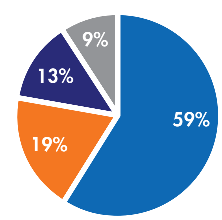
ONLINE WORKBOOK OPEN-LINK
PREFERRED ALLOCATION OF SPENDING

- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage



CUSTOMERS' REACTION TO SPENDING ALLOCATION

SMALL BUSINESS



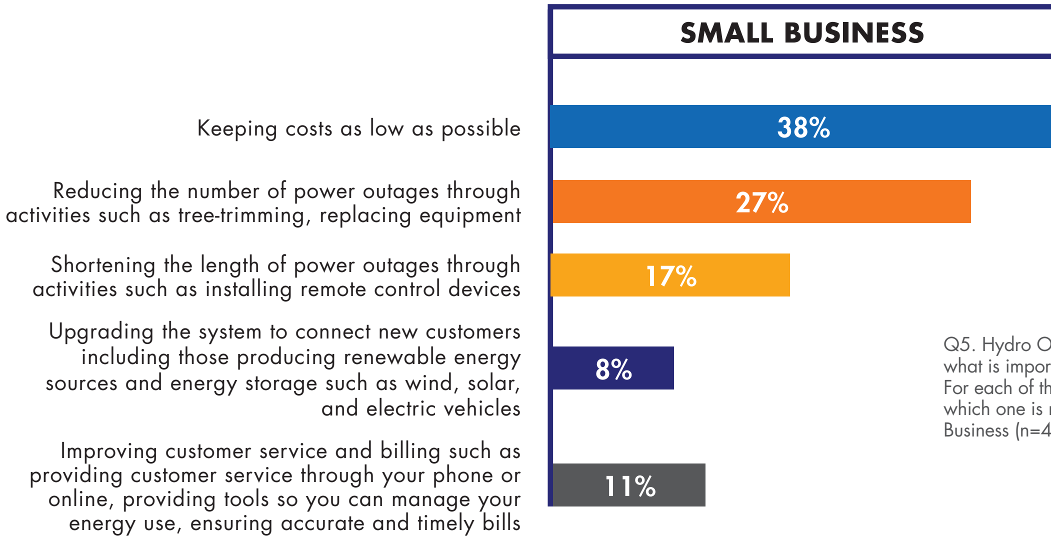
- Keeping the system reliable
- Restoring Power
- Customer Service
- Upgrading the system to connect new customers

Q4. What percentage would you allocate to...? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% Small Business (n=169)

ONLINE WORKBOOK OPEN-LINK

CUSTOMER PRIORITIES

As noted in earlier sections, a paired-choice exercise was used to identify customer priorities in order to help Hydro One better tailor its services. For more information on paired-choice refer to the Appendix.



Q5. Hydro One would like to better understand what is important to you as a business customer. For each of the pairs below, please indicate which one is more important to you. Base: Small Business (n=406).

The chart above shows that keeping costs as low as possible has a relative preference score of 38% among Small Business customers, and is the largest preference score of the options presented. This indicates that customers prioritize keeping costs as low as possible above the other options – reducing the number of outages, improving restoration times, improving customer service, or upgrading the system to connect new customers.

It is more than twice as important to customers as the latter three options (restoration times, customer service, and connecting new customers). Reducing the number of outages is the next most preferred option.

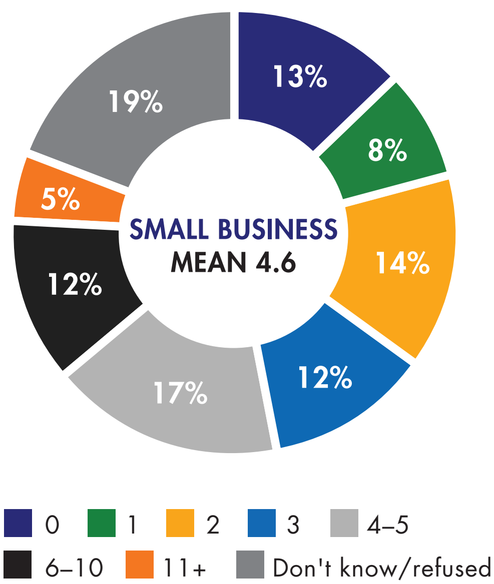
THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate the level of reliability they currently experience is in line with their expectations. Small Business customers who responded to the Open-Link report experiencing an average of roughly 4.6 outages of at least one minute in length in the past 12 months, directionally higher than the average of three outage reported by the 'uninformed' sample. The largest share of customers, 46%, indicate this level of reliability (number of outages) is about what they expect. But, 37% indicate that it is worse than they expect, which is double the 'uninformed' sample (16%).

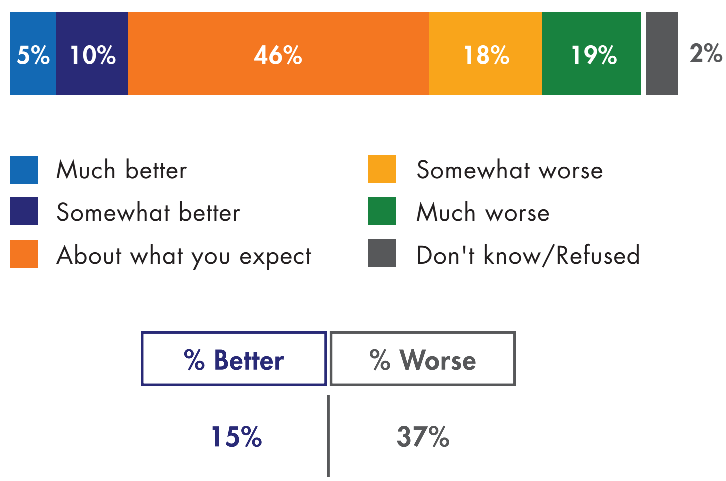
When it comes to length of outages, Small Business customers estimate the outages that they experience last an average of roughly two and half hours. Forty percent of customers indicate that the average length of outages they experience is worse than they expect.

ONLINE WORKBOOK OPEN-LINK

AVERAGE NUMBER OF OUTAGES AND EXPECTATIONS



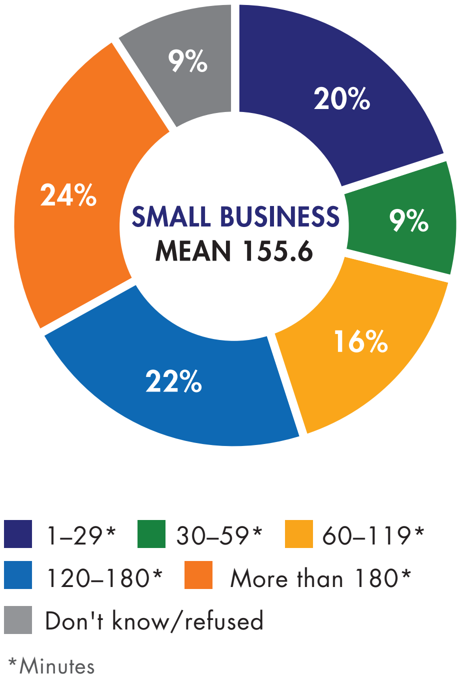
Q7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did your business experience in the past 12 months that you were not notified about in advance by Hydro One? Base: All respondents; Small Business (n=406)



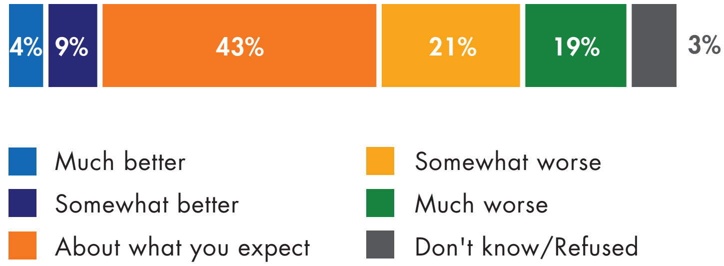
Q8. In general, when you think about how many power outages your business experienced over the last 12 months how did it compare to your expectations? Base: One or more sustained power outages in the past 12 months, Small Business (n=275)

ONLINE WORKBOOK OPEN-LINK

AVERAGE LENGTH OF OUTAGES



Q9. On average, how long did these unplanned outages last? Please answer in minutes. Your best guess is fine. Base: One or more sustained power outages in the past 12 months; Small Business (n=275)



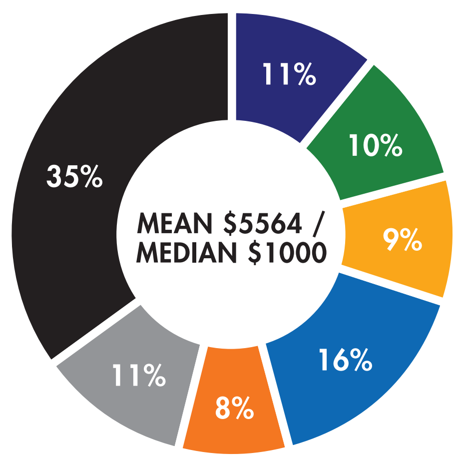
% Better	% Worse
14%	40%

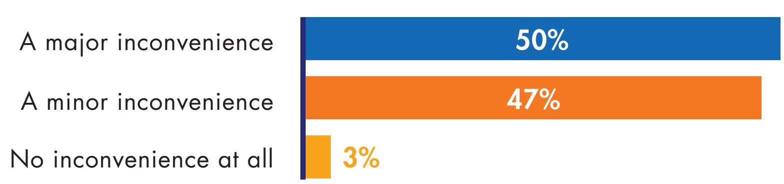
Q10. In general, when you think about the average length of the power outages your business experienced over the last 12 months how did it compare to your expectations? Base: One or more sustained power outages in the past 12 months; Small Business (n=275)

Half (50%) of Small Business customers who have experienced an outage in the past 12 months indicate that the outage(s) were a major inconvenience and most of the remainder say it was at least a minor inconvenience (47%). On average, customers indicate that these outage(s) cost their business $5,564.

ONLINE WORKBOOK OPEN-LINK

IMPACT OF POWER OUTAGES ON BUSINESSES





Q11. Thinking about the power outages your business experienced in the past 12 months, would you say they were? Base: One or more sustained power outages in the past 12 months; Small Business (n=275)

Q12. How much, if any, would you say the outages your business experienced in the past 12 months collectively cost your business? Please answer in dollars, do not include cents. Base: Those who faced a major and minor inconvenience in business due to power outages in past 12 months, don't knows excluded (n=266). The mean calculation includes 5 respondents who indicate that it cost their business $50,000 or more.

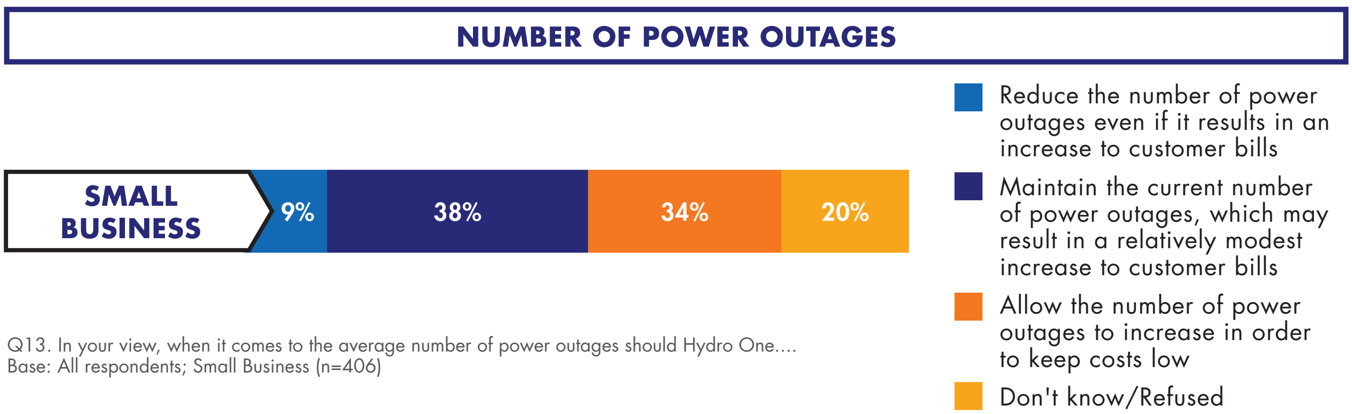
HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

Nearly half (47%) of Small Business customers responding to the Open-Link would be willing to accept a potential increase in their bill to maintain or improve the number of outages they experience, and nearly as many (41%) would accept an increase to maintain or improve the average length of outages they experience.

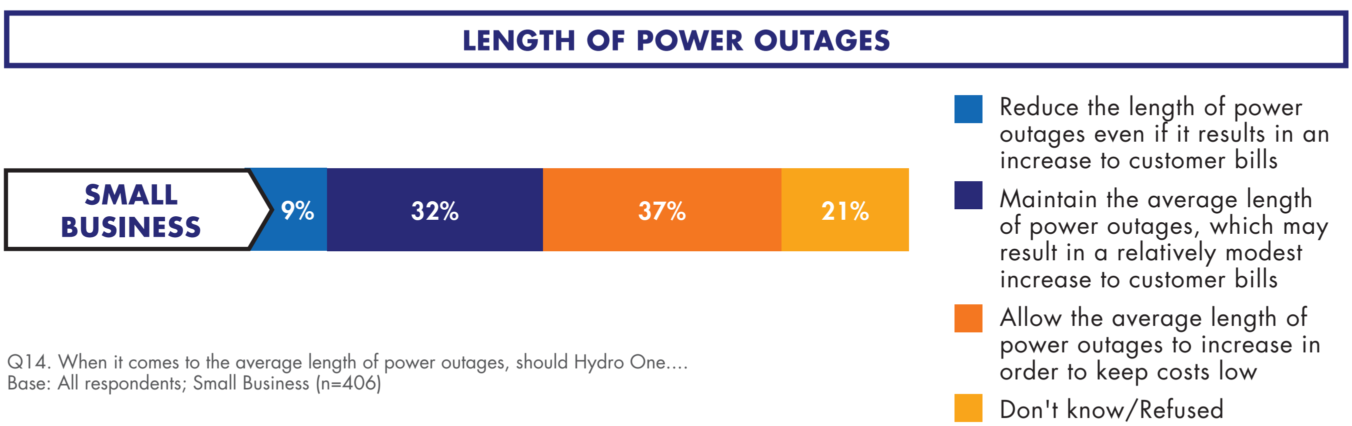
Customers' opinions on the number of outages break out very similarly when it comes to preferences about customer service. Forty-one percent would accept an increase in their bill to maintain or improve the level of customer service.

ONLINE WORKBOOK OPEN-LINK

RELIABILITY TRADE-OFF PREFERENCES



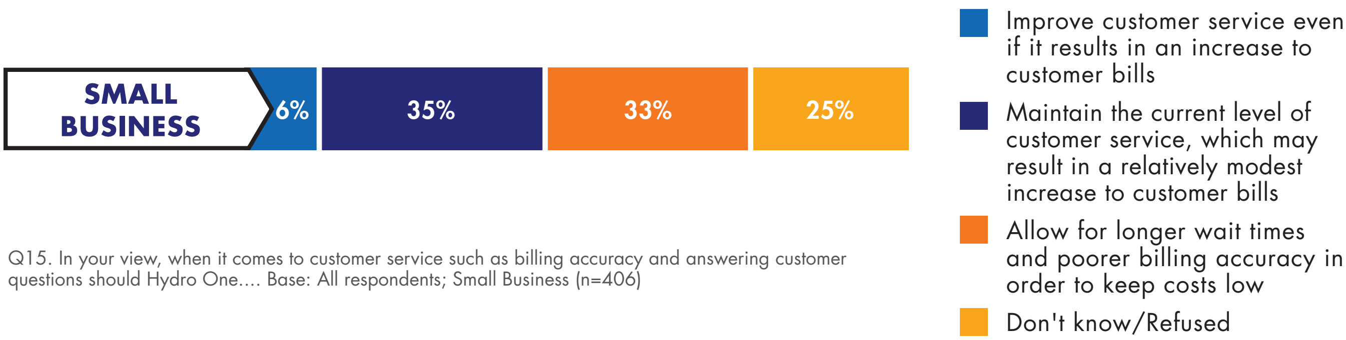
Q13. In your view, when it comes to the average number of power outages should Hydro One....
Base: All respondents; Small Business (n=406)



Q14. When it comes to the average length of power outages, should Hydro One....
Base: All respondents; Small Business (n=406)

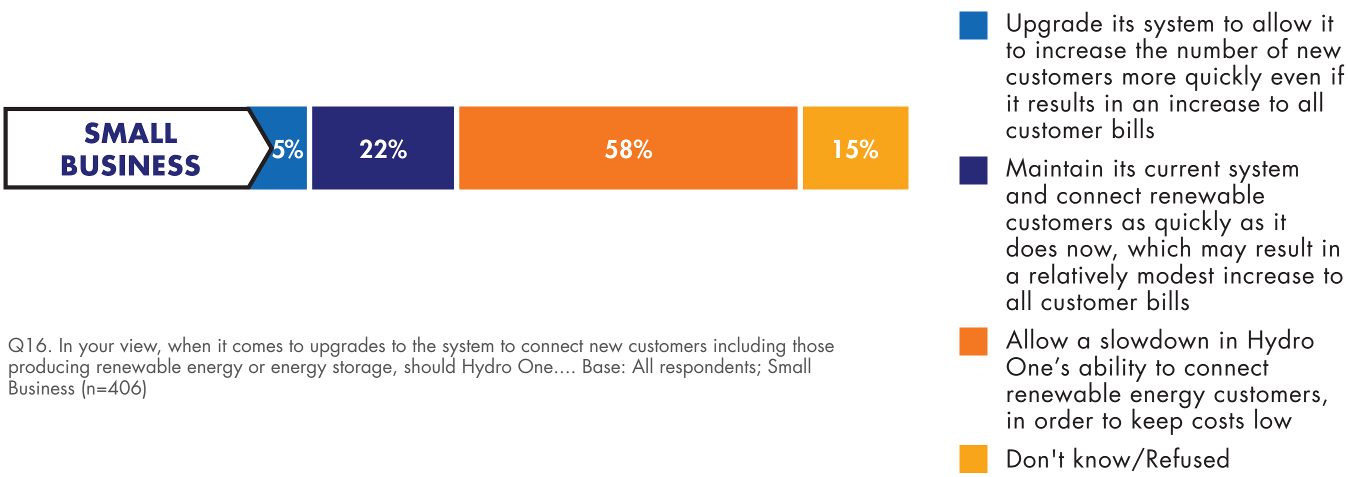
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One…. Base: All respondents; Small Business (n=406)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One…. Base: All respondents; Small Business (n=406)

These customers are less inclined to accept an increase to connect new customers more quickly.

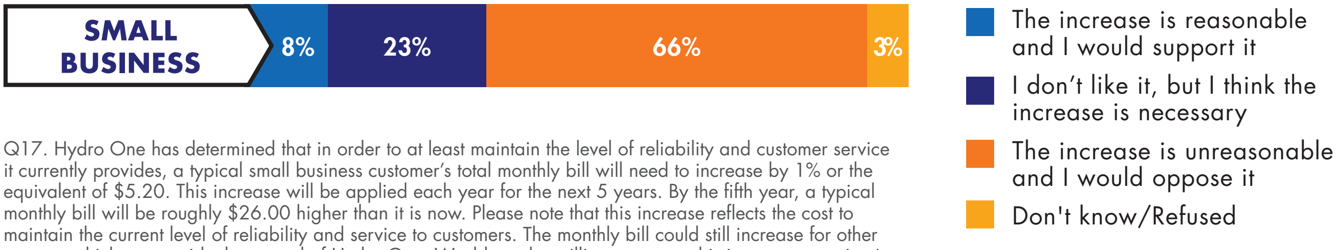
WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers were informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Small Business customer's **total monthly bill** will need to increase by 1% or the equivalent of $5.20, only 31% of customers are willing to accept the increase while roughly 66% are opposed and the remaining 3% do not offer an opinion.

Prior to answering this question, customers were informed the increase of $5.20 would be applied each year for the next five years, and by the fifth year a typical monthly bill would be roughly $26.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside Hydro One's control.

ONLINE WORKBOOK OPEN-LINK

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



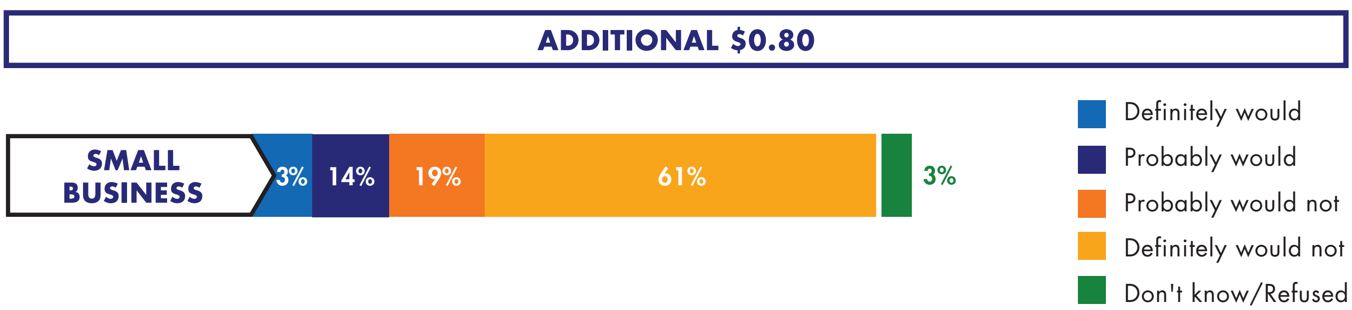
Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical small business customer's total monthly bill will need to increase by 1% or the equivalent of $5.20. This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly $26.00 higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Base: Small Business (n=406)

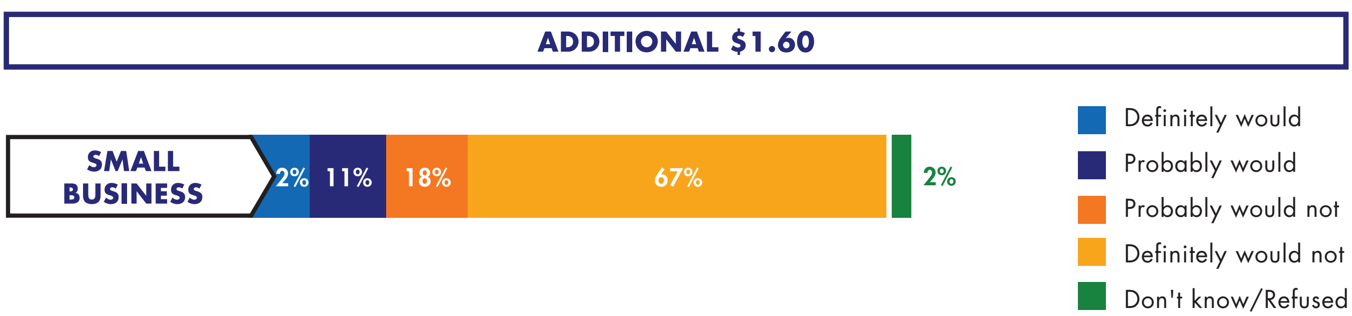
Customers were asked about their level of interest in a 10% reduction in the number and length of future outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $0.80 per month, or a total of $6.00 more on their monthly bill, and the other half was asked to consider a rate increase of $1.60 per month for a total of $6.80 more on their monthly bill.

Only 17% of customers say they would prefer to pay $6.00 more (or $30.00 by the fifth year), while 80% would not (including half who say they 'definitely' would not). Only 13% of customers say they would pay $6.80 more (or $34.00 by the fifth year) and 85% say they would not.

ONLINE WORKBOOK OPEN-LINK

WILLINGNESS TO PAY FOR IMPROVED LEVELS





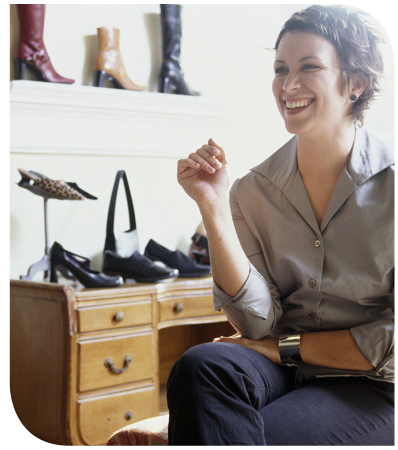
20B. Would you be willing to pay an additional [HALF OF RESPONDENT SHOW $0.80/OTHER HALF SHOW $1.60] per month over and above the $5.20 which would be approximately [SPLIT SAMPLE $6.00/$6.80] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$30.00/$34.00] higher than it is now. Base: SPLIT SAMPLE (Small Business n=194/n= 212)

FOCUS GROUPS

SUMMARY

A series of four focus groups with Small Business customers of Hydro One were conducted to further flesh out early learnings and findings from the Telephone Survey. In particular, gauging support or opposition to a rate increase, and understanding reasons in more detail for why some businesses accept and other do not accept rate impacts, were of interest. Furthermore, they were designed to understand general needs and preferences, for providing information about Hydro One and its operations, and to ascertain reaction to this information.

Small Business customers are seeking value and accountability as it relates to their services from Hydro One. Although participants in most regions except northern Ontario generally report satisfactory reliability, many have concerns about the cost of electricity, as well as ensuring the funds being paid to Hydro One are being spent prudently to both maintain reliability and plan for future needs of the grid.



An equal number of participants state they don't like an increase but believe it is necessary, along with those who are opposed to a rate increase. Those who are opposed have questions about how funds are currently being spent as well as how a rate increase would be spent. Others state they have concerns about Hydro One's accountability in their expenditures for items such as staff salaries and workers out in-field. Some are concerned about affordability and have a general sense that rising rates make them feel unsupported as businesses in Ontario.

Knowledge provided in the groups about the level of service was interesting and relevant for some to hear, with others stating that the information reflected their expectation of how Hydro One would need to plan and maintain their assets and services as any business would.

Many participants cited a range of customer service concerns which are in need of improvement including account set-up, billing accuracy, power restoration information, and call centre issues.

Small Business customers have more general awareness and knowledge of the energy sector than their Residential counterparts. They stated concerns with items such as exporting power to the U.S., the Debt Retirement Charge, and the rising cost of commodity prices to offset low load. Given these concerns, they are very interested in communications resulting in accountability and transparency to help them understand how value is being provided to them by Hydro One.

DETAILED FINDINGS

COSTS AND RATE INCREASES

Small Business customers expressed their concern with the cost of electricity. It is one of many expenses that need to be balanced with other needs and expenses of their operations. They stated a concern that rates will continue to rise with maintaining service being used as a justification.

"…we kind of get hit on every side of it, right? As business owners with taxes. There are so many other expenses, that you would hope that certain things would either level out, stay the same or not increase dramatically."

"I don't want in two years for them to come back with the same story that the money that they took from us, well, it just didn't fix what they promised they would, and here's another rate increase."

One participant made an organic mention of their belief that privatization would have a positive impact on Hydro One. Another participant stated their belief that the sector is entirely run by the government, who has made a number of unwise decisions as it relates to the energy sector.

"…my opinion is [hydro] should be privatized, because privatized is the only thing that keeps it fair. It keeps people from taking advantage of the system. And privatized is just better."

"…you really have to realize that Hydro is run by the government, and that should say everything about why stuff isn't done…they have no qualms about wasting money profusely. That's why, as you said, do I trust, and I say, no, because it's the government that runs the whole Hydro thing…"

RATE INCREASE: SMALL BUSINESS: 1% OR $5.20 FOR AVERAGE CUSTOMER

Small Business participants were polarized as to their acceptance of a rate increase. While the majority indicated they don't like the increase but think it is necessary, an equal number stated the increase is unreasonable and that they would oppose it.

For those who were opposed to a rate increase, their reasons included:

- Skepticism about the "average" amount being $5.20, or their own bills are much higher than average
- A lack of information as to where and how funds are currently used, and how a rate increase would be used
- A perceived lack of, or desire for, efficiencies instead of rate increases
- A perception that the funds are currently or will not be used wisely by Hydro One — for example, that the funds would go to wages and salaries, and not improving reliability
- A rise in electricity costs, or any costs, are a risk to their businesses' viability
- An inability to pass along the rate increase to their customers in the form of higher prices
- For those in Northern Ontario with poor reliability, paying more for already poor service is unacceptable

"The average person doesn't exist. So, I am absolutely against it just because it's the percentage. If they said to me, we're adding $5.00 to your bill and that's $5.00 flat rate… I would accept that. But this percentage stuff is total BS it never reflects the average."

"…they're saying that the average bill is about $520.00, right? I can tell you that the businesses that I run, our bills are never $520.00. They are double to triple that easily…when you look at it at a little bit of a bigger standpoint of $1,300, $1,500 a month or $2,000 or $2,500, depending, that tends to be quite a bit more than $26.00, and you're looking into the hundreds."

"What is that 1% made up of? Why should I take their word for it that it's 1% What are they going to spend this 1% on? Why can't they save money somewhere else…Are there no efficiencies to be gained anywhere else?"

"The only problem is, we keep on seeing horrendous mistakes being made, a tremendous amount of money being spent on things that are cancelled, and we constantly have to pay for debt retirement, where we seem to be paying for incompetence. That's what upsets us."

"I would like to see the money spent on infrastructure rather than wages and salaries."

"For a minor increase like that to go up…for just the delivery of our hydro never mind the actual hydro costs themselves, it could be a big difference in making my business able to survive. Small things like that add up big time, and I don't see why we should have to keep taking all these kinds of hits here and there…I can't raise my product prices any more than they really are."

"As a business owner, it comes down to being in the red or being in the black, and any things that a business owner can do to leverage profits, I would say is his or her benefit. So anything that ends up costing us more, would eventually be more prohibitive to us."

"…if we as a business raised our prices as much as our Hydro bill has gone [up], I think we would probably be out of business."

"...what it would take to keep the outages at their current level…we don't feel is acceptable at this point either… if it's going to stay at the same unacceptable level, then I wouldn't be prepared to pay extra for that."

A few indicated that they feel unsupported as Small Businesses in Ontario due to the number of expenses they incur.

"…in general of these increases, they come at the expense of the business owner. The business owner is the one in terms of when there's inflation and things…who end up making comparatively less, and the people on the unions, like Hydro One unions, are the ones who are protected or who just keep making more. The work to reward ratio for the small business owner, it just keeps going down and down and down and down."

"The increase is across the board, they're all claiming they're all separate entities, and then you get one bill with a price increase, and then they don't give you an explanation of it. Then you have the situation where they say, oh, we're just responsible for distributing power. But at the end of the day, when you get your bill, it doesn't matter, the price increase, whether it comes from one company or five companies, it doesn't matter altogether…the small companies are the ones that are getting shafted, primarily."

For Small Business participants who struggle with reliability, they would like to see a concrete improvement in reliability in the event of a rate increase.

"…if you're not seeing value for your money, then it really is increase for the sake of increase, and that's what I have found. There needs to be a plan put forward, to show exactly what they're going to do, for the money that they're going to be spending, in order for us to feel justified by that increase."

"…if there's going to be actual, tangible results…I think most of us concur that reliability of service is a relatively large stumbling block…I don't think they could guarantee it."

"Clearly, it's a matter of value for investment. If we are all saying there are issues with outages, supply, forestry and equipment deficiencies, that are affecting our reliable supply, can you guarantee that there will be an improvement in service and reliable supply for the increase. In our experience, here, we have not seen significant or any improvement related to additional investment and increase[s] in billing."

CURRENT AND FUTURE ASSET MANAGEMENT, AND ASSOCIATED COSTS

When provided with information about current asset management and asset conditions, some participants stated the information provided was in line with their expectations around managing the company's assets and the distribution delivery infrastructure.

However, many expressed deep concern over Hydro One's historical management of assets and infrastructure, and their planning or perceived lack of planning. Some Small Business participants stated that a wait-and-see approach typified one that many service companies have towards making improvements, to the point that it is almost too late. Problems are exacerbated as a result, and the increase in costs for resolving these issues are then passed on to customers.

"It makes me question as to why the poles etc. [weren't] kept up. Why are we having to increase all of a sudden to maintain now? What happened to our funds in previous years?"

"In any business — equipment replacement should be part of the budget. I have always wondered why this was not considered on an ongoing basis rather than under crisis management. 50–60 year life cycle is very long."

"…why haven't these things been maintained sooner so that this increase doesn't have to hit you at once. Maybe instead of a $5.20 increase, if they maintained it a little more appropriately, maybe we'd only have a $1.00 increase every year or something like that."

"…why weren't these anticipated, and why was this not done over a period of time. If you have aging equipment, there should be phases…Now if that was the case, then… [the rate increase] wouldn't be so significant…There was no planning in place, there was no project management in place, there's no assessment of the infrastructure. This is just like, last minute, things start to fail, and then they're like, oh crap. "

Planning and preparation of the grid for future needs was actively debated during the Small Business Focus Groups. Participants had mixed reactions to the notion of proactively anticipating and building infrastructure now, as opposed to responding to needs as they arise, as well as the role of renewable energy in the future of the grid.

For those who supported increased renewable energy being added to the grid, they believe there is a long-term economic benefit, although some acknowledge there may be a short-term rise in costs and subsequently, rates. As well, a few participants stated they would like the environmental benefits of renewables. One participant stated their belief that having new sources of electricity would help mitigate any electricity shortfall experienced by the province.

"I would get behind Hydro One for doing more to help us change, shift the landscape on renewables and alternate ways of generating, storing, distributing, that are more efficient, that are more mindful of the climate crisis. So I'm behind that, and I'm willing to invest in it, and I kind of expect I'm going to."

"…emphasizing lowering rates at a time when all these new technologies and changes to the grid are happening, I don't see is a wise investment. We should be spending money on handling the changes to the grid."

"I definitely think they should start preparing now for it just because I don't think the electricity that they're using at the moment is going to last forever…you may as well get on it before things get any worse or something happens or we're not prepared at all."

Some participants asked questions and expressed skepticism as to the value and benefit of adding renewable sources to the grid. Those who are opposed to proactively preparing the grid state this is a low priority area and have concerns about the costs associated with making or supporting these types of investments.

"It just seems, in general, that they continue to increase the volume [of electricity], but it's more than is required for the system…It just seems counter-productive, at the same time as we're subsidizing these incredibly high returns to these people for setting up the system. So I just think, when are they going to decide that this doesn't need to continue to be feasible."

"We've seen that with windmills and various things that we thought were the ultimate answer and now there are questions from anything from health to noise to all kinds of things."

"Currently, the programs to generate alternative forms of energy appear not to be working and, in fact, are costing the system and users more in higher rates."

A few participants opposed to proactively preparing the grid expressed concern about obsolescence of technology. That is, if Hydro One installs new technology today, it is possible for the technology to be outdated before it is used to its maximum potential. There were also concerns cited that any new technology implemented would fail entirely, as with their perception of Smart Meters.

"Just like if you bought a really fast computer 10 years ago or 20 years ago you thought you were going to use right away, you wouldn't buy a computer to use two years in the future because by then the computers are all new and all different anyway. So, if nobody is going to be filling up these electric vehicles and contributing with these solar panels, then don't spend the money now, because you're going to have to spend it all again in two years or three years or ten years whenever those people are driving the electric vehicles and using the solar panels. Because by then the technology is probably going to be completely different and/or your infrastructure is going to need to be redone anyway. I just think respond to demand."

"The smart meters weren't an effective program, which is why they have pulled it out. There were way too many errors. It was determined through an investigation that it was actually costing customers money because they were not working correctly from day one. So, they implemented something that ended up costing us in the long-run, which we are paying for as customers."

RELIABILITY AND POWER RESTORATION

Many Small Business participants are highly satisfied or satisfied with their service from Hydro One. Most do not struggle with reliability, with the notable exception of participants in northern Ontario, for whom reliability is a significant issue. For these participants, their experience impacts their productivity or the satisfaction of their own customers. Their perception is that Hydro One is insensitive to these impacts when they call into customer service.

"Reliable electricity is a requirement for my business. I get reliable power with almost no outages. When there is an outage, it is fixed promptly. I am satisfied."

"As far as maintaining the supply I have no problem."

"Living in rural central Ontario we face outages relatively frequently. Responses are generally prompt, although we are at times waiting many hours without service."

"Quite often businesses have to close during the day on weekdays, and several of them throughout the community…woe is me [at Hydro One] because we have such a big system to look after, but no sympathy at all for the person who has to close, and send their staff home for the day."

A few businesses have backup generators onsite to mitigate the impacts of any outages. Minimal contact with Hydro One is generally considered a positive as it means that the customer does not have any issues with the company.

"…I am fairly happy with their services in terms of the fact I do not have to deal with them often."

In terms of power restoration, information by phone or on the Hydro One website is often inaccurate — with estimated restoration times being both too short and too long. Sometimes it is difficult for customers to get through on the phone.

"Often they say it's going to be longer than it actually is, in our area…it seems sometimes they go overboard to make sure they're not wrong. [However] a more accurate measure could help production."

"I think that calling in is always a frustration for probably a lot of people."

"…when I have looked online and even called Hydro One to just see what the estimated time of getting everything back up was, they were usually longer than anticipated for most of them, quite a bit longer."

CUSTOMER SERVICE AND BILLING

For Small Business customers who participated in the Focus Groups, customer service from Hydro One is an area in need of significant improvement. They struggle with customer service in a number of different ways, including:

- Not having a dedicated account person or contact. They rely on publicly available information in the event of an outage, and call into the number on their bill in order to have ask questions or have issues addressed.
- When calling the call centre, they mention being passed around from one person or department to another on the phone and often not receiving a satisfactory answer to their questions or resolution on their issues.
- The process of resolving issues can take an excessive amount of time - months or years - if at all.
- Having a third party answering calls and managing the call centre creates the perception is that these individuals can't make decisions or provide concrete help to customers.

Participants stated the more complicated the issue, the more difficult it was to resolve. Some participants believe customer service representatives need better training in order to mitigate these issues.

"I find basic customer service reps are only good if it's a really basic question, because even when they did the bills wrong, they still couldn't help. They still had to get someone else. It's frustrating."

Participants spoke of billing irregularities such as being charged for the wrong meter or not receiving bills regularly. There were mentions that participants would like Hydro One to move away from e-post third party billing, and that the bills should come from Hydro One directly.

"We have a couple of times that we haven't received bills regularly and I've called to discover that our bills were being reviewed and redone. This took up to six months and then we had an extremely large bill that we had to negotiate payment arrangements for."

PERCEPTIONS, COMMUNICATION AND AWARENESS

Small Business Focus Group participants are generally more aware of the energy sector than their Residential counterparts. Several hold negative perceptions of Hydro One as a large and inefficient company.

"I see guys who work hard in the cold for 10 or 15 years, then everybody gets moved up into some type of cushy position. They hire new guys for the lines and the older guys don't have to work the lines and they get paid really, really, really well."

One participant expressed deep skepticism and rate increase fatigue, with any conservation efforts by businesses and concerns not having any positive impact on costs. There were also mentions of having commodity electricity prices increase at times of low load, which was disappointing to participants. Others stated that the information being presented was to justify a distribution rate increase by Hydro One.

"I don't think as a consumer, business or residential, we can ever see where any proactive move that we participate in as consumers help to keep the price down, or from going up. In fact, if you listen to the media, because we conserved, and too much power was being generated for use, we're going to see the price go up again...none of these initiatives that seem to be what they feel is going to make a better system, is impacting on rates at all."

> *"Now I see the tears. Sounds like they are trying to justify the prices."*

The Debt Retirement Charge was also mentioned by participants, with one participant stating his belief that the debt has been paid off, and yet consumers are still being charged for it. Customers are resentful that they are responsible for paying the Debt Retirement Charge, and point out that in any other business, paying off debt by raising prices would not be an option.

"...in any other business...I can't just charge because of other things, I can't charge more for my product, to make up for the difference that I'm losing somewhere else. So while I understand maybe where they're coming from, it's just not fair."

Some participants stated that they would like to experience better communication during outages. The majority call in to the number on their bills, with some checking Hydro One's website on their smartphones. Awareness of Hydro One's outage app is low.

Participants expressed interest in a number of different channels and some indicated that they would like to hear from/about Hydro One via multiple channels, including:

- Directly on the bill
- Bill inserts
- App
- Social media
- Separate letter
- E-mail
- Advertising
- Texts
- Website

When asked to give Hydro One a final piece of advice, participants were forthright about the need for increased transparency and accountability. Several stated that the information provided during the groups was a positive first step in this direction, and more information about Hydro One would continue to positively impact perceptions.

"The entire system and all its partners ha[ve] a massive PR problem — and broken trust is hard to mend, particularly when times like these demand innovation, reinvention, transparency and real accountability."

"Hydro One gets a lot of bad PR about wages, mismanagement and other difficulties which doesn't instill confidence. We need more information to convince us that we're getting good value for money."

"This was informative for me to learn more about Hydro One and see where the money is spent. Thanks."

> *"More or better communication from Hydro One would be beneficial — I feel a lot of issues we have with hydro are not Hydro One specific as they are just distributors."*

FIRST NATIONS CUSTOMERS

SUMMARY

There is a greater amount of dissatisfaction among First Nations residential customers when compared to Residential customers overall. Of all of the R&SB segments, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. However, First Nations customers are as likely to accept the proposed 1% increase on the total monthly bill to maintain the current level of reliability and customer service.

TELEPHONE SURVEY

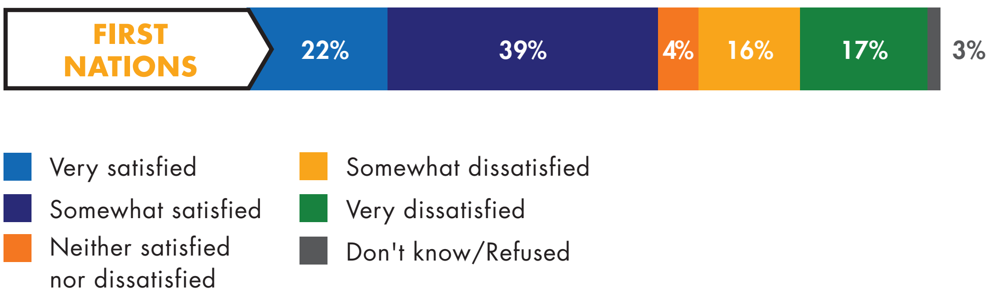
As outlined in the methodology section of this report, the following results are based on a Telephone Survey of a random and representative sample of n=300 First Nations customers. A stratified, random sampling approach was used to pull the sample from Hydro One's customer database. With a sample of this size, the results are considered accurate to within ± 5.7 percentage points, 19 times out of 20, of what they would have been had all First Nations customers been surveyed. That means that if the survey is repeated 20 times, 19 of those times the results of the survey will be the same within the margin of error. The margin of error will be larger for sub-groups of the population. This data was not statistically weighted because the unweighted sample composition closely matches the true regional and urban/rural proportions in the customer database. For more information on the survey methodology refer to the Customer Engagement Methodology Section of the report.

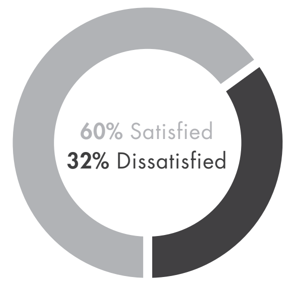
CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Six-in-ten (60%) of First Nations customers report they are satisfied with Hydro One overall, while one-third (32%) are dissatisfied. When asked on an unaided basis what Hydro One can do to improve its service, the most frequent answer customers give is to reduce their monthly bills. Some customers mention this in the context of lower prices or lower rates, while other just simply say lower cost.

TELEPHONE SURVEY

OVERALL SATISFACTION WITH HYDRO ONE





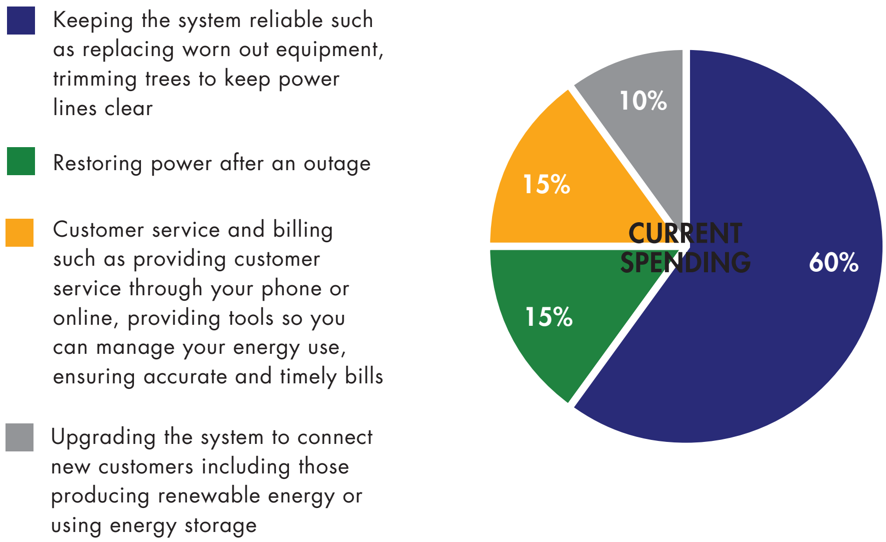
As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. Please think about Hydro One as I have just described it to you. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change, First Nation (n=204)

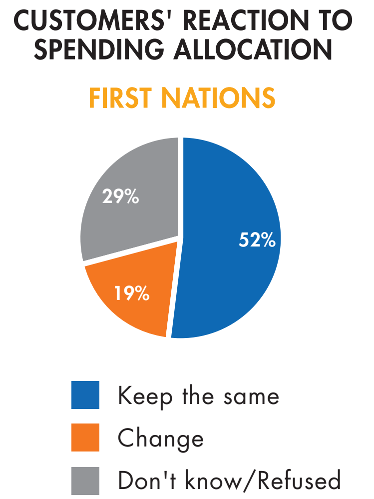
Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, half (52%) indicate they would not change how the money is currently allocated. Two-in-ten customers indicate they would change how the money is allocated.

In general, these customers allocate more money to restoring power after outages, doubling the amount of spending on it. They allocate more money for upgrading the system to connect new customers, including those producing renewable energy, by about 50%. They allocate less money to keeping the system reliable, reducing the amount by nearly half.

TELEPHONE SURVEY

OPINIONS ON CURRENT ALLOCATION OF SPENDING

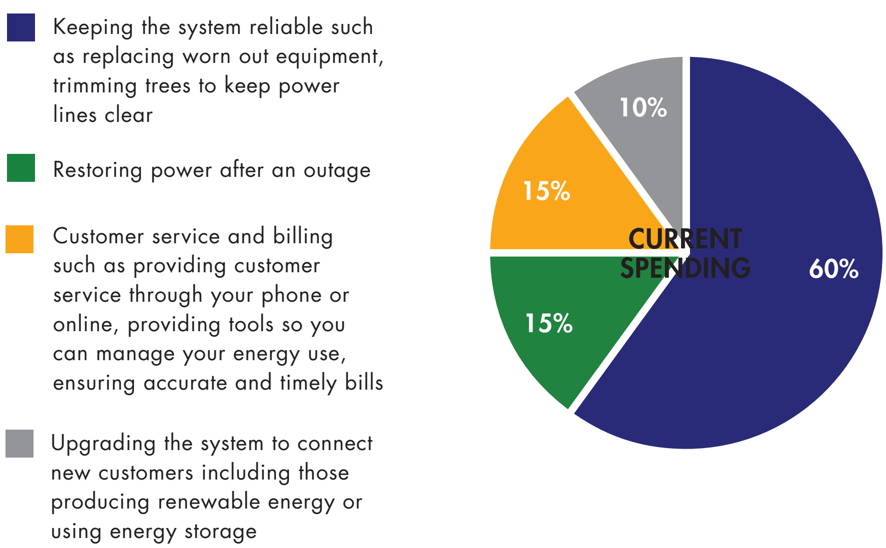


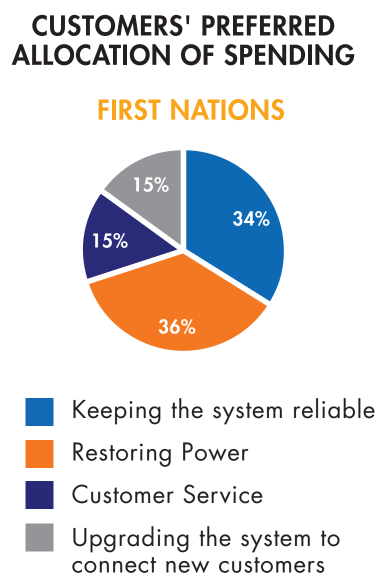


Q3. Please listen carefully as I will be reading out a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments and will be asking your opinion about the breakdown. Hydro One currently spends [READ LIST]… If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base: First Nations (n=300)

TELEPHONE SURVEY

PREFERRED ALLOCATION OF SPENDING





Q4. Of the 4 distribution investments you just heard, what percentage would you allocate to…? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% (First Nations n=54)

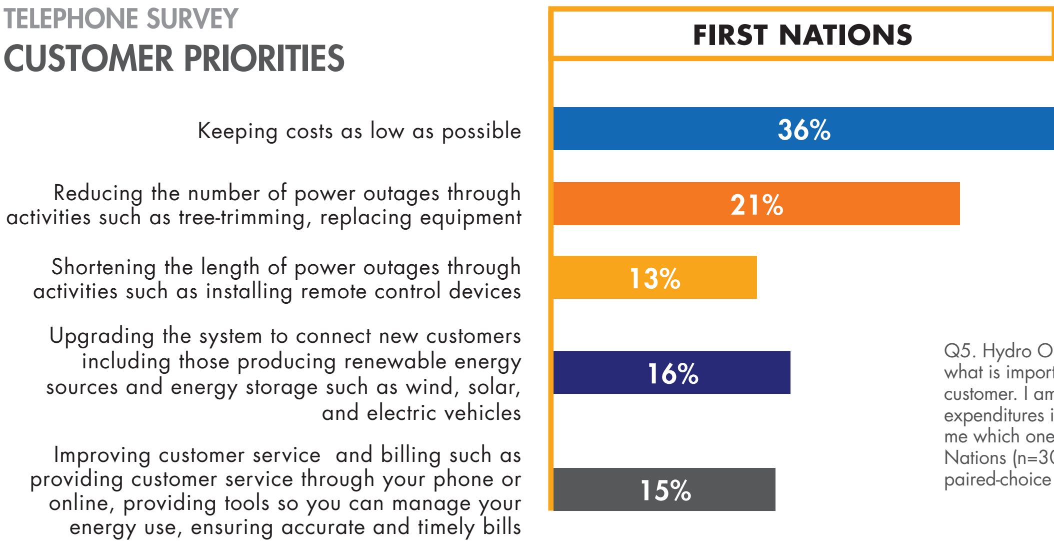
CUSTOMER PRIORITIES

The chart below shows that keeping costs as low as possible has a relative preference score of 36% among First Nations customers, which is the largest preference score of the options presented.

This indicates that customers prioritize keeping costs as low as possible above the other options – reducing the number of outages, improving restoration times, improving customers service, or upgrading the system to connect new customers. It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is the next more preferred option.

TELEPHONE SURVEY

CUSTOMER PRIORITIES



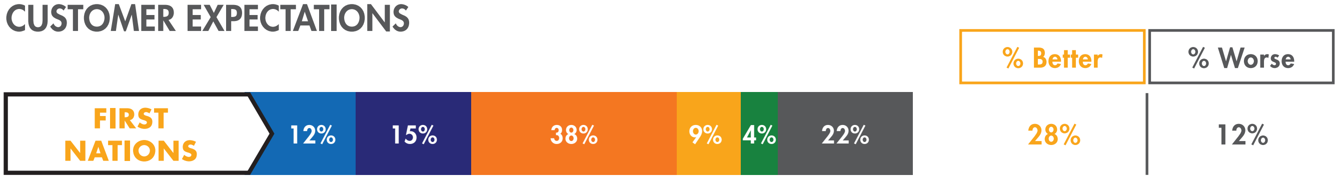
Q5. Hydro One would like to better understand what is important to you as a residential customer. I am going to read Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Base: First Nations (n=300) Pair-choice analysis paired-choice preferences relative to other options.

THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate the level of reliability they currently experience is at least in line with their expectations. First Nations customers report experiencing an average of roughly three outages of at least one minute in length in the past 12 months. The largest share of customers (38%) indicate that this level of reliability (number of outages they experienced) is about what they expect. Only 12% of customers who experienced at least one outage indicate the number of outages they experienced is worse than they expect.

TELEPHONE SURVEY

CUSTOMER EXPECTATIONS



Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; First Nation (n=217)

When it comes to length of outages, First Nations customers estimate that the outages they experience last an average of 3.7 hours. Similar to opinions of the frequency of outages, the largest share of customers indicate that this is about what they expect. Sixteen percent say this is worse than they expect.

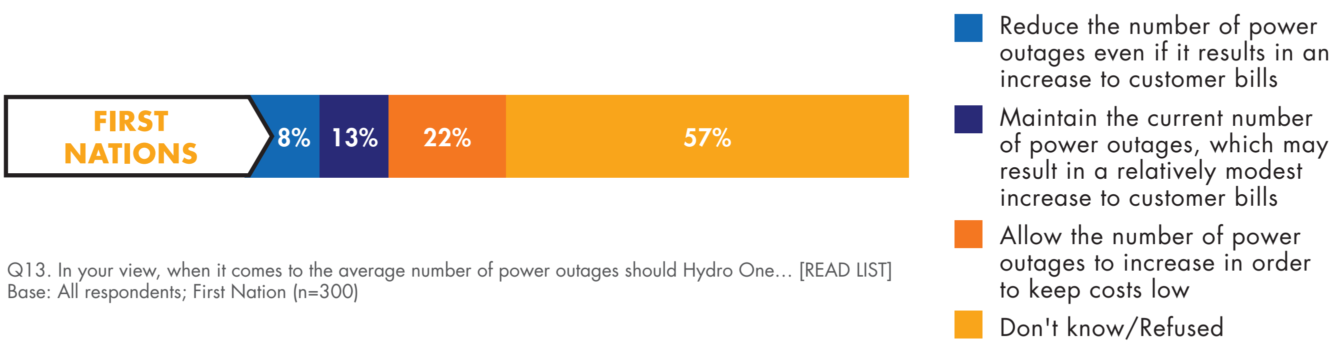
HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

Half (57%) of First Nations customers do not offer an opinion on how Hydro One should approach the issue of outages. Of those that do, opinions are generally split, with one-half willing to accept more outages and longer outages to keep rates as low, while the other half are willing to accept a modest increase to maintain the current number of outages or a larger increase to see fewer outages.

TELEPHONE SURVEY

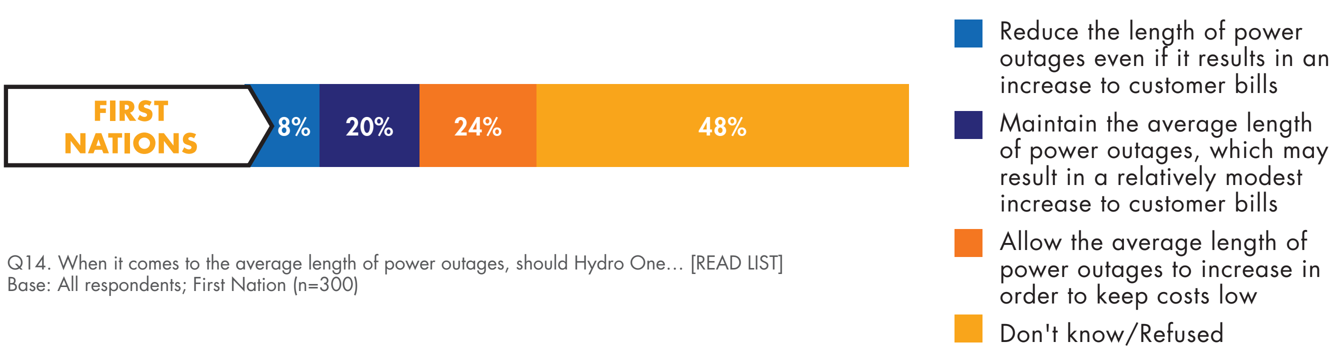
RELIABILITY TRADE-OFF PREFERENCES

NUMBER OF POWER OUTAGES



Q13. In your view, when it comes to the average number of power outages should Hydro One… [READ LIST]
Base: All respondents; First Nation (n=300)

LENGTH OF POWER OUTAGES

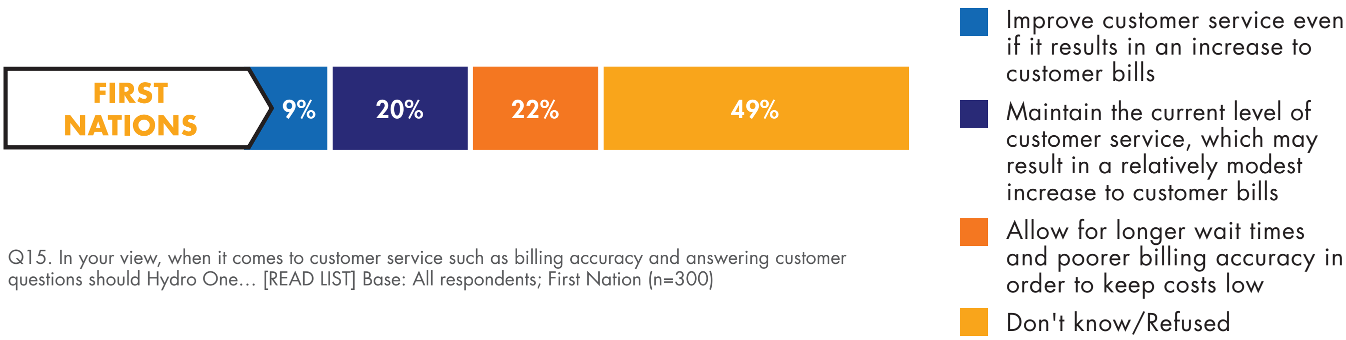


Q14. When it comes to the average length of power outages, should Hydro One… [READ LIST]
Base: All respondents; First Nation (n=300)

TELEPHONE SURVEY

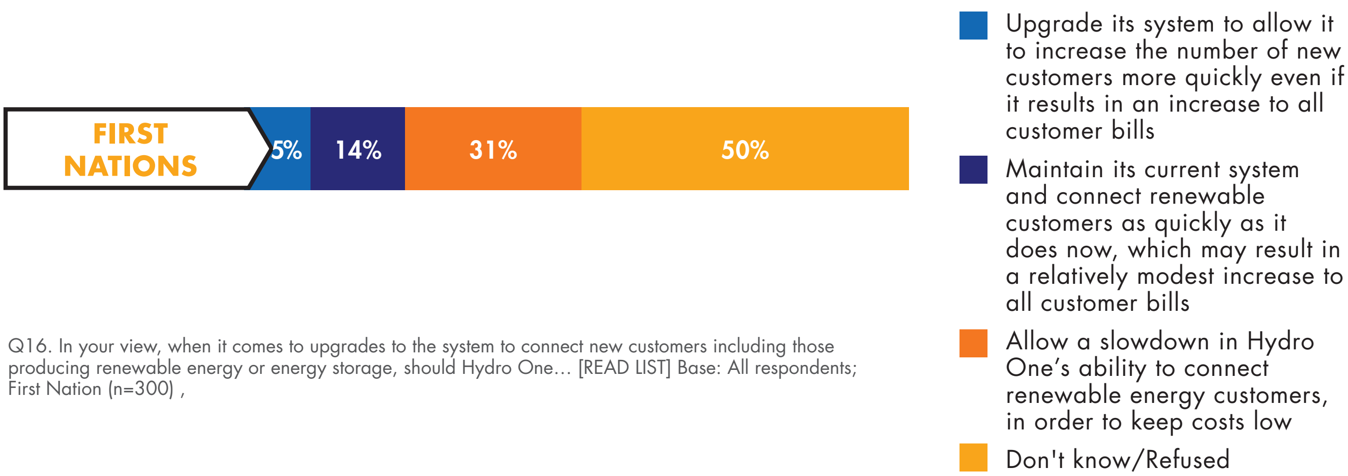
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One… [READ LIST] Base: All respondents; First Nation (n=300)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



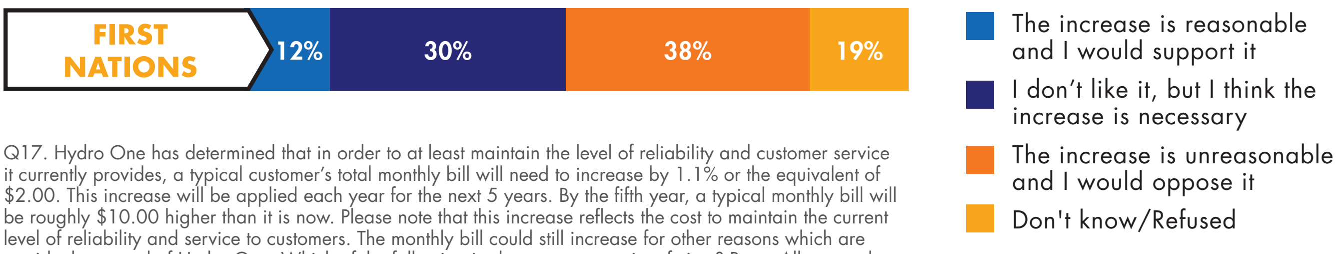
Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One… [READ LIST] Base: All respondents; First Nation (n=300) ,

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Residential customer's **total monthly bill** will need to increase by 1.1% or the equivalent of $2.00, 42% of First Nations customers are willing to accept it, 38% are opposed and the remaining 19% do not offer an opinion.

TELEPHONE SURVEY

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical customer's total monthly bill will need to increase by 1.1% or the equivalent of $2.00. This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly $10.00 higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Which of the following is closest to your point of view? Base: All respondents; First Nation (n=300)

Prior to answering this question, customers were informed that the increase of $2.00 would be applied each year for the next five years, and that by the fifth year a typical monthly bill will be roughly $10.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside of Hydro One's control.

First Nations customers are more willing than others to pay more than $2.00 to have better reliability than they have now, although those holding this opinion still represent a minority. Two-in-ten (19%) customers indicate they would be willing to pay more than the $2.00 (1.1%) increase in order to have **better reliability** than they have now. An additional 22% would consider it (selecting 'maybe' as their response).

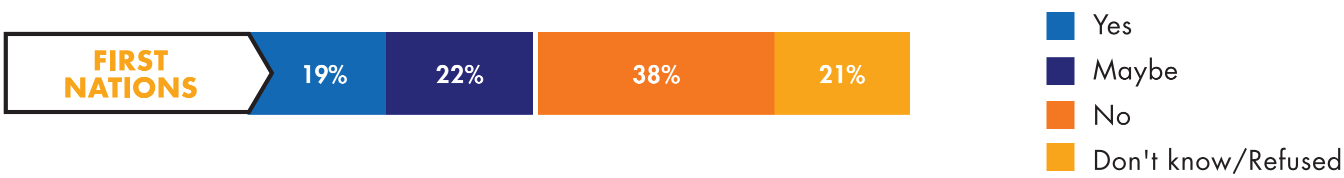
Unlike the 73% of Small Business customers who would not pay anything more or even Residential (off-reserve) customers where 64% would not, 38% of First Nations customers oppose, and 21% say they don't know/ refuse to answer. There is less interest in paying for an improved level of customer service, with only 16% saying they would be willing to pay extra for improved customer service, 16% saying maybe and 49% saying they would not.

Lastly, customers were asked about their level of interest in a 10% reduction in the number and length of future power outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $0.30 per month, or a total of $2.30 more (or $11.50 in the fifth year) on their monthly bill, and the other half was asked to consider a rate increase of $0.60 per month, or total of $2.60 more (or $13.00 by the fifth year) on their monthly bill.

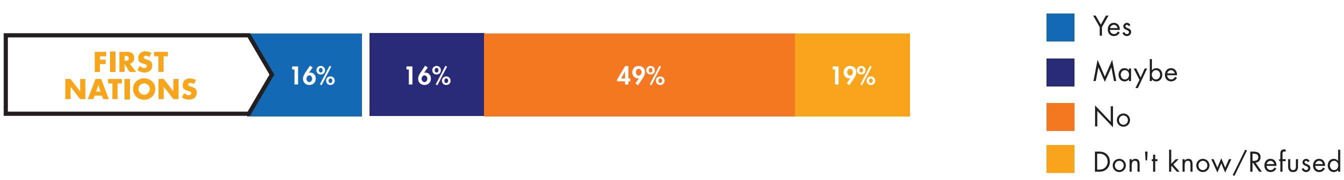
TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS

BETTER RELIABILITY



BETTER CUSTOMER SERVICE



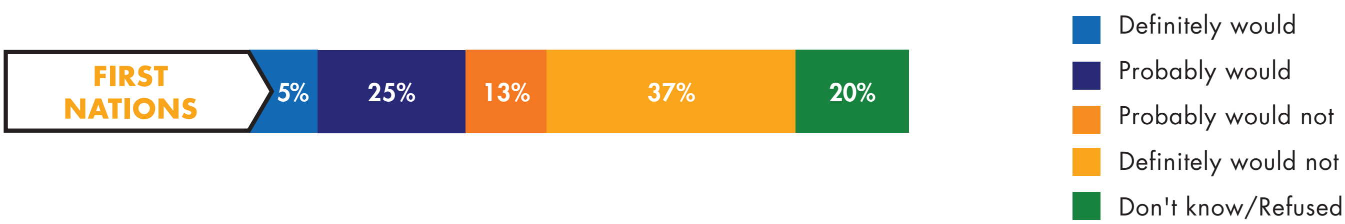
Q18. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have a better reliability than you have now? Q19. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have better customer service than you have now? Base: All respondents; First Nation (n=300)

Of those who were asked to pay an additional $0.30, only 30% of customers say they would prefer (definitely or probably would) to pay more, while 50% say they definitely or probably would not. Of those who were asked about an additional $0.60, 20% definitely or probably would and 58% definitely or probably would not.

TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS

ADDITIONAL $0.30



ADDITIONAL $0.60

Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30/OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30/$2.60] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50/$13.00] higher than it is now? Base: SPLIT SAMPLE FIRST NATIONS (n=150 were asked about each impact level)

LARGE CUSTOMERS

SUMMARY

There are some key differences between the various Large Customer segments. C&I customers prioritize keeping costs as low as possible, well ahead of other priorities such as reducing the number of outages or shortening the duration of outages. LDA customers strike more of a balance between reducing the number of outages and cost, and LDC/DG customers actually place equal importance on shortening the duration of outages and reducing the number of outages. Both of these are considered more important than simply keeping costs as low as possible.

These segments also vary fairly substantially in their preferences with how Hydro One invests in maintaining and reducing reliability and service. However, what is common among them is that all express a preference for Hydro One to improve power quality as they feel this would have a positive impact on their organization.

ONLINE WORKBOOK + WORKSHOP BOOKLET RESPONSES

As described in the Customer Engagement Methodology section, all of Hydro One's Large Distribution Accounts (LDAs) and Local Distribution Companies (LDCs) and a sub-set of Distributed Generators (DGs) were invited to participate in the facilitated in-person Workshops held in seven locations across the province. Hydro One invited all LDAs and LDCs that did not attend a Workshop to review the presentation and offer their feedback through an Online Workbook — the results of which are presented in this section. A stratified sampling of Commercial and Industrial customers was also invited to participate in the in-person Workshops. The remaining 5,000+ customers were invited (via e-mail or mail) to complete the online workbook. Refer to the Customer Engagement Methodology section for more details on the execution of the Workshops and Online Workbook.

Each Workshop session began with a presentation from Hydro One staff. After presenting specific information, participants were provided an opportunity to ask questions or offer comments and then given time to complete a survey booklet that was provided to each of them. The Online Workbook contained the same presentation that was delivered at the sessions and posed all but one of the same questions. The paired-choice questions on customer priorities could not be asked effectively in a hard copy and so it was asked as "pick the most important priority" in the survey booklet.

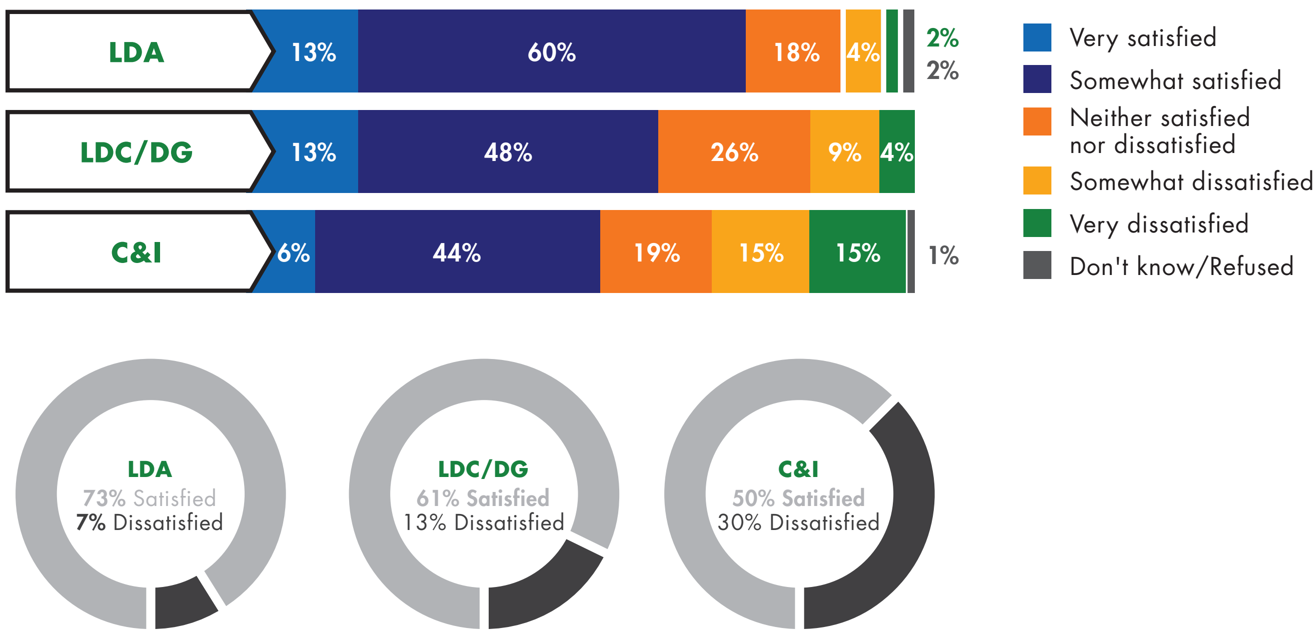
The results in this section combine the results of the completed survey booklets with the completed online workbook. The combined sample sizes are LDAs n=45, LDCs/DGs n=23, C&I n=133. The results of Large Customers are directional only.

CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

The majority of LDA and LDC/DG customers are satisfied with Hydro One. Satisfaction is directionally lower among C&I customers, of which half are satisfied and 30% are dissatisfied.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

OVERALL SATISFACTION WITH HYDRO ONE

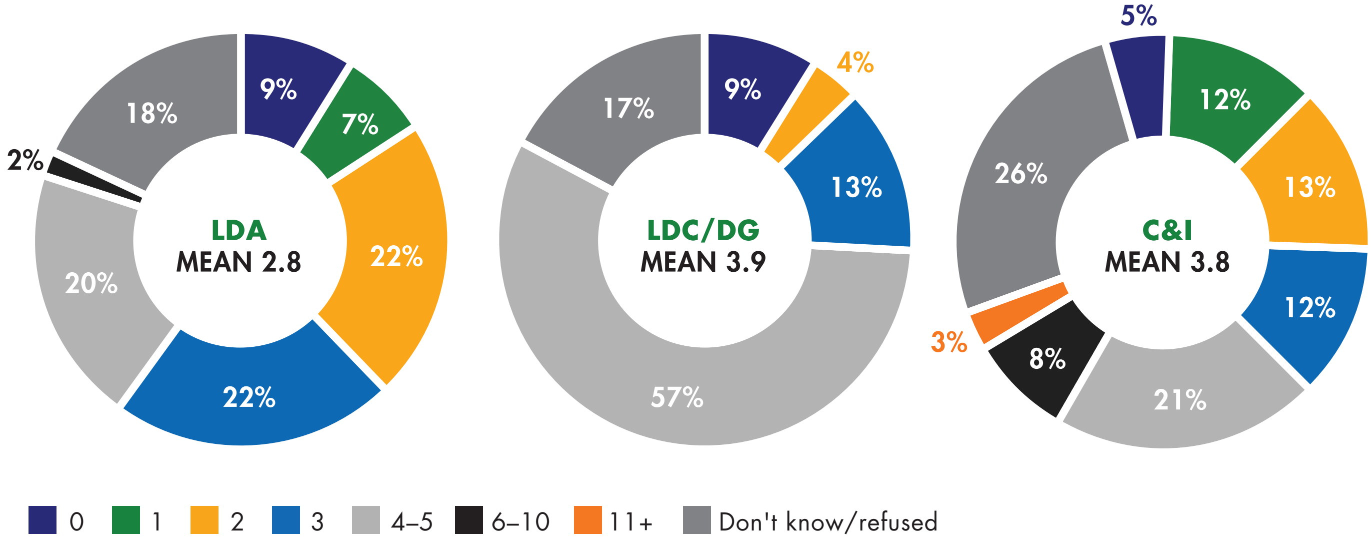


Q1. As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. How satisfied are you with Hydro One? Base: LDA (N=45), LDC/DG (n=23), C&I (n=133)

The number of sustained power interruptions that Large Customers experience is similar to that experienced by R&SB customers – ranging from three to four interruptions over a 12-month span. Notably, half of LDC/DG are experiencing four to five per year, directionally higher than LDAs or C&I, albeit 8% of C&I customers are experiencing 6–10, and 3% experience 11 or more.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

AVERAGE NUMBER OF INTERRUPTIONS

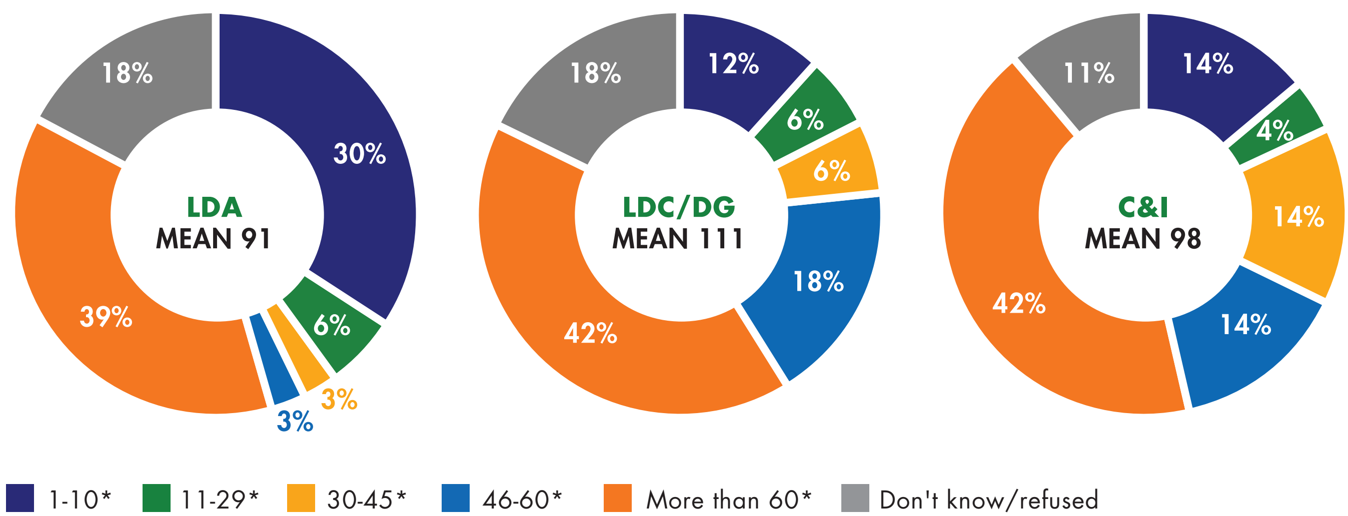


Q5.The term interruption refers to a complete loss of electric power and outage refers to the disabling of a component's capability to deliver power (planned or unplanned). An outage may or may not cause an interruption of service to customers. A sustained power interruption is one lasting at least 1 minute. How many did your organization experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. Base: LDA (n=45), LDC/DG (n=23), C&I (n= 133). Note: One C&I customer answered 99. It is unclear if this is correct information or a mistake. The mean above for C&I excludes this person's answer. If it is included the mean increases to 4.7

LDAs who experienced an interruption indicated the average length was roughly 1.5 hours. LDC/DG report an average of 1.9 hours and C&I report an average of 1.6 hours.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

AVERAGE LENGTH OF INTERRUPTIONS



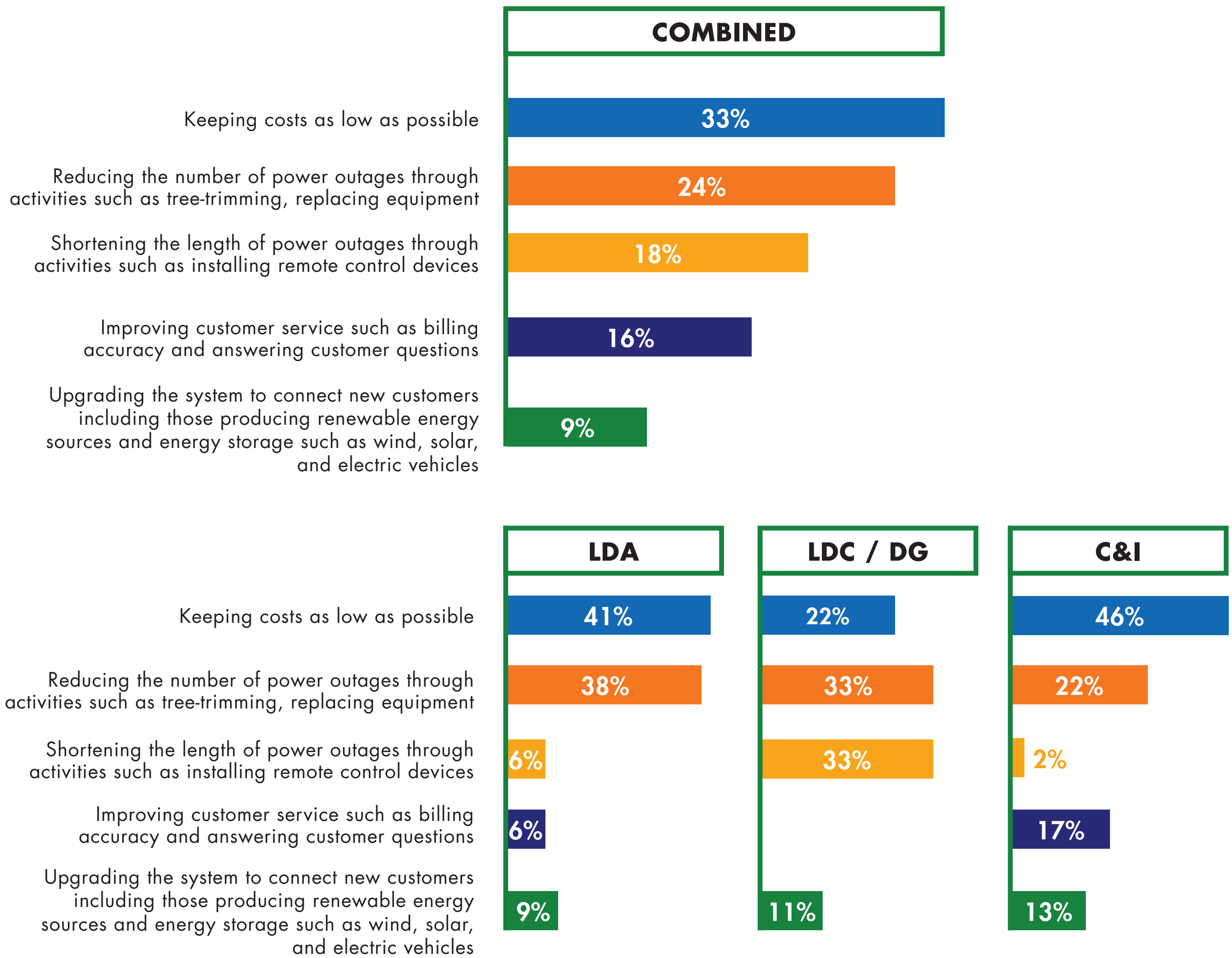
*Minutes

Q6. On average, how long did these unplanned interruptions last? Your best guess is fine. Base: Customesr who experienced at least one interruption. Base: LDA (n=33), LDC/DG (n=17), C&I (n=91) Note: Three customers gave answers that could be considered outliers 1,200 (20 hours) and 2,880 (48 hours). We have removed these 3 responses from the mean calculation. If they are included the mean change as follows: LDA = 194 instead of 91, C&I = 146 instead of 98.

CUSTOMER PRIORITIES

Large Customers, with the exception of LDC/DG customers, also prioritize keeping costs as low as possible over improved reliability, customer service or upgrades to the system to connect new customers including those producing renewable energy. LDC/DG customers prioritize better reliability, as well as both fewer and shorter outages ahead of all else.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET
CUSTOMER PRIORITIES



Q3. Hydro One would like to better understand what is important to you as a large customer. From the following list, which would you say is most important to your organization? (select one only) Base: Excludes don't know/refused. LDA (n=34), LDC/DG (n=18), C&I (n=46) Note: the online workbook asked this question in the form of a paired-choice and the analysis was conducted on the combined response (due to smaller base sizes) Base: LDA/LDC/DG/C&I (n=87).

THE TYPES OF RELIABILITY IMPROVEMENTS THAT CUSTOMERS VALUE

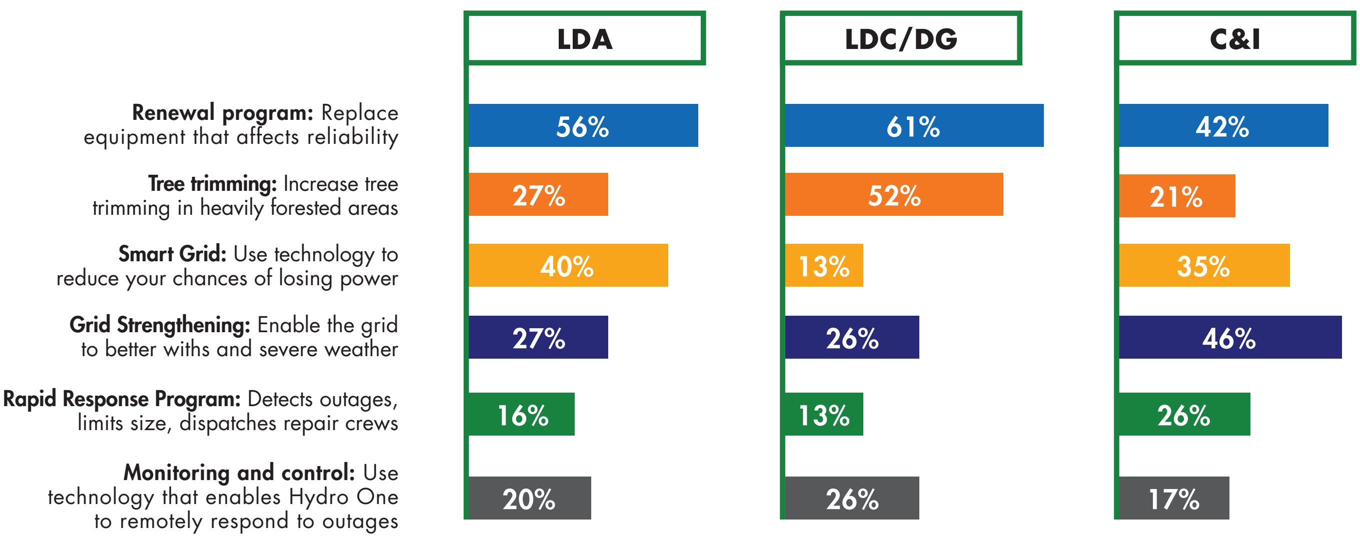
Large Customers were provided with various reliability investment options that Hydro One could prioritize and were asked to rank them in order from one to six, where one represents the item that would have the greatest positive impact on their organization and where six represents the item that would have the least positive impact. All Large Customer segments (LDA, LDC/DG and to a lesser extent C&I) prioritize the Renewal Program that focuses on replacing equipment that affects reliability ahead of others.

Views on the second and tertiary priorities vary somewhat. LDA customers place the second greatest priority on the Smart Grid, that is, using technology to reduce their chances of losing power. They place this slightly ahead of increased tree-trimming and Grid Strengthening. LDC/DG customers place tree-trimming in the second position – in fact nearly as many customers feel this would have the greatest positive impact on them as the Renewal program. C&I customers actually place as much of a priority on Grid Strengthening as the Renewal Program and then place Smart Grid as their tertiary choice.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

CUSTOMER PREFERENCES FOR WAYS TO IMPROVE RELIABILITY

Percentages shown represent % who ranked the item in the first or second position.



Q11. Please rank the RELIABILITY items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 6 represents the least positive impact. Base: LDA (n=45), LDC/DG (n=23), C&I (n=133).

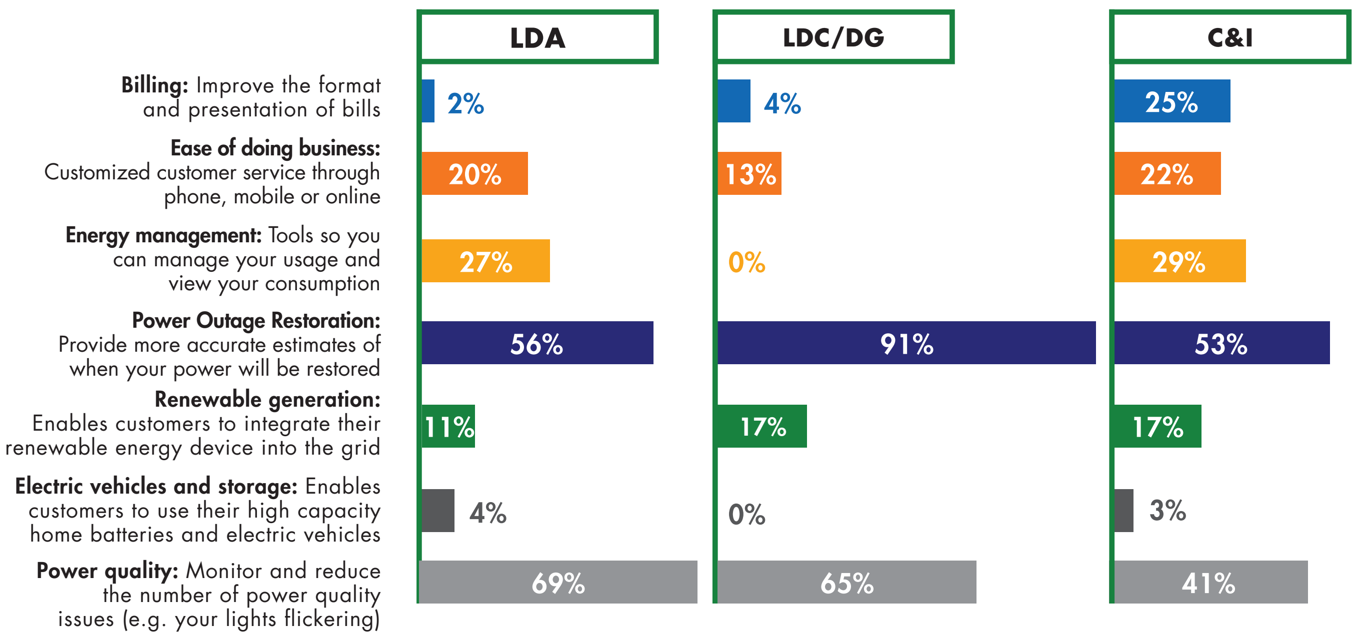
THE TYPES OF SERVICE IMPROVEMENTS THAT CUSTOMERS VALUE

When it comes to ranking seven service-related options, all three Large Customer segments prioritize Power Outage Restoration –providing more accurate estimates of when power will be restored. This is followed closely by Power Quality –monitoring and reducing the number of power quality issues (e.g., your lights flickering), and LDA customers actually place this slightly ahead of Power Outage Restoration.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

CUSTOMER PREFERENCES FOR WAYS TO IMPROVE SERVICE

Percentages shown represent % who ranked the item in the first or second position.



Q12. Please rank the SERVICE items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 7 represents the least positive impact. Base: LDA (n=45), LDC/DG (n=23), C&I (n=133).

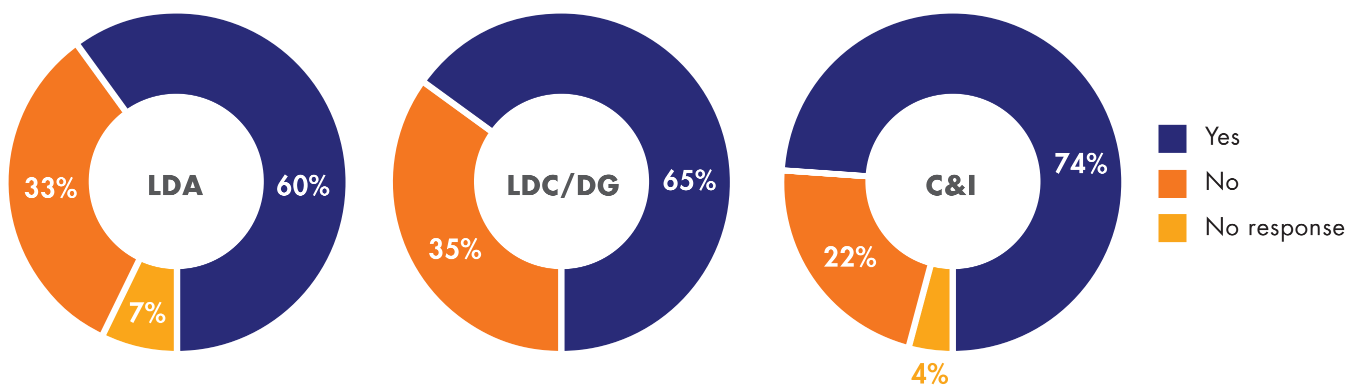
Note: for the online workbook, Billing was worded as - Ensure you receive timely and accurate bills, Ease of doing business was worded as - Seamless customer service through phone, mobile or online.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

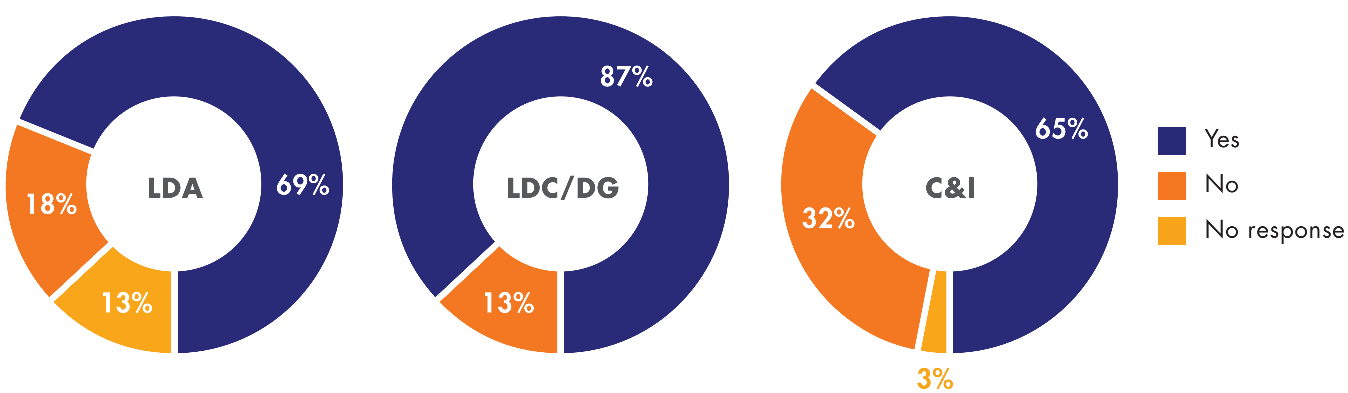
CUSTOMER REACTION TO HYDRO ONE'S CURRENT INVESTMENTS

The majority (60% and higher across the Large Customer segments) indicate that based on what they heard/read in the presentation by Hydro One, the investments that Hydro One is making today to maintain and improve the current level of reliability and service make sense.

TO MAINTAIN CURRENT LEVEL OF RELIABILITY AND SERVICE



TO IMPROVE THE LEVEL OF RELIABILITY AND SERVICE



Q9. Based on what you just heard/read in the presentation, do the investments to maintain the current level of reliability and service that Hydro One is making today make sense to you? Base: LDA (n=45), LDC/DG (n=23), C&I (n=133). Q10. Based on what you just heard/read in the presentation, do the investments to improve the current level of reliability and service that Hydro One is making today make sense to you? Base: LDA (n=45), LDC/DG (n=23), C&I (n=133).

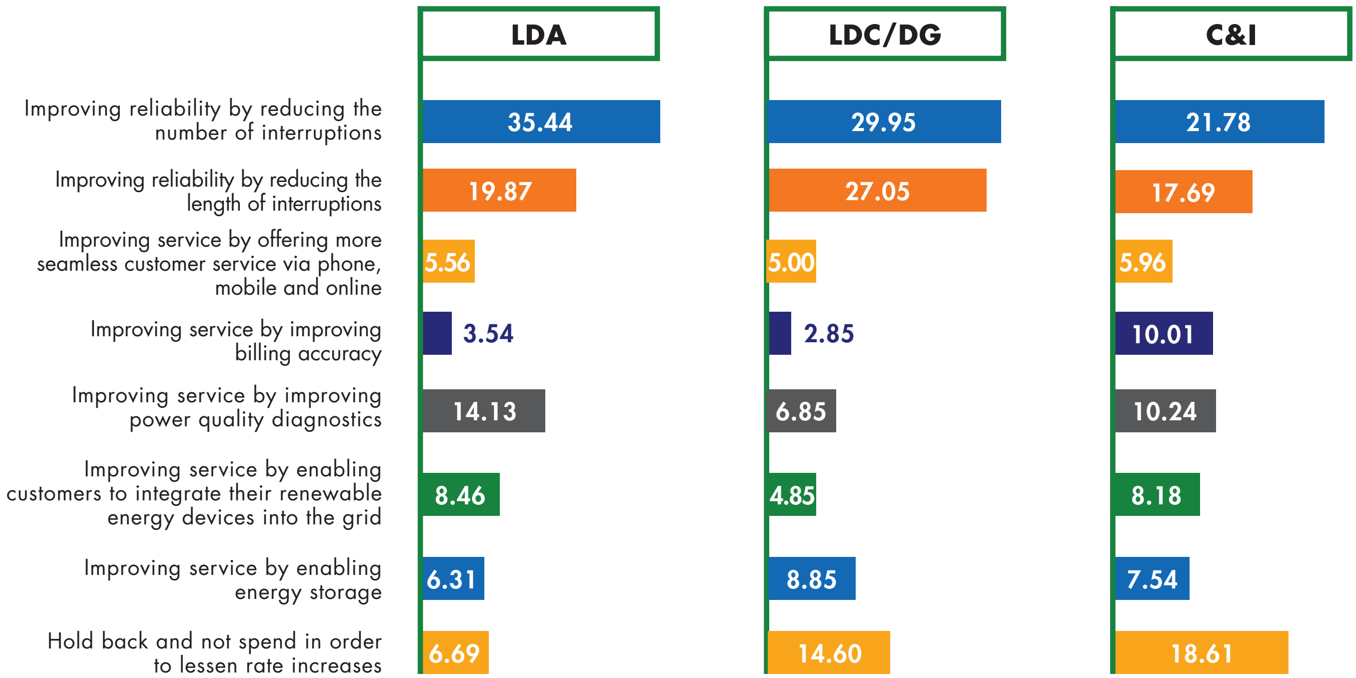
HOW CUSTOMERS WOULD ALLOCATE INVESTMENTS

Large Customers were provided with the opportunity to allocate $100 based on their preferences. All three customer segments allocate the most to reducing the number of interruptions (averaging from roughly 22% of spending to 35% of spending). LDA and LDC/DG customers allocate the next largest share to reducing the length of interruptions (LDA customers allocate an average of roughly 20% and LDC/DG allocate 27%).

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

HOW LARGE CUSTOMERS WOULD ALLOCATE SPENDING

Data shown below is the mean score – representing the average amount ($) customers would spend on these items.



Q13. To explore your preferences for reliability, service and level of rates, please complete the following exercise. If you had $100 to spend on the following, how would you allocate the money? Note that for the workshop survey booklet, the wording was "let's do a simple exercise". The data shown above excludes customers who do not answer the question or whose answer did not total $100. Base: LDA (n=39), LDC/DG (n=20), C&I (n=121).

For C&I customers the next largest share is allocated to savings, i.e. hold back and not spend in order to lessen rate increases (roughly 19%). LDC/DG customers would hold back an average of 15%, while LDA customers would hold back 7%. LDA customers allocate more to improving power quality (at roughly 14%) than LDC/DG or C&I customers.

CUSTOMER REACTION TO ILLUSTRATIVE INVESTMENT SCENARIOS

Large Customers were presented with the following illustrative investment scenarios and asked for their feedback. The three scenarios reflect the estimated rate impacts for declining reliability, maintaining the current level of reliability and improving reliability. The slide below was shown to Large Customers prior to introducing the three illustrative scenarios.

Introduction to investment scenarios

hydro one

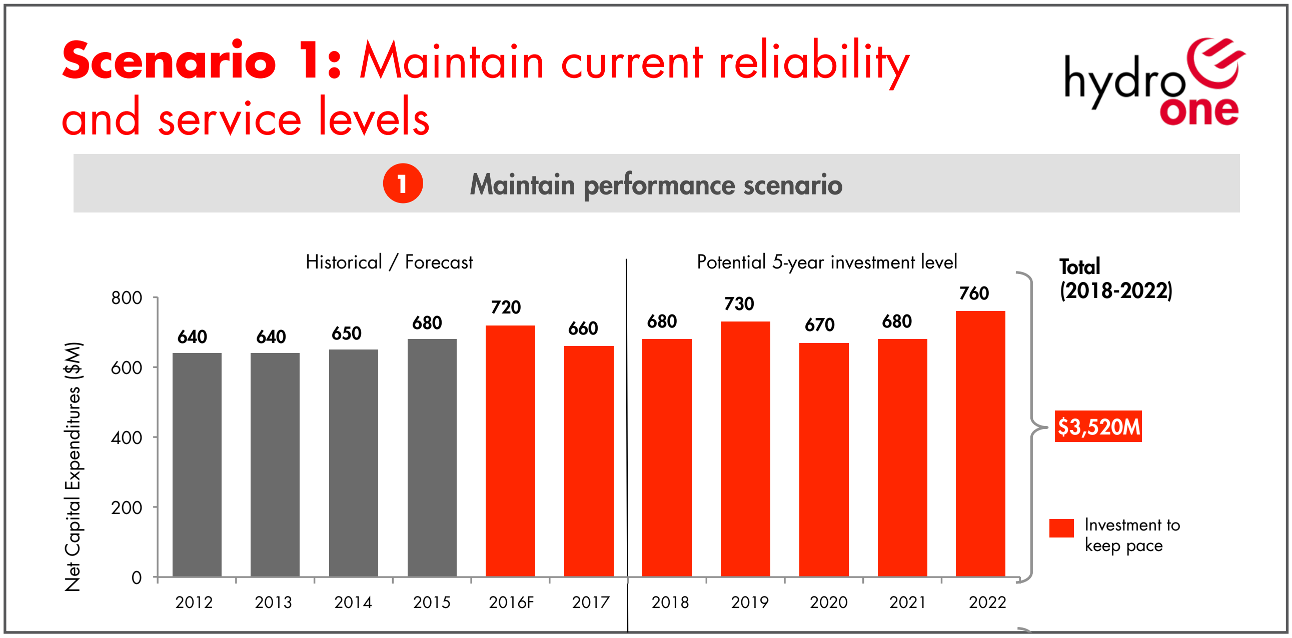
Illustrative scenarios have been developed for various levels of capital investment.

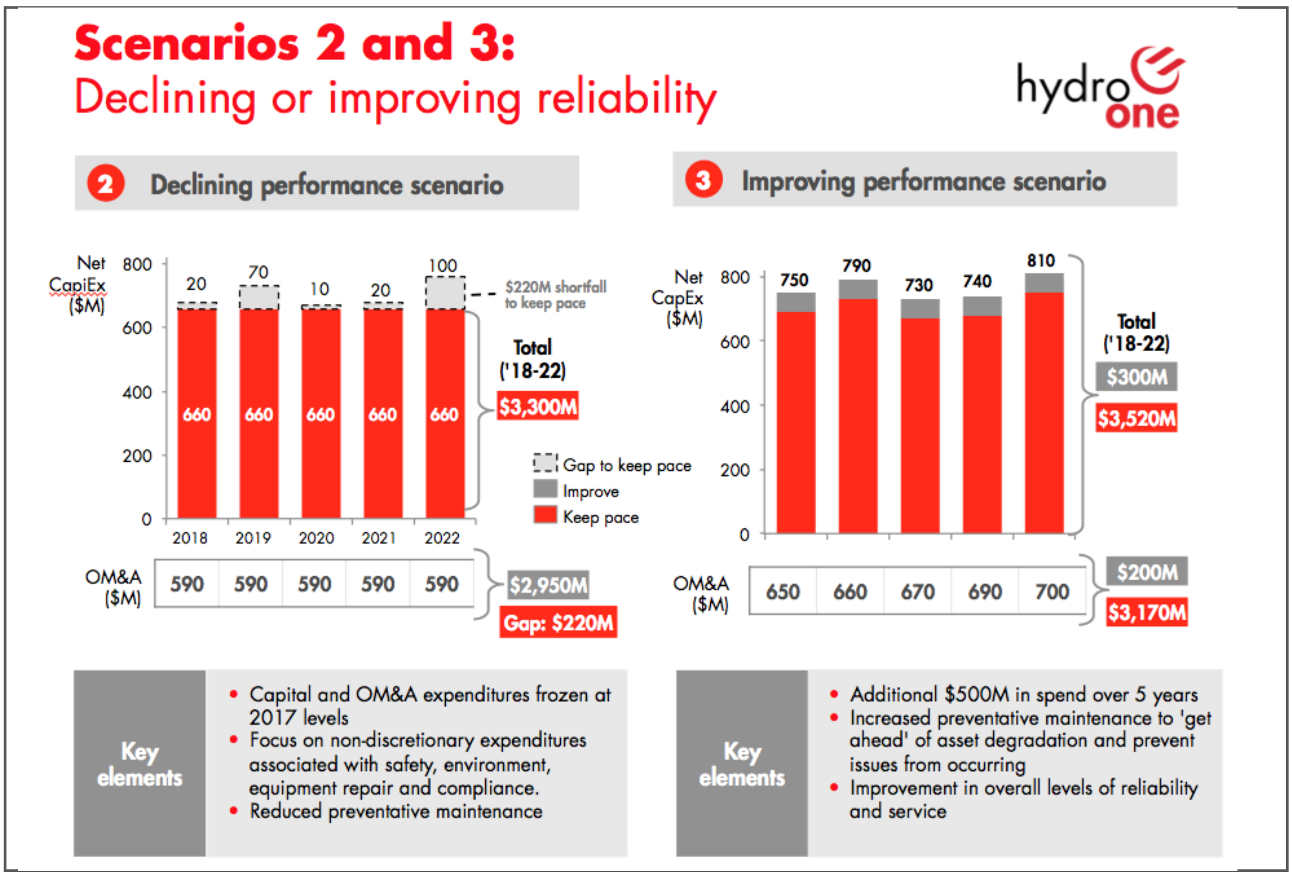
These in turn, result in different impacts on rates, reliability, and service levels.

These scenarios are meant to represent a spectrum of potential investment levels.

We do not have a recommended scenario, nor are we asking you to choose from the scenarios presented.

Through this conversation, we would like to better understand your business needs and preferences to inform our 5-year Distribution Investment Plan.

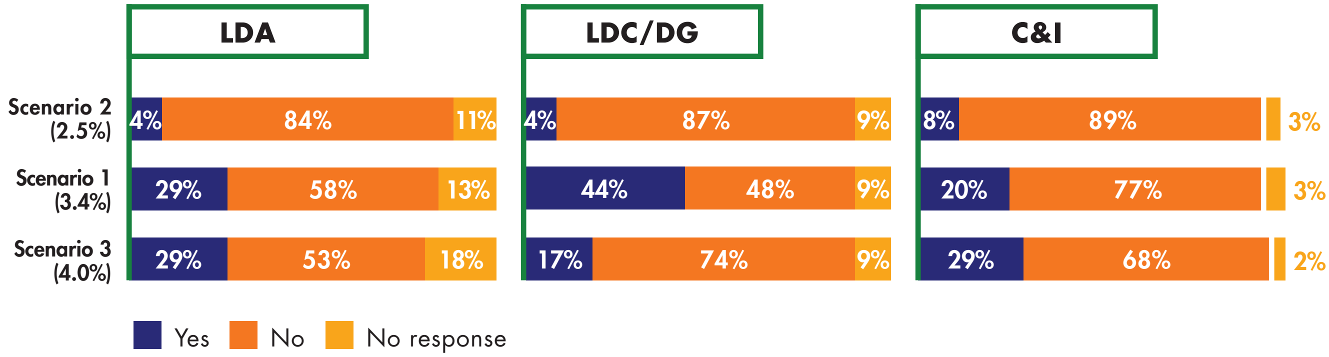




Overall, the majority of Large Customers are not willing to accept any of the rate impacts proposed in the illustrative examples (ranging from 2.5% - 4.0% on the distribution delivery rate). As shown in the chart, the vast majority of customers will not accept a rate increase (2.5% on the distribution rate delivery) where reliability declines. Customers are more likely to accept the larger rate impacts of 3.4% or 4.0% on the distribution delivery rate where reliability is at least maintained or improved. As shown in the qualitative section that follows, customers take issue with the idea that they would be asked to pay more for worse service.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

WILLINGNESS TO ACCEPT INVESTMENT SCENARIOS

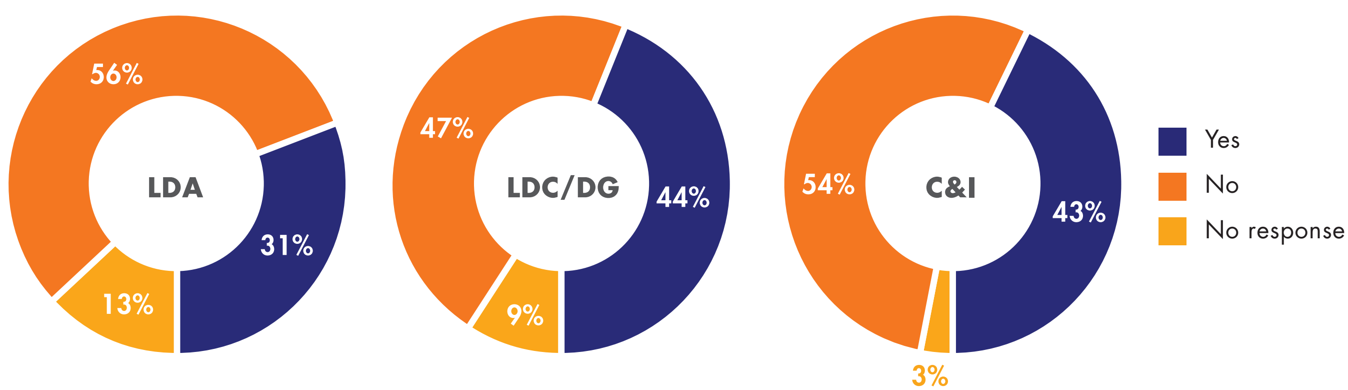


Q15. Would you be willing to accept a 2.5% distribution delivery rate increase where reliability and service performance declines (Scenario 2)? Base: LDA (n=45), LDC/DG (n23), C&I (n= 133) Q16. Would you be willing to accept a 3.4% distribution delivery rate increase where reliability and service performance remains the same as it is now (Scenario 1)? Base: LDA (n=45), LDC/DG (n23), C&I (n= 133). Q17. Would you be willing to accept a 4.0% distribution delivery rate increase where reliability and service performance improves (Scenario 3)? Note that for the online workbook, this was a 4.1% distribution delivery rate increase. Base: LDA (n=45), LDC/DG (n23), C&I (n= 133).

As part of the customer engagement, Large Customers were asked if they expect significantly higher or differentiated service than they receive today from Hydro One. After responding yes or no, there was a place for customers to explain their answer. The response was quite mixed. While a large minority of LDC/DG and C&I customers indicate yes, half or more say no.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

EXPECTATION OF SIGNIFICANTLY HIGHER OR DIFFERENTIATED SERVICE



"Service should be more highly scrutinized and held to a higher expectation. Does not always require more money."

"Service must be maintained and improved by offset internally by savings (just like in private business). Customers in LDA segment cannot keep absorbing huge, over inflation, cost increases."

"I [expect higher, differentiated service because] we are spending money to improve reliability in our manufacturing facilities."

"Our current service is quite good."

"If I will see an increase, I'd like to ensure there is "bang of my buck."

"Better balanced service at points near the end of the distribution grids, better communication of planned outages and better system of informing customers of anticipated return to power times."

"Our business should have a different rate plan since they operate only during peak hours."

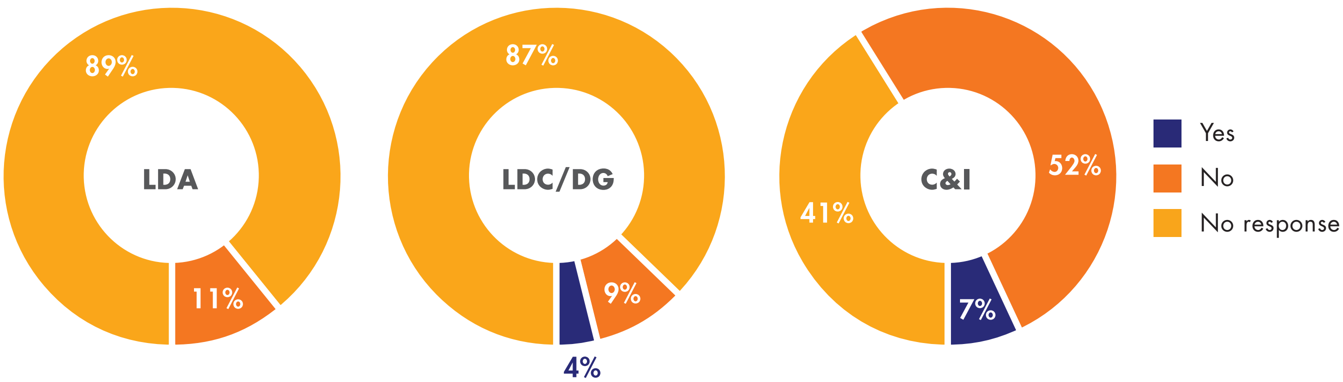
"I think everyone including Hydro One needs to learn how to do more with less just the like the rest of the market place."

Q18. Do you expect significantly higher or differentiated service than you have today from Hydro One? Yes, please explain/ No, please explain. Base: LDA (n=45) , LDC/DG (n23), C&I (n=133)

When asked if they would be willing to accept a distribution delivery rate increase greater than 4.0% in order to have customized reliability and/or service improvements, the majority of LDA and LDC/DG customers do not offer an opinion. More C&I customers answered the question with 7% indicating they would accept this increase for customized improvements.

ONLINE WORKBOOK/ WORKSHOP SURVEY BOOKLET

WILLINGNESS TO ACCEPT A RATE INCREASE ABOVE 4.0% FOR CUSTOMIZED IMPROVEMENTS?



"Power outages have a significant impact on our business. Any small extra investment to protect against this would be positive."

"We are continuously managing improvements at our facilities with little increases in our budgets so we believe Hydro One should as well."

"I don't fully understand 'customized' reliability."

"I feel the rate can be reduced with better usage of the existing assets."

"No. We are installing generators in the next few weeks and are going to be completely or almost completely eliminating our hydro use as a result of skyrocketing costs."

"Our live animals need constant heat, food, and water thus, having customized service that could guarantee perfect service would be ideal."

"We really need more detail but in principle it could put the cost where there is benefit."

Q19. Would you be willing to accept a distribution delivery rate increase greater than 4.0% in order to have customized reliability and/or service improvements? Yes, please explain/No, please explain. Base: LDA (n=45), LDC/DG (n23), C&I (n=133). Note: for the online workbook, this was a Rate Increase Above 4.1%.

FACILITATED, IN-PERSON WORKSHOPS

As noted in the Customer Engagement Methodology section of this report, the Workshop sessions were conducted with LDA, LDC/DG and C&I customers. The Workshops sought to serve Hydro One's customer goals of educating customers, and allowing for a two-way dialogue to have customer questions immediately answered. Hydro One was responsible for sending out the invitations as well as the follow-up, reminders and other communication outreach with a broad cross-section of its Large Customers for the Online Workbook. Hydro One's efforts to invite and encourage as many of these customers as possible to the in-person sessions has been documented.

A total of nine Workshop sessions were conducted in seven locations across Ontario involving 103 Large Customers and 129 participants. The locations were chosen by Hydro One in collaboration with Ipsos based on what would be the most convenient and accessible for customers.

The feedback provided across the Workshop sessions has been organized into six themes.

THEME #1: COST

SUMMARY

While most customers recognize the need for investments in Hydro One's aging infrastructure and distribution system, the majority of participants across the Large Customer Workshops do not accept a rate increase of any size, whether reliability remains the same or improves.

IMPACT OF ELECTRICITY COSTS

The rising/high cost of electricity in Ontario emerged as a theme of great interest and concern throughout the Workshops. For some Large Customers, they stated that the continued rise in electricity prices is a direct threat to the viability and competitiveness of their businesses. It is an expense that is one of or the highest after labour. As well, it is perceived as being higher than in other jurisdictions and participants have observed anecdotally that business is being lost to these other regions as a result — for example, manufacturing plants in Ontario have closed and moved to the United States and Mexico.

"How can a business afford to pay more? We are paying the most in North America. More increases [are] driving business to the US."

For a few participants, natural gas is an alternative energy source which is considered to be more reasonably priced and one participant stated that his organization is considering making a permanent switch to natural gas should the cost of electricity rise again.

"If we get a wee bit more [of an] increase, we will move, go off grid, very close. That's the bottom line. I only have to switch the switch. If you're hooked up on natural gas between 8 and 12 cents. We're very close."

UNDERSTANDING ELECTRICITY COSTS

Clarification was provided on the breakdown of costs and line items on customers' bills and this generated a large amount of discussion about each aspect of an electricity bill. While it was explained that Hydro One only makes a profit on the transmission and distribution delivery charges, and that other charges are pass-through only, participants were eager to share their thoughts and opinions on all line items.

As it relates to electricity conservation efforts, participants were incredulous that they are encouraged to conserve energy, only to have commodity prices rise to offset this, when load in Ontario is lower than expected. Although it was clarified they would still see savings in terms of reduced quantity, participants were nevertheless discouraged and dis-incentivized from trying to conserve energy as a result.

"The OEB did us all a big disservice by the last rate increase. We didn't use enough electricity, and that is why our rates are going up. We're trying to sell to our [LDC] customers that conservation is good: if you conserve, you'll save money. And then the regulator turns around now the rates are going up."

Several participants expressed their frustration with the fluctuating amount of the Global Adjustment charge each month. The lack of predictability makes budgeting and planning extremely difficult. The fluctuation can be very high, as much as tens of thousands of dollars each month, and participants questioned the reasons for this.

"Just looked at my electricity bill last month, the price was around $1,400, the Global Adjustment was $21,000. So that was pretty significant."

The Debt Retirement Charge was also mentioned by participants as being a source of dissatisfaction and confusion. One business participant stated she has heard several times over the years that the charge would be coming off the bill — which it hasn't. In general, customers are resentful that ratepayers are responsible for paying the Debt Retirement Charge, and point out that in any other business, paying off debt by raising prices would not be an option.

"The debt retirement [is] completely ridiculous, we all have our own business here. You know what happens if your business has too much cost and no income, you go broke."

Variations in distribution charges by Rate Class were brought up at times throughout the Workshops and clarification was provided as to how rate classes are determined. A few participants in northern Ontario indicated that their delivery charge exceeds their commodity costs and expressed their confusion and frustration over this.

"We got our hydro bill, $500 electricity, delivery charge was $1,500. That's the biggest issue I think all of us are having...Three times to deliver to the same pole standing there now for 20 years."

IMPACT OF PRIVATIZATION AND ROLE OF GOVERNMENT

Some participants made organic mentions of their belief that privatization would have a positive impact on Hydro One and ultimately ratepayers, as it would result in increased accountability of the organization, and in decision-making based on financial prudency.

"I'm really happy that Hydro [One] is privatized more and more, I think like any government organization just giving out money left right and centre, and not looking at costs, cause they never had to."

One participant stated his strong belief that the government should not have any influence on the electricity sector, and that prices should be subject to a user-driven open market, as with natural gas.

"Just get it completely out of the government's hands, right from top to bottom the whole way through."

Other participants stated their concern with privatization creating a conflict between shareholders and ratepayers, and pointed out the contradiction of Hydro One being both financially beholden to shareholders, as well as being accountable to ratepayers.

"The shareholder's interest is to make money, if you're the only game in town to go to my transmission for, I'm not sure that reliability is the shareholder's mind as being profitable."

COST EFFICIENCIES

Participants repeatedly inquired in all markets about efficiencies in operational and maintenance costs — and asked if Hydro One could improve in these areas in order to save money and re-invest in capital expenditures, instead of raising rates.

"…talking about a distribution delivery rate impact, revenue requirement, those include administration costs, when you're talking about improving performance, a lot of things in that mix, today [is about] only reliability and we don't know anything about cost efficiencies in a lot of other areas."

"Would have liked to see some slides on what Hydro One is doing internally to identify opportunities to create operational efficiencies and reduce costs internal to the organization."

"Efficiencies are not mentioned and need to be part of the consideration. Final scenarios need to include efficiency input."

"Look for ways to find the revenue needed within Hydro One BEFORE you increase rates for customers. Cut pay 5–10% for anyone over $100k. Show costs (budget)."

There were concerns both that Hydro One is mismanaging the funds it currently receives, and/or that funds were being misdirected into corporate needs such as promotions, salaries and payouts, instead of focusing on good customer service and reliability for its customers.

"…three million dollar payout, paying a president is not keeping [the] system reliable, not the best investment moving forward."

Customers expressed interest in seeing further details on the historical and current efficacy of maintenance programs, and capital expenditures already spent on improvements. They inquired as to whether Hydro One is using best practices and technological innovations in their maintenance and asset management. A few customers challenged the expenditure cost related to specific line items, while others stated they needed more information in order to gauge if the expenditures are prudent.

"…you've got $500M capital side, $450M on the operating side, these seem like awfully high numbers to the return on what investment is, the cost of maintaining is at the sacrifice of moving forward. Is there a plan to reduce these operating costs over time…$150M for vegetation management seems awfully high…looking for cost savings on those particular [items] not directly related to distribution itself."

With regard to OM&A costs, a few participants are of the belief that there should be a beneficial curve over time with an increase in capital improvements. That is, once assets have been replaced and would in theory require less maintenance, participants would like to know if there is benefit over time/in the long-term to OM&A costs that could eventually be passed onto customers in the form of lower rates. They wanted to know if there is a formula that can be used to calculate this.

"Investment dollars related to improving service levels is out of perspective, $60M to $1,250M to maintain more focus on improvement will reduce maintenance costs. Repair vs replace analysis — spending more to repair when replace will improve maintenance costs."

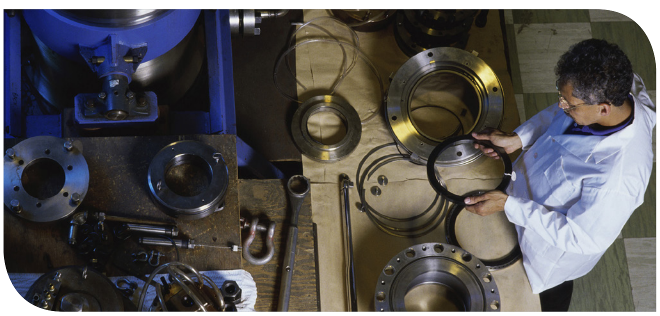
SCENARIO FEEDBACK AND RATE INCREASES

Rate increases are difficult for many customers to accept as they have serious concerns and numerous questions about Hydro One's operational efficiency, its ability to effectively manage costs, and its corporate integrity.

Some participants stated that it is difficult to know which scenarios they would accept in the absence of more detailed information.

"It's really difficult to answer this, because I don't know what's happening with the money that you receive now. So I can't say it's being well managed, give us 2.5% more and have declining performance. 3.4% to maintain. 4.0%. Why are those the only options?"

"Without seeing benchmarks without knowing if Hydro One is as efficient as it should be…another 2.5% or 3.5% to keep things as they are. Would like to see the study, even with the 2.5% increase in expenditures, reliability is going to decline. There had to be a major study would like to see that before I vote."



DECLINING SCENARIO ($3.3B CAPEX, $2.95B OM&A, 2.5% RATE INCREASE)

The vast majority of Workshop participants indicated that they would not accept an increase in rates for declining performance.

"Another 2.5% increase and service will decline — that's scary. Declining service will only result in deteriorating service as time passes — this is not acceptable. Power is an essential service."

"None of our customers would accept a 2.5% increase in price for less product. Why should we?"

"…it is hard to take a price increase to experience declining performance. In this day and age it is unacceptable. This is a difficult scenario to answer."

A few participants stated that a Scenario depicting a rise in rates with a decline in performance is unacceptable, and that presenting the Scenario to customers as an option speaks negatively to issues within Hydro One's company culture.

"How can we see a rate increase of this magnitude in general, but particularly for decreasing service? Why are there seemingly no attempts to maintain service but to reduce YOUR operating costs?"

MAINTAIN ($3.52B CAPEX, $3.17B OM&A, 3.4% RATE INCREASE) AND IMPROVEMENT SCENARIOS ($3.52B CAPEX, $3.17M OM&A, 4.0% RATE INCREASE)

The majority of participants across the Workshops indicated they do not accept a rate increase of any size, whether reliability remains the same or improves. Many participants stated their belief that Hydro One could and should increase efficiencies and improve maintenance programs rather than raising rates. They are looking for more drilled-down, detailed historical and current information on capital sustainment and improvement expenditures, as well as OM&A expenditures. In the absence of these details, participants were unsure of Hydro One's ability to make prudent investment decisions, which in turn made them skeptical of the company's ability to make good decisions as it relates to future investments.

"Investment scenarios are good in principle. However, [these] need to be funded by offsetting savings in other areas. LDA are already taxed significantly and increases between 2.5–4% are hard to accept. Combined with Global Adjustment increases, hard to stay cost competitive to U.S. and Mexico manufacturing sites."

"I think Hydro One needs to figure out how to deliver better service by maintaining their costs like the rest of the businesses have to."

Those in the minority who supported a rate increase would like to see a tangible improvement in reliability, including power quality. Their need for reliability outweighs their concerns about a rate increase. One participant indicated that based on his rate class he would support an even bigger rate increase.

"I would support extra customer costs as long as there is a benefit to the end user, e.g. reliability."

"I guess reliability is about quality of power. We want it all the time and we don't want bumps, we want quality. If we get that we're 100% satisfied, we'll likely bitch a little less about paying for it."

"I think those [scenarios] will be significant to increase reliability and much needed for quality performance and would be beneficial to all customers."

"If my bill is $100K a month, 2% category — so that's $2,000 a month. If I'm in the 2% distribution category, it's 2% of 25 which is like nothing. So the answer's pretty easy for us."

One participant expressed his concern with the proposed pacing of investments, as five years seems like a short period of time to be remedying it entirely.

"Can you spread it over a longer period of time…[it has been] 60 or 70 years [but are you] trying to solve it overnight. Look forward for 10, 15, 20, 30 years — do a proper study with life cycles and all the other components and spread out the capital costs over a greater period of years. "

THEME #2: CONSISTENCY

SUMMARY

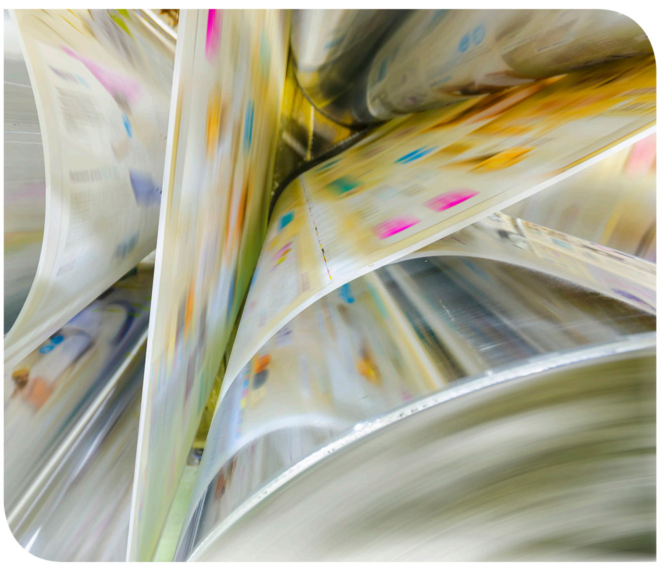
Power quality emerged as being the reliability issue of most concern to participants in the Large Customer Workshops. It was mentioned as being a significant and pressing priority for many customers in all markets.

Dips or spikes in voltage, brownouts, and interruptions of only a few seconds all have the same negative impacts as longer interruptions. Consequently, several participants throughout the customer engagement process challenged the fact that interruptions lasting less than one minute are not being tracked by Hydro One.

"Need to measure and benchmark type of interruptions. Complete outage is one issue, but surges and spikes are an impact on LDAs that use sensitive equipment."

"Need to be able to detect momentary outages. Just as much of an issue as prolonged outages."

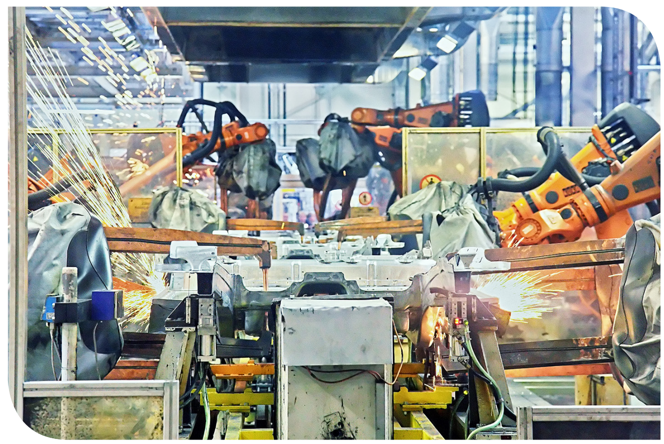
"Monitor outages [of] less than one minute or [allow us to] report bumps to Hydro [One]."



IMPACTS OF POOR POWER QUALITY AND RELIABILITY

The consequences of the impacts due to poor power quality were discussed in detail by participants. These include:

- Lost productivity
- Equipment failure — both temporary, and permanent
- Labour impacts — i.e., the uncertainty of sending workers home or keeping them at the facility
- Health and safety issues
- Financial impacts
- For LDCs, the whole municipality is without power
- Installing backup generation
- Technology / IT impacts



"Severely [impacted]. Food processes involving baking and cooking. Work in progress must be discarded and the line sanitized resulting in extra cost and lost production, i.e., $1,000/minute downtime including time to restart, one minute outage could result in 180 minutes of downtime."

"The 40 per year interruptions are shutting down our assets for one to two hours (even a blip of 100 sec). Annual loss of production $1.2 million."

"In our industry a one minute interruption results in a one to two hour downtown to reset pumps, fans, etc. and then there is cleanup [of] slime, rocks."

"Some are merely seconds but cause hours of downtime. Equipment loss, production loss. Morale issues in employees."

"Lost power in a whole town which is approximately 5–10 thousand customers."

"Has required the installation of a backup generator at major facilities (5)."

"Large cost due to downtime of highly automated and computerized systems."

"Safety risk due to sudden stoppage of processes that generate heat and cannot be sequentially shut-down and cooled. A recent outage cause a fire at our facility."

Participants were mostly unaware that Hydro One relies on its customers to give them feedback and information about power quality incidents. When it was mentioned that it is possible to have Hydro One help customers with their internal power quality capabilities and issues, this suggestion was of great interest.

CURRENT ASSET MANAGEMENT

Most participants in the Workshops recognized the need for continued investment in the system in order to maintain and improve assets and reliability. The current level of investments to maintain and improve reliability and service — as outlined in the presentation — made sense to most customers.

"It makes sense to monitor the current assets based on their expected service life and replace, as needed. It's important to replace aging equipment regularly to avoid having complete system failure, or having to replace all on emergency basis."

"I'm glad to hear that Hydro One performs sort of test/diagnosis on assets that are beyond their useful life prior to decide any needs of investment, optimizing this way budget and resources."

"Absolutely important to maintain and replace equipment as end of useful life approaches. Also good to hear that some high performing equipment may be operated beyond useful life to achieve balance in capital dollars spent."

Based on the information provided during the presentation, some customers expressed their concern as to the current condition of assets. They questioned whether Hydro One is maintaining and improving the system at a pace that mitigates the risk posed by poor asset conditions. The number of poles and stations approaching or beyond their service life were of particular concern. In spite of clarification around condition and not age being the main replacement consideration, these participants were still dismayed by the quantity of older assets.

"Why is the infrastructure so aged? [Has there been] improper spending of capital in the past."

FUTURE ASSET MANAGEMENT AND IMPROVEMENT

Planning and preparation of the grid for future needs was actively debated during the customer engagements. Participants had mixed reaction to the notion of proactively anticipating and building infrastructure now, as opposed to responding to needs as they arise. Additionally, they were divided as to whether the associated costs should be through a rate increase to all ratepayers, versus having only those who benefit directly pay for these changes.

Those participants who supported proactively preparing the grid believe it is important for Hydro One to effectively manage the grid as new technologies and power sources emerge. Some participants stated that it is Hydro One's responsibility to both proactively plan for, and include in their investment plans, items that take future needs and growth of the grid into account.

"To me it's not just about 10 kW and Tesla, [it is] having some grid management benefit as well."

"We're a producer and a user, certainly strengthening the grid is a key concern, to be able to supply, also the smart grid would add efficiency to that…increasing capacity from our perspective is important, and the efficiencies you get out of a smart grid system."

Those who are opposed to proactively preparing the grid state that this is a low priority area that should be of concern only to those who are directly benefiting, or as the need arises in the future. There were also concerns cited that any new technology implemented would fail entirely or not add value.

"My concern is [that we say] rah rah with technology, [and then] rush ahead with very expensive technology [which is] not doing the job."

Several participants stated their belief that underground lines would be a more economical and/or reliable method than overhead lines.

"When are you going to think about putting lines underground…nowadays you have good machinery and equipment to drill in even though it goes five feet down, wouldn't it be smart to start doing that?"

It was clarified by Hydro One that underground lines cost four to ten times more over the life of the line to both install and maintain, and as such, is currently considered cost prohibitive. As well, they are not more reliable than overhead lines, as they are subject to damage and decay. It was further clarified that subdivisions who installed underground lines did so as this was mandated by municipalities. The cost associated with the underground lines was then charged to homeowners by developers through the cost of the new home.

Participants inquired about use of alternate materials for poles other than wood, as well as condition testing for poles, and it was clarified that pilot programs are in place for composite poles, and that a benchmarking study has been commissioned by Hydro One for pole replacement.

REGIONAL CONCERNS

Regional reliability concerns were brought up as being of particular interest to some participants. For those in the Muskoka area, they were concerned about reliability issues caused by the dense forestry in their region, and questioned why trees in their area are not more proactively trimmed. For those in the northern markets, they expressed their concern that capital investments would be focused on areas of greater population density, i.e., in southern Ontario, and that they would not see the benefits of improved reliability. As such, they stated that they would like to see a detailed capital plan that included investments and benefits specific to the north. In general, participants also indicated an interest in seeing more region-specific investment details, to better understand reliability performance in their area of the province.

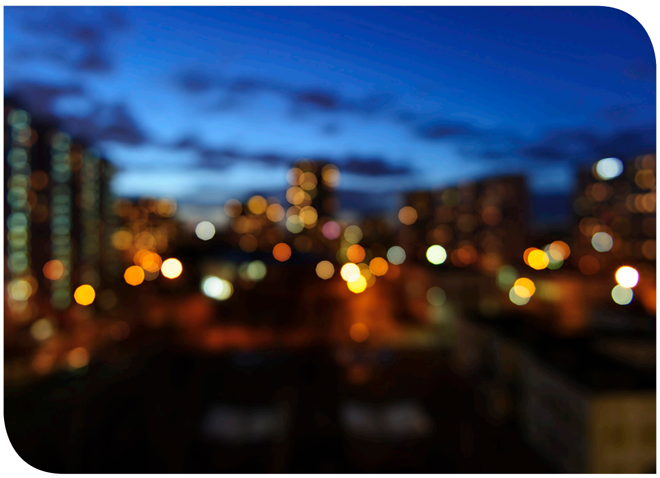
"Breakdown of historical CAPEX spent across Ontario. Are the 84% rural customers receiving proper allocation of CAPEX? Northern ON/Southern ON CAPEX breakdown."

"…province-wide management and cost per capita is not aligned. Popul[ation] in Southern Ontario is higher; more infrastructure repair is done there; rural should have a greater focus."

THEME #3: CUSTOMER SERVICE

SUMMARY

For most LDA/LDC customers, they stated that customer service is generally satisfactory. However, for many C&I customers as well as some LDA/LDCs, customer service from Hydro One is an area in need of significant improvement.



SATISFACTION WITH SERVICE

C&I participants who struggle with service cite a number of issues:

- Not having a dedicated account person or contact. They are reliant on publicly available information or the Ontario Grid Control Centre in the event of an outage, and call the number on their bill in order to have ask questions or have issues addressed.
- When calling the call centre, they mention being passed around from one person or department to another on the phone and often not receiving a satisfactory answer to their questions or resolution on their issues.
- The process of resolving issues can take an excessive amount of time — months or years, if at all.
- Receiving rebates can also take a long time.
- Bills and information on planned outages are sent to a corporate head office, instead of employees on the ground who need the information for planning and budgeting.
- Being unable to receive trustworthy advice. For example, whether or not participating in an energy-saving program is worth the risk.
- Making web meeting appointments with Hydro One employees who do not show up.
- Navigating complicated and time-consuming application processes for incentives and programs.

"…every time we deal with someone, it's someone different…They pass it down the line, [but] who do I contact, it's frustrating. Hydro [One] has a lot of different divisions, and I understand that, but one's not talking to another."

"…on several occasion of reaching out to Hydro One, either emails went unreturned or twice we set up meetings with our President and Vice-President and the gentlemen just never showed up for the teleconferences…"

"Normally I get [the bills] four months later, what good is that to me four months later. As these bills in larger corporate end up with some accountant as opposed to the people trying to run it."

BILLING

In general, participants were looking for two key elements on their bills: accuracy and clarity.

Some participants spoke of receiving estimated bills instead of those based on actual meter readings. They are puzzled as to why this is necessary, and object to paying a Hydro One employee to read meters if the bills are based on estimates.

"We have a couple of times that we haven't received bills regularly and I've called to discover that our bills were being reviewed and redone. This took up to 6 months then we had an extremely large bill that we had to negotiate payment arrangements for."

A few participants also mentioned challenges with consolidating bills if one company is receiving multiple bills for its different buildings/meters/ locations. This process was long, complicated, and difficult to resolve for these participants.

"From our perspective specifically attempting to get consolidated bills, has been brutal."

Several participants indicated that they find their bills confusing or the information provided is incomplete, and wished to receive clarity around charges. The ability to see information separate from the bill — either through an insert, or online — were also mentioned as being of interest. One participant indicated they have not been able to receive a satisfactory explanation of their bill from Hydro One.

"The one line that's not on the bill that should be, what the cost per kW hour is. The total cost…100 lines on this bill, nothing telling me [what the cost per kW hour is] — unless I do a lot of work to find it."

"Do you have the ability to further clarify that bill separately, we find it very confusing to understand it. Is there a way for you to clarify, do you have the ability to do that, [for example through] an insert?"

A few participants mentioned challenges around billing related to capital work fulfilled by Hydro One. One customer was unclear as to why it was necessary to pay in advance for capital work, with another receiving a bill for capital work months after the work was complete.

"…Hydro One is the only contractor I have to pay upfront before they do anything — design and implementation — [they] generally do a good job, [but they're] the only guys to pay upfront. Why is that?"

THEME #4: CONNECTIONS AND CAPACITY

SUMMARY

Customers in certain regions and industries state that a lack of sufficient power capacity is a hindrance to their ability to grow their businesses, that the process of applying for more capacity with Hydro One and the OEB is protracted and unsatisfactory, and that the rules and regulations around adding capacity through the beneficiary payment system are confusing.

CONNECTING NEW CUSTOMERS

Hydro One clarified that it is mandated by the OEB to connect any customer wishing to be connected to the distribution system. The rules around the associated costs were explained in detail, with some participants observing that they found the system confusing. A few participants stated their belief that the utility should be responsible for additional capacity as it helps industry and businesses create jobs and be more competitive in Ontario, while others stated their belief that only those who benefit directly should be paying for new connections.

"The other part is expansion which doesn't seem like you have the capital dollars to build things in rural areas. If the province believes about stimulating and getting people to build things, and they're gonna be partners, then there has to be cash."

"If someone wants to build a gold mine in the middle of nowhere, then is it our responsibility to pay for their power line for this gold mine or is it the gold mine's responsibility to bring the gold mine in…for a gold mine do we need to pay for power lines so there can be a gold mine there."

Hydro One clarified that under the beneficiary payment system, the cost of the connection over a period of 25 years is calculated and if Hydro One is able to recover their costs over that period, the beneficiary does not need to pay any out-of-pocket costs. Should another load customer connect to that same line, the original customer would receive a rebate. A few participants indicated that these costs are prohibitive to expansion. One customer expressed concern that their company is not able to increase load quickly enough to take advantage of the incentive. Furthermore, there is poor communication between customers, municipalities, and utilities — with one customer expanding their business within a municipality, only to discover there isn't power capacity to support its needs.

"We don't use it all at once, our growth is gradually coming up, are we going to hit that max that we have to hit by 2016, are they going to take [the incentive] away from us?"

"[The expense] is not communicated properly to the municipalities, because I meet with the municipality and say, I want to build the plant, do I have everything I need including utilities. Answer? No problem. My building's built, [then you] discover you're not going to get the power you need unless you bring it to you [by paying for it]…I find that really strange."

PROVIDING ADDITIONAL CAPACITY

Several participants stated their urgent need for additional power capacity in their region/industry and this was generally cited as being a highly unsatisfactory area. Participants expressed frustration that expansion in their regions has been extremely slow, with one participant stating that their region has been waiting for 20 years for additional power. One participant mentioned that his organization's application for additional power capacity has not been reviewed by Hydro One after five years. Participants also expressed frustration at the OEB's policy of only meeting current needs, versus planning for capacity expansion.

"Areas designated for industrial development have insufficient utility support and this will stop or slow growth. More needs to be spent on providing necessary services at competitive costs."

"…I think you're limited by the OEB that is ineffective in my opinion. For everything you gotta go back and ask for their permission and they only give you they have a view of 24 hours in terms of forecast, allow this, tomorrow another request and then we'll allow something else for the day after, that process takes nine months, you can imagine the automatic lag as a result of the process…"

A few participants expressed a desire to be more involved in the regulatory and rate filling process. They had concerns about the timeliness of the process to address their power needs, and wanted to actively engage in order to have their voices and concerns directly heard by the OEB, and not just through the customer engagement process.

"…do we have to direct our attention someplace else instead of Hydro One?...Can we help you, we're talking about billions of dollars every year, hundreds if not thousands of jobs going away if not being reduced because of this [lack of power capacity]. How can we help [Hydro One]."

RENEWABLE ENERGY

Participants were polarized as to their opinions on the role of renewable energy in the future of the grid: who would benefit from additional renewable sources, to what degree Hydro One should socialize costs, and to what degree Hydro One should set up/support infrastructure for both large-scale and individual renewable generators.

Some participants expressed skepticism as to the benefits of renewable energy, particularly in the context of power being sold to the U.S. at a loss. The success of renewable sources in adding value to the grid was also debated, with participants asking questions and expressing skepticism as to their benefit. They are reluctant to adopt renewable green energy sources if it means higher rates/prices or less reliable power. In their view, green energy should be used in areas where lines are expensive or difficult to run, and renewable energy generators should not receive an incentive at the expense of ratepayers.

"Why are we investing in infrastructure to connect green energy when we are currently dumping excess power."

"…I'm all for green power as far as the environment, but when it comes to cost it's hugely expensive…I don't agree the price we're paying for solar and wind…put them where it makes sense, where there's issues with the lines, rather than randomly dropping them where people don't need or want them."

The perceived advantages and drawbacks of microgrids, and of having consumers and small generators send power back to the grid, were also discussed. A few participants expressed their dissatisfaction with line loss charges for generators adding power back to the grid.

"Line loss as it relates to people who are supplying their own power…Hydro One will give a credit back to the individuals for producing their own power, but then they charge a line loss charge on that credit…you're being penalized by Hydro One for your own power."

EXPORTING POWER

The sale of electricity at a loss to the U.S. also emerged as a topic of discussion during some of the Large Customer Workshops. Hydro One explained some of the technical and economic considerations involved, including the role of contracts with renewable generators. It was further clarified that this is an area outside of Hydro One's control. Participants expressed concern and dismay that this is happening when rate increases are being considered. In one Workshop, participants from the greenhouse industry indicated their strong interest in using this excess energy to meet their needs, as they require lighting for their greenhouses overnight.

"We are going to take electricity. When you're paying to get rid of it, we're going to take it. We use a crazy amount of electricity right now [summer months], but the real load is from November till March and mostly at night. We're your best customer, we're your best friend and you've ignored us."

ROLE OF THE UTILITY IN SOCIALIZING COSTS OF OTHER POWER NEEDS

There was a debate among participants about whether or not it is within Hydro One's mandate to provide specialized power quality service to a small group of customers, or if their role is as a basic socialized service to all its customers. Some participants stated that ratepayers should not be paying for energy storage and renewables that benefit only a few.

"With a small percentage of customers that might have a specialized need, their tolerances are much higher or stringent than what they would be for the average customer. Really the bill should be on them. It shouldn't be socialized. Why should I pay for someone else's special need?"

Specific aspects of what costs should be socialized through a rate increase to all ratepayers, versus having only those who benefit pay for these improvements, were debated throughout the in-person sessions. Some indicated their belief that improvements benefit the overall economy of Ontario, with others stating that only those who benefit directly should be responsible for paying.

THEME #5: CREDIBILITY

SUMMARY

Hydro One's reputation including areas such as perceptions of workers, concerns with salaries and wages, and overall efficacy as an organization were discussed during the Workshops. As well, clarifying the role of regulators and the effect of a low understanding or misinformation as to what is regulated versus what are decisions by Hydro One were also explored during the Workshops.

ROLE OF REGULATORS

Many participants were unaware of the OEB and the IESO, and their respective roles in the energy sector. For C&I participants in particular, there was a lower understanding of the various players in the energy sector.

Numerous points of clarification were made throughout the customer engagements as to what is mandated and controlled by the respective regulators, including:

OEB:

- Information contained on electricity bills
- Commodity price of electricity as a pass-through charge only, and Hydro One's inability to profit from it
- Capacity expansion
- Beneficiary payment system for capital work
- Non-advisory customer service role – that is, that Customer Service representatives are disallowed from providing advice on the phone as to whether or not an external program is in the customer's best interest.

IESO:

- Global Adjustment
- Environmental incentive programs
- Contracts for generators, including renewable sources

As Hydro One is the customer-facing entity responsible for billing, customers' perceptions are negatively impacted by all aspects of the electricity bill and any poor perceptions of the sector in general.

"General public…paints you all [in the sector] with the same brush."

PERCEPTIONS OF HYDRO ONE AND ITS WORKERS

There was commentary made by some participants on perceptions of Hydro One and its workers. There were mentions of seeing Hydro One workers in coffee shops during working hours, or having too many workers show up to a job. These perceptions of poor productivity and management are particularly difficult to accept with the perception that electricity costs in Ontario are very high and a threat to the economic well-being of the province's businesses.

"People notice these things because it's hurting on the bill. If people felt like they were paying something that was fair, they wouldn't notice it, [but] because people feel like they're being bled dry those things are going to stand out."

They also challenged the idea of efficiency based on their own observations and experiences of working with Hydro One — in terms of customer service, or having negative perceptions of workers and management based on their own interactions.

"Those kinds of things don't make us feel happy like customers [such as] very elaborate vehicles, in the olden days [they] used a ladder, now there's four bucket trucks. That's what I see as we drive through… [I] know it's for safety don't get me wrong, [it's] just a matter of the perception."

COMPANY CULTURE

Some participants expressed their concern that Hydro One was presenting a scenario with a rate increase which depicted declining performance. A few stated their belief that this was an unacceptable approach that spoke negatively to Hydro One's culture. Others stated their belief that the information being presented was to justify a distribution rate increase by Hydro One.

Comparisons were made unfavourably to private companies in several ways: private companies deliver a better product for less money by finding efficiencies, and by being innovative without raising prices. Many participants pointed out that electricity rates have continued to climb for many years and their belief is that there is no end in sight as it relates to rate increases, thanks to poor management and decision-making by Hydro One.

"[Hydro One] is a little bit different than other companies, in that there's little incentive to get better. In the end if you can cover your costs by increasing the rate."

"…seems like Hydro One always has the luxury of asking for more. The reality is all the companies, we can't just add 10% to the end product, you guys it's always give a bit more, get a bit more, get a bit more, a bit more becomes a lot at the end of the line…The rate is out of control, doesn't seem like it's going to be better in the near future."

SHAREHOLDERS VS. RATEPAYERS

Participants inquired about Hydro One's profits, and it was clarified that Hydro One has a regulated rate of return on equity and that they generally come close to making this return. Based on this information, a few participants expressed deep concern and dismay that profits were given to shareholders, and not returned to the company in order make capital improvements, and/or reduce costs for ratepayers. They stated that this is a situation unique to Hydro One, and that other companies would not have the same option available to them — instead, they would put profits back into the company in order to maintain or reduce prices for their end-users, or profits are put back into making a better product. One participant called the approach of giving profits to shareholders while raising rates for ratepayers unethical.

"…you want to take another 2.5% to maintain your profit to shareholders. It's unethical."

"…should Hydro [One] take some of their money and maintain business? Yeah they should, every other company that's publicly or privately owned has to do that to maintain business."

ACCOUNTABILITY AND TRANSPARENCY

The themes of accountability and transparency for Hydro One emerged throughout the in-person sessions. Participants indicated concern at a lack of both, and a desire to see Hydro One undergo an organizational transformation. This would positively impact customers by being more informed, providing reassurance of reliability and service, and responsible stewardship of rates paid in the form of operational and maintenance efficiencies and prudent decision-making in future capital investment planning. While many customers cited deep concerns around rate increases, many were also open and receptive to understanding how and why Hydro One uses its funds.

"…when you have a monopoly sometimes wages can get out of line, and money can get spent without true accountability. It all starts with how transparent you want to be."

THEME #6: COMMUNICATION

SUMMARY

For many, a communication disconnect with Hydro One exacerbates grievous situations during an outage. There is much uncertainty around when power will be restored. The information provided is often inaccurate. There is low awareness of any available tools or resources, such as Hydro One's outage app.

COMMUNICATION DURING OUTAGES

Numerous participants throughout all customer engagement methods stated they would like to experience better communication during outages. The majority call in to the number on their bills or the OGCC, with a few checking Hydro One's website. Most stated that the information they receive or view is inaccurate, and this is a source of frustration in particular for businesses — many of whom stated that communication is an area in which Hydro One could help reduce the impact of outages. Participants indicated that they would like timely, accurate information on outages specific to their region or area.

"Better communication re: anticipated timing to restore power would help us with operational plans."

"Automated notification system to LDA accounts to quickly update, email or text type messages."

"Regional northwestern Ontario specific storm centre reporting with local knowledge."

ROLE OF UTILITY IN COST-SAVING STRATEGIES AND PROGRAMS

A few customers made organic mentions of positive experiences with energy/cost saving programs with Hydro One. One participant stated that he was unable to get recommendations or advice from Hydro One on external programs, which he found frustrating.

"…I'm taking advantage of a 50% audit program at our facilities…customers might benefit from knowing the programs out there."

"…called into the number on my bill, very helpful, introduced me to the portal, none of us had seen it until yesterday. It's brilliant. I got fantastic comparative by site, given me a very good understanding of the savings that we're generating. I would say, maybe little bit more awareness, a little section on the bill to tell me about this, a lot of people would really appreciate that. I thought it was fantastic."

"…why Hydro One can't give a clear answer and advice to people who are considering these options that come by e-mail telephone, clients say I didn't know anything about energy, this company sounds great but is it, if you phone Hydro One and ask you don't get an answer, you get a lot of talking around it."

For Large Customers eligible for cost-saving programs and incentives, awareness was generally low. For those who applied for these programs, the application process is frustrating and complicated, with one organization going so far as to hire an outside company to help them with the application process.

"…I was having coffee, talking to one guy [about] ERIP program, not knowing anything about it…they changed us to LED Lights, there was nobody ever knocked on [our] door here's what we can offer you. I was having coffee in the morning at a local restaurant when I found out about it."

"…when we did an energy audit a few years ago, my application this thick and had to re-submit three times, because it was missing a little piece of information."

CHANNELS

The means through which Hydro One can effectively communicate with its customers was discussed throughout the customer engagement process. Relevant information includes planned outages, rate increases, and service restoration.

Participants expressed interest in a number of different channels and some indicated that they would like to hear from/about Hydro One via multiple channels, including:

- Directly on the bill
- Bill inserts
- Texts
- For C&I customers a dedicated relationship with an account person, a local contact, or a dedicated business (non-residential) call centre line were all of interest.

GENERAL INFORMATION ON HYDRO ONE

While participants acknowledged that the information provided during the Workshops was helpful, in general, participants observed that there was insufficient detail provided. Many participants stated that in order to make decisions around which areas of investment would be of most benefit, as well as whether or not they would support an increase in rates, they would require more comprehensive information including specific costs, historical data, and cost efficiencies. This in turn would lead to trust that Hydro One is focused on efficiency and productivity.

More information on the company, its operations, and its future plans were viewed as being key to positively impacting perceptions of Hydro One — with the customer engagement process being a good start.

CONCLUSIONS

Ipsos has grouped the collective feedback from customers on their needs and preferences into six key themes based on its review and analysis of customer research and the views expressed by customers during the customer engagement process.

1. COST

Cost is the top priority for R&SB customers and among the top priorities for Large Customers. In the context of potentially degrading reliability, a majority of R&SB customer will accept the proposed rate increase to maintain the current levels of service. Although most don't like rate increases, they accept that they are necessary to avoid declining service. Large Customers are more focused on reliability and in some cases less sensitive to cost, but are unwilling to accept the illustrative rate impacts without greater understanding and assurances that Hydro One will improve its operational efficiencies.

2. QUALITY

Reliability and quality electricity service emerged as the second most important priority. For Large Customers improving power quality is as important as reducing the number and duration of sustained outages. Their preference is for Hydro One to invest in improving power quality ahead of several other service improvements. For R&SB customers, in the context of rate impacts, their preference is for Hydro One to maintain the current number and duration of outages rather than improve it.

3. CUSTOMER SERVICE

Customer satisfaction varies substantially across distribution customer segments. Of them, C&I customers appear to be the most under-served and express this in many ways. The feedback suggests that Hydro One should consider establishing a similar key account system as it does for LDA customers so that C&I customers can have their inquiries resolved more promptly and with greater ease.

4. CONNECTIONS AND CAPACITY

Several Large Customers expressed a desire for greater capacity and would like Hydro One to more strongly advocate and support their requests. There was some debate around whether or not the costs of capacity-building should be borne exclusively by the customers or whether in some circumstances the cost should be socialized across Hydro One's ratepayers.

5. CREDIBILITY

It is evident that many customers have negative perceptions of Hydro One that are not necessarily based on their service experience. In part these perceptions are influenced by the fact that customers have a low awareness of Hydro One's role in the energy sector and ultimately their bill. For some negative views of the industry and/or government bleed-into their views of Hydro One. For others their perceptions are influenced by what they believe to be an excessively large and inefficient organization. Large Customers expressed a desire for greater transparency of the organization's operations and administration including OM&A investments.

6. COMMUNICATION

Large Customers indicated they would like to see Hydro One improve their communication with customers during outages. They would like to Hydro One to provide more accurate estimates of when power will be restored.

APPENDIX FOR HYDRO ONE DISTRIBUTION REPORT

GENERAL PUBLIC SURVEY COMMUNICATIONS

We'd like your feedback.

We're planning tomorrow's electricity system and we'd like to hear what matters most to our customers.

Hydro One's first job is to deliver electricity safely and reliably to our customers. We're in the process of developing a five-year plan for our electricity distribution system.

We'd like your feedback regarding the level and type of service that you expect from Hydro One. What you tell us will be considered as we develop our plan. It will also be included in the process the Ontario Energy Board uses to set electricity delivery rates for Hydro One's customers.

Fill out our confidential Customer Survey by July 18, 2016 at:
www.ipsosresearch.com/hydroone

We want to hear from everyone. To take the survey by phone, please contact our Survey Team at **1-866-477-6751**.

MCC 901722

hydro one

Nous aimerions recevoir vos commentaires.

Nous sommes en train de planifier le système d'électricité de demain, et nous voudrions avoir votre opinion sur les sujets qui sont les plus importants pour vous, nos clients.

La première responsabilité de Hydro One est d'assurer une livraison d'électricité sûre et fiable à notre clientèle. Nous préparons actuellement un plan quinquennal (5 ans) pour le système de distribution d'électricité.

Nous sollicitons vos commentaires concernant le niveau et le genre de service que vous attendez de Hydro One. Vos réponses seront prises en compte dans la préparation de notre plan. La Commission de l'énergie de l'Ontario les inclura aussi dans son processus de fixation des tarifs de livraison pour les clients de Hydro One.

Remplissez notre Sondage clientèle avant le 18 juillet 2016 à :
www.ipsosresearch.com/hydroone

Nous souhaitons entendre l'opinion de tous. Pour répondre au sondage par téléphone, veuillez contacter notre équipe Sondage au **1 866 477-6751**.

hydro one

DISTRIBUTION CUSTOMERS EBLAST EMAIL COPY
ENGLISH

Have your say in the plan for tomorrow's electricity system.

hydro one

Hydro One's first job is to deliver electricity safely and reliably to our customers. We're in the process of developing a five-year plan for our electricity distribution system.

We'd like your feedback regarding the level and type of service that you expect from Hydro One. What you tell us will be considered as we develop our plan. It will also be included in the process the Ontario Energy Board uses to set electricity delivery rates for Hydro One's customers.

Fill out our confidential Customer Survey by July 18, 2016 at: www.ipsosresearch.com/hydroone

We want to hear from everyone. To take the survey by phone, please contact our Survey Team at **1-866-477-6751**.

DISTRIBUTION CUSTOMERS EBLAST EMAIL COPY
FRENCH

À vous la parole! Planifiez avec nous le système électrique de demain.

hydro one

La première responsabilité de Hydro One est d'assurer une livraison d'électricité sûre et fiable à notre clientèle. Nous préparons actuellement un plan quinquennal (5 ans) pour le système de distribution d'électricité.

Nous sollicitons vos commentaires concernant le niveau et le genre de service que vous attendez de Hydro One. Vos réponses seront prises en compte dans la préparation de notre plan. La Commission de l'énergie de l'Ontario les inclura aussi dans son processus de fixation des tarifs de livraison pour les clients de Hydro One.

Remplissez notre Sondage clientèle avant le 18 juillet 2016 à : www.ipsosresearch.com/hydroone

Nous souhaitons entendre l'opinion de tous. Pour répondre au sondage par téléphone, veuillez contacter notre équipe Sondage au **1 866 477-6751**.

MPP OFFICE CONSTITUENT POSTERS
EMAIL

Dear MPPs and Constituency Staff,

Hydro One is currently in the process of developing a five-year plan for Ontario's electricity distribution system. As part of this process, we are conducting a customer survey, which will inform Hydro One's plans to meet the future needs of our 1.3 million customers in Ontario and help ensure their voices are heard.

Hydro One would like your feedback and your constituents' feedback regarding the level and type of service that you expect from Hydro One. This feedback will be included in the process that the Ontario Energy Board uses to set electricity delivery rates for our customers.

In the next few days you will be receiving a small poster to each of your constituency offices, which will invite members of your community to participate in a confidential customer survey.

We would appreciate it if, given the room, you could post this notice on your office wall for the next few weeks, as we are hoping to hear from as many customers as possible.

Thank you in advance. Please let us know if you have any questions or concerns.

Warm regards,

Simmer Anand
External Relations Advisor
Hydro One Networks Inc.
483 Bay St, Toronto, ON
(O) 416-345-6818
Simmer.Anand@hydroOne.com

Have your say in the plan for tomorrow's electricity system.

We're in the process of developing a five-year plan for our electricity distribution system, and we'd like to hear what matters most to our customers.

We'd like your feedback regarding the level and type of service that you expect from Hydro One.

Fill out our confidential Customer Survey by July 18, 2016 at: www.ipsosresearch.com/hydroone

We want to hear from everyone. To take the survey by phone, please contact our Survey Team at:

1.866.477.6751

hydro one

MPP OFFICE CONSTITUENT POSTERS
FRENCH

À vous la parole! Planifiez avec nous le système électrique de demain.

Nous préparons aujourd'hui un plan de 5 ans pour notre réseau de distribution électrique, et nous voudrions savoir ce qui est le plus important pour vous.

Nous sollicitons vos commentaires sur le niveau et le genre de service que vous attendez de Hydro One.

Remplissez notre Sondage clientèle confidentiel avant le 18 juillet 2016 à : www.ipsosresearch.com/hydroone

Nous souhaitons entendre l'opinion de tout le monde. Pour répondre au sondage par téléphone, contactez notre équipe Sondage au :

1 866 477-6751

hydro one

NEWSPAPER AD SURVEY CAMPAIGN
ENGLISH

We'd like your feedback.

We're planning tomorrow's electricity system and we'd like to hear what matters most to our customers.

Hydro One's first job is to deliver electricity safely and reliably to our customers. We're in the process of developing a five-year plan for our electricity distribution system.

We'd like your feedback regarding the level and type of service that you expect from Hydro One. What you tell us will be considered as we develop our plan. It will also be included in the process the Ontario Energy Board uses to set electricity delivery rates for Hydro One's customers.

Fill out our confidential Customer Survey by July 31, 2016 at: www.ipsosresearch.com/hydroone

We want to hear from everyone.
To take the survey by phone,
please contact our Survey Team at
1-866-477-6751.

hydro one

NEWSPAPER AD SURVEY CAMPAIGN
FRENCH

Nous aimerions recevoir vos commentaires.

Nous sommes en train de planifier le système d’électricité de demain, et nous voudrions avoir votre opinion sur les sujets qui sont les plus importants pour vous, nos clients.

La première responsabilité de Hydro One est d’assurer une livraison d’électricité sûre et fiable à notre clientèle. Nous préparons actuellement un plan quinquennal (5 ans) pour le système de distribution d’électricité.

Nous sollicitons vos commentaires concernant le niveau et le genre de service que vous attendez de Hydro One. Vos réponses seront prises en compte dans la préparation de notre plan. La Commission de l’énergie de l’Ontario les inclura aussi dans son processus de fixation des tarifs de livraison pour les clients de Hydro One.

Remplissez notre Sondage clientèle avant le 18 juillet 2016 à :

www.ipsosresearch.com/hydroone

Nous souhaitons entendre l’opinion de tous. Pour répondre au sondage par téléphone, veuillez contacter notre équipe Sondage au **1 866 477-6751**.

hydro one

NEWS RELEASE

Hydro One Asks its Customers for Feedback on Five-Year Distribution System Plan; Customers' Input Will Help Shape Future Investments

TORONTO, June 3, 2016 - Hydro One announced today that it has launched a province-wide consultation process to seek input from its customers on the development of a five-year electricity distribution plan. The plan will help shape the company's future investments in Hydro One's electricity distribution system, so the Company can deliver its mandate to provide safe, reliable and efficient electricity.

The purpose of the consultation process is to understand whether Hydro One customer needs are being met by the current system and which types of reliability and service improvements customers value most.

"All of our distribution customers will have the opportunity to provide their input through workshops, focus groups, surveys, and/or one-on-one discussions," said Rob Quail, Vice President, Customer Service, Hydro One. "We look forward to hearing our customers' views concerning the future service levels they expect from our electricity delivery system."

In addition to meeting customers' needs, the plan will also address:

- aging electricity infrastructure; some of which was built in the 1950s and 1960s;
- responding to power outages and repairing the electricity system, particularly following significant weather events;
- power quality and reliability enhancements; and,
- offering new products, se vices and web-enabled tools to make it easier for customers to do business with Hydro One.

All feedback concerning customer needs and preferences will in turn influence plans that the Company will submit to the Ontario Energy Board. The Ontario Energy Board will examine the plan in a full public hearing and will ultimately determine new rates to be paid by Hydro One's customers between 2018 and 2022.

To learn more about Hydro One's five-year plan and to complete the online survey, please visit **www.ipsosresearch.com/hydroone**.

Quick Facts

- Hydro One's distribution rates are approved by the Ontario Energy Board. The rate setting process is open and transparent, with opportunities for public participation.
- Hydro One must submit evidence to demonstrate the amount of funding it needs to safely and reliably distribute electricity to its customers.

- Distribution costs are contained in the delivery line of the bill. On average, electricity distribution services account for 29 per cent of a Hydro One bill covers the costs of electricity distribution services. This is the amount collected by Hydro One to pay for the costs of poles, lines, transformers and other equipment that makes electricity delivery possible.
- Hydro One is the largest electricity distribution company in Ontario, providing electricity to 25 per cent of the province – more than 1.3 million customers.
- With the largest and most vast service territory, Hydro One is the only utility in Ontario with more distribution poles (1.6 M) than customers, Hydro One is planning tomorrow's electricity distribution system for its 1.3 million customers and would like to hear what matters most to its customers.

About the Company

Hydro One Limited is Ontario's largest electricity transmission and distribution company headquartered in Toronto, Ontario with approximately $24.3 billion in assets and 2015 revenues of over $6.5 billion. The company delivers electricity safely and reliably to over 1.3 million customers across the province of Ontario, and to large industrial customers and municipal utilities. Hydro One owns and operates Ontario's approximately 29,000 km circuit high-voltage transmission network and an approximately 123,000 circuit km primary low-voltage distribution network. Hydro One Limited common shares are listed on the Toronto Stock Exchange (TSX: H).

For further information: contact Hydro One Media Relations 24 hours a day at **1-877-506-7584** (toll-free in Ontario only) or **416-345-6868**. Our website is **www.HydroOne.com**.

PRESS RELEASE 2

NEWS RELEASE

If You Were in Charge of Hydro One Would You Change How Spending is Allocated?

Customer Consultation on Five-Year Distribution System Plan

Toronto – June 21, 2016 – Hydro One is asking its customers to complete an online survey at **www.ipsosresearch.com/hydroone**. The purpose of the survey is to obtain customer input necessary to shape future investments in electricity assets as the Company begins to build a five-year plan for its electricity distribution system. Hydro One is encouraging all customers to have their say in its investment plan by completing the survey by July 18, 2016.

All feedback concerning customer needs and preferences will influence plans the Company will submit to the Ontario Energy Board. The Ontario Energy Board will examine the plan in a full public hearing and will ultimately determine new distribution rates for Hydro One's customers between 2018 and 2022.

"The purpose of the consultation process is to understand whether Hydro One customer needs are being met and which types of reliability and service improvements customers value most," said Warren Lister, VP, Customer Service, Hydro One. "Our customers' point of view is critical to this process and we hope they will take a few minutes to have their say."

In addition to the survey, the Company's distribution customers have had the opportunity to provide their input through workshops, focus groups, and/or one-on-one discussions.

In addition to meeting customers' needs, the plan will address:

- aging electricity infrastructure; some of which was built in the 1950s and 1960s;
- responding to power outages and repairing the electricity system, particularly following significant weather events;
- power quality and reliability enhancements; and,
- offering new products, services and web-enabled tools to make it easier for customers to do business with Hydro One.

Quick Facts

- Hydro One's distribution rates are approved by the Ontario Energy Board. The rate setting process is open and transparent, with opportunities for public participation.
- Hydro One must submit evidence to demonstrate the financial investment needed to distribute safe and reliable electricity to its customers.
- Distribution costs are contained in the delivery line of the bill. On average, electricity distribution services account for 29 per cent of a Hydro One bill. This amount is collected by Hydro One to pay for poles, lines, transformers and other equipment that makes electricity delivery possible.

- Hydro One is the largest electricity distribution company in Ontario, providing electricity to 25 per cent of the province – more than 1.3 million customers.
- With the largest and most vast service territory, Hydro One is the only utility in Ontario with more distribution poles (1.6 M) than customers.

About the Company

Hydro One Limited is Ontario's largest electricity transmission and distribution company headquartered in Toronto, Ontario with approximately $24.3 billion in assets and 2015 revenues of over $6.5 billion. The company delivers electricity safely and reliably to over 1.3 million customers across the province of Ontario, and to large industrial customers and municipal utilities. Hydro One owns and operates Ontario's approximately 29,000 km circuit high-voltage transmission network and an approximately 123,000 circuit km primary low-voltage distribution network. Hydro One Limited common shares are listed on the Toronto Stock Exchange (TSX: H).

-30-

For further information: contact Hydro One Media Relations 24 hours a day at **1-877-506-7584** (toll-free in Ontario only) or **416-345-6868**. Our website is **www.HydroOne.com**.

RADIO AD SCRIPT

Version 1 (85 words)

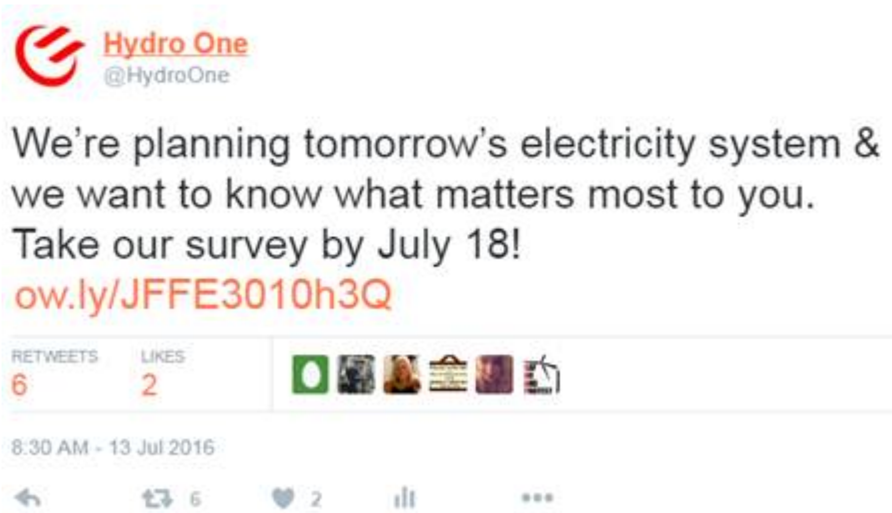
29.5 seconds

Hydro One's first job is to deliver electricity safely and reliably. We're developing a five-year plan for our electricity distribution system and want to know about the level and type of service you expect. What you tell us will be considered as we develop our plan. It will also inform the process the Ontario Energy Board uses to set electricity delivery rates for Hydro One's customers.

Fill out our confidential Customer Survey by July 17, 2016 at www dot Ipsos Research dot com slash HydroOne.

TWITTER ENGAGEMENT

ORGANIC TWEETS – Organic tweets were 'pinned' to our Twitter profile to create maximum visibility



Hydro One
@HydroOne

We'd like to hear what matters most to you. To ensure our distribution system meets your needs, take our survey: ow.ly/JFFE3010h3Q

RETWEETS 4 LIKES 2

9:33 AM - 27 Jun 2016

4 2

Hydro One
@HydroOne

We'd like to hear what matters most to you. To ensure our distribution system meets your needs, take our survey: ow.ly/JFFE3010h3Q

9:20 AM - 23 Jun 2016

2

Hydro One
@HydroOne

We'd like to hear what matters most to you. To ensure our distribution system meets your needs, take our survey: ow.ly/JFFE3010h3Q

LIKES 2

1:11 PM - 9 Jun 2016

2

Hydro One
@HydroOne

We'd like to hear what matters most to you - learn about our Customer Survey and how to share your feedback: ow.ly/NMkX3010kyi

RETWEET 1

9:46 AM - 7 Jun 2016

1

PAID TWEET – We ran a paid Twitter campaign for 10 days in June. The total spend was over $2K. This was promoted to individuals not currently following our Twitter account and may have missed our organic tweets.

We also promoted the survey to customers who interacted with us directly, where appropriate

TARGETED FACEBOOK DISTRIBUTION DIGITAL ADS

Big Box A | Big Box B | Big Box C

TARGETED FACEBOOK DISTRIBUTION DIGITAL ADS

Leaderboard A

Leaderboard B

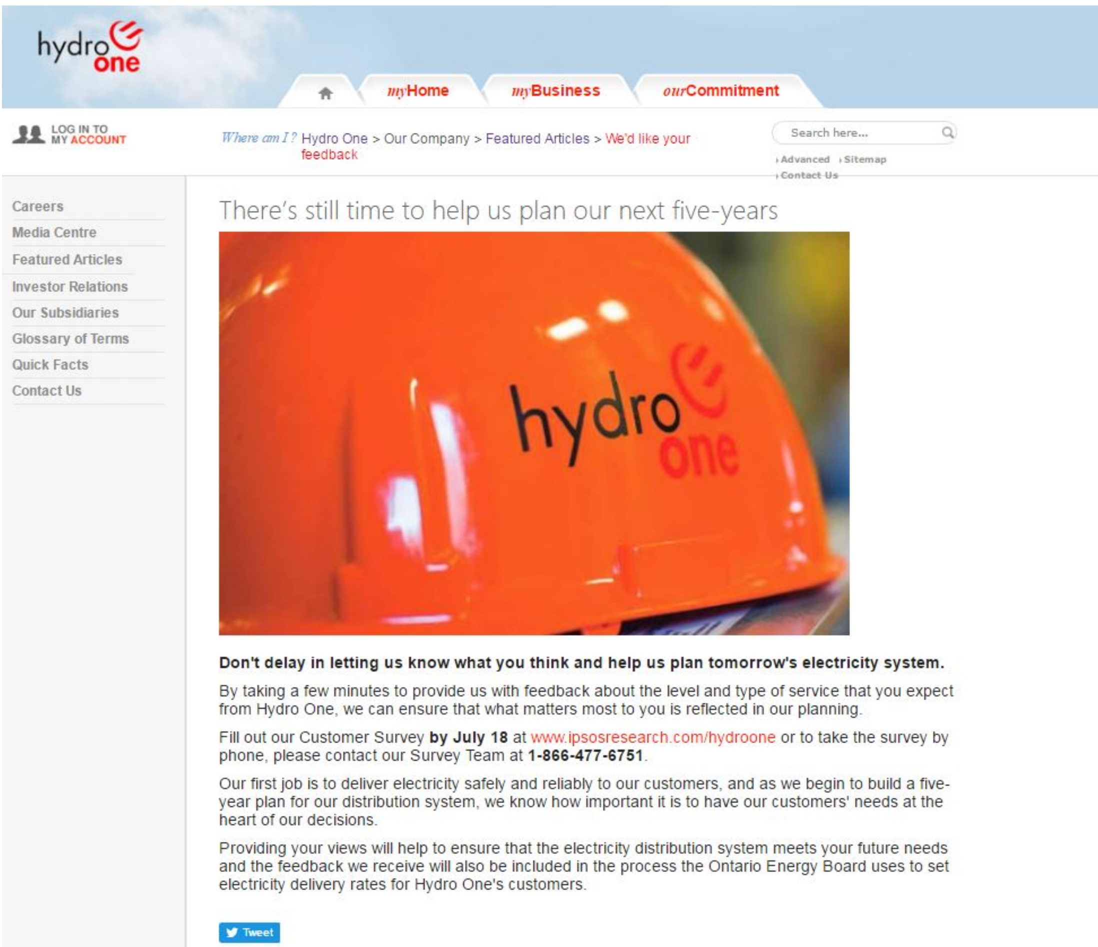
Leaderboard C

WEBSITE HOMEPAGE LINK

Screen shots used for the **www.hydroone.com** carousel that invited customers to participate.

The article page that the Carousel/homepage link would have led to throughout the duration of the campaign.

The image was changed a few times throughout the campaign.


hydro one

*my*Home *my*Business *our*Commitment

LOG IN TO MY ACCOUNT

Where am I? Hydro One > Our Company > Featured Articles > We'd like your feedback

Search here...

Advanced Sitemap Contact Us

Careers
Media Centre
Featured Articles
Investor Relations
Our Subsidiaries
Glossary of Terms
Quick Facts
Contact Us

There's still time to help us plan our next five-years

Don't delay in letting us know what you think and help us plan tomorrow's electricity system.

By taking a few minutes to provide us with feedback about the level and type of service that you expect from Hydro One, we can ensure that what matters most to you is reflected in our planning.

Fill out our Customer Survey **by July 18** at www.ipsosresearch.com/hydroone or to take the survey by phone, please contact our Survey Team at **1-866-477-6751**.

Our first job is to deliver electricity safely and reliably to our customers, and as we begin to build a five-year plan for our distribution system, we know how important it is to have our customers' needs at the heart of our decisions.

Providing your views will help to ensure that the electricity distribution system meets your future needs and the feedback we receive will also be included in the process the Ontario Energy Board uses to set electricity delivery rates for Hydro One's customers.

Tweet

SURVEY MATERIALS

DISTRIBUTION CUSTOMER TELEPHONE SURVEY

DRAFT Dx Customer Engagement Survey for Residential and General Service Customers

ÉBAUCHE Dx Sondage sur l'engagement de la clientèle destiné aux clients résidentiels et des services généraux

Version final (May 26, 2016)
Version finale (26 mai 2016)

Notes in blue are for translator (edits since translation was done)

[Introduction]

Customer Segment	CSEG	
Residential Customers	1	n=400
Seasonal Customers	2	n=100
Business	3	n=200
First Nation	4	n=300

Good morning/afternoon/evening. This is ——- calling from IPSOS, a public opinion research firm. We are conducting a survey of [CSEG=1: Residential customers CSEG=2: seasonal customers CSEG=3: business customers CSEG =4 Residential customers] on behalf of Hydro One. This call may be recorded or monitored for quality assurance purposes. (IF NECESSARY) Would you be so kind as to answer some questions? All of your answers will be kept strictly confidential.

Bonjour/Bonsoir. Je m'appelle __________ et je vous téléphone de la part d'IPSOS, une entreprise de recherche sur l'opinion publique. Nous menons un sondage [CSEG = 1 : clients résidentiels CSEG = 2 : clients saisonniers CSEG = 3 : clients commerciaux CSEG = 4 : clients résidentiels] au nom d'Hydro One. Cet appel peut être enregistré ou surveillé aux fins d'assurance de la qualité. (AU BESOIN) Auriez-vous la gentillesse de répondre à quelques questions? Toutes vos réponses resteront strictement confidentielles.

(IF NECESSARY) The survey will last about 15 to 20 minutes and I think you will find it quite interesting.

(AU BESOIN) Le sondage durera de 15 à 20 minutes et je crois que vous le trouverez assez intéressant.

(IF YES) Thank you.

(SI LA RÉPONSE EST OUI) Merci.

(IF NO) When is a better time for me to call back? (SCHEDULE APPOINTMENT)

(SI LA RÉPONSE EST NON) À quel moment serait-il préférable que je rappelle? (FIXER UN RENDEZ-VOUS)

A. Are you one of the individuals who is responsible for paying the electricity bills and handling questions or concerns for your [IF CSEG =3 business's] [IF CSEG = 1 OR 4 household's] [IF CSEG= 2 seasonal home's] electricity service?

Êtes-vous l'une des personnes responsables de payer les factures d'électricité et de traiter les questions ou les préoccupations en lien avec le service d'électricité de votre [S'IL S'AGIT DE CSEG = 3 entreprise] [S'IL S'AGIT DE CSEG = 1 OU 4 foyer] S'IL S'AGIT DE CSEG = 2 résidence secondaire]?

Yes
Oui
No
Non

[IF YES, CONTINUE, IF NO ASK TO SPEAK WITH PERSON WHO IS RESPONSIBLE, REINTRODUCE YOURSELF OR SCHEDULE CALL-BACK AS REQUIRED
[Si oui, continuez. Si non, demandez de parler avec la personne responsable. Présentez-vous encore, ou fixez une rendez-vous, au besoin]

B. Are you or is any member of your **[IF CSEG = 1 OR 2 OR 4, INSERT 'household'. IF CSEG = 3, INSERT 'business']** currently employed by any of the following types of organizations …? **(READ LIST, SELECT ONE PER ITEM) (ACCEPT MULTIPLE RESPONSES)**

Est-ce que vous ou un membre de votre **[SI CSEG = 1 OU 2 OU 4, INSÉRER 'foyer'. SI CSEG = 3, insérer 'entreprise']** travaille dans l'un ou l'autre des types d'organisation suivants…? **(LIRE LA LISTE ET SÉLECTIONNER UNE RÉPONSE PAR ÉLÉMENT. VOUS POUVEZ ACCEPTER PLUS D'UNE RÉPONSE.)**

A public relations or market research company
Une entreprise de relations publiques ou d'étude de marché
TV, radio, magazine or newspaper publishing
Une chaîne de télévision, une station de radio ou un éditeur de magazines ou de journaux
A company that provides electricity
Un fournisseur d'électricité
An energy regulator
Un organisme de réglementation de l'énergie
An elected official or on the staff of an elected official
Un représentant élu ou un membre du personnel d'un représentant élu

Yes
Oui
No
Non

[IF B = "YES" TO ANY OCCUPATION OR DK/REF, RECORD AND TERMINATE. OTHERWISE CONTINUE]
[Si B = « OUI » POUR N'IMPORTE QUELLE ORGANISATION, OU « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », RECORD ET CONCLURE. AUTREMENT, CONTINUER.]

C. **(DO NOT READ)** Record gender **(RECORD ONE ONLY)**

(NE PAS LIRE) Inscrire le sexe **(INSCRIRE UNE SEULE RÉPONSE)**

Male
Masculin
Female
Féminin

[IF CSEG = 1, 2, 4 CONTINUE; CSEG =3 - SKIP TO INSTRUCTIONS BEFORE I]
[SI CSEG = 1, 2, 4 CONTINUER; CSEG =3 - PASSEZ AUX INSTRUCTIONS AVANT I]

D. Which of the following categories includes your age? **(READ LIST, RECORD ONE ONLY)**

Dans laquelle des tranches d'âge suivantes vous situez-vous? **(LIRE LA LISTE. INSCRIRE UNE SEULE RÉPONSE.)**

Under 18
Moins de 18 ans
18-24
18 à 24 ans
25-39
25 à 39 ans
40-49
40 à 49 ans
50-59
50 à 59 ans
60-69
60 à 69 ans
70 or older
70 ans et plus

[IF D= UNDER 18 OR DK/REF, TERMINATE; IF CSEG =2 SKIP TO INSTRUCTION BEFORE H]; OTHERWISE CONTINUE]
[SI D= MOINS DE 18 ANS OU « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », CONCLURE; SI CSEG =2 PASSEZ À L'INSTRUCTION AVANT H]; AUTREMENT, CONTINUER.]

E. Thinking about your primary residence, do you own that home or do you rent? **(RECORD ONE ONLY)**
Êtes-vous propriétaire ou locataire de votre résidence principale? **(INSCRIRE UNE SEULE RÉPONSE)**

Own
Propriétaire
Rent
Locataire

[IF E =DK/REF, TERMINATE; IF E=OWN, CONTINUE, OTHERWISE SKIP TO INSTRUCTION BEFORE G.]
[SI E = « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », CONCLURE; SI E=PROPRIÉTAIRE, CONTINUER, AUTREMENT PASSER À L'INSTRUCTION AVANT G.]

F. Do you pay your electricity bill… **(READ LIST, RECORD ONE ONLY)**

Payez-vous votre facture d'électricité… **(LIRE LA LISTE. INSCRIRE UNE SEULE RÉPONSE.)**

Directly to the electricity company
Directement à l'entreprise d'électricité
Indirectly, as part of condominium maintenance fees
Indirectement, dans vos frais de copropriété

[IF F. =INDIRECTLY OR DK/REF, TERMINATE; OTHERWISE SKIP TO INSTRUCTIONS BEFORE J]
[SI F. = INDIRECTEMENT OU « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », CONCLURE; AUTREMENT PASSER À L'INSTRUCTION AVANT J.]

[IF E =RENT, ASK G.; OTHERWISE SKIP TO INSTRUCTIONS BEFORE J]
[SI E =LOCATAIRE, DEMANDER G.; AUTREMENT PASSER À L'INSTRUCTION AVANT J.]

G. Do you pay the electricity bill… **(READ LIST, RECORD ONE ONLY)**

Payez-vous votre facture d'électricité… **(LIRE LA LISTE. INSCRIRE UNE SEULE RÉPONSE.)**

As part of your rent
À même votre loyer
Separately, that is, directly to the electricity company
Séparément, c'est-à-dire directement à l'entreprise d'électricité

[IF G =AS PART OF RENT OR DK/REF, TERMINATE; OTHERWISE SKIP TO INSTRUCTIONS BEFORE J.]
[SI G = À MÊME VOTRE LOYER OU « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », CONCLURE; AUTREMENT PASSER À L'INSTRUCTION AVANT J.]

[IF CSEG=2, ASK H; OTHERWISE SKIP INSTRUCTIONS BEFORE J]
[SI CSEG=2, DEMANDER H; AUTREMENT PASSER À L'INSTRUCTION AVANT J.]

H. Do you have a seasonal or vacation home that you own, that you rent, or do you not have a seasonal or vacation home at all? **(RECORD ONE ONLY)**
Possédez-vous ou louez-vous une résidence secondaire de loisir ou de vacances ? **(INSCRIRE UNE SEULE RÉPONSE)**

Own
Propriétaire
Rent
Locataire
No
Non

[IF H= RENT, NO, DK/REF, TERMINATE. OTHERWISE SKIP TO INSTRUCTIONS BEFORE J.]
[SI H= LOCATAIRE, NON, « JE NE SAIS PAS/PRÉFÈRE NE PAS RÉPONDRE », CONCLURE; AUTREMENT PASSER À L'INSTRUCTION AVANT J.]

[IF CSEG=3, ASK I; ALL OTHERS SKIP TO INSTRUCTIONS BEFORE J]
[SI CSEG=3, DEMANDER I; TOUTES LES AUTRES : PASSER AUX INSTRUCTIONS AVANT J]

I. Are you this organization's…? **(READ LIST, RECORD ALL THAT APPLY) (IF DK/REF PROBE WITH:** What is the best description of your role in the business? What would be an equivalent position for your role in another organization?)

Lequel des rôles suivants détenez-vous au sein de cette organisation? **(LIRE LA LISTE. INSCRIRE TOUTES LES RÉPONSES QUI S'APPLIQUENT. SI LA RÉPONSE EST « JE NE SAIS PAS/JE REFUSE DE RÉPONDRE », POSER LA QUESTION SUIVANTE :** Quelle est la meilleure description de votre rôle au sein de l'entreprise? Quel serait le poste équivalent à votre rôle dans une autre organisation?)

Owner or part owner
Propriétaire ou copropriétaire
General manager
Directeur général/directrice générale
Facility or plant manager
Chef d'installation ou d'établissement

Or do you have some other title **(Specify) [OPEN ENDED VERBATIM]**
Ou avez-vous un autre titre **(préciser) [OPEN ENDED VERBATIM]**

[IF I = DK/REF TERMINATE; ALL CONTINUE]
[SI I = « JE NE SAIS PAS/JE REFUSE DE RÉPONDRE », CONCLURE; TOUS CONTINUER]

[ASK TO ALL]
[DEMANDER À TOUS]

J. Which of the following best describes the area in which you **[IF CSEG = 1 OR 4 'live' / IF CSEG = 2 'have your seasonal home' / IF CSEG =3 'have your business']? (READ UNTIL ANSWERED, RECORD ONE ONLY)**

Lequel des énoncés suivants décrit le mieux la région dans laquelle **[SI CSEG = 1 OU 4 'vous vivez' / SI CSEG = 2 'se trouve votre résidence saisonnière' / SI CSEG = 3 'se trouve votre entreprise']? (LIRE LA LISTE JUSQU'À L'OBTENTION D'UNE RÉPONSE. INSCRIRE UNE SEULE RÉPONSE.)**

In a rural or country area or a reserve
Dans une région rurale, à la campagne ou dans une réserve
In a small town of less than 2,000 people
Dans une petite ville de moins de 2 000 habitants
In a town of about 2,000 to less than 5,000 people
Dans une ville qui compte entre 2 000 et 5 000 habitants
In a town of about 5,000 to 20,000 people
Dans une ville qui compte entre 5 000 et 20 000 habitants
In a town of about 20,000 to less than 50,000 people
Dans une ville qui compte entre 20 000 et 50 000 habitants
In a city of 50,000 to less than 100,000 people
Dans une ville qui compte entre 50 000 et 100 000 habitants
In a large city of 100,000 or more people
Dans une grande ville de 100 000 habitants ou plus

K. For your **[IF CSEG = 1 OR 4 'primary residence' / IF CSEG= 2 'seasonal home' / IF CSEG = 3 'business']**, which company do you pay your electricity bills to? **(DO NOT READ. RECORD ONE ONLY)**

Pour votre **[SI CSEG = 1 OU 4 'résidence principale' / SI CSEG = 2 'résidence saisonnière' / SI CSEG = 3 'entreprise']**, à quelle entreprise payez-vous vos factures d'électricité? **(NE PAS LIRE. INSCRIRE UNE SEULE RÉPONSE)**

Hydro One
Hydro One
Ontario Hydro, Ontario Hydro Service Company
Ontario Hydro, Ontario Hydro Service Company
Ontario Hydro Energy
Ontario Hydro Energy
Other
Autre

[IF K = 'HYDRO ONE' SKIP TO INSTRUCTIONS BEFORE Q1, OTHERWISE CONTINUE]

[SI K = 'HYDRO ONE' PASSER AUX INSTRUCTIONS AVANT Q1, AUTREMENT CONTINUER]

L. Are you billed by HYDRO ONE or by another company?

L. Recevez-vous votre facture de HYDRO ONE ou d'un autre fournisseur?

Hydro One
Hydro One
Other
Autre

[IF L = OTHER/DK/REF THANK AND TERMINATE, OTHEWISE CONTINUE]

[SI L = AUTRE/JE NE SAIS PAS/REFUSE DE RÉPONDRE, REMERCIER ET CONCLURE, AUTREMENT CONTINUER]

[IF CSEG =3 READ BELOW, OTHERS CONTINUE TO Q1]

For this interview, please keep your organization’s electricity services in mind, not your residential electricity service

[SI CSEG =3 LIRE LE TEXTE CI-DESSOUS, TOUS LES AUTRES CONTINUER À Q1]

Pour cette entrevue, veuillez garder à l'esprit les services d'électricité de votre organisation, et non votre service résidentiel d'électricité.

[IF CSEG=2 READ BELOW, OTHERS CONTINUE TO Q1]

For this survey please think about your seasonal property even if Hydro One is also your electricity provider on your primary residence.

[SI CSEG=2 LIRE LE TEXTE CI-DESSOUS, TOUS LES AUTRES CONTINUER À Q1]

Pour ce sondage, veuillez penser à votre résidence saisonnière même si Hydro One est également le fournisseur d'électricité de votre résidence principale.

[FLYSHEET, IF RESPONDENT ASKS INTERVIEWER IF THIS IS THE SAME SURVEY THAT HYDRO ONE IS PROMOTING ON RADIO/NEWSPAPER/ON THE BILL ABOUT RATES, INTERVIEWER CAN READ: ‘Yes this is the same survey. We are calling a random sample of customers to phone to supplement the online survey.’]

[FLYSHEET, IF RESPONDENT ASKS INTERVIEWER IF THIS IS THE SAME SURVEY THAT HYDRO ONE IS PROMOTING ON RADIO/NEWSPAPER/ON THE BILL ABOUT RATES, INTERVIEWER CAN READ: ‘Oui, c’est le même sondage. Nous communiquons avec un échantillon aléatoire de clients par téléphone afin de compléter le sondage en ligne.’]

[IF RESPONDENT WANTS TO SPEAK WITH SOMEONE FROM HYDRO ONE – GIVE CYNTHIA TETAKA’S CONTACT INFO - 416.345.5774]

[IF RESPONDENT WANTS TO SPEAK WITH SOMEONE FROM HYDRO ONE – GIVE CYNTHIA TETAKA’S CONTACT INFO - 416.345.5774]

[IF RESPONDENT WANTS TO SPEAK WITH SOMEONE FROM IPSOS – GIVE DIANA MACDONALD'S CONTACT INFO - 416.572.4446]

[IF RESPONDENT WANTS TO SPEAK WITH SOMEONE FROM IPSOS – GIVE DIANA MACDONALD'S CONTACT INFO - 416.572.4446]

MAIN QUESTIONNAIRE

[Only read CSEG=2]

For this survey please think about your seasonal property even if Hydro One is also your electricity provider on your primary residence.

[LIRE CE TEXTE SEULEMENT SI CSEG=2]

Pour ce sondage, veuillez penser à votre résidence secondaire même si Hydro One est également le fournisseur d'électricité de votre résidence principale.

[READ TO ALL]

As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.

Comme vous le savez peut-être, Hydro One construit et entretient des lignes électriques, des pylônes et des poteaux, fournit de l'électricité en toute sécurité, relève les compteurs, calcule vos frais, répond à vos appels, intervient lors d'interruptions de service et élague les arbres et la broussaille autour des lignes électriques. Hydro One ne produit pas d'électricité ni ne fixe le prix de l'électricité.

1. Please think about Hydro One as I have just described it to you. How satisfied are you with HYDRO ONE overall? Would you say you are… ? (READ LIST, RECORD ONE ONLY)

Veuillez penser à Hydro One comme je viens de vous décrire. Dans quelle mesure êtes-vous satisfait(e) d'Hydro One dans son ensemble? Diriez-vous que vous êtes…?

Very satisfied
Très satisfait(e)
Somewhat satisfied
Plutôt satisfait(e)
Neither satisfied nor dissatisfied
Ni satisfait(e) ni insatisfait(e)
Somewhat dissatisfied
Plutôt insatisfait(e)
Or, very dissatisfied
Ou , très insatisfait(e)

2. Is there anything in particular that Hydro One can do to improve its service to you? (ACCEPT ALL MENTIONS)

Y a-t-il quelque chose en particulier qu'Hydro One peut faire pour améliorer le service qu'elle vous offre? (ACCEPTER TOUTES LES RÉPONSES)

3. Please listen carefully as I will be reading out a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments and will be asking your opinion about the breakdown. Hydro One currently spends…

(READ AND RANDOMIZE)

Veuillez écouter attentivement, car je donnerai le pourcentage approximatif des dépenses que Hydro One fait dans divers aspects de la distribution d'électricité. Je vous demanderai ensuite ce que vous pensez de cette répartition. Des sommes qu'elle investit, Hydro One en consacre...

(LIRE ET CHANGER L'ORDRE DES ÉNONCÉS D'UN RÉPONDANT À L'AUTRE)

60% on Keeping the system reliable (such as replacing worn out equipment, trimming trees to keep power lines clear)

60 % à l'entretien du réseau pour garantir la fiabilité de ce dernier, notamment en remplaçant l'équipement usé et en taillant des arbres pour dégager les lignes électriques)

15% on Restoring power after an outage

15 % au rétablissement du service après une panne

15% on Customer service and billing (such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)

15 % au service à la clientèle et à la facturation (par exemple, offrir un service à la clientèle par téléphone ou en ligne, fournir des outils vous permettant de mieux gérer votre consommation d'énergie, établir des factures exactes et en temps opportun)

10% on Upgrading the system to connect new customers including those producing renewable energy or using energy storage

10 % à la modernisation du réseau afin de raccorder de nouveaux clients, notamment ceux qui produisent de l'énergie renouvelable ou ceux qui stockent de l'énergie

If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it is now?

Si vous étiez en charge d'Hydro One, modifierez-vous la répartition des dépenses ou la garderiez-vous telle qu'elle est maintenant?

Change
La modifierait
Keep the same
La garderait telle quelle
Don't know
Ne sait pas

[IF CHANGE ASK Q4, OTHERWISE SKIP TO Q5]

[SI « MODIFIERAIT » DEMANDER Q4, AUTREMENT PASSER À Q5]

4. Of the 4 distribution investments you just heard, what percentage would you allocate to…?

Veuillez indiquer quel pourcentage des dépenses vous alloueriez à chacun des quatre aspects de la distribution d'électricité suivants.

(READ IN THE SAME ORDER USED IN Q3)

(LIRE DANS LE MÊME ORDRE QU'À LA Q3)

Keeping the system reliable (such as replacing worn out equipment, trimming trees to keep power lines clear)

Garantir la fiabilité du réseau, notamment en remplaçant l'équipement usé et en taillant des arbres pour dégager les lignes électriques)

Restoring power after an outage

Rétablir le service après une panne

Customer service and billing (such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)

Assurer le service à la clientèle et la facturation (par exemple, offrir un service à la clientèle par téléphone ou en ligne, fournir des outils vous permettant de mieux gérer votre consommation d'énergie, établir des factures exactes et en temps opportun)

Upgrading the system to connect new customers including those producing renewable energy or using energy storage

Moderniser le réseau afin de raccorder de nouveaux clients (par exemple, utiliser des sources d'énergie renouvelable et stocker de l'énergie)

[TOTAL MUST ADD TO 100% UNLESS DON'T KNOW OR REFUSED ANSWERED]

[LA SOMME DOIT ÊTRE ÉGAL À 100% SAUF S'IL/ELLE RÉPONDAIT « JE NE SAIS PAS/REFUSE DE RÉPONDRE ».]

5. Hydro One would like to better understand what is important to you as a [IF CSEG = 1, 2, OR 4: residential or seasonal customer / IF CSEG =3: business customer]. I am going to read Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you.

Hydro One aimerait mieux comprendre ce qui est important pour vous ENT TANT QUE [SI CSEG = 1, 2, OU 4: CLIENT RÉSIDENTIEL OU CLIENT SAISONNIER/ SI CSEG =3: CLIENT COMMERCIAL]. Je vais vous lire les dépenses majeures d'Hydro One par paire. Pour chacune, veuillez m'indiquer laquelle des deux dépenses est la plus importante pour vous.

Reducing the number of power outages through activities such as tree-trimming, replacing equipment

Réduire le nombre de pannes de courant grâce à des mesures comme tailler les arbres et remplacer l'équipement

Shortening the length of power outages though activities such as installing remote control devices

Réduire la durée des pannes de courant grâce à des mesures comme installer des appareils contrôlés à distance

Improving Customer service and billing (such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)

Améliorer le service à la clientèle et la facturation (par exemple, offrir un service à la clientèle par téléphone ou en ligne, fournir des outils vous permettant de mieux gérer votre consommation d'énergie, établir des factures exactes et en temps opportun)

Upgrading the system to connect new customers including those producing renewable energy or using energy storage such as wind, solar, and electric vehicles

Moderniser le réseau afin de raccorder de nouveaux clients, notamment ceux qui produisent de l'énergie renouvelable ou ceux qui stockent de l'énergie (par example, l'énergie éolienne, l'énergie solaire, et les véhicules électriques)

Keeping costs as low as possible

Garder les coûts aussi bas que possible

6. Is there anything else that is important to you that was not read out? (PROBE UP TO 2 TIMES)

Y a-t-il autre chose qui est important pour vous que je ne vous ai pas lu à voix haute? (RELANCER AU PLUS DEUX FOIS)

The next few questions are about your experience with power outages. Please think about your experience in terms of how frequently they occur and how long they last.

Les quelques questions suivantes portent sur les pannes de courant que vous avez subies. Veuillez réfléchir à la fréquence et à la durée des pannes.

7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did [IF CSEG = 1, 2, OR 4: you / IF CSEG =3: your business] experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine.

Une panne de courant soutenue est une panne qui dure au moins une minute. Combien de pannes soutenues [SI CSEG = 1, 2, OU 4 : avez-vous / SI CSEG = 3 : votre entreprise a-t-elle] subies au cours des 12 derniers mois et à propos desquelles vous n'aviez pas été informé(e) à l'avance par Hydro One? Veuillez fournir la meilleure estimation.

[RECORD NUMERIC] [RANGE ZERO TO 99]

[RECORD NUMÉRO] [ZÉRO À 99 PERMIT]

[IF ZERO, DK/REFUSED SKIP TO INSTRUCTION BEFORE Q11]

[SI ZÉRO, JE NE SAIS PAS/REFUSE DE RÉPONDRE, PASSER À L'INSTURCTION AVANT Q11]

8. In general, when you think about how many power outages [IF CSEG = 1, 2, OR 4: you / IF CSEG =3: your business] experienced over the last 12 months, how did it compare to your expectations?

Lorsque vous pensez au nombre de pannes de courant subi par [SI CSEG = 1, 2 OU 4 : vous / SI CSEG = 3 : votre entreprise] au cours des 12 derniers mois, dans quelle mesure ce nombre se compare-t-il à vos attentes?

Much better
Il est bien meilleur que ce à quoi vous vous attendiez
Somewhat better
Il est un peu meilleur que ce à quoi vous vous attendiez
About what you expect
Il correspond à ce à quoi vous vous attendiez
Somewhat worse
Il est un peu moins bon que ce à quoi vous vous attendiez
Much worse
Il est bien pire que ce à quoi vous vous attendiez
Don't know
Ne sait pas

9. On average, how long did these unplanned outages last? Please answers in minutes. Your best guess is fine.

En moyenne, combien de temps ces pannes non prévues ont-elles durées ? Veuillez exprimer votre réponse en minutes. Veuillez fournir la meilleure estimation.

[RECORD NUMERIC] [RANGE 0 TO 999]

[RECORD NUMÉRO] [0 À 999 PERMIT]

10. In general, when you think about the average length of the power outages [IF CSEG = 1, 2, OR 4: you / IF CSEG =3: your business] experienced over the last 12 months, how did it compare to your expectations?

En général, lorsque vous pensez à la durée moyenne des pannes de courant subies par [SI CSEG = 1, 2 OU 4 : vous / SI CSEG = 3 : votre entreprise] au cours des 12 derniers mois, dans quelle mesure la durée se compare-t-elle à vos attentes?

Much better
Elle est bien meilleure que ce à quoi vous vous attendiez
Somewhat better
Elle est un peu meilleure que ce à quoi vous vous attendiez
About what you expect
Elle correspond à ce à quoi vous vous attendiez
Somewhat worse
Elle est un peu moins bonne que ce à quoi vous vous attendiez
Much worse
Elle est bien pire que ce à quoi vous vous attendiez
Don’t know
Ne sait pas

[ASK Q11-Q12 TO CSEG =3 ONLY]

[ASK Q11-Q12 TO CSEG =3 ONLY]

11. Thinking about the power outages your business experienced in the past 12 months, would you say they were?

En ce qui concerne les pannes de courant subies par votre entreprise au cours des 12 derniers mois, diriez-vous...?

A major inconvenience
Qu'elles ont été un inconvénient majeur
A minor inconvenience
Qu'elles ont été un inconvénient mineur
No inconvenience at all
Qu'elles n'ont pas du tout été un inconvénient
Don’t know
Ne sait pas

[IF MAJOR OR MINOR ASK Q12 OTHERWISE SKIP TO Q13]

[IF MAJOR OR MINOR ASK Q12 OTHERWISE SKIP TO Q13]

12. How much, if any, would you say the outages you experienced in the past 12 months collectively cost your business? Please answer in whole dollars, do not include cents.

Le cas échéant, combien au total les pannes subies au cours des 12 derniers mois ont-elles coûtées à votre entreprise? Veuillez répondre en dollars entiers, sans inclure les cents.

[RANGE 0 TO 100000]

[RANGE 0 TO 100000]

[KEEP Q13/Q14 TOGETHER AND KEEP Q15/Q16 TOGETHER BUT ROTATE THE ORDER OF THE SETS]

[KEEP Q13/Q14 TOGETHER AND KEEP Q15/Q16 TOGETHER BUT ROTATE THE ORDER OF THE SETS]

[CLIENT SERVICE: MONITOR # OF DON’T KNOW RESPONSES FOR Q13-20]

[CLIENT SERVICE: MONITOR # OF DON'T KNOW RESPONSES FOR Q13-20]

13. In your view, when it comes to the average number of power outages should Hydro One…. (READ LIST) (ACCEPT ONE RESPONSE)

À votre avis, en ce qui concerne le nombre moyen de pannes de courant, Hydro One devrait-elle…? (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

[ROTATE 1 TO 3 / 3 TO 1]

[ROTATE 1 TO 3 / 3 TO 1]

Reduce the number of power outages even if it results in an increase to customer bills

Réduire le nombre de pannes de courant, même si cela entraîne une augmentation des coûts pour les clients

Maintain the current number of power outages, which may result in a relatively modest increase to customer bills.

Maintenir le nombre actuel de pannes de courant, ce qui pourrait entraîner une augmentation relativement modique des coûts pour les clients

Allow the number of power outages to increase in order to keep costs low.

Permettre le nombre de pannes de courant à monter pour maintenir les coûts bas pour les clients

Don’t know

Ne sait pas

14. When it comes to the average length of power outages, should Hydro One…. (READ LIST) (ACCEPT ONE RESPONSE)

En ce qui concerne la durée moyenne des pannes de courant, Hydro One devrait-elle…? (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

[ROTATE 1 TO 3 / 3 TO 1]

[ROTATE 1 TO 3 / 3 TO 1]

Reduce the length of power outages even if it results in an increase to customer bills

Réduire la durée des pannes de courant, même si cela entraîne une augmentation des coûts pour les clients

Maintain the average length of power outages, which may result in a relatively modest increase to customer bills

Maintenir la durée moyenne des pannes de courant, ce qui pourrait entraîner une augmentation relativement modique des coûts pour les clients

Allow the average length of power outages to increase in order to keep costs low.

Permettre la durée moyenne de pannes de courant à monter pour maintenir les coûts bas pour les clients

Don’t know

Ne sait pas

15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One…. (READ LIST) (ACCEPT ONE RESPONSE)

À votre avis, en ce qui concerne le service à la clientèle, comme établir des factures exactes et répondre aux questions des clients, Hydro One devrait-elle…? (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

[ROTATE 1 TO 3 / 3 TO 1]

[ROTATE 1 TO 3 / 3 TO 1]

Improve customer service even if it results in an increase to customer bills

Améliorer le service à la clientèle, même si cela entraîne une augmentation des coûts pour les clients

Maintain the current level of customer service, which may result in a relatively modest increase to customer bills

Maintenir le niveau actuel de service à la clientèle, ce qui pourrait entraîner une augmentation relativement modique des coûts pour les clients

Allow for longer wait times and poorer billing accuracy in order to keep costs low.

Permettre les temps d'attente à augmenter et l'exactitude des factures à baisser, pour maintenir les coûts bas pour les clients

Don't know

Ne sait pas

16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One…. (READ LIST) (ACCEPT ONE RESPONSE)

À votre avis, lorsqu'il s'agit de moderniser le système pour raccorder de nouveaux clients, notamment ceux qui produisent de l'énergie renouvelable ou ceux qui stockent de l'énergie, Hydro One devrait-elle…? (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

[ROTATE 1 TO 3 / 3 TO 1]

[ROTATE 1 TO 3 / 3 TO 1]

Upgrade its system to allow it to increase the number new customers more quickly even if it results in an increase to all customer bills

Moderniser le réseau, et ainsi augmenter plus rapidement le nombre de nouveaux clients, même si cela entraîne une augmentation des coûts pour l'ensemble des clients

Maintain its current system and connect renewable customers as quickly as it does now, which may result in a relatively modest increase to all customer bills

Maintenir le réseau actuel et raccorder les clients d'énergie renouvelable au même rythme qu'en ce moment, ce qui peut entraîner une augmentation relativement modique des coûts pour l'ensemble des clients

Allow a slowdown in Hydro One's ability to connect renewable energy customers, in order to keep costs low.

Permettre un ralentissement de la vitesse à laquelle Hydro One raccorde de nouveaux clients à des sources d'énergie renouvelable, pour maintenir les coûts bas pour les clients

Don't know

Ne sait pas

(INTERVIEWER TO READ SLOWLY)

(LIRE LENTEMENT.)

The percentages and equivalent dollar amounts that I am going to read out to you in the next few questions are estimates and are subject to change.

Les pourcentages et les montants équivalents en dollars que je vais vous lire dans les questions suivantes sont des estimations et sont susceptible d'être modifiés.

17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [IF CSEG = 1, 2 OR 4: residential or seasonal / IF CSEG =3: small business] customer's total monthly bill will need to increase by [IF CSEG = 1, 2 OR 4: 1.1% or the equivalent of $2.00 / IF CSEG =3: 1% or the equivalent of $5.2O.

Hydro One a déterminé que pour maintenir, au minimum, le niveau de la fiabilité et le service à la clientèle qu'elle offre actuellement, la facture mensuelle type [SI CSEG = 1, 2 ou 4 : d'un client résidentiel ou saisonnier / SI CSEG = 3 : d'une petite entreprise] devra augmenter de [SI CSEG = 1, 2 ou 4 : 1,1 % ou l'équivalent de 2,00 $ / SI CSEG = 3 : 1 % ou l'équivalent de 5,20 $].

This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF RESIDENTIAL OR SEASONAL $10.00 / IF BUSINESS: $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One.

Cette augmentation sera appliquée chaque année pendant les cinq prochaines années. À la cinquième année, une facture mensuelle sera d'environ [SI CLIENT RÉSIDENTIEL OU SAISONNIER 10,00 $ / SI CLIENT COMMERCIAL : 26,00 $] plus élevée qu'elle ne l'est maintenant. Veuillez prendre note que cette augmentation reflète le coût de maintenir les niveaux de fiabilité et de service actuels. La facture mensuelle pourrait tout de même augmenter pour d'autres raisons qui sont hors du contrôle d'Hydro One.

Which of the following is closest to your point of view? (READ LIST) [ACCEPT ONE RESPONSE]

Parmi les énoncés suivants, lequel se rapproche le plus de votre point de vue? (LIRE LA LISTE) [ACCEPT ONE RESPONSE]

The increase is reasonable and I would support it

L'augmentation est raisonnable et vous l'accepteriez

I don't like it, but I think the increase is necessary

L'augmentation ne vous plaît pas, mais vous croyez qu'elle est tout de même nécessaire

The increase is unreasonable and I would oppose it

L'augmentation est déraisonnable et vous vous y opposeriez

Don't know

Je ne sais pas

[ROTATE THE ORDER OF Q18 AND Q19]

[ROTATE THE ORDER OF Q18 AND Q19]18. Would you be willing to pay anything higher than the [IF CSEG =

1, 2 OR 4: $2.00 or about 1.1% / IF CSEG =3: $5.20 or about 1%] more on your total monthly bill if it meant you would have better reliability than you have now? (READ LIST) [ACCEPT ONE RESPONSE]

Seriez-vous prêt(e) à payer plus que l'augmentation de [SI CSEG = 1, 2 ou 4 : 2,00 $ ou environ 1,1 % / SI CSEG = 3 : 5,20 $ ou environ 1 %] sur votre facture mensuelle si cela pouvait vous procurer une fiabilité supérieure à celle dont vous bénéficiez maintenant? (LIRE LA LISTE) [ACCEPT ONE RESPONSE]

Yes
Oui
Maybe
Peut-être
No
Non
Don't know
Ne sait pas

19. Would you be willing to pay anything higher than the [IF CSEG = 1, 2 OR 4: $2.00 or about 1.1% / IF CSEG =3: $5.20 or about 1%] more on your total monthly bill if it meant you would have better customer service than you have now? (READ LIST) [ACCEPT ONE RESPONSE]

Seriez-vous prêt(e) à payer plus que l'augmentation de [SI CSEG = 1, 2 ou 4 : 2,00 $ ou environ 1,1 %/ SI CSEG = 3 : 5,20 $ ou environ 1 %] sur votre facture mensuelle si cela pouvait vous procurer un service à la clientèle supérieur à celui dont vous bénéficiez maintenant? (LIRE LA LISTE) [ACCEPT ONE RESPONSE]

Yes
Oui
Maybe
Peut-être
No
Non
Don't know
Ne sait pas

[IF CSEG = 1, 2 OR 4 ASK 20A. IF CSEG =3 SKIP TO Q20B]

20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30 / OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30 /$2.60 more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50 / $13.00] higher than it is now. (READ LIST. ACCEPT ONE RESPONSE)

Seriez-vous prêt(e) à payer [HALF OF RESPONDENTS SHOW 0,30 $ / OTHER HALF SHOW 0,60 $] de plus par mois en sus des 2,00 $, ce qui équivaudrait environ à [SPLIT SAMPLE 2,30 $ /2,60 $ de plus par mois si cela permettait à Hydro One de réduire le nombre et la durée des futures pannes de 10 %? L'augmentation serait appliquée chaque année pendant les cinq prochaines années de sorte qu'à la cinquième année, votre facture mensuelle sera d'environ [11,50 $ / 13,00 $] plus élevée qu'elle ne l'est maintenant. (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

Definitely would
Certainement
Probably would
Probablement
Probably would not
Probablement pas
Definitely would not
Certainement pas
Don’t know
Ne sait pas

[Ask only CSEG =3]

20B. Would you be willing to pay an additional [HALF OF RESPONDENT SHOW $0.80 / OTHER HALF SHOW $1.60] per month over and above the $5.20 which would be approximately [SPLIT SAMPLE $6.00 /$6.80 more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$30.00 / $34.00] higher than it is now. (READ LIST. ACCEPT ONE RESPONSE)

Seriez-vous prêt(e) à payer [HALF OF RESPONDENT SHOW 0,80 $ / OTHER HALF SHOW 1,60 $] de plus par mois en sus des 5,20 $, ce qui équivaudrait environ à [SPLIT SAMPLE 6,00 $ /6,80 $ de plus par mois si cela permettait à Hydro One de réduire le nombre et la durée des futures pannes de 10 %? L’augmentation serait appliquée chaque année pendant les cinq prochaines années de sorte qu’à la cinquième année, votre facture mensuelle sera d’environ [30,00 $ / 34,00 $] plus élevée qu’elle ne l’est maintenant. (LIRE LA LISTE. ACCEPTER UNE SEULE RÉPONSE.)

Definitely would
Certainement
Probably would
Probablement
Probably would not
Probablement pas
Definitely would not
Certainement pas
Don’t know
Ne sait pas

We’re almost finished the survey I just have a few more classification questions to ask.

Le sondage est presque terminé. Je n'ai plus que quelques questions à vous poser aux fins de classification.

21. Deleted

[IF CSEG =1 OR 4 ASK Q22, IF CSEG = 2 SKIP TO Q23, IF CSEG=3 SKIP TO THANK YOU]

[IF CSEG =1 OR 4 ASK Q22, IF CSEG = 2 SKIP TO Q23, IF CSEG=3 SKIP TO THANK YOU]

22. Which of the following best describes your primary residence? Select the one which best applies. (READ LIST) [ACCEPT ONE RESPONSE]

Lequel des énoncés suivants décrit le mieux votre résidence principale? Sélectionnez l'énoncé le plus pertinent. (LIRE LA LISTE) [ACCEPT ONE RESPONSE]

Single, detached or semi-detached house
Maison unifamiliale, individuelle ou jumelée
Duplex, row or townhouse
Duplex, maison en rangée ou maison de ville
Apartment
Appartement
Condo
Copropriété
Mobile home
Maison mobile
Other
Autre

23. What was your total household income before taxes in 2015? Just stop me when I reach your category. (READ LIST)

Quel était le revenu total brut de votre foyer en 2015? Veuillez m'arrêter lorsque j'aurai mentionné la bonne catégorie. (LIRE LA LISTE)

Less than $20,000
Moins de 20 000 $
$20,000 to just under $40,000
20 000 $ à moins de 40 000 $
$40,000 to just under $50,000
40 000 $ à moins de 50 000 $
$50,000 to just under $75,000
50 000 $ à moins de 75 000 $
$75,000 to just under $100,000
75 000 $ à moins de 100 000 $
$100,000 or more
100 000 $ ou plus

24. Which of the following best describes your employment status? Just stop me when I read your category (READ LIST) [ACCEPT ONE RESPONSE]

Parmi les énoncés suivants, lequel décrit le mieux votre situation professionnelle? Veuillez m'arrêter lorsque j'aurai mentionné la bonne catégorie. (LIRE LA LISTE) [ACCEPT ONE RESPONSE]

Full time employed or business owner

Employé(e) à temps plein ou propriétaire d'entreprise

Part time employed, non-student

Employé(e) à temps partiel, non-étudiant ou non-étudiante

Full or part-time student, including if employed

Étudiant ou étudiante à temps plein ou à temps partiel, même si employé(e)

Full time homemaker and/or full-time parent
Personne au foyer à temps plein et/ou parent à temps plein
Retired
À la retraite
Currently unemployed
Actuellement sans emploi
Other
Autre

25. What is the highest level of education you have completed? (READ LIST)

Quel est le plus haut niveau d'études que vous avez atteint? (LIRE LA LISTE)

Less than high school or never attended school
Études secondaires non terminées ou moins, ou n'a jamais fréquenté à l'école
Some high school / High school diploma or equivalent
Études secondaires non terminées, diplôme d'études secondaires ou l'équivalent
Some college/university
Études collégiales ou universitaires non terminées
College or University degree (Associates or Bachelors)
Diplôme collégial ou universitaire (grade d'associé ou baccalauréat)
Post Graduate or professional degree
Études supérieures ou diplôme professionnel

26. How many adults other than you, live in your household?

Combien d'adultes, vous excluant, vivent dans votre foyer?

[RANGE 0 TO 10]

[RANGE 0 TO 10]

27. How many children under the age of 18 live in your household?

Combien d'enfants de moins de 18 ans vivent dans votre foyer?

[RANGE 0 TO 10]

[RANGE 0 TO 10]

[IF CSEG = 2 SKIP TO END]

[IF CSEG = 2 SKIP TO END]

28. How long have you been a customer of Hydro One? (READ LIST)

Depuis combien de temps êtes-vous un client/une cliente de Hydro One? (LIRE LA LISTE)

Less than 5 years
Moins de 5 ans
5 -10 years
Entre 5 et 10 ans
10-20 years
Entre 10 et 20 ans
20 years or more
20 ans ou plus

Thank you for taking part in our survey and providing Hydro One with your opinion on keeping the electricity delivery system strong and ready for the future.

Nous vous remercions d'avoir participé à notre sondage et d'avoir fait part à Hydro One de votre opinion sur l'importance de maintenir la force du réseau de distribution d'électricité.

Dx Customer Engagement Survey for Residential and General Service Customers

OPEN-LINK Version final

In which language do you wish to complete the survey?
En quelle langue désirez-vous compléter le sondage?

English/Anglais
Français/French

CONFIDENTIAL INFORMATION

In this presentation, "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 presentation on a confidential basis in order to solicit your feedback. The feedback from this customer consultation will be considered when making regulatory filings. Any information concerning Hydro One provided as part of this presentation 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 presentation and should not use the information for any other purpose.

In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of Hydro One is intended only to illustrate past performance and is not necessarily indicative of future performance.

Forward-Looking Information

This presentation contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation 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 how Hydro One can improve reliability and other aspects of customer service, including the status of various initiatives; the use of customer feedback from the consultation process and its impact on the Company's investment plans; statements regarding upcoming rate applications: and statements about monthly bill impacts.

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 presentation 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.

A. Are you responding to this survey as….(select all that apply) [Multi punch]

A residential Hydro One customer
A seasonal Hydro One customer
A small business Hydro One customer
Other

[IF OTHER, THANK AND TERMINATE – "Thank you for your interest, but this survey is for residential, seasonal or small business customers of Hydro One".]

[IF SELECT MORE THAN ONE ASK]

B. For the purposes of the survey, would you prefer to answer questions related to your …? (select all that apply) [Multi punch]

[PIPE IN SELECTED RESPONSES]
Primary residence
Seasonal residence
Business

C. What are the first 3 digits of the postal code of your …? (select all that apply) [Multi punch]

[IF ONE ONLY SELECTED PIPE IN SELECTED RESPONSE, IF SELECTED MORE THAN ONE PIPE IN SELECTED RESPONSES]

Primary residence [TEXT BOX]
Seasonal residence [TEXT BOX]
Business [TEXT BOX]

[IF RESIDENTIAL OR SEASONAL SELECTED AT QB ASK QD-QE. IF BUSINESS WAS THE ONLY SELECTION AT QB SKIP TO QG]

D. Are you one of the individuals in your household who is responsible for paying the electricity bill for either your primary or seasonal property?

Yes
No

[IF NO THANK AND TERMINATE 'This survey is intended for customers who have some responsibility for paying the electricity bill.']

E. What is your gender? [single punch]

Male
Female
Prefer not to say

F. Which of the following categories includes your age? [single punch]

Under 18
18-24
25-39
40-49
50-59
60-69
70 or older
Prefer not to say

[ASK ALL]

G. Are you or anyone in your family currently employed by any of the following types of organizations? [Multi punch]

A public relations or market research company
TV, radio, magazine or newspaper publishing
A company that provides electricity
An energy regulator

An elected official or on the staff of an elected official
None of the above [Exclusive]

H. Do you pay the electricity bill for you ......?

[ROW]
[Pipe in QC]

[COLUMN]
Directly to Hydro One
Included in rent/other

[IF INCLUDED IN RENT/OTHER FOR ALL THANK AND TERMINATE – 'This survey is intended for customers who pay the electricity bill directly to Hydro One.']

[IF THE RESPONDENT SELECTED MULTIPLE RESPONSES IN B AND ONE OF THE RESPONSES WAS BUSINESS, SHOW QI, ALL OTHERS PROCEED TO Q1]

I. You indicated that you would like to respond to the survey as both a residential/seasonal customer as well as a business customer. You will have the opportunity to go through the survey twice. For the first go around, would you prefer to complete the survey as a…

Residential /seasonal customer
Small business customer

[IF RESIDENTIAL/SEASONAL USE THAT MARKER FOR SURVEY, IF SELECT SMALL BUSINESS USE BUSINESS MARKER FOR SURVEY]

[BUSINESS 'For the first go around, please keep your organization's electricity services in mind, not your residential or seasonal electricity service.']

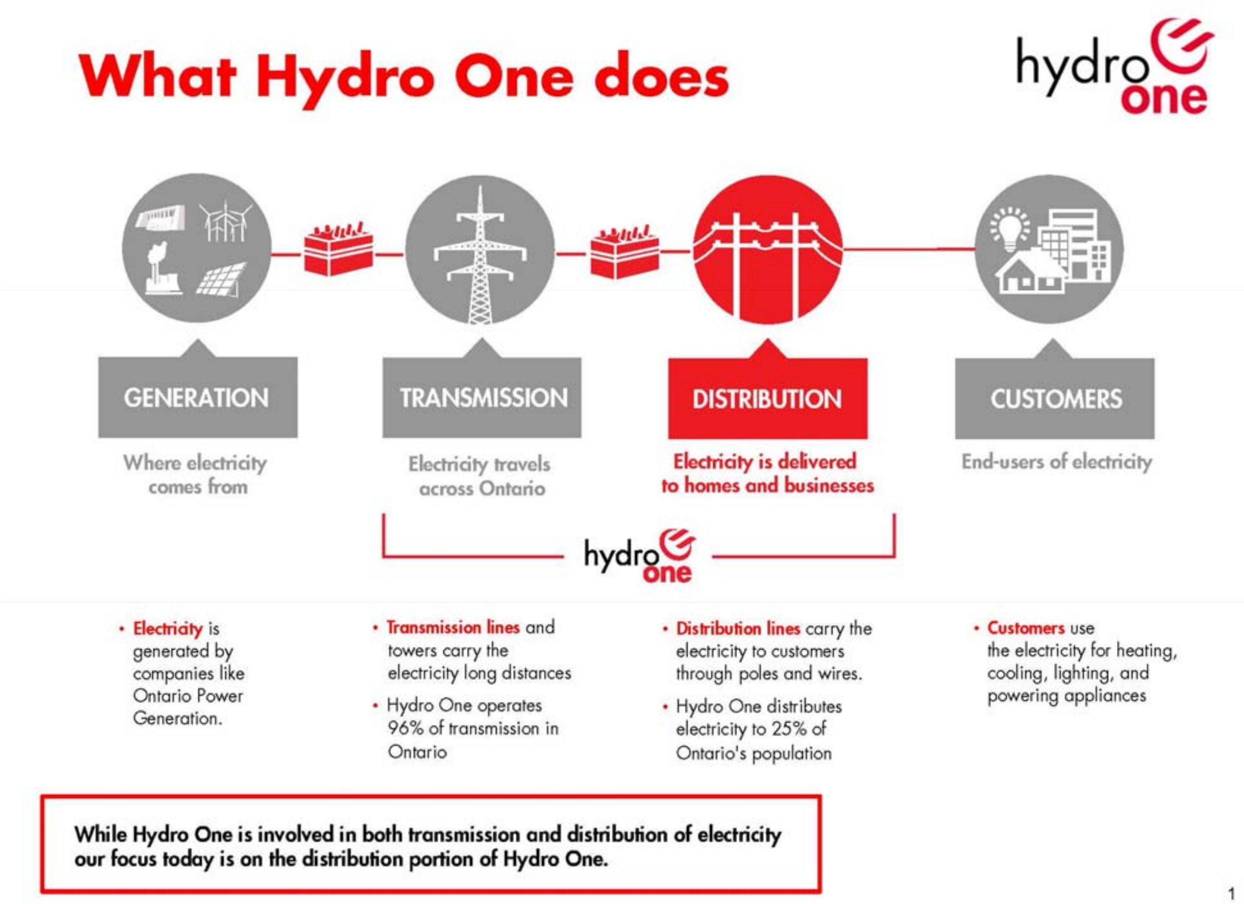
[RESIDENTIAL/SEASONAL 'For the first go around, please keep your residential or season property's electricity services in mind, not your organization's electricity service.']

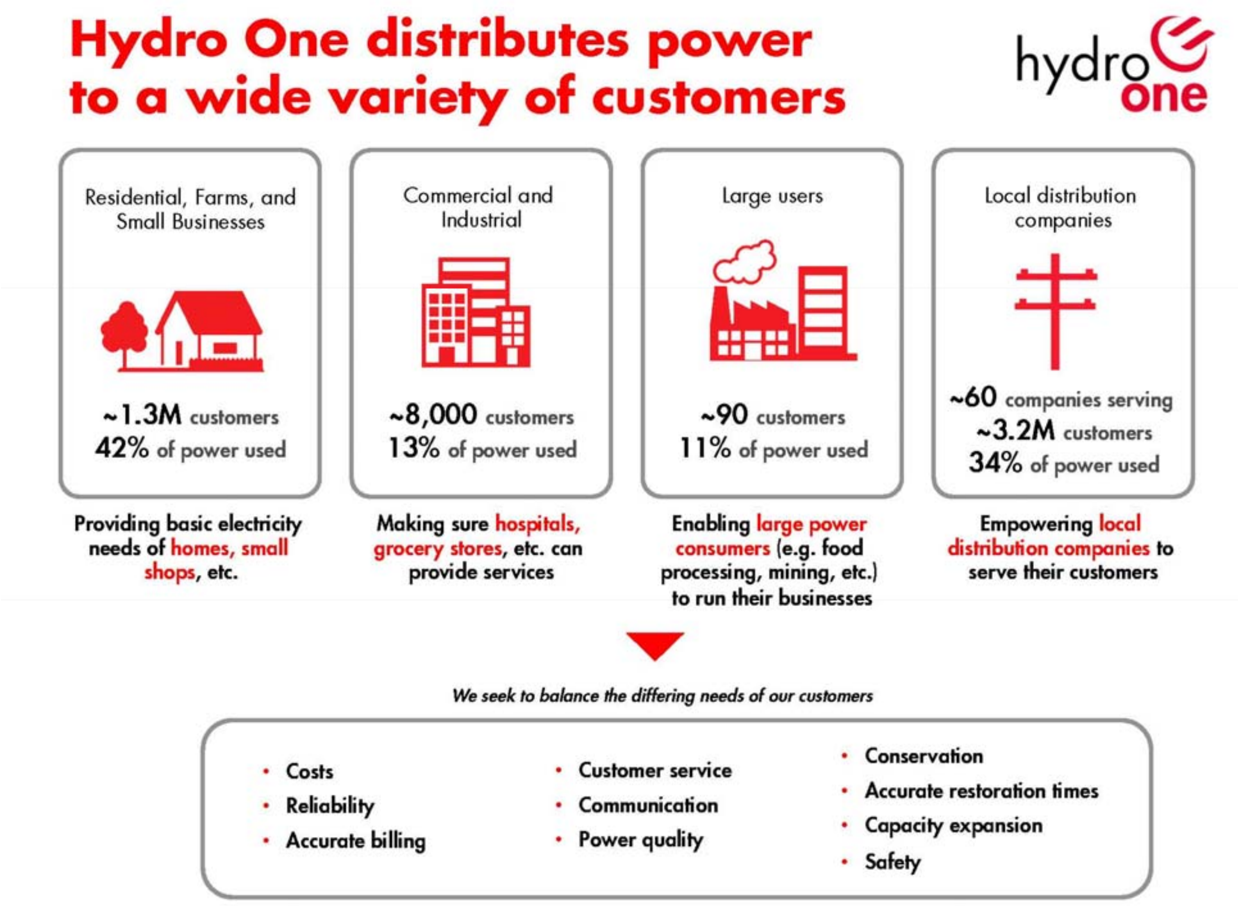
[Ask all]

We'll begin by showing you some information. Then we'll ask you some questions so we understand what you value most when it comes to the level and type of service that you expect from Hydro One.

Every utility in Ontario submits a rate application to the Ontario Energy Board. Hydro One's application will outline its plans and costs to achieve particular outcomes. It will be reviewed by the Ontario Energy Board and they will decide whether the plans are sensible and in customers' interests. The Ontario Energy Board determines what rates utilities are allowed to charge customers to recover the costs of these plans.

Hydro One is currently preparing their rate application and that's the reason why they're asking for their customers' opinions – to help inform the plans contained in this rate application. The application will explain the money that's required by Hydro One in order to maintain the safe and reliable distribution of electricity.





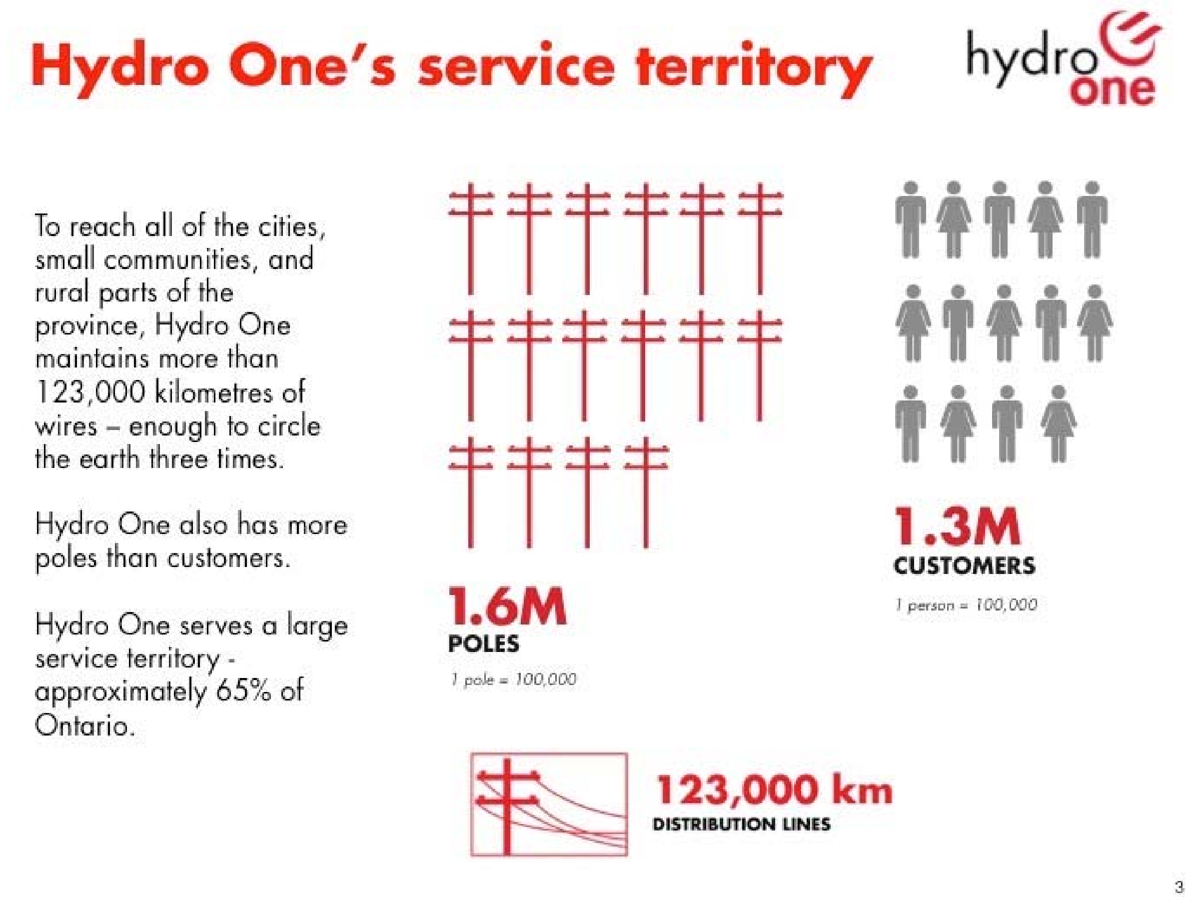
As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.

1. How satisfied are you with Hydro One overall?

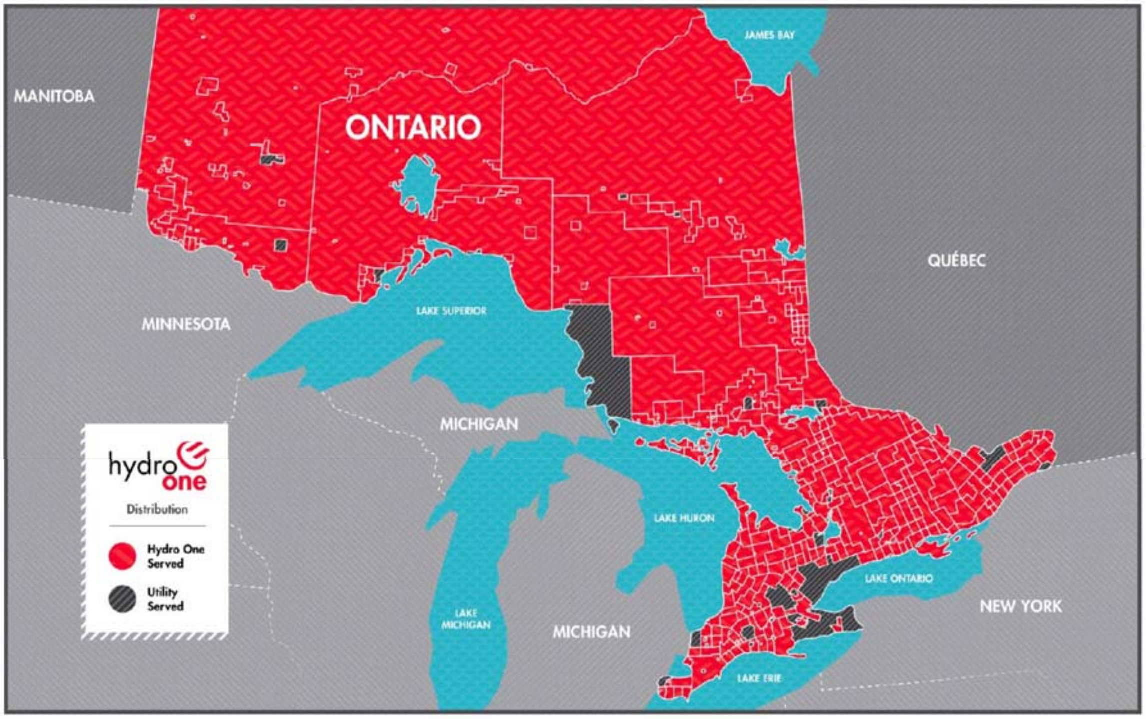
Very satisfied
Somewhat satisfied
Neither satisfied nor dissatisfied
Somewhat dissatisfied
Very dissatisfied

2. Is there anything in particular that Hydro One can do to improve its service to you?

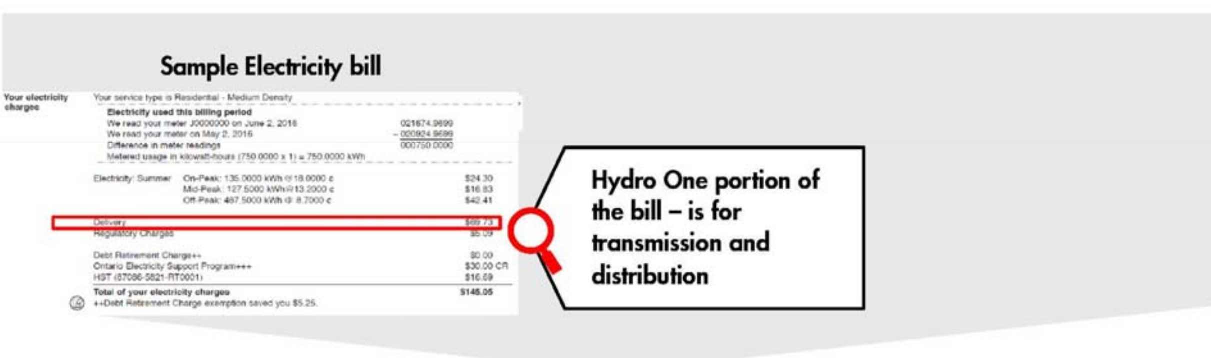
[Open-end]



Hydro One's service territory

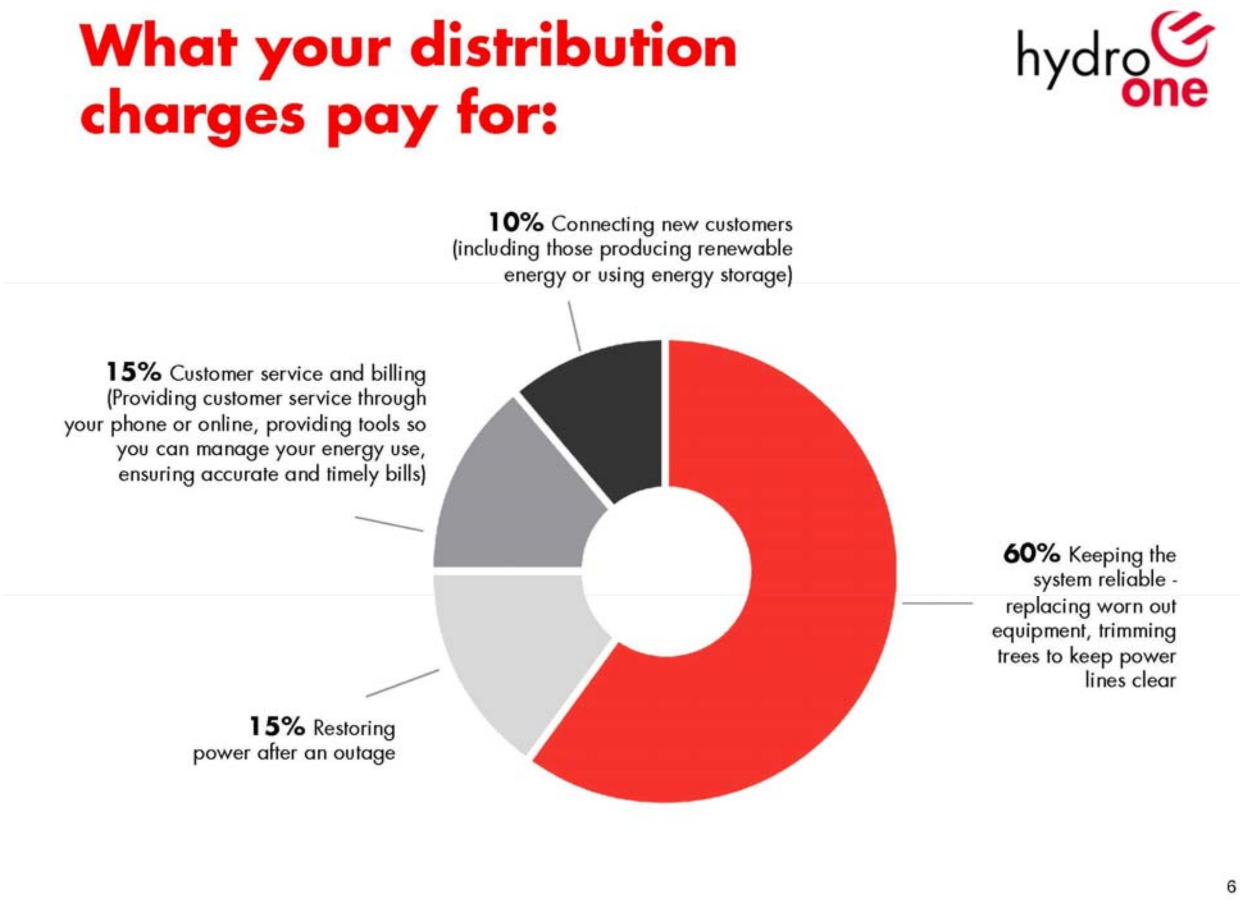


Sample Electricity Bill



The portion of the bill that goes directly to Hydro One is what you see on the delivery line of the bill. Most of this amount is for distribution.

The rest is collected by Hydro One on behalf of generators and other electricity entities.



3. **[Info screen]** The pie chart above shows a rough estimate of what Hydro One currently spends on each of its major electricity distribution investments.

   If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? [Single punch]

Change
Keep the same
Don’t know

[IF CHANGE ASK Q4, OTHERWISE SKIP TO Q5]

4. What percentage would you allocate to…?

[RANDOMIZE]
Keeping the system reliable (such as replacing worn out equipment, trimming trees to keep power lines clear)
Restoring power after an outage
Upgrading the system to connect new customers including those-producing renewable energy or using energy storage
Customer service and billing (such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)

5. Hydro One would like to better understand what is important to you as a [IF RESDIENTIAL/SEASONAL; residential or seasonal / IF SMALL BUSINESS: business customer. For each of the pairs below, please indicate which one is more important to you. [PAIRED CHOICE EXERCISE PROGRAMMING]

Reducing the number of power outages (through activities such as tree-trimming, replacing equipment)
Shortening the length of power outages (through activities such as installing remote control devices)
Improving customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills)
Upgrading the system to connect new customers including those producing renewable energy sources and using energy storage (such as wind, solar, and electric vehicles)
Keeping costs as low as possible

6. Is there anything else that is important to you?
[Open-end]

The following few questions are about your experience with power outages. Please think about your experience in terms of how frequently they occur-and how long they last.

7. A sustained power outage is one lasting at least 1 minute. How many sustained power outages did [IF RESIDENTIAL/SEASONAL: you / IF BUSINESS: your business] experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. [Single punch]

None
Don't know/can't recall

[IF NONE, DON'T KNOW/CAN'T RECALL SKIP TO INSTRUCTION BEFORE Q13]

8. In general, when you think about how many power outages [IF RESIDENTIAL /SEASONAL: you / IF BUSINESS: your business] experienced over the last 12 months, how did it compare to your expectations? [Single punch]

Much better
Somewhat better
About what you expect
Somewhat worse
Much worse
Don't know

9. On average, how long did these unplanned outages last? Please answers in minutes. Your best guess is fine. [Single punch]

Don't know/can't recall

10. In general, when you think about the average length of the power outages [IF RESIDENTIAL/SEASONAL: you / IF BUSINESS: your business] experienced over the last 12 months, how did it compare to your expectations? [Single punch]

Much better

Somewhat better
About what you expect
Somewhat worse
Much worse
Don't know

[ASK Q11-Q12 TO SMALL BUSINESS ONLY]

11. Thinking about the power outages your business experienced in the past 12 months, would you say they were? [Single punch]

A major inconvenience
A minor inconvenience
No inconvenience at all
Don't know/recall

[IF MAJOR OR MINOR ASK Q12 OTHERWISE SKIP TO Q13]

12. How much, if any, would you say the outages you experienced in the past 12 months collectively cost your business? Please answer in whole dollars, do not include cents. [Single punch]

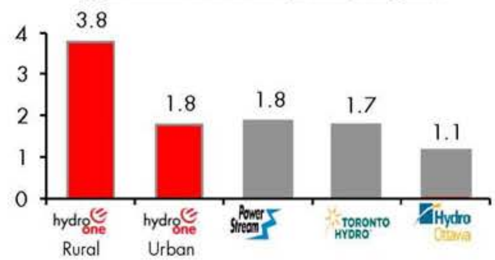
Don't know

Reliability explained

Reliability is measured in two ways - how many times the power goes out, and how long the power is off.

Hydro One trails peer utilities in Ontario on both metrics

An average rural Hydro One customer has about 4 outages per year. Urban customers experience about 2 outages per year.



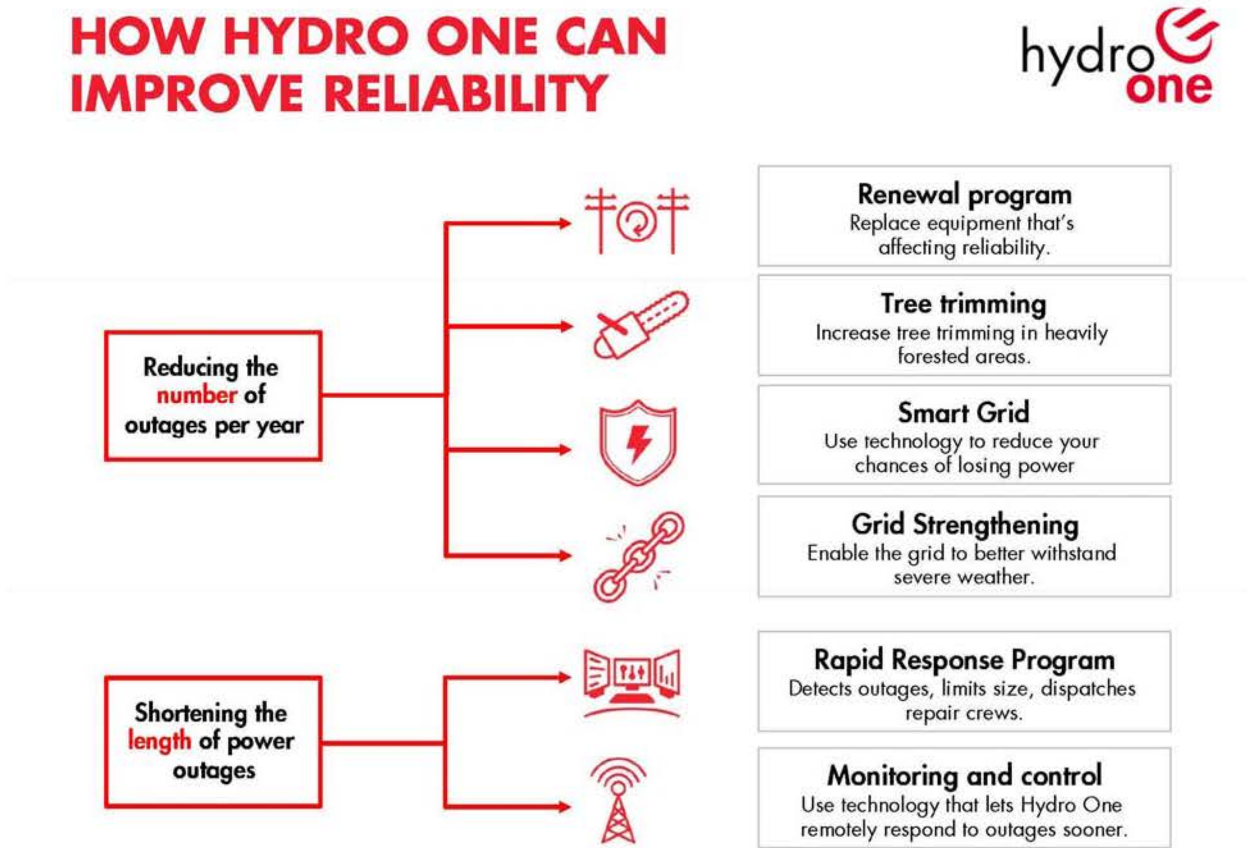
An average rural Hydro One customer's outage lasts about 4 hours. Urban customers' outage is about 3 hours.

1. Metrics for Hydro One based on average from 2013-2015; metrics for other distributors based on average from 2011-2013. Numbers below are approximate. Source: OEB distributor handbook, peer utility rate filings

WHAT CAUSES YOUR POWER TO GO OUT

Power outage causes (2013-2015)

Trees	**24%**	Trees fall on lines during storms.
Equipment failure	**24%**	Poles, transformers, lines failures can cause an outage.
Unconfirmed causes	**19%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Scheduled outages	**16%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Loss of power supply	**12%**	Issues relating to the larger grid like damage to transmission lines.
Animal or vehicle damage to equipment	**5%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.



KEEP Q13/Q14 TOGETHER AND KEEP Q15/Q16 TOGETHER BUT ROTATE THE ORDER OF THE SETS]

13. In your view, when it comes to the **average number of power outages** should Hydro One…. [select one one]

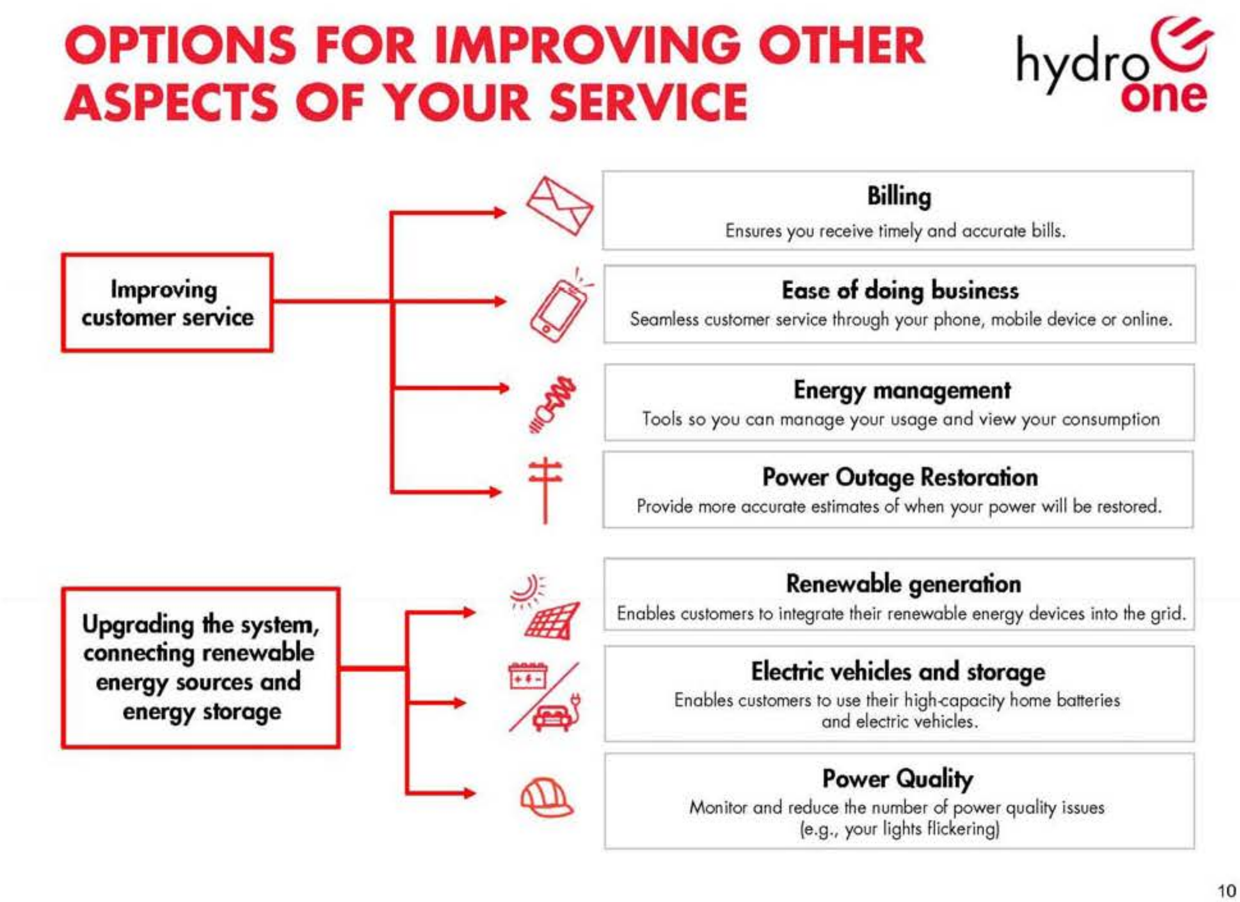
[ROTATE 1 TO 3 / 3 TO 1]

Reduce the number of power outages even if it results in an increase to customer bills
Maintain the current number of power outages, which may result in a relatively modest increase to customer bills
Allow the number of power outages to increase in order to keep costs low
Don't know

14. When it comes to the **average length of power outages**, should Hydro One…. [select one one]

[ROTATE 1 TO 3 / 3 TO 1]

Reduce the length of power outages even if it results in an increase to customer bills
Maintain the average length of power outages, which may result in a relatively modest increase to customer bills
Allow the average length of power outages to increase in order to keep costs low
Don't know



15. In your view, when it comes to **customer service (such as billing accuracy and answering customer questions)** should Hydro One…. [Select one only]

[ROTATE 1 TO 3 / 3 TO 1]

Improve customer service even if it results in an increase to customer bills
Maintain the current level of customer service, which may result in a relatively modest increase to customer bills
Allow for longer wait times and poorer billing accuracy in order to keep costs low
Don't know

16. In your view, when it **comes to upgrades to the system to connect new customers (including those producing renewable energy or energy storage)**, should Hydro One…. [select one only]

[ROTATE 1 TO 3 / 3 TO 1]

Upgrade its system to allow it to increase the number new customers more quickly even if it results in an increase to all customer bills
Maintain its current system and connect renewable customers as quickly as it does now, which may result in a relatively modest increase to all customer bills
Allow a slowdown in Hydro One's ability to connect renewable energy customers, in order to keep costs low
Don't know

Please read the following information carefully. Feel free to re-read the question more than once if necessary to provide a response. The percentage increases and equivalent dollar amounts shown in the next few questions are estimates and are subject to change.

17. **[Info screen]** Hydro One has determined that in order to **<u>at least maintain</u>** the level of reliability and customer service it currently provides, a typical [IF RESIDENTIAL/SEASONAL: residential / seasonal / IF BUSINESS: small business] customer's total monthly bill will need to increase by [IF RESIDENTIAL/SEASONAL: 1.1% or the equivalent of $2.00/ IF BUSINESS: 1% or the equivalent of $5.20].

    This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF RESIDENTIAL OR SEASONAL $10.00 **/** IF BUSINESS: $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One.

Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? [Single punch]

The increase is reasonable and I would support it
I don't like it, but I think the increase is necessary
The increase is unreasonable and I would oppose it
Don't know

[ROTATE THE ORDER OF Q18 AND Q19]

18. Would you be willing to pay anything higher than [IF RESIDENTIAL/SEASONAL: $2.00 or about 1.1.% / IF BUSINESS: $ 5.2O or about 1%] more on your total monthly bill if it meant you would have better reliability than you have now? [Single punch]

Yes
Maybe
No
Don't know

19. Would you be willing to pay anything higher than [IF RESIDENTIAL/SEASONAL: : $2.00 or about 1.1.% / IF BUSINESS: $ 5.2O or about 1%] more on your total monthly bill if it meant you would have better customer service than you have now? [Single punch]

Yes
Maybe
No
Don't know

[IF RESIDENTIAL / SEASONAL ASK 20A. BUSINESS SKIP TO Q20B]

20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30 / OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30 /$2.60 more per month if it meant that Hydro One could **<u>reduce the number and length of future power outages by 10%</u>**? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50 / $13.00] higher than it is now.

Definitely would
Probably would
Probably would not
Definitely would not
Don't know

[Q20B SHOWN TO BUSINESS ONLY]

20B. Would you be willing to pay an additional [HALF OF RESPONDENT SHOW $0.80 / OTHER HALF SHOW $1.60] per month over and above the $5.20 which would be approximately [SPLIT SAMPLE $6.00 /$6.80 more per month if it meant that Hydro One could **<u>reduce the number and length of future power outages by 10%</u>**? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$30.00 / $34.00] higher than it is now.

Definitely would
Probably would
Probably would not
Definitely would not
Don't know

Please answer a few more classification questions.

20. Which of the following best describes the area in which [IF RESIDENTIAL/SEASONAL: you live IF BUSINESS: you have your business]? [Single punch]

In a rural or country area or a reserve
In a small town of less than 2,000 people

In a small town of about 2,000 to less than 5,000 people
In a town of about 5,000 to 20,000 people
In a town of about 20,000 to less than 50,000 people
In a city of 50,000 to less than 100,000 people
In a large city of 100,000 or more people

[IF RESIDENTIAL CONTINUE OTHERWISE SKIP TO THANK YOU]

21. Which of the following best describes your primary residence? Select the one which best applies. [Single punch]

Single, detached or semi-detached house
Duplex, row or townhouse
Apartment
Condo
Mobile home
Other

22. What was your total household income before taxes in 2015? Please include income from all sources and count income for all people who lived in your household. [Single punch]

Less than $20,000
$20,000 to just under $40,000
$40,000 to just under $50,000
$50,000 to just under $75,000
$75,000 to just under $100,000
$100,000 or more
Prefer not to answer

23. Which of the following best describes your employment status? [Single punch]

Full time employed or business owner
Part time employed, non-student
Full or part-time student, including if employed
Full time homemaker and/or full-time parent

Retired
Currently unemployed, but looking for work
Currently unemployed, and not looking for work
Unable to work due to disability or illness
Prefer not to answer

24. What is the highest level of education you have completed? [Single punch]

Less than high school or never attended school
Some high school / High school diploma or equivalent
Some college/university
College or University degree (Associates or Bachelors)
Post Graduate or professional degree
Prefer not to answer

25. How many people, other than you, live in your household? [Single punch]

Adults over 18 [0-10]
Children under 18 [0-10]
Prefer not to say

26. How long have you been a customer of Hydro One? [Single punch]

Less than 5 years
5 -10 years
10-20 years
20 years or more
Prefer not to say

[IF THE RESPONDENT SELECTED MULTIPLE RESPONSES AND ONE OF THE RESPONSES WAS BUSINESS IN QUESTION B, CONTINUE, ALL OTHERS PROCEED TO THANK YOU MESSAGE]

You will have the opportunity to go through the survey a second time as a [PIPE IN RESPONSE AT QO NOT SELECTED], AND LOOP BACK TO Q1 WITH THE APPROPRIATE MARKER]

[For all]
THANK YOU MESSAGE: Thank you for taking part in our survey and providing Hydro One with your opinion on keeping the electricity delivery system strong and ready for the future.

APPROACH SPRING 2011
THE SOCIAL RESEARCH NEWSLETTER FROM IPSOS MORI SCOTLAND www.ipsos-mori.com/scotland

Identifying Priorities with Paired Choice Analysis

Identifying people's priorities can help organisations better tailor their services. We have previously discussed qualitative methods for gauging public priorities in local authority budget setting (Approach, autumn 2010). However, there are a range of quantitative methods available and one of the most effective of these is 'paired choice'.

Say we want to measure public preferences for the following ten options available to the Scottish Government to reduce the budget deficit.

1. Raise Council Tax
2. Cut spending on the NHS
3. Freeze public sector pay
4. Cut public sector jobs
5. Cut public sector pensions
6. Increase the free bus travel qualifying age from 60 to 65
7. Charge older people on higher incomes for their personal care
8. Increase prescription charges
9. Introduce tuition fees
10. Charge drivers for using major roads

We could ask them to rate each option on a scale of one to ten in terms of how strongly they feel that it should or shouldn't be adopted, from which we can calculate mean scores. However, meaningful interpretation is limited because it is possible for respondents to indicate that every option should or shouldn't be adopted and most options tend to become clustered around the same score.

Alternatively, we can ask respondents to rank the options from most to least preferred. However, while ranking is effective with a small number of options, it becomes less reliable when respondents are asked to rank longer lists. Respondents tend to find it relatively easy to identify the one or two options they prefer and one or two they like least, but find it difficult to discriminate between middle ranking items. As a result, neither rating nor ranking exercises give us a clear indication of the public's relative preferences.

Paired choice is designed to draw out the extent to which respondents prefer each option in relation to every other option. It works by pairing options off so that they are essentially 'competing' against one another. A series of these pairs are presented to respondents, who are asked to choose which of the two options they prefer. Respondents are forced to choose an option and cannot give a 'don't know' answer.

The number of pairs presented to respondents will depend on the number of options being tested and the methodology used to administer the questionnaire. In this example, 10 options would create 45 pairs[1], which is too many to present to every respondent. The most we would recommend is 15 pairs if conducting the survey via telephone and only slightly more if conducting it face-to-face or online (self-completion paper questionnaires are less suitable for paired choice). However, providing the sample size is large enough, respondents do not have to be shown all possible pairs to obtain reliable results. In this example, the 45 pairs are divided into five groups of nine pairs (see table 1 below), with each respondent given one group. Thus a sample of 1,000 will ensure each pair is put to 200 respondents, while nine is a comfortable number of pairs for respondents to complete.

Relative preference scores are used to estimate the extent to which each respondent prefers each option over each of the other options. The position of each option in the ranking and its overall score is calculated by taking an average of the score for each option across all respondents (see Figure 1 below). In addition, with a large sample we can examine how preferences differ between specific groups.

Reporting the results of this analysis can be tricky. Relative preference scores reflect the share of total preference each option has, which means we have to imagine that there is a pool of total preference to be allocated across each of the options. For

1 Calculated by multiplying the number of options (10) by the number of options it will be paired against (9) and then dividing by 2 (to account for the fact that each pair is used only once)

Table 1

	Group 1	Group 2	Group 3	Group 4	Group 5
Pair 1	3 v 6	1 v 5	7 v 2	2 v 4	9 v 6
Pair 2	1 v 4	5 v 7	9 v 10	10 v 3	8 v 4
Pair 3	7 v 9	6 v 10	8 v 7	1 v 7	10 v 2
Pair 4	4 v 7	2 v 8	3 v 5	9 v 1	2 v 9
Pair 5	2 v 1	8 v 3	5 v 9	4 v 6	7 v 3
Pair 6	5 v 2	7 v 6	4 v 3	5 v 8	1 v 10
Pair 7	10 v 5	4 v 9	6 v 1	7 v 10	6 v 8
Pair 8	9 v 3	3 v 2	1 v 8	6 v 5	4 v 5
Pair 9	8 v 10	10 v 4	2 v 6	8 v 9	3 v 1

example, figure 1 shows that raising the free bus travel qualifying age has a relative preference score of 31%, which means that 31% of the total preference would be allocated to this option. Essentially, relative preference reflects a collective strength of feeling towards a particular option in relation to the others – the higher the percentage, the more strongly it is preferred among respondents.

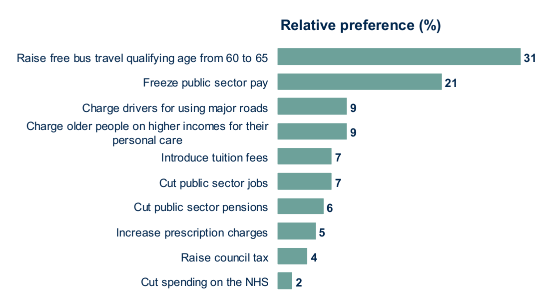
Analysing the data in this way allows us to reflect the public's preferences in-line with the decisions facing the Scottish Government. After all, the Scottish Government can introduce several of the options at once – they do not have the restriction of having to choose just one of the options. Therefore, the relative preference scores provide a general measure of the Scottish public's preference across all of the options. In other words, it reflects how likely they are to accept each option. This allows us to say that raising the free bus travel qualifying age is over three times more preferred than charging drivers for using major roads or charging older people on higher incomes for their personal care.

Paired choice does have limitations. It relies on respondents making instant decisions based on relatively abstract concepts which they may know little or nothing about. For example, respondents are not given information on the net saving each option is likely to generate, what proportion of the required savings this would be or the impact of the option on them. Knowing any of these may alter their preferences. Paired choice also requires a lot of specialist input, both prior to fieldwork, in scripting the complex routing required for the questionnaire, and after fieldwork, in conducting the analysis, which can make it more expensive than rating or ranking methods.

Overall, paired choice is an effective method that can be used to gauge respondents' priorities on anything from government policy and public spending to service provision and journey planning.

Figure 1

Relative preference



Source: Ipsos MORI

R&SB TELEPHONE SURVEY SAMPLE COMPOSITION

DENSITY						
	Residential/Seasonal Telephone		First Nations Telephone		Residential/Seasonal Online Panel	
	Unweighted	Weighted	Unweighted	Weighted	Unweighted	Weighted
Low	26%	28%	50%	50%	94%	89%
Medium	34%	41%	50%	50%		
Urban	20%	20%	-	-		
Seasonal	20%	11%	-	-	6%	11%
Total	100%	100%	100%	100%	100%	100%

The density (low, medium, urban) variable is present in the Hydro One customer database only, and thus not available for the online panel sample.

	REGION/URBAN/RURAL							
	Telephone				Online Panel			
	Residential		Seasonal		Residential		Seasonal	
	Unweighted	Weighted	Unweighted	Weighted	Unweighted	Weighted	Unweighted	Weighted
K- Urban	15%	14%	5%	5%	17%	17%	11%	4%
K- Rural	23%	24%	33%	32%	20%	20%	28%	34%
L- Urban	9%	9%	5%	5%	13%	13%	16%	5%
L- Rural	9%	9%	8%	7%	10%	10%	9%	6%
N- Urban	11%	11%	5%	5%	10%	10%	6%	3%
N- Rural	20%	20%	18%	18%	18%	18%	5%	16%
P- Urban	6%	5%	10%	11%	6%	6%	12%	6%
P- Rural	8%	8%	16%	16%	7%	7%	15%	26%
Total	100%	100%	100%	100%	100%	100%	100%	100%

	REGION/URBAN/RURAL			
	Telephone			
	First Nations		Small Business	
	Unweighted	Weighted	Unweighted	Weighted
K- Urban	1%	1%	7%	7%
K- Rural	18%	18%	26%	26%
L- Urban	5%	5%	8%	12%
L- Rural	16%	16%	6%	8%
N- Urban	2%	2%	14%	10%
N- Rural	26%	26%	28%	22%
P- Urban	4%	4%	5%	8%
P- Rural	28%	28%	6%	7%
	100%	100%	100%	100%

DEMAND/NON-DEMAND		
	Small Business Telephone	
	Unweighted	Weighted
<50 KW PEAK (Demand)	8%	5%
>50 TO <500 KW PEAK (Non-Demand)	92%	95%
Total	100%	100%

	POSITION IN ORGANIZATION
	Small Business (Telephone)
Owner or part owner	64%
General manager	14%
Facility or plant manager	2%
Other	21%
Total	101%

WORKSHOP INVITATIONS

WORKSHOP ATTENDANCE GRID

	C&I					LDA					LDC					
Venue	**Total**	**Target**	**RSVP**	**Act Attend**	**% Target**	**Total**	**Target**	**RSVP**	**Act Attend**	**% Target**	**Total**	**Target**	**RSVP**	**Act Attend**	**% Target**	**Total**
Hamilton	63	19	8	9	**47%**	17	6	6	5	**83%**	23	12	5	1	**8%**	103
Collingwood	40	12	13	9	**75%**	10	4	9	8	**200%**	11	6	-	1	**17%**	61
Timmins	21	6	4	5	**83%**	9	3	6	4	**133%**	6	3	-	-	**0%**	36
Thunder Bay	4	1	6	6	**600%**	5	2	-	1	**50%**	4	2	-	-	**0%**	13
London	90	27	17	7	**26%**	15	5	8	5	**100%**	13	6	12	9	**150%**	118
Windsor	76	23	16	10	**43%**	0	1	2	3	**300%**	0	-	-	-	**0%**	76
Kingston	41	12	6	4	**33%**	26	9	12	9	**100%**	13	6	7	6	**100%**	80
	335	**100**	**70**	**50**	**50%**	**82**	**30**	**43**	**35**	**117%**	**70**	**35**	**24**	**17**	**49%**	**487**
		30%					35%					50%				

WORKSHOP INVITATION EMAIL
COMMERCIAL AND INDUSTRIAL

Dear Customer:

We are about to begin planning for the future of our electricity system and I would like to hear what matters most to you.

Investment is needed to ensure the reliability of electricity delivery for you, but there are some choices as to how, when, and in what we invest. The feedback that you provide regarding your needs and preferences will be considered as part of the process with the Ontario Energy Board that determines the rates to deliver electricity to you.

You have been selected to participate in one of the workshops, and we would ask you to please read the attached invitation from Hydro One's President and CEO, Mayo Schmidt, for more details about this process. Please let us know which workshop venues you would prefer to attend, listed below, by **Friday, June 3rd, 2016**.

This is a new approach for us at Hydro One and we look forward to your participation.

Sincerely,

Rob Quail
Vice President – Customer Service
Hydro One Networks

Hamilton –June 8th , 2 PM – 5 PM
Crowne Plaza Hotel and Conference Centre - 150 King Street East, Royal Pavilion B, Hamilton, ON

Collingwood—June 9th, 9:30 AM - 12:30 PM
Blue Mountain Resorts LP - 218 Jozo Weider Blvd., Blue Mountains, ON

Timmins—June 13th, 9:30 AM - 12:30 PM
Cedar Meadows Resort & Spa - 1000 rue Norman Street, Salon Cartier, Timmins, ON

Thunder Bay—June 14th, 9:30 AM - 12:30 PM
Valhalla Inn - 1 Valhalla Inn Road, Odin Room

London—June 16th, 2 PM – 5 PM
Four Points By Sheraton - 1150 Wellington Road South, Bristol C, London, ON

Windsor—June 17th, 9:30 AM - 12:30 PM
St Clair College Centre for the Arts - 201 Riverside Drive West , Union Gas/Taq Taq Room , Windsor, ON

Kingston—June 24th , 2 PM – 5 PM
Delta Kingston Waterfront Hotel - 1 Johnson Street, Lakeview Room, Kingston, ON

WORKSHOP INVITATION EMAIL
LARGE DISTRIBUTION ACCOUNT

Subject: Large Distribution Account Workshops

Hello (Customer's name),

As part of the preparations for our 2017 Distribution Rate Filing, we are reaching out to our customers to better understand your needs and preferences so that we can incorporate them into Hydro One's investment plan over the next several years. To do so, we are holding workshops for selected customers around the province as well as making an online survey available to all. We have brought on Ipsos Reid, an independent firm, to collect your input and prepare a report documenting your feedback.

You have been selected to participate in one of the workshops, and we would ask you to please read the attached invitation from Hydro One's President and CEO, Mayo Schmidt, for more details about this process. Please let us know which workshop you would prefer to attend by **Friday, June 3rd, 2016**.

This is a new approach for us at Hydro One and we look forward to your participation.

Sincerely,

On behalf of (Superintendent's name)

WORKSHOP INVITATION LETTER
COMMERICAL AND INDUSTRIAL

Hydro One Inc.
483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5
www.HydroOne.com

Mayo Schmidt
President and CEO

May 27, 2016

Dear Sir or Madam,

I am writing to you today as Hydro One Networks Inc. is embarking on the process of developing its Distribution asset investment plan and we would like to receive your input to attain optimum results.

Following a successful Initial Public Offering (IPO) last fall, Hydro One is now operating as a public company. Consistent with our new reality, we are seizing a more proactive and disciplined approach in all aspects of the company. We are fully focused on increasing efficiencies, delivering improved business performance, and targeting our customers by placing a deeper focus on you. We will also continue to make prudent, cost-effective, short and long-term investments in our structure to ensure the electricity needs of Ontario are met now and well into the future.

The Distribution Investment Plan that we develop will, in turn, inform our Distribution Rates Application to the Ontario Energy Board for 2018 to 2022. In the course of developing this Investment Plan, we will identify, confirm and incorporate your needs and preferences into the Plan and ultimately our rate filing.

For this reason, we are asking you to participate in a consultation session with our planning and operations staff. We will hold these sessions across the province in the month of June so that we may:

- hear your views about your specific needs and preferences
- informed decisions will be made about balancing service levels versus cost; and,
- reflect your feedback in the development of an asset investment plan that achieves a balance linking managing reliability, service and cost.

During the course of the meeting, we will:

- provide an overview of our system and describe our historic approach to developing, maintaining and sustaining our distribution assets
- discuss system improvement priorities including their cost and rate implications
- discuss customer preferences for system and service improvements; including their cost and rate implications
- outline our approach to reducing costs and targeting efficiencies in our business
- obtain customer input on rates; striking the right balance between service and costs
- discuss how customer feedback will be considered in the development of our investment plan
- track and document customer feedback.

Ultimately, our aim is to ensure our investment plan identifies, prioritizes and schedules the precise investments in our distribution system so that your electricity needs are met.

Once you confirm your interest in participating, we will provide you with background information to prepare for our discussion. In the meantime, if you have any questions, please contact the Hydro One Business Customer Centre at HydroOneBCC@HydroOne.com or 1-866-922-2466.

We're eager to hear your insights and look forward to your confirmation that you will participate in this important process.

Please join us at one of the following locations:

- Hamilton – June 8th
- Collingwood – June 9th
- Timmins – June 13th
- Thunder Bay – June 14th
- London – June 16th
- Windsor – June 17th
- Kingston – June 24th

My best,

Mayo Schmidt
President & CEO

Hydro One Inc.
483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5
www.HydroOne.com

Mayo Schmidt
President and CEO

May 11, 2016

Dear (Customer's name),

I am writing to you today as Hydro One Networks Inc. is embarking on the process of developing its Distribution asset investment plan and we would like to receive your input to attain optimum results.

Following a successful Initial Public Offering (IPO) last fall, Hydro One is now operating as a public company. Consistent with our new reality, we are seizing a more proactive and disciplined approach in all aspects of the company. We are fully focused on increasing efficiencies, delivering improved business performance, and targeting our customers by placing a deeper focus on you. We will also continue to make prudent, cost-effective, short and long-term investments in our structure to ensure the electricity needs of Ontario are met now and well into the future.

The Distribution Investment Plan that we develop will, in turn, inform our Distribution Rates Application to the Ontario Energy Board for 2018 to 2022. In the course of developing this Investment Plan, we will identify, confirm and incorporate your needs and preferences into the Plan and ultimately our rate filing.

For this reason, we are asking you to participate in a consultation session with our planning and operations staff. We will hold these sessions across the province in the month of June so that we may:

- hear your views about your specific needs and preferences
- informed decisions will be made about balancing service levels versus cost; and,
- reflect your feedback in the development of an asset investment plan that achieves a balance linking managing reliability, service and cost.

During the course of the meeting, we will:

- provide an overview of our system and describe our historic approach to developing, maintaining and sustaining our distribution assets
- discuss system improvement priorities including their cost and rate implications
- discuss customer preferences for system and service improvements; including their cost and rate implications
- outline our approach to reducing costs and targeting efficiencies in our business
- obtain customer input on rates; striking the right balance between service and costs
- discuss how customer feedback will be considered in the development of our investment plan
- track and document customer feedback.

Ultimately, our aim is to ensure our investment plan identifies, prioritizes and schedules the precise investments in our distribution system so that your electricity needs are met.

Once you confirm your interest in participating, we will provide you with background information to prepare for our discussion. In the meantime, if you have any questions, please contact (Superintendent's name) at (Superintendent's cell phone number).

We're eager to hear your insights and look forward to your confirmation that you will participate in this important process.

Please join us at one of the following locations:

- Hamilton – June 8th
- Collingwood – June 9th
- Timmins – June 13th
- Thunder Bay – June 14th
- London – June 16th
- Kingston – June 24th

My best,

Mayo Schmidt
President & CEO

WORKSHOP MATERIALS

Dx CUSTOMER ENGAGEMENT

WORKSHOP MATERIALS

June 2016

Agenda for today's conversation

1	Introduction: Who we are and what we do	*30 minutes*
2	Review: Current system performance	*30 minutes*
	Break: ~15 min	
3	Context: Investing in the system	*30 minutes*
4	Discussion: What's best for you?	*75 minutes*

Agenda

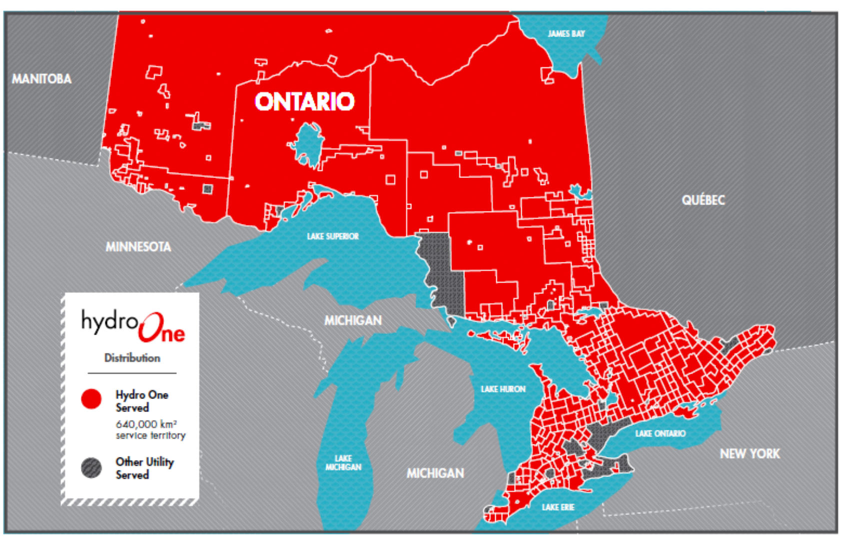
1. **Introduction:** Who we are and what we do

2

Hydro One: Who we are and what we do

Hydro One is the **largest electric power distributor in Ontario**. Hydro One serves 25% of Ontarians — more than **1.3 million customers** across the province.

The distribution service territory covers vast areas and the majority of the province.

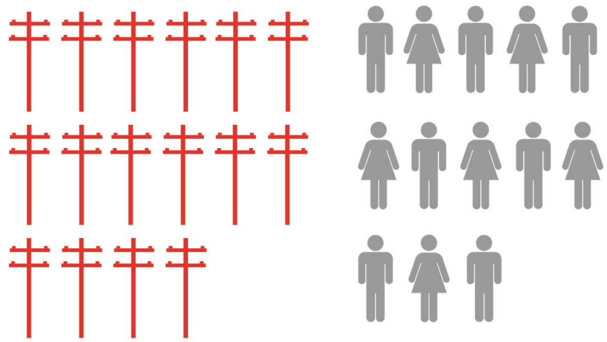


3

Hydro One: How we serve you

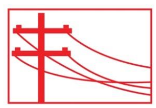
Hydro One's assets include **123,000 kilometres of lines** (enough wire to circle the earth 3 times) and approximately **1,000** distribution and voltage regulating stations.

Hydro One also has more poles than customers.



1.6M
POLES

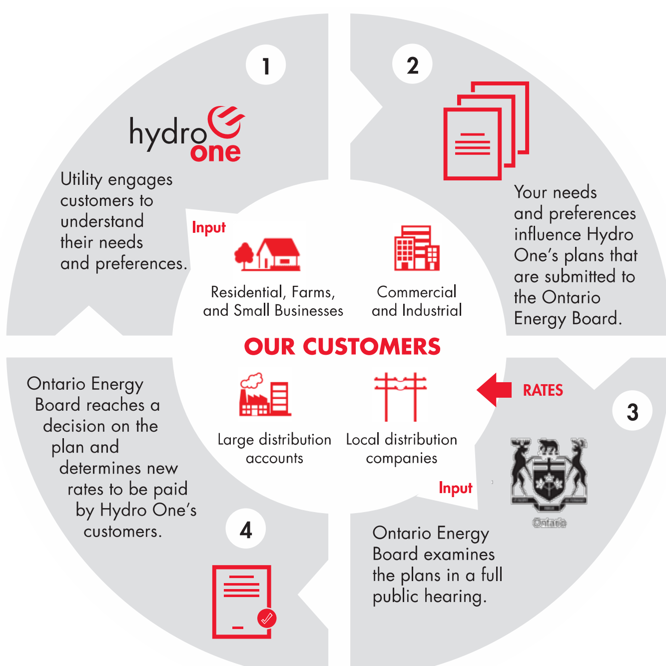
1.3M
CUSTOMERS



123,000 km
DISTRIBUTION LINES

4

Hydro One wants your input



5

Further context for this workshop

The Ontario Energy Board (OEB) ensures that all customers have the opportunity to provide input in its process to set utility rates in Ontario.

Hydro One is currently **preparing a distribution rate application** which will be filed in early 2017.

- The application will explain Hydro One's investment plan that the OEB will assess to determine electricity distribution rates from 2018-2022.

All of Hydro One's distribution customers will have the opportunity to provide input into the investment plan through workshops, focus groups, surveys, and one-on-one discussions.

Hydro One's objective is to provide its customers with safe and reliable electricity.

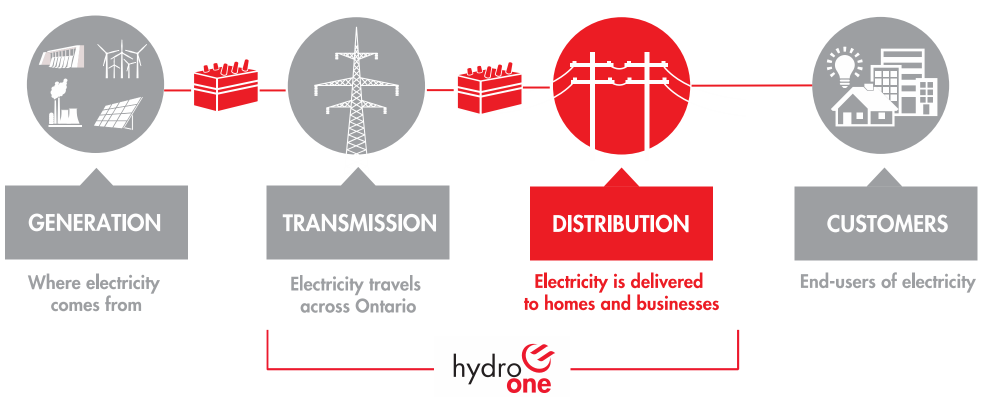
- In pursuing this goal, Hydro One must make tradeoffs between cost impacts, reliability and other services they provide to you.

Hydro One wants to understand whether your needs are being met by the current system and **which types of reliability and service improvements you value most.** Hydro One will also share information and request your feedback on **potential rate impacts.**

Your input will be considered as Hydro One develops its plans, along with other considerations including its mandatory obligations, asset condition assessments and the ability to resource, schedule and execute the plan.

6

Hydro One's role in the electricity system



- Electricity is produced by generators including Ontario Power Generation, Bruce Power, NextEra and other generators.

- The **transmission system** conveys electricity from generators to distributors and large consumers.
- Hydro One operates 96% of transmission in Ontario

- The **distribution system** conveys electricity to customers.
- Hydro One distributes electricity to 25% of Ontario's population.

- Residential
- Commercial and Industrial
- Large Consumers
- Other Distributors

While Hydro One is involved in both transmission and distribution of electricity our focus today is on Hydro One's distribution system.

7

Hydro One's customers are diverse

hydro one

Residential, Farms, and Small Businesses	Commercial and Industrial	Large users	Local distribution companies
~1.3M customers 42% of power used	~8,000 customers 13% of power used	~90 customers 11% of power used	~60 companies 34% of power used
Homes, small shops, local farms	Hospitals, grocery stores and other businesses	Food processing, mining, and other large businesses	Smaller utilities

Hydro One seeks to balance the differing needs of customers

- Costs
- Reliability
- Accurate billing
- Customer service
- Communication
- Power quality
- Conservation
- Accurate restoration times
- Capacity expansion

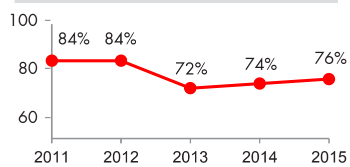
8

What Hydro One has heard from larger customers

hydro one

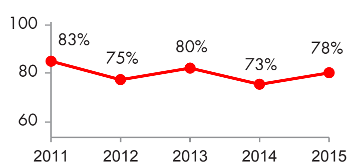
Customer Segment	Recent Customer Satisfaction Surveys	Customer Priorities

Commercial and Industrial



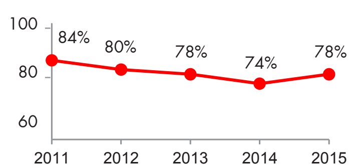
- Customer service, rates, and billing

Large Distribution Account



- Communication with Hydro One, reliability / power quality, customer service, and rates

Local Distribution Company



- Rates, reliability, and capacity expansion

9

What part of your monthly bill goes to Hydro One for distribution?

hydro one

Bill breakdown for typical customer profiles

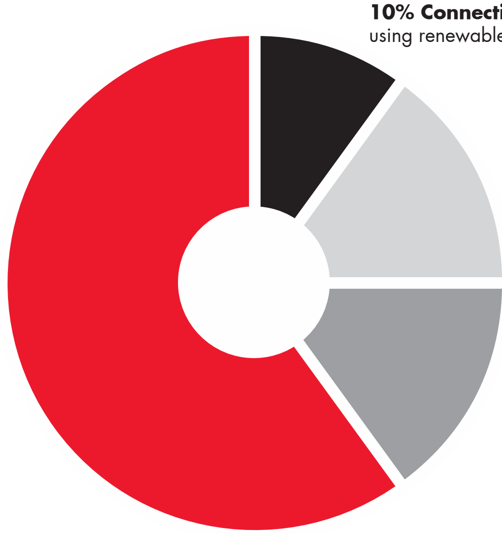
	Commercial and Industrial				Large Distribution Accounts & Local Distribution Companies	
	Rural		Urban			
	Typical	Large	Typical	Large	Typical	Large
Energy consumption (kWh)	35,000	200,000	35,000	200,000	1,450,000	5,000,000
Peak energy use (kW)	150	500	150	500	3,000	10,000
Total Bill with GST/HST ($)	**7,800**	**36,900**	**6,700**	**33,300**	**217,100**	**748,100**
– Commodity	47%	57%	54%	62%	69%	69%
– Distribution delivery charge	30%	20%	20%	13%	3%	2%
– Transmission delivery charge	5%	4%	8%	5%	8%	8%
– Other (Regulatory, Debt Retirement, GST/HST)	18%	19%	18%	20%	20%	21%

10

What do distribution rates pay for?

hydro one

Breakdown of Hydro One's 2016 distribution Capital and Operating, Maintenance and Administration (OM&A) costs



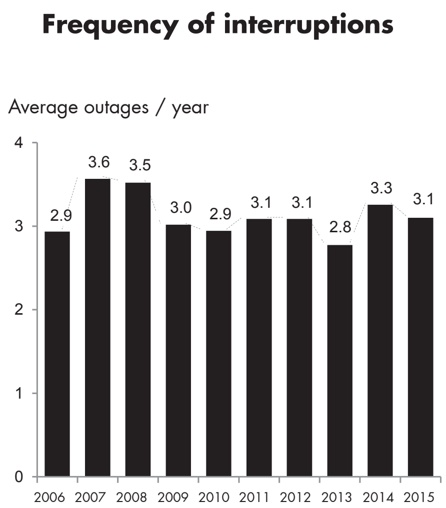
11

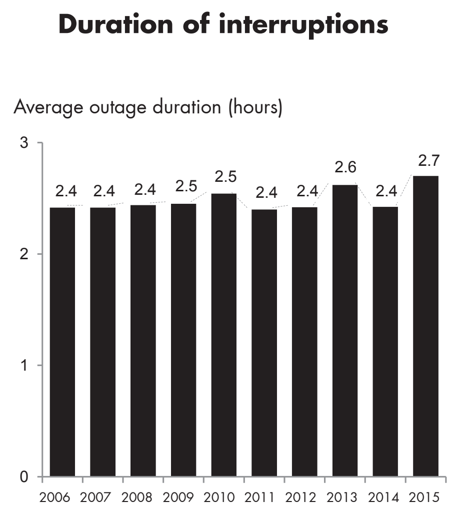
Agenda

2. **Review:** Current system performance

12

Over time, Hydro One's provincial reliability performance has remained consistent





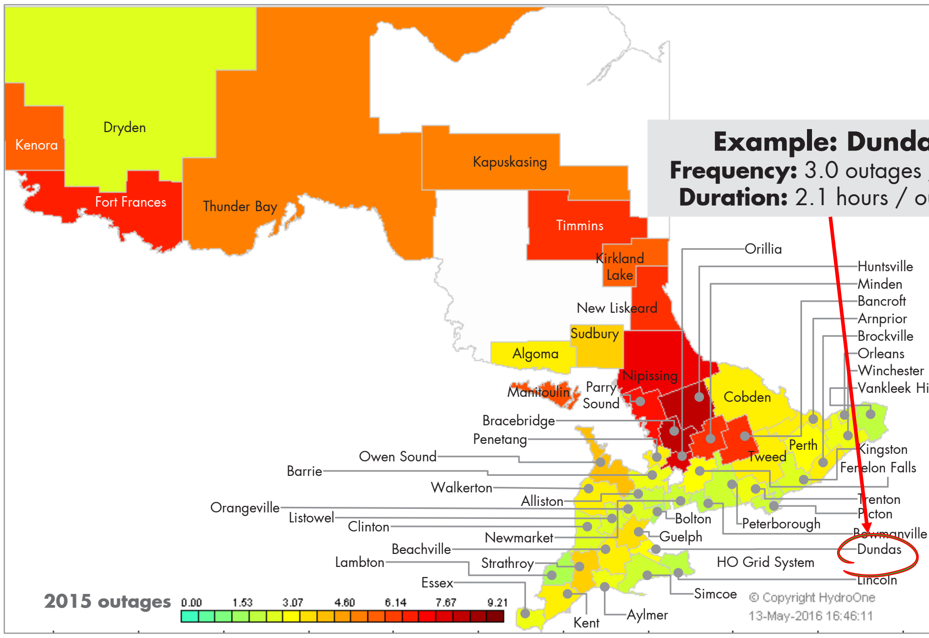
13

Reliability varies by location within the province

hydro one

Hamilton

Example: Dundas
Frequency: 3.0 outages / year
Duration: 2.1 hours / outage



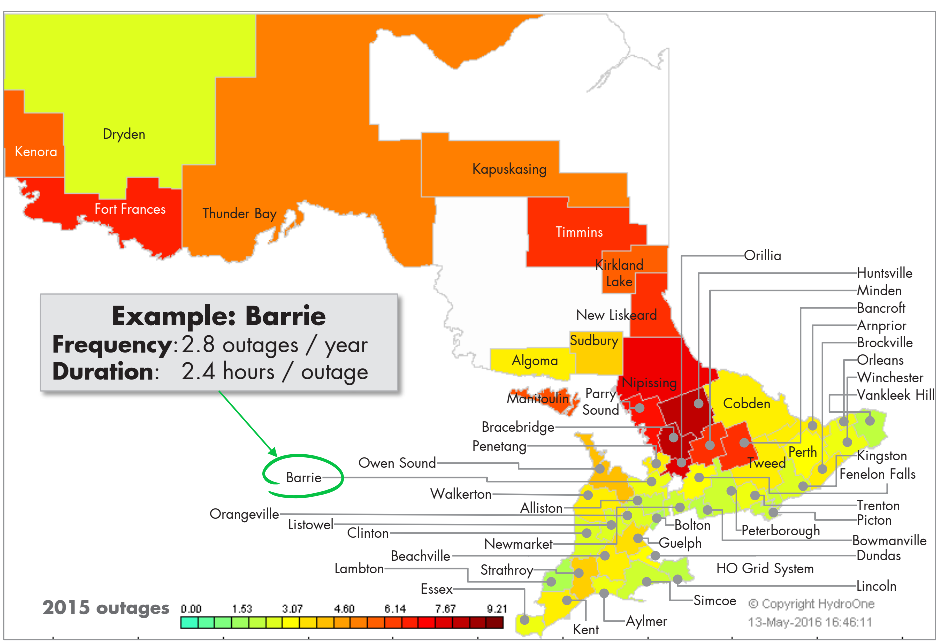
Note: Includes force majeure outages

16

Reliability varies by location within the province

hydro one

Example: Barrie
Frequency: 2.8 outages / year
Duration: 2.4 hours / outage

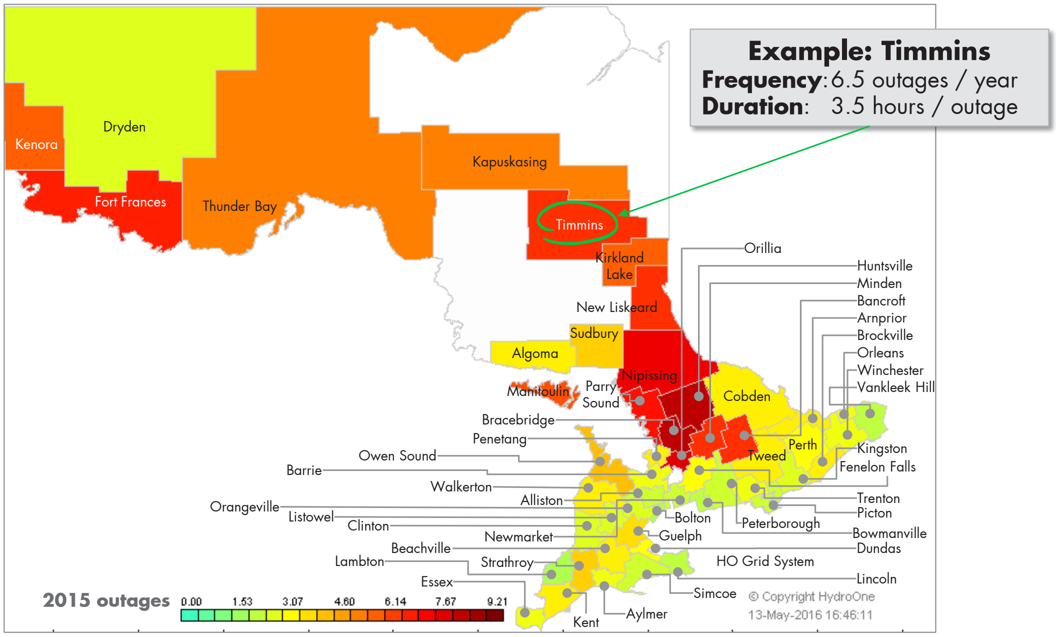


Note: Includes force majeure outages

14

Reliability varies by location within the province

hydro one

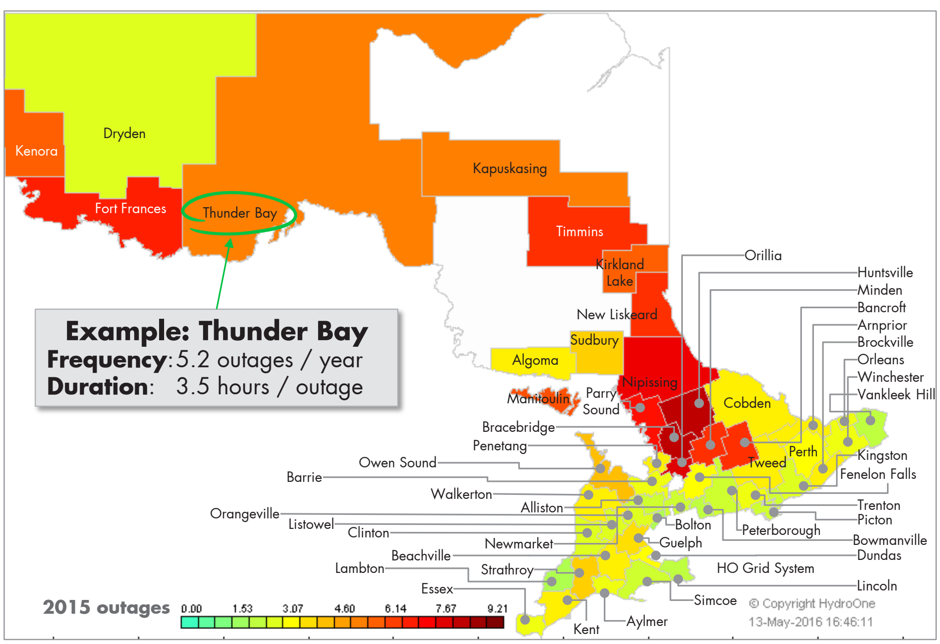


Note: Includes force majeure outages

16

Reliability varies by location within the province

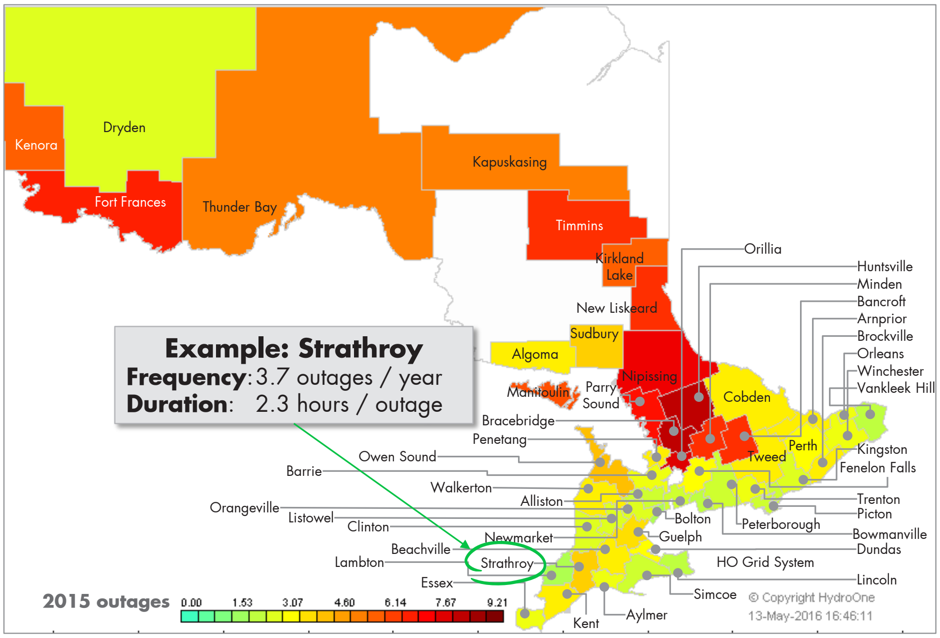
hydro one



Note: Includes force majeure outages

16

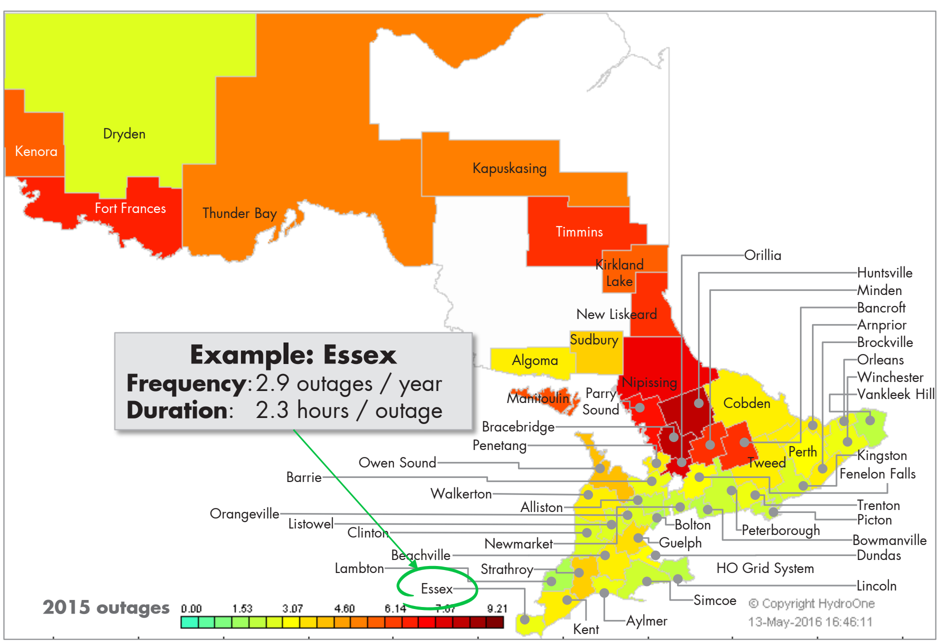
Reliability varies by location within the province



Note: Includes force majeure outages

16

Reliability varies by location within the province

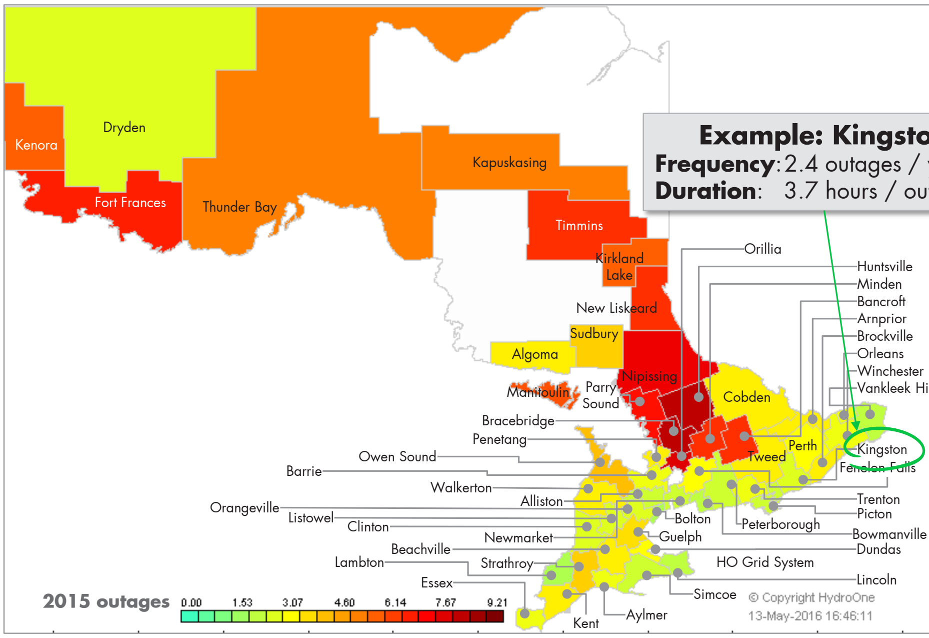


Note: Includes force majeure outages

16

Reliability varies by location within the province

hydro one



Note: Includes force majeure outages

16

Hydro One serves both rural and urban customers

hydro one

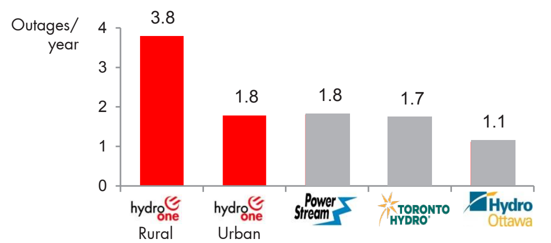
Hydro One's system is larger and more rural than other Ontario utilities'

	Utility	# of customers	Service area (km²)	Km of power lines
hydro one	**Hydro One**	1,300,000 Rural: 84% Urban 16%	640,000	123,000
TORONTO HYDRO	Toronto Hydro	740,000	630	10,000
PowerStream	PowerStream	350,000	800	7,600
Hydro Ottawa	Hydro Ottawa	320,000	1,100	5,500

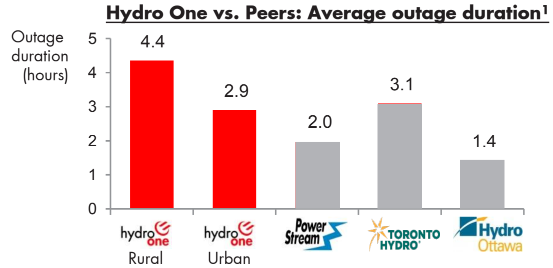
Reliability performance is affected by factors such as: system design, vegetation, equipment performance, geography, exposure to adverse weather.

Hydro One's urban customers experience reliability comparable to other urban utilities'

Hydro One vs. Peers: Average outages / year[1]



Hydro One vs. Peers: Average outage duration[1]



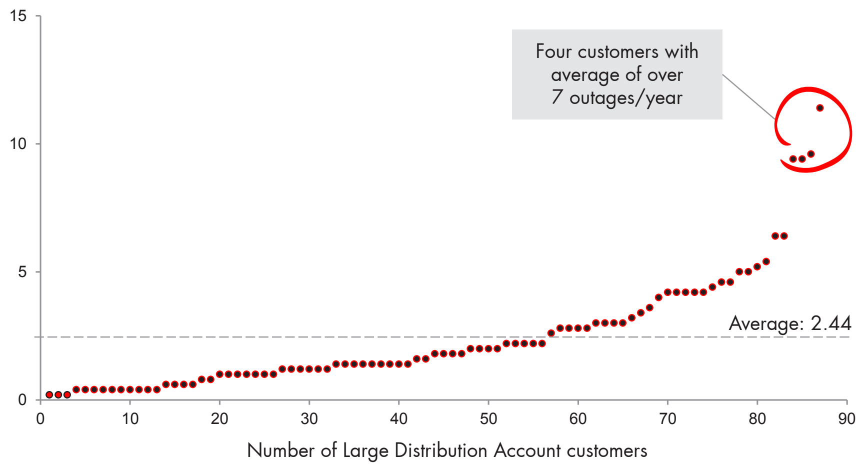
1. Outage metrics based on average from 2012-2014. Includes force majeure, excludes loss of supply.
Source: Ontario Energy Board electricity distributor scorecards. Hydro One outage data.

15

Reliability varies from customer to customer

hydro one

Large Distribution Account (LDA) Outages / year (average 2011-2015)



Hydro One is looking at options to target poor-performing areas

16

Trees and equipment failures cause almost half of Hydro One's power outages

hydro one

Power outage causes (2013-2015)

Tree damage	**24%**	Trees fall on lines during storms.
Equipment failure	**24%**	Poles, transformers, lines failures can cause an outage.
Unconfirmed causes	**19%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Scheduled outages	**16%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Loss of power supply	**12%**	Issues relating to the larger grid, like damage to transmission lines.
Animal or vehicle damage to equipment	**5%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.

17

Reliability challenges

Challenges all utilities face	Issues specific to Hydro One
Geography: Forested service territories are prone to outages caused by tree contact. In order to restore power, repair crews must locate and travel to source of an outage.	Much of Hydro One's service territory is heavily forested compared to other utilities'.[1] In 2014, Hydro One cleared over 9,000 km of distribution line. Hydro One's large service area means outages are longer and are more costly to locate and repair. Hydro One's network uses a radial circuit design to cover a large area, which does not provide redundant power supplies common in urban areas.
Weather: Major storms inevitably cause damage to power lines.	Hydro One's large service territory exposes it to all of Ontario's most challenging weather conditions.
Infrastructure: Most electric power grids were built up over many years with a huge volume of equipment and a mix of different technologies.	Hydro One's system serves an average of 10 customers per kilometre of power line while other utilities serve about 70 customers per kilometre. This requires Hydro One to maintain a large number of assets per customer.

1. Hydro One 2009 Vegetation Management Benchmarking Study by CN Utility Consulting, Inc.

Agenda

3. Context: Investing in the system

Hydro One is focused on efficiency and productivity

hydro one

Between 2014-2015 unit costs declined by:

- 4% for brush control
- 10% for line clearing
- 12% for wood pole replacement

This has been accomplished through the use of:

- A large, seasonal, mobile, contingent workforce
- Increased use of mechanical harvesting equipment to fell trees
- Targeted herbicide application, where feasible, reducing brush control costs
- Improved planning to prioritize and execute work
- Technology deployment that improves operational monitoring and control

Hydro One is contributing in a material way by reducing its costs.

20

Factors that influence Hydro One's investments

hydro one

Investments are identified, prioritized and scoped to manage risks associated with:

Safety	Keeping the public and employees safe is Hydro One's number one priority
Customer	Meeting customers' service quality expectations
Reliability	Maintaining reliability
Productivity	Achieving efficiencies
Continuous innovation	Adopting proven and effective technologies
Environment	Protecting the environment and complying with regulations
Shareholder Value	Complying with laws and regulations, earning public trust, achieving financial targets

21

2016 expenditures

Approximately $1,250M is spent to maintain reliability and service levels

	Largest investment programs include:	Budget (2016, $M)
	Replacing and refurbishing assets	320
	Connecting new customers	150
	Mandatory system upgrades	30
OM&A	Managing vegetation near lines	150
OM&A	Planned asset maintenance	110
OM&A	Responding to outages	100
OM&A	Customer service	90

$60M is spent to improve reliability and service levels

Outcomes

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy sources and energy storage

Your input will help Hydro One determine how to invest going forward

22

Maintain: Largest programs involve replacement and refurbishment of assets in poor condition

Wood poles

- **240,000** wood poles (15% of the fleet) are currently beyond their expected service life of 60 years.
- **400,000** wood poles (25% of the fleet) would be beyond their expected service life by 2022 if no replacements are made.

Distribution stations

- Approximately **144** station transformers (12% of the fleet) are currently beyond their expected service life of 50 years.
- Approximately **360** station transformers (30% of fleet) would be beyond their expected service life by 2022 if no replacements are made.

Much of the system was built in the 1950s and 1960s. Consequently many assets are approaching or beyond the end of their expected service lives. Replacement decisions are based on actual asset condition.

23

Improve: There are several outcomes Hydro One can pursue

hydro one

Outcomes	Enabling expenditures
1 Reducing the number of outages 2 Shortening the length of power outages 3 Improving customer service 4 Improving power quality 5 Upgrading the system to connect renewable energy and energy storage	**Improving system design** • Example: Where practical, providing backup capability as old lines are replaced **Vegetation Management** • Example: Trimming trees more frequently, on a selective basis, to reduce consequences of tree-related outages **Improving Monitoring and Control** • Example: Enhancing the capabilities at Hydro One's operating centre and installing equipment that can be controlled remotely • Example: Installing power quality monitoring equipment

26

Improve: There are several outcomes we can pursue

hydro one

Ways we can improve

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Central Ontario

Project	Customer benefits	Details
Muskoka forestry initiative	• Improved reliability	• More aggressive vegetation clearing program on targeted power lines • Timing 2016 • **Cost: ~$20 M**
Algonquin Park tie line	• Improved reliability • Improved power quality	• 12 km tie line to connect two power lines together • Timing 2013-14 • **Cost: ~$3 M**
Rosseau DS	• Improved reliability • Increased capacity • Improved power quality	• New distribution station built to provide load relief to 3 neighboring stations • Timing 2011-12 • **Cost: ~$9 M**

24

Improve: There are several outcomes we can pursue

hydro one

Ways we can improve

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Northeastern Ontario

Project	Customer benefits	Details
City of Timmins voltage conversion	• Improved reliability • Reduction in future maintenance costs	• Replace obsolete distribution stations and lines and standardize city voltage • Completed in 2015 • **Cost: ~$11 M**
Manitouwadge TS M2 rebuild	• Improved reliability • Improved power quality	• Rebuild 80 km long line and replace with larger size standard conductor • Timing 2014-18 • **Cost: ~$18 M**
Martindale TS M5 relocation	• Improved reliability • Reduction in future maintenance costs	• Relocate 45 km long line at end of life to roadside • Timing 2012-16 • **Cost: ~$16 M**

27

Improve: There are several outcomes we can pursue

hydro one

Improvement priorities

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
1. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Northwestern Ontario

Project	Customer benefits	Details
• **Barwick TS**	• Improved reliability • Increased capacity • Connection of solar farms	• New transmission station divided 100 km long feeder into two 50 km long feeders • Completed in 2014 • **Cost: ~$20 M**
• **Nipigon Town voltage conversion**	• Improved reliability • Increased capacity	• Voltage feed of Nipigon Town being converted to allow integration with areas north of town • Est. 2017 completion • **Cost: ~$2 M**
• **New Keewatin DS**	• Improved reliability • Increased capacity	• New distribution station built to permit addition of new load, allowing growth in the community • Completed in 2013 • **Cost: ~$5 M**

27

Improve: There are several outcomes we can pursue

hydro one

Ways we can improve

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Southwestern Ontario

Project	Customer benefits	Details
Palmerston TS M2 extension	▪ Improved reliability ▪ Increased capacity	▪ Extend power line by 11 km to provide source of supply to the town of Mount Forest ▪ Timing: 2016 ▪ **Cost: ~$2 M**
Edgeware TS M3 relocation	▪ Improved reliability ▪ Increased capacity	▪ New feeders built from Duart TS to sectionalize Kent TS and St Thomas TS feeders ▪ Timing: 2013 ▪ **Cost: ~$2 M**
Commerce Way TS	▪ Improved reliability ▪ Increased capacity	▪ New transmission station to provide load relief to neighboring station ▪ Completed in 2015 ▪ **Cost: ~$13 M**

27

Improve: There are several outcomes we can pursue

hydro one

Ways we can improve

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Southwestern Ontario

Project	Customer benefits	Details
Leamington TS feeder	• Improved reliability • Increased capacity	• Construction of new power line • Timing 2016-18 • **Cost: ~$60 M**
Lauzon / Belle River TS feeder reconfig	• Increased capacity	• Power line reconfiguration to provide load relief to neighboring power line • Completed in 2013 • **Cost: ~$2 M**

27

Improve: There are several outcomes we can pursue

hydro one

Ways we can improve

1. Reducing the number of outages
2. Shortening the length of power outages
3. Improving customer service
4. Improving power quality
5. Upgrading the system to connect renewable energy and energy storage

Examples of improvement projects in Southeastern Ontario

Project	Customer benefits	Details
Orleans TS	• Improved reliability • Increased capacity	• New transmission station to provide supply for future growth in east end of Ottawa and surrounding area • Timing 2015-16 • **Cost: ~$17 M**
St. Lawrence submarine cable	• Improved reliability • Increased capacity • Improved power quality	• Replace end of life submarine cables from mainland to nearby islands • Timing 2013-16 • **Cost: ~$7 M**
44kV relocation	• Improved reliability • Reduction in future maintenance costs	• Relocate off-road line at end of life to roadside • Complete 10-yr project • **Cost: ~$20 M**

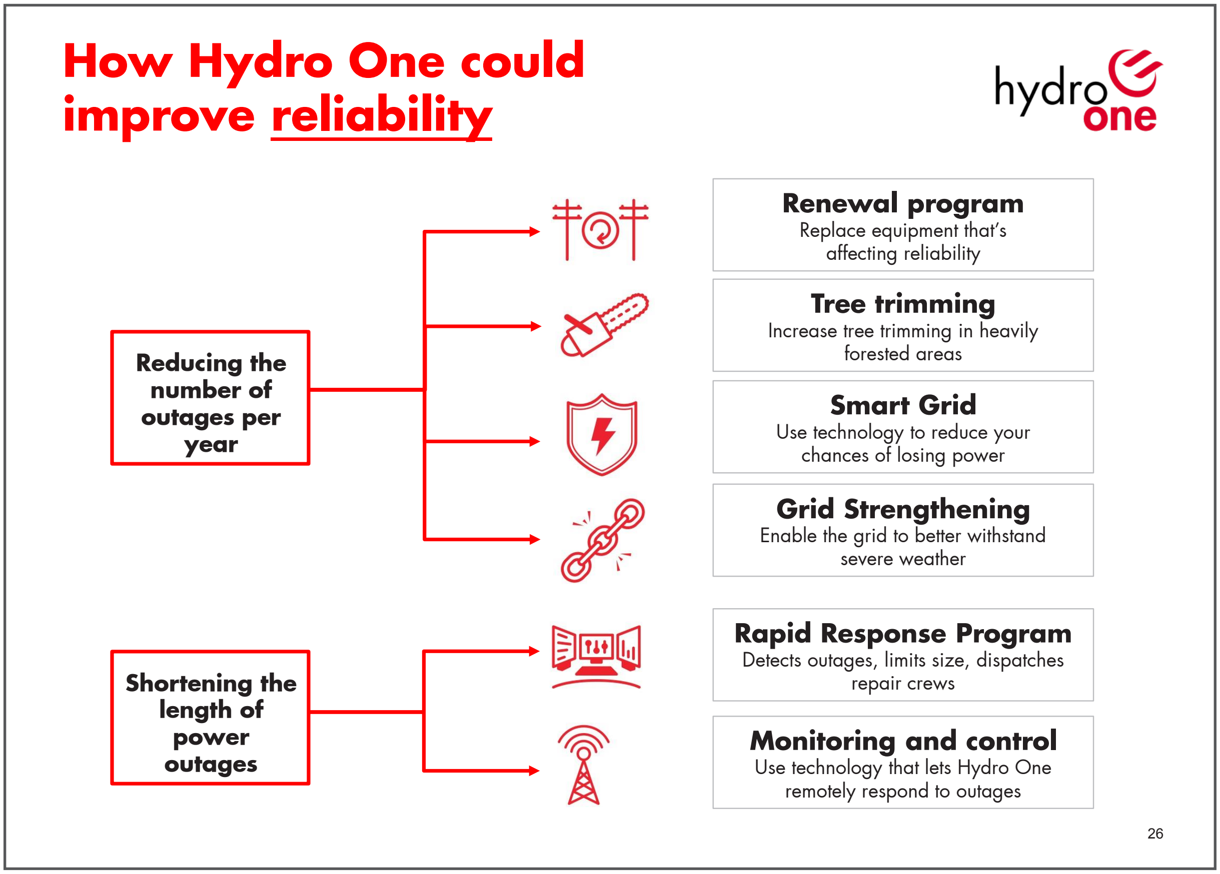
27

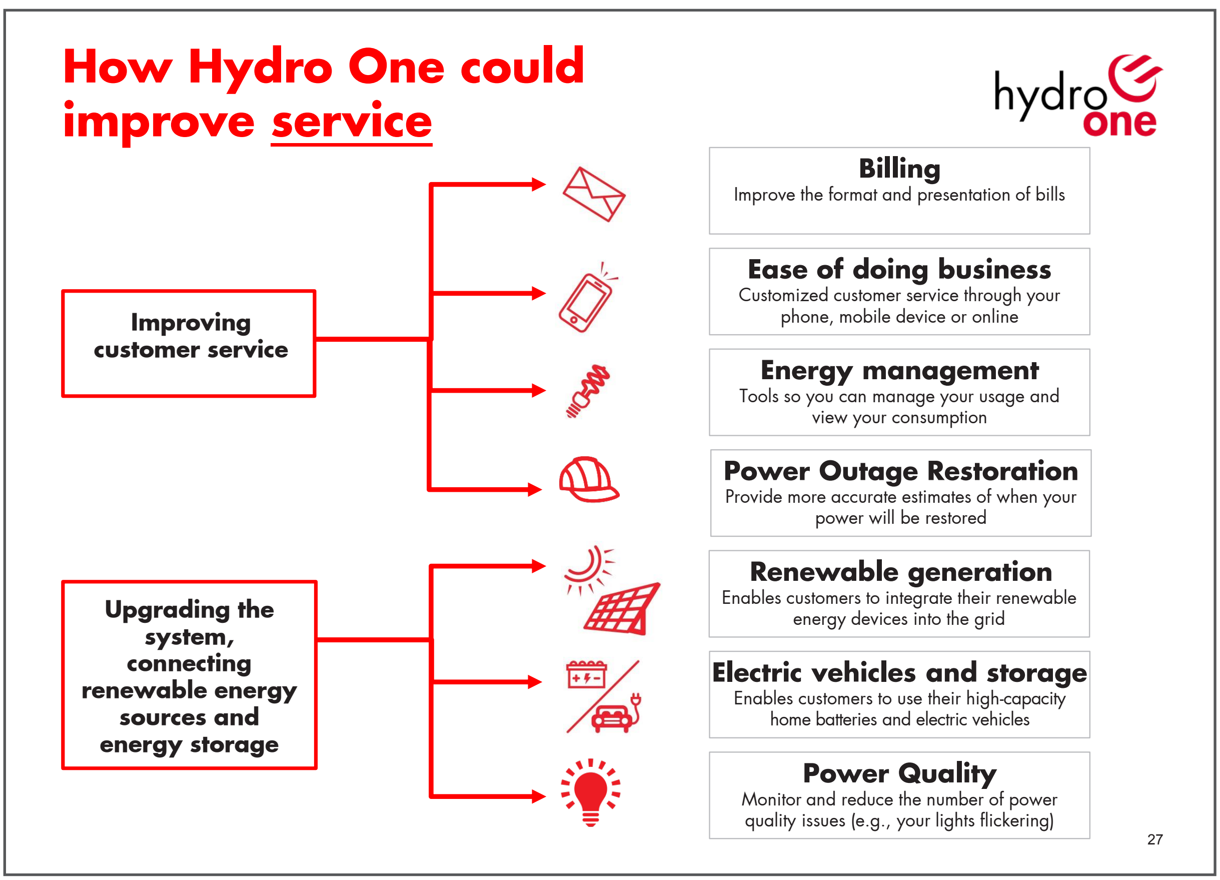
Agenda

hydro one

4. Discussion: What's best for you?

25


How Hydro One could improve reliability
hydro one
Reducing the number of outages per year
Renewal program
Replace equipment that's affecting reliability
Tree trimming
Increase tree trimming in heavily forested areas
Smart Grid
Use technology to reduce your chances of losing power
Grid Strengthening
Enable the grid to better withstand severe weather
Shortening the length of power outages
Rapid Response Program
Detects outages, limits size, dispatches repair crews
Monitoring and control
Use technology that lets Hydro One remotely respond to outages
26


How Hydro One could improve service
hydro one
Improving customer service
Billing
Improve the format and presentation of bills
Ease of doing business
Customized customer service through your phone, mobile device or online
Energy management
Tools so you can manage your usage and view your consumption
Power Outage Restoration
Provide more accurate estimates of when your power will be restored
Upgrading the system, connecting renewable energy sources and energy storage
Renewable generation
Enables customers to integrate their renewable energy devices into the grid
Electric vehicles and storage
Enables customers to use their high-capacity home batteries and electric vehicles
Power Quality
Monitor and reduce the number of power quality issues (e.g., your lights flickering)
27

Introduction to investment scenarios

Illustrative scenarios have been developed for various levels of capital investment.

These in turn, result in different impacts on rates, reliability, and service levels.

These scenarios are meant to represent a spectrum of potential investment levels.

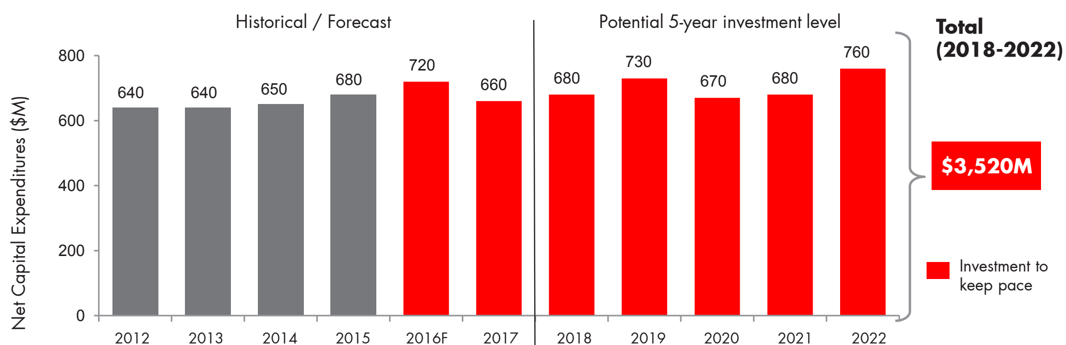
We do not have a recommended scenario, nor are we asking you to choose from the scenarios presented.

Through this conversation, we would like to better understand your business needs and preferences to inform our 5-year Distribution Investment Plan.

28

Scenario 1: Maintain current reliability and service levels

1 Maintain performance scenario



OM&A ($M)	2012	2013	2014	2015	2016F	2017	2018	2019	2020	2021	2022	Total (2018-2022)
	550	610	680	570	590	590	610	620	630	650	660	$3,170M

Key elements

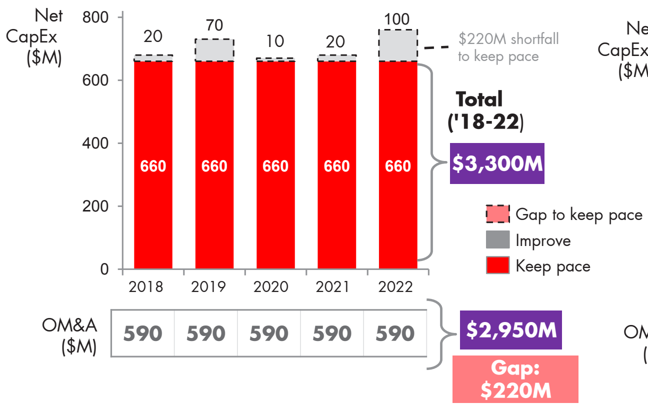
- Increased capital expenditures to keep pace with need to renew aging / deteriorating infrastructure and continue proactive investments to prevent issues
- OM&A growth limited to rate of inflation
- Reliability and service levels unchanged

29

Scenarios 2 and 3:
Declining or improving reliability

hydro one

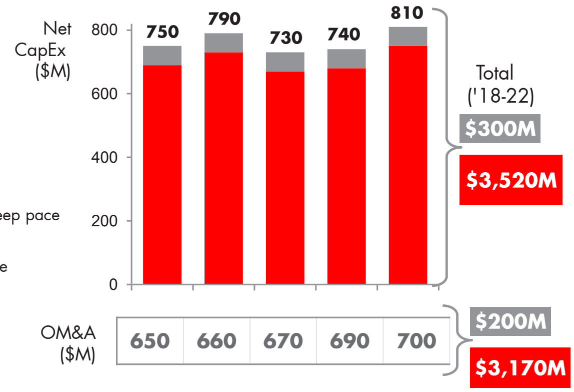
2 Declining performance scenario



Key elements

- Capital and OM&A expenditures frozen at 2017 levels
- Focus on non-discretionary expenditures associated with safety, environment, equipment repair and compliance
- Reduced preventative maintenance

3 Improving performance scenario



Key elements

- Additional $500M in spend over 5 years
- Increased preventative maintenance to 'get ahead' of asset degradation and prevent issues from occurring
- Improvement in overall levels of reliability and service

Preferred levels of reliability and service will affect rates

hydro one

	2 Declining performance	1 Maintain performance	3 Improving performance
Distribution delivery rate impact	Increase: **2.5%** [1]	Increase: **3.4%**	Increase: **~4.0%**
	Average across all customers – could be higher or lower if investments are specifically targeted towards customers in certain rate classes		
Reliability impact	• Average number of outages increases ⟷	• Average number of outages remains the same ⟷	• Average number of outages decreases ~10%
	• Average duration of each outage increases ⟷	• Average duration of each outage remains the same ⟷	• Average outage duration decreases by ~8% (~15 minutes)
Customer Service impact	• Longer response times to customer inquiries ⟷	• Continued focus ⟷	• Increased customized customer service offerings and tools

Assumes full capital expenditure improvement budget allocated to reliability

[1]Hydro One's asset base will continue to increase as old assets are replaced with new ones.

31

Hydro One could target investments to offer differentiated reliability and service to large customers

hydro one

Context	• Many large customers have unique needs and have asked for much higher reliability and/or service levels, beyond the "improve" scenario • Certain portions of the distribution system provide differing levels of performance by virtue of geography and design • Hydro One recognizes that power delivery issues have a significant effect on some customers' businesses • Hydro One wants to support customers' business needs and help them be successful in the face of competition • We would like to open a discussion around customer requirements and what Hydro One could do to better meet your needs

32

HYDRO ONE DISTRIBUTION CONSULTATION

C&I WORKSHOP SURVEY BOOKLET

INTRODUCTION

This survey booklet is organized into sections that correspond with the flow of the workshop today. You will be provided time after each section of the workshop presentation today for you to answer the survey. Feel free to refer back to the Hydro One Presentation/Workbook as needed in deciding your opinion.

Please answer all of the questions in the survey.

If you require more space, please write on the back of your survey. If you have any questions, please ask one of the IPSOS staff present at the session today.

WHO WE ARE AND WHAT WE DO

As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.

1. How satisfied are you with Hydro One overall?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied

Is there anything in particular that Hydro One can do to improve its service to you?

2. Hydro One would like to better understand what is important to you as a large customer. From the following list, which would you say is most important to your organization? (select one only)

- ☐ Reducing the number of power outages (through activities such as tree-trimming, replacing equipment)
- ☐ Shortening the length of power outages (through activities such as installing remote control devices)
- ☐ Improving customer service and billing (such as billing accuracy and answering customer questions)
- ☐ Upgrading the system to connect new customers including those producing renewable energy sources and using energy storage (such as wind, solar, and electric vehicles)
- ☐ Keeping costs as low as possible

If something is more important to you than these five items, please write it into the text box below.

REVIEW: CURRENT SYSTEM PERFORMANCE

3. Is there anything unclear about what has been presented in Current System Performance section of the presentation/workbook today?

The following few questions are about your experience with unplanned power interruptions.

The term interruption refers to a complete loss of electric power and outage refers to the disabling of a component's capability to deliver power (planned or unplanned). An outage may or may not cause an interruption of service to customers.

4. A sustained power interruption is one lasting at least 1 minute. How many did your organization experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. Circle your choice.

None 1 2 3 4 5+ Don't know /Can't recall

5. On average, how long did these unplanned interruptions last? Please answer in minutes. Your best guess is fine.

- ☐ No unplanned interruptions
- ☐ Don't know/can't recall

6. How, if at all, did these unplanned interruptions impact your organization?

7. What, if anything, would you like Hydro One to do to manage unplanned interruptions?

CONTEXT: INVESTING IN THE SYSTEM

8. Based on what you just heard/read in presentation, do the investments to maintain the current level of reliability and service that Hydro One is making today make sense to you?

- ☐ Yes, please explain below
- ☐ No, please explain below

9. Based on what you just heard/read in presentation, do the investments to improve the current level of reliability and service that Hydro One is making today make sense to you?

- ☐ Yes, please explain below
- ☐ No, please explain below

5

What's best for you? How Hydro One could improve reliability and service

10. Please rank the RELIABILITY items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 6 represents the least positive impact.

Write in your ranking from 1 to 6 in the column to the left

	Renewal program - Replace equipment that affects reliability
	Tree trimming - Increase tree trimming in heavily forested areas
	Smart grid - Use technology to reduce your chances of losing power
	Grid strengthening - Enable the grid to better withstand severe weather
	Rapid response program - Detects outages, limits size, dispatches repair crews
	Monitoring and control – Use technology that enables Hydro One to remotely respond to outages

11. Please rank the SERVICE items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 7 represents the least positive impact.

Write in your ranking from 1 to 7 in the column to the left

	Billing - Improve the format and presentation of bills
	Ease of doing business – Customized customer service through phone, mobile or online
	Energy management - Tools so you can manage your usage and view your consumption
	Power outage restoration – Provide more accurate estimates of when your power will be restored
	Renewable generation – Enables customers to integrate their renewable energy devices into the grid

6

	Electric vehicles and storage – Enables customers to use their high-capacity home batteries and electric vehicles
	Power quality – Monitor and reduce the number of power quality issues (e.g. your lights flickering)

12. To better understand your preferences for reliability, service, and level of rates, please complete the following. If you had $100 to spend on the following, how would you allocate the money?

Write in how much money you would allocate to each in the column to the left

$	Improving reliability by reducing the number of interruptions
$	Improving reliability by reducing the length of interruptions
$	Improving service by offering more seamless customer service via phone, mobile and online
$	Improving service by improving billing accuracy
$	Improving service by improving power quality diagnostics
$	Improving service by enabling customers to integrate their renewable energy devices into the grid
$	Improving service by enabling energy storage
$	Hold back and not spend in order to lessen rate increases

$100

INTRODUCTION TO INVESTMENT SCENARIOS

13. What's your overall reaction to the investment scenarios presented?

14. Would you be willing to accept a 2.5% distribution delivery rate increase where reliability and service performance declines (Scenario 2)?

- ☐ Yes
- ☐ No

15. Would you be willing to accept a 3.4% distribution delivery rate increase where reliability and service performance remains the same as it is now (Scenario1)?

- ☐ Yes
- ☐ No

16. Would you be willing to accept a 4.0% distribution delivery rate increase where reliability and service performance improves (Scenario 3)?

- ☐ Yes
- ☐ No

17. Do you expect significantly higher or differentiated service than you have today from Hydro One?

- ☐ Yes, please explain below
- ☐ No, please explain below

8

18. Would you be willing to accept a distribution delivery rate increase greater than 4.0% in order to have customized reliability and/or service improvements?

- ☐ Yes, please explain below
- ☐ No, please explain below

19. What metrics and targets should these programs be based on?

9

20. Which of the following industry classifications most closely represents your organization? (select one only)

- ☐ Agriculture, forestry, fishing, and hunting
- ☐ Arts, entertainment, and recreation
- ☐ Educational services
- ☐ Health care and social assistance
- ☐ Manufacturing
- ☐ Mining, quarrying, and oil and gas extraction
- ☐ Other services (except public administration)
- ☐ Public administration
- ☐ Retail trade
- ☐ Utilities
- ☐ Wholesale trade
- ☐ Other (specify)____

21. What are the first three characters of the postal code of your organization's main/corporate office? (example, L5M)

22. What is your title/position within your organization?

Thank you for your feedback!

Please return your survey to an IPSOS staff member.

10

HYDRO ONE DISTRIBUTION CONSULTATION

LDA/LDC WORKSHOP SURVEY BOOKLET

1

INTRODUCTION

This survey booklet is organized into sections that correspond with the flow of the workshop today. You will be provided time after each section of the workshop presentation today for you to answer the survey. Feel free to refer back to the Hydro One Presentation/Workbook as needed in deciding your opinion.

Please answer all of the questions in the survey.

If you require more space, please write on the back of your survey. If you have any questions, please ask one of the IPSOS staff present at the session today.

1. Are you representing an:

☐ LDA

☐ LDC

2

WHO WE ARE AND WHAT WE DO

As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.

1. How satisfied are you with Hydro One overall?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied

2. Is there anything in particular that Hydro One can do to improve its service to you?

3. Hydro One would like to better understand what is important to you as a large customer. From the following list, which would you say is <u>most</u> important to your organization? (select one only)

- ☐ Reducing the number of power outages (through activities such as tree-trimming, replacing equipment)
- ☐ Shortening the length of power outages (through activities such as installing remote control devices)
- ☐ Improving customer service and billing (such as billing accuracy and answering customer questions)
- ☐ Upgrading the system to connect new customers including those producing renewable energy sources and using energy storage (such as wind, solar, and electric vehicles)
- ☐ Keeping costs as low as possible

3

If something is more important to you than these five items, please write it into the text box below.

REVIEW: CURRENT SYSTEM PERFORMANCE

4. **Is there anything unclear about what has been presented in Current System Performance section of the presentation/workbook today?**

The following few questions are about your experience with unplanned power interruptions.

The term interruption refers to a complete loss of electric power and outage refers to the disabling of a component's capability to deliver power (planned or unplanned). An outage may or may not cause an interruption of service to customers.

5. **A sustained power interruption is one lasting at least 1 minute. How many did your organization experience in the past 12 months that you were not notified about in advance by Hydro One? Your best guess is fine. Circle your choice.**

None 1 2 3 4 5+ Don't know /Can't recall

6. **On average, how long did these unplanned interruptions last? Please answer in minutes. Your best guess is fine.**

- ☐ No unplanned interruptions
- ☐ Don't know/can't recall

4

7. How, if at all, did these unplanned interruptions impact your organization?

8. What, if anything, would you like Hydro One to do to manage unplanned interruptions?

CONTEXT: INVESTING IN THE SYSTEM

9. Based on what you just heard/read in presentation, do the investments to <u>maintain</u> the current level of reliability and service that Hydro One is making today make sense to you?

- ☐ Yes, please explain below
- ☐ No, please explain below

5

10. Based on what you just heard/read in presentation, do the investments to improve the current level of reliability and service that Hydro One is making today make sense to you?

- ☐ Yes, please explain below
- ☐ No, please explain below

What's best for you? How Hydro One could improve reliability and service

11. Please rank the RELIABILITY items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 6 represents the least positive impact.

Write in your ranking from 1 to 6 in the column to the left

	Renewal program - Replace equipment that affects reliability
	Tree trimming - Increase tree trimming in heavily forested areas
	Smart grid - Use technology to reduce your chances of losing power
	Grid strengthening - Enable the grid to better withstand severe weather
	Rapid response program - Detects outages, limits size, dispatches repair crews
	Monitoring and control – Use technology that enables Hydro One to remotely respond to outages

6

12. Please rank the SERVICE items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 7 represents the least positive impact.

Write in your ranking from 1 to 7 in the column to the left

	Billing - Improve the format and presentation of bills
	Ease of doing business – Customized customer service through phone, mobile or online
	Energy management - Tools so you can manage your usage and view your consumption
	Power outage restoration – Provide more accurate estimates of when your power will be restored
	Renewable generation – Enables customers to integrate their renewable energy devices into the grid
	Electric vehicles and storage – Enables customers to use their high-capacity home batteries and electric vehicles
	Power quality – Monitor and reduce the number of power quality issues (e.g. your lights flickering)

13. To better understand your preferences for reliability, service, and level of rates, please complete the following. If you had $100 to spend on the following, how would you allocate the money?

Write in how much money you would allocate to each in the column to the left

$	Improving reliability by reducing the number of interruptions
$	Improving reliability by reducing the length of interruptions
$	Improving service by offering more seamless customer service via phone, mobile and online
$	Improving service by improving billing accuracy
$	Improving service by improving power quality diagnostics
$	Improving service by enabling customers to integrate their renewable energy devices into the grid
$	Improving service by enabling energy storage
$	Hold back and not spend in order to lessen rate increases

$100

7

INTRODUCTION TO INVESTMENT SCENARIOS

14. What's your overall reaction to the investment scenarios presented?

15. Would you be willing to accept a 2.5% distribution delivery rate increase where reliability and service performance declines (Scenario 2)?

- ☐ Yes
- ☐ No

16. Would you be willing to accept a 3.4% distribution delivery rate increase where reliability and service performance remains the same as it is now (Scenario1)?

- ☐ Yes
- ☐ No

17. Would you be willing to accept a 4.0% distribution delivery rate increase where reliability and service performance improves (Scenario 3)?

- ☐ Yes
- ☐ No

18. Do you expect significantly higher or differentiated service than you have today from Hydro One?

- ☐ Yes, please explain below
- ☐ No, please explain below

8

19. Would you be willing to accept a distribution delivery rate increase greater than 4.0% in order to have customized reliability and/or service improvements?

- ☐ Yes, please explain below
- ☐ No, please explain below

20. What metrics and targets should these programs be based on?

Thank you for your feedback!

Please return your survey to an IPSOS staff member.

GENERAL SURVEY INVITATION EMAIL TO COMMERCIAL AND INDUSTRIAL

GENERAL SURVEY INVITATION EMAIL TO COMMERCIAL AND INDUSTRIAL

Hydro One Networks Inc.
483 Bay Street
6TH Floor, South Tower
Toronto, Ontario, M5G 2P5
www.HydroOne.com

Tel: (416) 345 5509
Fax: (416) 345 4141

Warren Lister
VP, Customer Service
Hydro One Networks Inc.

June 17, 2016

Dear Customer:

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share with us what you believe our priorities should be and what matters most to you in the development of this plan.

Our development plan will form part of our distribution rate application which we will file in the spring of 2017 with the Ontario Energy Board (OEB). Our application will explain our investment plan that the OEB will assess to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey by June 30, 2016 at: www.ipsosresearch.com/hydrooneC&I.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Warren Lister
Vice President – Customer Service
Hydro One Networks

WORKSHOP NON-ATTENDEE SURVEY INVITATIONS

SURVEY EMAIL TO WORKSHOP NON-ATTENDEE
COMMERCIAL AND INDUSTRIAL

Good afternoon,

We recently contacted you about a Hydro One Workshop, although you were unable to attend this year's session, we would appreciate you filling out our online survey for Commercial & Industrial Customers.

Please see the attached communication from our Vice President, Warren Lister, for more details and the link to the survey (also found here: http://www.ipsosresearch.com/hydrooneC&I/).

We are looking forward to hearing from you.

Best Regards,

Hydro One Business Customer Centre
1-866-922-2466

SURVEY EMAIL TO WORKSHOP NON-ATTENDEE
LOCAL DISTRIBUTION COMPANY

Dear [redacted]

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share your priorities with us and your views regarding the measures that should be included in our plans.

Our development plan will form part of our distribution rate application which we will file in the Spring of 2017 with the Ontario Energy Board (OEB). The OEB will assess our application to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey by June 30, 2016 at: **www.ipsosresearch.com/hydrooneLDC** using your ID **# 685**.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Mike Penstone
VP – Planning
Hydro One Networks Inc.

SURVEY EMAIL TO WORKSHOP NON-ATTENDEE
LOCAL DISTRIBUTION COMPANY

Dear [redacted]

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share your priorities with us and your views regarding the measures that should be included in our plans.

Our development plan will form part of our distribution rate application which we will file in the Spring of 2017 with the Ontario Energy Board (OEB). The OEB will assess our application to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey by July 7, 2016 – click here to complete the survey and key in your unique ID # 667.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Mike Penstone
VP – Planning
Hydro One Networks Inc.

SURVEY LETTER TO WORKSHOP NON-ATTENDEE
COMMERCIAL AND INDUSTRIAL

Hydro One Networks Inc.
483 Bay Street
6TH Floor, South Tower
Toronto, Ontario, M5G 2P5
www.HydroOne.com

Tel: (416) 345 5509
Fax: (416) 345 4141

Warren Lister
VP, Customer Service
Hydro One Networks Inc.

June 17, 2016

Dear Customer:

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share with us what you believe our priorities should be and what matters most to you in the development of this plan.

Our development plan will form part of our distribution rate application which we will file in the spring of 2017 with the Ontario Energy Board (OEB). Our application will explain our investment plan that the OEB will assess to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey by June 30, 2016 at: **www.ipsosresearch.com/hydrooneC&I**.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Warren Lister
Vice President – Customer Service
Hydro One Networks

SURVEY LETTER TO WORKSHOP NON-ATTENDEE
LARGE DISTRIBUTION ACCOUNT

Hydro One Networks Inc.
483 Bay Street Tel: (416) 345 6207
12TH Floor, North Tower Fax: (416) 345 6223
Toronto, Ontario, M5G 2P5 Cell: (416) 579 3016
www.HydroOne.com

Jon Rebick
VP, Lines & Forestry
Hydro One Networks Inc.

June 17, 2016

Dear [*Customer Name*]:

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share with us what you believe our priorities should be and what matters most to you in the development of the plan.

Our development plan will form part of our distribution rate application which we will file in the spring of 2017 with the Ontario Energy Board (OEB). Our application will explain our investment plan that the OEB will assess to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey **by June 30, 2016** at: **www.ipsosresearch.com/hydrooneLDA** using your ID [####].

You may have recently completed a survey which deals with topics related to customer satisfaction with Hydro One. This survey is different and is to learn what you believe our priorities should be and what matters most to you.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Jon Rebick
Vice President – Lines & Forestry
Hydro One Networks

SURVEY MAIL INVITATION TO WORKSHOP NON-ATTENDEE
COMMERCIAL AND INDUSTRIAL

Hydro One Networks Inc.
483 Bay Street
6TH Floor, South Tower
Toronto, Ontario, M5G 2P5
www.HydroOne.com

Tel: (416) 345 5509
Fax: (416) 345 4141
Cell: (416) 427 7075

Rob Quail
VP, Customer Service
Hydro One Networks Inc.

June 8, 2016

Dear Customer:

We are in the early stages of building our five-year plan for our electricity distribution system and I would like to invite you to share with us what you believe our priorities should be and what matters most to you in the development plan.

Our development plan will form part of our distribution rate application which we will file in the spring of 2017 with the Ontario Energy Board (OEB). Our application will explain our investment plan that the OEB will assess to determine our electricity rates from 2018-2022.

Our objective is to provide our customers with safe and reliable electricity, so we want to understand whether your needs are being met by our current system and which types of reliability and service improvements you value most. Your input will be considered as we develop our plans, along with other considerations including our mandatory obligations, asset condition assessments and our ability to resource, schedule and execute our plan.

All of our distribution customers will have the opportunity to provide input into our investment plan through workshops, focus groups, surveys, and one-on-one discussions. You can participate in this important process by filling in a confidential Customer Survey by June 30, 2016 at: **www.ipsosresearch.com/hydrooneC&I**.

Thank you in advance for taking part in our online survey and providing your views on how we should keep the electricity delivery system strong and ready for the future.

Sincerely,

Rob Quail
Vice President – Customer Service
Hydro One Networks

WORKSHOP PARTICIPANT LIST

WORKSHOP PARTICIPANT LIST
ALL MARKETS

Distribution Customer Engagements - Large Workshop Participant List

Hamilton LDA

Keith Vanderwood, Air Canada Products Canada
Grant Nopper and Kristen Montague, Canadian Gypsum Company
Kevin Hodgins, St. Mary's Cement Inc.
Denis Yeung, Oakrun/Aryzta
Randy Gao, Royal Canin
Hamilton LDC
Rosso Parra, Grimsby Power Inc.

Hamilton C&I

Vern Mills and Paul McCoy, McCoy Foundry
Sara Peckford and Caitlin McFadyen, Town of Caledon
Fidel Reijerse, RESco Energy
Carl Loewith, Joe Loewith & Sons
Joe Lannan, Great Lakes Elevator
Dave Sabola, Pepsico Canada
Stephen Hart, HK Travel Centre
Bob Burlakoff and Abu Sanneh, Hamilton Airport
Natasha Murry and George Bougiouklis, Chartwell Mastercare
Linda Campbell, City of Hamilton

Collingwood LDA

Bill Koniuch, Honda of Canada Manufacturing
Shawn Plowright and Adem Nezirevic, KTH Shelburne MFG
Dan Moca, Husky Injection Moulding
Michael Flood and Kim Rowe, Tenneco Canada In.
Lisa Cox and Ken Anderson, Casino Rama
Kevin Tone and Lindsay Ayers, Blue Mountain Resorts
Rene Landry, Kimberley Clark of Canada
Al Sobbart, Panolam Industries

Collingwood LDC

Brian Elliot, Lakeland Power

Collingwood C&I

Steven Parkes, Craigleith Ski Club
Jeff Conn and Jamie Cutherberth, The Osler Bluff Ski Club
Dough Wansborough, Devils Glen Country Club
Randy Fielder, Bonaire Golf & Country
Nick Levangie, JW Marriott
Sean, Owen Sound Ledgerock Ltd.
Ken Rounds, Simcoe County
Jeff Struewing, Grey Standard Condo Corp 75
Ian Miles, Energy Plus

Timmins LDA/LDC

Ross Byron, Imerys Talc Canada Inc.
Eric Buteau, Lecours Lumber Co Ltd
Dan Gagnon and Harvey Dasti, Primero Gold
Shoaib Zia and Lori Smith, Goldcorp

Timmins C&I

Sue Howson, Northern College of Applied Arts and Tech
Travas Hack, Eacom Timber Corp
Carole Horton, District School Board Ontario
Eric St-Pierre, French Catholic School Board
Ron Wink and Scott Tam, City of Timmins

Thunder Bay LDA/LDC

Dale Kosie, Goldcorp

Thunder Bay C&I

Cody Randle, Azgard Solar
Harold Harkonen, Pure Gold Mining Inc./Laurentian Goldfields Ltd
Carol Maki, Hacquoil Construction
Peter Tillberg, Gordon Trailers
Wayne Chiupka, Nakina District School Area Board
Linda Chiupka, Corporation of the Township of Terrace Bay

London LDA

Tim Prescott, Formet Industries
Pragnesh Shah, Rothsay
Jeff Simpson, Westcast Industries
Jared Rowntree and Jodi Dellemonache, Superior Essex
Vicky Hammell, Wallensteinskup Feed Ltd.

London LDC

Leslie Dugas, Bluewater Power Sarnia
John Vankerhoven, Blue Water Power
Sheraz Mustafa, Westario Power Inc.
Jeff Graham, Festival Hydro Inc - Stratford
Wayne Dyce, Centre Wellington Hydro
Josh Smith and Scott Brooks, Erie Thames Powerlines
Jim Klujber, Wellington North Power Inc.
Jim Hamilton, First Solar
Matthew Wright, Halton Hills Hydro Inc.

London C&I

Dirk Nauwelaerts, Belleview Acres Ltd.
Tony Di Nardo, Cooper Standard Automotive
Erica Kiestra, Kie Farms
Howard Lucas, Lambton County Admin Office
Adrian Roelands, Roeland Plant Farms Inc.
Garry Fortune, Stanton Bros Ltd.
Linda MacDonald, Walker Dairy Inc.

Windsor LDA/LDC (did not complete survey booklet)

Howard Huy, Huy Greenhouses

Windsor C&I

Robert Saroli, Canadian Art Aluminum Extrusion
Terry Attewell, Canadian Department of Agriculture
Louis Chibante and Paul Mastronardi, Golden-Acres Inc.
Kathleen Qenneville, Greater Essex City
Todd Brophy and Peter Quiring, Nature Fresh Green Houses
George Dekker, Southshore Greenhouses Inc.
Mazim Naim, TRQSS Inc.
Dale Hodgins and Mark Stephens, AP Plasman
Justin Martens, Johno Foods
Pat Fleming, Milofais
Wanda Juricic, Union Gas
Guido van het Hof, Great Northern Hydroponics

Kingston LDA

Rod Moffatt, Strathcona Paper LP (Paper Works)
Edward Kalinowski, Gagan Gill and Steve Hughes, Invista Canada Company (Maitland)
Brent Quennell, IKO Industries Ltd.
Brent Williams, Goodyear Canada
Audrey Wood, Norampac
Bill Smith, Nestle Enterprises Ltd.
Habib Arshad, Pembroke MDF
Brian Reil, Kraft Foods Ltd.
Tom Horvath and Dominic Phaneuf, Greenfield Johnstown Limited Partnership

Kingston LDC

Jerick Astejada and Deonnie Macabables, Great Circle Solar
April Barrie and Matthew McGrath, Hydro Ottawa
Charles Watson and Jane Donnelly, Ottawa River Power
Mike Ploc, Peterborough Distribution Inc.
Bill Nippard, Renfew Hydro
John Walsh, Rideau St. Lawrence Distribution Inc.

Kingston C&I

Megan Jessup, Graves Eng. and Finishing
Ross Burt and David LaMontagne, Moose Creek Tire Recycling
Ricki Campbell and Richard Baccari, Crystal Springs
Bob Smith, Assurance Solutions

FOCUS GROUP MATERIALS

DISCUSSION GUIDE FOR HYDRO ONE ONLINE FOCUS GROUPS

RESIDENTIAL AND SMALL BUSINESS CUSTOMERS

Version 3, July 5 2016

SESSION BREAKDOWN

Welcome and Introduction	5 Minutes
Section 1: Satisfaction with Hydro One and improvement expectations	25 Minutes
Section 2: Trade-off between reliability and cost	25 Minutes
Section 3: Trade-off between customer service and cost	10 Minutes
Section 4: Communication and open floor	10 Minutes
SESSION TOTAL	**75 Minutes**

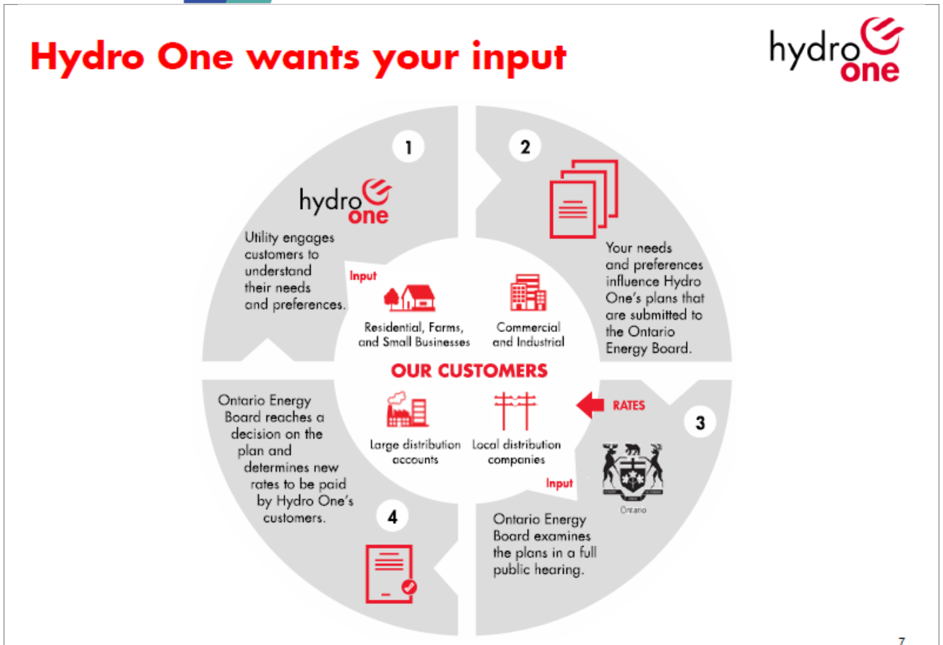
DETAILED SESSION AGENDA

MODERATOR Welcome	• Welcome & thanks for attending • Overview of the session purpose • Overview of technology and how session will work, inputting data into your computer • Good engagement practices • Rules of engagement - informed, passionate, and respectful dialogue • Audio taping for notetaking purposes and report • Importance of being in a quiet room with a closed door

WHY WE'RE HERE TODAY

Hydro One is looking for customer input to shape future investments in electricity assets as the Company begins to build a five-year plan for its electricity distribution system. These focus groups are a part of a larger consultation process that Hydro One is undertaking. They are speaking to both residential / small business customers like you, as well as all the other types of customers they provide electricity to.

Screen grab below will appear in Ideation platform. Moderator to provide brief description.



Unless otherwise noted, all questions are open-ended responses in the Ideation Exchange platform, followed by a Group Discussion.

SECTION 1: SATISFACTION WITH HYDRO ONE AND IMPROVEMENT EXPECTATIONS
25 MINUTES

As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices.

Q1. Thinking about Hydro One as I have just described it to you, please tell us about how satisfied or not satisfied you are with Hydro One overall, and why?

How could Hydro One improve its service to you / your household / business or are you happy with the service as it is now?

Q2. I would like you to consider the following four areas as it relates to Hydro One:

- Keeping the system reliable - avoiding power outages.
- Restoring power quickly after an outage and communicating with customers when the power is out.

2

- Customer service and billing – such as being able to interact with Hydro One through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills.
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage. Here we are talking about how well Hydro One is proactively preparing the electricity system and grid for more electric vehicles, or allowing more customers with solar panels on their roofs to send power back into the system.

Would you say that Hydro One needs to make improvements in any or all of these areas, or would you prefer that Hydro One not worry about improving in any of these areas and instead focus on keeping costs as low as possible for customers? Please tell us about your view.

Moderator to probe:

Keeping the system reliable
- How many outages do you estimate you experience per year?
- What's an acceptable number of outages, to you?
- What do you think is the most common cause of power outages?
- Restoring power quickly after an outage and communicating with customers when the power is out

Restoring power after an outage
- Has anyone ever downloaded Hydro One's app? What do you think of it? What would you expect to do/see on the app?
- Has anyone accessed Hydro One's website during an outage? What's your experience been like?

Customer service and billing
- Would you like to be able to interact with Hydro One more easily? For example, would you like to be able to text or email Hydro One with a question rather than phoning the call centre?

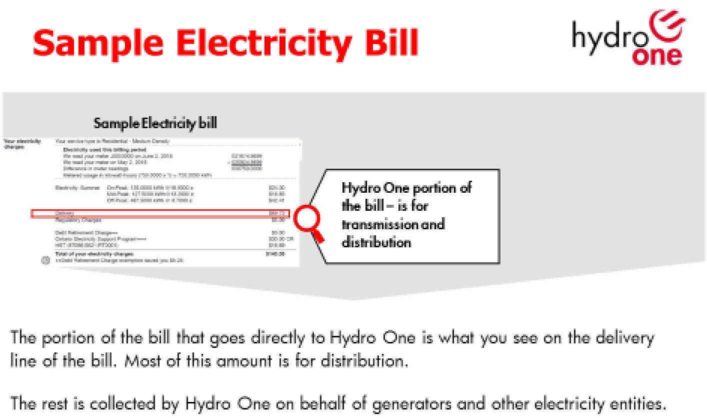
Upgrading the system to connect new customers
- Do you have a view of how well Hydro One is doing in this area?
- Do you have a sense of how many people are producing renewable energy or using energy storage? Do you think it is going to increase slowly or increase quickly over the next few years?

Moderator to probe:
- Is there anything missing from this list in terms of what you would like Hydro One to improve upon?

SECTION 2: TRADE-OFF BETWEEN RELIABILITY AND COST
25 MINUTES

As mentioned at the start of the session, Hydro One is responsible for the safe and reliable delivery of electricity, not the price of electricity. Hydro One does not make any money on the commodity or supply of electricity – Hydro One bills you the cost of electricity as a pass-through. Hydro One only makes a profit on the delivery charge portion of your bill.

Screen grab below will appear in Ideation platform. Moderator to provide brief description.



Q3. How much of this did you know about Hydro One?

In preparing for future planning, Hydro One has determined that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical residential / business customer's total monthly bill will need to increase by 1.1% or $2.00 residential / 1% or $5.2O business.

Moderator to clarify as needed:
The increase is on the delivery charge only, but we have expressed the increase as a percentage of the total bill because it is simpler for customers to think about what they typically pay on each month.

This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly $10.00 residential **/** $26.00 business higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability - meaning in order to maintain the frequency of outages to its current level. The monthly bill could still increase for other reasons which are outside the control of Hydro One.

Q4. Before we get into a discussion on this, can we start by having you indicate your view.
Please tell us which of the following statements most closely matches your view.
IDEATION PLATFORM - ACCEPT ONE RESPONSE

- The increase is reasonable and I would support it
- I don't like it, but I think the increase is necessary
- The increase is unreasonable and I would oppose it
- Don't know

Moderator to probe (focus on don't know and opposed):

4

- If don't know, what do you need to know?
- If opposed – why?
- Is it that it is unaffordable? - the $2 residential / $5.20 business now, or the $10 residential / $26.00 business in the future
- Can afford it, but feel on principle that it's too big of an increase - the $2 residential / $5.20 business now, or the $10 residential / $26.00 business in the future
- Don't mind worsening reliability (without a rate increase, reliability will worsen, acceptable?)
- Trust/distrust Hydro One to spend the money well?
- Would more information on how the money will be spent to improve reliability help?

Probe if necessary (if many opposed):
Q5. There is a trade-off between what is the desired level of reliability and cost. For everyone, what would you be willing to accept in terms of more frequent and/or longer power outages to avoid the rate increase?

Q6. What would you need to hear or see from Hydro One in order to feel that a $2.00 residential / $5.20 business increase per month on your bill is reasonable?

Moderator to probe:
- Would it make any difference knowing how the money will be invested?

Q7. If instead of paying $2.00 / $5.20 more per month as we have discussed for the same level of reliability that you experience now, would you be willing to pay $2.30 residential / $6.00 business for **better reliability**? Why or why not?

If clarification required: "Better" refers to a reduction in the number and length of future power outages by 10%. Remember it is $2.30 each year for 5 years, so by the fifth year it will be $13.00 more per month (as compared to $10.00 to maintain current reliability).

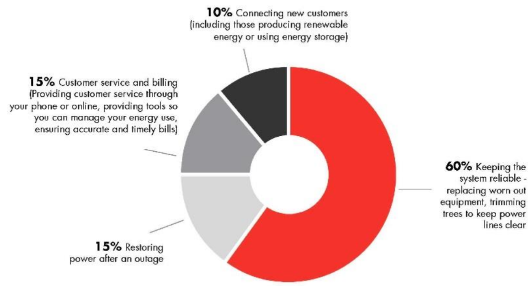
Here is some general information about Hydro One - the type of service they provide, some of the challenges they have, as well as the condition of their poles and lines.

Screen grabs below will appear in Ideation platform. Moderator to provide brief description

hydro one Ipsos

What your distribution charges pay for:

hydro one



6

WHAT CAUSES YOUR POWER TO GO OUT

hydro one

Power outage causes (2013-2015)		
Trees	24%	Trees fall on lines during storms.
Equipment failure	24%	Poles, transformers, lines failures can cause an outage.
Unconfirmed causes	19%	Sometimes Hydro One crews can't determine the exact cause of an outage.
Scheduled outages	16%	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Loss of power supply	12%	Issues relating to the larger grid like damage to transmission lines.
Animal or vehicle damage to equipment	5%	Animal contacts with Hydro One's equipment and car accidents that damage poles.

6

Reliability challenges

Challenges all utilities face	Issues specific to Hydro One
Geography: Forested service territories are prone to outages caused by tree contact. In order to restore power, repair crews must locate and travel to source of an outage.	Much of Hydro One's service territory is heavily forested compared to other utilities'.[1] In 2014, Hydro One cleared over 9,000 km of distribution line. Hydro One's large service area means outages are longer and are more costly to locate and repair. Hydro One's network uses a radial circuit design to cover a large area, which does not provide redundant power supplies common in urban areas.
Weather: Major storms inevitably cause damage to power lines.	Hydro One's large service territory exposes it to all of Ontario's most challenging weather conditions.
Infrastructure: Most electric power grids were built up over many years with a huge volume of equipment and a mix of different technologies.	Hydro One's system serves an average of 10 customers per kilometre of power line while other utilities serve about 70 customers per kilometre. This requires Hydro One to maintain a large number of assets per customer.

1. Hydro One 2009 Vegetation Management Benchmarking Study by CN Utility Consulting, Inc.

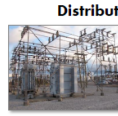
20

Maintain: Largest programs involve replacement and refurbishment of assets in poor condition

Wood poles

- **240,000** wood poles (15% of the fleet) are currently beyond their expected service life of 60 years.
- **400,000** wood poles (25% of the fleet) would be beyond their expected service life by 2022 if no replacements are made.

Distribution stations



- Approximately **144** station transformers (12% of the fleet) are currently beyond their expected service life of 50 years.
- Approximately **360** station transformers (30% of fleet) would be beyond their expected service life by 2022 if no replacements are made.

Much of the system was built in the 1950s and 1960s. Consequently many assets are approaching or beyond the end of their expected service lives. Replacement decisions are based on actual asset condition.

26

Q8. Does this impact your view of Hydro One at all? If so, how?

Moderator to probe: Do you trust Hydro One to make appropriate decisions on when and how to refurbish and replace aging equipment?

7

SECTION 3: TRADE-OFF BETWEEN CUSTOMER SERVICE AND COST 10 MINUTES
Let's talk a little more about customer service and billing. We heard some feedback on this earlier. Q9. For those of you who would like to see some improvements in customer service and billing, what kind of investments would you like to see Hydro One make? **Moderator to probe:** • Is that something you would be willing to pay for? Why/why not? • How much? $2.30 more per month? • What about more accurate estimates of when power will the restore when it is out? • What about tools to help you better keep track of your electricity consumption?
SECTION 4: COMMUNICATION AND OPEN FLOOR 10 MINUTES
I would like to understand from you how you would like to hear about information from Hydro One such as planned outages, rate changes, or improvements being made by Hydro One in your region. Q10. Is there an ideal way you would like to receive information? How about ask questions? **Moderator to probe:** • Would you ever proactively seek information from Hydro One? For example, go to their website, or follow them on social media such as Twitter or Facebook? Why or why not?
Q11. Before we conclude this session - are there any final thoughts or feedback you'd like to give to Hydro One?
SESSION CONCLUSION AND WRAP-UP

Ipsos Public Affairs

Hydro One Ideation Sessions
Recruitment Screener

Recruitment Strategy:

10 participants per residential group; 40 residential participants total

Session	Region	Other demographics	Date/Time	Time
1	GTA / Horseshoe L FSAs	Residential	Monday, June 27	5:30 pm (EST)
2	Southwestern Ontario N FSAs	Residential	Monday, June 27	7:00 pm (EST)
3	Southeastern Ontario K FSAs	Residential	Tuesday, June 28	5:30 pm (EST)
4	Northern Ontario P FSAs	Residential	Tuesday, June 28	7:00 pm (EST)

All should be Hydro One customers

Exclude those who hold very positive or very negative views of Hydro One

In each group, recruit good mix of: gender, age, working status, income & education level

INTRODUCTION

Hello, this is _________________ calling from Ipsos, a professional public opinion research firm. Today we are contacting individuals to invite them to participate in an online research session. This study will involve participation in an online group discussion lasting approximately **75 minutes**. You will be required to log on to our secure website using your personal computer, as well as call in to a toll-free conference line to participate in the group discussions. If you qualify and are able to participate in the session, you will receive an honorarium for your time. ($75)

Would you be interested in participating in this study?

Yes **CONTINUE**
No **THANK & GOODBYE**

1. Have you or any member of your household ever worked for: [**READ. CIRCLE AS MANY AS APPLY**]

An advertising agency or market research firm, marketing firm or marketing department in your own firm
A public relations company

1

News media, such as television, radio or a newspaper
A utility (e.g. hydro, water, gas) company

Yes
No

IF YES TO ANY AT Q1 – THANK AND TERMINATE

2. Have you participated in a market research study in the past six months?

Yes	**THANK & TERMINATE**
No	**CONTINUE**

3. Are you the person in your household who is responsible or jointly responsible for dealing with household admin such as paying utility bills?

Yes	**CONTINUE**
No	IF NO ASK TO SPEAK TO APPROPRIATE PERSON; IF PERSON IS PUT ON LINE REDO INTRO AND SCREEN; IF NOT AVAILABLE SCHEDULE RE-CONTACT.
Don't know	**THANK AND TERMINATE**

4. For your **primary residence (ask per Q3 above)**, which company do you pay your electricity bills to? (DO NOT READ.) RECORD ONE RESPONSE ONLY)

Hydro One	**CONTINUE**
Other	**THANK AND TERMINATE**
Don't know	**THANK AND TERMINATE**

5. Which of the following best describes your overall opinion and perceptions of Hydro One?

Very positive	**THANK AND TERMINATE**
Somewhat positive	**CONTINUE**
Neither positive nor negative	**CONTINUE**
Somewhat negative	**CONTINUE**
Very negative	**THANK AND TERMINATE**
Refused/no opinion/don't know	**THANK AND TERMINATE**

6. RECORD GENDER

Male
Female

RECRUIT GOOD MIX

7. Which of the following age categories can I place you in?

18-24 years old
25-34 years old
35-44 years old
45-54 years old

55-64 years old
65 years or older

RECRUIT GOOD MIX

8. What is your current employment status? Are you….? (READ LIST AND MARK ONE RESPONSE)

A full-time employee
Working part-time
Working full or part-time but currently on leave
Unemployed but currently looking for work
A stay-at-home parent
Retired
Other (please specify)

RECRUIT GOOD MIX

9. What is the highest level of education that you have completed? Please select one response only.

Grade school or some high school
Completed high school
Technical or trade school/Community college
Some university
Complete university degree
Post-graduate degree

RECRUIT GOOD MIX

10. Which of the following income groups best represents your annual <u>household</u> income before taxes? **[READ LIST]**

Less than $20,000	**CONTINUE**
$20,000 to less than $40,000	**CONTINUE**
$40,000 to less than $60,000	**CONTINUE**
$60,000 to less than $80,000	**CONTINUE**
$80,000 to less than $100,000	**CONTINUE**
$100,000 to less than $125,000	**CONTINUE**
$125,000 to less than $150,000	**CONTINUE**
$150,000 or more	**CONTINUE**
Prefer not to say	**THANK & TERMINATE**

RECRUIT GOOD MIX

11. To take part in the session, we need you to log into a website and dial-in via a telephone line. You therefore need access to a computer (pc/laptop NOT tablet or smartphone), an internet connection and telephone line. Can you please confirm that you have all that?

Yes	**CONTINUE**
No	**THANK AND TERMINATE**

12. And how often do you do the following…

Check email
Upload & download documents/pictures from email (word/excel/powerpoint etc)
Shop online (Amazon, ebay etc)
Use online banking
Use social media (Facebook, Imgur, a Blog, Reddit …etc.)
Download or Stream Videos (Netflix, Hulu, Sidereel, Fastpasstv, etc.)

Every day
2/3 times a week
Once a week
2/3 times a month
Once a month
Less often than once a month
Never

CONTINUE IF AT LEAST ONCE A WEEK TO 2 OR MORE ITEMS

We would like to invite you to participate in an online research session on [INSERT DATE]. As a token of our appreciation for your time, we are offering each participant **$75 residential**

Are you interested in participating? (DO NOT READ. CIRCLE ONE ANSWER)

Interested in participating
Not interested in participating

Excellent! In order to participate in this session you will need access to the internet via a PC/Mac (not via smart phone) and telephone line. Because there is a conference call component, and the discussion we will have is equally as important as your input via the online tool, we ask that you participate from a quiet room so there is less background noise on the call. We will provide you with a unique URL and toll-free 1-800 number for you to log in.

Date:

Time:

Place:

PLEASE LOG ON 5-10 MINUTES BEFORE THE SCHEDULED START TIME SO WE CAN MAKE SURE EVERYONE IS PROPERLY SET UP

WHEN COLLECTING PERSONAL DETAILS, PLEASE MAKE SURE YOU RECORD EMAIL ADDRESSES SO THAT WE CAN SEND OUT LOG IN DETAILS IN ADVANCE.

Ipsos Public Affairs

Hydro One Ideation Sessions
Recruitment Screener

Recruitment Strategy:

8 participants per small business group; 32 small business participants total

1	GTA / Horseshoe L FSAs	Small business	Tuesday, July 5	5:30 pm (EST)
2	Southwestern Ontario N FSAs	Small business	Tuesday, July 5	7:00 pm (EST)
3	Southeastern Ontario K FSAs	Small business	Wednesday, July 6	5:30 pm (EST)
4	Northern Ontario P FSAs	Small business	Wednesday, July 6	7:00 pm (EST)

All should be Hydro One customers

Exclude those who hold very positive or very negative views of Hydro One

In each group, recruit good mix of: gender, age, working status, income & education level

INTRODUCTION

Hello, this is _________________ calling from Ipsos, a professional public opinion research firm. Today we are contacting individuals to invite them to participate in an online research session. This study will involve participation in an online group discussion lasting approximately **75 minutes**. You will be required to log on to our secure website using your personal computer, as well as call in to a toll-free conference line to participate in the group discussions. If you qualify and are able to participate in the session, you will receive an honorarium for your time.

Would you be interested in participating in this study?

Yes **CONTINUE**
No **THANK & GOODBYE**

1. Have you or any member of your household ever worked for: [**READ. CIRCLE AS MANY AS APPLY**]

An advertising agency or market research firm, marketing firm or marketing department in your own firm
A public relations company
News media, such as television, radio or a newspaper

A utility (e.g. hydro, water, gas) company

Yes
No

IF YES TO ANY AT Q1 – THANK AND TERMINATE

2. Have you participated in a market research study in the past six months?

Yes	**THANK & TERMINATE**
No	**CONTINUE**

3. Are you the person in your business who is responsible or jointly responsible for dealing with paying utility bills?

Yes	**CONTINUE**
No	IF NO ASK TO SPEAK TO APPROPRIATE PERSON; IF PERSON IS PUT ON LINE REDO INTRO AND SCREEN; IF NOT AVAILABLE SCHEDULE RE-CONTACT.
Don't know	**THANK AND TERMINATE**

3b. How many people does your company currently employ?

[RECORD ANSWER] **RECRUIT IF 50 EMPLOYEES OR LESS**

4. For your **primary business (ask per Q3 above)**, which company do you pay your electricity bills to? (DO NOT READ.) RECORD ONE RESPONSE ONLY)

Hydro One	**CONTINUE**
Other	**THANK AND TERMINATE**
Don't know	**THANK AND TERMINATE**

5. Which of the following best describes your overall opinion and perceptions of Hydro One?

Very positive	**THANK AND TERMINATE**
Somewhat positive	**CONTINUE**
Neither positive nor negative	**CONTINUE**
Somewhat negative	**CONTINUE**
Very negative	**THANK AND TERMINATE**
Refused/no opinion/don't know	**THANK AND TERMINATE**

6. RECORD GENDER

Male
Female

RECRUIT GOOD MIX

7. Which of the following age categories can I place you in?

18-24 years old
25-34 years old

35-44 years old
45-54 years old
55-64 years old
65 years or older

RECRUIT GOOD MIX

8. What type of business do you operate/ manage ? (READ LIST AND MARK ONE RESPONSE)

____

AIM FOR A MIX

9. What is the highest level of education that you have completed? Please select one response only.

Grade school or some high school
Completed high school
Technical or trade school/Community college
Some university
Complete university degree
Post-graduate degree

RECRUIT GOOD MIX

10. To take part in the session, we need you to log into a website and dial-in via a telephone line. You therefore need access to a computer (pc/laptop NOT tablet or smartphone), an internet connection and telephone line. Can you please confirm that you have all that?

Yes **CONTINUE**
No **THANK AND TERMINATE**

11. And how often do you do the following…

Check email
Upload & download documents/pictures from email (word/excel/powerpoint etc)
Shop online (Amazon, ebay etc)
Use online banking
Use social media (Facebook, Imgur, a Blog, Reddit …etc.)
Download or Stream Videos (Netflix, Hulu, Sidereel, Fastpasstv, etc.)

Every day
2/3 times a week
Once a week
2/3 times a month
Once a month
Less often than once a month
Never

CONTINUE IF AT LEAST ONCE A WEEK TO 2 OR MORE ITEMS

We would like to invite you to participate in an online research session on [INSERT DATE]. As a token of our appreciation for your time, we are offering each participant **$150**

Are you interested in participating? (DO NOT READ. CIRCLE ONE ANSWER)

Interested in participating
Not interested in participating

Excellent! In order to participate in this session you will need access to the internet via a PC/Mac (not via smart phone) and telephone line. Because there is a conference call component, and the discussion we will have is equally as important as your input via the online tool, we ask that you participate from a quiet room so there is less background noise on the call. We will provide you with a unique URL and toll-free 1-800 number for you to log in.

Date:

Time:

Place:

PLEASE LOG ON 5-10 MINUTES BEFORE THE SCHEDULED START TIME SO WE CAN MAKE SURE EVERYONE IS PROPERLY SET UP

WHEN COLLECTING PERSONAL DETAILS, PLEASE MAKE SURE YOU RECORD EMAIL ADDRESSES SO THAT WE CAN SEND OUT LOG IN DETAILS IN ADVANCE.

KEY INSIGHTS PRESENTATION DECK

KEY INSIGHTS PRESENTATION DECK

Distribution Customer Consultation

Interim results: July 19, 2016

1

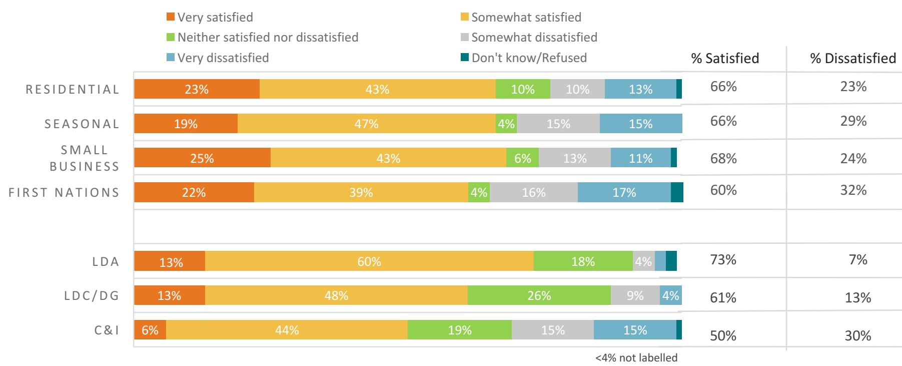
SURVEY RESULTS

SATISFACTION IS GENERALLY CONSISTENT ACROSS SEGMENTS – C&I DIRECTIONALLY LOWER

2

ALL CUSTOMER SEGMENTS

Overall satisfaction with Hydro One



As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1., How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from 1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change; Residential (n=243), Seasonal (n=68), General Service (n=159), First Nations (n=204), LDA (N=45), LDC/DG (n=23), C&I (n=133)

3

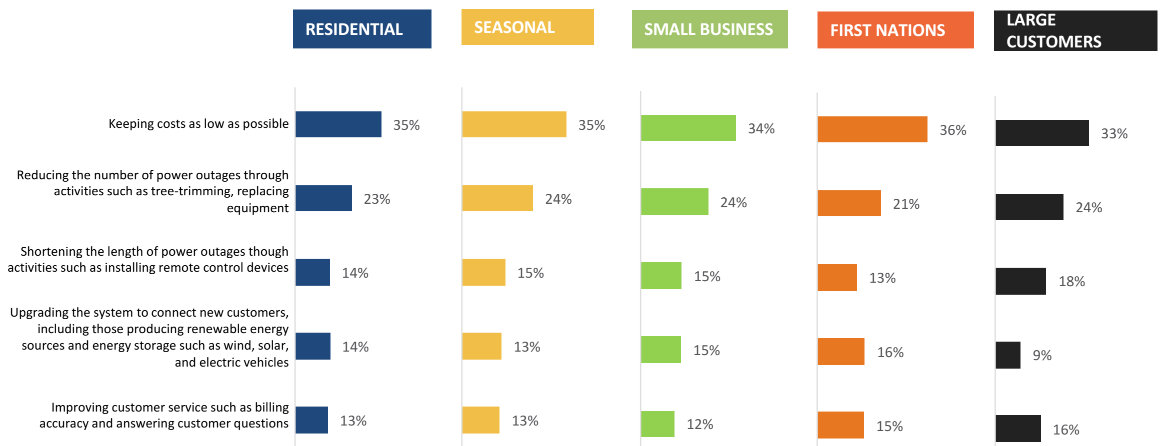
SURVEY RESULTS

KEEPING COSTS LOW IS A PRIORITY

4

ALL CUSTOMER SEGMENTS

Customer priorities



© 2016 Ipsos

Q5. Hydro One would like to better understand what is important to you as a [insert] customer. [Below is/ I am going to read]Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Shown in the chart is the Paired choice preferences relative to other options. Base: Uninformed Residential (n=399). One respondent opted not to answer Q5. Uninformed Seasonal (n=100). Small Business (n=199). One respondent opted not to answer Q5. First Nations (n=300), Large Customers responding to Online Workbook (n=87).

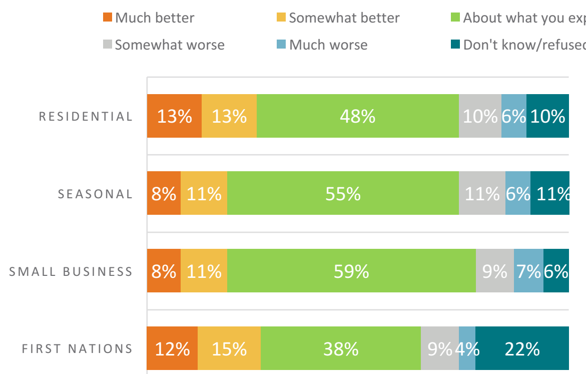
SURVEY RESULTS

R&SB CUSTOMERS SAY RELIABILITY IS OKAY

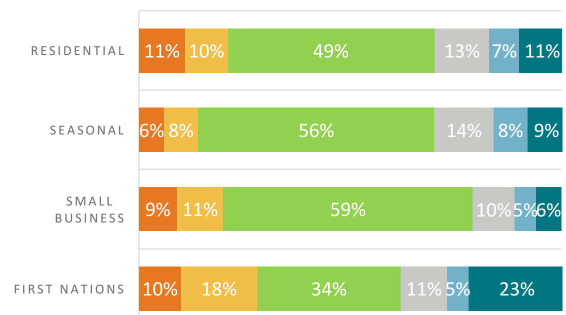
TELEPHONE SURVEY

Reliability Expectations

NUMBER OF OUTAGES



LENGTH OF OUTAGES



Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66), Small Business (n=144), First Nations (n=217)

Q10. In general, when you think about the average length of the power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; Residential (n=314), Seasonal (n=66), Small Business (n=144), First Nations (n=217)

Ipsos 7

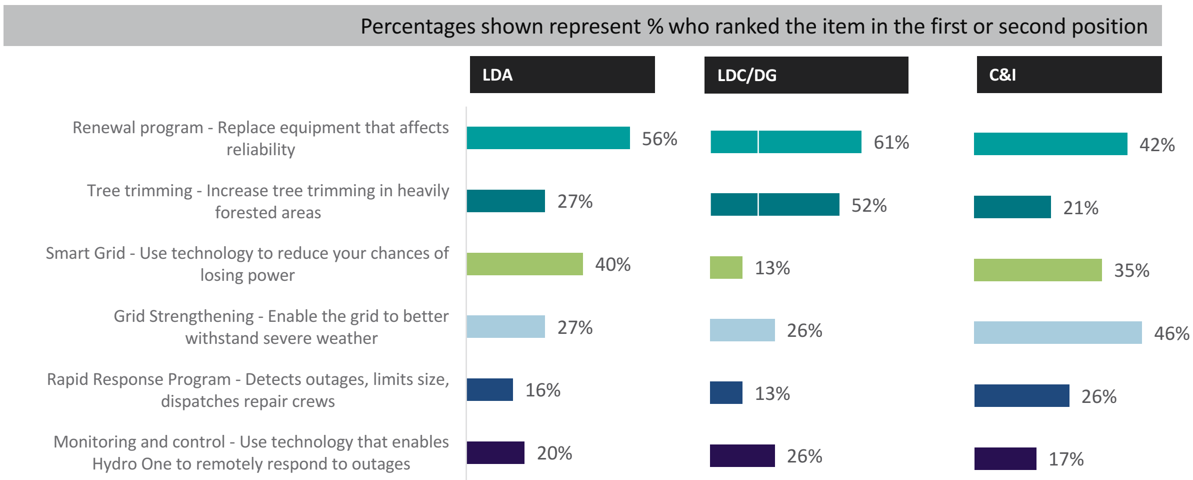
SURVEY RESULTS

LARGE CUSTOMERS' PREFERRED INVESTMENTS IN RELIABILITY VARY SOMEWHAT

Ipsos 8

ONLINE WORKBOOK/WORKSHOP SURVEY BOOKLET

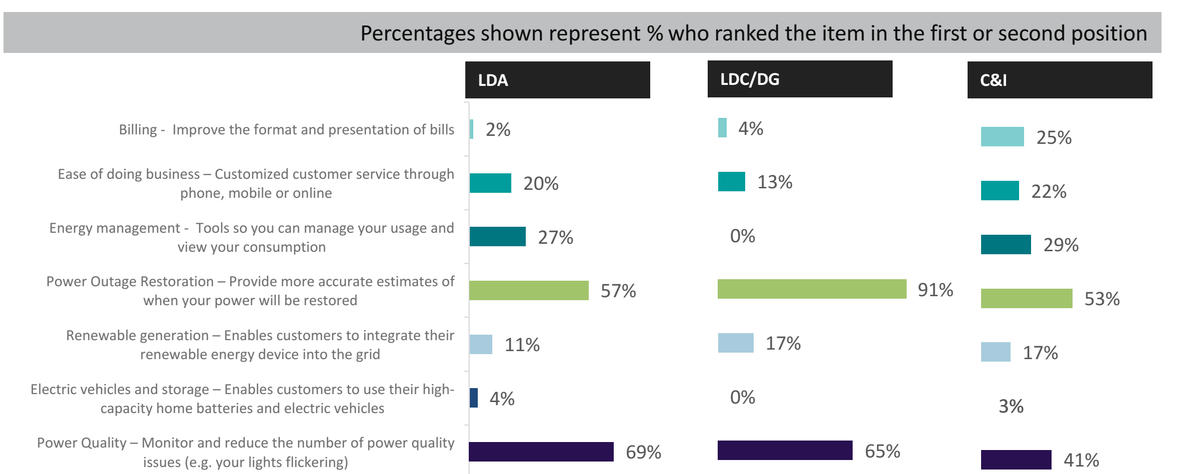
Customer preferences for ways to improve reliability



Q11. Please rank the RELIABILTIY items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 6 represents the least positive impact? Base: LDA (n=45), LDC/DG (n=23), C&I (n=133)

ONLINE WORKBOOK/WORKSHOP SURVEY BOOKLET

Customer preferences for ways to improve service



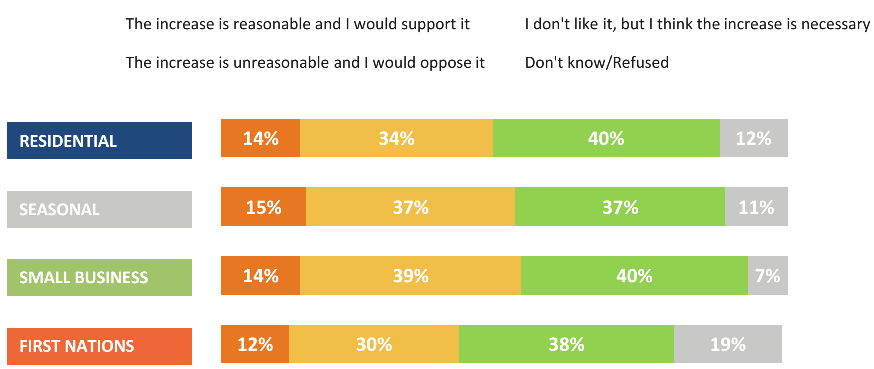
Q12. Please rank the SERVICE items below in the order in which they would have the greatest positive impact on your organization, where 1 represents the item that would have the most positive impact and 7 represents the least positive impact? Base: LDA (n=45), LDC/DG (n=23), C&I (n=133)

SURVEY RESULTS

R&SB CUSTOMERS HAVE MIXED OPINIONS ON RATE IMPACTS, BUT SLIM MAJORITY ACCEPT THE IMPACT NECESSARY TO MAINTAIN RELIABILITY/SERVICE LEVELS (EXCLUDING DKS)

TELEPHONE SURVEY

Acceptability of rate increase to maintain levels



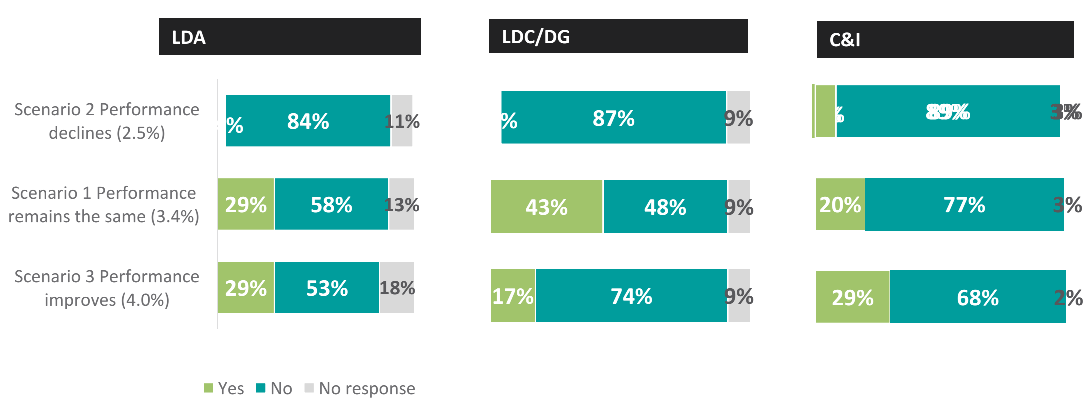
Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [residential or seasonal / small business] customer's total monthly bill will need to increase by [1.1% or the equivalent of $2.00 / 1% or the equivalent of $5.2O]. The increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [residential or seasonal $10.00 / small business $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Base: All respondents; Residential (n=400), Seasonal (n=100), Small Business(n=200), First Nations (n=300)

SURVEY RESULTS

LARGE CUSTOMERS ARE NOT WILLING TO ACCEPT A RATE INCREASE, PARTICULARLY FOR DECLINING RELIABILITY

ONLINE WORKBOOK/WORKSHOP SURVEY BOOKLET

Willingness to accept investment scenarios



Q15. Would you be willing to accept a 2.5% distribution deliver rate increase where reliability and service performance declines (Scenario 2)? Base: LDA (n=45), LDC/DG (n=23), C&I (n= 133)
Q16. Would you be willing to accept a 3.4% distribution delivery rate increase where reliability and service performance remains the same as it is now (Scenario 1)? Base: LDA (n=45), LDC/DG (n=23), C&I (n=133)
Q17. Would you be willing to accept a 4.05% distribution delivery rate increase where reliability and service performance improves (Scenario 3)? Base: LDA (n=45), LDC/DG (n=23), C&I (n= 133)

FOCUS GROUP & WORKSHOP

THEMES

THEMES

Overview

- Cost
- Consistency
- Customer Service
- Connections and Capacity
- Credibility
- Communication

THEMES

COST

COST

Impact of hydro costs and affordability

- For residents, many are interested in lowering the cost of hydro. For a few, it is already unaffordable or approaching being unaffordable
- For small businesses, it is one of many expenses of their operations and a threat to their profitability. Small businesses feel squeezed from many sides, and unsupported in Ontario
- For some large business customers, they stated that the continued rise in hydro prices is a direct threat to the viability and competitiveness of their businesses.
  - it is an expense that they state is one of or the highest after labour
  - it is perceived as being higher than in other jurisdictions and participants have observed anecdotally that business is being lost to these other regions as a result - for example, manufacturing plants in Ontario have closed and moved to the United States and Mexico

COST

Understanding hydro bills

- For residents, many are interested in seeing more information about their bills, particularly in a graphic or illustrative format
- For Large Customers, clarification was provided on the breakdown of costs and line items on customers' bills and this generated a large amount of discussion about each aspect of a hydro bill
- Participants in the small business and large workshops were incredulous that they are encouraged to conserve energy, only to have commodity prices rise to offset this when load in Ontario is lower than expected
- The Debt Retirement Charge and Global Adjustment were also mentioned by participants as being a source of dissatisfaction and confusion

COST

Privatization

Several organic mentions of the benefits and drawbacks of privatization

- Benefits: better accountability and transparency, better decision-making
- Drawbacks: conflict between ratepayers and shareholders, a perception of higher prices

COST

Efficiencies

- Large customers inquired repeatedly in all markets about efficiencies in operational and maintenance costs - and asked if Hydro One could improve in these areas in order to save money and re-invest in capital expenditures, instead of raising rates
- They expressed interest in seeing further details on the historical and current efficacy of maintenance programs, and capital expenditures already spent on improvements. This would help them determine if efficiencies are being achieved

COST

Rate increases

- For residents, most don't like the rate increase but understand that it is necessary, several oppose or don't know if they support a rate increase, with a few supporters
- For small businesses, several don't like the rate increase but understand that it is necessary, with an equal number who oppose it
- For large customers, overall the majority are unwilling to accept a rate increase of any size, whether reliability remains the same or improves
- All segments express a desire for more detailed information as to how the rate increases would be spent, so that they can determine if the investments are truly impacting reliability - rather than going to wages, salaries, or payouts to Hydro One employees

THEMES

CONSISTENCY

CONSISTENCY

Power quality and reliability

- Power quality emerged as being the reliability issue of most concern to participants in the large workshops - it was mentioned as being a significant and pressing priority for many customers in all markets.
- Several participants throughout the consultation process challenged the fact that interruptions lasting less than one minute are not being tracked by Hydro One
- The consequences of the impacts due to poor power quality were disseminated in detail by participants during the consultations. These include:
  - Lost productivity
  - Equipment failure - both temporary, and permanent
  - Labour impacts - i.e. the uncertainty of sending workers home or keeping them at the facility
  - Health and safety issues
  - Financial impacts
  - For LDCs, the whole municipality is without power
  - Installing backup generation
  - Technology / IT impacts

CONSISTENCY

Current asset management

- A few residents and in particular small businesses expressed concern at infrastructure not being managed at a pace that mitigates the risk of aging assets
  - They expressed concern that this was as a result of poor planning and maintenance
- Many large customers were satisfied with the current level of asset management

CONSISTENCY

Future asset management

Preparing the grid for future needs - including the role of renewable energy and technology - was debated by participants in all groups and workshops

- Some believe that more renewable energy would benefit the grid and ultimately ratepayers in the long term by being more economical than other forms of generation, although they acknowledge that costs may go up in the short term
- For those who advocate for proactively preparing the grid, the pace of adapting the grid should be measured and the approach balanced
- Detractors are concerned that technology will be obsolete before it is beneficial to the maximum number of people
- They believe that associated costs should be borne by the few who benefit, rather than all ratepayers

CONSISTENCY

Regional concerns

Regional reliability concerns were brought up as being of particular interest to some participants

- For those in the Muskoka area, they were concerned about reliability issues caused by the dense forestry in their region, and questioned why trees in their area are not more proactively trimmed
- For those in the northern markets, they expressed their concern that capital investments would be focused on areas of greater population density, i.e. in southern Ontario, and that they would not see the benefits of improved reliability. As such, they stated that they would like to see a detailed capital plan that included investments and benefits specific to the north
- In general, participants indicated an interest in seeing more region-specific investment details, to better understand reliability performance in their area of the province

THEMES

CUSTOMER SERVICE

CUSTOMER SERVICE

Satisfaction with service

- Most residential customers are satisfied with customer service, with long wait times on the phone being the biggest issue
- For most LDA/LDC customers, they stated that customer service is generally satisfactory
- For many C&I customers, some LDA/LDCs, and small businesses, customer service from Hydro One is an area in need of significant improvement
  – Not having a dedicated account person or contact.
  – Being passed from one person or department to another instead of receiving a satisfactory resolution to issues
  – The process of resolving issues can take an excessive amount of time - months or years, if at all. Receiving rebates can also take a long time.
  – Bills and information on planned outages are sent to a corporate head office, instead of employees on the ground who need the information for planning and budgeting.
  – Being unable to receive trustworthy advice - for example, whether or not participating in an energy-saving program is worth the risk.
  – Making web meeting appointments with Hydro One employees who do not show up.
  – Navigating complicated and time-consuming application processes for incentives and programs.

CUSTOMER SERVICE

Billing

In general, participants were looking for two key elements on their bills: accuracy and clarity.

- Accuracy challenges included:
  – receiving estimated bills instead of those based on actual meter readings
  – consolidating bills if one company is receiving multiple bills for its different buildings/meters/locations
- Clarity challenges included:
  – finding their bills confusing
  – feeling that the information provided is incomplete
  – format issues: wanting a more visual format such as a chart, pie or graph

THEMES

CONNECTIONS & CAPACITY

31

CONNECTIONS AND CAPACITY

Providing additional capacity

Customers in certain regions (northern Ontario) and industries (mining, greenhouses) state:

- that a lack of sufficient power capacity is a hindrance to their ability to grow their businesses
- the process of applying for more capacity with Hydro One and the Ontario Energy Board is protracted and unsatisfactory
- the rules and regulations around adding capacity via the beneficiary payment system are confusing

32

CONNECTIONS AND CAPACITY

Exporting power

- The sale of electricity at a loss to the US also emerged as a topic of discussion during some of the large workshops and focus groups.
- Participants expressed concern and dismay that this is happening when rate increases are being considered
- In one workshop, participants from the greenhouse industry indicated their strong interest in using this excess energy to meet their needs, as they require lighting for their greenhouses overnight.

THEMES

CREDIBILITY

CREDIBILITY

Role of regulator

Because Hydro One is the customer-facing entity responsible for billing, customers' perceptions are negatively impacted by all aspects of the hydro bill and any poor perceptions of the industry in general.

There was low awareness of the role of regulators and numerous points of clarification were made throughout the consultations as to what is mandated and controlled by the respective regulators, including:

- OEB:
  - Information contained on hydro bills
  - Commodity price of electricity and inability to profit on it
  - Capacity expansion
  - Beneficiary payment system for capital work
  - Non-advisory customer service role
- IESO:
  - Global Adjustment
  - Environmental incentive programs
  - Contracts for generators, including renewable sources

CREDIBILITY

Perceptions of Hydro One

- There was commentary made by some participants on perceptions of Hydro One and its workers
  - There were mentions of seeing Hydro One workers in coffee shops during working hours
  - Having too many workers show up to a job
  - Linesmen who are promoted to “cushy”, high-paying jobs within the organization
  - Perception of excessively high quality of working vehicles
- These perceptions of poor productivity and management are particularly difficult to accept with the perception that hydro costs in Ontario are very high, and a perceived threat to the economic well-being of the province’s businesses

CREDIBILITY

Company culture

- Some participants in all segments stated their belief that the information being presented was to justify a distribution rate increase by Hydro One.
- Comparisons were unfavourably made to private companies:
  - private companies deliver a better product for less money, by finding efficiencies, and by being innovative without raising prices
  - many participants pointed out that hydro rates have continued to climb for many years and their belief is that there is no end in sight as it relates to rate increases, thanks to poor management and decision-making by Hydro One.
- Small businesses and large customers pointed out that they are unable to raise their own prices to offset an increase in hydro prices

37

CREDIBILITY

Shareholders vs. ratepayers

- A few participants expressed deep concern and dismay that profits were given to shareholders, and not returned to the company in order make capital improvements, and/or reduce costs for ratepayers.
- They stated that this is a situation unique to Hydro One, and that other companies would not have the same option available to them - instead, they would put profits back into the company in order to maintain or reduce prices for their end-users, or profits are put back into making a better product
- The inherent contradiction between keeping costs low and reliability high for ratepayers, versus making profits for shareholders, was pointed out by participants

38

CREDIBILITY

Accountability and transparency

- The themes of accountability and transparency for Hydro One emerged throughout the in-person consultations.
- Participants indicated concern at a current lack of both, and a desire to see Hydro One undergo an organizational transformation that would positively impact customers in terms of:
  - helping them become informed consumers
  - providing reassurance of reliability and service
  - providing reassurance responsible stewardship of rates paid in the form of operational and maintenance efficiencies, and prudent decision-making in future capital investment planning
- While many customers cited deep concerns around rate increases, many were also open and receptive to understanding how and why Hydro One uses its funds.

THEMES

COMMUNICATION

COMMUNICATION

Communication during outages

- Numerous participants throughout all consultation methods stated that they would like to experience better communication during outages
  - The majority call in to the number on their bills or the OGCC, with a few checking Hydro One's website.
- Most stated that the information they receive or view is inaccurate, and this is a source of frustration in particular for businesses - many of whom stated that communication an area in which Hydro One could help reduce the negative impact of outages
- Participants indicated that they would like timely, accurate information on outages specific to their region/area
- Awareness of other tools and resources for outage information, including Hydro One's app, is low

COMMUNICATION

Cost saving ideas and programs

- Some residents indicated their interest in having Hydro One provide ideas and information on ways to save and conserve energy and ultimately, the cost of their hydro bill
  - This might be through programs, coupons, or simply being able to track their detailed usage between bills
  - Having this information come from Hydro One would lend credibility to the information.
- For large customers, a few customer made organic mentions of positive experiences with energy/cost saving programs with Hydro One.
  - For those who are eligible for cost-saving programs and incentives, awareness was generally low.
  - For those who have already applied for these programs, the application process is frustrating and complicated

COMMUNICATION

Channels

Participants expressed interest in a number of different channels and some indicated that they would like to hear from / about Hydro One via multiple channels, including:

- Directly on the bill
- Bill inserts
- App
- Social media
- A separate letter
- Email
- Advertising
- Texts
- For business customers: a dedicated relationship with an account person, a local contact, or a dedicated business (non-residential) call center line were all of interest.

COMMUNICATION

General information on Hydro One

- Participants in all segments expressed an interest in learning more detailed information about Hydro One
- Many participants stated that in order to make decisions around which areas of investment would be of most benefit, as well as whether or not they would support an increase in rates, they would require more comprehensive information including specific costs, historical data, and cost efficiencies
  - This in turn would lead to trust that Hydro One is focused on efficiency and productivity.
- For many, the information provided during the consultations had a positive impact on their perceptions of the company

ABOUT IPSOS

Ipsos ranks third in the global research industry. With a strong presence in 87 countries, Ipsos employs more than 16,000 people and has the ability to conduct research programs in more than 100 countries. Founded in France in 1975, Ipsos is controlled and managed by research professionals. They have built a solid Group around a multi specialist positioning Media and advertising research; Marketing research; Client and employee relationship management; Opinion & social research; Mobile, Online, Offline data collection and delivery.

Ipsos is listed on Eurolist NYSE Euronext. The company is part of the SBF 120 and the Mid 60 index and is eligible for the Deferred Settlement Service (SRD).

ISIN code FR0000073298, Reuters ISOS.PA, Bloomberg IPS:FP

www.ipsos.com

GAME CHANGERS

At Ipsos we are passionately curious about people, markets, brands and society. We deliver information and analysis that makes our complex world easier and faster to navigate and inspires our clients to make smarter decisions.

We believe that our work is important. Security, simplicity, speed and substance applies to everything we do.

Through specialisation, we offer our clients a unique depth of knowledge and expertise. Learning from different experiences gives us perspective and inspires us to boldly call things into question, to be creative.

By nurturing a culture of collaboration and curiosity, we attract the highest calibre of people who have the ability and desire to influence and shape the future.

"GAME CHANGERS" – our tagline – summarises our ambition.

Wave 2 Distribution Consultation – Hamilton LDC/LDA Session

June 8, 2016

Attendees and the company they work for	• Rosso Parra, Grimsby Power Inc. • Keith Vanderwood, Air Canada Products Canada • Grant Nopper, Canadian Gypsum Company (CGC) • Kristen Montague, Canadian Gypsum Company (CGC) • Kevin Hodgins, St. Mary's Cement Inc. • Denis Yeung, Oakrun/Aryzta • Randy Gao, Royal Canin
Mood / tone in the room **Level of engagement**	• Mood in the room was quiet and subdued, but participants arrived open and willing to hear what was being presented, and were thoughtful and engaged. Most had a high level of understanding of the energy sector and had a detailed knowledge of their own electricity needs and challenges. • Oded Hubert was present to greet the participants in addition to presenters Graham Henderson and Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	• Customers spoke of challenges due to service interruptions and the subsequent impact on their organizations. • For one LDA, communication during interruptions is the key concern. They state that although it's apparent why the interruption is occurring, i.e. severe weather, they would like communication as to when service will be resumed, including clarification on timing of any necessary repairs. • For other LDAs, they state that communication and customer service from Hydro One is outstanding. For these, their issue is around unreliable service from feeders, stations and transformers not controlled by Hydro One. These are poorly managed and create power issues without an apparent means of recourse for the customer. • For the LDAs who face interruptions, regardless of the cause and communication experience, there are significant impacts as it relates to labour and safety. Manufacturers are unsure as to whether they should send their workers home or keep them onsite. Additionally, there are safety hazards associated with service interruptions (e.g. working with volatile materials). *"A little more communication or availability to answers as to estimated time of outages. Is it 2 hours, is it 8 hours…That's a big difference. Unplanned outages. What's the repair going to take."* *"We schedule the labour force. Do we undertake this undertaking or not? Are we*

	going to be up and running in 5 minutes or 10 hours? For labour reallocation we need to know that – do we send people home or keep them here?" • In terms of ranking areas to improve reliability, there was no clear winner with various participants choosing different areas as being of importance. One participant indicated it's difficult to make a choice between reducing the number of outages or lessening the frequency, as they both have different consequences associated with them. Rather, they felt that it was important to strike a balance in addressing both. *"I think it's good to keep a good balance of both, because any power flicker 5 seconds we have to restart our production lines. But then duration is very important too, every hour you can bring the power back on earlier, is a lost time you can save. It's really a mix of both, one not more important than the other."* • For the improving service ranking, power quality was by far the most pressing concern - in fact, a couple of participants feel that it's more important than reducing frequency or duration of interruptions - to them, reliability equals power quality. However these participants recognize Hydro One is not always responsible for these interruptions, as it's a flaw within the grid. *"Power quality is probably the biggest. Above all."* *"The basic flaw is you're looking at interruptions and duration…for us reliability is quality not interruption and duration. It's not that we don't have power, it's that quality isn't what we need and it's causing us problems."* • For the Scenarios, participants asked for clarification around their specific rate class on delivery distribution charges. Once ascertained that their rate is 2%, a 4% increase was considered very reasonable, with one participant indicating he would be willing to pay a 10% rate increase. *"If my bill is $100K a month, 2% category – so that's $2000 a month. if I'm in the 2% distribution category, It's 2% of 25 which is like nothing. So the answer's pretty easy for us."*
Any follow-ups or points of concern / consideration	• With power quality being a concern, participants indicated interest in having Hydro One manage it on their behalf. • The suggestion by Hydro One that there are ways to minimize impact internally within their organization's infrastructure, i.e. its ability to mitigate the effects of drops in voltage - was of great interest to participants.
Emerging Themes on Customer Needs and	• **Communication**: Providing timely information about outages and repairs to drive decision-making for customers. • **Power Quality**: Having power quality managed by Hydro One as well as working to improve internal capacity/ability to deal with PQ incidents.

Preferences	

Hydro One Distribution Consultation – Hamilton C&I Session

June 8, 2016 - 2pm

Attendees and the company they work for	• Vern Mills and Paul McCoy, McCoy Foundry • Sara Peckford and Caitlin McFadyen, Town of Caledon • Fidel Reijerse, RESco Energy (generator) • Carl Loewith, Joe Loewith & Sons • Joe Lannan, Great Lakes Elevator • Dave Sabola, Pepsico Canada • Stephen Hart, HK Travel Centre • Bob Burlakoff and Abu Sanneh, Hamilton Airport • Natasha Murray and George Bougiouklis, Chartwell Mastercare • Linda Campbell, City of Hamilton
Mood / tone in the room Level of engagement	• Mood in the room was engaged and lively. Participants were eager to ask questions and provide their thoughts and perceptions on a wide range of topics related to Hydro One. • Participants included those with a more basic understanding of the energy sector and Hydro One's role specifically, as well as those with a more sophisticated understanding of the electricity system, including detailed technical knowledge of their own challenges and needs. • Hydro One VP of Regulatory, Oded Hubert, was present to greet the participants in addition to Hydro One presenters Graham Henderson and Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	Throughout the discussion, several points of clarification were made about factors/concerns not controlled by Hydro One, including: • **Energy Retailers:** Participants asked about the energy salesperson who knock at their door. It was clarified that these are companies with whom consumers sign a contract for a fixed price on the commodity portion of their bill (electricity or natural gas) • **Bill Format:** Based on feedback by participants on the current bill format not being as detailed as they would like, it was clarified that the format and breakdown included in Hydro One's bills to customers is prescribed by the OEB. • **Global Adjustment Charge:** It was clarified in response to customer questions and comments that this charge includes payment of contracts that the IESO has with generators. As well, any conservation incentive programs that consumers participate are funded through GA. • **Wi-Fi:** One participant inquired as to whether Hydro One is a potential provider of Wi-Fi. It was clarified that this misconception may be related to

	Hydro One's smart metering network but that they are not a provider of Wi-Fi. • **Payment Terms:** One participant remarked that they were required to pay upfront for requested capital work. It was clarified that these payment terms are prescribed by the OEB for any capital work requested by a customer and fulfilled by Hydro One. • **Commodity Price of Electricity**: It was clarified that the commodity price of electricity, which comprises the majority of a customer's overall bill, is a pass-through charge by Hydro One which they are not allowed by law to make a profit on. Feedback specific to Hydro One included: <u>Billing Concerns and Feedback:</u> • Positive experiences as well as challenges faced related to billing were voiced at various times throughout the session. • A couple of participants had positive experiences as it relates to billing, including one who observed that billing accuracy has improved significantly over the past few years. *"…as somebody who looks at bills every single day, [accuracy] has improved significantly, would like to see it improve further, but it has gotten a lot better. "* • One participant stated that they would like a more detailed breakdown of their bill to understand usage and kw/hour. • Another participant had a billing issue where they were charged 3 years later for work in the tens of thousands of dollars. *"Hydro One did the work, the bill came in about 3 years later. That was no longer in our books, 30 or 40 or 50K, it was substantial, fell through the cracks."* <u>Unplanned interruptions:</u> • Service interruptions of less than one minute in duration are a major concern to one manufacturing customer. For this customer a short interruption is just as impactful as a longer one. They stated that a 10-second interruption can close their plant for 5 hours, which costs them thousands of dollars a minute. They asserted that interruptions less than 1 minute should be tracked. *"…a 10 second blip takes the entire factory down, then has to be purged, sanitized, and lack of production could be thousands of dollars a minute. For certain manufacturers, it can be extreme, those [interruptions of] less than 1 minute should absolutely be tracked."* • For a participant who manages a long-term care facility, duration of interruptions was of particular concern with hydro service restoration taking as long as 72 hours in a facility with a vulnerable population (seniors with

medical issues). They do not have a contact person or relationship with an account representative and are instead reliant on publicly available information to contact Hydro One. Finding a person within the organization to provide specific answers is an ongoing challenge.

"In some cases you can't determine how long it's going to be - getting that information is pulling teeth, having some contact for medium [size] businesses with huge impact, next level customer service…my power interruption at home is different than a long-term care home."

Communication and Customer Service

- Customers state that they have faced challenges in trying to receive information and resolution as it relates to both immediate (service interruption and repair) and longer term (clearing brush, billing for LED lights) needs.
- Information on planned outages, as well as bills, are often sent to a customer's head office instead of directly to the employees on the ground who are directly affected. For unplanned outages, this means that employees are unable to plan ahead accordingly. For bills, employees receive bills from their head office months later which affects their ability to plan and budget.
- Some of the issues and challenges faced have been ongoing, with resolution of issues such as billing errors being a long process. A couple of participants had positive experiences with Hydro One staff but in general, finding the right person to help is a challenge.
- A couple of customers spoke of positive experiences with tools and programs offered by Hydro One, including...
    - A 50% funding audit program at a participant's facility.
    - An energy management billing portal recommended through customer service to a participant. They are able to see comparative kw/hr, compare to last year/month, and understand their savings.
    - These were identified as being awareness opportunities for Hydro One.

"I had the same challenge, I got Hydro One to send me the bill because it never comes to me...Normally I get them four months later, what good is that to me four months later. All these bills in larger corporate end up with some accountant as opposed to the people trying to run it."

"As a municipal client we do have some challenges with Hydro One staff in cleaning up the brush…residents come to us first, especially when it has to do with trees…that was challenging to get answers to communicate to our residents."

Planning and Efficiencies

- A municipality pointed out the inherent contradiction in wanting to create a tree canopy for their region, while Hydro One is actively trimming trees.
- Participants asked about the potential to bury lines underground vs. having the poles and line aboveground. It was clarified that for developers, if the

municipality mandates that developers bury their lines underground, Hydro One fulfills the work, and the developer is the one to pay for it. For municipalities, should they request that their lines be buried underground, they are also required to pay for it.

- Hydro One's role in providing capacity and flexibility to consumers for renewable energy sources, such as in-home charging for electric cars, was debated. This was perceived as being a lower priority by one participant with another seeing it as a high priority because it is important for Hydro One to effectively manage the grid as new technologies and power sources emerge.

"How are your costs for these things distributed? Are the costs of doing business in Timmins maybe higher than that of say down in here [Southern Ontario]. So is there a cost base distribution of rates, or is it a big pot, everybody pays the burden of whatever the cost of maintaining the system?"

"…I have put electric vehicles and storage lower down…to me it's individual homeowner, charging station in garage, as opposed Hydro One additional service."

"To me it's not just about 10 kw and Tesla, having some grid management benefit as well."

Power Quality

- Power quality was voiced as a significant issue with severe consequences for affected businesses. One customer defined power quality as a drop in voltage, which could occur as many as 15 times an hour. These drops in voltage have the same impact as a service interruption.

"For us, power quality is bigger…when I think of reliability, I don't think of power outages. But when you drop the power and the generator goes on and comes off 15 times in an hour, you can't run the business that way."

Reliability and Rates

- In response to participant questions, clarification was provided on urban vs. rural rate classes. Participants wanted to know how Hydro One ensures that customers have been correctly assigned to the appropriate rate class. It was clarified that rate classes are determined by the density of customer base, i.e. customer load per kilometre of line.
- One large industrial expressed frustration at the continuously rising cost of electricity in Ontario. For them the rising cost is a barrier to remaining competitive. Another participant stated that they have struggled with fluctuating bill amounts without any way of predicting or understanding why their bill amount changes so much, thus making budgeting extremely challenging. Although these remarks were based on the overall bill and not specifically the delivery distribution charge, they expressed the belief that Hydro One should have a vested interest in facilitating success for businesses

	or better communicating available programs to customers. • A participant inquired as to how being a public company would affect investment plans, and expressed concern that capital investments resulting in improved reliability might not be in the shareholder's best interest. • Questions were raised about whether or not improved technology and the associated increased efficiency/benefits are being considered and calculated into the investment plan. • Some participants are willing to accept a rate increase if there is a demonstrable benefit to their hydro service, customer service and efficiency. *"…what does the consumer need to be more successful, if you don't make them more successful, what have you accomplished."* *"In general, we're all willing to pay more if we receive more, and if the outcomes we can visualize are very tangible."* *"…being out of hydro for 72 hours is unacceptable, Hydro One has known about this problem for 3 years and is unwilling to do anything about it."*
Any follow-ups or points of concern / consideration	• Tools, resources and programs that work in conjunction with municipalities and businesses to improve coordination, provide better customer service, and locate specific information such as a breakdown of their bills, are of great interest to participants.
Emerging Themes on Customer Needs and Preferences	• **Awareness:** Make customers more aware of available tools and resources for billing and service, as well as any programs that may be of benefit to them. • **Communication**: Providing information about outages and repairs, as well as a better understanding what is within Hydro One's domain/control and what isn't. • **Customer Service and Relationship**: Provide timely, efficient, and customer-specific service. For C&I customers, they face challenges in receiving answers and resolution from the call centre and central numbers with their issues often being bounced from person to person. • **Power Quality**: Improve power quality by mitigating frequency of drops in voltage. • **Rate Increase vs. Reliability:** Guarantee a tangible improvement in reliability and service in the event of a rate increase.

Hydro One Distribution Consultation – Collingwood LDA, LDC and C&I Session

June 9, 2016 - 9:30am

<table>
<tr><td>Attendees and the company they work for</td><td><u>LDA/LDC</u>
Bill Koniuch, Honda of Canada Manufacturing
Shawn Plowright and Adem Nezirevic, KTH Shelburne MFG.
Dan Moca, Husky Injection Moulding
Michael Flood and Kim Rowe, Tenneco Canada Inc.
Lisa Cox and Ken Anderson, Casino Rama
Kevin Tone and Lindsay Ayers, Blue Mountain Resorts
Rene Landry, Kimberley Clark of Canada
Al Sobbart, Panolam Industries
Brian Elliot, Lakeland Power

<u>C&I</u>
Steven Parkes, Craigleith Ski Club
Jeff Conn and Jamie Cutherberth, The Osler Bluff Ski Club
Doug Wansborough, Devils Glen Country Club
Randy Fielder, Bonaire Golf & Country
Nick Levangie, JW Marriott
Sean, Owen Sound Ledgerock Ltd.
Ken Rounds, Simcoe County
Jeff Struewing, Grey Standard Condo Corp 75
Ian, Energy Plus</td></tr>
<tr><td>Mood / tone in the room
Level of engagement</td><td>Mood in the room was thoughtful and serious, with many participants contributing to the discussion.
Participants had a high level of knowledge of the energy industry as well as the needs and challenges of their own organizations.
Graham Henderson from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenter Paul Brown.
Other Hydro One account persons and staff were present to provide local context and engage with customers.</td></tr>
<tr><td>Quotes to summarize the general conversation</td><td><u>Reliability</u>
Commercial/industrial participants struggle with the frequency of unplanned interruptions, with some customers experiencing as many as 50 unplanned interruptions per year.
Once an interruption has occurred at a manufacturing plant, their processes need to be re-started and that can take hours to get back-up and running.
Financial consequences can be dire, costing $1.2 million per year for one participant and hundreds of thousands per outage for another.</td></tr>
</table>

	"...Every time [an unplanned interruption] happens re-starting takes hours. Our [cost] impact is $1.2 million a year of repairing parts..." <u>Location/Area specific</u> • Participants from this session were particularly interested in maintenance and outage prevention activities specific to their area. The Muskoka region was identified as being one of the most tree-dense areas in Ontario, and as a result there is a high concentration of power interruptions caused by trees. They would like to see an investment plan that addresses their region-specific concerns with more pro-active tree-trimming, to reduce the number of interruptions and improve reliability performance. • Participants had questions and concerns around future load capacity for their area, which is an area that they indicate is growing exponentially. • Because of the seasonal nature of the businesses in the Muskoka region (i.e. busy ski resorts in winter, and vacationers in the summer months), an unplanned interruption can have serious financial and customer service consequences. *"For us in ski season [interruptions] have a big impact on our business. Imagine a day where we have 2500-3000 people in area and at restaurants, and the power goes out. Our customers are wanting refunds. We can't operate washrooms."* <u>Communication</u> • At various times during the session, a few participants stated Hydro One does not do a good job communicating when power will be restored after an interruption occurs. In their experience it is difficult to get an accurate estimate of when power will be restored. *"During major storm… OGCC only gives ballparks and they're pushing out information they get from local guys. I don't know if there's a better way to tighten up those restoration times, but we want [power restoration times] to be accurate."* <u>Planning, Efficiencies and Accountability</u> • The general consensus in the room was that participants are sensitive to investments that will result in higher costs to them. Customers accept that Hydro One is making efforts to manage and reduce costs, but want greater reassure that in preparing its investment plan Hydro One is maximizing efficiencies and making prudent decisions with an eye toward long-term financial benefits (lower costs) to customers. • Concerns were raised around the fact that Hydro One is a monopoly in their distribution area and that because of this there may not be sufficient accountability of Hydro One. One participant stated that he would like to see Hydro One be more transparent, so that it can be held accountable for its decisions and actions more than it is now.

	"…when you have a monopoly sometimes wages can get out of line, and money can get spent without true accountability. It all starts with how transparent you want to be." <u>Energy Storage and Conservation</u> • A participant questioned whether stored energy was being exported to the US at a loss. • A few participants indicated that in their view the regulator (OEB) is allowing rates to go up to off-set lower consumption among customers. This is incredulous to them given that consumers are being encouraged to reduce their consumption. *"The OEB did us all [of us] a big disservice by the last rate increase. We didn't use enough electricity, and that is why our rates are going up. We're trying to sell to our customers that conservation is good: if you conserve, you'll save money. And then regulator turns around now the rates are going up."* <u>Scenario Feedback</u> • Some participants stated that a Scenario in which there is a rate increase for declining performance was unacceptable, and that having such a Scenario reflected negatively on Hydro One's mindset and culture as an organization. • A few participants drew an analogy between Hydro One and private industry and indicated that their customers would not accept an increase in price for a poorer product. In fact, their customers expect them be more innovative and improve their technology in order to provide a <u>better product</u> at a reduced price. *"I think that it is ingrained in the mindset of the company to give us the same as what we had yesterday, [yet] we gotta pay 3.4% more. None of our customers are going to accept that. Most of our customers expect that we have found improvements [so that we can] sell our product to them for less money next year or have found ways to make it better, and not to ask them for more money for the same product."* • There was debate amongst participants about whether or not it is within Hydro One's mandate is to provide specialized power quality service to a small group of customers, or if their role is as a basic socialized service to all its customers. *"Power quality -- you can add those elements, but they're on the market. You can see specifications of what you can buy, and specifically say what quality of electricity that you need to put in. You should look at that, as a specification. This is what you can buy across the world."* *"With a small percentage of customers that might have a specialized need, their*

	tolerances are much higher or stringent than what they would be for the average customer. Really the bill should be on them. It shouldn't be socialized. Why should I pay for somebody else's special need?"
Any follow-ups or points of concern / consideration	• Participants would like to see more specific historical system performance (reliability and power quality) data from Hydro One as well as a historical breakdown of Hydro One's performance that goes back further than what was shown in the presentation. • Some participants stated that Hydro One needs to improve power quality as well as be more innovative in how it maximizes productivity and efficiency, and in providing value to customers, but participants also stated that it would be irresponsible of Hydro One to expect to be able to socialize the costs of customized needs across all rate payers.
Emerging Themes on Customer Needs and Preferences	• **Planning:** Participants stated that they would like Hydro One to be more pro-active in its asset management, in particular more pro-active with its tree-trimming program. • **Cost Reduction and Efficiencies**: Participants expect that through prudent investments and good planning, Hydro One can over time reduce OM&A costs. • **Company Culture**: Participants believe that Hydro One needs to become more innovative and manage costs better, before or rather than, raising rates. And they believe that raising rates for declining performance unacceptable. • **Role of Utility**: While some expressed a desire for Hydro One to be more actively involved in, and responsible for, power quality, others feel this is a specialized need that should be paid for by the specific end user, and that these needs should not be paid for by all end users on an aggregate level. • **Local Needs**: Participants would like better service and better communication that addresses their needs as seasonal business, and would like to see the investment plan include more tree-trimming.

Hydro One Distribution Consultation – Timmins LDA, LDC and C&I Session

June 13, 2016 - 9:30am

Attendees and the company they work for	LDA/LDC • Ross Byron, Imerys Talc Canada Inc • Eric Buteau, Lecours Lumber Co Ltd. • Dan Gagnon and Harvey Dasti, Primero Gold • Shoaib Zia and Lori Smith, Goldcorp • Sue Howson, Northern College of Applied Arts and Tech • Eric St-Pierre, French Catholic School Board • Carole Horton, District School Board Ontario • Travas Hack, Eacom Timber Corp C&I • Ron Wink and Scott Tam, City of Timmins
Mood / tone in the room Level of engagement	• Mood in the room was thoughtful and serious, with many participants contributing to the discussion. • Participants were generally knowledgeable about the energy industry as well as the needs and challenges of their own organizations, and of other businesses in their region. • Vice President Construction Services Brad Bowness from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenters Graham Henderson and Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	• Participants asked for details on Hydro One's rate of return. It was clarified that Hydro One has a regulated return on equity of 9.4% for distribution. • They asked for information on Hydro One's recent transmission rate filing, and a brief description was provided at the outset of the session. It was clarified that there was a transmission rate increase Scenario in the application of approximately 5%. Participants observed that with 94% of the transmission in Ontario there are few comparators, to which it was clarified that comparator transmitters are in BC Hydro and Manitoba Hydro, as well as other transmitter utilities in the US. • Participants observed that Ontario has one of the highest electricity rates compared to other provinces, Quebec in particular. Details and clarification were provided as to the reasons for this difference, that are mainly based on the different type of generation, i.e. mostly hydro-electric generation in QC vs. nuclear in Ontario. As well, Hydro Quebec is a structurally distinct organization from Hydro One with its generation, transmission and distribution all being fully vertically integrated, and therefore more cost

	efficient. • Participants received clarification that the commodity portion of their electricity bill is a pass-through cost by Hydro One and that Hydro One does not having any control over who it buys electricity from or at what price. As with all distributors in Ontario, price and suppliers are dictated by the IESO. • Details on Global Adjustment were provided including details on the contracts between generators (OPG and others) and the IESO. • In spite of the explanations of the differences in commodity price, one participant expressed skepticism that this was the sole reason for the considerable difference in electricity prices in Ontario compared to Quebec. *"…say you have a cottage in Quebec, 100 km from here - completely different bill. So there's more to it than just commodity cost, what is it."* • Cost and reliability were the two most pressing concerns cited by session participants. • The cost of hydro was mentioned as being a major expense for the businesses in the room, and for one participant, the cost of hydro is the business' second-highest cost after labour. *"From my perspective in managing an operation, hydro is [the] number two cost, labour is one, hydro is number two. Cost is important for us to remain competitive."* • Reliability and power quality are viewed interchangeably by this group. Interruptions of less than one minute - even just a few seconds - can have a profound impact on their operations. • The implications of power interruptions vary from one business or another: for municipalities it affects the airport, sewage and water plants, while for mining companies and manufacturing plants it means shutting down production with significant financial implications. Technology and IT systems also fail as a result of power interruptions. With momentary interruptions, backup generators don't kick in. • It was suggested that Hydro One and its customers could work cooperatively to track power quality issues. *"Asking us to tell you how many one-minute interruptions is pointless. [More important is] how many one-second interruptions do we have? Two summers ago I had 40 [one-second interruptions]. And we have at least one or two [of those] a month. Taking the plant down for one-second, I lose $5,000 per hour. If you take me out [4 times] I'm losing $20,000. It's significant."* *"We did talk a lot about small interruptions that Hydro can't see, [those that are] one-minute duration. So what about Hydro teaming [up] with customers, putting meters at customer facilities to see those bumps and those issues a lot better?"*

- Hydro One clarified that the current beneficiary-payer system for capital work is regulated and mandated by the OEB. Some participants felt that these costs should be socialized/shared across all rate payers.
- At least one participant stated that he expects Hydro One's profits be reinvested into capital improvements, rather than to shareholders.

"Every other business takes capital expenditure and either has a way of getting payback for it by the money they put out, or it's the cost of doing business. So what you're saying is, should Hydro take some of their money and maintain business? Yeah they should, every other company that's publicly owned or privately owned has to do that to maintain business."

- Some participants commented positively about the communication that they receive from Hydro One during interruptions, while others stated that Hydro One does not do a good job of this.
- Customer service was cited as an issue for several participants, who spoke of specific incidents such as being passed around from one person to another when calling into the call centre, having emails unreturned, or having Hydro One representatives miss pre-booked phone calls.
- Some participants commented that Hydro One does not resolve customer problems quickly enough and stated that in their experience issues they encountered took a long time to resolve.
- In particular, problems with estimated bills, and problems with requesting to have multiple bills across an organization consolidated were mentioned.
- There is low awareness of incentives and other programs. Those who have experience with them indicated that the application process is frustrating and complicated, with one organization going so far as to hire an outside company to help them with the application process.
- One participant indicated that in their mind, improving customer service should not cost additional money for Hydro One and should just mean better training. Another suggested having a local and/or dedicated contact for their organization as a potential workaround.

"…on several occasions of reaching out to Hydro One, either emails went unreturned or twice we set up meetings with our President and Vice President and the gentlemen just never showed up for the teleconferences… "

"…every time we deal with someone, it's someone different, [so answers questions with] I don't know. They pass it down the line, [but] who do I contact, it's frustrating. Hydro has a lot of different divisions, and I understand that, but one's not talking to another."

"…when we did an energy audit a few years ago, my application this thick and had to re-submit three times, because it was missing a little piece of information."

- Participants expressed concern that southern Ontario would be the main

	beneficiary of any capital expenditures. They would like to see investments in the North that would have a direct benefit to the area. • A few mentioned that they would like to see capacity expanded in the North without the restrictions placed on them by incentives and cost sharing. They argue that limited capacity translates into an inability to expand their businesses, and therefore, they are not in turn helping Ontario's economy. *"…looking at us Kirkland Lake, because of the upgrade of equipment, money not put into Northern Ontario as Southern Ontario."* *"…how you distribute that, does money go north?"* *"that may not be enough money for growth for industry, the industry has to foot the bill, couple of other stories, generators and stuff, we thought maybe someone would help us but there was no money. To help with growth that may not enough money."* • Some participants stated that they are willing to accept a distribution rate increase as long as it results in improved reliability (specifically better power quality), while others stated that they would require more information as to how money is currently being managed by Hydro One in order to comment on the Scenarios. *"I guess reliability is about quality of power. We want it all the time and we don't want bumps, we want quality. If we get that we're 100% satisfied, we'll likely bitch a little less about paying for it."* *"…you're already getting a lot of money, how efficient are you with that money, [and what is the] operational effectiveness of Hydro One as a group to deliver the product? If we give you $100 and it's mismanaged, [then instead] I'll give you $120 [and] it's still mismanaged. That's where I think you were headed."* • Participants indicated that Hydro One is generally viewed as a large and inefficient operation that does not properly manage its labour force and assets. • Some participants expressed an interest in understanding and learning more about what "Hydro One 2.0" looks like, and how its management and efficiency has improved based on all the recent changes it has undergone. *"…I could bring you to a coffee shop here at 10 o'clock, a lot of hydro trucks there, that doesn't look good, they should go back to the shop and hide…That is bad for your own reputation. You're going to get bashed."* *"…there is this general tendency to think of Hydro One as being inflated in terms of its management. What I would like to hear is what this new management is doing making [the organization] a leaner meaner machine, which ultimately*

	translates into better value for customers. Was hoping to hear New Hydro One 2.0. To the contrary, I think what I heard the same continuation of that old story."
Any follow-ups or points of concern / consideration	• Power quality incidents of less than one minute should be tracked and how participants can work together with Hydro One about these incidents should be made clear. • Participants would like to see a more detailed breakdown of how Hydro is currently spending its money in order to make an informed decision about the Scenarios. Although they acknowledge that Hydro One does have an aging asset infrastructure, they state that if money is currently being mismanaged, there is little point in giving Hydro One even more money via a rate increase.
Emerging Themes on Customer Needs and Preferences	• **Cost:** This is the top-of-mind and most pressing issue for most participants. • **Reliability:** Power quality is the most significant reliability issue faced by participants' organizations. Duration of interruption as little as a few seconds can have a profound impact. • **Capacity and Expansion:** Participants in this region would like to see additional capacity in order to stay competitive. However, there is some debate as to whether funding should be a shared cost by all ratepayers, or come from Hydro One's profits. • **Customer Service**: Participants have struggled with poor customer service and have expended time and resources in order to receive resolution on their issues with Hydro One. • **Efficiency**: Demonstrating efficiencies in Hydro One as an organization and as it relates to managing costs is of great interest to this group.

Hydro One Distribution Consultation – Thunder Bay LDA, LDC and C&I Session

June 14, 2016 - 9:30am

Attendees and the company they work for	LDA/LDC • Dale Kosie, Goldcorp C&I • Cody Randle, Azgard Solar • Harold Harkonen, Pure Gold Mining Inc./Laurentian Goldfields Ltd • Carol Maki, Hacquoil Construction • Peter Tillberg, Gordon Trailers • Wayne Chiupka, Nakina District School Area Board • Linda Chiupka, Corporation of the Township of Terrace Bay
Mood / tone in the room Level of engagement	• The mood in the room was engaged and thoughtful, with most participants contributing to the discussion. • Participants had a range of awareness and knowledge of the energy industry, as well as a detailed understanding of the needs and challenges of their own organizations. • Graham Henderson from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenter Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	• As a group, participants were particularly sensitive to cost both in relation to the bills they are paying (specifically the delivery charge being too high), as well as how well Hydro One is managing its costs. They would like to see Hydro One better manage costs in order to keep their rates low. • Participants offered a few examples of ways in which it appears to them that Hydro One is not managing costs effectively. These included: seeing too many trucks in use, more workers doing tasks than may be required, elaborate employee vehicles, higher quality paper and printing of bills than is necessary, as well as what is perceived to be inflated CEO and COO salaries. • One participant commented that their distribution delivery charge is three times the commodity cost (see quote below). • According to one participant, Hydro One's brand and reputation are inextricably linked to government policies and IESO decisions. Disagreement with government policy direction and IESO decisions reflects negatively on Hydro One as well. *"We got our hydro bill, 500 electricity, delivery charge was 1500. That's the biggest issue I think all of us are having."*

	"Keep escalating out of proportion, one of our highest costs is electricity, doing everything we can in efficiencies, only way to reduce cost is to shut process down and lose more money that way." *"People notice those things because it's hurting on the bill. If people felt like they were paying something that was fair, they wouldn't notice it, because people feel like they're being bled dry those things are going to stand out."* *"I am] physically seeing the waste that's happening. We had 5 trucks show up to fix a transformer on our property. That's just overkill. You can't tell me it takes that many. Things like that - the public has had enough."* • Power quality was mentioned by participants as being a significant concern and is seen to be synonymous with reliability. • There was consensus among participants that frequency of interruption is a greater concern than duration. *"[My comments have to do] with voltages and frequencies being out of our spec, [I] believe it should be incorporated, they've been out of spec in certain areas - the outlying areas of Thunder Bay. It put us down for a few months."* *"Power quality is almost as big an issue as a power outage to a large industrial client, but that seems to be minimized all the time. Voltage is lights flickering, but it's more. It's motors shutting down that same as an outage."* *"For a large industrial 30 second outage that causes an 8-hour production outage. Sometimes just keying in on outage duration misses big picture."* Throughout the session Hydro One offered statements to clarify comments and answer questions that were raised. These included: • Tree growth. One participant mentioned a concern about municipalities and homeowners planting trees along power lines. It was clarified that Hydro One is working closely with municipalities on vegetation management. • Materials used for poles. A question was raised about the use of alternate materials for hydro poles. Hydro One stated that although there is interest in using materials other than wood - which can be damaged by woodpeckers and beavers - composite material poles cost 2.5 times more than wood poles. Hydro One indicated that composite material is currently being tested and piloted in a number of locations. • The cost of hydro in Ontario compared to other provinces. Hydro One clarified that Ontario's power generation is mostly based on nuclear and renewable energy, whereas in Quebec and Manitoba, power generation is hydro-electric, which is less expensive to generate. • Excess power being shipped out of province and power separation by region. One participant expressed a desire to see power separated from other jurisdictions. Hydro One clarified that participating in the larger North

	American grid is important for the overall stability of the grid. Even if there is a generator close by, there needs to be a power source from elsewhere should the generator shut down. • One participant indicated that because their business is located close to a generating plant their business should see cost savings because the delivery point is so close. *"…take Ontario and divide it based on where power is generated and pro-rate the cost of the grid to those areas."* • One participant commented that new equipment he received from Hydro One was obsolete only a few years later. • One participant suggested that smart metering should be extended to hot water heaters in homes in order to help customers save money on their electricity costs. • One participant expressed frustration that increases in rates are cancelling out the benefits of their efforts and investments to reduce their consumption. *"… [According to the news] hydro rates increase due to loss of profit. We implemented energy savings measures, LED lights, and the rates go up because hydro didn't make enough money based on consumption. It felt like a punch in the gut. What reward do we get with 25% variation in consumption."* • For those participants that have had poor experiences with Hydro One's call centre, customer service is a concern and needs improvement. • Participants object to paying a Hydro One employee to read meters because the bills are based on estimates. *"The customer service is just terrible."* *"…we have a problem with estimated billing. We have found errors in the estimated billing that negatively impacted our budget by thousands of dollars. We refuse to pay. We call, we get a random person with one name, promise that it will has never happen again. Next month another estimated bill - it goes on and on and on…no vested interest in long term."* • One participant stated that the Scenarios are how Hydro One is justifying rate increases. They would prefer to have the profits from Hydro One fund proposed capital investments, rather than raise rates. • A participant from the mining sector stated that given the choice, their business would opt to move out of province. Hydro costs in Ontario are cost prohibitive. *"…With the amount of profits Hydro One has generated, why would they not be looking at their reserves for capital replacement rather than [doing it] on the backs of consumers. I don't think we have any more money to give."*

	"…it's the rates that are killing everybody. We're shutting businesses down [due to] high labour rates and hydro." • Hydro One was applauded for their customer consultation process. *"Good for Hydro One. They've been under the radar, [but it is] very brave of [them] to come out and do these sessions."*
Any follow-ups or points of concern / consideration	• Participants reiterated that Hydro One needs to carefully review its operations and whether or not there is wasteful spending. Their operations are expected to reflect Hydro One's commitment to cost savings and efficiency.
Emerging Themes on Customer Needs and Preferences	• **Cost:** Participants in this market are struggling with the perceived high cost of their electricity bills, including the distribution delivery charge. In their view, the cost they pay for electricity is a real barrier to the viability and profitability of their businesses. • **Efficiencies and Optics:** In order to mitigate negative perceptions of Hydro One, consideration need to be given to optics – the things that people see out in the market and in their area with respect to workers, vehicles etc. Customers want to see evidence of how Hydro One is working hard to manage costs, and proof that they are operating effectively. • **Power Quality:** In this session participants did not view power quality any differently than reliability. To them they are one in the same. When it comes to duration vs. frequency, for this group frequency is the greater concern.

Hydro One Distribution Consultation – London AM LDA, LDC Session

June 16, 2016 - 9:30am

Attendees and the company they work for	• Leslie Dugas, Bluewater Power Sarnia • John Vankerhoven, Blue Water Power • Sheraz Mustafa, Westario Power Inc. • Jeff Graham, Festival Hydro Inc – Stratford • Wayne Dyce, Centre Wellington Hydro • Josh Smith and Scott Brooks, Erie Thames Powerlines • Jim Klujber, Wellington North Power Inc. • Jim Hamilton, First Solar • Tim Prescott, Formet Industries • Pragnesh Shah, Rothsay • Jeff Simpson, Westcast Industries • Matthew Wright, Halton Hills Hydro Inc. • Jared Rowntree and Jodi Dellemonache, Superior Essex • Vicky Hammell, Wallensteinskup Feed Ltd.
Mood / tone in the room Level of engagement	• The mood in the room was engaged but mostly quiet, with a few vocal participants enthusiastic to share their views of Hydro One and the energy industry. • Participants had a high level of knowledge the energy industry, as well as a detailed understanding of the needs and challenges of their own organizations. • Graham Henderson from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenter Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	• The Global Adjustment - in particular, the unpredictability of the percentage amount of Global Adjustment - was raised as a concern by more than one participant in the session. • One participant inquired about whether or not Hydro One has looked into electronic billing and whether or not Hydro One believes that it would generate cost-savings that could be passed along to customers. • Some participants in this session indicated that they have difficulty making sense of their bills. Although it was clarified by Hydro One staff that the information on the bill is prescribed by the Ontario Energy Board, the participant indicated that Hydro One staff should still to able to explain the information on the bill. This participant has not been able to get a sufficient explanation from Hydro One staff to date. *"Is anyone able to forecast it [Global Adjustment], forecast our global adjustment?*

	Is it going to be 20, [but] comes out as 30. As a manufacturing plant we should know exactly it's going to be. It's a huge problem you can't forecast." *"We had some folks from Hydro One come to our plant and [they] couldn't explain the bill to us."* • When asked about impact of outages, both a solar generator and an auto industry manufacturer indicated that they experience significant negative impacts from outages. • A few participants spoke about concerns that they have with Hydro One's power quality. For them, power quality is as much of a concern for them as outages. • One participant indicated that he would like to see better reporting of momentary interruptions. He would like to see a reporting of momentary interruptions, as well as the causes of the interruption, within 24 hours. • One participant said that his organization is willing to work with Hydro One and to share in the cost of addressing their specific issues with reliability. A loss of service has severe financial consequences, and thus they are willing to pay for what it will take to improve their specific reliability issues. *"A flicker causes the same impact as an outage."* *"What I want, if possible is if there's a flicker within an hour or two hours, a specific report… a quick 24 hour report if there's a tree branch."* *"…is there any way we can help come up with cost sharing [arrangement with Hydro One to address our concerns]? This week alone it was $500,000 in financial losses just from outage time. Shift over and put protections back, have some redundancy. [We are]willing to invest in that."* Several clarifying questions were asked throughout the presentation, including: • One participant inquired about the process that Hydro One uses to restore service when there is an outage. It was clarified that there are priority areas that are addressed first, such as critical feeders to the area, followed by the lines that serve the highest number of people. • A few participants inquired about the pace at which poles and transformers are being replaced, as well as if the decision to replace assets is primarily based on age, as they would like to understand if the pace at which assets are being replaced is fast enough. It was clarified that Hydro One actively monitors and tests the condition of assets and that recently their testing has been ramped up to meet the levels need for sustainment. • Hydro One also clarified that the best channel for LDCs to provide information back to Hydro One with regard to distribution feeds is through the OGCC. General comments that arose spontaneously during the session:

	• There were times during the session when one participant expressed strong concerns about the way Hydro One is being run. He was incredulous that the previous Hydro One CEO received a $3 million payout, indicating that these fund would have been better directed to improving system reliability. He also stated that any increase in rates, related to the distribution delivery charge or otherwise, would result in the closure of his plant in Simcoe, which would be moved to a location where hydro costs are cheaper.This participant is of the opinion that Hydro One does not operate efficiently and indicated that not putting profits back into capital costs and investments is unethical. Hydro One indicated that they would follow up with him at a meeting already scheduled to address his concerns. • Another participant expressed concern that in their view there was no option for them to answer "no" to each of the scenarios. Ipsos clarified that the participant could in fact answer "no" to each of the scenarios and indicated that each question about willingness to accept the rate increase offered a yes, no or don't know option for the participants to choose from. This participant also stated that there should be a 0% rate increase option, or a rebate option offered to participants. *"Shouldn't that slide have a 3 million dollar payout. Paying a president is not keeping system reliable, [and] not the best investment moving forward."* *"Voicing facts of where I live today. Ontario government, OPG, Bruce Power continue the onslaught on manufacturing. The plant will not exist."* *"You're telling us 2.5% [rate impact], private is taking 0% to maintain jobs here, you want to take another 2.5% to maintain your profit to your shareholders. It's unethical… It's unethical, it's unethical, it's unethical."* *"Why [is there] not an option with 0% [rate increase] or 5% rebate."*
Any follow-ups or points of concern / consideration	• Participants in this session, of all of the sessions, spoke with the greatest frustration and concern about hydro costs and the impact the perceived high cost of electricity is having on the manufacturing plants in the region. They feel that their long-term viability would be directly at risk should Hydro One raise rates.
Emerging Themes on Customer Needs and Preferences	• **Communication:** Two main communications related points where made by participants. The first was to desire for Hydro One to implement a process of immediate (24 hour) reporting of momentary interruptions. The report should include the cause of the interruption. The second is related to making it easier for customers to provide or share information about reliability issues and concerns with Hydro On, so that Hydro One has an accurate understanding of power quality and reliability. The benefit would be that both Hydro One and the customer can therefore more promptly and effectively mitigate and/or address reliability or power quality issues.

	• **Power Quality:** It was articulated during the session that momentary interruptions affect customers as much as longer interruptions, so duration is less of an issue than power quality. • **Rates**: Increasing rates are perceived as direct and real threat to the manufacturing industry. • **Responsibility to ratepayers vs shareholders**: One participant felt strongly that Hydro One's profits should re-invested into the system for the benefit of customers, not shareholders.

Hydro One Distribution Consultation – London PM C&I Session

June 16, 2016 - 2:00pm

Attendees and the company they work for	• Dirk Nauwelaerts, Belleview Acres Ltd. • Tony Di Nardo, Cooper Standard Automotive • Erica Kiestra, Kie Farms • Howard Lucas, Lambton County Admin Office • Adrian Roelands, Roeland Plant Farms Inc. • Garry Fortune, Stanton Bros Ltd. • Linda MacDonald, Walker Dairy Inc.
Mood / tone in the room Level of engagement	• The mood in the room was largely thoughtful, with a few vocal participants enthusiastic to share and discuss their views of Hydro One and the energy industry. • Knowledge of Hydro One and the energy industry was mixed, but most had an understanding of the needs and challenges of their own organizations. Participants asked many questions throughout the session on a broad range of topics related to energy. • Graham Henderson from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenter Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	Several points of clarification were made at the outset of the session with regard to the following items: • A participant expressed her dissatisfaction with the debt retirement charge, and said that she understood that it was supposed to have come off the bill multiple times in the past several years, but that her organization is still being charged for it. It was clarified that the decision to remove the charge is one that the government makes. It is not influenced by Hydro One. • A participant shared his experience with getting a new connection. He explained that the cost of the connection was paid for upfront by his organization. He stated that it is unfair for his organization to pay for part of the connection charge for generators via the distribution delivery charge, when his own organization paid for all of their connection charge. It was clarified that his understanding that his organization still is charged the distribution delivery charge is accurate. While generators have a certain amount of their connection charge paid by all ratepayers, in the case of load customers, the expected revenue is calculated over a certain period to see if it will cover the cost of the connection. If not, the customer has to pay for the incremental cost. • A participant asked who the Ontario Energy Board is and it was clarified that this is a quasi-judicial independent regulator run by the provincial

government.

- When asked about whether or not Hydro One should be burying lines underground, Hydro One clarified that it costs 10x over the life of the line to bury lines underground versus having them overhead.
- One participant inquired about Hydro One's rate of return and it was clarified that Hydro One's return on equity is 9.4% and that this amount as prescribed by the Ontario Energy Board.
- There was a discussion about rate classes and how LDA customers are distinguished from Commercial, and what the three qualifying criteria for LDA are. It was clarified that in order to qualify as an LDA, the customer must have a minimum load, supply their own transformation, and have a minimum voltage.

Feedback was heard throughout the session on other issues as well. This is described below:

Billing

- One participant asked if Hydro One intends to move to e-billing away from e-post. It was clarified that this is of interest to Hydro One and is currently in development. However, there has been resistance from Hydro One's customers to electronic forms of communication as their customer base is an older demographic.
- One participant mentioned that he finds the current billing format very confusing. Although he is aware that the information contained is prescribed by the regulator, he wondered if it would be possible to have Hydro One provide further explanation on charges separately - for example, as a bill insert. Hydro One indicated that this would be within their ability to do, however they are sensitive to the cost of such initiatives.
- Another participant mentioned that he is having difficulty in consolidating his bills, calling the process "brutal".

"Do you have the ability to further clarify that bill separately…we find it very confusing to understand it. Is there a way for you to clarify, do you have the ability to do that, an insert [that says] this is what [the charge] actually means…That would be helpful."

Privatization

- A few participants believe that privatization will have a positive impact on Hydro One and ultimately ratepayers, as there will be increased accountability of the organization, and that decisions will be made based on financial prudency. One participant stated his strong belief that the government should not have any influence on the electricity industry, and that prices should be subject to a user-driven open market, as with natural gas.

"[Before privatization] I think that like any government organization [Hydro One was] just giving out money left right and centre, and not looking at costs because

they never had to."

"…our entire power system right from the top to bottom, the whole thing, should have nothing to do with the government… I would really like to see the entire thing privatized and moved the same way natural gas is. Just get it completely out of the government's hands, right from top to bottom the whole way through."

Renewables and Microgrid

- Participants posed two questions to Hydro One regarding renewable energy. The first was about how reliable power generation from renewable sources (such as wind) is and the second was whether green/renewable energy should be incentivized and promoted by the government and regulator instead of focusing on giving customers the power capacity they need from non-renewable sources. In addition, at least one participant said that they disagree with the premium cost/price associated with renewable sources of energy.
- Hydro One clarified that this is studied before the generator (such as a wind power generator) is connected. If the generator meets all of the technical requirements, then it is considered a reliable source of power quality.
- Another participant asked if Hydro One has a positive view of renewables and microgrids. Hydro One responded that there are potential benefits for customers as well as themselves. These benefit relate to not having to run a long line to remote customers. However, one of the potential drawbacks is that customers may choose to leave the grid entirely as a result.

  "I'm all for green power as far as the environment, but when it comes to cost it's hugely expensive…I don't agree the price we're paying for solar and wind, just drop things all over where we don't need the power…it would be nice to say focus this wind and solar to these remote communities put them there [as it] makes sense, where there's issues with the lines, rather than randomly dropping them where people don't need or want them."

Power Quality

- Power quality is a significant concern for participants.
- For one customer, poor power quality also meant spikes in voltage which damages equipment.
- There is a time lapse between the outage and when a generator kicks in.
- Even a very short interruption shuts down production for manufacturers.
- When it was clarified that Hydro One is dependent on their customers for power quality feedback, and participants indicated they were unaware of this.
- It was also clarified that power quality issues are usually internal to the customer's operations/facilities.

"…the interruptions are very disruptive. Us a manufacturing plant, not even the outages, quality of power, if it's a split second it shuts entire plant down. Takes a couple of hours to recover, [it] happened twice this year. [Then you] get it up and

running power fluctuates again, and it is down for a couple more hours."

Proactive Asset Management

- Participants were in general agreement that proactively managing and strengthening the grid makes more sense than fixing problems after they happen, particularly as it relates to preparing for more electric vehicles and energy storage needs.

"…logic would suggest that money you invest in preventing an outage as opposed to fixing it would make more sense."

"We're a producer and a user, certainly strengthening the grid is a key concern, to be able to supply, also the smart grid would add efficiency to that."

Other forms of electricity generation

- At different times throughout the session, participants talked about their ability to generate their own power as either a primary or secondary source. One farming operator spoke about having a bio digester onsite. Hydro One recommends to greenhouses and livestock farms to have sufficient backup generation onsite.
- Some participants also use natural gas as a source of energy for their operations. For one, in the event that hydro costs go up further, they may make the decision to switch to natural gas entirely.

"If we get a wee bit more increase, we will move, go off grid, very close. That's the bottom line. I only have to switch the switch. If you're hooked up on natural gas between 8 and 12 cents. We're very close."

Cost and Scenarios

- Despite the concerns about power quality and reliability that participants raised during the session, it became clear that cost is the most important and pressing concern for this group. Rate increases of any kind, even on the distribution delivery charge only, were viewed negatively.
- Even in a "run-to-failure" scenario for Hydro One/the grid, there were questions about the efficiency of Hydro One's operations. The perception is that Hydro One does not operate as efficiently as its peers.
- A few participants stated would like Hydro One to demonstrate how it is operating efficiently before commenting on the Scenarios.

"You've heard manufacturing, all of that is about reducing our costs and improving our efficiencies, what's Hydro One doing to do more with less how are you getting more efficient so that we don't have a 2.5% increase."

"I do think you have not been efficient in the last 20 years and I think there's a lot of costs you can cut. This yeah, what do you think is acceptable, 2.5 or 4% increase? … How efficient have you become in the last 5 years, do you have that?

	What efficiency rate do you go on, 43% or 30 or 50 plus, what efficiency rate are you at?"
Any follow-ups or points of concern / consideration	• Participants indicated a desire to see more detailed information on the bill, specifically explanations of the various components and charges on the bill. • A few participants said that they would like to better understand the activities and programs that Hydro One has undertaken in the past to make its operations more efficient before they are able/willing to render an opinion about whether or not the rate increases presented in the session are justified. • One participant expressed the desire for an opportunity to provide electricity at night to greenhouse operators based in southwestern Ontario, who are currently building facilities in Michigan and Ohio in order to take advantage of available capacity and cheaper hydro rates. He suggested that this would be a fortuitous opportunity and fit, given that Ontario currently exports power to the US at a loss at night.
Emerging Themes on Customer Needs and Preferences	• **Billing:** Understanding the bill, as well as ease of having billing issues resolved, was of interest to participants in this session. • **Future of the Grid:** While participants stated their opinion that Hydro One should be proactively managing the grid, they are reluctant to adopt renewable green energy sources if it means higher rates/prices or less reliable power. In their view, green energy should be used in areas where lines are expensive or difficult to run, and generators should not receive incentivization at the expense of ratepayers. • **Rate Increases and Efficiencies:** The scenarios were received negatively, with participants expressing their unwillingness to offer an opinion until they have a good sense of whether there have been sufficient efficiencies by Hydro One in recent years to justify rate increases. For those with other potential sources of energy such as natural gas to draw on to run their operations, a rate increase is a potential reason for attrition.

Hydro One Distribution Consultation – Windsor LDA, LDC and C&I Session

June 17, 2016 - 9:30am

Attendees and the company they work for	• Robert Saroli, Canadian Art Aluminum Extrusion Inc. • Terry Attewell, Canadian Department of Agriculture • Louis Chibante and Paul Mastronardi, Golden-Acres Inc. • Kathleen Qenneville, Greater Essex City • Todd Brophy and Peter Quiring, Nature Fresh Green Houses • George Dekker, Southshore Greenhouses Inc. • Mazin Naim, TRQSS Inc. • Dale Hodgins and Mark Stephens, AP Plasman • Howard Huy, Huy Greenhouses • Justin Martens, Johno Foods • Pat Fleming, Milofais • Wanda Juricic, Union Gas • Guido van het Hof, Great Northern Hydroponics
Mood / tone in the room Level of engagement	• The mood in the room was highly engaged and participants were eager to voice their thoughts on the information being presented. • Participants had a high level of sophisticated and detailed technical knowledge about the energy industry, and brought forward the needs and challenges of their own organizations and industry sector. • Graham Henderson from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenter Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general conversation	• A major concern for participants is the Global Adjustment charge. The fluctuation in price of this charge is extremely frustrating and puzzling. The unpredictability of Global Adjustment makes scheduling and budgeting a challenge. • Because of the direct inverse relationship of commodity price to Global Adjustment, participants stated that they feel dis-incentivized from attempting to conserve their power consumption. Although it was clarified by Hydro One that reducing overall quantity - i.e. units of power - as a way to save costs, in terms of the price of electricity, the Global Adjustment appears to discourage customers from conservation activities. *"There's no incentive to save. My electricity bill goes down, but my Global Adjustment goes up. I thought it was a joke at first."* Beneficiary Payer System • Clarification was provided as to the beneficiary-payer system as prescribed by

	the Ontario Energy Board after participants spoke of their experiences with the process of getting new connections/lines built to service their needs. • Hydro One stated that the potential cost to a new connection customer is calculated on a 25-year basis using forecasting on estimated load. If the cost of the connection over 25 years cannot be recovered, the beneficiary is asked to pay upfront before the work commences. • Additional clarification was provided about new users on a line that a customer has paid for out-of-pocket. The customer is eligible for a rebate in situations when another user uses the line on a pro-rated basis. • Participants expressed their discontent around this system, stating the belief that they should not have to pay the cost of connection, and/or that they shouldn't then also have to pay for ongoing distribution charges once they have paid for a connection. *"I'm dealing with Hydro One and what they're telling me is, I have to pay for poles and infrastructure where I have to pay to bring that power to my plant. I'm also going to pay again for distribution after I've paid the capital cost for bringing that to me?"* Customer Service and Communication • One participant stated that their new connection request forms have gone unanswered. When he met with staff from Hydro One's head office, they said that there is sufficient capacity in his area for his power needs, although he strongly disagrees. • A participant stated that he has received conflicting responses to inquiries from different departments at Hydro One. • Communication between municipalities and Hydro One was also cited as a concern. One participant was encouraged by a municipality to build a plant in their region, only to discover that there was no available power capacity. • Communication during power outages was mentioned as being a concern for participants. They would like to see Hydro One employ technology (such as their website or an app/texting) to communicate to customers the reason for the outage, as well as the estimated restoration time. This in turn would empower the customers to make decisions accordingly. It would also help to understand if the problem is from Hydro One or internal to the customer's facility. *"…there are apps where it goes right to your phone. If you guys are giving information to your line crews, feed us in on that…we're not [going to wait] on the phone, sitting there 20 mins waiting for somebody. We just need some information to make relevant decisions on our part. Those types of things are cheap to implement and they are very helpful for us. That would be a huge thing for us."* *"Planning is very important [for example when you have to] call in a shift or cancel in a shift. If you bring them in and the power is still down you've got to pay them or maybe you call everybody to say don't come in because we're going to be down.*

	[Either way] we need to know as quick as possible." *"[When the power is down] we're not sure if it was Hydro One or our internal power. It would help to say it is your problem, not ours and stop trying to troubleshoot."* <u>Regulatory Concerns</u> • One participant stated that they are strongly concerned with the current energy regulatory environment. He stated that in the case of natural gas, the process to get the line approved and built can take several years and by the time the pipe is actually put in, it is too small. He stated his belief that the Ontario Energy Board needs to be more forward-looking rather than only responding to current needs. In his view, this is a threat to the expansion of industry in Ontario. • As it relates to the upcoming Leamington TS, participants expressed frustration that it has taken over 20 years to get this project off the ground and that it has been promised in the past without actually being built. They also expressed concern that the capacity provided would not be sufficient for current needs. *"…the Ontario Energy Board will only approve the current demand, no expansion. Can you imagine the insanity? They put a gas line in the ground which takes, 2 or 3, 4 years to approve. So by the time they put it in, the information is 4-5 years old, they're putting it in based on [information] 5 years ago. It's too small the day they put it in. Can you imagine how little it would cost to put a bigger pipe in? It would cost virtually no more money. Yet in the wisdom of the Ontario Energy Board that's not possible. We keep paying and paying and paying to put more and more pipes in the ground, which environmentally and in every other way that makes no sense. This is no different. You're going to put a power line in that's too small the day you put it in."* <u>Power Quality</u> • Power quality was cited as an issue both in terms of voltage spikes and dips. Spikes and surges have the potential to damage equipment, while dips cause outages that have negative impacts on operations such as plants going down. • When a manufacturing plant's power goes down, decisions need to be made around sending staff home and/or asking the next shift of staff to come in. *"Power quality, low voltage electronics, where we don't have the life expectancy in Ontario as where we would use that piece of equipment somewhere else in the world because of the power flickers that they have, surges, now we're down to installing through a third party diodes to make sure power quality is filtered."* <u>Investment Planning and Consultation Process</u> • Rather than commenting on the specific ranking and scenarios presented, participants raised concerns that they are being asked to provide feedback on

	areas in which they don't have enough information and an understanding of what the key issues are. All areas asked about in the survey booklet are considered important to participants and some stated that they would like all issues to be resolved, rather than give permission to Hydro One to prioritize one or another. • Participants raised questions about Hydro One's efficiencies and productivity, and if/how they are incentivized to improve in these areas, as they are a monopoly. *"Our answer is simple, we want all those issues to be resolved. All of them have [to be] priority number one."* *"[Since Hydro One is] basically a monopoly why is there an incentive to then improve?* <u>Capacity</u> • For participants in this session, which was comprised mostly of greenhouse growers, the need for additional power capacity to facilitate growth and expansion of their businesses is extremely high and of the utmost importance. • Participants stated the belief that their power needs exceed that of other industries including automotive. • They stated repeatedly that they have electricity needs not currently being met by the grid in their region and expressed frustration that investments are not being made to meet them. • One participant stated that there are currently 2600 acres of greenhouses in Ontario, with 50% of those having lights at half a Megawatt per acre. *"We are going to take electricity. When you're paying to get rid of it, we're going to take it. We use a crazy amount of electricity right now [summer months], but the real load is from November till March and mostly at night. We're your best customer, we're your best friend and you've ignored us."* <u>Future of the Grid</u> • One participant inquired as to whether Hydro One would have the capacity to deal with the additional demand that would be created should natural gas be phased out. Hydro One responded that the grid would not currently be able to support that scenario. Further, their investment scenarios do not take government climate change policy into consideration, as they are unaware as to what the policy is/will be. *"…it seems that your boss, the Ontario government, wants to switch the whole power spectrum from gas to hydro, implying that Hydro One has the infrastructure in place to take on this increased demand."*
Any follow-ups or points of	• Participants in this session were quite vocal and asked repeatedly if there was a way for them to convey their frustrations around the issue of capacity with

concern / consideration	either the Ontario Energy Board or the Ministry of Energy. It was clarified that they are able to register as an intervenor during the rate application process, participate via an industry association such as AAMCO, or write a letter of comment directly to the Ontario Energy Board. • The Greenhouse Growers in this session indicated an interest in using (and paying for) excess power - which is currently being exported to the States at a loss - during the months of the year when load on the grid is not being maximized, i.e. November - March. Further, they would use the power at night when load is low. This is made possible thanks to the flexibility of their needs. They expressed frustration that they are Hydro One's best customer, who use more power than automotive manufacturers, who feel as though their needs have been forgotten.
Emerging Themes on Customer Needs and Preferences	• **Capacity:** For this group, the most pressing issue far and away is power capacity. They state that they are a neglected group of potential high volume customers whose needs are not currently being met, or even listened to. Further, they state that the regulatory environment of only meeting current needs, rather than planning for future need, is a barrier to expansion. • **Power Quality:** Participants face challenges with power quality in both surges/spikes and dips, with significant impacts for their facilities. A lack of communication, and their inability to find information, makes decision-making during an outage difficult for them and they also want this improved by Hydro One.

Hydro One Distribution Consultation – Kingston LDA, LDC and C&I Session

June 24, 2016 - 9:30am

Attendees and the company they work for	LDC • Jerick Astejada and Deonnie Macabales, Great Circle Solar • April Barrie and Matthew McGrath, Hydro Ottawa • Charles Watson and Jane Donnelly, Ottawa River Power • Mike Ploc, Peterborough Distribution Inc. • Bill Nippard, Renfrew Hydro • John Walsh, Rideau St. Lawrence Distribution Inc. LDA • Rod Moffatt, Strathcona Paper LP (Paper Works) • Edward Kalinowski, Gagan Gill and Steve Hughes, Invista Canada Company (Maitland) • Brent Quennell, IKO Industries Ltd. • Brent Williams, Goodyear Canada • Audrey Wood, Norampac • Bill Smith, Nestle Enterprises Ltd. • Habib Arshad, Pembroke MDF • Brian Reil, Kraft Foods Ltd. • Tom Horvath and Dominic Phaneuf, Greenfield Johnstown Limited Partnership C&I • Megan Jessup, Graves Eng. and Finishing • Ross Burt and David LaMontagne, Moose Creek Tire Recycling • Ricki Campbell and Richard Baccari, Crystal Springs • Bob Smith, Assurance Solutions
Mood / tone in the room Level of engagement	• The mood in the room was engaged with participants thoughtfully filling out their survey booklets with lengthy comments. • Participants had a mixed level of technical knowledge about the energy industry. • Vice President Planning Mike Penstone from Hydro One was present to greet the participants and provide an introduction to Hydro One, in addition to co-presenters Graham Henderson and Paul Brown. • Other Hydro One account persons and staff were present to provide local context and engage with customers.
Quotes to summarize the general	• One participant mentioned his experience in dealing with energy retailers, and stated that he turned to Hydro One for advice as to whether the program was worthwhile. However, he was unable to get an answer or a

conversation	recommendation from Hydro One. It was clarified that due to licensing conditions from the Ontario Energy Board, Hydro One is unable to direct customers or offer advice on retail energy programs. • In spite of this clarification, the participant stated his belief that Hydro One should use their technical expertise to help customers make decisions on whether or not to participate in programs. He does not feel it is right for the customers to accept all of the risk associated with this decision because customers are less knowledgeable about the benefits and drawbacks of programs than Hydro One. • This same customer also raised a concern and expressed disappointment about the amount of time his organization has had to wait to receive his rebate/payment back. He would like to see customers receive rebates more promptly. *"…[the risk in retailer programs] is not clear and I think Hydro One has the technology and expertise .. and should be able to say that is a good application of technology for that project. A little bit disappointing."* Clarifying questions were asked about the following topics: • A participant inquired about whether or not Hydro One's surplus profit is re-invested into the business so that future rate impacts are lower for customers. Hydro One clarified that it comes close to the regulated rate of return, and that this is the first rate filing application under the incentive mechanism which is intended to put more of an emphasis on performance. • Participants inquired about Hydro One's flat reliability performance over the past ten years and what spending that reflects. Hydro One clarified that the spend level and strategy over the past ten years has been to spend the minimum amount necessary to maintain the same reliability performance. • One participant inquired about the 19% of interruptions where the cause is unknown. They asked whether there is technology that can help Hydro One find the underlying causes of these outages. Hydro One clarified that it is possible that there is technology that could help this, and the decision to invest in this kind of technology in investment plan as not been made yet. The decision would be informed by customer need and preferences for reliability. • One participant asked why Hydro One does not run underground/bury lines and whether or not this approach would generate efficiencies and savings. It was clarified that underground lines cost approximately 4-10 times more over the life of the line compared to overhead lines. In municipalities and developments where there are underground lines, the developer pays the premium for them. • One participant inquired about whether or not Hydro One has looked into using composite poles. Hydro One clarified that composite poles are being piloted in areas that get a significant animal damage to wood poles; however the long-term life expectancy of composite poles has yet to be determined, because they are relatively new and haven't been around long enough to

determine the longevity of them.

Other areas of feedback included:

Maintenance and Monitoring

- A participant inquired about standards around tree-trimming and asset condition testing. They wanted to know whether the standards are mandated for, or decided by, Hydro One. Hydro One clarified that the decisions are made by Hydro One. It decides how and in what pacing to conduct condition testing and vegetation management, although the Ontario Energy Board does set some minimum requirements, for example, pole testing every 3-6 years.
- Participants inquired about whether Hydro One uses best practices and technological innovations, in its maintenance and asset management (e.g. maximizing asset life vs. premature replacement). The participant asked to see this information and wondered if it should be shared with other LDCs as well. Hydro One clarified that a benchmarking study has been commissioned by Hydro One on pole replacement. Assets are replaced not just on age, but also condition. Age is only one indicator.

"…[Referring to one study the participant had reviewed] The average transformer life is 21 years, but some in the sample were 85 years old. Replacement also depends on the loading which impacts condition over time."

"Just with the amount of trees a covered conductor would seem to be a good standard."

Region-Specific Investments and Reliability

- A couple of LDC participants spoke about the need for more load and improvement in the duration of outages (for example the Village of Lakefield and as well in eastern Ottawa) and asked that their needs be considered in Hydro One's investment plans.
- One participant expressed concern that slide showing the breakdown of reliability across Ontario that Hydro One showed in the presentation (slide 16) was insufficient. More specific location breakdowns should be used to better understand varying reliability performance. Hydro One clarified that the Ontario Energy Board is now requiring a higher level of detail in investment plans that are region-specific.

"[In my answer to this question in the survey booklet] I wrote about the Village of Lakefield and had a specific comment about reducing the duration of outages…. They're on a 44KV radial feeder, the line has been improved to bring it to roadside and add a re-closure, but the outstanding issue is that duration of outages is quite long… the cost for providing a feed there was considered cost prohibitive. It is going to continue to come up as time goes on. If there is anything you can do to build it into your long-term plan as you build the system, that would be appreciated."

	"…Eastern Ontario one of the worst in terms of loss of supply." *"When you spread out [reliability performance reporting] across the whole province [the differences] gets watered down. The geographic disparity in reliability seems to be informational. Reporting one number for Ontario to the OEB [Ontario Energy Board] doesn't provide any useful information."* <u>Efficiencies and Scenarios</u> • A participant expressed concern that there is no incentive for Hydro One to encourage conservation among customers. *"…you're a supplier, are you really interested in efficiency…, because that [will] reduce the volume you have to supply. What incentive is there for you to tell an end-user customer to replace their lighting because it's more efficient. It seems counter-productive."* • Participants stated that they need more information in order to comment on the scenarios. They need more information about how Hydro One builds in efficiencies, and stated that it is difficult to know what the best decisions are in the absence of the whole rate application and the broader picture. *"Today is only [about] reliability and we don't know anything about cost efficiencies in a lot of other areas."* *"I'd like to see the whole rate application and your capital in order to make some of those decisions. I want to see capital, operating, billing, admin, same things all other utilities are judged on and we have to present to our customers when we're asking them do you think we're doing a good job."* • Another participant had a concern with the proposed pacing of investments. Although they acknowledged that Hydro One's asset infrastructure is aging, five years seems like a short period to be remedying it entirely. *"Can you spread it over a longer period of time… [it has been] 60 or 70 years [but are you] trying to solve it overnight. Look forward for 10, 15, 20, 30 years - do a proper study with life cycles and all the other components and spread out the capital costs over a greater period of years."* • One participant stated that they do not have reliability issues, but if they did, they would be willing to pay for improved reliability. *"… we don't have a problem with reliability, if it were [a problem] we would pay for it. We've got good reliability, [there is] not much more [for us] to gain."*
Any follow-ups	• Participants would like to see more information on current efficiencies and a

or points of concern / consideration	more detailed breakdown of investment plans in order to comment on Scenarios. In the absence of this information, especially given that some participants do not have reliability issues, this was of particular importance to this group and stressed more than once.
Emerging Themes on Customer Needs and Preferences	• **Regional Concerns:** Participants have concerns about poor reliability in their region that they would like to see reflected in Hydro One's investment plan. • **Sharing of Expertise**: LDCs would like to understand best practices and innovations as it relates to maintenance of assets.

Distribution Productivity Studies
Hydro One Stakeholder Session
Thursday October 22, 2015
DoubleTree Hotel by Hilton – The Toronto Ballroom
108 Chestnut Street
8:30am – 4:30pm

Overview

On October 22, 2015 Hydro One Networks Inc. hosted a stakeholder session with intervenors and OEB staff. The purpose of this meeting was to present and seek feedback on the proposed approach and framework for four separate distribution productivity studies: Vegetation Management Program Study; Total Factor Productivity Study; and Pole Replacement Program Study and Distribution Station Refurbishment Program Study.

The stakeholder session included:

- Welcoming remarks from Maxine Cooper (Senior Regulatory Advisor, Hydro One Networks);
- A presentation on the proposed approach and framework of the Vegetation Management Program Study delivered by William Porter (CN Utility Consultants);
- A presentation on the proposed approach and framework of the Total Factor Productivity Study by Steve Fenrick (Power Systems Engineering); and
- Two presentations on the proposed approach and framework of the Pole Replacement Program and Distribution Station Refurbishment Program Study by Benjamin Grunfeld (Navigant Consulting) and Ken Buckstaff (First Quartile Consulting).

The draft summary was written by Matthew Wheatley and Bianca Wylie, who provided independent facilitation services for the stakeholder session. It provides a high level summary of the main points shared by participants as captured in the "live" notes written during the meeting, and is not intended as a verbatim transcript of the meeting.

This summary was shared in draft with participants for their review prior to being finalized.

Note that there are three appendices to this summary (attached separately), including:

Appendix 1. List of Participants
Appendix 2. Submissions Received After the Meeting
Appendix 3. Presentation Slides

NOTE: This summary reflects what happened during the meeting and does not attempt to integrate the written feedback received after the meeting. Please see Appendix 2 for the additional feedback received.

Part 1 – Vegetation Management Program Study

William Porter from CN Utility Consultants delivered an overview presentation that described the overall framework and proposed approach for the Vegetation Management Program Study. Following William's presentation participants asked questions of clarification and provided feedback. A summary of the questions and feedback is provided below.

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Suggestions and Comments on Study Methodology & Outcomes

- **Make comparisons between Hydro One's regions and comparable companies.** It seems possible that a company like Southern Georgia would look a lot like Hydro One's southern region but nothing like Hydro One in its entirety. Therefore, it would be useful to compare Hydro One's southern region to Southern Georgia. Then, where it makes sense you could compare all of Hydro One to other companies such as Manitoba Hydro. *We will be looking for the comparisons between Hydro One's different regions and their comparators.*
- **The study should be able to demonstrate how Hydro One's different regions are being managed**, including where there are differences among the regions, in terms of cost, and why these differences exist. If the study is not able to do demonstrate this, to me, this study will have failed.
- **What we want to understand from this study is whether or not Hydro One costs more, in terms of vegetation management, on a comparable basis and secondly, why this would be the case.** The fact that some utility companies may have inexperienced workers is a reason their costs are different but not a reason to adjust their comparability. Our main concern is where this study is making adjustments and we feel they should not be made for comparability. You will need to be very clear which adjustments are being made for comparability as we may disagree on these.
- **Measuring SAIFI and SAIDI comingles other factors that make it difficult to draw any conclusions from**. SAIFI and SAIDI are going to have other problems that make it difficult to measure actual effectiveness. *The first time we did this study we looked at SAIDI and SAIFI, for this study we are going to down play SAIDI and SAIFI. We are asking companies to report their tree related SAIFI separate from their system SAIFI.*
- **Identify the top-performing comparators.**
- **If you are going to measure Hydro One, you need to measure on hard things, not soft.** The average percentage of trees in contact at time of maintenance is not a useful indicator. Three things have to happen for an accident: there has to be a tree; there has to be a person and there has to be a line.
- **Stay away from speculative measures that are not established in data**. Speculative safety measures are not established in data pertaining to Hydro One. If you are going to come back with a benchmark study that says Hydro One is spending a lot of money but it is the right thing to do because they are avoiding a lot of accidents, I won't buy it.

Suggestions and Comments on Productivity and Resource Utilization

- **The OEB wants to know if Hydro One is getting more productive and whether it is doing best practices.** It is also looking for metrics that tell you whether Hydro One is doing a good job and if it is getting better at it. I looked at some of the things CN is proposing to do - it has by in large been done before and most of it is pretty good.
- **A huge thing that is missing is resource utilization.** Hydro One has a lot of workers and there is a lot of money invested in training professionals that are highly paid. They also have

a lot of very expensive equipment and minor fixed assets that are dedicated to their forestry program. Hydro One is running their forestry program about six months of the year and once it stops all the assets are parked.

- **Resource utilization has to be addressed if you are comparing with peer utilities**. If peer utilities are either running a 12 month a year program or are hiring contractors that can redeploy resources they will have a natural advantage over a utility that doesn't run its program 12 months a year.

- **It would be worthwhile for CN to look at other utilities to see which ones treat productivity as a function of how the program is treated by the utility.** If Hydro One is managing dollars as opposed to kilometres they are going to have a big problem if they spend all the money in their budget but don't get the kilometres.

Suggestions and Comments on Performance Measures and Objectives

- **Looking at the UVM objectives, be careful that you only focus on objectives that you can reasonably measure.** I do not know that you can reasonably measure how many fires can be prevented or how much you can preserve in terms of environmental quality. As for the one on safety, I would suggest you break that out into results for employees and results for public, they are different.

Suggestions and Comments on Clearing Sites and Cycles

- **The Board will be interested in information about the clearing cycles.** The Board has heard in the past that the length of the clearing cycle is a major driver of current costs when measured on a per kilometre basis. There are different clearing cycles historically; this is something that is going to need to be addressed and something that you control for when doing cross utility cost comparisons.

Questions of Clarification

Benchmarking Methodology

- My understanding of a benchmark study is that you compare different companies to see what their performance is. This sounds like you are doing a study to see how Hydro One can spend more money on vegetation management by doing it better. The theme appears to be "spend more". Can you help me on this? *What we are charged with doing here is understanding performance and improvement performance. We want to look at those metrics that we think indicate where there are areas for improvements independent of how much work is done, where the work is done or why the work is done. One of the objectives that has been brought up is should we look at SAIFI and SAIDI as metric of performance, do we look at how many outages there are per kilometre as a measure of performance. We want to determine this and we want to compare Hydro One with other companies to measure their performance.*
- Then the study is not benchmarking the cost of vegetation management, it is benchmarking only the areas? *The cost of vegetation management is the outcome. We are going to ask lots of questions about cost and productivity. We do not think it is fair to simply compare the raw numbers side by side. So much of what we do is try to figure out how these comparisons are comparing apples to apples as opposed to apples to oranges and those are productivity factors that may not be just the raw numbers of cost. For instance, if you are working with instances of dense forest, terrain, limited ability to access other logistics your cost may be greater than if you are just going from one tree to another tree.*

- How is worker turnover an independent variable? *My experience in the industry is that a worker may be on the job for weeks and find themselves in a tree and may not really know what they are doing and the productivity in that situation may not be the same as in an instance with someone that has been through a six-year apprenticeship program.*

Study Outcomes

- Is it correct to say that this study will do two things: measure the cost of vegetation management and make adjustments because not every company that does vegetation management is comparable; and measure the outcome of that vegetation management program to see if it is effective. *Yes, that is correct.*

Measuring Reliability

- With respect to reliability you say that this is a longitudinal study, however, it appears that you are doing a cross section study of a lot of companies. Will you also examine Hydro One's performance over time against itself, along with a comparison to other companies? *Yes, with the exception that we also have time over time data on the other companies going back to 1997 so we have an ability to do a longitudinal study across not only Hydro One over time but inclusive of the other companies.*
- Your intent is to report on both Hydro One's performance over time against itself and other companies? *Yes.*
- In Ontario every utility reports outages by Cause Code and one of these is tree contact. This is a direct output of vegetation management. Will this study look at the Cause Code outages used, in terms of reliability? *Most assuredly, in fact we have data already on the causes and how much relative to the total number of outages by the system versus vegetation management. Within vegetation management we know that the vast majority of outages are caused by trees and/or branches that fail into lines, as opposed to trees that are simply growing into lines. There is a direct correlation to the time at which maintenance is performed and the number of outages that occur. We also see a relationship between maintaining the space around conductors and the number of outages that occur.*
- Does your study try to create a relationship between outages as recorded by cause code and how will you demonstrate whether the money spent on vegetation management has an effective outcome? *Yes, one of the ways that we normalize cost is by looking at how many labour hours are expended on a project. This is a way to understand across a lot of different factors of compensation that we won't be looking at. This allows you to judge whether company X or company Y is getting more from their productivity based on how many labour hours they are spending. Our main measurement for reliability is the number of outages that occur and we look at that on a per kilometre basis as opposed to reliability metrics that are based on customer densities.*
- Can you tell us briefly about 101 for Reliability Centred Maintenance (RCM) - where is it in terms of is best practices, is that a framework that you will be using in your report to bring together best practices? *I believe that RCM has great value in the delivery of electricity. I do not think that RCM is necessarily the route a vegetation management program should take in order to meet its objectives. That being said, we ask questions about reliability. If companies are performing vegetation management according to RCM ideas, it is going to come out in the study.*
- We now hear a lot more about RCM being the approach to vegetation management, are you going to push in that direction as far as this study? *I think that ultimately our recommendation in terms of innovation will be to seek clarity in measurement performance and if that can be achieved through some reliability measurement than that is what we will advise.*

Overall Comparisons

- Which utilities, in your experience, are the best at vegetation management, just at a high level? *This is a very difficult question to answer because we use a lot of different measurements to determine this. The methodology within Canada, which is to eliminate vegetation within a required zone then maintain a corridor, is best in class.*
- Why can't you tell us the best three on the list of comparators you have provided? *We have discussed giving an award for the best company overall. However, we haven't done this, simply because the evidence isn't in that any company has mastered the problem.*

Peer Group Selection Criteria

- You have some Canadian peers that from my perspective would probably be useful like Manitoba Hydro, are you able to confirm which of these on the list are in the upcoming study? *No, not at this time.*
- How did you pick your comparators and is Hydro One helping you do that? *No, Hydro One is not helping us pick our comparators. The lists provided are all companies we have already done studies with and they will be the companies we invite first. We will also invite additional companies. The final list is our choice, not Hydro One's.*
- Is the final list based on some empirical analysis? *The final list is based on a list of companies that meet the criteria we are looking for. We have a peer group and we have a general group. For the peer group we are going to look at several factors. The most important factors will be the tree density and customer density. The other factors we are going to look at are the region of North America they are in and some of the individual characteristics that match up with Hydro One.*
- Is workforce one of the factors you will be looking at when selecting the peer group? *Hydro One is unique in their workforce to almost all of the companies that we have studied.*
- In your presentation you list the criteria that will be used to choose future comparators, are these the criteria that you will use? *Yes, this is how we are going to divide up the peer group from the general group.*
- Is Total Factor Productivity a factor being used to choose peers? *No, total productivity factors are all of the different parts of the programs that distinguish the different parts from one another. We are trying to match up what we think are good comparators based on the types of programs they have.*
- I understand the independent variables; I don't understand the other ones. *The other variables are independent in that these companies have made particular choices or are driven by particular regulatory rules. We are going to make this completely clear in our study, which companies are included and which types of company are not included. For example, if one company is a complete outlier we may take them out.*

Comparing Hydro One's different regions to other companies

- Why have you added one more region within Hydro One in this study versus the previous study? *Simply because this is the structure that Hydro One is operating under.*
- Are you going to look at Hydro One's different regions separately when making comparisons? *Yes, Hydro One's different regions will be treated like single companies. A lot of the other comparators are doing the same thing, they have different groups and they report data for each operating group separately so they are able to see each of those internal operations as compared to the other companies in the study.*
- When the study is complete will we be able to see Hydro One's southern region compared to other comparable southern region companies to determine whether Hydro One performed well or indifferent under this comparison? *Yes.*

- Are you going to have different peer groups for Hydro One's five regions? *The short answer is no. The comparisons are inclusive, if the southern region of Georgia Power is one comparator and if the southern region of Hydro One is one comparator they will both be in the comparison so you can evaluate that one with the other one. They are included, however, the rest of the comparators will also be included in the comparison.*

Performance Measures and Objectives

- You mentioned other program efficiencies should include other stated objectives, what would other program efficiencies be? *Generally, when we evaluate programs, we look at your objectives and you need to show the metrics which are showing that you are achieving those objectives.*
- Is there an industry standard or metric for cost effectiveness? *In terms of cost effectiveness there is not a standard metric for vegetation management. One of the outcomes of the study is being able to inform the company if there is an improvement they can make and whether they will be able to generate a return on this improvement by looking at how much it would cost to mitigate versus not mitigating.*

Clearing Sites and Cycles

- Aren't clearing sites and cycles controlled by cut back protocols from municipalities, the province or what the local residents say is an acceptable cutback for aesthetic or other reasons? *There are constraints on every utility company for maintaining their clearing and cycle objectives. There are issues in achieving these that relate to municipal rules or customers themselves so compromises are made along the way. We do ask questions about the company's greatest constraints in terms of clearing, these are part of what we call a productivity factor.*

Other Questions of Clarification

- Was Hydro Quebec included in the 2009 study. *Yes, Hydro Quebec was in the 2009 study.*
- Are you going to compare the results from this study with the results from the 2009 study, which you completed? *Yes.*
- Will you also be identifying changes in the methodology between the 2009 study and this study? *Yes.*

Part 2 – Total Factor Productivity Study

Steve Fenrick from Power Systems Engineering delivered an overview presentation that described the overall framework and proposed approach for the Total Factor Productivity Study. Following Steve's presentation participants asked questions of clarification and provided feedback. A summary of the questions and feedback is provided below.

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Suggestions and Comments on Study Methodology

- **Find out if the financial data from Hydro One is available by region. It would be interesting to do the outputs by region,** even without the financial data, to determine if reliability is being improved by region.

Suggestions and Comments on Measuring Reliability and Cost Efficiencies

- **Use tried and true ways of calculating the lag related to the timelines of investments and identifying with empirical evidence what the lag is.** I don't believe that a 20-year trend would capture the lag, you would have to know what the lag is. *We can certainly take that under consideration as far as something we think is useful.*
- **Measuring Productivity should include keeping wages at a reasonable level.** *This is certainly important for cost levels. However, I think this would be captured by a different study as this is not traditionally a TFP measure.*
- **Include the incremental cost of units of improved outputs in your report.** *We can certainly take that under consideration.*

Suggestions and Comments on Comparisons to Peer Companies

- **It is good to have TFP improving but you need to know how Hydro One relates to their peers.** On the TFP study the most obvious input is the lack of any comparison to any 3rd part peer/peer group comparison on a TFP basis is a big flaw. *In the OEB Decision, the OEB stated it saw value in Hydro One measuring its own productivity over time and directed Hydro One to determine its own study method. An external comparison is therefore outside of the scope of this study.*

Questions of Clarification

Measuring Reliability and Cost Efficiencies

- How do you address timelines related to investments? Costs in one year may produce outputs 3 years down the road; will this report look holistically at the time period or simply put all the numbers in columns on a spreadsheet? *The report will likely produce columns on a spreadsheet. You are correct that there tends to be a lag in terms of investments and outputs. The fact that we are doing a 20-year trend will hopefully capture some of this lag. We could also do a 3 year rolling average in an effort to capture any lag.*
- *For a well-managed stable operation it is true that you need to increase inputs for reliability to improve. However, for a business where things are not optimally managed you don't necessarily need to incur more costs to get better outputs.*
- Will inflation, which is one of your TFP drivers, include the cost of Hydro One's union contracts? *Yes, it should. It is independent but it also a resource that Hydro One is using related to outputs.*
- In terms of the correlation between reliability and cost, will your study measure the incremental cost of these units, that is, how much more we would pay for each unit of safety, for example? *The TFP measurement should quantify an x percentage improvement in reliability leads to an x percent drop in TFP. Those could then be translated into costs, however, we are primarily concerned with TFP trends.*
- Am I correct that the TFP will go down if Hydro One spends more to keep reliability at the same level? *All else being equal that would drive down the TFP. This is why it will be important to look at TFP over a 20-year time period so that we can see if investments made in one year will increase productivity 2, 3 or even 4 years later.*

Measuring Independent Variables

- My understanding is that the industry sample you are performing will identify and measure independent variables and will not compare Hydro One to anyone else, is this correct? *Yes, that is correct.*

Using the TFP Study for other purposes

- Will this TFP study also be used by Hydro One to develop adjustment mechanisms for rates?
  (Hydro One) Every one of these studies will be reviewed and where possible incorporated into the business plan that support the distribution application to be filed in the first quarter of 2017.
- Will the outputs from this study be used by Hydro One in the design of the next IRM? *(Hydro One) The outputs will be considered as an input.*
- *(Power Systems Engineering) The TFP trends that are likely to come out of this study really should not be used in an I – X formula because they should be revenue weighted. Outputs should be based on what drives revenues which is how PEG did the 4th generation IR, which is the proper approach for rate setting. We are going to be evaluating performance trends for Hydro One.*
- This is a productivity study and therefore the outputs should be included in your application. *(Hydro One) The outputs will be reflected in some way, whether it is done strictly mathematically or qualitatively is yet to be determined.*

Ontario Energy Board's decision regarding PEG

- Will you be able to respond to the Ontario Energy Board's decision, should they decide they support the way PEG performed their benchmarking study, particularly in terms of reliability? *Yes, we would likely be in the first two steps of our study and would be able to incorporate the OEB's feedback. Additionally, these previous studies were benchmarking comparisons, whereas we are only comparing Hydro One to itself over time.*

Regions

- Does this study in any way deal with Hydro One's different regions as an output? *Currently, this study was going to look at Hydro One as a whole company. It is our understanding that the financial data is available on a company wide level.*
- Is the financial data available on the regional level or company wide level? *(Hydro One) We can't speak to finance right now but this is something we can definitely look into.*

Additional Cost Drivers

- You mentioned that you might be considering additional cost drivers, can you give us some examples? *We listed additional cost drivers because we are looking for feedback as we talk with Hydro One and stakeholders. If anyone here has any ideas we would be open to considering these.*

Measuring Outputs

- How will your study normalize the weather component for outputs including SAIDI and SAIFI? *We are going to exclude the major weather event days.*
- What do you mean by environmental output? *These include energy efficiency type activities that may increase costs. We are aware that we will need to be careful to the extent that these costs are calculated in the CDM and are outside the distribution system. However, we are going to look at indirect costs that could be included in the TFP measure.*
- How do you measure customer service levels? *By looking at the score card metrics and looking at how that's changed on TFP trends at different utilities. To the extent that we can come up with an empirical model we will try to do that. This has never been done before so we are not certain we can correlate customer service levels to TFP trends but we will have a better answer to this in the second quarter.*
- Can you explain the output you have listed as system capacity at peak demand? *This refers to the output used in the 4th generation IR proceeding, which was a measure that took the*

maximum peak demand in a year and used it going forward until that demand was an exceeded. It would stay the same until peak demand exceeded its maximum of the past.

- One of the cost issues over time for Hydro One is that capacity continues to increase while basic demand does not. *If Hydro One is doing that that would tend to drive down their TFP, if they are making extra investments and increasing their capacity without a requisite increase in peak demand that is going to drive down their TFP.*

Study Timeline

- When will we see a draft of the TFP report? *The preliminary results will be presented during the next stakeholder session, which is scheduled for Q2 of 2016.*

Part 3 – Pole Replacement and Distribution Station Refurbishment Program Study Approach

Ben Grunfeld from Navigant and Ken Buckstaff from First Quartile delivered an overview presentation that described the overall framework and proposed approach for the Pole Replacement Program and the Distribution Station Refurbishment Program Studies. Following their presentation participants asked questions of clarification and provided feedback on the proposed approach. A summary of the questions and feedback is provided below

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Suggestions and Comments on Peer Selection

- **Explain your method to address the quality of your selected group in the report**. There are tests you can do to address the quality of your selected group - do you do this? *In our annual study we run results of our annual studies against what we can get publicly available, primarily on cost (using FERC data). We find that the average for our group is right about the same as the overall average, there is no apparent bias.*
- **Select additional peers with more similarities to Hydro One and be aware of some of the major differences with the ones already on the list.** As far as criteria go for the peer group – there are companies on the map that don't seem to be similar to Hydro One in any way. Texas, for example, with weather patterns, is significantly different than Ontario. Same with SoCal Ed. You don't have Wisconsin, Michigan, and Minnesota, which are much more similar in terms of geography and density. *We have a couple of others that we will be approaching; we started with the list that is in our benchmarking group. Texas, for example, you would be surprised how similar they are, in service territory - densities are different but if you take out Dallas they are quite similar. They have ice storms too. One of the ones we are going to approach is NorthWestern – they cover South Dakota and Montana - it's not on this list yet because they are not in our panel. They have similar wide-open spaces and similar bad weather. They have a number of similarities. And if there are other utilities that are perceived to be good for this sample we are happy to reach out to folks, that's part of the feedback we'd like to get from you today.*

Suggestions and Comments on Study Format & Outputs

- **Use econometrics for benchmarking.** You are doing peer group benchmarking rather than econometric benchmarking. If you have a diverse group of utilities that you want to compare then one way to do it is to use econometrics to get at the relationship between your independent variables and your outputs. *No, we're not planning on doing that*.
- **If you don't use econometrics for benchmarking, provide a rationale in the report.** Yet because you have a diverse group, it would seem that using econometrics would be the

obvious way to do it, it's unclear to me why you're not doing it. *Part of the challenge is defining all of the drivers and not having to deal with admitted variable biases and things of that nature. You can't necessarily trust the outcome of the econometric study unless you are comfortable with the formulas and you have identified all the major drivers. To your point, this is a panel benchmarking exercise. We are not doing regressions; we hadn't planned to do that.*

- **Provide correlation data**. I thought you were going to do regressions with labour costs so we could see if there is a true correlation that goes with labour costs. *We can provide some correlation data but correlation is different from a full regression analysis.*

Suggestions and Comments on Regional Analysis

- **Be consistent in doing regional analysis across all of the studies.**
- **Do peer analysis based on regions.** Regarding the peer group analysis – have you considered splitting up to the various regions of Hydro One and comparing regions where they have regional data to comparators that are similar to those regions. Take SouthWestern Ontario for example - it will be similar to certain other utilities, whereas Northern Ontario won't be similar to those same utilities. Can you add that in to ensure you have better comparability? *We are talking to Hydro One about that - to the extent to which the data is available and we can do these comparisons.*
- Hydro One divides itself up corporately into regions and they run it regionally and some of those regions are run better than others. If one were to test that theory, it would be helpful to have this study done regionally. *What you are really trying to get at are the drivers. What you really want to know is what is causing a cost difference. If there is no difference in driver other than geography than there is not a great level of value to this data. Part of the analysis for us, when we ask questions about and look at practices, as to how they are different in different parts of the province. It is reflected, even if we're not able to get down to that granular level of cost data. Some of the studies do regional studies and some don't so this will be an issue when looking at all of the studies.*
- **Highlight drivers and the impacts of drivers that Hydro One can control**. By splitting up into regions you can identify the operational differences, the reasons why Hydro One is more expensive in the same geography. Get rid of the independent drivers because those you can easily measure and get to the ones where there is a difference that Hydro One can control. *You are going to see that whether you are comparing SouthWestern operations to Integris or whether you are comparing Hydro One generally to another utility. The distinctions around operating practices aren't that varied that you don't see it even when you look at the utility as a whole relative to other utilities as a whole.*
- **Consider comparing what type of pole is being taken out versus what is being put in**. E.g. 35 foot pole to a 50 foot pole

Questions of Clarification

Study Format & Outputs

- The presentation says that the peer group will be confidential - will we know who is on the list or not? *Yes, you will know who is on the list but you won't know the performance of the entity, other than Hydro One.*
- Regarding the limitations on who can be in the group – if you have approximately 21 companies on this list, and then if you only get 60% that's 12 companies - does that affect the statistical quality of your results? *It's always a case of "the more the better" in terms of statistics. In terms of who self-selects to participate, it is companies that have some interest in the area or who are willing to do it for us as a favour – they work with us in our annual studies and get a lot out of that. They help the community by participating in these kinds of*

one-off studies. *The companies that self-select are not at the bottom or top of the performance spectrum, we get a range.*

- Did you talk to Hydro One about regional analysis? I don't see it anywhere here. *We are talking to Hydro One about that.*
- One of the variables is the results of one approach versus another approach. What we saw from the other studies is that one of the things you have to look at are impacts on reliability, maintenance cost, and others' results. I didn't see how other variables such as these will be factored in to this study. *We have been asked to look at the cost of replacement or refurbishment, the cost of the action once that decision has been made.*
- So you are not providing any input on whether there should be a higher rate of replacement or different cycles? Are you not going to be evaluating reasons for replacement/refurbishment? *No, we are not looking at recommending changes to decisions around reasons for replacement and/or refurbishment.*
- The Hydro One mantra for years has been we are a unique utility and you can't compare us to anyone else and now you're saying no, no problem, we can do it. *What I'm saying is that you can identify where those differences come from.*

Terms of Reference

- Regarding the Terms of Reference for this study: If you read the board's decision and look at the six points in the second slide about the benchmarking studies (plural) – the board says you will carry out an internal trend analysis to show the variability of these unit costs over time year over year. In the last rate proceeding EB-2013-0416, they filed that data on some basis, certainly for the poles. So let's start with poles, what are you going to add, other than the data that they've already filed, to comply with the Terms of Reference? *We are looking over a historical period of time and Hydro One data over a historical period of time, as well to some extent, the peer group and the peer utilities over a historical period of time. The one aspect that is completely brand new is where Hydro One sits relative to others on these. That's one new element. On the same metrics we are reporting comparisons against peers we can also provide a trend for what Hydro One has done based on what they have reported over a period of time.*
- Are you going to redo the cost analysis that Hydro One has previously done with the same format and same assumptions as the peer group? *I wouldn't say we'll redo it. We'll do trend analysis in addition to the benchmarking study.*
- How do we compare the two, what they filed last time with what they'll file next time, assuming the data will be different? *Where there are differences we'll identify those.*

Study Methodology – Pole Replacement and Construction Standards

- Can you just do cost per pole? *Once you get into the nuances of what is included and what's not included in that cost of pole replacement there are a lot of differences to what is included*.
- As for unit cost analysis, will you be differentiating between proactive and reactive pole replacement? *It's still uncertain as to whether we can get sufficient data to benchmark this across utilities separately. We recognize it's a potential driver of variation in cost, so we'll have this in the questionnaire where it plays in and how it plays into the data we collect. We will be trying to do this.*
- Regarding construction standards – these are changing over time, in terms of the height of the pole you are putting in. Will this be considered in the study? *Yes, there is consideration for the way demographics are shifting. You can have varied construction standards for poles but more so for stations, particularly for Hydro One and also for peer groups companies.*

Understanding exactly what you're getting for the money you're spending on assets is definitely part of this. There are still some questions about how much you can benchmark these differences, given how many differences there are. At the minimum we will have an understanding of relative contributions.

- Pole replacements programs tend to be the most expensive way to replace poles. How are you going to capture this with the different utilities? A utility with a high-growth rate will have a very low pole replacement program, per se. Do you bundle them all together or separate them out? *One of the questions we ask in the questionnaire is what is the reason for replacement. To the extent that people can give us that data, it's very useful. For the standard proactive replacement (because they got old) there tends to be good data. In the case of other reasons (such as road widening) there is not as much data. We will try to get the different drivers for that.*
- Does the type of pole impact the cost? *We will ask that question and collect that data. Hydro One is predominantly wood. We want to make sure that the peer groups we look at are also predominantly wood, and if they're not, then we adjust for it.* Does the type of wood matter? *Not really.*
- Are you going to be looking at the size of the pole replacement program in its totality relative to the demographics of the pole population? Does Hydro One cut off at 30 or 40 years and someone else cuts off at 50? Curious to know how it affects unit cost. *We don't know whether it affects unit costs - this is something we are going to check, find out the pole replacement rates at the utilities*

Study Methodology – Labour Costs

- How is the labour cost of these utilities considered as an input, how does one understand if there is a correlation between the labour cost and final unit cost of the replacement or if there is no such correlation? *That is one of the open questions. We will ask about the total cost of the program, then we will ask if they can break that down into labour, etc. For the respondents that can give us this we will include it. We will likely get this information from about half of the utilities we ask, many won't be able to give us that level of detail.*
- Why is that? The utilities have labour costs for the type of work that is done on poles. It would let you understand if there a correlation of the unit labour cost vs. labour cost of utilities – then you can say the labour cost is actually driving the difference. *The question is whether people are willing to give us this data. Part of the reason you can only get half of this data is that companies that outsource the work just have a single large number.*
- Will we be able to see the differences between the utilities that outsource the work vs. those that do it in house? *Yes, this is the type of and level of data that we are going to work to get.*

Other Questions of Clarification

- What do you mean by a panel? *A panel is a collection of comparators.*

Part 4A – DISTRIBUTION STATION REFURBISHMENT PROGRAM STUDY METRICS

Ken Buckstaff from First Quartile delivered a presentation that described the proposed program metrics for the Distribution Station Refurbishment Program Study. Following his presentation participants asked questions of clarification and provided feedback on the proposed program metrics. A summary of the questions and feedback is provided below. Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Suggestions and Comments on Methodology

- **Consider who does the work, not just outside versus inside.** In the case of Hydro One distribution systems, overhauls are done by transmission station workers, who aren't the cheapest labour. You might be able to find difference between utilities to help guide Hydro One to a better practice
- **Consider environmental drivers of refurbishment.** Hydro One used to use arsenic trioxide so some of the costs may be due to environmental drivers. *Great advice, thank you.*

Questions of Clarification

Cost Analysis

- Are you measuring the units of property cost or the program cost? *We will end up with the total program cost divided by the number of units when we're done – so you will end up with the cost per substation refurbished, with some definitions alongside this as to what's in this cost.*
- So these costs will be controlled by the strategy, right? *It will be affected by the strategy, which is why we're asking these questions at the front end, as to what the strategy is and how does it work. And in terms of unit cost, we'll be doing it per station, but we'll also do it per KVA or MVA of capacity, to be able to compare the difference between companies.*
- You have the same issue with pole replacement, where you have a program cost at the bottom and the unit cost at the side [of the presentation slide]. *In this case as well, the total cost will be compared.*

Peer Group Selection

- How are you going to be sure you are going to get like for like in the Hydro and peer definitions? As a subset of that, Hydro One is moving to IMDS - how will you control for that? *We have IMDS in the methods section, it is quite different from doing a more traditional refurbishment and we are going to try to get the data for both. We've spent some time in the past couple days to try to understand how much of a difference there is between the practices when you using one system versus the other.*
- Do you think you will be able to find a peer group that does it the same way? *We will get some. We will also find a number who don't do it that way, who do it purely by components. What we do there, we have to take what they do and try to modify it to fit what Hydro One does.*

Other Questions of Clarification

- What is IMDS? *IMDS is a modular station.*

Part 4B – POLE REPLACEMENT PROGRAM STUDY METRICS

Ben Grunfeld from Navigant and Ken Buckstaff from First Quartile delivered a presentation that described the proposed program metrics for the Pole Replacement Program Study. Following their presentation participants asked questions of clarification and provided feedback on the proposed approach. A summary of the questions and feedback is provided below.
Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Suggestions and Comments on Methodology

- **Treatments of the poles is not relevant to this context.** It's unlikely that Hydro One is doing treatment on the poles. e.g. injections, this is not relevant to our context.
- **Be careful when considering differences in the phases**. When you are looking at demographics such as single phase versus three phase. 80% of the lines at Hydro One are

single phase, not sure that 80% of the replacements are single phase – may be replacing with more than you think.

- **Consider the type of programs being used for pole replacement**. There are 5 different programs that replace poles. For example, service upgrades can be part of this if the pole is replaced as part of the service upgrade because of its condition. Line refurbishment is where you rebuild the whole line because you bypass the threshold for the amount of poles on the line that need to be replaced, so this is a different program. All poles on the line need to be replaced whether each individual one needs to be replaced or not. Other things that may drive the replacement program include the engineering standards between the old pole and the new pole e.g. the height of the old pole vs. the existing pole. If you don't create this kind of context for the analysis, the cost of pole replacement may look artificially high, because it does not take into account all the pole replacement that was pushed into other programs.
- **Consider adding other criteria that appear to missing, such as density, remoteness, and the median distance between the pole replaced and the service centre**. Given that the end product of the exercise is the unit cost for pole replacement, a lot of these criteria seem to be more related to what drives the number of poles that get replaced in a particular time frame, which is not relevant to the key metric (unit cost).

Questions of Clarification

Cost Drivers

- 90% of Ontario is either rural or really remote - how have you factored this in as a cost driver? Or is the cohort selection process going to take care of that? *We intend to gather the information about what is being replaced, such as whether they are in the urban or rural area. In terms of the drivers, some of those make a difference in the sense that if you are replacing 4% a year you're not going to let them get very old versus if you are replacing 1% a year you're likely to have a lot more failures.*
- I thought you weren't measuring cost of pole replacements? *It's not the core function, but we will be asking for those volumes.* You can rest assured that we'll be 1% or less, not 4%.
- I don't think that's correct that the whole system is remote, there are towns like Ancaster and Kingston, and all sorts of places like that served by Hydro One, you need to let the data tell you about this.
- I want to confirm what you are studying: The question is: How efficiently is Hydro One replacing the poles in total, not the crews individually – you are looking at the entire strategy, there are a lot of different drivers in there in terms of cost impact. *Correct, this is what we are measuring, including all the factors outside of the crew replacing the pole.*

Next Steps in the Study

Ben Grunfeld from Navigant and Ken Buckstaff from First Quartile reviewed the final slides regarding Next Steps for their study. Following their presentation participants asked questions of clarification and provided feedback on the proposed approach. A summary of the questions and feedback is provided below. Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Questions of Clarification

- Looking at the previous version of the presentation – where your second bullet says finalize peer group selection metrics and identify candidate. Have you finalized your peer group selection metrics? It was my understanding that what was presented here was a sample, as some factors to consider, not the final list, but now I think you're saying that this is your final list. *Yes, that's the primary criteria, but it will be updated based on some of what we heard today.*

- Is the list from presentation your list of candidates? *Yes, this is the final list, plus any that are suggested today.*
- Do you have a list or table somewhere that maps your candidates to your criteria? *Yes.* Can you share it? *Yes.*
- From the first version of the presentation, it says schedule first round of "local practice workshops" - what are those? *That's with Hydro One, to understand what their practices are.* Have you held them yet? *No, we have scheduled them, but we have not had them yet.*
- (To Hydro One) – When are you filing your rate application? (Hydro One) *We currently plan on filing Q1 2017 for 2018-2022 distribution rates. Transmission, we plan filing Q2 2016, for two years, 2017 and 2018 rates.*

Process Next Steps

The facilitator thanked all participants for their input and reviewed the process feedback received throughout the session, which is summarized below and followed by participant questions about next steps for the process.

Comments and Suggestions on the Meeting Process

- **Provide the meeting content (for the next meeting, the detailed results) a week to 10 days prior to the meeting.** When we are looking at actual results, getting detailed content like these results at the meeting is not helpful. We need to get it a week or 10 days in advance so we can do some analysis and ask some questions in advance, send them along before the meeting. *Yes, we can do this.*
- **Indicate the time allocated for feedback in the agenda**.
- **Create separate worksheets per presentation.** For example, this session would have had four worksheets (one per presentation).
- The facilitator noted the adjustment made to enable a better flow of questions between the participants and the presenter and took this as helpful advice for future meetings.
- **Thanks to Hydro One and to Swerhun for your work**. Really appreciate that you included the OEB Decision information in the package, helped a lot.

Questions of Clarification

- Will there be a follow-up session when the consultants put their work together for the intervenor groups to ensure that it matches up with the direction from the OEB? *Yes, this will be the next stakeholder session. Preliminary results and recommendations will be shared before they're finalized.*
- At the next stakeholder meeting are your going to provide drafts of the reports? *We will be sharing the preliminary results and findings.*

Wrap Up – Maxine Cooper, Hydro One

Maxine thanked participants for their feedback and encouraged them to share additional input and feedback via email/the soft copy of the worksheet. She also encouraged participants to be in touch at any point between this session and the next if they had any topics they wanted to discuss. Maxine noted that participants will have until October 30th for written feedback, and will receive the soft-copy of the feedback worksheet on the following day (October 23rd).

Hydro One Stakeholder Session
October 5th, 2016
DoubleTree Hotel by Hilton – The Toronto Ballroom
108 Chestnut Street
8:30am – 4:30pm

OVERVIEW

On October 5th, 2016 Hydro One Networks Inc. hosted a full-day stakeholder session. The purpose of this meeting was to present and discuss the preliminary findings and recommendations of the following studies:

1. Total Factor Productivity
2. Vegetation Management Program
3. Pole Replacement Program
4. Distribution Station Refurbishment Program.

The stakeholder session included:

- Opening Remarks from Oded Hubert (Vice President, Regulatory Affairs, Hydro One Networks);
- Welcoming remarks from Maxine Cooper (Senior Regulatory Advisor, Hydro One Networks);
- A presentation on the Preliminary Findings and Recommendations of the Total Factor Productivity Study, delivered by Steve Fenrick (Power Systems Engineering); and
- A presentation on the Preliminary Findings and Recommendations of the Vegetation Management Program Study, delivered by William Porter (CN Utility Consultants);
- Two presentations on the Preliminary Findings and Recommendations of the Replacement Program and Distribution Station Refurbishment Program Study by Benjamin Grunfeld (Navigant Consulting) and Ken Buckstaff (First Quartile Consulting).

This summary was written by Dave Hardy and Jeremiah Pariag, who provided independent facilitation services for the stakeholder session. It provides a high level summary of the main points shared by participants as captured in the "live" notes written during the meeting, and is not intended as a verbatim transcript of the meeting.

Note that there are two appendices to this summary (attached separately), including:

Appendix 1. List of Participants
Appendix 2. Presentation Slides

Presentation #1 – Total Factor Productivity Study

Steve Fenrick from Power Systems Engineering delivered an overview presentation that described the Preliminary Findings and Recommendations of the Total Factor Productivity Study. Following Steve's presentation, Dave Hardy facilitated a discussion during which participants asked questions of clarification and provided feedback. A summary of the questions and feedback is provided below.

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Questions of Clarification

- How much have the Electric Utility Construction Price Index (EUCPI) and Handy-Whitman Index (HWI) varied from each other? *They vary over time. Handy-Whitman has escalated faster than the EUCPI, but from year to year, it is dependent on interest rates. EUCIP is sensitive to interest rates, whereas Handy-Whitman does not incorporate rates.*
- In regards to slide 11, are the numbers shown adjusted or unadjusted? *The numbers shown on this slide are unadjusted.*
- If the utility was selling less power, would this decrease the Total Factor Productivity (TFP)? *Yes, this is possible.*
- Would the TFP be lowered if costs were fixed and less power was sold? *Yes, but in the output index, customers are given more weight than sales. Note: Weights have been determined by the OEB study.*
- Does conservation spending go towards the capital budget? *No.*
- In the consultation leading to the 4th gen, Toronto Hydro and Hydro One were significant outliers. Moving to 2015, were Toronto Hydro and Hydro One pulled out? *The numbers presented do not include Toronto Hydro and Hydro One*
- Both the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI) are being used in the presentation, why is the System Average Interruption Duration Index (SAIDI) not included? *SAIDI is implicitly included in the two overall components. (SAIDI = average duration time of outages in time for a customer, SAIFI = frequency of outages, CAIDI = average duration time per outage)*
- Have any adjustments been made to the figures presented? *Loss of supply was not included. Major event days were also not included because this could skew the index. Power supply outages were not included.*
- What are you measuring for outputs for safety? *Outputs for safety are measured by the number of recordable injuries per 200,000 hours worked.*
- Lots of things are outputs, safety is different. How prevalent is including a variable like this in the US? Much of the data is not public. *This may be the first application of incorporating safety and reliability into the TFP trend.*
- What justification do you have for using the Lawrence Berkeley National Laboratory paper as opposed to others? *The Lawrence Berkeley National Laboratory paper was used for the US Department of Energy and seems very reliable. It provides a good starting point for pricing outages and reliability for the TFP.*
- In the report that will be produced, will a more detailed analysis be done in regards to interpretation of negative TFP and how other factors are assessed, like the impact of distributed generation (DG)? *Many costs directly related to the cost of DG are not*

included because it is not part of the 4th Generation Incentive Rate-setting method (4GIR), but it is difficult to calculate the cost.

- Are scheduled outages included? *Yes, scheduled outages are included because the customer's experience would be the same for both planned and unplanned outages.*
- Why was EUCPI discontinued? *EUCPI was discontinued because, according to Stats Canada, the methodology that was being used needs to be verified. It is currently under review and it may or may not return.*
- The OEB is asking utilities to use the Pacific Economics Group (PEG) model in their forecasts. Is that in this scope? *This study just looks at the TFP trends, it does not do any total cost benchmarking for Hydro One. This study only looks at how Hydro One's TFP has changed over time.*
- As stated, between 2002 and 2015, the average annual TFP trend declined by 0.9%. What would this do to the Board's current X-Factor? *It should lower the X-Factor.*
- During the presentation, it was noted that Hydro One spends 6% on safety. What is this percentage in reference to? *It is 6% of the total cost of Hydro One*
- If you are spending this money on safety, is the result included in the output index? *Injury data is incorporated into the output index with predetermined weights. It is represented by the change in injuries per 200,000 hours worked.*
- Why is safety an output? It seems to be a common element of running a business? *Output may not be the best word – performance measure or metric is better. It is not a profit function to make a safety a priority because it is the right thing to do, so it can be thought of a society output. Customers don't experience this output, but if it were to be excluded as part of the cost function, it would be giving an advantage to utilities that are not focusing on safety.*
- About 75% of outages are caused because of factors that are out of the control of utilities, e.g. weather and human contact. Could you measure outages that are caused mainly by failure of equipment? *Within that 75%, there are some factors that are tied back to how the utility performs in regards to tasks such as tree trimming. Having said that, one main reason why major event days were removed was because the statistics skewed the numbers, and we also focus on a three-year rolling average, which gives a better indication of the impacts on customers.*
- Conceptually, could you adjust the SAIDI and CAIDI by a factor due to weather? *Yes, it is possible. There have been wind variables used in the past. Toronto Hydro makes a case for reliability benchmarking.*
- Could you take the Ontario industry and measure it over a 10 year wage rate for a utility vs. a wage rate for the province as a whole to understand the impact? *The industry will have its own provision of required employees and there will be a different composition in that industry, so it is hard to compare*
- If you were to take Hydro One's forecasted costs, could you determine the TFP for the next five years? *Yes, but assumptions would need to be made on pricing changes.*
- Are the costs associated with reliability increasing over time? *This is one possible explanation, but it could be the opposite. A utility could be getting worse on its reliability because it is cutting costs. At some point, reliability is likely to worsen. So we should include the worsening of reliability into the TFP as well.*
- Does spending money on safety and reliability lead to better performance for Hydro One? *Typically, more money is spent to improve an outcome. For Hydro One, the reliability factor adjustment really is not improving things, reliability has stayed flat. It is difficult to determine what the exact costs of reliability are.*
- Was using an overall construction index considered to compare Hydro One capital spending to other industries? *No.*

- Are the numbers consistent with the 4GIR up to 2012? *Yes.*
- Will the HWI figures for 2016 be updated for the upcoming application filing? *It is unlikely because the 2016 data will probably not be available.*
- Are the Canadian indexes and the Handy-Whitman index moving in the same direction? *Yes, they are both increasing over time.*
- Is the Handy-Whitman index the only one that could be used? *It seems to be. This is the only index that is utility specific and looks at capital assets – there is not currently a Canadian equivalent, but if there was, it would be used. The current index being used is the best available.*
- Was there any other data that was adjusted other than what was mentioned? *A minor change was made to a Hydro One value for peak demand in 2013 because it looked inconsistent.*

Presentation #2 – Vegetation Management Program Study

William Porter from CN Utility Consultants presented the Preliminary Findings and Recommendations of the Vegetation Management study. Following William's presentation participants asked questions of clarification and provided feedback. A summary of the questions and feedback is provided below.

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Questions of Clarification

- What does the term "managed kilometer" mean? *This is a kilometer that was managed by vegetation management staff per year.*
- The techniques surrounding vegetation management have not changed. Why is the number of labor hours going up per tree? *Recent events, such as fires can affect how many labor hours are used. This creates a more strategic and targeted approach towards vegetation that often requires more time. This is also dependant on cycle lengths.*
- Hydro One has much higher costs per kilometer. Is this because Hydro One staff is being paid more? *There is an increase of overall cost on an hourly basis, but the labor burden, equipment costs, and administrative costs can drive up the cost per kilometer.*
- Is it recommended that Hydro One employees conduct the work instead of contractors? *Usually, yes. The full time employee system has led to low turnover and better safety. Substitution of low cost contractors can hurt these outcomes.*
- What does "Establish flexible variable cycles of inspection and maintenance to achieve objectives" mean? It means e*stablishing flexibility to be more strategic to look at areas of the company and determine whether or not there needs to be a more dynamic approach instead of a standardized cycling approach.*
- What "additional metrics" are being referred to? *This refers to an area of metrics that are able to define the objectives that are harder to quantify and measure such as, safety, environmental stewardship and customer service.*
- During an outage, would a vegetation management employee be sent in? *Hydro One has an outage investigation that is performed by a non-vegetation management employee based on a very limited number of data entries.*
- Would a metric that correlated vegetation-caused outage and vegetation management visits make sense? *Yes.*
- Should there be a metric to test the effectiveness of vegetation management procedures? *No answer provided, as the questioner moved on to another question before allowing William to answer*
- "Labor hours per tree treated" is a term used. How is this number determined? *Companies are asked to report how many trees they have treated.*
- In regards to cost per tree treated, how has Hydro One only increased costs by 3% while the rest of the industry has shown an increase of 97%? *Hydro One still has the highest cost per managed kilometer of all the peers. This is done by managing ingrowth effectively and how long the cycle length is.*
- Regarding cycle length, are regional differences taken into account? *Yes, but these are not planned cycle lengths. The m class is on target to be managed at 6.5 years. Much of the system is in a backlog. A minimum of 8 years would be more appropriate.*

- If you change the cycle length, what does it do to the cost? *It is hard to determine this exactly. If you look at example X9 on the productivity slide, lower cycle length does not necessarily mean lower costs. To get feeders to 6.5 years will take six years.*
- In regards to the peer group, how many are Canadian? How many are in Ontario? *There are five Canadian utilities in the peer group. There are none from Ontario.*
- Is data available to determine if contractors are more efficient than Hydro One in regards to their labor metric? *All of the peers except for one are contractors. When looking at labor statistics per tree and per kilometer, Hydro One seems to be more productive than the peers. There is no data for in-house management. Hydro One is an outlier.*
- Regarding outsourcing, are the prices fixed or is it based on an hourly cost? *The largest component is time and material, but the unit price has substantially grown over the last 5-10 years. Due to this, it is mostly based on a unit price cost because lump sums can lead to inaccuracies because of the number of variables present.*
- Is there ability to monitor branches and hit lines? *Theoretically, it is possible.*
- Could you data mine trends for outages? *Don't know if it is possible, but the science is there and it is improving, but setting up a reactive system might create an increased cost.*
- How is tree density determined? *It is the total number of trees managed.*
- Is it possible to clearly identify what data is needed from distributors in Ontario for them to be used as part of the peer group? *The cost of managing a tree in a town and in rural areas is different. If the Ontario distributors are primary suburban/urban distributors, their data will look much different than Hydro One's.*
- Is the ratio of management staff measured between Hydro One and the peer group? *There are comparative labor rates that are compared. The charge out rate, labor burden, and wage are all compared, but there is no conclusive data for quantity of staff.*
- Two of the goals listed were maintaining 100% clearance of ROW (Right of Way) and achieving ROW conversion over time. Is information available about the percentage of ROW converted for the peer group or the amount of ROW they targeted or achieved? *The peer group was not asked this question.*

Presentation #3 – Pole Replacement and Distribution Station Refurbishment Program Studies

Ben Grunfeld from Navigant and Ken Buckstaff from First Quartile presented the Preliminary Findings and Recommendations of the Pole Replacement Program and the Distribution Station Refurbishment Program Studies. Following their presentation, participants asked questions of clarification and provided feedback on the study. A summary of the questions and feedback is provided below.

Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Questions of Clarification

- How was currency adjusted? *All currency was converted to Canadian Dollars.*
- Why was it converted to Canadian dollars when operations and purchasing is done in Canada? *This is done to directly compare Hydro One to American companies.*
- Does it make sense to weigh the currency change based on the influence it actually has? *If the exchange rate keeps moving, yes, but for the majority of the comparisons in this study, a majority of the data predates 2014, so it does not have a major impact on this study.*
- How does Hydro One conduct physical inspections? *Hydro One only does limited physical testing.*
- When estimating life time costs, did you adjust the cycles? *No, they are actual inspection cycles used.*
- It would be nice to know the breakdown and cost of equipment in regards to tree maintenance.
- In cost per pole 'touched', what does 'touched' mean? *Inspected, replaced, or refurbished this year. This includes visual inspections.*
- There is a recommendation for a vigorous refurbishment program. Would this be more cost effective? *The recommendation is for Hydro One to consider introducing a vigorous refurbishment program. The cost effectiveness depends on a number of factors. If a pole is too old, then replacement makes sense, but for newer poles that are failing prematurely, there could be a case for refurbishment instead. Other utilities do have a refurbishment program. This is only applicable to a small percentage of poles.*
- Who determines the useful life of poles? *The utilities.*
- So many Hydro One poles are at end of life or past useful life. How important is the useful life statistic? *The useful life may not be reflective of the actual life of the poles.*
- Is it valid to examine looping and redundancies knowing that it will be cost effective? *This would not be effective across the board, but it would work in some instances. However, there are no written recommendations regarding this.*
- Is there specific data for each of the peer group members, such as how many poles each peer touched, and does this have any impact on the cost of poles touched? *This data is present, but as a percentage of their system, the cost is similar.*
- Did you draw any conclusions regarding trend and unit cost between 2012 and 2014? *There is a slight increase, but not for all criteria. Inflation was not measured, but it was not dramatically out of line when compared to the peer group.*
- Did you assess quantity of assets replaced? *The information is present, but this was assessed across the comparison group.*

- Did you assess the condition of assets? *No.*
- Did you find that as companies increase the amount of poles they were replacing, that they became more efficient? Did they decrease costs through economies of scale? There are generally economies of scale with this type of activity; however, across the comparison panel we did not perceive clear evidence of incremental economies of scale.
- How were replacement costs calculated? *Total dollars/total poles.*

Notable Themes and Discussion Points

Following the end of the final presentation, Dave Hardy noted the main themes and discussion points that arose during the presentation.

Total Factor Productivity

- Safety was a theme noted as a measure of TFP
  - Safety index; whether or not safety should be an output
- Whether TFP includes an appropriate value for reliability
- Whether there is scope for more detailed correlation of factors and effects to measure TFP
- Weight given to outages caused by weather and major events

Vegetation Management

- Exploring administration and overhead costs
- Additional metrics – safety, environment quality, customer service
- Cycle length and relation to cost and performance
- What data should and should not be part of the peer group comparisons
- When Hydro One should or should not be compared to the peer group

Pole replacement

- Data gathering and ROW maintenance
- Definition of useful life vs. actual life

Distribution Station

- Looping and redundancy
- Economies of scale

Final Comments

Following the final presentation and recap of notable themes, Dave Hardy provided time for each participant to note additional comments and questions they had regarding any of the sessions. The following comments and questions were noted.

TFP

- Have another other outputs been tested other than safety and reliability? If so, what were the results? *Unanswered during session.*

Vegetation Management

- Weather impact should have been considered more because Hydro One has some volatile regions. Vegetation Management cycle might need to be altered for areas with more volatile weather.
- Was the CN study adjusted for currency? *Yes*.

Pole Replacement Study

- Clarify terminology (i.e. "touched")

Miscellaneous

- When is Hydro One planning on filing the application? *At the end of the first quarter of 2017.*
- Who can further questions be directed to? *The worksheets will be sent out electronically following the meeting. Please submit any additional questions on the worksheet by October 12th.*

Wrap Up – Maxine Cooper, Hydro One

Maxine Cooper thanked participants for their feedback and encouraged them to share additional input and feedback via email/the soft copy of the worksheet. She also encouraged participants to be in touch at any point between this session and the next if they have any topics they want to discuss. Maxine noted that participants will have until October 12th, 2016 for written feedback.

PARTICIPANT LIST

The following is a list of participants that attended the meeting and the organizations they represent.

Stakeholders & Consultants

- Bayu Kidane, *Power Workers Union*
- Benjamin Grunfeld, *Navigant Consulting (Presenter)*
- Bohdan Dumka, *The Society of Energy Professionals*
- Brady Yauch, *Energy Probe Research Foundation*
- Chris Codd, *Ontario Energy Board*
- David MacIntosh, *Energy Probe Research Foundation*
- Dmitry Balashov, *Toronto Hydro-Electric System Limited*
- Harold Thiessen, *Ontario Energy Board*
- Ian Nokes, *Ontario Federation of Agriculture*
- Jane Scott, *Ontario Energy Board*
- Jie Han, Canadian *Niagara Power*
- Ken Buckstaff, *1st Quartile (Presenter)*
- Mark Garner, *Vulnerable Energy Consumer Coalition*
- Mark Rubenstein, *School Energy Coalition*
- Mike Jessop, *Ontario Power Generation*
- Rob Earle, *1st Quartile*
- Shelley Grice, *Association of Major Power Consumers in Ontario*
- Steve Fenrick, *Power System Engineering (Presenter)*
- William Porter, *CN Utility (Presenter)*

Hydro One Networks Inc.

- Erin Henderson, *Hydro One Networks Inc.*
- Maxine Cooper, *Hydro One Networks Inc.*
- Oded Hubert, *Hydro One Networks Inc.*
- Paul Brown, *Hydro One Networks Inc.*
- Jody McEachran, *Hydro One Networks Inc.*
- Karen Taylor, *Hydro One Networks Inc.*

Hardy Stevenson and Associates Limited

- Dave Hardy, *Facilitator*
- Jeremiah Pariag, *Note taker*

DISTRIBUTION RATE APPLICATION

Summary Report for Participant Review
Stakeholder Session #3
Wednesday November 30, 2016
DoubleTree Hotel by Hilton – The Toronto Ballroom
108 Chestnut Street
9:00am – 1:45pm

SESSION OVERVIEW

On November 30, 2016, Hydro One Networks Inc. hosted a third stakeholder session to discuss its upcoming Distribution System Plan (DSP) application. The purpose of this meeting was to present information on various aspects of that DSP application, including a high-level summary of extensive qualitative and quantitative stakeholder research undertaken by Ipsos, and to seek stakeholder comment on those presentations and research. Hydro One Networks will host a subsequent stakeholder meeting in February 2017 on its DSP, which, like this meeting in November, will inform Hydro One Network's final DSP application, to be submitted by March 12, 2017.

The stakeholder session included welcoming remarks from Oded Hubert [Vice President, Regulatory Affairs, Hydro One Networks] and facilitator Ted Griffith [The Fixers Group] in advance of presentations by Iain Morris [Partner, Human Capital Business Leader, Mercer Group], Sandy Guiry [SVP, Quantitative Research, Ipsos] and Brad Griffin [SVP, Qualitative Research, Ipsos], Jody McEachran [Senior Regulatory Advisor, Hydro One Networks], and Paul Brown [Director, Distribution Asset Management, Hydro One Networks]. Ted Griffith closed the stakeholder session in asking for any subsequent questions or comments, and thanking everyone for attending.

This summary was written by Ted Griffith and Steven Bright of The Fixers Group, who provided independent facilitation services for the stakeholder session. This report provides a high-level summary of the main points discussed by the participants as captured in "live" notes written during the meeting. It is not meant to be a verbatim transcript of the meeting.

Note that there are two appendices to this summary (attached separately), including:

Appendix 1. Individual Submissions Received After the Meeting
Appendix 2. Presentation Slides

Note: This summary reflects what happened during the meeting and does not include written feedback received after the meeting. Please see Appendix 1 for the additional feedback received.

FEEDBACK SUMMARY

The presentation from Iain Morris described key features of a comprehensive compensation cost benchmark study, the fourth in a series of such benchmark studies. He also presented the study's methodology and its findings. Sandra Guiry and her Ipsos colleague Brad Griffin presented high-level findings of quantitative and qualitative stakeholder research that they undertook for Hydro One Networks in the summer of 2016. Jody McEachran of Hydro One Networks spoke to slides on the Performance Metrics that Hydro One Network proposes to use in their upcoming DSP application. Lastly, Paul Brown of Hydro One Networks spoke to slides that outlined customer engagement impacts on the DSP.

Following each presentation, stakeholders asked questions of clarification and provided feedback. These questions and feedback are reflected in this summary. Each of the following sessions begins with key messages, which are intended to be read together with the more detailed feedback that immediately follows. Please note feedback from participants is in **bold**, while the responses by presenters (and in some cases a Hydro One Networks employee in the audience who answered many questions) are in *italics*.

Part 1 – Total Compensation and Benchmarking Study (Iain Morris, Mercer)

KEY MESSAGES

1. The 2016 study mirrors similar benchmark studies done in 2013, 2011 and 2008, thus allowing for reasonable comparisons and trend analysis across the time horizon of these four reports.
2. Many factors impact the results, among them long-term incentives and headcount reductions.
3. Overall, the compensation of Hydro One Networks is a multiple of 1.14 compared to the 50th percentile of the study group.

QUESTIONS OF CLARIFICATION

<u>Benchmark Methodology</u>

- **The "regional maintainer" position was pulled from the research. How many positions were previously in the study?** *I don't have those exact numbers but can follow up if you like.*
- **Enersource and Horizon are not in the current study, but they were in earlier benchmark studies, while PowerStream is in the current study. Any impact on the current review of not having Enersource or Horizon?** *We looked at the overall sample, and not having these two organizations is not a material change. What we found is representative, but there would be some effect in not having them.*

- **On slide 9, was overtime considered in base wage?** *No.*
- **On slide 18, what is total number of incumbents?** *Total number of employees captured is around 5,200.*
- **Does Hydro One own the survey data, or can others use the data?** *All participants get the data, not sure what they do with it*
- **Will share grants be incorporated in next study?** *The current study was a point in time study and share grants were not included this time, but they will be part of next study.*
- **Which is better, using the 50% percentile figures or an average?** *Percentile is better, more stable, less impacted by extreme values. Others may have other views ... this is our view at Mercer … but percent rank is standard way across the industry research.*

Variability in Findings

- **In looking at slide 15 we see different positions, some are up and some are down. Why the variance?** *There have been some changes within Hydro One, but sample group differences might better explain variances as these can have a bigger effect than other factors.*
- **What is the relative impact of short-term incentives on overall comp? Does this contribute to variability?** *Short term tends to vary with jobs (i.e., level of job) and across different organizations. There are many factors, and these vary. In the aggregate, short-term incentives vary less than what you might think.*

Hydro One Compared to Industry

- **In the "Represented" groups, the universe is primarily small companies, yet Hydro One surrounds them. So I think smaller utilities is the actual comparator in many cases.** *We try to balance everything, which is why we include LDCs. We could re-define and broaden the competitive market in this regard in terms of the survey, which would give us a somewhat different answer. But I'm confident that what we did in this survey is a good picture of what's happening.*
- **I realize you're replicating the study year over year, but the universe of Hydro One itself is significantly broader than other organizations. Are we really getting accurate assessment of those with whom Hydro One is competing for labour?** *Confident we're getting some good results in this survey. We could look more broadly, but the single panel approach we're taking in this survey was the better approach in terms of repeatability*
- **Am I correct that Hydro One is moving away from the industry benchmark? Are compensation and incentives at Hydro moving farther away from the overall average than Hydro One pensions are moving from the average?** *We didn't look at data that way, so the effects of pension changes don't show up here in the data set.*

- **Do you poll other industries? My concern is that our industry is moving away from other industries? Can we break out industry data?** *Different industries do different things. The energy sector pays well, but there is no hard data in our study on whether the energy sector is paying more and more compared to other sectors.*

Pensions

- **In terms of pension comparison, how did you actually do the comparisons with changes in pensions?** *We looked at plans for each incumbent. DC plans applied to only 6 out of almost 3,000 people surveyed. We used similar approach to all organizations involved.*
- **Do you have historical data to break out pensions?** *Yes.*

Part 2 – Customer Preferences (Sandra Guiry and Brad Griffin, Ipsos)

KEY MESSAGES

1. The role of this stakeholder research is to ensure that Hydro One's distribution investment plan is informed by customer needs, preferences and priorities.
2. The research reflects a total of nearly 20,000 customers and more than 20,000 responses between June and July 2016.
3. Overall, keeping costs as low as possible is customers' top priority.
4. More specifically, small and residential customers would accept a small tradeoff of increase costs for current reliability, while large customers have limited acceptance of rate increases.

QUESTIONS OF CLARIFICATION

First Nations

- **Referring to slide 7, what's the definition of First Nations?** *Ipsos received a list from Hydro One for modeling, and took names flagged as First Nations from that list.*
- **Referring to slide 9, do the residential and small business numbers include members of First Nations?***Theoretically, but not identified as such.*

Residential and Small Business

- **Asking about the Appendix slides, does the full report also focus on residential and small business customers?** *Yes it does.*
- **Relative to slide 7, why was the quota for small business customers not based on density?** *We can't answer that now and will get back to you.*

- **Looking at slide 21, you probed distribution impacts for larger customer but not for residential customers. Why?** *We thought residential customers would be more familiar with their overall bills than the specific delivery charge portion of their bills. But larger customers have a better understanding of that delivery portion, so we included that specific part in asking them about this.*
- **In the online workbook, did you ask residential customers about the delivery charge?** *No, as we feel they better understand their total bill.*
- **Were residential and small business participants in the eight online focus groups in same room such that they could ask their own clarification questions?** *These were online platforms with participants also on a conference call, which allowed for some discussion. Telephone and online surveys did not feature that sort of interaction.*

<u>Definitions and Methodology</u>

- **What's the definitional difference between C&I and large?** *We will default to Hydro One for detail, with Hydro then confirming that they would get back an answer on that question.*
- **Are results from the two one-on-one sessions included in the report?** *Yes.*
- **The survey said some customers were not invited. Why was that?** *Ipsos said Hydro One handled the recruiting, at which point a Hydro One representative said that they have 8,000 C&I customers, and many of those have multiple meters.*
- **Did the survey, in talking about the component parts of customer bills, specifically outline who is responsible for what?** *We gave respondents in the online workbooks, focus groups and workshops some detail of the bill, saying they could check their telephone script for details on how much detail this particular method gave on the issue.*
- **What is the definition of DG as used in the survey? Does it mean commercial operators?** *Ipsos said they weren't certain of the precise definition in this context. At which point, a Hydro One representative clarified that DGs are a wide range of embedded generators, and that they would have different points of view than traditional residential customer. They promised to follow-up with more details on this issue, which they did at the meeting's conclusion.*
- **Did participants in the qualitative interviews understand distribution portions?** *Mostly yes. And when they were not clear on specifics they spoke with Hydro One representatives in the meetings to provide clarity.*
- **How did the focus groups actually work?** *With members of the general population and small business customers we ran surveys and focus groups. For large business customers we ran consultative workshops. Ipsos ran these workshops with Hydro One speaking briefly and Ipsos facilitating the discussion for two to three hours. Hydro One representatives could address any detailed questions. Having Hydro One in the room did not prevent participants from speaking their minds.*

- **Did participants in the survey understand the full context of a proposed $1 increase?** *The wording of the question defines the increase as a percentage of the total monthly bill and the equivalent average dollar amount. It also states how much higher the total monthly bill would be at the end of the fifth year. The question also states that the monthly bill could still increase for other reasons which are outside the control of Hydro One.*
- **Ipsos ran nine in-person sessions but only seven cities?** *London and Hamilton had two sessions each due to large demand to participate.*
- **Do the illustrative scenarios in the research report use historical levels?** *Hydro One said they would follow up, which they did at the end of the meeting.*
- **How many investment years were embedded in the various scenarios?** *Five years.*

<u>Reliability</u>

- **With respect to power quality as outlined on slide 14, can Hydro One track power interruptions of under 1 minute?** *A Hydro One representative at the table answered at this point, saying yes, they do have that capability.*
- **Were reliability performance figures included in the survey questions?** *Yes, we gave information on average outages to both residential and large customers in the "informed" surveys.*

<u>Costs</u>

- **This survey was in field in this summer, in June/July. It appears that energy now (i.e., late November) is more on their minds now than six months ago. Does that affect the results?** *Surveys are snapshots, representing the feelings of respondents at the time. We couldn't say if results would be different now. A Hydro One representative added that price dominated the results in the full research report, findings that broadly align with current news and feelings on energy prices.*
- **Slide 11 is matter of fact in talking about cost. How intensely do people feel about cost?** *Cost, in one qualitative session in London session, was most the contentious issue. This is consistent with other findings, as cost was contentious in other cities, but to various degrees of intensity. Similarly, in the quantitative research, cost and rates were the most prominent issues. They were particularly evident when respondents were asked to trade off cost to other factors. Keeping costs low was the number one preference in these trade-off questions.*
- **In looking at slide 12 and the wording about "willing to accept" rate changes, what size majorities did the research find?** *Results for question 17, shown on slide 20, show that acceptances were "a little bit over" the majority.*

- **How does the 1.1% increase equate to Hydro's portion of the increase?** *A Hydro One representative said information given to the "informed" group showed Hydro One's increase in the scenarios. She added that there are many different customer classes, and it can be challenging to use the same messaging in asking the same questions in trying to get statistically valid responses that can be generalized across Hydro One's broad customer range.*

Part 3 – Performance Metrics

KEY MESSAGES

1. OEB set out four categories of customer outcomes: Customer Focus; Operational Effectiveness; Public Policy Responsiveness; and Financial Performance. Hydro One will provide information on all four, plus additional metrics relating to Customer Focus and Operational Effectiveness.
2. Hydro One proposes to cease reporting on four metrics from previous applications: Number of Replaced Poles; Number of Pole Top Transformers with PCB Oil; Residential and Small Business Satisfaction; Estimated Bills Issued as % of Total Issued.

QUESTIONS OF CLARIFICATION

Targets and the scorecard

- **Will the Hydro One application have rewards or targets?** *Only targets.*
- **Will Hydro One link these targets to its corporate scorecard?** *We're working on that scorecard now.*
- **Is residential satisfaction included on scorecard?** *This is a combined scorecard, so it's mixed.*

Reliability

- **In looking at slide 5, what is a distribution outage?** *Paul Brown of Hydro One answered this question, saying a distribution outage is an unplanned outage of more than one minute, and the lights are out. He added that transmission systems have built-in redundancies, but these back-ups don't existing in distribution systems.*
- **Does operational effective and system reliability, as outlined on slide #7, consider SAIDI and SAIFI?** *No, they are a work in progress on the momentary outages.*

Poles

- **In referencing slide #9, is the number of poles replaced covered elsewhere?** *Yes.*

- **What did you previously report on poles with PCB poles?** *We reported on the number actually replaced, but this is not large component of our overall performance metrics program. We're focusing more on work throughput than replacement.*

Billing

- **What does the fourth metric on slide 9, (i.e., "estimated bills issued as % of total issued) refer to?** *We look at this as a way to drive a reduction in the number of bills that are estimated and not meter-read. Our billing accuracy metric on correct meter reads will replace this metric. So it's a duplication, which is why we propose to cease reporting.*

Methodology

- **Are the findings on slide 5 based on surveys?** *Yes.*

Industry Comparisons

- **In looking at slide 6, are other utilities reporting on these five values such that you can compare against them?** *Factors 7 and 8 (i.e., OM&A per customer and OM&A per km of line) are standard industry comparators. However, factors 4, 5 and 6 (i.e., pole replacement – cost per pole; vegetation management – cost per cyclical km; and station refurbishment – cost per MVA) are not standard across the industry.*

Part 4 – Customer Preferences, Metrics and the Distribution System Plan

KEY MESSAGES

1. Customers told Hydro One four main things: keep costs low; maintain reliable service; large customers are more concerned about reliability and capacity; and overall willingness to accept a rate increase is limited.
2. Hydro One has implemented a number of productivity initiatives to reduce unit and operating costs.
3. Hydro One is executing on various productivity and efficiency enhancements to change and reduce its cost structure.

QUESTIONS OF CLARIFICATION

Risk Models and Demographics

- **Does distribution use the same risk model as transmission?** *No, distribution is performance based.*
- **In looking at "Plan B Modified" in 2022, will demographics be worse than now?** *We don't focus as much as demographics. Rather, we want our fleet to be the same, which we means we focus on condition more than demographics. Our investment plan is being driven by performance of the network, which is correlated to condition more than demographics.*

We replace defective assets, and we use demographic information to look ahead to volume requirements.

Rates and Capital Spending

- **Can Hydro One quantify its costs savings by the respective approaches?** *Yes, we could show how effective we're being in our upcoming rate application.*
- **In looking at slide 28, will rates go up after 2018? And why is the dip in that graph important?** *We will have some fixed, non-discretionary expenditures in 2017-18 that will impact our 2018 numbers.*
- **Is the aim of Plan B Modified to reduce capital expenditure or rates?** *A Hydro One representative said Hydro One went through a very iterative process that included several levels of the organization – including up to the Board of Directors – to try and find a balance between rates, preferences and assets in 2018 and throughout the full five-year period. So when talking about the investment plan, we're talking about capital spending and the OM&A envelope interacting to create outcomes that are valued by the customer. In other words, we're trying to find a balance of capital and OM&A and a rates profile for 2018 and the full five years that is consistent with regulatory and customer expectations. A lot of that is found in productivity improvements and in doing the most we can with money we already get before we ask for more.*
- **Will rates go down in 2018?** *No. Capital spending may go down, but not rates.*
- **In looking at slide 22 (i.e., power quality initiatives), will there be incremental spending over the next five years on this quality issue?** *Yes, but these will not be material costs in grand scheme. Rather, it will be extra funding within the existing envelope, as we know there's a quality issue to be addressed.*
- **In referencing station improvements and pole replacements, what accounts for the uptick at end of planning session?** *Our estimates are tempered until 2018, then flat in 2019-2021 to allow for large transmission capital improvements. The 2022 uptick is to account for the planned smart metering re-fresh.*

Reliability

- **Is the use of "reliability" on slide 27 a judgment or a calculation comment?** *We're getting better at forecasting the reliability impact of things such as pole failures as an example. For example, in looking at the condition of our asset fleet, we're getting better at saying that if it degraded by X, then it will have X impact.*

<u>Productivity</u>

- **Looking at Hydro One's productivity initiatives on slides 7-10, are recently undertaken initiatives already embedded, or will you undertake them in the upcoming planning period?** *Some initiatives are in the future, with their respective benefits accruing early in the 2018-2022 time period. Various investments are built into our plan in various stages of implementation in 2017, with a bias towards driving for cost savings early on in that planning cycle.*

CLOSING COMMENTS

After discussion on all of the presentations, Ted Griffith went around the table asking every stakeholder if he/she had any further questions. He added that they would all receive a follow-up email the next day to see if they had any subsequent questions and, if so, they would have an additional seven days to submit those questions.

<u>Process going forward</u>

- *In these closing questions, one stakeholder asked about the process going forward with respect to Hydro One's DSP and stakeholdering. In response, a Hydro One representative said that the OEB suggested Hydro One consider third-party input into the DSP to ensure that it meets best practices. Hydro One therefore contracted an external firm to do exactly that, which Hydro One will share with stakeholders on a meeting scheduled for February 8, 2017. Input from that meeting will be incorporated into Hydro One's final filing.*

<u>Definition of DG</u>

- *A Hydro One representative provided answers to a question posed earlier in the stakeholder session about the definition of a DG customer, saying that a residential and/or small business customer could in fact be included in this DG definition in the research.*

<u>Base case scenarios</u>

- *As a follow-up to an earlier question, a Hydro One representative provided all attendees with more information on the base figures used in the investment scenarios previously discussed. She said that scenario #1 was the "status quo", scenario #2 was "improve", and scenario #3 was "degrade", adding that the first of these scenarios aligned with Plan B Modified as outlined in Paul Brown's slides. Maxine Cooper of Hydro One agreed to confirm that with a follow up email.*

PARTICIPANT LIST

The following is a list of all attending participants and their respective organizations:

Stakeholders
1. Andrew Blair – *Power Workers' Union*
2. Kim McKenzie – *Power Workers' Union*
3. Bimbola Ayo – *Toronto Hydro*
4. Brady Yauch – *Energy Probe*
5. David MacIntosh – *Energy Probe*
6. Bill Harper – *VECC*
7. Harold Thiessen – *OEB*
8. Mark Rubenstein – *SEC*
9. Matthew Higgins – *Toronto Hydro*
10. Michael Jessop – *OPG*
11. Patrick McMahon – *Union Gas*
12. Scott Pollock – *CME*
13. Shelley Grice – *AMPCO*
14. Vicki Power – *Society of Energy Professionals*

Hydro One and Consultants
1. Iain Morris – *Mercer (Presenter)*
2. Sandra Guiry – *Ipsos (*Presenter)
3. Brad Griffin – *Ipsos (Presenter)*
4. Oded Hubert – *Hydro One Networks (HONI)*
5. Jody McEachran – *Hydro One Networks (HONI)*
6. Paul Brown – *Hydro One Networks (HONI)*
7. Karen Taylor – *Hydro One Networks (HONI)*
8. Maxine Cooper – *Hydro One Networks (HONI)*
9. Erin Henderson – *Hydro One Networks Inc. (HONI)*

The Fixers Group
1. Ted Griffith – *Facilitator*
2. Steven Bright – *Note taker*

Hydro One Networks Inc.
2018-2022 Distribution Rate Application

Stakeholder Session #4

Summary Report

Doubletree Hotel by Hilton
Toronto Ballroom, 2nd Floor
108 Chestnut Street
Toronto, Ontario

February 8, 2017

Session Overview

Hydro One Networks Inc. hosted a series of stakeholder sessions with the purpose to exchange information with its stakeholders regarding the 2018-2022 Distribution Rate Application. This summary report is a synthesis of the information and discussion from the fourth, and final, session. Additional meetings with Metis and First Nations communities will also be held. Hydro One is aiming to submit the application at the end of March with an update in June 2017.

Oded Hubert, Vice Present, Regulatory Affairs, Hydro One Networks, welcomed stakeholders to the event and provided introductory remarks. Mr. Hubert highlighted the importance of early and ongoing engagement with stakeholders. The full-day session was facilitated by Tracey Ehl of Ehl Harrison Consulting Inc. and included four presentations:

1. 2018 to 2022 Custom Incentive Rates Application Framework (Oded Hubert)
2. Econometric Benchmarking of Hydro One's Total Distribution Costs (Steve Fenrick)
3. Cost Allocation Methodology, Rate Design and Bill Impacts (Henry André)
4. Core Capital and OM&A Work Programs (Paul Brown)

A facilitated discussion followed each of the presentations. This summary report reflects the questions asked, the responses provided, information requested and any additional comments and advice provided by stakeholders during the session. Stakeholder questions are generally shown in bold text, with the responses 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. These notes also include links to additional information requested by participants such as the results of the customer engagement process, benchmarking studies, a previous executive compensation study, and notes from previous stakeholder sessions.

Stakeholder Discussions

A. 2018 to 2022 Custom Incentive Rates Application Framework (Oded Hubert)

Summary:
Prior to commencing, Mr. Hubert provided and explained a Disclaimer regarding Forward Looking Information for participant review. Mr. Hubert then provided an overview of the distribution rate application framework. He emphasized that the application is aimed at balancing competing priorities, those being asset needs, customer needs and preferences, and rate impacts. He provided a review of the 5-year revenue requirements, the estimated rate changes over the period and the contributing factors. Mr. Hubert also provided an overview of proposed Earnings Sharing Mechanisms (ESM) and Capital In-Service Variance Account (CISVA).

Key messages:

- Acquired LDCs will be fully integrated in 2021.
- The load forecast is still being finalized.
- There will be a load forecast update in 2020 for setting 2021 and 2022 rates.
- The Hydro One Board of Directors approved the Transmission Business Plan and the Distribution Business Plan in December 2016.

Discussion:

1. **Costs are going up but consumption is going down (referencing 3Q report). Why aren't costs reduced when consumption drops?**
   Declining consumption is a contributing factor to the rate increase. Customers are looking to Hydro One to cut costs and increase efficiency. However, a number of our costs are fixed and most are unrelated to the consumption, such as customer service and our call center. This application builds in a number of approaches to increase productivity and efficiency.

2. **Should there be a variable component built into the forecasted OM&A?**
   No. It is recommendation that this question be parked at this time.

3. **When you take over a local distribution company (LDC) are there any benefits to ratepayers? Does this ever result in reduced rates?**
   Acquiring LDCs can result in a number of synergies and these synergies can be passed on to customers.

4. **Is there a business plan/strategic plan underpinning this application?**
   Yes, on December 2, 2016, the Board approved the Transmission Business Plan and the Distribution Business Plan. The latter is the basis for this application. The OEB Handbook is also a guiding document for this application.

5. **What is the basis for the addition of the custom capital factor? Will it be adjusted to reflect 2017 OEB's ACM/ICM parameters?**
   A similar approach was taken in the Toronto Hydro application. The custom capital factor will be applied in all four years (following the initial cost of service year).

6. **For the acquired LDCs, will rates be harmonized? What will the impact be on rates of the acquired LDCs?**
   Most customers of the acquired LDCs will be assigned to new "acquired" rate classes. The impact on their rates is still being finalized. It appears that rates for residential customers of the acquired LDCs will see an increase commensurate with that of other Hydro One customers.

7. **Why did you decide on a deadband of 100 basis points to trigger the ESM?**
   This threshold number was selected as it is commonly used and has been accepted by the OEB and intervenors in other filings. It seems to be reasonable for aligning the customers' and the utility's interests in this application. It was not derived using any special analysis.

8. **Will this application include a capital forecast for the acquired LDCs?**
   Yes, this will be included. Also, the load forecast will be updated for 2021 and 2022.

9. **For the Capital In-Service Variance Account (CISVA), how was the 2% deadband determined? It appears that the stretch factor is already included.**
   It may be very difficult to hit 100% of forecasted in-service additions in any given year. 2% seems reasonable as it provides flexibility in work program execution and allows for a small carry over from year end to the beginning of the next year, where needed.

10. **Is there any interaction between the Earnings Sharing Mechanism (ESM) and CISVA?**
    The ESM will be structured in consideration of the CISVA to avoid double counting of over-earnings.

11. **Is there a financial incentive to reduce energy losses?**
    The losses are a pass through, so incentives would come from planning processes, and are not tied to revenue requirement.

12. **Would you be willing to consider making Line Losses part of revenue requirement?**
    This wouldn't be consistent with our revenue model or how the revenue requirement is established, using the OEB's current methodology. Hydro One does take actions and make investments in phase balancing and through re-conductoring that reduce losses.

13. **Is your intention to apply an annual rate adjustment?**
    No, except as required by the OEB for the purpose of rate setting (e.g. to derive new rates each year that reflect the predetermined load forecast adjustment). However, there will be a number of rate adjustments in 2021 to reflect the ROE, Load Forecast and OM&A associated with the acquired LDCs.

14. **Will the capital factor apply for all five years?**
    Yes, it will apply for all four years, following the initial rebase year.

15. **Is Hydro One comfortable with the inflation rate? Should a different inflation index apply to a Revenue Cap than to a Price Cap? The inflation rate should be applied to the overall rate.**
    Yes, Hydro One is comfortable. We had not contemplated that a different inflation factor would apply for a Revenue Cap.

16. **There is still confusion as to how acquired LDCs fit into the application? Are they licensed until 2021?**
    Operationally, the three acquired LDCs have been integrated but each had a five-year rate freeze in place. For two LDCs, this rate freeze is until 2021. We are proposing to extend the rate freeze for Norfolk by an additional year (i.e. 6 years), so that all three LDCs will be integrated in 2021 for rate setting purposes.

17. **How will Hydro One demonstrate that some of its ISVA shortfall was the result of productivity?**
    We have not determined the specifics for demonstrating this, but we believe it is an appropriate adjustment. The onus will be on Hydro One to demonstrate such savings to the OEB's satisfaction.

18. **Are all of the rate riders included in the rate impacts shown here, or will there be additional ones in the application?**
    Yes, they are all included here and shown in the rate impacts.

19. **Regarding the regulatory process, 2018, would you utilize a mechanistic adjustment for OM&A, and a capital factor that emulates a cost of service approach (not intended to sound derogatory) for Capital.**
    Yes, as applicable.

20. **Are senior managers going to continue to be rewarded for exceeding the OEB-approved level of in-service additions? The targets should be aligned with OEB-approved levels.**
    Hydro One will align these targets with OEB approved levels.

21. **Do you have your Capital Factor stated as a % for each year?**
    This number isn't available at this time.

22. **Why does OM&A increase at a greater pace in 2021?**
    The incremental OM&A of the acquired LDCs will be added in 2021.

23. **Is the line loss factor included in the scorecard?**
    No, it isn't included.

24. **Could you incorporate an incentive to reduce the line loss factor? If possible, this could be part of the score card.**
    It is possible to identify specific economic investments required to reduce line losses. This will be taken under consideration.

25. **You have identified costs over 5 years including the capital factor. Is there a separate mechanism to capture Other revenue?**

    A forecast of Other Revenue is provided for each of the 5 years in the application term.

B. Econometric Benchmarking of Hydro One's Total Distribution Costs (Steve Fenrick)

Summary:
Mr. Fenrick presented the findings of an econometric study conducted to identify an appropriate stretch factor for upcoming rate application. The presenter highlighted the robust data set compiled as part of developing the benchmarking model. The data variables, results from model, and recommendation were provided.

Key messages:

- Hydro One has a unique service territory.
- Distribution costs are not really sensitive to energy sales.
- One challenge is a lack of comparable data sets in Canada. To overcome this, US examples were utilized.
- Stakeholders identified interest in incorporating additional data sets (such as BC Hydro and Québec Hydro), and possibly removing some data sets that are not as similar to Hydro One as others.
- The recommendation can be updated if new data becomes available

Discussion:

1. **With a sample of 380 utilities, checking quality of the data seems very challenging. How do you address this?**
   We conducted a screening process of the entire data set to identify any outliers in terms of peak demand, customers, and costs. Outliers were disregarded.

2. **Did you consider narrowing the sample size?**
   No, narrowing the sample size was not considered. Typically, a larger sample size is more desirable. We looked at all utilities with 10,000 customers and above. No other limiting factors were applied. This was done so as to be inclusive rather than arbitrary.

3. **Your sample size is 380 utilities. Are all of them in the United States?**
   Yes, all of the utilities in the sample are American. American municipal utilities were not included as they do not have standard reporting.

4. **Do you know the percentage of the rate paying population that were sampled?**
   This number is likely high, although the exact number is not known.

5. **Why were Ontario utilities left out?**
   Comparative data is not readily available. Each utility would have to be approached individually.

6. **Was a variable to account for transmission incorporated into the model?**
   No, this variable was not used as it was not significant. Rural utilities are distribution only, and this could potentially skew results.

7. **How are differences related to Canadian and US currency addressed?**
   The differences are addressed through having both the costs and input prices in the same and original currency of the utility. This enables the comparison to be in real numbers and accounts for the differences between Canadian and U.S. currencies.

8. **In your sample, was there an attempt to come up with a balance of urban/rural similar to Hydro One?**
   Yes, the data sample encompasses a range of both urban and rural utilities. PSE accomplished this through including both the U.S. investor-owned utilities and U.S. rural electric cooperatives. This allows us to design model variables/estimates and then the compare against Hydro One. The sample is not meant to exactly mimic Hydro One, but rather to correlate variables to costs (i.e. if one customer is added, this is the resulting cost impact) and identify cost relationships.

9. **The large sample size used for Hydro One is different than the approach used for Toronto Hydro. Why?**
   Generally, more (relevant) data is better. For Toronto Hydro, 150 large utilities were sampled. There were no highly rural utilities in that dataset.

10. **Are you able to forecast productivity for the five year revenue period?**
    Yes, this is possible if the required inputs are available. This was done for both Toronto Hydro and Hydro Ottawa.

11. **Is this data being used in many studies?**
    Both the IOU and rural electric cooperative data sets have been utilized separately for previous studies. This is the first time that we have combined the urban and rural data sets.

12. **What does the range of benchmark scores look like for rural utilities?**
    There is a natural bell curve with a cluster around 0%. The range is usually around +/- 40 or 50%.

13. **A better measure of cost would be to use kilometre of line per customer instead of square kilometre per customer.**
    While this has been tried, a choice had to be made between variables and it is felt that square kilometer per customer is a stronger variable.

14. **Hydro One has a challenge with long lines which result in reduced efficiency. Is it possible to look at particular companies that are 'most like' Hydro One?**
    It is recognized that Hydro One has a unique service area with some areas of very low density. It was felt that the range of utilities in the data set was appropriate because this analysis was performed to derive a correlation between distribution costs and various independent variables. For this reason, similarity to Hydro One is not necessary for the correlation to be determined. It is possible to run other comparators if data is available.

15. **Please confirm that the +28% difference from the benchmark includes consideration of the difference in currencies (Canadian vs US)?**
    Yes it does, as each is considered in its own currency for both the costs and the input prices and therefore considered in real and comparative values.

16. **How is a 0.6% stretch factor derived when productivity is 28% above the benchmark?**
    The stretch factor is based on the OEB decision. Since the Ontario distribution industry has been found to have negative productivity, the 0.6% productivity target for Hydro One is a target that requires the company to outpace the industry productivity by an amount

far beyond the 0.6% target. The 0.6% stretch factor amounts to a very challenging target.

17. **It appears that Hydro One's delivery costs are twice that of other utilities in the study.**
    Hydro One serves a far more challenging service territory that necessitates higher cost levels than its peers. Reliability and customer service performance also factor in to this.

18. **There are other methods that could have been utilized for this study. Why did you choose this econometric benchmarking?**
    Economic benchmarking is superior because it is rigorous in that more variables are utilized than in other methods and it is Board tested and accepted.

19. **Hydro One has never participated in the annual client rate survey (survey of 62 companies)? Why?**
    Hydro One indicated they are not familiar with the study and therefore have no comment.

20. **Hydro One has a challenge with long lines in vast rural areas. Can we look at particular companies that are 'most like' Hydro One like BC Hydro and Hydro Quebec?**
    To explore further the 'density' characteristic, companies like BC Hydro and Hydro Quebec could be considered in the future. Making sure the cost reporting is able to provide the same cost definitions may be a challenge. Comparing directly would be problematic because Hydro One is unique in their service territory.

21. **Why were case studies from Hydro BC and Hydro Québec not included? The service areas may be more similar than many of the utilities in the data set utilized.**
    Data reporting and availability is the issue. If the data was available, it could be utilized as well.

22. **Did study results show any trending over time related to costs and productivity?**
    Similar to the TFP study findings, there was some decline in performance since 2002. Also similar to the TFP study findings, this decline in performance has leveled off in recent years.

C. Cost Allocation Methodology, Rate Design and Bill Impacts (Henry André)

Session description:
Mr. André discussed four broad areas: load forecast; cost allocation; rate design; and, bill impacts. Mr. André noted that 2018 to 2022 will continue to include the seasonal class as part of rate design. The presentation highlighted changes in 2021 including the proposed 6 new acquired rate classes.

Key messages:

- Lower than forecast customers and consumption, relative to 2017 approved levels, are largely due to the negative economic situation in 2015 and 2016.
- The bump up in 2021 reflects acquired customers/rate classes.
- All R/C ratios for existing Hydro One rate classes are within Board approved ranges except for the Dgen class.
- Some R/C ratio adjustments for new acquired general service classes are anticipated
- Bill impacts across rate classes will vary from the average values shown

Discussion:

1. **Do the new LDCs have any seasonal class customers? Why?**
   No we have not identified seasonal customers within acquired utilities. To be consistent with Board decisions, we also haven't broken out the acquired service territory into Hydro One density zones. Hydro One has had a seasonal class since the 1960s and the Board has agreed with this. The Board has initiated a new proceeding to eliminate this rate class and there is a report before the Board on this matter.

2. **There are rebates for conservation. Isn't this counterproductive to Hydro One's bottom line?**
   This is a fair point. These targets are established by the IESO and Government. To the extent that load declines due to conservation, Hydro One must increase rates in order to collect its revenue requirement. However, for an individual consumer, the assumption is that the costs saved through CDM (lower consumption) should at least offset rising rates, and hence result in total lower energy costs for the consumer.

3. **Is the fourth quarter forecast available?**
   We are not aware of what the fourth quarter results are at this time.

4. **Are Hydro One CDM forecasts different than provincial forecasts?**
   My understanding is that the forecasts and historical values used for load forecasting are consistent with IESO data. This will be confirmed.

5. **Is it correct that the Dgen rate will go up?**
   Yes, Dgen customers were severely underpaying. To address this gap, further R/C ratio adjustments will be needed until 2020.

6. **Can we expect year-end 2016 updates in the June update submission? Will load forecasts be available at the same time?**
   Hydro One will use the latest forecast, including 2016 updates, as part of its filing at the end of March. The June 'blue-page update' will reflect audited 2016 numbers for the purpose of finalizing deferral and variance account disposition and riders.

7. **How much consideration was given to doing bump up of rates across years to smooth impacts?**
   Moving revenues across years to smooth impacts was considered in Hydro One's last distribution customer IR application, but the Board did not accept this approach.

8. **How do rates for acquired LDCs compare with other rates?**
   Residential customers of acquired LDCs will see an increase over current distribution rates similar to what all customers are experiencing. General Service acquired customers may see larger impacts as a result of needing to adjust R/C ratios.

9. **How long do you expect to keep 6 new rate categories?**
   Hydro One is hoping to minimize the addition of new rate classes. It is uncertain at this point how long the new categories will be maintained, but we expect to use them for other acquisitions, such as Orillia, as appropriate. (It was clarified that the Orillia application is not yet approved.)

10. **Are the rates lower in LDC territories?**
    Typically, yes they are.

11. **Can you provide an update on the seasonal class? Will it be eliminated? (directed to OEB staff)**
    OEB response: The Board has indicated that it would be eliminated. The procedures to do so have not been established yet. The Board has initiated a proceeding to review Hydro One's updated report on this matter. This proceeding will get under way over the next month or two.

    Hydro One response: Until the outcome of the Board proceeding is known, Hydro One will not include the elimination of the seasonal class in its filing.

12. **Will you have the ability to update any aspect of the load forecast over the 5 year period?**
    The same load forecast as proposed in the application will be utilized over the 2018-2020 period. The load forecast will be updated as part of annual 2020 submission for 2021-2022.

13. **Clarify the factors developed to adjust fixed assets allocated to acquire rate classes.**
    At a high level, factors have been developed to true up the amount of assets allocated by the cost allocation model to the new acquired classes with the amount of acquired utility assets at the time of acquisition plus any in-service additions to 2021. This will be detailed in the application.

14. **Will the LDC customers permanently stay in these new rate classes?**
    Yes, that is the thinking right now.

15. **Do you have any classes where the expected impact is 10% or more?**
    Potentially, however we will adjust using a phased approached so impacts won't be higher than 10%.

16. **How does the 5.8% rate increase for 2018 compare to other companies?**
    To our knowledge, this comparison hasn't been done.

17. **Could you clarify whether the revenues are going up by same %? (slide 8)**
    Yes, this is consistent with the revenue cap approach. We will assess rate impact disparities, which may prompt a look at alternatives that take into account the impact of changing load forecast by rate class.

18. **Have you done a re-fresh of the rate classifications?**
    Yes, a rate class review has been completed and it will be implemented in January 2018. Only a relatively small number, 12,000, customer will be impacted.

19. **There are two sets of Guidelines for Revenue-to-Cost Ratios, the generic requirements, and the OEB's decision for Hydro One. Which are you referring to?**
    Hydro One will be using the broader Board ranges if it helps mitigate bill impacts.

20. **Does the update to class load profiles include smart meter data?**
    Yes, it does.

21. **Is there a gap where hourly metering is not available?**
    There are some customers for whom hourly data is not available, but these will be few in number and not expected to impact the load shapes. This will be confirmed.

22. **Did you notice an impact on revenue - cost ratios as a result of updating load shapes?**
    None of Hydro One's R/C ratios are getting driven outside of the range, so there hasn't been a prompt to look in greater detail. Given Hydro One has historically updated our load shapes, a large impact would not be expected.

23. **When a new utility is acquired, should Hydro One, through policy, be required to apply the same rate setting methodology as it does for its legacy customers? The Hydro One costs to deliver services seems to be higher than that of other rural utilities.**
    This is not the approach Hydro One has adopted for this application. Hydro One is trying to accommodate the Board decision to align rates with costs to serve acquired LDC customers.

    Stakeholder comment: During a previous proceeding support was expressed for reflecting the true cost of service to newly acquired LDC customers.

D. Core Capital and OM&A Work Programs (Paul Brown)

Session description
Mr. Brown provided an overview of the Distribution System Plan (DSP). Mr. Brown highlighted key findings from the recent (July 2016) customer engagement and how this has informed areas of priority for the application. In addition, a number of cost management strategies to reduce rate impacts were presented.

Key Messages
- Through customer engagement, the number one priority identified is keeping costs low. This is followed by maintaining (not improving) reliability levels.
- This application aligns with customer preferences: keep costs low; maintain reliable service; address reliability and capacity concerns raised by large customers; and, manage rate impacts.

Discussion
1. **Do you have a target for SAIFI?**
   Yes. This will be included in the rate application.

2. **For investments that target improvements for large customers, will costs be directly allocated to them?**
   Yes they will. In most cases, these customers are served by the sub-transmission system, and the costs will be recovered from the ST rate class.

3. **Will there be a reliability risk model in the application? You mention it, but it doesn't seem as integral?**
   That is correct. Reliability performance, rather than reliability risk, is more clearly linked with our distribution investments. This is because the distribution system does not have the same level of redundancy as the transmission system. As a result, equipment failures lead directly to interruptions and reflect in lower reliability performance. We look at investments across classes and will largely base investment decision on condition and performance.

4. **Have the four customer preferences impacted this rate application?**
   Yes, the customer preferences and priorities shaped the approach to this application.

5. **Will you be following normal Board filing format?**
   Yes, the application will be aligning more closely to this format.

6. **In previous sessions, we were talking about benchmarking studies. How do they fit into the current plan?**
   There were three studies: pole benchmarking; distribution station benchmarking; and, the vegetation benchmarking study. The outcomes of the studies either validated or challenged unit costs to undertake work. For example, the costs are slightly high regarding station costs. For poles, we gained a sense of the impact of technologies we are investing in to potentially extend the service life. The vegetation benchmarking study also had impacts that we are looking at.

   For additional information, please visit the information posted for the October 5, 2016 session at http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx .

7. **Are you proposing to adjust depreciation rates for any assets? It would seem to me that you should adjust. In the application, there should be an explanation as to why the current depreciation rate is still appropriate.**
   Hydro One is proposing to keep the same rates as in the previous application. Hydro One has found that (some) older assets are still useful beyond their service life as they were either over-built or running at lower capacities. Comparatively, some newer assets aren't performing as well as expected. Overall, on a fleet basis, the performance remains aligned with past expected service life numbers. Also note that useful life for depreciation is not the same as the useful life for assessing condition.

8. **Provide additional details regarding the customer engagement process.**
   Ipsos was contracted to undertake an in-depth engagement process that included customer surveys (online and by phone), focus groups, and workshops (with LDCs, large distribution account customers, and Commercial/Industrial customers). [Also see Question 24.]

9. **Is there going to be a more robust quantification of efficiency savings?**
   This will be given further consideration. There will be a new approach to this in the application with solid ability to quantify the efficiency savings.

10. **Is the customer power quality program new?**
    This is new for distribution customers. Hydro One is working with customers to address power quality issues through on-site monitoring. Some businesses are quite sensitive to changes to power quality. In certain facilities, audits have been conducted to identify approaches to becoming more resilient. This initiative has been well received by large customers.

11. **Toronto Hydro subcontracts pole replacements. Does Hydro one do this?**
    Some components of pole replacement (i.e. digging, drilling) are subcontracted, but full pole replacement is not.

12. **What is the operational metric for "greatest value for customers" so that we can understand in the future if we are hitting it? (slide 5)**
    This is correlated with the customer preferences shown on slide 3. There are a number of related metrics in the application.

13. **A lot of money is being spent on vegetation management, with the intent of hitting a 7 year cycle. Why was this not achieved?**
    This is partly due to the catch-up that is necessary.

14. **Are you going to have a metric to get costs in-line?**
    Yes, there is plan to address cost efficiencies through proposed metrics.

15. **Can some of the line care be contracted out?**
    This is not currently in the investment plan from a work implementation perspective.

16. **Clarify the slide regarding asset condition and use of an age proxy.**
    In the 5-year plan, Hydro One has specifically identified assets with health issues based on condition. Asset condition (not age) is driving the plan.

17. **Is the pole replacement program driven by the condition of the pole or are there other reasons for replacement? Are the majority of pole replacements a result of the pole itself as opposed to circuits etc.?**
    Poles are replaced for a variety of reasons such as putting taller poles in for new feeders or moving them for roadway widening. In the process of these other drivers, some poles that are in poor condition get replaced. The pole replacement program, however, is to manage the remaining fleet of poles whose condition has been assessed and that need replacement as a result of their poor condition.

18. **Is there a reliability metric that deals with outage impacts that will be included in the application?**
    Yes, there is a metric that addresses this.

19. **With metrics, the difficulty is how they take on meaning. How will they drive behavior? It would be helpful to be as specific as possible regarding the purpose of specific metrics within the application (i.e. how is it expected to be implemented, monitored etc**.).
    In addition to the OEB's Distribution score card measures, there will also be outcome measures. It is a good point. Performance measures always have to be balanced, as there are tradeoffs involved, and one of the benefits of a robust set of performance measures is the further discussion that can result from them.

20. **Do municipalities contribute to the cost of poles replaced as a result of municipal road widening projects?**
    Yes, there is a formula for cost sharing.

21. **Do you have a third party review the condition of the assets?**
    No, however a third party did review the distribution system plan.

22. **Is Hydro One considering burying the lines?**
    This has been looked at it, but the economics aren't really there.

23. **Has a study been done regarding the executive compensation package?**
    Yes. The compensation studies can be found with the following links.
    - Hugessen Consulting: Preliminary CEO/CFO Pay Benchmarking
    - Towers Watson: Hydro One Executive Compensation Benchmarking
    - Towers Watson: Hydro One Competitive Compensation Review

24. **Please provide additional information about the customer engagement process, as well as the results.**
    This information can be found in the November 30, 2016 presentations at www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx.

Session Wrap-up

As a summary of the day's discussion, participants were asked to provide their 'top' priority for Hydro One to consider as the Company finalizes the distribution rate application, or feedback on the stakeholder process. These ideas are summarized below.

1. Act more like a private corporation, less like public service. Take ownership of results.
2. Connect the executive compensation with benchmarks in reaching results and realizing efficiencies (i.e. lower rates).
3. Consider contracting out major expenses.
4. Consider comparing more closely with 'like' companies such as BC Hydro and Québec Hydro.
5. Get the rate levels down.
6. There is a marked improvement in this application. Building from the transmission rate application, it is suggested that Hydro One prepare a proper presentation for compensation (2K).
7. Include meaningful compensation schedules to help our assessment.
8. Be transparent in what is being proposed by making clear and direct linkages to explain how outcomes were derived.
9. Prepare and include a succinct guide to the filing for inclusion in part 1 of the application.
10. The studies by Mercer are circular in that they have no relationship to what others are making. A study of compensation should include consideration of how Hydro One wages and wage changes compare both to other companies and also within Hydro One. Horizontal studies should be completed to understand how executive compensation compares to that of people in the field.
11. Hydro One is doing good work on metrics, but this needs to be supported by the specific reasons "why", otherwise, they are just metrics. It needs to be explained why these metrics are useful for change making.
12. Appreciation was conveyed to Hydro One for including other utilities into the process, as it helps the entire sector to move forward. The courtesy will be returned for future applications.

All stakeholders were thanked for their participation. Additional questions and/or comments were invited within seven days following the session.

Appendix A: List of Participants

The following is a list of all attending participants and their respective organizations:

Stakeholders
Shelley Grice – AMPCO
Nicholas Copes – Balsam Lake Coalition
Bill Cheshire – Balsam Lake Coalition
Marion Fraser – BOMA
Marion Fraser – BOMA
Julie Girvan – CCC
Scott Pollock – CME
Cary Ferguson – DeMarco Allan LLP
Brady Yauch – Energy Probe Research Foundation
David MacIntosh – Energy Probe Research Foundation
Ian White – Federation of Ontario Cottagers Associations
Jack Gibbons – Ontario Clean Air Alliance
Harold Thiessen – OEB
Jane Scott – OEB
Andrew Bodrug - OEB
Saba Zadeh – OPG
Andrew Blair – Power Workers' Union
Kim McKenzie – Power Workers' Union
Mark Rubenstein – SEC
Alison Fraser – Shared Value Solutions
Bohdan Dumka – The Society of Energy Professionals
Vicki Power – The Society of Energy Professionals
Andrew Sasso – Toronto Hydro
Daliana Coban – Toronto Hydro
Patrick McMahon – Union Gas
Bill Harper – VECC
Mark Garner - VECC

Hydro One and Consultants
Steve Fenrick – Power System Engineering Inc.
Uri Akselrud - Hydro One Networks
Henry André – Hydro One Networks
Oren Ben-Schlomo - Hydro One Networks
Paul Brown – Hydro One Networks
Erin Henderson – Hydro One Networks
Oded Hubert – Hydro One Networks
Jody McEachran – Hydro One Networks

Tracey Ehl – Facilitator
Jodi Ball – Note taker

Hydro One and First Nations Engagement Session
Mandarin Room, DoubleTree by Hilton
Thursday, February 9, 2017

SESSION REPORT

TABLE OF CONTENTS

Note Taking Summary of Hydro One Key Messages

- There is a new team at Hydro One who is committed to working with First Nations through honest and respectful engagement.
- Hydro One is working to improve service, responsiveness, and reliability of the power system.
- Hydro One committed to finding solutions to address the affordability challenges faced by First Nations.

Note Taking Summary of First Nations Key Messages

- Hydro rates are burdensome for many First Nations, in particular for Elders and vulnerable people. There needs to be immediate and significant action to mitigate the high costs.
- First Nations are interested in exploring the idea that a unique rate for First Nations should apply to First Nations people both on and off reserve.
- First Nations must enjoy the benefit of resources that are drawn from their territories.
- Hydro One staff working in First Nations communities needs some level of cultural awareness training. This should include knowledge about land regimes and treaty relationships.
- Many First Nations are willing to engage with Hydro One in order to achieve results for First Nations communities and people.

WELCOME

Mr. Phil Goulais, Session Facilitator: Mr. Goulais began the meeting by introducing Elder Andrew Wesley who provided an opening prayer and a smudge. Chief Reginald Niganobe, of Mississauga #8 First Nation, welcomed the participants on behalf of the Mississauga Nation, the host territory for the meeting, thanked the Elder for the prayer and acknowledged the sacred items in the room.

Mr. Goulais introduced himself to the room as a member of the Nipissing First Nation, where he was the Chief for many years. He is currently working part time on a contract with Hydro One, which has allowed him to work in many First Nations communities. He thanked the participants for sharing their knowledge and welcoming contractors into their communities with kindness. This work was part of a commitment to relationship building, which is still ongoing. Mr. Goulais shared that he expected many of the topics discussed on those community visits would be discussed at this session: Hydro One billing system sessions; career opportunities at Hydro One; and, procurement workshops for First Nations businesses.

Mr. Goulais reflected that in their conversations with communities, First Nations leaders have expressed an interest in impacting policy development and/or change with Hydro One. Both First Nations and Hydro One leadership are seeking to establish how to work together better. This engagement session is a response to that shared goal of working together better. With this in mind, Mr. Goulais expressed the goal of the engagement session: to hear First Nations' priorities; to share current thinking; and, to solicit feedback on the upcoming Distribution Rates submission to the Ontario Energy Board. The agenda attempts to balance information sharing from Hydro One and discussion.

Mr. Goulais thanked the Hydro One staff for working hard to make the engagement session happen. He also thanked the Chiefs, Councillors and other participants. He also noted the presence of the Ontario Regional Chief, Isadore Day and Grand Chiefs in the room.

Mr. Goulais concluded by noting the participation of senior leadership at Hydro One, which demonstrates a clear willingness to work with First Nations. It was noted that notes of the meeting are being taken and participants would receive the written notes of the session for review.

INTRODUCTIONS

The participants were asked to provide their name, where they are from and their expectations for the gathering.

Lisa Kooshet, Councillor, Wabigoon Lake First Nation: Ms. Kooshet came to the meeting looking for information to inform the development of the Wabigoon Lake First Nation community energy plan

Chief Brian Perrault, Couchiching First Nation: Chief Perrault was attending the meeting with an expectation of talking about on-reserve hydro rates and the potential for eliminating the distribution rate on hydro bills. He noted that, in many of communities, Elders and others have to decide between paying the hydro bill or putting food on the table. He noted that his community is close to Fort Frances, which has low hydro rates because of the n which generates power. However, reserve lands had to be flooded to build that dam. First Nations have paid a price for the low energy rates that Fort Frances enjoys. Chief Perrault came to this session to identify how we can lessen the financial burden on Elders and others.

Jerry Fontaine, Hydro One Contractor: Mr. Fontaine noted that he has been involved with Hydro One for many years. He reiterated the comments from Chief Perrault related to the struggle to sustain basic standards and the need to decide between food and light. This is a struggle alongside the struggle for housing, economic development and employment opportunities. Mr. Fontaine recognized Ms. Lee Anne Cameron (Hydro One's Director of First Nations and Metis Relations), for initiating this discussion and saw the meeting as an opportunity for change. He concluded that he is part of Treaties 1 and 3, and that historically Treaty 3 did not recognize the border.

Phil Goulais, Hydro One Contractor: Mr. Goulais shared that he was looking forward to network throughout the day and was also acting as the Master of Ceremonies for the dinner in the evening.

Mayo Schmidt, President and CEO of Hydro One: Mr. Schmidt welcomed everyone and thanked them for their participation and openness to dialogue. He also thanked Ms. Cameron for organizing the event. He suggested that hearing from participants presents a great opportunity to act on the things that they, as Hydro One, learn through the discussion.

Lee Anne Cameron, Director, First Nations and Metis Relations, Hydro One: Ms. Cameron thanked the participants for attending the session today.

Chief Reginald Niganobe, Mississauga #8 First Nation: Personal introduction

Chief Gerry Duquette Jr., Dokis First Nation: Personal introduction

Darryl Hill, Community Energy Planner, Six Nations of the Grand River Territory: Personal Introduction

Chief Warren Tabobondung, Wasauksing First Nation: Chief Tabobondung noted that they have many issues around Hydro One in his area, including development and power generation dams. These have a significant impact on the hunting, fishing and gathering for his people. Flooding was identified as a challenge. He shared his expectation of the meeting to exchange information about whom his people are and how they are impacted. He also noted that he wanted to talk about the high cost of hydro, which put their Elders in a position to choose between food and light. The Elders are the people who have persevered through so much change. Chief Tabobondung noted that the issue is also about land and the fact that Crown assets (i.e.- transmission lines) are sitting on Treaty territories. Reducing hydro rates by a few percentage points is not going to solve these bigger issues. He noted that he would like the discussion to get to these bigger issues. He also recognized that things have changed including the increasing voice of First Nations since the 1960s. He is optimistic and willing to exchange information and ideas and work together to resolve the issues facing his community.

Karen Taylor, Hydro One: Ms. Taylor stated she was attending the meeting to listen and l

Chief Tom Bressette, Kettle and Stony Point First Nation: In attending today, Chief Bressette shared his hope to examine ways through government engagements. He suggests looking at the Treaties; his is from pre-Confederation. He continues to observe political leaders, Trudeau and Wynne, making commitments about partnerships. However, in reality there does not seem to be much going on. There are a lot of promises but little financial commitment. Chief Bressette reiterated the earlier comments about economic insecurity and the impact on communities including Elders and youth. This is particularly challenging in the winter and impacts mental wellness. He noted that he has seen promises from governments before and challenges them to move from talk to action. He also noted that he sees Hydro One going through challenges, trying to sell off assets, with human resources issues and aging infrastructure. These things cost money and are the reason why hydro rates are so high. However, Chief Bressette reminds attendees that the Treaty talks about sharing resources, yet he sees everyone but his people benefitting from First Nations resources. This is also part of honouring the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP). He also expressed frustration over having to go back to his community without an answer for high hydro rates. He is no longer “asking” for a response, he is “demanding” a response. It is time to share these resources.

Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One: Mr. Pugliese expressed thanks to Mr. Goulais, Mr. Fontaine, Mr. Kakeway and everyone who worked on this event. He noted that Hydro One wants to list en an act on the things that they can and capture the attendees’ comments.

Councillor Ted Williams, Chippewas of Rama: Chief Williams stated he was attending to listen and hear some other issues out there. He said he was pleased for the opportunity to dialogue, but that action is best.

Chief Greg Nadjiwon, Chippewas of Nawash Unceded First Nation: Chief Nadjiwon noted he shared many of the previous comments from Chief Tom Bressette. He stated that he was attending to find out how to collectively move forward in true partnerships, true resources sharing and open and transparent communication. He notes that three decades ago the corporate mindset was flood the lands and deal with the rest after; however, the corporate mindset has changed towards Indigenous relations. For his community it has been a success story; they have a contact and the results happen quite quickly. The results are not always positive, but they get answers more quickly. He views this engagement as an opportunity to move the yardstick, to have a constructive day and network.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): Chief Miskokomon notes that the Minister of Energy asked how we can change thinking. However, from his perspective Crown corporations do not listen to First Nations. Crown corporations must remember that they are accountable to First Nations and citizens, meaning they need to be more transparent in the way activities are undertaken and services delivered in his territory. He notes the changing tide, as evidenced by the Truth and Reconciliation Commission of Canada (TRC). There must be meaningful partnerships. Hydro distribution costs are very high. The Chief also identified the need for Hydro One staff to undertake cultural sensitivity training. Working with First Nations requires getting to know First Nations. In addition, Chief Miskokomon cited the need to look at alternative energy. This also means supporting First Nations in becoming educated on what is out there and ensure capacity within First Nations. This requires professional support in establishing First Nations owned and run utility companies on-reserve that will not include redistribution costs. All of these ideas require people to be more creative. The Chief reminded the group that non-Indigenous people are still visitors in the territory. Partnerships must be built based on trust.

Chief James R. Marsden, Alderville First Nation: Chief Marsden also shared support for the words of Chief Bressette. As far as this meeting, he was interested in discussing “blanket agreements.” What is it? He notes that in the ‘Addition to Reserve’ process, Indigenous and Northern Affairs Canada (INAC) asked for blanket agreements. They have never had a blanket agreement with Hydro One and asked if this type of agreement was required for his reserve.

Marlene Stiles, Manager of Economic Development, Chippewas of Georgina Island: Ms. Stiles commented that she was attending to listen, learn and take information back to her community.

Marvin Sinclair, Elk Clan, Band Manager, Washagamis Bay Obashkaandagaang: Mr. Sinclair noted that he has previously been on Council and been the Chief of his community. He also shared that his brother was the Chief of his community and passed on last week. The First Nations in the room all share the same challenges, including broken promises and poor people. Mr. Sinclair recently moved back to his community from Sault Ste. Marie and can see the difference in hydro rates between the reserve and the urban centre. He notes this will be a common theme of the day. He also articulated that when people talk about "resource" they are actually talking about the source of life, which is worth much more than a dollar sign. First Nations have a connection to the land. If even a fraction of the Treaty promises were honoured there would be no need to have these discussions. Rather, First Nations would be financially independent and stable. Mr. Sinclair suggested it was a privilege to be a part of the conversation and hoped that Hydro One officials would heed what they heard.

George Kakeway, Hydro One Contractor, Rat Portage: Mr. Kakeway stated that it was nice to see many old friends at the engagement event. He noted the importance of the session in terms of engagement. In addition, he shared that most of his work is done in Treaty 3 communities. He noted that there was diversity between communities, but there were also universal issues including delivery charges. He saw this session as an opportunity to engage, move forward and see how the communities could be helped.

Joe Cheechoo, Elder Councillor, Moose Cree First Nation: Elder Cheechoo shared that he was attending the session to better understand how the hydro system works.

Chief Patricia Faries, Moose Cree First Nation – Chief Faries began as Chief last August and was happy to attend the meeting. She sees engagement as the important first step. A meeting was held in her community on January 10, 2017and the primary concern that was raised related to hydro was outrageous delivery charges. She shared that she is on a fixed income and wants to understand what can be done to address these charges. She sees people suffering under the delivery charges. She notes that her community signed an agreement with Ontario Power Generation (OPG). She also wonders what is the fiduciary duty Hydro One has to her community and all First Nations. She also notes that she expected to hear clarity at this meeting because her time is precious, and hydro is just one of the many issues she needs to address. She suggests that reconciliation means that there must be a discussion about the benefits that Hydro One enjoys at the cost of First Nations land use. She sees Hydro One using Indigenous land only to sell hydro back to Indigenous people. She notes that she has to have tangible things to report back to her people and is expected to report back on February 21, 2017. She also reminded the room of the Lower Mattagami project, right in her community's back yard that included four (4) dams built from 1960 to 1966. Former leaders signed an agreement. Yet today these dams have to be fixed. She suggested that the conversation focus on what is possible from Hydro One and how Hydro One can help her people right now.

Chief Leslee White-Eye, Chippewas of the Thames: Chief White-Eye echoed the words of the previous speakers. She noted the need for some discussion on the corporate history of Hydro

One. She also expressed that there is a need for the federal government to participate in these discussions because of permitting and issues related to lands. She was also seeking a contact person within Hydro One who could discuss negotiating this new payment and who will pay for it.

Errnol Gray, Councillor, Aamjiwnaang First Nation: Councillor Gray noted he was participating to listen, but also to discuss the line crossing at the St. Clair river, which goes through First Nations and the Treaty area. He also noted that he is on a fixed income and has trouble paying his high hydro bills. His community signed an agreement in 1953 and the payments have not increased since. He suggests a new agreement needs to be negotiated.

Chief Melvin Hardy, Biinjitiwaabik Zaaging Anishinaabek: The Chief thanked the host for allowing them on their traditional lands as well as thanking his friend Elder Andrew Wesley. Related to the importance of land, the Chief noted that the youth go out on the land and sustain a relationship with, and right to, the land. He described his First Nation, which is found on the southeast side of Lake Nipigon. He suggested that Hydro One officials needed to spend some time living in some of the homes in his community. He wondered, if the government does not give First Nations authority over their own lands, why would Hydro One do it? He noted that it is cold in First Nations communities, which contributes to Elders and children getting sick. This is exacerbated when the power goes out. There is no compensation when the power goes out and communities are forced to collect their own wood and go without. Chief Hardy noted that his community is constantly in deficit because of high costs of hydro. He also identified that there had not yet been an engagement session in his community and that it needed to happen.

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: Mr. Hubert welcomed the kinds of comments that attendees had been sharing as it is important for him, as a Hydro One official to understand the issues.

Edward Skeid, Councillor, Wauzhushk Onigum First Nation: Councillor Skeid asked that Hydro One staff stake the comments made by the attendees seriously and take them to their superiors.

Deputy Chief Fabian Blackhawk, Ochiichagwe'babigo'ining Nation (Dalles): Deputy Chief Blackhawk began by acknowledging the sacred items in the room and the prayer from the Elder. He noted that he certainly relates to the comments made so far. He was looking for some direction on what this meeting is supposed to accomplish. He also shared that leaders and youth have told him many of the things that were already mentioned. It is tough to see all these people making money off First Nations resources and lands with First Nations people in poverty. His community signed an agreement for the hydro lines and cannot make any adjustments. Of the session, he expected an open dialogue to make good decisions to take back to his people.

Harold Thiessen, Ontario Energy Board: Mr. Thiessen expressed his intention to listen and learn.

Gary Schneider, Vice President of Shared Services, Hydro One: Mr. Schneider shared that he works on procurement as well as land matters. When it comes to the issue of land he has heard the frustration in the room and agrees that agreements with First Nations need to move forward.

Amy Lickers, Chiefs of Ontario: Ms. Lickers introduced herself as coming from Six Nations and works with the Chiefs of Ontario Chiefs Committee on Energy. She noted she attended the session to listen.

Yvette Maiangowi, Energy Planner, Wikwemikong Unceded First Nation: From her perspective, Ms. Maiangowi notes that nothing has changed; in fact the situation in her community has worsened. She also asked those in the position to negotiate agreements with First Nations to stand up. She noted a need for a clear path forward including timelines. She concluded by saying that the time for talking has passed.

Craig Aldred, Wahgoshig First Nation (Abitibi #70): Mr. Aldred noted a need to address distribution costs, as these high costs negate their efforts to build sustainable communities when the costs end up being covered by the bands. He expressed a need to develop long term solutions.

Rob Globocki, Director, Customer Care, Hydro One: He expressed to the participants that he was also here to listen and learn.

Sara Mainville, Associate, Olthuis Kleer Townshend LLP: Ms. Mainville introduced herself as an advisor to Regional Chief Day. She also does work with Grand Chief Peters on Hydro One opportunities. Ms. Mainville expressed that she was happy to attend and see many Chiefs in attendance.

Grand Chief Gord Peters, Association of Iroquois and Allied Indians: Grand Chief Peters noted that the Hydro One process has been a long process that they have been involved in for some time. He also acknowledged Chief Ava Hill from Six Nations for working on this issue. At the last All Ontario Chiefs Conference (AOCC), there was a meeting attended by the new Minister Thibeault who committed to developing a First Nations rate. This commitment was made 8-9 months ago. This remains the issue for the discussion at this session. He posed a number of questions including, what is the rate going to look like and how will that be brought to our communities? He heard that the distribution charge is one of the easier things to change, so wanted a commitment on that. He noted that should Ontario continue to privatize beyond 60% of Hydro One, the province would remain liable for all the damages that continue to flow. His community is the same as Alderville in that there are no agreements in place. They are dealing with the Additions to Reserve process and are 12 years in. He reminded the attendees that “you have to have full permit or cannot move ahead”. His community is still in the talking stages. He suggested that these are the things that become irritants in the process. In order to move forward, Grand Chief Peters says that we have to learn how to get along and there will have to be a better arrangement for First Nations.

Chief Jim Leonard, Rainy River First Nation: Chief Leonard describes his community as between Thunder Bay and Winnipeg near the American border. His community had engaged with Hydro One a number of years ago where they talked about past grievances and decided they need to set those aside to move forward. They acquired, constructed and commissioned a solar farm. Without technical support or shared engagement with Hydro One it is difficult to make these things happen. He was attending the engagement session to advance that process. He saw it as important for Hydro One to listen to the grievances shared because they still impact First Nations, but also recognize that First Nations are ready to move forward. There is the potential for this to be a revenue stream and support to communities.

Deputy Grand Chief Derek Fox, Nishnawbe-Aski Nation (NAN): Deputy Grand Chief Fox began by thanking the Elder for the prayer. He described NAN as being comprised of 49 First Nations and 7 tribal councils. NAN communities extend from the Manitoba border to James Bay. This is a huge land mass and most communities are remote. People in these communities are passionate about their hunting, culture, water, river systems and language. Deputy Grand Chief Fox noted that he is from Treaty 3, Shoal Lake 40 where there are profound water issues. When he was younger he was driven to become a lawyer and learn the systems that govern. He expressed concern over claims to jurisdiction over Indigenous lands. He concluded by sharing that he was participating in the session to support NAN Chiefs, to listen, to talk about NAN initiatives and hoped to have a meaningful discussion.

Jamie Scarlett, Executive Vice President, Chief Legal Officer, Hydro One: Mr. Scarlett commented that he was attending the session primarily to listen and learn. Within his duties, he has some involvement in rates so hearing from the First Nations participants was impactful for him. He noted that he is appalled at how long it takes for Hydro One to deal with these issues. He offered his personal commitment to drive these issues forward to be dealt with in a clear, open, transparent and timely way. He reflected that he had heard the message that 'these are just words, but First Nations want actions.

Chief Ted Roque, Wahnapitae First Nation: Chief Roque began by thanking the Elder and acknowledging the land where the meeting was held. He was attending the meeting to hear more about new rates. He noted that it would be great to see lowered rates and it would make a huge difference for his people. He recognized that there is only one year left in the Wynne government's mandate and he does not want to see these discussions get lost; whether the next Premier is Wynne or someone else, these negotiations must continue. He noted that there must be more sharing of resources and opportunities and true partnership.

Andrew Wesley, Elder: The Elder introduced himself as hailing originally from Fort Albany, but has been living in Toronto for many years. He shared that traditionally electricity was known as Thunderbird Fire. This demonstrates the close relationship between First Nations and mother earth.

Deputy Chief Kevin Mossip, Zhiibaahaasing First Nation (Cockburn): Deputy Chief Mossip shared that in his community hydro rates increased 72% in two years and this increase has caused hardships. He brought a message from his Council that the engagement session was in no way, shape or form to be considered consultation. In addition, his community would not agree to anything unless the hydro rates were lowered by 72%

Warren White, Councillor, Naotkamegwanning First Nation: Councillor White came to the meeting to speak for his community and see the faces of Hydro One. He notes that his Elders, the ones who are struggling, are paying the wages of Hydro One staff. He provided a welcome to the Chiefs, Grand Chiefs and Councillors. He noted that he knows how it feels to be accountable to the Chiefs and the community. He met with 35 Elders in his community last week. They told him that the HST rebate does not impact their hydro bills. Each of those Elders was paying over $1,000. He notes that he burns wood and his bill is still $1,000. He states that he did not want to attend the meeting and did not want to hear the same rhetoric from Hydro One. There is a lack of trust with Hydro One. The delivery charges in his community average out to about $250 each month, which amounts to $50,000 a month for the whole community. Councillor White suggested that he plans to charge Hydro One double that amount to enter his community; this includes any hydro trucks. When Prime Minister Trudeau had his town hall recently there was a woman crying about hydro and the media was all over that. Yet when it comes to First Nations and their hydro rates, there is no media. He said something has to be done. He suggests that his community does not support Hydro One dealing through the Chiefs of Ontario as there are too many grievances that need to be dealt with including the dams in Treaty 3 and the flooding. He asked what Hydro One was willing to do about it. He expressed skepticism as he views Hydro One as only being motivated by money. He concluded by reaffirming that something has to be done otherwise his community would start charging Hydro One to come in.

Annette Currie, Technician, Pic Mobert First Nation: Personal Introduction

Deanna Major, Councillor, Animakee Wa Zhing #37: Councillor Major expressed that she would like to see the salary disclosure for Hydro One and an explanation of how those salaries are justified.

Gary Allen, Executive Director, Grand Council Treaty #3: Mr. Allen introduced himself and that he was attending on behalf of Grand Chief Francis Kavanagh, who is travelling with Minister Zimmer in Treaty 3 territory. Last year, prior to a meeting between Hydro One and Grand Chief White, Treaty 3 citizens were asked to send their hydro bills. They brought a binder full of these bills that demonstrated the exorbitant costs faced by his people. He also noted that he checked the sunshine list for Hydro One and saw over 600 employees earning more than $100K. He found this incredible considering the suffering in First Nations communities. He shared his support for the Great Earth Law, the Sacred Law, and also the laws of the 28 First Nations in Treaty 3.

Lance DeCaire, Technician, Wahta Mohawks: Mr. DeCaire noted that the most pressing issue facing his community is the delivery charges and the impact that those high delivery charges have on the success of the community's economic development initiatives.

Chief Rodney Noganosh, Chippewas of Rama First Nation: Chief Noganosh began by reiterating the comments of previous speakers that there are many people that are upset with the situation. He also expressed concern that there was not a great deal of time on the agenda for discussion, which was upsetting given that Chiefs travelled far to attend. He noted the need to see results very quickly. First Nations should be exempted from delivery charges. People cannot pay those delivery charges and the communities always have to step in and help. He referred to an economic development project in Barrie and his expectation to receive information on that project so that they would be able to bid on those types of projects. He also expressed interest in learning about the 'blanket agreement' idea, because there has not been much information shared to date.

Ted Snache, Councillor, Chippewas of Rama First Nation: Councillor Snache began by thanking the Elder for the prayer. He noted that if he had a wish, it would be to have elections on the same day to build unity. He expressed the strength in First Nations communities, with young people getting education and women who are water keepers. He expressed that the Ontario Energy Board (OEB) hides behind legalese, but because First Nations are getting educated, that strategy will not work for long. He concluded by asking when the delivery charges will be eliminated for First Nations.

Dave Mowat, Technician, Mississaugas of Scugog: Mr. Mowat notes that the Ontario Energy Board said that if they can focus on the delivery charge, that will have the most impact on the consumer. He would like to know what is going on with that. He also asked what Hydro One is doing about a security plan.

Chief Mary McCue-King, Beausoleil First Nation: Chief McCue-King suggests that First Nations should not be talking to Hydro One because it is not the organization that sets the rates. Hydro One only makes a submission to the Ontario Energy Board; therefore, First Nations should be talking to the Ontario Energy Board before they approve the rates. The Ontario Energy Board should be consulting with First Nations.

Chief [Name Not Heard]: The Chief shared the belief of the previous speaker that First Nations are meeting with the wrong people. The Chief asked now that Hydro One has heard their concerns, what do they propose as the fix? He expressed frustration based on the belief that there are no decision-makers attending the meeting and there will therefore be no deliverables from the meeting. He would like to know the next steps? When can First Nations expect action?

Chief Kevin Tangie, Brunswick House First Nation: Chief Tangie noted that his community experiences the same issues identified by previous speakers and wants to hear answers, solutions and ideas.

Jason Batise, Executive Director, Wabun Treaty Council: Mr. Batise echoed the comments of previous speakers and shared a desire to hear practical solutions. He notes that a First Nations hydro rate was committed to, but that there is no mention of that and the elimination of the delivery charges in the Hydro One submission. He expressed that they had given practical solutions in earlier engagement sessions and they are not reflected in the submission.

Warren Lister, Vice President, Customer Care, Hydro One: Mr. Lister introduced himself as a new member of the Hydro One team and shared his commitment to changing the way they do business. He stated that he intended to listen and welcomed the opportunity to dialogue.

John Onabigon, Councillor, Long Lake No.58 First Nation: Councillor Onabigon shared that he was trying to get resource development for his community. He recounted that in the 1930s and 1940s; Hydro One built their dam and flooded his traditional territory without any regard for the impact on the community. However, he noted that the voice of his people is getting stronger and it is not acceptable that others get the benefits from resources taken from the land of his people. He stated that there is only one square mile left for his reserve and the rest has been flooded. There are many grievances and his people live below the poverty line. He stated that the message from his community has been consistent for years: that there must be a balance of sharing. In his community there is a high level of dependence on Ontario Works and the unemployment level is 85%. He sees this as a game or cycle with people dependent on Ontario Works who pay their excessively high Hydro One bills to keep the lights on to the detriment of other things. Hydro One never feels the pain, but the First Nations do. He notes that his community maintains and asserts the right to their own resources; yet have to battle to get any benefits from them. He then asked why some have so much and some have so little? He also mentions that First Nations are overwhelmed with engagements, and yet nothing has changed for his people. He has seen nothing change over 25 years of doing this work. He added that talking about procurement sounds good but communities do not even have the capacity to be a part of procurement processes.

Cesar Martinez, Customer Care at Hydro One: Mr. Martinez mentions the tools that were brought to the meeting today and encourages participants to bring them to the communities.

Sarah Bruggeman, S. Burnett and Associates Ltd.: Ms. Bruggeman is participating as she is working with a community on an energy plan.

Lisa Johnson, S. Burnett and Associates Ltd.: Ms. Johnson works with Ms. Bruggeman.

Cynthia Jamieson, Executive Director, Mississaugas of the New Credit First Nation: Ms. Jamieson expressed some confusion over the process. She notes that they were expecting a letter from the Minister of Energy to the Ontario Energy Board to hold those sessions. She wonders if that is what this meeting was about. She notes that there were already engagement sessions last fall and wonders if those participants wasted their time. She was seeking clarity on the process.

Chief Tom Bressette, Kettle and Stony Point First Nation: Chief Bressette wanted to add to his earlier statement. He notes that Hydro One is being talked about related to the Bruce Nuclear Power Plant, and burying nuclear waste near the Great Lakes. He was astounded that the Canadian government would consider burying nuclear waste near the Great Lakes. Related to the North America Free Trade Agreement (NAFTA), he notes that First Nations better not be left out of the next rounds. He again expressed disappointment that Hydro One considered that waste facility near the Great Lakes and asked, when it cracks where are we going to get more water?

Chief Simon Fobister, Grassy Narrows First Nation: Chief Fobister described being born and raised on the trap line, where there was no hydro and they carried water. They did not need those things. He was elected Chief in 1976, when he was 21. At that time his community members spoke about a time when water was so clear, but then people came in exploring for hydroelectricity. Now you cannot even see your hand in the water around his community. His community did receive compensation. In Grassy Narrows, hydro bills are high, around $1,000 a month. He notes the need to find ways to cut those rates. He attended the meeting to hear Hydro One tell him their plans to cut the rates. He expressed concern that 60% of hydro comes from nuclear power. Like it or not, the nuclear waste will be buried, and the question is whose backyard will that be in?

Introductory Remarks from Hydro One

Presentation from Mr. Mayo Schmidt, President and CEO, Hydro One

Mr. Schmidt expressed a warm welcome to all of the attendees who committed their precious time. He noted the importance of this engagement for Hydro One. He also provided a warm thank you to Elder Wesley, acknowledged the Mississaugas of New Credit and thanked Chief Niganobe for the welcome.

Mr. Schmidt noted that the work that he does at Hydro One is not the kind of work he has traditionally been involved in. He grew up on a farm and his life's work has been in agriculture. He was approached to work at Hydro One from the prairies and worked to identify a leadership team that could effect change. There was not one Hydro One leader in attendance that does intend to commit to change.

Mr. Schmidt lists three (3) things he is hopeful will come out of this session:

1. To listen and learn;
2. Provide some education on who is responsible for what, what we each do, how can we as a company can to advocate for you and your community; and,
3. Commit to action. The hope is to move this conversation to an outcome (educate/advocate/action).

Background: There are a lot of names out there with involvement in this area. The producer of the power is Ontario Power Generation, which also owns Bruce Nuclear Generating Stations, but leased them to Bruce Power. The Ontario Energy Board approves the rates that Hydro One charges to operate and maintain Hydro One's transmission and distribution systems and sets the price of power. Independent Electricity Systems Operator is responsible for real time operations – the ebbs and flows of power and where electricity goes or comes from.

Hydro One collects from customers for the cost of power (electricity price), and delivery of the power, and delivers the bill. The name Hydro One is on all bills. While Hydro One is the party that bills the party that bills the consumer, the electricity pricing comes from someone else, and Hydro One passes those revenues on.

Hydro One recognizes that they need to address their costs and get them down, and apply to have costs reduced. They also have to do their part to ensure that there are no brown-outs or power outages.

Mr. Schmidt suggests that the feedback that they get from the engagement sessions will go into their upcoming distribution rates submission to the OEB. The information will be collected as part of the application and the First Nations participants' voices will be heard there.

Hydro One is transitioning with a new leadership team with a purpose to put customers first. Hydro One is a publicly listed company with lots of opportunity but everyone must act together. In this there is a need to build and maintain relationships with First Nation communities. Hydro One serves 88 First Nation communities.

Mr. Schmidt recognized that consultation is a protected right and First Nations have a unique cultural relationship with the land. While First Nations are not the only customers, they do have a special relationship. The rising cost of electricity is a concern for all of us, so we will redouble our efforts.

In terms of how billing is structured, 51% of the costs that consumers pay comes from nuclear, hydroelectric, wind or solar producers (will fluctuate, but this is the average), 12% sales taxes and 37% is payable to Hydro One for delivery of power through the network of wires, poles and transmission stations. There is a cost to maintaining this infrastructure, and as an example, Mr. Schmidt mentioned the example of a recent transformer fire, where in replacing that asset, Hydro One recognized that it was built in 1962, so there is a need for continual maintenance of aging assets.

On the question of how do we keep the costs down, Hydro One intends to have a customer presence in local offices; the customer bill was redesigned because customers need to understand the bills; Hydro One has reinforced the commitment to service and of responding in a timely manner.

There was a recent meeting with the province to talk about the cost of power where Hydro One advocated for lower power costs; Hydro One had also proposed to the Ontario Energy Board that the delivery charge to First Nations be lowered as part of the First Nations rate being studied by the Minister.

Hydro One has met with many First Nations over the last 8 years, including over 200 community visits. Mr. Schmidt suggested that communities interested in inviting Hydro One to visit, attendees should introduce themselves to Ms. Cameron and she will get a team out there.

The Hydro One First Nations and Métis Relations team demonstrates an appreciation for the concerns of First Nations communities. They want your feedback on how that works.

Hydro One is committed to making a change as demonstrated by offering additional regional outreach on procurement, by participating in First Nations employment, training and career fairs and through the First Nations Conservation Program.

Mr. Schmidt notes that Hydro One has come far with communities and individuals, by taking issues and solving them one-on-one. If session participants are looking for that attention, then Hydro One is willing to work with them.

Question from the audience: How about eliminating the reconnection fee?

- Mr. Schmidt responded that it costs Hydro One money to send trucks out to turn off and turn on power and that there is a better way to do this -- whether it is giving people who need it more time to pay their bills, getting them on to access programs to assist them, and work with Hydro One to provide guidance on these things.

Comment from the audience: A Chief noted that the connection fee is attached to bills in payment of arrears and is a stumbling block for community members.

* **Response:** Mr. Schmidt responded Hydro One launched a new Winter Relief Program to reconnect customers prior to the winter. This was a practice that started in November 2016 and asked participants to let Hydro One know when people are in that situation.
* **Follow up audience comment:** People are paying this now, sometimes two or three times per year.
* **Response**: Mr. Schmidt responded that if a customer is disconnected, they have to take some hardware off after six months and there are costs associated with that.
* **Follow up audience comment:** Hydro One gets all their fees paid.
* **Response:** Mr. Schmidt responded that in the past this might have been the case, but to participate in the Winter Relief Program, Hydro One needs the names on those accounts and there would be no fees. In general, those fees go into maintaining the system.

Mr. Schmidt: Mr. Schmidt noted that it is important for Hydro One to hear from the participants and focus on things that can be changed. He committed to listen, but also committed to meeting again in the future to work on some of the things we want to accomplish together. It will take bold action by all of us to effect change. It is a complicated industry, with complicated pricing. For these reasons Mr. Schmidt encouraged everyone to focus on what is within their power to change and set priorities. Hydro One is accountable to customers including the meeting participants. The team in place is a new team, and Mr. Schmidt encouraged meeting participants to place their trust and work with the team.

Chief Perrault: The Chief shared that last fall he received a call from a community member who had a Hydro One truck at their door ready to disconnect. He went down there and had to drag the guy off the hydro pole and asked him to leave the community or risk his boss getting a call. There is a perception that there is a push to cut people off before the snow flies. He believed this had to be addressed.

Mr. Schmidt**:** Mr. Schmidt shared that he cannot speak to what has happened in the past, but going forward, the focus is on getting people connected rather than disconnected. He also committed to dealing with the issue of cut-offs himself, along with Hydro One legal counsel. The time frames will be addressed, but in general there is no gain for anyone by cutting people off. The larger issue is that we need the cost of power to be reasonable.

Councillor Warren White: Councillor White commented that he has heard many of these promises before from government officials, but respectfully, he will believe it when he sees it. Further, he identifies a fundamental difference between how connections and disconnections are treated. For example, Hydro One is quick to disconnect but is slow to reconnect clients. There is often a long waiting period, even if the bill is paid. Related to procurement, Councillor White recognizes that there are procurement arrangements with some communities, but the only thing he sees by way of procurement opportunities is cutting brush. He thinks there must be more to offer than that. Councillor White noted that while there may be an Ontario-wide Engagement process, there are different issues; the grievances are different in Treaty 3 and therefore he strongly encouraged Hydro One to have more regional-type meetings. In addition, given geography, it is challenging for community representatives to get to meetings in Toronto, for example. Councillor White commented that February and March are stressful months for Elders because of the accumulation of bills that they cannot pay, and they know they will be cut off. Councillor White notes that Hydro One activities constitute a breach of the Treaties (through flooding, etc.). In addition, there is supposed to be a relationship and a partnership that is not yet realized. Councillor White concluded by sharing a personal story related to disconnection. He had an overdue bill of $1,200, and received a disconnection notice. The bill was paid on Friday and yet his power was cut off on Monday. He attempted to demonstrate to Hydro One that the bill was paid, but was told that the payment had not reached Hydro One's bank yet, so the disconnection went ahead. These situations are real.

Mr. Schmidt: Mr. Schmidt stated that he agreed with Councillor White, that Hydro One needed to be reasonable and to rethink previous behaviours that were practiced. He notes that there are a lot of attitudes to change throughout the organization and hopes to do better.

Chief Patricia Faries: Reflecting on Mr. Schmidt's previous comment about constitutionally protected rights, Chief Faries affirms that this is an important point to set the context. She stated unequivocally that the engagement is in no way to be considered consultation and accommodation between Hydro One and the Moose Cree First Nation. She emphasizes that action is key, and she wants a definitive answer on how to move forward. There are power lines going through her land that are intrusive. She expected a response on how her community would be engaged and compensated.

Mr. Schmidt: Mr. Schmidt assured participants that the engagement session was not consultation and they did not view it as such. Related to engagement and compensation at a community-level, Mr. Schmidt introduced Jamie Scarlett and Gary Schneider who can sit and meet with communities to work through their issues.

Jamie Scarlett, Hydro One, provided his email address (Jscarlett@hydroone.com) in order to set up future conversations.

Chief Nadjiwon: Chief Nadjiwon sought an update on the discussions around the delivery charge.

Mr. Schmidt: It was noted that industry was in conversation with government last week on this issue and discussions are ongoing. Mr. Schmidt notes that Hydro One is advocating for changes related to the delivery charge issue. He invited other Hydro One staff to comment.

Hydro One Representative, Oded Hubert: The Minister has asked the Ontario Energy Board to develop a First Nations rate, and the Ontario Energy Board has prepared a recommendation that has gone back to the Minister for consideration. Chief Ava Hill provided comments on the recommendations and Hydro One supplied data. It is with the Minister now.

Question from the audience: Is there a timeframe for an answer?

Hydro One does not have a time frame at this time, as this is the Minister's initiative.

Comment from Chief [Name Not Heard]: The Chief has attended many meeting over the years, some of which were classified as consultation. The Chief noted that the Hydro One Board of Directors was joining the meeting for dinner, and the CEO is accountable to the board, which gives the organization direction [Mr. Schmidt indicates this is correct]. The Chief commented that having the board at the dinner is fine, but they should have been at the engagement session to hear First Nations' concerns firsthand.

Mr. Schmidt**:** Mr. Schmidt clarified that the Board of Directors does not run the company or specifically direct the CEO. Rather, Mr. Schmidt's team determines a plan, which is presented to the Board for comment. This is different than being instructed by the Board. It is not a decision-making group on an operations level body. In addition, plans that are developed by Hydro One must be approved by the regulator.

Chief Tom Bressette: Chief Bressette suggested that Hydro One must have come up with a proposed First Nations rate, given that they engaged with First Nations last year. He questioned why that rate was not presented to the engagement session. In addition, he felt as though the meeting was centrally about politics. He noted that it may be the same old song and dance and First Nations are growing frustrated without little reason to believe anything has changed.

Mr. Schmidt**:** Mr. Schmidt responded that the reason Hydro One felt that this engagement was important was the need to have a respectful conversation. Hydro One does not set the price of power; however, Hydro One can advocate alongside First Nations to address the price of power. He notes that it comes down to whether or not the participants are prepared to give Hydro One a chance.

Customer Care: Vision, Strategy and Key Initiatives

Presentation from Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One

Mr. Pugliese is the Executive responsible for customer care and Indigenous relations. He noted his appreciation for the openness of the conversation. As the company changes direction from a Crown corporation to a public company, there is an opportunity. The electrical system in Ontario is complicated. In this shift there are three (3) things they have embarked on:

- The first is education, to help explain this complicated system including its regulation, etc. Hydro One has started to uncover what can be addressed and asked for the opportunity to first understand and then work on the things that they can change.
- The second task is related to advocacy. Hydro One owns the hydro bills and holds custody of the relationships with communities and customers. Hydro One has an impactful voice in advocacy similar to the loud voice that First Nations have.
- Mr. Pugliese reiterated that the session was not designed to be a consultation; rather, it was the first step in a series of discussions that will lead to change. He also recognized, like Mr. Schmidt, that change is indeed required, particularly in the area of affordability.

Mr. Pugliese recounted a meeting from the previous week between himself, Mr. Schmidt, the Chair of the Board and Premier Wynne. The Hydro One representatives shared stories similar to those that were heard at this engagement session. He noted that he has been to communities where the distribution charges are more than the power charges themselves and recognized the burden that this places on people like retirees.

He noted that he does not expect the participants to trust Hydro One at its word, but rather, to judge the new Hydro One team on their actions. They committed to visiting First Nations communities, reconnect those who are disconnected, and waive the fees. He asked that the participants let them know which of their community members need this assistance.

Mr. Pugliese recognized, once again, that the primary issue is around affordability, and noted that if Hydro One could control the rates, that the rates would be reduced. However, these changes require advocacy and lobbying. Their conversation with Premier Wynne was for that very purpose.

Mr. Pugliese asked the participants to trust that the information shared at the engagement session would not fall on deaf ears. Some action has been taken such as reconnections and winter relief. Previously, the collection process lacked flexibility and was unforgiving and that has changed. He encouraged participants to speak with Hydro One staff about these issues. The engagement session is one step in a new direction and changes will continue.

Mr. Pugliese left his email address and encouraged participants to hold him accountable to his promises (ferio.pugleise@hydroone.com).

Warren Lister VP Customer Care Hydro One**]:** Hydro One has indicated that they had solutions and ideas to give to the Minister. Many of the short-term solutions that are needed in the communities can be acted on immediately. Hydro One is willing to visit communities that they have not yet visited. For people having difficulty with payments, there can be new payment plans set up. In addition, the winter reconnection program can help get people connected and stay connected. There are still things Hydro One can learn regarding changes that need to be made for communities. The Hydro One staff present were there to answer specific questions and the Minister would be available during the evening dinner. The dinner is an opportunity for both Hydro One and First Nations to use their strong voices for change.

Grand Chief Gordon Peters: Grand Chief Peters noted that his organization has been involved in the process for some time beginning in 1989 around the grievance process. Since that time there has been a lot of work done in the communities and grievances were settled. Issues including billing and grievances arose again within the privatization process. The Hydro One customer care was terrible and did nothing to support communities. Grand Chief Peters was pleased to hear that things would be different; however, he warned that expectations are now high. Grand Chief Peters participated in the engagement process in the fall of 2016. He notes that Hydro One should have laid out the plan at that time; that Hydro One was looking at short-term and immediate changes while looking forward to a longer term plan. It needs to be laid out ahead of time and made less complex. First Nations are seeking how to participate effectively.

Warren White, Councillor: Councillor White shared that he met with Premier Wynne recently. He also met with her two years ago and raised the issue of high hydro bills. He took her his hydro bill, which was $4,200 at the time. The Premier has known about this issue for a long time.

Mr. Pugliese reaffirmed Hydro One's commitment and assured the participants that the commitment will be ongoing. He reaffirmed the need for a partnership with First Nations to get the required changes made. That is the reason why they invited the Minister to participate at the dinner, as he is the policy maker that can affect the changes that are needed.

Chief [Name Not Heard]: The Chief described that when a hydro truck pulls up to a house it dehumanizes the residents. He asked that hydro come to the band office first before disconnecting people. In the past, First Nations had the same experience with archaeologists. The Chief also noted that governments had left it to companies to do that engagement themselves, but that can be traumatizing to communities. The Chief asked what Hydro One is prepared to do when the power goes out in order to get people reconnected in a reasonable time.

Mr. Pugliese responded that the situation described by the previous speaker is not how Hydro One wants to do business. He noted that a colleague, Mr. Greg Kiraly, the Chief Operating Officer, would be joining in the afternoon and would like Mr. Kiraly to hear these concerns as well, as he is looking at the operations side of the business. They want to ensure that in the case of outage that restoration occurs in a timely manner.

Councillor Lisa Kooshet: A participant asked for a recap of the new positions within communities. She asked if there were going to be new Hydro One offices and how those would benefit First Nations communities. She notes that she worked for Ontario Hydro in the past and as a single mom, even while working, had a hard time paying the hydro bill. She expressed that this was disheartening.

Mr. Pugliese noted that Hydro One has launched "Get Local" and written letters to all customers. They are in the process of re-establishing regional or community business offices. They are currently building plans to reinstate regional/community offices to resolve customer issues. In addition, Hydro One is putting a great deal more emphasis on Indigenous Affairs and building more of a strategy around that builds on the good work of Mr. Cameron. This engagement session is the beginning of how Hydro One wants to move forward in doing business. They want to go to the community and regional level on a regular basis.

Distribution Rate Filing (2018-2022)

Presentation by Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One [Distribution Rate PowerPoint]

Mr. Hubert began by explaining what a Distribution Rate Filing means, which is a submission that seeks Ontario Energy Board approval of distribution rates for a five-year period [2018-2022]. The application has not gone in yet, but Hydro One is currently preparing the application and is planning to file at the end of March, 2017.

Hydro One conducted many customer engagements, including 300 First Nations customers, in developing the application. However, Hydro One is still seeking input, and this engagement is a good opportunity to inform the submission.

The distribution rate will apply to all Hydro One customers. There has been discussion on a First Nations rate; there is a request from the Minister of Energy to the Ontario Energy Board to develop an on-reserve rate or rate mitigation for reserves. The Ontario Energy Board responded that they would work on that and in doing so consulted both with Hydro One and First Nations representatives.

Question from the audience: Why is there a discussion on something that is not complete? The commentator shared the worry that this is creating false expectations.

- Mr. Hubert responded that the discussion was taking place in order to hear back on what they are proposing as part of the distribution rate filing, before the Company submits it, so that the input can be included in the Application.

Question from Chief Rick Allen, Constance Lake First Nation: Chief Allen wondered as to the extent of First Nations input on the plan?

- Mr. Hubert responded that there has been some First Nations customer input.
- Mr. Hubert clarified that there are three different initiatives underway, which is leading to some confusion,
- The proposal by Hydro One to the Ontario Energy Board is an Application for distribution rates for the next 5 years.
- There is also working underway on a First Nations rate, which is being reviewed by the Minister.
- The other issue of hydro affordability is one for all customers, and especially for rural customers in Ontario, and this issue is being examined by the Premier .
- Hydro One is here to seek feedback on the first item, the proposed Distribution Rates Application.

Comment from Chief Bressette: Chief Bressette commented that in areas where there are wind turbines, First Nations people could not hunt. This is a violation of Treaty rights. They have found that there are very sudden restrictions based on hydro applications to the Ontario Energy Board.

- Mr. Hubert provided an overview of the generation, transmission and distribution system that serves industrial/residential/commercial customers. Related to Chief Bressette's question, Mr. Hubert notes that Hydro One's only role is to connect generators to the system. Hydro One does not have anything to do with land rights for generating facilities.
- **Chief Bressette:** Chief Bressette responded that First Nations own the land and expressed frustration at the common narrative that First Nations do not own the land and that Canada has rights to the land and resources. First Nations do not beg for "help"; rather, First Nations have a right to benefit from the resources drawn from First Nations land.

Question from Chief Allen: Chief Allen asked why Hydro One is talking about a specific distribution rate for First Nations. Given what Hydro One heard form participants already, why would there even be a distribution cost for First Nations.

- Mr. Hubert responded that Hydro One is not in a position to simply tell the Ontario Energy Board that First Nations will not be charged anything for distribution; however, there is an opportunity to do something, and Hydro One has made some recommendations to inform the OEB's review of the First Nations Rate. The Minister mentioned a First Nations rate or rate mitigation and asked the OEB to prepare a recommendation. At the same time, Hydro One is preparing for an Distribution Rates application that applies to all customers. It is up to the Ontario Energy Board to approve it or not. In addition, the Minister may be able to make changes related to a First Nations rate, but that decision is with the Minister alone.

- **Chief Allen:** The Chief pushed back on the idea that Hydro One is still applying a distribution charge to First Nations and he recommended that Hydro One just tell the Ontario Energy Board that they are eliminating the charge for First Nations.
- Mr. Hubert noted that they are working on this as part of Hydro One's advocacy role around the rates for First Nations customers and affordability issues in general. They have asked the Ontario Energy Board to adjust the distribution charge.

Comment from Chief Bressette: Chief Bressette noted that the Ontario Energy Board has never invited First Nations to discuss this issue with them.

- Mr. Hubert noted that he believed that the Ontario Energy Board spoke with First Nations representatives about the First Nations Rate Report, but he was not aware of who was involved on behalf of the First Nations.
- **Chief Bressette:** Chief Bressette reminded the room that there is more than one Chief in Ontario and more than one First Nations provincial/territorial organization as well.
- Mr. Hubert stated he was not entirely sure about the Ontario Energy Board process.
- **Chief Bressette:** The Chief noted that the Ontario Energy Board gives other groups a lot of authority over First Nations land without the involvement from First Nations. It is very powerful as evidenced by breaking up Ontario Hydro and making changes without speaking to First Nations. He reiterates that First Nations own the land and are not reported to at all. He states that this way of operating has to change.
- In response, Mr. Hubert notes that forums such as this are intended to drive change. He also committed to finding out about the Ontario Energy Board process when it comes to the discussions that the OEB held on the First Nations Rate.
- **Chief Bressette:** The Chief reiterated that the Ontario Energy Board should be talking to First Nations; OEB should talk to First Nations.

Question from Amy Lickers: Ms. Lickers, in relation to the information on the PowerPoint, what is the difference between the transmission and distribution area in Hydro One

- Mr. Hubert explained that transmission is above 50,000 volts, and typically involves the larger, steel towers and large transformer stations, whereas distribution is below 50,000 volts. He likened the system to the highway and roads systems in the Province.
- **Follow up question from Chief Faries:** Chief Faries asked if that means Moose Factory First Nation were in distribution then, and if that was why the delivery fees are so high.
- Mr. Hubert explained that there is a delivery charge in both, but the majority of the delivery charge is for distribution. Mr. Hubert referred to his PowerPoint [Slide 6] and noted that electricity makes up the majority of the charge. He also committed to provide both hard and electronic copies of the presentation to the attendees.
- **Follow up by Chief Faries:** The Chief asked if it was the Ontario Energy Board who proposed a credit for remote communities. Also, she posed a question to the Chiefs of Ontario, who helped coordinate the engagement session, around whether or not the engagement needed to be with the Ontario Energy Board. In general, what is the

strategy and is meeting with Hydro One the best way to spend our energy. She also asked where Regional Chief Day was.

- Mr. Hubert suggested that the participants were indeed at the right forum and while there were many issues Hydro One cannot deal with, such as nuclear power for example, it is Hydro One who puts together the bill and delivers it to customers. So Hydro One, plays a role in explaining the system to customers. Hydro One proposes rates, but the Ontario Energy Board approves the rates. Mr. Hubert again invited a constructive conversation.

Grand Chief Gord Peters,: Grand Chief Peters noted that it was not Hydro One, but rather the Ontario Energy Board that did the visit last fall, to discuss the First Nations Rate. . He also mentioned again that Chief Ava Hill worked on this and at the time they could not get anyone else to sit on the committee with her. He acknowledged her for taking on that work. He also noted that other people got involved in the process and as that went forward only a handful of other people came to participate. He stated that the participants were there because they had been invited into the process. He did, however, note that Hydro One should have been clearer about what was going to be discussed and the goals of the meeting.

- Mr. Hubert recognized that they were not clear on the invitation that this is a discussion on the Distribution Rates Application by Hydro One, not the First Nations rate; however, they are not a stage where they can give an answer on the First Nations rate, nor are they in a position to do so, as this is the Minister's initiative.

Chief Daniel Miskokomon: Chief Miskokomon noted the need for cultural sensitivity training for Hydro One staff working within First Nations communities.

Councillor Ted Snache: Councillor Snache asked for clarity. From his understanding, power generation was from the Bruce Power plant, and then Hydro One buys the power and then distributes the power. He also noted that Bruce Power makes so much power that they sell it to the United States at a reduced rate.

- Mr. Hubert clarified that Hydro One does not buy the energy; rather they just deliver the power and issue the bills. Hydro One collects the money and then sends it to the Independent Electricity System Operator (IESO, a Crown agency) which then remits it to the power generators. The IESO is responsible for the market and the system operation. Related to shipping power to the United States, the IESO decides at certain times that it is more economical to ship to other jurisdictions at a lower price than to shut down the nuclear plant and start it back up again.

Cynthia Jamieson: Ms. Jamieson asked for additional clarity on the distribution rate application to the Ontario Energy Board. She asked if the three rates were: First Nations rate, regular rate, and an affordability issue.

- Mr. Hubert clarified that there were three independent issues: the First Nations rate, a Hydro One Distribution l rate application, and energy affordability, in general.
- **Follow up question from Ms. Jamieson**: Sought more explanation of the rural rate.
- Mr. Hubert noted that there was a separate discussion going on with government related to energy affordability.

Chief Brian Perrault: Chief Perrault reflected that the primary role of Hydro One is transmission and the business side of energy. He noted that the CEO spoke about trying to support First Nations. He reiterated that the expectation is to get rid of the distribution charge. He wondered why it would be in Hydro One's interest to get rid of that distribution charge. He ended by sharing some cynicism related to Hydro One's commitment to First Nations issues given that it would seem to go against their own business interests.

- Mr. Hubert assured the Chief that these two goals are compatible. He noted that Hydro One needs to collect the total revenues it needs to operate and maintain the distribution system, but rates for different groups could be different, although getting rid of a distribution rate is not an option that Hydro One was looking at. The reduced rate for First Nations, if implemented, will have to be made up somewhere else to fund the business operations.
- **Follow up from Chief Perrault:** The Chief shared that for some homes in his community, the delivery charge is more than half of the bill. He asked what is the percentage of the bill for delivery charge that Hydro One is comfortable with and going to the Ontario Energy Board with.
- Mr. Hubert explained that Hydro One does not have a percentage in mind. When the application is put together, they advise the OEB how much money it takes to run the system, and then developed a budget for five years for the OEB to approve. Once it is approved, Hydro One can recommend different rates for different classes. The Minister can ultimately make that recommendation and adjust through other income sources the rates for other groups..
- **Chief Perrault:** The Chief advised Hydro One against raising the rates of power itself to make up funding from the (potentially lower) distribution rates.
- Mr. Hubert noted that setting the electricity prices was beyond his control but he would not like to see that happen as it would essentially lead to a vicious cycle.

Councillor John Onabigon: Councillor Onabigon asked Hydro One to define a First Nations customer. Is it only on reserve? He noted that First Nations maintain the same rights no matter where they reside.

- Mr. Hubert noted that the letter from the Minister referred to exploring a rate for First Nations on reserve only.

Chief Rick Allen: Chief Allen asked who was involved in developing the First Nations rate. Was it the Chiefs of Ontario?

- Mr. Hubert responded that ultimately it is in the hands of the Minister however, there was an earlier discussion run by the Ontario Energy Board that did not involve Hydro One.
- **Chief Allen followed up:** The Chief asked Mr. Hubert if he knew who ran it.
- Mr. Hubert reiterated that the process was the OEB's and he did not know much more than that about the discussions that the OEB with First Nations. He then further explained the distribution system map in the PowerPoint [slide 4]. He noted that some First Nations are also serviced by Hydro One Remotes who have their own rates, separate from the Hydro One Distribution rates.
- Mr. Hubert elaborated on how the Hydro One distribution charges are spent: preventing outages (47%); upgrading the system (21%); customer service (12%); responding to power outages (10%) [Slide 7].

Chief Reginald Niganobe: Chief Niganobe stated that he participated in one of the sessions between the OEB and the Chiefs of Ontario. He shared a concern noted by an earlier speaker related to off reserve First Nations people. He noted that First Nations know who the members of their communities are. He concluded by asking Hydro One officials if there would be an opportunity to work towards considering off reserve First Nations for the special rate as well.

- Mr. Hubert stated that Hydro One is open to hearing that idea and, in fact, this was the kind of feedback they were hoping to get from this session. He hopes to find a way to work together on issues.

Councillor Skied: Councillor Skied asked about the loss ratio, how the loss is calculated and why customers are burdened with that loss [Slide 6].

- Mr. Hubert explained that line loss represents 4% of electricity costs to customers. He notes that line loss is an expenditure for Hydro One and has to be paid for by someone. The electricity generator produced it, but some of the power is lost as heat during delivery on the distribution system, and the losses have to be paid by someone. He noted that he understand the frustration over end users paying for something they did not get, so Hydro One is always trying to minimize those losses and costs.

Grand Chief Gord Peters: Related to First Nations people in urban areas, distribution charges go down in areas of higher density. He suggested that these reforms could be made in phases; first address First Nations on reserve and then move to urban areas.

- Mr. Hubert restated that the letter from the Minister only mentioned an on reserve rate or mitigation.

Chief Tom Bressette: Chief Bressette sees the on-reserve/off-reserve issue as an attempt to divide First Nations rights. He notes that those living off reserve have never given up their rights. It is called the principle of portability of rights. First Nations were never to be locked on to a little piece of land forever. The OEB should have an answer to the on-reserve/off-reserve issue. It is about Treaty rights and human rights. Canada recognizes human rights. The Chief reiterated that people who live off reserve have portability of rights and can come and go as they please in their own territory.

Councillor John Onabigon: Councillor Onabigon shared that if there are different rates for on and off reserve people it will mean that his Chief and Council will have to discriminate against their own people; however, they were elected by all of the First Nations membership no matter where they reside.

Chief Leslee White-Eye: Chief White-Eye inquired about the cost structure; specifically, what charges the OEB approves for Hydro One.

- Mr. Hubert clarified that Hydro One was responsible for operating the Transmission and Distribution systems. Further, IESO gets a small part of that bill as well.
- **Follow up from Chief White-Eye:** The Chief asked if there was a transportation levy to enter her community, the operating system is where it would fall?
- Mr. Hubert sought clarity on the question. Was the Chief asking who would pay a levy set by a community?
- **Chief White-Eye:** The Chief asked if a company would have to pay a levy.

- Karen Taylor, Hydro One, responded that there is sometimes a charge from communities for access and the presence of Hydro One facilities. This is included in the distribution portion of the bill and is also included as part of the company's revenue requirements.
- **Chief White-Eye:** The Chief asked if that is from the First Nation or the OEB.
- Ms. Taylor clarified that when Hydro One sets the rates they add up all of the costs and it is passed on within the rate. Any fees paid to First Nations for access are passed on through customer bills.
  Chief White-Eye: The Chief suggests that those costs should be passed on to the distributors and generators.
  Gary Schneider, Hydro One, clarified that Hydro One pays for land use, for the value of land and also payment in lieu of property taxes. He noted that they might be able to make unique payments to First Nations, depending on the situation.

Chief Mary McCue-King: The Chief expressed surprise to hear that the year-end amount was $6.5B with costs of $1.1B. There is quite a lot of profit, so she expressed frustration of being told Hydro One cannot afford to lower rates.

- Mr. Hubert noted that the proposed rate increases within the five year application does not take into account a First Nations rate yet. He notes that the majority of the increases are due to the costs of maintaining infrastructure and upgrades.
- **Chief McCue-King:** The Chief noted that in the annual report ending in 2015, Hydro One's debt to capital ratio was 50%. She stated that Hydro One could afford to lower rates as they profited $620M in net earnings. She stated that she listened to what everyone is saying and that Hydro One can afford to eliminate the delivery rate for First Nations communities or both that and profit sharing on the transmission lines going through our communities.
- Mr. Hubert responded that Hydro One had an 8.87% Return on Equity allowed by the OEB, which is the profit and that we are allowed to earn, but if we significantly exceed it we can return some of it to customers as part of the Hydro One's Earning Sharing proposal.

Chief Tom Bressette: Chief Bressette reminded Hydro One that they do not own the land neither does Canada, Ontario or the Ontario Energy Board. Yet Hydro One is taxing it. He wondered what the First Nations' portion of those profits is.

- Mr. Hubert responded that this is a broader question.
- **Follow up from Chief Bressette:** The Chief reiterated that Hydro One is taxing First Nations and he wanted to know where the First Nations' share is. He noted that Hydro One and First Nations are partners. The land is First Nations land, and First Nations people are generous to share it and help non-Indigenous people on these lands. First Nations did their part of fairness and goodness within a partnership and are asking for their half in return.
- Mr. Hubert suggested that the issue of partnership is a broad question. There are some partnerships developed with First Nations already and he hoped that more discussions on partnerships come out of the engagement session.

Councillor Ted Snache: Councillor Snache asked about the potential for breaks related to peak time rates.

- Mr. Hubert said that related to peak rates, this is a challenge because those rates are determined by the OEB. Therefore, any adjustment would have to be explored with the OEB. The Hydro One recommendation was a limited to a change in the delivery charge.

Councillor Warren White: Referring to the Ontario map in the PowerPoint presentation, Councillor White noted that he is a Treaty person, as part of Treaty 3. He asked the Hydro One team if they are willing to honour and respect the Treaty 3 Sacred Law. He asked if Hydro One knows the Sacred Law, or Treaty 3 Resource Law? He suggests that Hydro One needs to learn First Nations laws within Treaty 3. He noted that it is a land base of 55,000 square miles. Hydro One does not have a territory. He notes that education is an important part of any partnership and within regional engagements, and that Chiefs should be educating Hydro One about First Nations resource laws. With this in mind, Councillor White recommended changing the PowerPoint slide with the map of Ontario, which refer to Hydro One's Service Territory, because Hydro One does not have a territory.

Councillor [Name Unknown]: The Councillor wondered if Hydro One staff could explain rate classes. In addition the Councillor mentioned that there are seasonal customers and wonders why they cannot have their own class.

- Mr. Hubert said that in regards to rate classes, when Hydro One applies to the OEB, they develop proposals for specific rates including: urban, two rates for rural, seasonal, and commercial/industrial. He notes that they could also add a First Nations rate. These rates are based on the cost of the assets that serve them. A proposed rate that is not cost-based is therefore a policy decision of the Government and the OEB and is not an arbitrary process.

System Investments

Presentation by Mr. Greg Kiraly, Chief Operating Officer, Hydro One

Mr. Greg Kiraly provided personal background information. He is in charge of operations and is responsible for the Transmission and Distribution System (T&D system) along with Mike Penstone, Vice President of Planning, and Gary Schneider, Vice President of Shared Services.
In his role, Mr. Kiraly is responsible for safety and reliability of the system (including the number of outages and duration of outages). He noted that his job is also to keep costs low or lower costs. This essentially means trying to improve productivity and decrease costs, decrease vendor costs. Essentially, his aim is to keep the system safe, reliable and affordable.

Mr. Kiraly also acknowledged that he does not know much about First Nations and this has been an education for him. He noted that his job is to achieve operational excellence. To identify where Hydro One is at, identify where they can get to and to put a plan into place to get Hydro One there.

Representative from the Chippewas of Rama [No Name Provided]: The speaker questioned what Mr. Kiraly's presentation has to do with hydro rates. They noted that they had to cancel some important meetings to attend this engagement session.

- Mr. Kiraly responded that he will get to a discussion about reliability and how that affects everyone within the system.

- Referring to the PowerPoint [slide 8] he noted that within the transmission system the primary causes of interruptions is equipment failure and weather. Other causes are major environmental events (tornados, fires, etc.) and animal/vehicle/tree contacts.

Chief Patricia Faries: Referring to Slide 9, she noted the green dots, which indicate issues with reliability. She wondered why there were no lines identified on the slide in those areas.

- Mike Penstone, Vice President of Planning, Hydro One, explained that not all Hydro One lines are represented on the map as it would be too cluttered. He noted that they are monitoring those lines within the distribution system where there are system disruptions. Where Hydro One sees deterioration or degradation, there will need to be repairs and costs associated with those improvements.
- Mr. Kiraly added that it costs more in northern and remote areas to service the system.

Chief Gerry Duquette Jr.: The Chief suggested this is just a reality in Canada. Further, he noted that his community was not represented by a dot on the map within the slide.

- Mr. Penstone clarified that the dots represent hydro stations, not communities.
- **Follow up from Chief Duquette:** The Chief noted that his community had created their own energy project, where the band paid for the line in the 1950s. He suggested that it is discouraging when he hears about the costs. He also suggested that Hydro One should provide their employees a lunch box as many times they are working close to restaurants and so once they leave to get lunch, it takes a long time and things do not get done. In his community they had outages for 11 days; also during Christmas time. Chief Duquette suggests that he is looking forward to change and that his community has been asking what was going to happen. He needs to take the information back and share it with his community.
- Mr. Kiraly responded that Hydro One does not rest until every customer has their power back on but recognizes that it is more challenging in the remote north.

Chief Melvin Hardy: The Chief suggested that Hydro One look at repairing the transmission lines around Lake Nipigon. There is a station near his community and there is still trouble. He also asked a question around when the lines break and are repaired, would the rates go up.

- Mr. Penstone responded that, in order to ensure transmission networks provide reliable service, investments need to be made. He notes that Hydro One is spending money to sustain its networks and those investments are recovered through hydro rates.
- **Follow up from Chief Hardy:** The Chief asked that if it breaks do customers pay for it?
- Mr. Penstone responded that Hydro one anticipates that there will be repairs and costs
- **Chief Hardy:** Responds by saying that there are lots of hours with power and when Hydro One equipment fails, do customers pay for it?
- Mr. Penstone answers that, yes, but all rate payers pay for the repairs.
- **Chief Hardy**: Notes that there is greater density in the south and thus they have lower rates. He noted that Hydro One should have some statistics that are First Nations specific.

Mr. Kiraly noted that Hydro One is looking at getting coverage around the clock and is working with the unions on that. He notes that they have good reliability on the transmission system but less so on the distribution system as it does not have the same technology. Mr. Kiraly notes that

Hydro One workers sometimes have to check an entire line; that could be 100 miles long. Hydro One needs to upgrade this to avoid these delays. These upgrades will take years of investment and changing labour agreements, all aimed at improving reliability.

Chief Brian Perrault: The Chief recounts an incident last spring where there was a Hydro One crew in his community clearing trees around the lines. The crew came right into his yard where he had 5 trees. Instead of trimming the trees, they cut them all down. The Chief's wife's grandfather planted those trees and he felt like he should have been spoken to about it before they were cut.

- Mr. Penstone said that Hydro One has not trimmed in a long time. There are OEB standards related to dying and diseased trees. However, Mr. Penstone felt that he could not comment any further because he did not know about the specific situation. In addition, he committed to following up.

Councilor Ted Snache: Councillor Snache noted that the cost saving measures were part of what Hydro One does and it makes sense to redo the lines as quickly as possible.

- Mr. Kiraly noted that it is about balance. That Hydro One can ask the OEB to make these kinds of investments that are needed, but if we ask for that there needs to be an increase in the rates.

Chief Mary McCue-King: The Chief noted that there were issues with the lines in her area and asked if this is that going to impact the hydro rates in her community. She noted that Hydro One had proposed a change from a single phase to three phase power. She wonders if that is necessary and if it were more expensive.

- Mr. Kiraly responded that it would be more expensive. What you are talking about is a submarine cable and the cost would be borne by all rate-payers. Referring to slide 10, Mr. Kiraly describes the line performance for First Nations in 2016.

Chief Leslee White-Eyes: The Chief thanked the presenters and noted that the information was helpful. She was wondering about the relationship to community emergency planning. Specifically, she asked if Hydro One develops relationships in the community or is it more reactive. For example, can there be collaborative work to develop poles that have street lights on them. In this, Hydro One would be giving back to the community. She asks if there are other details of potential relationships going forward including sponsorships, career fairs, developing community protocols for when Hydro One comes into First Nations.

- Mr. Kiraly responded that Hydro One is open to any of the ideas the Chief just mentioned.
- Mr. Penstone said that related to the street lights, there is a legacy of sentinel lighting, but Hydro One is open to any suggestions.
- Mr. Kiraly mentioned that related to emergency planning, there are some relationships with communities around that, but he recognized that there is certainly not enough of that going on. He continued that they are open to any protocol that the Chiefs feel is most appropriate, for example, Hydro One workers stopping at the band office to let the leadership know what is going on. Mr. Kiraly concluded by saying that many of the items that Chief White-Eye mentioned were possible to achieve.

hydro One

WRAP UP

Mr. Goulais indicated that as heard from the participants, Hydro One should be providing the wrap-up.

Mr. Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One, began by thanking Mr. Goulais and calling up the Hydro One Executive Team to the front. He noted that the conversations were captured visually and in notes. He reminds participants that these are the beginning of more discussions in order to lead to action. Mr. Pugliese identifies the main themes of the discussion.

1. The short-term, immediate economic issues including affordability: There is the additional rural burden and hefty delivery charges. There needs to be serious attention paid to the economic realities faced by First Nations and identify how to provide relief.
2. The need for policy change: A First Nations rate is beyond the power of Hydro One to change, but the Minister will be attending the dinner and may have more insight into the First Nations rate.
3. Longer term issues: There is a need to address longer term issues including outstanding agreements around access, rights, land use, assets on the land. There have been fruitful agreements in the past and Hydro One will continue to work on agreements with First Nations.
4. Relationships and Engagement: Hydro One needs to work with First Nations to develop a long term strategy on engagement. This was the first of many meetings. Hydro One is willing to come to your communities, regions, and tribal councils. These are opportunities to share information and educate both ways.

Mr. Jamie Scarlett, Executive Vice President, Chief Legal Officer, Hydro One, noted that the executive team members see working with First Nations as an overlapping mandate across their areas of focus. He noted that they understand it is critical to deal with costs and rates and Hydro One needs help from the government on that. Senior management understands how acute the issue is for First Nations. Regarding land use and resources, the team learned about how long negotiations have gone on and how this has been unacceptable for First Nations. They do not want these kinds of delays to continue. In order to achieve this, he encouraged direct, open and energized conversations. He encouraged a principled and fact-based method of moving forward. Thirdly, he noted the need to move forward on partnerships and co-ventures and working with First Nations more in the area of procurement.

Mr. Greg Kiraly, Chief Operating Officer, Hydro One, expressed gratitude for being at the engagement session. He thanked the crowd for good questions, comments and providing an education for him. He also noted that the participants could count on him and his team to improve the reliability of the system and get costs under control.

Mr. Pugliese asked for any questions or final comments?

Councillor Ted Williams: Councillor Williams shared an appreciation for the meeting and noted that he learned a few things. He stated that it was a difficult day and he appreciates that Hydro One heard their community issues. He noted that he does not want to come back in a year with nothing changed for the better regarding power. He commended the senior officials for facing a tough crowd.

Mr. Pugliese noted that he wants to be back here celebrating success in one year. The comments will be shared with board members. He concluded by noting that the meeting will end but the conversation will not. He encouraged participants to reach out to Hydro One if there is something you would like to add, and Hydro One will be happy to come to your communities for similar meeting. Thank you.

Meeting Adjourned

Hydro One and First Nations Engagement Session
Mandarin Room, DoubleTree by Hilton
Friday, February 10, 2017

SESSION REPORT

Table of Contents

WELCOME

Mr. Phil Goulais, Session Facilitator, called the meeting to order and introduced Elder Andrew Wesley. Elder Wesley provided the opening prayer and a smudge. Mr. Goulais noted that on the previous day, the session was welcomed by the Mississaugas of New Credit First Nation and he thanked them for continuing to allow the attendees to meet on their territory.

Mr. Goulais provided background information from the previous day and thanked participants for letting him share the day with them. He noted that he was pleased to see his own Chief present, Chief McLeod. In his work with Hydro One, Mr. Goulais has built relationships with communities and has travelled to communities to give procurement workshops and share career opportunities at Hydro One. He noted that Chiefs were asking how to work with Hydro One and effect change, particularly around hydro rates. At the same time, Hydro One was asking how to work with First Nations. This came from an understanding of the need to work better together. This was part of the motivation for hosting the engagement session.

Mr. Goulais shared the message from the invitation related to the objective of the session: "*Our most important objective is to hear from you and the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board.*" He reassured participants that these discussions did not constitute consultation, and that it was just meant as a discussion. He noted that it was an honour to work with the Chiefs and Councillors, Grand Chiefs, Deputy Grand Chiefs and the Regional Chief. It was an honour to hear firsthand what community members are saying.

Mr. Goulais noted three senior executives from Hydro One in the room, noting that they are the decision-makers and the engagement is an opportunity to draw from their experience and knowledge. They were attending to hear the views of First Nations. He concluded by stating that the engagement is an important first step. He commended the participants for venturing out and taking that step. He shares his hope for a productive day of information sharing and discussion as well as establishing a plan going forward to continue the discussions and strengthen the relationship further. He asks that everyone consider what they will collectively leave as a legacy for their young people and generations to come.

As far as the morning's agenda, Mr. Goulais asked that participants introduce themselves, state where they are from and any early comments. Mr. Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs will give a presentation on customer service. He asked participants to speak to what they would like to get out of the session, and what great customer service means to them. It was noted that notes of the meeting are being taken and participants would receive the written notes of the session for review. In addition, a graphic artist is capturing comments in a graphic way.

INTRODUCTIONS

Chief Barron King, Moose Deer Point First Nation: Personal Introduction

Jerry Fontaine, First Nations and Métis Relations, Hydro One: His work with Hydro One involves travelling to communities and conducting relationship-building work. He is from Treaty 1 in Manitoba, Sagkeeng First Nation. He is also party of Treaty 3, as the treaties did not recognize provincial borders. He noted that at the session yesterday there was some confusion on the point the purpose of the meeting, so he clarified that it is about building a relationship, trying to do things right, and identify where there can be changes at Hydro One. The company is seeking how to do things differently.

George Kakeway, First Nations and Métis Relations, Hydro One: Mr. Kakeway introduced himself as from Rat Portage, Treaty 9. He noted that he works with Treaty 3 communities and has been doing this work for Hydro One for about three years. In doing so he follows the traditional spiritual protocols before entering each community.

Chief Tom Johnson, Seine River First Nation: Chief Johnson noted that in his community when they see a Hydro One truck it is only for one thing [presumably to cut off service]. He notes that it has been a long process of negotiations and he would like to walk out of the engagement session feeling good about the process. He recognized that one day would not solve everything; there will need to be more time. However, he was looking for something to look forward to regarding hydro rates.

Rob Globocki, Director, Customer Service, Hydro One: This Customer Care Director noted the desire to establish connections with customers. They do not want to be seen as just people who come to cut people's power off. He suggests that Hydro One wants to work with First Nations, provide information and ask about First Nations' needs and priorities.

Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One: Mr. Pugliese noted that he has only been with Hydro One for five months. He is originally from Ontario. He describes his responsibility as being about customer care and Indigenous Relations. He thanked the participants for coming and noted that the previous day had been a frank and honest discussion. He suggested that the Hydro One executive team were forging a new commitment to relationship building. He reiterated that Hydro One appreciates the presence of the attendees and recognized that they were busy. He reaffirmed that the session is a conversation and is not a consultation. He saw this as the first chance to meet and get to know the new team and answer participant questions. He also mentioned that they wanted to do more community visits.

Steven Nootchtai, Councillor, Atikameksheng Anishnawbek: Personal introduction.

Chief Alex Batisse, Matachewan First Nation: Chief Batisse noted that he was attending to voice his concerns about the very high delivery rates.

Amy Lickers, Chiefs of Ontario: Ms. Lickers introduced herself and said that she works with the Chiefs of Ontario Chiefs Committee on Energy.

Sherrylyn Sarazin, Councillor, Algonquins of Pikwakanagan: Councillor Sarazin noted that her community has a long-held grievance with the energy sector. Dams took away their food; the eels disappeared. Energy lines were brought through in 1954 without permission. They are only now almost at an agreement. She noted the need for more cross-cultural sensitivity training for the staff dealing with First Nations. They should know the Seven Grandfather Teachings. She wondered how her community members could see relief directly on the bills, given the rising cost of living and high hydro bills with delivery fees costing more than the energy. She is seeking a solution.

Chief William Diabo, Magnetewan First Nation: The Chief noted that he is in his third term in office. He thanked the organizers for putting together the gathering to bring his community's concerns to the table. His concerns are primarily about the relationship, the services and the high rates faced by his community. He noted his hope to achieve a solution, not just hear more words.

Chief Greg Peters, Delaware Nation (Moravian of the Thames): The Chief noted he is in his fifth term in office. He was attending the meeting for similar reasons to everyone: the standard of living for his people is in jeopardy. They have lower standards of living than other communities. To address this, they need to come up with a plan.

Chief Dean Sayers, Batchewana First Nation: Chief Sayers notes that the government of Ontario compels Hydro One to work with First Nations. His Elders make sure he expresses the fact that First Nations in Ontario pay the highest taxes of anyone. They had to give up 50% of their revenues and their quality of life. In the 1800s they were managing the resources but that was taken away. They refused to pay taxes to the government because they already paid with the violations on the land. Any tax that is paid today (PST, GST, etc.) is a violation of their Treaty. He notes that one measure that Ontario could do is point of sale exemptions for all First Nations in Ontario for any tax. If First Nations, no matter where they live, show a status card in paying a Hydro One bill, all taxes should be removed. The delivery charge should also be removed because of the lines going across their lands. Chief Sayers notes that there are many other issues that he would like to bring forward. He thanked Hydro One for inviting him and the other Chiefs for attending as well.

Tausha Esquega, First Nations and Métis Relations Team, Hydro One: Personal introduction.

Cesar Martinez, Customer Care, Hydro One: Mr. Martinez was attending the session to find solutions that are mutually agreeable.

Chief Scott McLeod, Nipissing First Nation: The Chief shared that he was encouraged to hear that Hydro One wants to hear the issues faced by First Nations. The situation is tough. His community just signed a bunch of cheques to help seniors make it through the winter. Most of the homes in his community are heated by electricity, so people have to choose between food and heat. He also echoed the comments from Chief Sayers regarding the constant struggle with the government to honour their Treaty obligations. He notes that hydro is a resource that is taken from the land, and instead of sharing; First Nations have to pay huge costs for it. Energy is generated from Mother Earth, and we have agreed to share it in the Treaties. The Chief hopes he can start seeing the government live up to their obligations.

Kathleen Naponse: Ms. Naponse noted that she is from Whitefish Lake but is attending on behalf of Thessalon First Nation. She would like to know what is happening with the rates and where there are plans for more lines to go. She sees this as impacting her Treaty rights.

Imran Merali, Interim Director, First Nation and Métis Relations, Hydro One: Personal introduction.

Karen Taylor, Senior Director of Regulatory Affairs, Hydro One: Ms. Taylor noted that she worked on the application to the Ontario Energy Board (OEB) and she was also a member of the Ontario Energy Board at one time. From the meeting, she hoped to take away sustainable and actionable items.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte: Chief Maracle described his vast traditional territory that extended to both sides of the river. This territory was never surrendered nor was any of the rights within that territory surrendered. The Niagara Power Generation Station is within that territory and his community is looking for benefits from that. First Nations' resources have led to a comfortable life for the colonizing nation to the detriment of First Nations quality of life. People on reserves are paying the highest rates. These people are further away from big cities, have lower incomes, can only find part-time jobs and often work minimum wage. He notes that the dynamics within the province were not considered in developing the current rates. In addition, municipalities have collected royalties from power lines that cross First Nations land. Sometimes there are land claims or lands that have not been surrendered at all and First Nations should be compensated. He notes that First Nations have contributed resources to the country and have also contributed in times of war. Rates are a political decision, and thus can also be changed by politicians. The rural rate is not properly applied to First Nations. From the meeting, Chief Maracle was looking for some kind of commitment. The OEB will do what the Minister tells it to do. If the Minister was committed to developing a First Nations rate, they should have already had their discussion and told the Chiefs what the decision is. He noted that he hopes this happens. He also hopes that First Nations can build a better working relationship with Hydro One and Ontario, based on the actions that are taken in response to First Nations' concerns.

Art Jacko, Manager of Lands and Resources, Whitefish River First Nation: Mr. Jacko noted that Chief Shining Turtle could not attend, so he was attending in his place, primarily to find out more information. His territory encompasses Treaty 3. None of the promises were ever fulfilled. Fast forward here today, Ontario has created a huge regulated monster. He stated that he was glad to see there is a new management group and will be watching to see how things change. He noted that the process is about the Hydro One application to OEB. He agrees that the infrastructure needs to be addressed. He noted that he knows the cost of running a business however, it is hard to understand and to explain to his people the rationale and reason for the rates that are being contemplated. While there are huge profits at Hydro One, First Nations communities continue to suffer and have not seen any breaks. In the 1853 treaty, First Nations were promised $4 at that time. Today it is still $4. He noted that he looked forward to seeing the application that Hydro One will submit and how they intend to deal with those Treaty issues.

Peter Nahwegahbo, Consultation Officer, Aundeck Omni Kaning First Nation (Sucker Creek): Mr. Nahwegahbo noted that he was attending on behalf of the Chief, and will be taking information back for the Chief. He noted that he was looking forward to this meeting, as it was his first session with Hydro One. He recalled that, 15 years ago, he went to his Chief about his hydro bill and then followed up 10 years ago. The Ombudsman of Ontario is finally hearing his case.

Chief Edward Wawia, Red Rock Indian Band: The Chief noted that 15 years ago his mother was Chief and she was saying the same things being said at this engagement session. His community has three dams in their back yard. They are close to Nipigon and yet their bills are 2 or 3 times higher. He would like an answer for why that is. He explained that they teach their young people to conserve energy and pay their bills, but when their bills are so high and the delivery charge is so high, they have troubles paying. He suggested that the delivery charge is so high because First Nations cannot be taxed. He concludes with a comment on maintaining the hydro lines; he would like to see a manual way of tending the lines and an end to spraying the lines.

Gary Schneider, Vice President of Shared Services, Hydro One: Mr. Schneider explained that procurement and land matters falls under his area of responsibility.

Chief Dwight Sutherland, Takwa Tagamou Nation: Personal introduction.

Peter Archibald, Councillor, Takwa Tagamou Nation: Councillor Archibald cited a number of issues that needed to be discussed with Hydro One. He mentioned a transmission agreement process they are hoping to start and they need to know who to speak with and where to go from here. He reflects that delivery charges are another issue. These charges are sometimes three times the electricity charge. There are also transmission problems despite there being several generating sites in his territory. One was just built at New Post Creek. They have also been impacted by not being able to fish out of their river anymore. There are well-documented impacts of sewage dumping, including damage to the environment, and the animals cannot drink there either. This is not being monitored. They are also impacted by Highway 101 and mining in the area. There was no regulation on these activities prior to the Environmental Assessment process. He shares that there is no doubt that people got sick and died from the contamination. He concludes by inviting Mr. Cesar Martinez to meet with him and discuss these issues further.

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: Mr. Hubert noted that he would be giving a presentation later in the afternoon.

Devi Shantilal, First Nations and Métis Relations, Hydro One: Personal introduction.

Lucy Trudeau, Band Manager, Sheguiandah First Nation: Ms. Trudeau noted that she would like to bring back to her community real world solutions to the many issues they face related to hydro.

Daniel Charbonneau, First Nations and Métis Relations, Hydro One: Personal introduction.

Erin Henderson, Regulatory Affairs, Hydro One: Ms. Henderson noted that she had been working with the First Nations and Métis groups at Hydro One in relation to this session.

Valerie George, Consultation Coordinator, Chippewas of Kettle and Stony Point First Nation: Ms. George noted that she wanted to follow up on a point made earlier by Chief Sayers around transmission lines. She also raised the point around an off-reserve exception because sometimes people have to move off-reserve but that does not mean they have forgone their right. She ended by reminding Hydro One that this is not a consultation and Hydro One was not provided consent for anything.

Chief Paul Eshkakogan, Sagamok Anishnawbek First Nation: The Chief expressed his desire to talk more about solutions and the work that needs to be done to achieve those solutions. He noted that the Premier could impact the rates. He added that there was a need in his community for employment and training. He recalled, years ago, when Hydro One was building the 250kV line from Sudbury to Sault Ste. Marie; they were recruiting community members across the North Shore. He noted that now, we need to go back and look at how First Nations can participate in the business and create employment in his community. He would also like to look at partnering with Hydro One to look at creating energy efficient communities. He notes that there are many energy sources in First Nations that should be considered. He shared that he was looking forward to the discussion.

Warren Lister, Vice President of Customer Care, Hydro One: Mr. Lister explained that his role is everything to do with billing and energy conservation. He noted that they are waiting to hear about rate relief from the Minister, but that in the meantime, Hydro One can do some things to assist First Nations and that is what he was interested in speaking about. He noted that he knows Hydro One has work to do as it relate to policies and procedures and committed to taking action on those.

Chief Wayne Pamajewon, Shawanaga First Nation: The Chief explained that he was attending the session out of a concern for where we are headed and how we get there. He also affirmed the words of Chief Sayers. He notes that the issues with Hydro One have been around for a long time. His community signed an agreement on hydro in 1951, which clearly points out that power would be delivered, to his community and three other communities at no cost. The interpretation of the agreement is not done from the First Nations perspective. His band members are telling him that they cannot pay their hydro bills and have to choose between food, power or rent. He notes that he came from a time where they would study using a coal oil lamp and when they ran out of oil they borrowed or got creative. Today people need power. We must find a way to make it better for his people. He notes the treaty, which begins at the Severn River and goes to Batchewana Bay. Those lands belong to his community and Hydro One has not paid for crossing those lands. That Treaty said that the First Nations would get benefits. This has not happened. According to that Treaty, his people should not be paying for hydro. They have paid enough. The Chief noted that his community needs three-phase power. They have upgraded the lines a little bit in the community but they still have lower electricity costs and very high delivery charges. The Chief had asked his community members to hand in their bills in order to record the total costs his people were facing. He suggested that all the leadership in the room do that. As Chief, in 2012, he sat at a huge table with First Nations on one side and Hydro One lawyers on other. They did not get very far. He questions how Bell Canada can be paying Hydro One for the use of the poles with no agreement from the First Nations. He noted that he wished some Hydro One policy people had to live on the reserves before making policy for First Nations. He concluded by saying he wanted to talk about the future for his community.

Mary Ann Giguere, Councillor, Thessalon First Nation: Councillor Giguere noted that she has concerns about the high hydro costs, and was attending the meeting to take information back to her people.

Chief Patricia Big George, Anishnaabeg of Naongashiing: Chief Big George began by stating her community was part of Treaty 3. Many of the issues that had already been brought up, resonated with her. She described that her community is at the end of Highway 21. She notes that the delivery charges are usually way more than the hydro charges. She asked if anyone sits at a negotiation table with Hydro One. She described a substation about 35 km from her community that was built when a mine came in. She thought that hydro rates would go down, as a result, but they actually went up. She viewed Hydro One as catering to the mine as there is an economic incentive coming from the mine. Regarding procurement, she noted that the only contract work for First Nations seems to be cutting trees around the line. She asked if that was the only work available. She asserted that First Nations are worth more than menial tasks. She noted that about 60% of her community members are taking their hydro bills to the band office because they cannot afford to pay them. They should not have to rely on band funds to pay those astronomical rates.

Chief Lorraine Crane, Slate Falls First Nation: Chief Crane noted that she wanted to come to the meeting to discuss the many issues with Hydro One. She describes being born and raised on the land. Hydro One entered the area in 1930. There were agreements between Hydro One and six bands signed in the 1990s. She notes that they have never received reserve status, partly, she believes, because of Hydro One. They have been fighting for decades. The Chief recalled talking to a woman at Hydro One and the woman said Hydro One held the pen. This was both frustrating and offensive. In addition, her community shares many of the same struggles with Hydro One as others have mentioned. Hydro One can just drive in any time and disconnect people, and the community struggles to get people connected so the pipes do not freeze. The hydro bills are high and there is not a lot of employment in her community. They have annual contracts with Hydro One for clearing the land around the lines. She noted that when she was growing up, she always respected the hydro line going through the land. They always let people go through the land. This adds to her frustration alongside no reserve status, high costs of hydro and Hydro One can just come in whenever they want. She wants this to stop.

Chief Dorothy Towedo, Aroland First Nation: Chief Towedo noted that their concerns were many of the same already stated. She is new as a Chief and is learning. Her community is about four hours from Thunder Bay. They also do not have reserve status. She noted the outrageous cost of hydro while her people live in poverty. It makes it hard to pay for heating in winter. Many in her community are unemployed. Many families are forced to choose between power and food. This is also a challenge for Elders and people on fixed income. They also face challenges with interruptions to power that sometimes last days. As a result food gets spoiled and these are people who cannot afford to waste any food. Many people come to the band office for help with food or the hydro bill. The Chief concluded by stating that she was attending to learn how the system works and how these rates are determined.

Chief Elaine Johnston, Serpent River First Nation: Chief Johnston expressed gratitude for attending the session. She supported the comments of Chief Sayers regarding the Treaties. Her community is part of the Robinson Huron treaty area. The political conversation around 'Canadian Values' from Kellie Leitch reminds her that everyone who came to Canada is an immigrant. She posed the question: what are Canadian values? How did settlers treat First Nations people? She reminded the room that First Nations people treated newcomers well but that was not reciprocated. The way that First Nations have been treated for 500 years has been abysmal. Regarding relationships, the Chief notes that each side has to understand one another. She was pleased for the opportunity to open up a conversation; however, there is a need for some cultural understanding and an understanding of First Nations history, in order to understand where First Nations are coming from. The fathers of confederation gave First Nations people the residential school system. Hydro One needs to know the history of this country. Regarding energy, the Chief noted three things: 1) the Minister of Energy is the one making decisions; 2) there is confusion around Hydro One and the OEB. Who is doing what? and, 3) there needs to be some cultural recognition within Hydro One from the bottom to top. In addition, there needs to be designated staff as part of the call centres that can respond to land issues and taxation issues, etc. The Chief noted that when members call the call centre they get nowhere. Chief Johnston concluded by sharing appreciation to Hydro One for hosting this event because relationships start with dialogue. While Hydro One is sharing information, First Nations should share their perspectives too.

Deborah Wetzel, Councillor, Big Grassy First Nation: Councillor Wetzel concurs with everything previously said.

Lee Anne Cameron, First Nation and Métis Relations, Hydro One: Personal introduction.

Chief Wayne Smith, Naicatchewenin First Nation: Chief Smith noted that it was a pleasure to attend the engagement session. He came hoping to know more about delivery charges, as it is the biggest issue facing his First Nation. He recounted a personal anecdote that was instructive of what his community members deal with related to Hydro One. He shared that he had a rental unit that he paid the hydro for monthly. His tenant moved out in October, so he closed off the account. When a new tenant moved in, he transferred the bill to the new tenant. He received an excellent letter of recommendation from Hydro One, but also received a $126 bill from the month before. He forgot about it and missed the due date by a week and a half. Ultimately he paid the bill online. However, when he came back from vacation it had been sent to collections by Hydro One. The Chief noted that First Nations members are badly treated by Hydro One customer service and there is a real need for a change in attitude. He also agreed with the issues brought up by the other participants. Out of this meeting, the Chief was hoping to learn more about Hydro One and also move from talking to action.

Jason Laronde, Director of Lands and Resources, Union of Ontario Indians: Mr. Laronde shared that he was attending the meeting to listen.

Brendon Huston, Economic Development Coordinator, Union of Ontario Indians: Mr. Huston noted that he was also attending to listen.

Chief Wayne Pamajewon, Shawanaga First Nation: The Chief noted that when it comes to submersible lines, that First Nations never gave up rights to the water.

CUSTOMER CARE

Mr. Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One
Mr. Pugliese began by thanking the participants for the frank discussion and open dialogue. He noted that Hydro One was undergoing a lot of changes, including a new system in Ontario. There are a lot of moving parts. For its part, Hydro One is undergoing profound changes, because of the shift towards a private company with shareholders. Providing some clarity, Mr. Pugliese noted that Hydro One was not in the power generation business, but in the Transmission and Distribution businesses. Hydro One does manage the delivery charges. He admitted that the new team at Hydro One recognizes that things had happened in the past when it came to First Nations land and communities. While they cannot change what happened in the past, the new Hydro One team is making a commitment to work differently, in partnership with First Nations. He asked the attendees to judge the new team on their actions. He noted that in a year from now, or sooner, Hydro One will be able to share insights and progress on closing out past grievances, in helping community members with bills, and making movement on

affordability. He recognized that this meeting was the first step in a long journey of building relationships.

Mr. Pugliese provided information on four points: the First Nations rate, affordability, calls to action, and understanding the distribution rate filing. Regarding the First Nation rate: in Ontario hydro bills are generally made up of the following: 50% for generation costs (nuclear, hydro, gas, wind, solar, biofuel) and 37% of the bills are distribution costs. These costs vary based on density (more poles than people in rural areas). Hydro One applies for, but does not set the distribution rates; those are set by the OEB. However, Hydro One is trying to influence change related to those distribution rates. Mr. Pugliese recalled seeing bills where the delivery charge is larger than the consumption charge. He noted that he views this as a serious problem. He recognized that in remote communities, where there is electrical heat combined with poorly insulated homes (not on gas lines for forced air), the result is high consumption charges plus even higher delivery charges.

Regarding the potential for a First Nations rate; this is an issue being managed by the Minister of Energy. In developing the proposed First Nations rate, there were meetings with the Chiefs of Ontario and five (5) sessions that included 48 communities. The First Nations consultation was completed last fall in 2016. Mr. Pugliese shared that the final paper was filed by the OEB with the Minister on December 29, 2016 and he believes an announcement on the First Nations rate is imminent.

Hydro One does not want those high rates for communities and has teams working on affordability issues. Once those are resolved, then they can move on to system issues. Hydro One has been focused on education, advocacy and responsiveness. The need for education is acute because not many people understand the hydro system in Ontario. Customers, communities and even decision makers/policy makers need to understand the breakdown of costs and why they are so high. There was a cost increase once Ontario got off coal, for example, which was transferred to the cost to consumers. Hydro One can watch its costs, save money in different ways, and defer expenditures, where possible. Hydro One operates on the cost recovery system, and there are costs associated with maintaining that system which requires capital investments. These plans all have to be submitted to OEB.

Mr. Pugliese noted that Hydro One also plays an important role in advocacy that includes going to policy meetings at the Minister's office and also with the OEB. Hydro One met with the Premier last week and presented an advocacy position on behalf of customers. In that meeting, Hydro One described the situation as a crisis that needed radical redesign of policy in order to address the affordability issue. At that meeting, Hydro One shared information on how the redesign might look to reduce costs on the power generation side, etc. Mr. Pugliese noted that it was not just Hydro One who brought this message to the Premier, although Hydro One probably feels the most pressure because their name is on the bill. Hydro One owns that relationship with customers. Hydro One needs to start listening to the impact that high bills are having. The message was well received by the Premier and the level of engagement and knowledge of the Premier and her staff was impressive. Mr. Pugliese commented that Hydro One saw it as time to act as the voice for their customers, but this advocacy is not something that they can do alone. Hydro One believes that the voice of First Nations on this issue is strong. Hydro One and First Nations sharing the same message on affordability would be powerful. Related to improving Hydro One's responsiveness, Mr. Pugliese noted that they have heard First Nations speak about empty promises from the past. The new team at Hydro One will improve on this performance.

Mr. Pugliese notes that there are some actions that are beyond their ability to change, however, where they can; there are some actions that can be taken to respond to First Nations concerns. Recently they have taken some steps such as waiving reconnection fees. A customer was in arrears and had failed in the payment plan, but in working with the customer they learned that, it was not that the customer could not pay, they just could not follow the plan exactly. Hydro One recognized that they must be more flexible to meet customers' realities. Payment plans can be worked out to better suit customers. Also related to 'taking action', Mr. Pugliese asked participants to let Hydro One know what they wanted in terms of training programs for communities. They are willing to go to communities to work on individual bills, explain the bills, and get clients on plans; however, these activities take many visits. Another option is training people within communities to host these meetings and provide this service within the community. These programs are just getting started, but Hydro One will continue to work with communities in this area.

Chief R. Donald Maracle: The Chief noted that some councils loan monies to community members for bills in arrears. He asked what Hydro One could do for communities in this situation. Some people have had to go to high interest rate companies to borrow, which is a hard cycle for people to get out of.

- Mr. Pugliese responded that people would generally have to rely on social service agencies and that Hydro One does not have a policy on this issue, but can potentially look into it. In addition, he noted that they spoke with the Premier on affordability funding. The current program qualifiers are stringent but perhaps Hydro One can use the surpluses in cases such as this.
- **Follow up from Chief Maracle:** The Chief notes that in smaller communities there are no service agencies and have to depend on the band council.
- Mr. Martinez, Hydro One, noted that when they come to the community in March they will bring the United Way with them. Community members can apply for relief from the United Way. He has done this with First Nations communities before.
- Mr. Pugliese noted that this issue has come up before and is something that they want to look at. They are looking to support an adjudication process in order to address it. This is a potential suggestion for action going forward.

Chief Elaine Johnston: Chief Johnston noted that a lot of her people are living in poverty, so a payment plan will not help them. They are having a hard time paying for food. There are other social service programs, but those have a limit.

- Mr. Pugliese commented that Hydro One cannot address poverty in a general sense. It is a very broad, complex social issue. However, Hydro One can focus on the bills as part of their own social responsibility. Also related to community social services, perhaps Hydro One can support those through Hydro One's community giving program.

Peter Archibald, Councillor: Regarding Hydro One coming into communities and turning off power, Councillor Archibald asked if it was possible to put a load limiter on these houses. He reiterated that when the power is turned off pipes freeze causing unnecessary renovations that cost even more money. He also expressed frustration that Hydro One staff go on reserve to shut people's power off and do not even stop at the band office first. If this does not change, Councillor Archibald suggested that Hydro One staff would no longer be welcome in his community. He reiterates that concerns must be addressed, especially the delivery charges. He shared his position that the delivery charge should be removed altogether.

- Mr. Pugliese responded that Hydro One supports Councillor Archibald's position on the delivery charge; however, it is not Hydro One that controls that. Regarding Hydro One staff entering the community, Hydro One has heard this concern previously and believes that their staff must respect the community protocols. They should first visit the band office. Finally, with respect to the disconnection and whether there could be load limiters, Mr. Pugliese noted that there are resources on this that Hydro One is willing to share through their outreach activities.

Chief Wayne Pamajewon: Chief Pamajewon brought back the conversation on the agreement from 1951, which was signed by four communities. He inquired about how much revenue was generated through that agreement over the years. He would like to see the historical numbers. He also suggested the conversation on submersible cables should move forward.

- Mr. Pugliese responded that he is sure there must be information on the revenues generated through those agreements. He noted that he and the Chief Legal Officer had been going through all of the agreements to identify what had gone wrong in the past and where there are fixable issues. Hydro One wants to re-evaluate all of those agreements and resolve outstand issues. Regarding submersibles, Mr. Pugliese noted that they are happy to sit and meet to have a discussion. In addition, the Chief Operations Officer would be presenting later and would be better suited for that discussion.

Chief William Diabo: Chief Diabo spoke about delivery costs. He shared that they have houses in his community that they rent. They turn the breakers off in the summer and yet they still receive bills with an astronomically high delivery charge. He is seeking an explanation for that. In addition, he asked for more details about the First Nations rate and the consultation with First Nations on that issue.

- Mr. Pugliese noted that consultation has not started for Hydro One on that issue. Regarding the First Nations rate, that was a consultation conducted by the OEB last year.
- **Response from Chief Diabo:** The Chief noted that his community was not consulted and added that the Chiefs of Ontario does not consult for his community; rather, they only advocate for his community.
- Mr. Pugliese noted that Hydro One can provide more information on that consultation initiated by the OEB and on the request for a First Nations rate.

WELCOME REMARKS FROM THE PRESIDENT

Mr. Mayo Schmidt, President and CEO, Hydro One

Mr. Schmidt provided a warm welcome to the Grand Chiefs and Chiefs. He recognized that the participants were looking for action and outcomes. He noted that the Hydro One team was learning more about the issues that are facing First Nations. Many of the issues identified the previous day were brought up again at this session. Hydro One is going through a period of transition. As part of the transition, the company has taken a renewed focused on customer service. He assured participants that their voices are being heard, not just by the leadership team in attendance, but also the entire Board of Directors. Hydro One, being a publicly listed company, opens up an opportunity to advocate on behalf of customers, whereas before Hydro One just took instructions from the province. The leadership team has come to understand how painful the delivery charge is for First Nations and they are speaking with the province to try to address that. Hydro One serves 88 different First Nation communities, which represent a great deal of diversity. He noted the need to account for constitutionally protected rights and unique cultural connection to the land.

Mr. Schmidt shared that Hydro One met with the majority of the First Nations communities that they serve, which included over 200 community visits. He noted that they are looking to expand community visits and welcomed the participants to let Hydro One know if they were interested in a community visit. He appreciated the goals and aspirations, as well as the needs of First Nations rights-holders and landowners, in terms of business development and community relationships.

The rising cost of power is a serious concern and Hydro One would like to see lower rates. He assured the room that Hydro One staff were listening and taking notes which they will use to advocate First Nations concerns when meeting with the Premier and Minister of Energy, in making those points about affordability. Mr. Schmidt noted that Hydro One has information about how the rate increases occurred and plans for how they can be addressed. They will use this information to try and influence better outcomes for customers. Hydro One met with the OEB on the First Nations rate and supported reducing the delivery charge for First Nation communities. They also met with the Premier. Mr. Schmidt shared his optimism in seeing a policy change in the near future.

Regarding high bills and high arrears Mr. Schmidt noted that they are expanding the delivery of a new service model in First Nations communities. The new model centres on sitting down with customers face-to-face to review accounts and provide assistance where possible. To date, they have met with over 600 customers and are seeking to expand. Mr.. Schmidt stated that if this is of interest to participants, to let Hydro One staff know. He noted that in the coming months they will be developing new programs for sustainable relationships. He views this as not only good business but also the right thing to do.

Mr. Schmidt concluded by thanking attendees for participating, as well as thanking the Minister of Energy and Regional Chief Day for working together towards building a strong and sustainable relationship.

Chief Dean Sayers: The Chief began by thanking Mr. Schmidt for attending the meeting. He explained that Indigenous people in Ontario pay the most taxes of anyone. There was an agreement to share the economy with settlers based on the understanding that First Nations people do not have to pay taxes. In Ontario, this is largely unrecognized. Chief Sayers asked if Hydro One would be willing to honour the point of sales tax exemption for all Indigenous people in Ontario no matter where they live. This was his formal request. The Chief's second point is on working for mutual benefit; he wondered how working together would look, and what would be the benefits, in general.

- Mr. Schmidt asked his staff member, Ms. Lee Anne Cameron [First Nations and Metis Relations], to make a note on the issue of taxes. He stated that given the complexity of the tax system there would have to do some analysis on that. He committed to going back to Chief Sayers on that topic.
- Ms. Cameron sought to clarify Chief Sayers' statement; that the tax can be removed for customers on reserve once Hydro One receives a status number, but she believes what Chief Sayers is referring to is eliminating the taxes even for those First Nations who are not living on reserve.

- **Chief Sayers:** The Chief clarified that at the time the agreement was made, there was no differentiation between on-reserve or off-reserve.
- Ms. Cameron said that Hydro One would go back to their tax group to discuss as well as talk to the province. She noted that they had been audited several times by the Canadian Revenue Agency related to tax collection. She also noted that, on a personal level, she agreed with Chief Sayers.

Mr. Schmidt described recent conversations with the province where they sought to provide solutions to the challenge of high delivery charges. The Province is currently looking at those issues. Hydro One is seeking to make progress on the big issues, and is trying to get away from disconnecting customers; rather, they are seeking to turn the power back on and work with customers one-on-one to try and solve the challenges.

Chief Scott McLeod: Chief McLeod shared that his band council had to issue 220 cheques to Elders to assist them in paying their hydro bills. That is $88,000 in one month. He notes that it is not just the financial burden; they view it as insulting and immoral. The Chief shared that there are two major lines running through his First Nation, and yet leadership has to explain why citizens who are struggling are getting delivery charges. He noted that his community members are outraged, particularly because Hydro One does not pay anything to the community for the lines running through their territory and then Hydro One turns around and charges outrageous rates. They view this as money that is owed to them, and they need a conversation about that.

- Mr. Schmidt noted that Hydro One staff needed to meet with Chief McLeod on this issue and wondered if the contract lapsed or was ever renewed? He committed to reviewing these agreements.
- Ms. Cameron suggested that Mr. Gary Schneider, Hydro One, can talk with the Chief on this issue.
- **Chief McLeod:** The Chief explained that the issue cannot be resolved because the land is the First Nations' land, it was unsold and un-surrendered. It took 50 years to get the land back from the federal government. In the meantime, the delivery charges keep rising.
- Mr. Schmidt commented that Hydro One could work with the First Nations as a partner in approaching the federal government when these things are taking so long to resolve.

Peter Archibald, Councillor: Councillor Archibald noted that when it comes to projects in their area, the First Nations should be contacted for employment. He noted the case of Otter Rapids specifically. They had sent permits for the band council to review, and when the band signed off, the contractor said "oh sorry, no jobs." Councillor Archibald's second point is related to disconnections. He does not believe that Hydro One staff are aware of the new policies around working with people one-on-one to avoid disconnections because in his community they just cut people off. He noted that he sent a letter to Mr. Schmidt's office and received no response.

- Mr. Schmidt assured Councillor Archibald that he responds to every note that comes into his office. He asked that he resend a copy and he will respond. In terms of employment, Mr. Schmidt stated that he could not agree more and wants First Nations employees to participate in projects. He committed to putting people in touch with Ms. Judy McKellar, Executive Vice President, Chief Human Resources Officer. In regards to disconnection, Mr. Schmidt asked participants to let Hydro One know of anyone living without power. Hydro One wants to get them connected. If any community has people headed in that direction, Mr. Schmidt asked them to let Hydro One know and they will try and find a way to manage. In addition, if your community would like Hydro One to make a community visit, just ask.

- **Councillor Archibald:** He commented that Hydro One comes to the community and does not want to hire his people.
- Mr. Schmidt noted that this might have something to do with Ontario labour law, and they will look into it.
- Mr. Martinez, Hydro One, announced that they would pass around a note and for participants to identify any preferred dates for community visits.

Chief Edward Wawia: The Chief shared that he did not get anything out of the presentations today. He felt that he needed to return to his community with answers for the Elders and young people about why their bills are so high. Based on this meeting he noted that nothing will be done about the high bills except another group of people will come to the community to show them how to manage their bills. That is degrading for his community members. The solution on offer is just extending their payments for a longer period of time. The Chief noted that what is actually required is getting serious about profit sharing so First Nations can deal with the huge bills.

- Mr. Schmidt clarified that Hydro One is in the transmission and distribution business, and it is the regulators who set the prices. Hydro One is indeed advocating getting better rates, but they cannot control the rates themselves. However, Hydro One can control certain things and make some changes such as infrastructure repairs and such. Hydro One can also provide assistance before a disconnection. He again encouraged people to approach Hydro One to see what they can do on that end. He reiterated that Hydro One is just one part of a much larger system. He also reiterated that the organization is undergoing a culture shift and asked that they be given a chance.

Steven Nootchtai, Councillor: Councillor Nootchtai began by thanking the organizers of the event. He noted that many of the concerns raised were also concerns for his community. Councillor Nootchtai provided a recommendation: that Hydro One uses their influence with their suppliers, because he views externalized costs as a Treaty issue. Hydro One has much more power than First Nations to influence change.

- Mr. Schmidt was in agreement with the speaker. He noted that Hydro One went from a Crown corporation to a commercial operation and in doing so has a greater influence on their suppliers. In addition, they are asking the province to make adjustments where necessary. He noted that, as a company, Hydro One has to get costs down as well. They are doing more work with less people and are reinvesting the savings back into stabilizing the system.

Chief R. Donald Maracle: Chief Maracle reminded the room that land was never surrendered to the Crown, yet the Crown gave letters of patent to others for some of his reserve land. Some members of his community live on that land part time. He wondered if their bills could be tax exempt, as their rights are being infringed on.

- Mr. Schmidt offered to talk to legal counsel on the issue and help investigate the situation. He noted that, if necessary, Hydro One could advocate the community's position with the provincial and federal governments as well.
- Mike Penstone, Vice President of Planning, Hydro One suggested that what the Chief was describing was a federal jurisdictional issue. The land was not surrendered. Secondly, the status of First Nations as it relates to tax is also a federal issue that would have to be determined by the Canadian Revenue Agency.

- **Chief Maracle**: The Chief restated that the land was not surrendered.
- Mr. Penstone responded that he understands the Chief's argument, but it is an argument that needs to be made to the federal government.
- **Chief Maracle**: Chief Maracle asked why Hydro One does not just try it and see what the Canada Revenue Agency says.
- Mr. Penstone responded that this might be an option for the Chief.

Chief Wayne Pamajewon: The Chief began by describing an issue his community had related to a road. The province was involved, and the First Nations took them to task on that. Cottagers were pushing the province to build a road west of his community. The community knew that those lands were still theirs. All the blasting required to build that road affected the aquifer and wells dried up. The community had to fight INAC on that issue. His community drilled the well and successfully negotiated with the Ministry of Transportation. Now the community has a water station, which requires power to operate. The Chief noted that there are many power outages and as a result, the community had to purchase generators for the well and the facility. There are a number of outstanding expenses related to power failures.

- Mr. Schmidt commented that Hydro One formed a group specifically to deal with water station outages. On occasion they have supplied the province with generators and fuel in the past. Mr. Schmidt suggested that perhaps Hydro One could support First Nations in this way, with the support of the province and the OEB.
- **Chief Pamajewon:** The Chief responded that his community had already expended that money
- **Lee Anne:** Ms. Cameron suggested that they would ask Mr. Penstone to speak to this point in the next presentation.

SYSTEM INVESTMENTS

Mr. Mike Penstone, Vice-President, Planning, Hydro One

Mr. Penstone explained the power system within the PowerPoint presentation. He explained that the transmission system map shows the system that takes the power from the generation to "load centres" through high-voltage transmission lines. The Hydro One distribution system (map) does not support the entire province. It mostly supports the rural part of Ontario. So, for example, Toronto uses Toronto Hydro for a distribution system rather than Hydro One. Most First Nations are in rural areas and are served by the Hydro One distribution system. The number of assets within the transmission and distribution systems is enormous and Hydro One are one of the larger transmitters in North America.

Question from Chief Elaine Johnston: The Chief asked how Hydro One does not service Toronto and if there is some type of agreement.

- Mr. Penstone responded that within their transmission network, Hydro One brings power to Toronto's boundaries and then Toronto uses its own distribution network to reach customers. There are operational agreements in place, as the operations and investment need to be coordinated.
- Mr. Penstone noted that the primary causes of interruption are equipment failure (49%) and weather (18%). Hydro One has to spend money to maintain or replace equipment. This costs roughly $1.4B annually. He added that a lot of the equipment is from the 1950s and 1960s and is reaching end of life. It will need to be replaced and Hydro One needs to ensure there is the money to do that.

Chief McLeod: The Chief asked if the rates covered the delivery and upgrades

- Mr. Penstone responded positively.
- **Chief McLeod:** Chief McLeod noted that he runs a business and when upgrades are required it comes out of his profit. He wondered why Hydro One did not operate that way.
- Mr. Penstone responded that Hydro One collects money to cover ongoing costs of operating the business and providing reliable service is their business and requires upgrades. He also noted that Hydro One does have a net income and Mr. Hubert, Hydro One, would be able to explain that more in the next presentation.

Steven Nootchtai, Councillor: Councillor Nootchtai questioned whether there were investments in innovation or research in order to replace the old equipment.

- Mr. Penstone responded that yes, Hydro One invests in finding better, less costly ways of delivering reliable service. One potential innovation is drones. Utility companies can use them, but there is a lot of resource and development work that goes into determining how they could be used. Specialized drones can be used to inspect the lines for example. . Also they are looking at technology that can identify failures in the system to address them quickly.
- Mr. Penstone noted that Hydro One is maintaining reliability in the transmission system by increasing capital investments (lines) and leveraging technology. He noted that disruptions to the distribution system are most often caused by trees (24%) and equipment failure (24%).
- Vegetation management is a sensitive issue for customers and landowners all across the province because it involves cutting down trees. Hydro One recognizes that it is controversial but the company's focus is on reliability. However, Hydro One workers should not be surprising homeowners with action taken on their trees. They are working to notify homeowners prior to cutting.
- Related to First Nations distribution connections, they are often long, heavily treed lines. There is an impact on reliability for those reasons.

Question from Ms. Amy Lickers: Ms. Lickers wondered if these distribution connections are less likely to get three phase power.

- Mr. Penstone responded that he is referring only to the performance of the wire. It is a separate issue related to the demands for electricity. Converting lines from single to three phases is because of high consumption.
- Related to maintaining reliability of the distribution system, Mr. Penstone is looking to reduce the number of outages per year through the renewal program, tree trimming and the smart grid and shortening the length of outages through improved outage response, monitoring and control.
- Mr. Penstone noted that Hydro One asked customers about their priorities and they responded that the priority should be minimizing costs and less of a priority on improving reliability. The survey included 300 customers in First Nations communities.
- In order to control costs Hydro One is pacing expenditures, undertaking vegetation management and moving to mobile technology. He noted that Hydro One spent $100 million this year on vegetation management.

Chief Paul Eshkakogan: The Chief noted that this morning a Hydro One representative said that they could not do anything about poverty in First Nations communities, yet the company spent $1.4 billion on equipment. He asked what percentage of that goes into First Nations communities in terms of contracts and employment. He suggested that there should be more effort in integrating First Nations communities and business and helping them get a piece of that $1.4 billion. When it comes to procurement, terms like “best efforts” are not effective. He referred to the use of “set asides” or sole source contracts. He also noted that training is an important component. Communities are getting better at drafting and negotiating Impact Benefit Agreements (IBAs) with industry. He did, however, observe that Ontario and its Crown corporations are lagging behind other sectors when it comes to meaningful and capacity building opportunities for First Nations. The Chief would like to see a table developed to move this work around contracts and employment/training forward. As an example of his frustration, the Chief noted that even on the issue of vegetation management, they could not get anyone on the project because of a union issue. He reiterated that they need jobs in his community to pay the bills. The Chief expressed a desire to come to an agreement to continue the dialogue related to unlocking job and contracting opportunities for First Nations.

- Mr. Penstone agreed with the Chief and noted that there have been instances where First Nations communities provided material and services for projects. Mr. Penstone directed the comment to his colleagues in procurement.
- A Hydro One representative agreed with the Chief and suggested that they do a workshop with the community and their businesses in order to participate in the Hydro One sourcing events. He also commented that he supported the idea of a table for dialogue and is considering what that would look like from a strategic perspective. He agreed that they needed to start those discussions.
- **Chief Eshkakogan:** The Chief noted that that was pretty weak language and something they are used to hearing. He noted that he does not believe any company is going to work with First Nations, despite their best efforts. Rather, what will work is when communities have something of value like contract work in their hands, businesses will come to them. Hydro One can choose the company that they want to work with and allow the community to build capacity through that relationship. There is a lot that can be learned from each other. His community established the Lake Huron Transmission Company and participated in a procurement process on the east/west line. It was ultimately not successful but it was a good learning process. Hydro One should be unbundling larger contracts to support First Nations, as they likely do not have enough capacity to do the full contracts. The Chief concludes that there are many things that can be done and companies that could partner with First Nations. In addition, he offered to make himself available to work on this issue with Hydro One.

Chief Patricia Big George: The Chief asked why Hydro One does not move forward on sole source processes for First Nations. Also, related to the work around vegetation control, the Chief asked where to find out more information.

- Mr. Penstone noted that a description of where they spend their money and how is included in all applications to the OEB. They are on the OEB website and they are also on the Hydro One website. The descriptions go into a great deal of detail. Hydro One staff would provide the links to those websites.

Chief Elaine Johnston: Chief Johnston expressed some concern about the survey, which determined that cost was more important than reliability. She noted that clearly they needed to deal with the high bills, but they also need reliable lines. Reliable lines are needed for economic development initiatives to work; it is how the community functions. She asked what plan was in place for those lines that are unreliable. She suggests perhaps a pilot project for other initiatives to deal with reliability.

- Mr. Penstone responded that the customer survey was only to determine customer priorities. Hydro One is not using the survey to justify ignoring the reliability aspects of the lines. He reassured the attendees that Hydro One continually monitors performance and where it is bad or degrading they will make investments. When lights go out in the community there are health and safety impacts. This is also part of determining where investments in reliability are made.

DISTRIBUTION RATE FILING (2018-2022)

Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One

Mr. Hubert described how Hydro One is going to the OEB with a distribution rate application that, if approved, would provide the necessary Revenue Requirement to operate the system for the next five years (2018-2022). This is the standard application that Hydro One has to complete (from now on, every five years). It is completely separate from the policy decision around a First Nations rate that the Minister will decide on.

To assist the OEB's work on a First Nations rate,

- Hydro One has given the OEB a significant amount of information to make their determination including the size of bills and the amount of the delivery charge compared to the commodity charge.

Also, the Premier asked Hydro One, among others, for advice on providing relief to rural customer, given that the delivery charge is often higher than the commodity charge.

Chief Elaine Johnston: wondered what was the difference between the All-Ontario rate and the First Nations rate.

- Mr. Hubert responded that the general distribution delivery rate is for all Hydro One customers. The Minister will decide the First Nations rate and then the Minister will tell the OEB what the First Nations rate will be. The general rates (other than the First Nations rate) are determined by the OEB, through Hydro One's application.
- Hydro One is filing this submission at the end of March and is looking for input before it is completed. Included in the submission will be results from the customer engagement surveys, and also the notes from this meeting. There are some First Nations that have actually represented themselves at the OEB, so there is a voice for First Nations at the hearings.

Chief R. Donald Maracle: thanked Hydro One for advocating for a reduction in the rates paid by First Nations. He asked if First Nations would benefit from the rural/remote reduction.

- Mr. Hubert responded that everyone within the R2 classification already receives a subsidy on their bills automatically.
- **Chief Maracle:** The Chief inquired as to the total profits for Hydro One last year.

Mr. Hubert responded that this figure is available online (Hydro One Limited's consolidated Net Income for 2016 was $721 M).

First Nations Representative [name unknown]: The participant wondered about the implications for members that do not live on reserve.

- Mr. Hubert noted that the Minister's letter which asked them to explore the idea of a First Nations rate specified on-reserve customers only.

- **First Nations Representative:** First Nations leadership has a responsibility for all of their members, no matter where they live.
- **Chief McLeod:** The Chief noted that it is a huge concern, if the rates for off-reserve First Nations go up; while on-reserve it goes down.

Chief R. Donald Maracle: Chief Maracle asked if hydro rates overall are going up 10% next year

- Mr. Hubert responded that not according to Hydro One's numbers. The PowerPoint presentation will explain further.
- Slide 6 showed the breakdown of electricity costs to customers. The diagram represents an average customer: 51% goes to electricity generation, 37% goes to Hydro One delivery charges, 5% is a sales tax, 3% is regulatory charges and line losses represent 4%.

Chief Elaine Johnston: Chief Johnston wondered why rates had increased so much.

- Mr. Hubert responded that the increase is due to a few factors: the increased cost of electricity, the move to eliminate coal, renewable energy and infrastructure costs.
- Slide 7 showed how distribution charges are spent by Hydro One: preventing outages (47%), upgrading the system (21%), customer service (12%), responding to power outages (10%), and information technology (7%) and, administration (3%).
- The next slide details how distribution rates are set by the OEB.
- Mr. Hubert explained that this year Hydro One could earn an allowed profit (Return on Equity) of about 8.78%.
- Slide 10 identifies the stages in developing and submitting an application to the OEB including preliminary matters (3-4 months), issues and discovery (2-3 months), hearing (3-4 weeks), and decision and approvals (2-4 months). In total, the process usually takes 8-12 months.
- Slide 11 shows that the Hydro One application must balance key considerations including customer needs and preferences, rate impact and asset needs.
- Related to customer needs and preferences, Hydro One called about 800 customers including 300 First Nations people. In general, First Nations had greater levels of dissatisfaction, more cost sensitivity and placed greater importance on keeping costs low. In general, the First Nations surveyed would accept a 1% bill increase if they saw some improvement in service. Many findings were similar with the non-First Nations respondents.
- Mr. Hubert's presentation also noted that shrinking consumption so the cost serving each consumer has to go up.

First Nations Representative [Name Not Heard]: The participant asked if the seasonal rate is more than the rural rate 2 (The R2 rate).

- Karen Taylor, Hydro One**,** explained that the charge is based on how much a customer consumes. She noted that the OEB is looking at moving those into fixed monthly charges and eliminating the variable component.
- Mr. Hubert noted that Hydro One is asking the OEB for rates for five years and will not be going back except for minor adjustments. However, over the five years, Hydro One can continue to search for productivity savings, innovations, and better technology and reduce costs. This could lead to more profit, but Hydro One has committed that if it were

more than a 1% increase above the allowed ROE, the additional profit would be shared 50/50 with customers.

Chief Patricia Big George: Chief Big George asked if this would affect the First Nations rate.

- Mr. Hubert responded that it would not change the First Nations rate and that they would all have to see how the First Nations rate unfolds.

Chief Elaine Johnston: Chief Johnston asked what is causing the decreasing consumption.

- Mr. Hubert responded that it was mostly due to conservation activities and economic conditions.
- Mr. Hubert concluded that the participants can send any additional questions via email.

WRAP UP

The Facilitator closed the meeting by mentioning that the PowerPoint presentations would be available. In addition, pictures of the artwork and copies of the notes will be distributed.

Summary points:

- Where they went from here will be determined by relationship building that will continue. There will be ongoing meetings set up including community meetings.
- Please judge Hydro One based on actions and results over the next five years.

The closing prayer was done by Elder Andrew Wesley.

Meeting Adjourned.

1.4 (5.2.3) PERFORMANCE MEASUREMENT AND OUTCOME MEASURES

The Renewed Regulatory Framework (RRF) is an outcomes-based approach to regulation. Hydro One recognizes the need to demonstrate how it will achieve the four RRF outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. The Electricity Distributor Scorecard, including the targets (Exhibit A, Tab 5 Schedule 1), shows Hydro One's success achieving these outcomes and the performance levels that Hydro One expects to achieve over the 2018 to 2022 rate setting period.

In addition to the measures already reported through this scorecard, Hydro One is proposing to report on several additional performance measures in its Distribution Scorecard that also demonstrate the distribution system outcomes the Company provides. Hydro One is committed to both sets of performance measures as it evaluates its progress executing its 2018 to 2022 investment plan that aligns the needs and preferences of customers, compliance and condition needs of Company assets, and rate impacts. Hydro One's plan has a number of initiatives that control costs, increase productivity and maintain levels of reliability in rural and urban areas. These are all outcomes that customers have indicated they value, are central to Hydro One's Business Objectives, and the OEB's Renewed Regulatory Framework.

1.4.1 (5.2.3 A AND B) METHODS AND MEASURES

In considering outcome measures to be included in scorecards, Hydro One identified potential metrics drawn from internal and external sources that include Hydro One's past performance management metrics, benchmarking studies, and scorecards and metrics of other utilities in the public domain. The selection process was also guided by the OEB's

Handbook for Utility Rate Applications, which indicates the OEB will evaluate proposed outcomes and performance metrics using the following key considerations:

- A focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes that are demonstrated to be of value to customers; and
- Performance metrics that will accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

The Distribution OEB Scorecard provided in the table below, includes the metrics that Hydro One is proposing to report on and includes targets for 2018. Hydro One proposes to report the results on an annual basis or as determined by the OEB. As described in the attached Productivity Reporting Governance Document (DSP Section 1.4, Attachment 1), Hydro One operations managers and the Executive Leadership Team will be reviewing progress on these metrics on a regular basis. This reporting and governance structure will allow Hydro One's management to assess progress towards targets and determine corrective action, when warranted, to help ensure that a performance or outcome measure is effective and does not result in unintended consequences. Hydro One will be considering these metrics in its business planning processes and will be setting new targets on an annual basis.

Table 8 – Distribution OEB Scorecard

			Historical Results						Target	
RRF Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2018
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	72%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	86%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	81%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,640	8,733
		Vegetation Management - Gross Cyclical Cost per km $	New Program						9,441	9,382
		Station Refurbishments - Gross Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	461,000	454,000
		OM&A dollars per customer	456	451	498	551	453	455	449	455
		OM&A dollars per km of line	4,723	4,676	5,109	5,654	4,719	4,773	4,700	4,758
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,200	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	6,900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	145	145
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.1	9.0
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.4	3.4
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.8	2.8
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.7	1.7
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		135	197	228	136	143	143

*There were no station refurbishment units matching the criteria completed in 2012

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

Customer Focus Measures

Customer Satisfaction – Perception Survey %

Hydro One included this metric for reporting as part of its previous distribution rates application (EB-2013-0416), referred to as 'Residential and Small Business Satisfaction' at that time. Hydro One proposes to continue reporting this metric as part of this Application. Hydro One measures customers' perception of the Company as a whole, whether they have interacted with Hydro One recently or not. The survey indicates how well the Company meets customers' expectations. The perception surveys are conducted twice per year by an external service provider, who contacts randomly selected customers. The reported results reflect what customers have indicated as their overall satisfaction with Hydro One. Although the results may be influenced by the overall price of electricity on a customer's bill, Hydro One still seeks to improve its score on this measure.

Handling of Unplanned Outages Satisfaction

Hydro One began reporting this metric as part of its previous distribution rates application (EB-2013-0416) and proposes to continue reporting it as part of this Application. This metric measures customers' satisfaction of Hydro One's handling of a customer's last unplanned outage. The Handling of Unplanned Outages was indicated as a source of frustration for customers during recent customer consultation, as described in Section 1.3 of the Distribution System Plan. Satisfaction is measured through the results of a survey that Hydro One conducts in two segments per year, targeting 1,200 interviews per segment. The telephone survey contacts a random sample of customers that have called into Hydro One's customer centre over the previous 12 months. Customers are asked if they have experienced an unplanned outage over the last 6 months. Those respondents that answer "yes" are then asked how satisfied they are with the way Hydro One handled the most recent unplanned outage.

Call Centre Customer Satisfaction

This metric is newly proposed as part of this Application and is intended to measure customer satisfaction with services provided by Hydro One's call centre, which is often the first point of contact Hydro One has with a customer when they have a question or an issue that needs to be resolved. Customer satisfaction after the call is a strong indication of whether or not a customer inquiry has been addressed appropriately. This metric demonstrates that services are being provided in a manner that is responsive to customer needs. The call centre customer satisfaction survey occurs shortly after the phone call, which allows the call centre to capture timely and accurate information and to address any areas for improvement.

My Account Customer Satisfaction

This metric is newly proposed as part of this Application and is intended to measure customer satisfaction with services delivered by Hydro One's My Account web portal. My Account allows customers to find the information they need so that they can manage their bills and electricity usage. With My Account, Hydro One is able to provide customers with the information and services they are seeking in a convenient, efficient manner. This measure will demonstrate whether the services are being provided in a manner consistent with customer expectations. The satisfaction level is determined by using an online survey, which is emailed to customers through a third party and contains a link inviting them to take part in the survey. This email is sent out to customers who have accessed and logged on to My Account within the past two days.

Operational Effectiveness Measures

Hydro One's customers have indicated that effective cost management and efficiency are outcomes that they value. The following metrics are designed to measure and track Hydro One's operational effectiveness.

Pole Replacement – Cost per Pole

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is in delivering productivity improvement in this area. In addition, the pole replacement program has been an area of interest in previous applications, with the OEB directing Hydro One to complete a benchmarking study to support this Application. Hydro One completed this study through Navigant and First Quartile, which can be found in Section 1.6 of the Distribution System Plan. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors. There are many factors that could impact the average cost per pole such as whether it is going into earth or rock, or the height and type of pole required. These circumstances will change the cost of poles and will cause fluctuations within the program, which is why the programs cost per unit should be viewed as a trend versus an individual year. In addition to providing useful information on cost trending, variances in performance between periods will also inform management on factors affecting costs and enable corrective actions and improvements to be made.

$$= \frac{Total\ Cost\ of\ Pole\ Replacement\ Program}{Number\ of\ Poles\ Replaced}$$

Vegetation Management – Cost per KM

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is at delivering productivity improvement in its vegetation management program. In addition, this program has been an area of interest in previous applications, with Hydro One directed by the Board to complete a benchmarking study to support this Application. Hydro One has completed this study through CN Utility Consulting, Inc., which can be found in Section 1.6 of the

Distribution System Plan. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors.

There are many factors that affect the average cost per unit for vegetation management, including the density of vegetation and the remoteness of the location. These factors have a significant impact on the costs related to the program which is why the average cost per unit should be viewed as a trend rather than an individual year. This measure is the dollar cost per km of cyclical line cleared.

$$= \frac{Cost\ of\ Forestry\ Cyclical\ Line\ Clearing}{KM's\ of\ Line\ Cleared}$$

Station Refurbishment MVA – Cost per Unit

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is in delivering productivity improvement in its station refurbishment projects. This has been an area of interest in previous applications. As a result, the OEB directed Hydro One to complete a benchmarking study to support this Application. Hydro One has completed this study through Navigant and First Quartile, which can be found in Section 1.6 of the Distribution System Plan. Every station refurbishment project has a different scope of work that will change the total cost per project. As a result this metric should be viewed as a trend over a number of years. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors, as well as inform management of the potential for improvements and aid in setting improvement targets.

$$= \frac{Total\ Cost\ of\ Station\ Refurbishment\ Program}{Total\ Stations\ MVARefurbished}$$

Note that the cost per MVA only considers projects which have a station MVA of less than 10 MVA. Including projects greater than 10 MVA would cause large cost fluctuations from year to year depending on how many were included due to the significantly lower per MVA cost. The smaller MVA category shows the most potential for improvement as it has the highest historical cost per MVA. This covers approximately 75% of the station refurbishment projects in 2018.

<u>OM&A cost per Customer</u>

This metric is newly proposed as part of this Application. Through the customer consultation process, residential and small business customers indicated that cost is their top priority and Large Customers indicated it was among their top priorities. This metric will help demonstrate how successful Hydro One is in delivering productivity improvement through OM&A reductions. This metric will also allow for benchmarking and cost comparison over time for Hydro One as well as comparisons with other comparable utilities.

$$= \frac{Total\ OM\&A}{Number\ of\ Customers}$$

<u>OM&A Expense per km of Line</u>

This metric is newly proposed as part of this Application. Through the customer consultation process, residential and small business customers indicated that cost is their top priority and Large Customers indicated it was among their top priorities. This metric will help demonstrate how successful Hydro One is in delivering productivity improvement through OM&A reductions. This metric will also allow for benchmarking and cost comparison over time for Hydro One as well as comparisons with other comparable utilities.

$$= \frac{Total\ OM\&A}{Number\ of\ line\ km's}$$

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

<u>Line Equipment Caused Interruptions</u>

Hydro One began reporting this metric as part of its previous distribution rates application (EB-2013-0416) and proposes to continue reporting it as part of this Application. This metric is a count of the total number of outages caused by line equipment failures on an annual basis. Customers indicated, in general, that they value sustaining current reliability levels while managing rate impacts and effective cost management. This metric demonstrates the outcome of Hydro One's capital and maintenance programs in terms of line equipment caused outages. Benchmarking, over time, will demonstrate Hydro One's success in maintaining reliability and how effective Hydro One has been in the spending of resources on areas of the system that are in need.

$$= Line\ Equipment\ Caused\ Outages$$

<u>Vegetation Caused Interruptions</u>

Hydro One previously agreed to report this metric as part of EB-2013-0416. This metric is a count of the total number of vegetation-caused outages on line equipment on an annual basis. Visibility to the vegetation-caused outages allows for focus to be placed on those areas with less than optimal performance while ensuring Hydro One's on-cycle program for critical feeders is delivering good performance. Ultimately, the expected outcome and customer benefit of the vegetation management program is a reduction in vegetation-caused outages. This metric is directly impacted by the number of kilometres that were managed over many years and is not immediately impacted by the number of kilometres managed in the current or previous year. As a result this is a lagging indicator of the outcomes of the vegetation management program.

$$= Total\ Vegetation\ Caused\ Interruptions$$

Substation Caused Interruptions

Hydro One previously agreed to report this metric as part of EB-2013-0416. This metric is a count of the total number of substation equipment failure outages. Substation equipment failures often cause outages that are significantly longer in duration compared to vegetation-caused outages. This, in part, is due to limitations in transfer capabilities on Hydro One's network. Hydro One will manage these events by tracking these failures and adjusting the pace of substation refurbishment programs to align with customer expectations on system reliability. This metric is intended to measure the effectiveness of Hydro One's distribution station refurbishment program, through which Hydro One is endeavoring to reduce the cost per unit as demonstrated in the Station Refurbishment MVA Cost per Unit metric.

$$= Total\ Substation\ Caused\ Interruptions$$

SAIDI – Urban

This metric is newly proposed as part of this Application. Distinguishing between rural and urban reliability provides a better basis for benchmarking to other utilities and a higher quality metric for internal comparison. The Electricity Distributor Scorecard includes the Hydro One System Average Interruption Duration Index ("SAIDI") for the overall system. The SAIDI-Urban metric tracks the duration of interruptions for Hydro One's urban areas only and Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Urban\ Customer\ Hours\ of\ Interruption}{Total\ Urban\ Customers\ Served}$$

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

SAIFI – Urban

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One System Average Interruption Frequency Index ("SAIFI") for the overall system. The SAIFI – Urban metric tracks the frequency of interruptions for the urban areas only. Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Urban\ Customer\ Interruptions}{Total\ Urban\ Customers\ Served}$$

SAIDI – Rural

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One SAIDI for the overall system. The SAIDI-Rural metric tracks the duration of interruptions for the rural areas only and Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Rural\ Customer\ Hours\ of\ Interruption}{Total\ Rural\ Customers\ Served}$$

SAIFI – Rural

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One SAIFI for the overall system. The SAIFI-Rural metric tracks the frequency of interruptions for the rural areas only. Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term which aligns with customer expectations.

$$= \frac{Total\ Rural\ Customer\ Interruptions}{Total\ Rural\ Customers\ Served}$$

Large Customer Interruption Frequency Large Distribution Accounts (LDAs)

This metric is newly proposed as part of this Application. During the customer engagement process, Large Distribution Accounts ("LDA") informed Hydro One that their top priority was interruption frequency as even a short outage could have major financial impacts to their operations. Hydro One will track this new measure to address this specific reliability concern. The goal is to improve performance compared to historical results. This metric tracks the total number of sustained interruptions to all LDA customers connected to Hydro One.

$$= \frac{Total\ Interruptions\ for\ Large\ Distribution\ Customers}{Total\ Large\ Distribution\ Customers\ Served}$$

1.4.2 OUTCOME MEASURES: EB-2013-0416

In its previous distribution rate Application (EB-2013-0416), Hydro One submitted a list of outcome measures for future reporting. The measures and the results have been captured in Table 9 below. From the measures listed in the table below, Vegetation Caused Interruptions, Substation Caused Interruptions, Distribution Line Equipment Caused Interruptions, Handling of Unplanned Outages Satisfaction, and Residential and Small Business Satisfaction are metrics that Hydro One proposes to continue reporting in the future.

Table 9 – Outcome Measures from EB-2013-0416

Year	Actual		
	2014	2015	2016
Vegetation Caused Interruptions	6,540	6,944	7,674
Substation Caused Interruptions	158	141	103
Distribution Line Equipment Caused Interruptions	8,311	8,164	7,439
Number of Replaced Poles	11,179	11,837	12,355
Number of Pole Top Transformers with PCB Oil	NA	34	347
Residential and Small Business Satisfaction (%)	67%	70%	66%
Handling of Unplanned Outages Satisfaction (%)	75%	76%	83%
Estimated Bills Issued as % of Total Issued*	NA	4%	NA

***No longer measured, replace by bill accuracy measure**

Hydro One proposes to cease reporting the Number of Replaced Poles and Number of Pole Top Transformers with PCB Oil, as these measures are activity-based, which is not consistent with the intent of the RRF. Hydro One has replaced these measures with cost per unit metrics, which are consistent with the intention of the RRF in terms of demonstrating continuous productivity improvement. Hydro One proposes to cease reporting the Estimated Bills Issued as a % of Total Bills Issued as it believes this is adequately covered under the Billing Accuracy metric already reported on Hydro One's Electricity Distributor Scorecard.

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

1.4.2.1 RELIABILITY RESULTS

This section contains the reliability statistics for the historic period from 2012 to 2016.

Customer interruptions are analyzed and reported internally throughout the year. Interruption data is collected and recorded in the Distribution Operations and Maintenance Centre (part of Ontario Grid Control Centre) through communications with field staff involved in the interruption restoration. It is input into a database system called Outage Response Management System, which provides data for in-depth performance analysis to drive strategy and business investment decisions.

Interruption data is used to calculate the OEB reliability indices monthly, and results are reported internally. There is ongoing analysis of approximately 40,000 annual interruptions. Trends of frequency, duration, cause of interruptions, feeders, location, and other factors, are analyzed to allow prioritization of maintenance and capital programs on the distribution system.

Measures

Reliability is measured in terms of the duration of outages (SAIDI), the frequency of outages (SAIFI) and the average interruption time ("CAIDI"). The SAIDI, SAIFI and CAIDI statistics for the last five years are included in the tables below. For the distribution system as a whole, both SAIDI and SAIFI are reported with and without Loss of Supply ("LOS") and Force Majeure ("FM") events. In addition, details of the outages in terms of outage cause are also included. These statistics are reported including LOS and FM.

Duration of Interruptions (SAIDI)

The average numbers of hours that distribution customers served by Hydro One were without power in the year.

Frequency of Interruptions (SAIFI)

The average number of times that distribution customers served by Hydro One were interrupted in the year.

Average Interruption Time (CAIDI)

The average interruption duration (in hours) of Distribution customers who were interrupted. $(CAIDI = SAIDI \div SAIFI)$

The above reliability indices measure all interruptions caused by planned and unplanned interruptions of one minute or more.

Force Majeure

Hydro One deems a *force majeure* to have occurred when a storm or other event(s) causes the interruption of 10% of customers or more and causes a change in normal restoration business processes. All Hydro One customers interrupted throughout the duration of the event while normal restoration business processes are suspended are counted in the determination of the numerator of the percent interrupted. The denominator is the total number of customers served at the end of the month when the force majeure occurred. Details of all *force majeure* events that have occurred from 2012 to 2015 are provided below.

2012 Force Majeure Events

In 2012, there were four force majeure events.

- From March 2 to 4, an early spring storm that tracked up from Texas across Lake Huron and Georgian Bay to Lake Nipissing dragged a sharp cold front with strong winds from east to west across Southern Ontario. The winds reached up to 105 km/h along the Niagara Peninsula. This event affected 173,000 or about 14% of customers.
- From July 23 to 26, a strong lightning/thunderstorm, with hail and winds gusting up to 110 km/h moved through southeast Ontario and crossed over the Northeast areas. This storm caused widespread damage and affected 158,000 or about 13% of customers.
- From October 29 to 31, remnants of Hurricane Sandy, including winds moving up to 100 km/h, moved across Southern Ontario from the lower Great Lakes passing through Sarnia, Georgian Bay and the Niagara region. The combination of strong winds and residual leaves on trees caused power outages due to falling limbs and downed trees snapping power lines. This event affected 258,000 or about 21% of customers.
- From December 21 to 23, Environment Canada issued a weather warning for Eastern and Northern Ontario when up to 30 cm of snow fell in these regions. This winter storm caused severe damage to the distribution system; heavy wet snow and high winds caused trees to contact distribution lines. This event affected 147,000 or about 12% or customers.

These storms resulted in a contribution to the annual SAIDI of 3.9 hours and annual SAIFI of 0.6 interruptions per customer.

2013 Force Majeure Events

In 2013, there were seven force majeure events.

- From April 12 to 16, Environment Canada issued a weather warning when a slow moving low pressure system combined with Artic air to produce a mix of snow, rain, ice pellets and freezing rain over Southern Ontario. It laid down a blanket of 2 to 4 cm of snow and ice pellets in a band from Toronto to Lake Huron. The storm was accompanied by gusting winds of up to 65 km/h that caused downed tree limbs resulting in widespread power outages. This event affected 419,000 or about 34% of customers.
- From May 21 to 24, a tornado warning was issued by Environment Canada when two clusters of thunderstorms made their way through Southern Ontario. Both tornadoes were accompanied by intense lightning, hail, heavy downpours and wind gusts of up to 100 km/h that caused broken poles and downed trees. This event affected 147,000 or about 12% of customers.
- From May 31 to June 3, a line of thunderstorms with winds up to 90 km/h moved through Southern and Central Ontario. Hail, heavy rain and frequent lightning accompanying the storm caused widespread outages. This event affected 121,000 or about 10% of customers.
- From July 19 to 23, scattered thunderstorms moved over Northwestern Ontario accompanied by wind gusts of 90 km/hour, hail greater than 2 cm in diameter and downpours of up to 50 mm. At the same time, isolated thunderstorms moved over Southern and Central Ontario that were also accompanied with high winds, hail and heavy rain. Both incidents resulted in power interruptions to 434,000 or about 35% of customers.
- From November 1 to 3, a Colorado low pressure system bought rain and high winds to much of Southern Ontario. The winds reached speeds of up to 100 km/h in areas near Lake Erie and Lake Ontario. This event affected 315,000 or about 25% of customers.
- From November 17 to 19, another low pressure system from Colorado caused a strong cold front with heavy winds of up to 90 km/hour for much of South Western

and South Central Ontario. This event impacted both the distribution and transmission system and caused interruptions to 367,000 or about 28% of customers.

- From December 21 to 29, a low pressure system originating in Texas collided with a warm front causing up to 40 mm of freezing rain, snow and ice pellets to spread into Southern and Southwestern Ontario. As a result, ice accumulated on tree branches causing wide spread outages from downed trees. After the storm passed, light rain continued with extreme cold temperatures causing ice accumulation of up to 30 mm on surfaces and tree branches. The ice storm was followed by a windstorm of up to 55 km/hr that caused the ice-covered tree branches to contact distribution lines. This ice storm affected 585,000 or about 46% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 20.1 hours and annual SAIFI of 1.8 interruptions per customer.

2014 Force Majeure Events

In 2014, there were two force majeure events.

- From September 5 to 6, a thunderstorm with large hail, high winds greater than 75 km/h, and heavy rain moved over Northwestern Ontario, Northeastern Ontario, Georgian Bay, Central Ontario, and Southern Ontario. This event affected a total of 137,000 or about 11% of customers.
- From November 24 to 25, strong wind storms passed through Southern Ontario with sustained wind speeds of 60 to 70 km/h. Gusts of 90 to 100 km/h passed through north of Lake Erie and Lake Ontario, Central Ontario, Grey /Bruce area and the GTA. Northeastern Ontario experienced freezing rain and snow with accumulations of up to 30 cm. This event affected a total of 238,000 or about 18% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 2.0 hours and annual SAIFI of 0.3 interruptions per customer.

2015 Force Majeure Events

In 2015, there were three force majeure events.

- From August 1 to 4, a severe thunderstorm with wind speeds of up to 55 km/h, lightning and heavy downpours passed through Southern Ontario causing tree branches to fall on various portions of the power lines. This event caused interruptions to 144,000 or about 11% of customers.
- From November 6 to 9, a strong wind storm passed through Southwestern Ontario, Northwestern Ontario and Georgian Bay with wind speeds of up to 100 km/h. The high speed winds damaged poles and caused broken tree branches to fall on the lines causing power outages. This event caused interruptions to 277,000 or about 21% of customers.
- From December 24 to 26, a strong wind storm passed through Southwestern Ontario along the shores of Lake Huron with wind speeds of 70 to 90 km/h, damaging poles and causing tree branches to fall on various portions of the lines, which resulted in severe widespread outages. This event caused interruptions to 189,000 or about 14% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 4.6 hours and annual SAIFI of 0.5 interruptions per customer.

2016 Force Majeure Events

In 2016, there were three force majeure events.

- From February 24 to 25, a winter snow storm with freezing rain and wind gusts between 60 and 80 km/h, travelled from Southern and Western Ontario towards Eastern Ontario. This late winter storm caused several power interruptions, affecting approximately 135,000 or 10% of Hydro One customers.
- From March 24 to 28, a severe ice storm with freezing rain and wind gusts of 70 to 90 km/h, hit Ontario causing wide-spread damage. Damage from the ice and wind, as well as fallen trees and branches caused several outages. In total this event impacted approximately 371,000 or 28% of Hydro One customers.
- From July 8 to 9, a severe thunderstorm moved across Ontario from the west to the east, causing extensive power interruptions. This event impacted approximately 143,000 or 11% of Hydro One customers.

Reliability Summary

The historical results for the past five years for SAIDI, SAIFI and CAIDI are provided below in Tables 10, 11, and 12, respectively. Results have been provided including and excluding both Loss of Supply (LOS) and Force Majeure (FM). From 2012 to 2016, reliability performance (SAIDI and SAIFI) excluding FM and LOS has generally been constant at 7.3 hours and 2.6 timers per customer per year. SAIDI and SAIFI for the overall system have generally deviated by less than 6% from the five-year average for the period. Force Majeure events increased these statistics, on average, by 90% for SAIDI and 25% for SAIFI. Loss of Supply also increased these statistics, on average, by 5% for SAIDI and 15% for SAIFI. As highlighted above, a number of storms in 2013 dramatically increased the frequency and duration of outages as can be seen in the tables and figures below. CAIDI is derived by dividing SAIDI by SAIFI. As a result, the performance of this measure is largely explained by the performance of SAIDI and SAIFI, as discussed above.

SAIDI and SAIFI by outage cause is provided in Tables 13 and 14. Tree contacts were the most common cause of outages for most years, followed by defective equipment.

Table 10 - Historical SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	11.3	27.4	9.9	12.9	13.2
Including LOS and Excluding FM	7.5	7.3	7.9	8.3	8.3
Excluding LOS and Including FM	10.6	26.6	9.4	12.2	12.6
Excluding LOS and Excluding FM	7.0	6.9	7.4	7.6	7.8

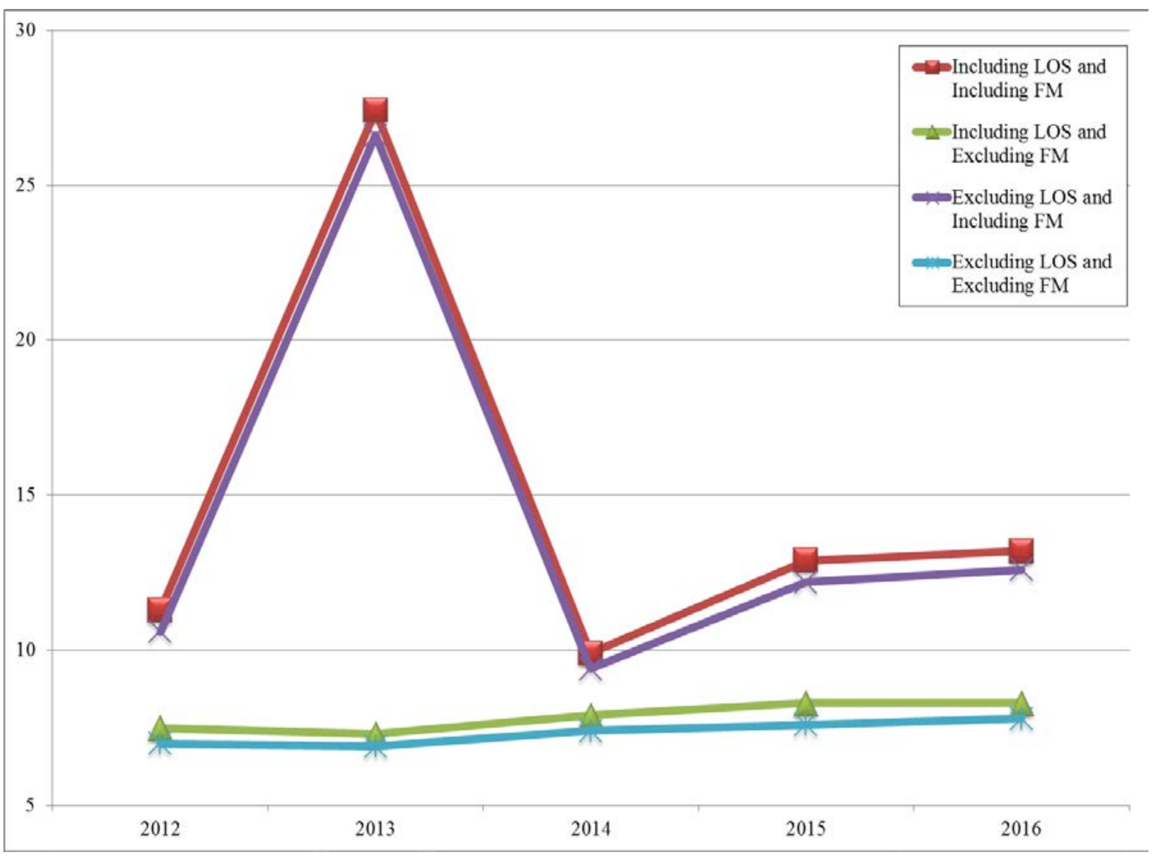


Figure 3 - Chart of Historical SAIDI

Table 11 - Historical SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	3.7	4.6	3.6	3.6	3.4
Including LOS and Excluding FM	3.1	2.8	3.3	3.1	2.8
Excluding LOS and Including FM	3.2	4.2	3.0	3.1	2.9
Excluding LOS and Excluding FM	2.6	2.5	2.7	2.6	2.5

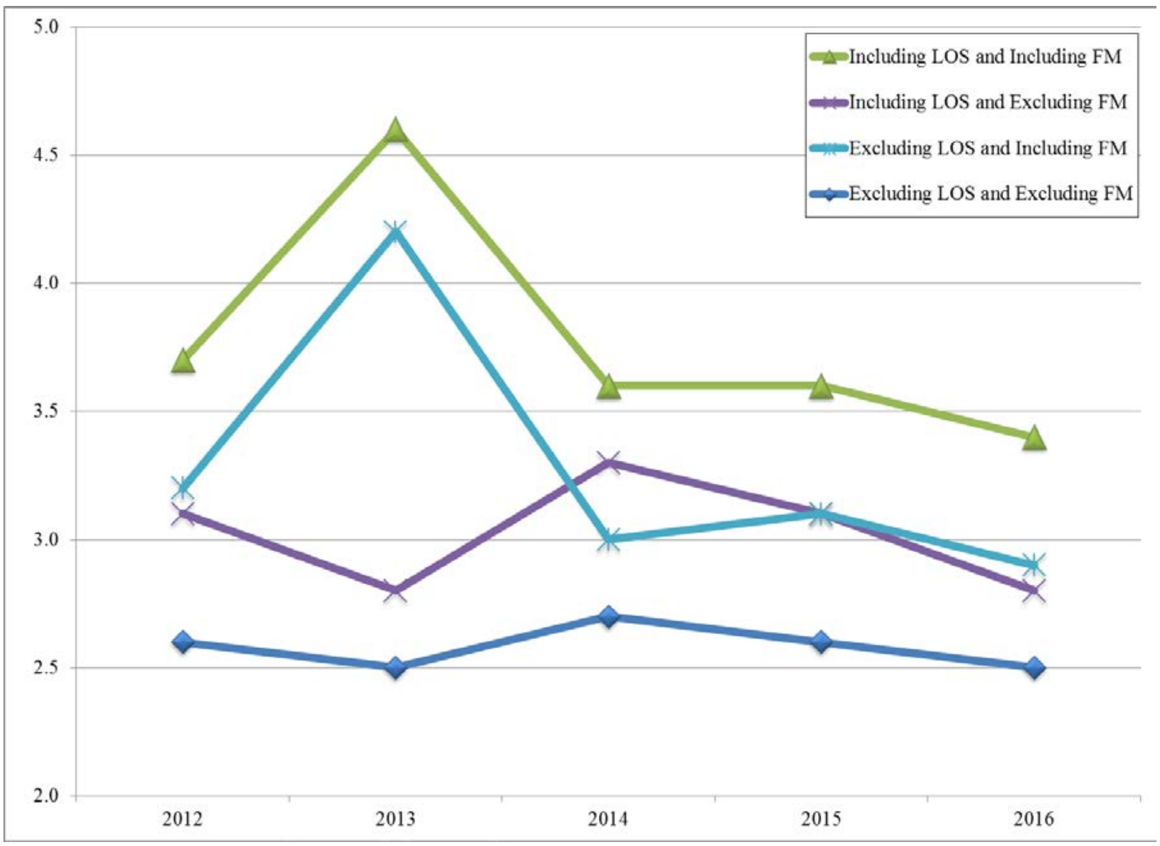


Figure 4 - Chart of Historical SAIFI

Table 12 - Historical CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	3.1	6.0	2.8	3.6	3.9
Including LOS and Excluding FM	2.4	2.6	2.4	2.7	3.0
Excluding LOS and Including FM	3.3	6.3	3.1	3.9	4.3
Excluding LOS and Excluding FM	2.7	2.8	2.7	2.9	3.1

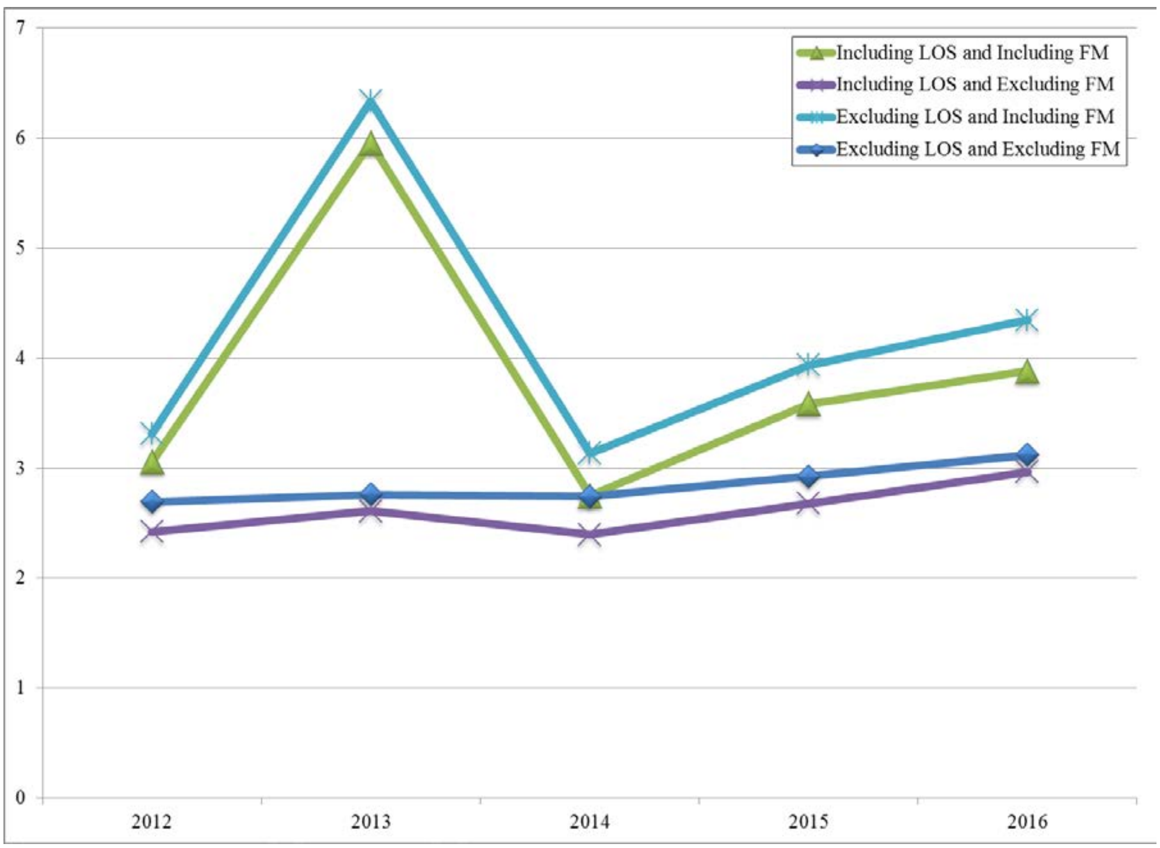


Figure 5 Chart of Historical CAIDI

Table 13 - SAIDI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.03	0.01	0.00	0.02	0.03
Defective Equipment	2.57	6.59	3.03	3.55	3.00
Foreign Interference	0.44	0.46	0.44	0.40	0.41
Human Element	0.04	0.11	0.08	0.08	0.05
Loss of Supply	0.72	0.96	0.56	0.72	0.61
Scheduled	1.41	1.53	1.48	1.43	1.48
Tree Contacts	4.24	14.67	3.36	5.53	6.17
Unknown/Other	1.84	3.09	0.96	1.20	1.43
Includes outages due to Loss of Supply and Force Majuere					

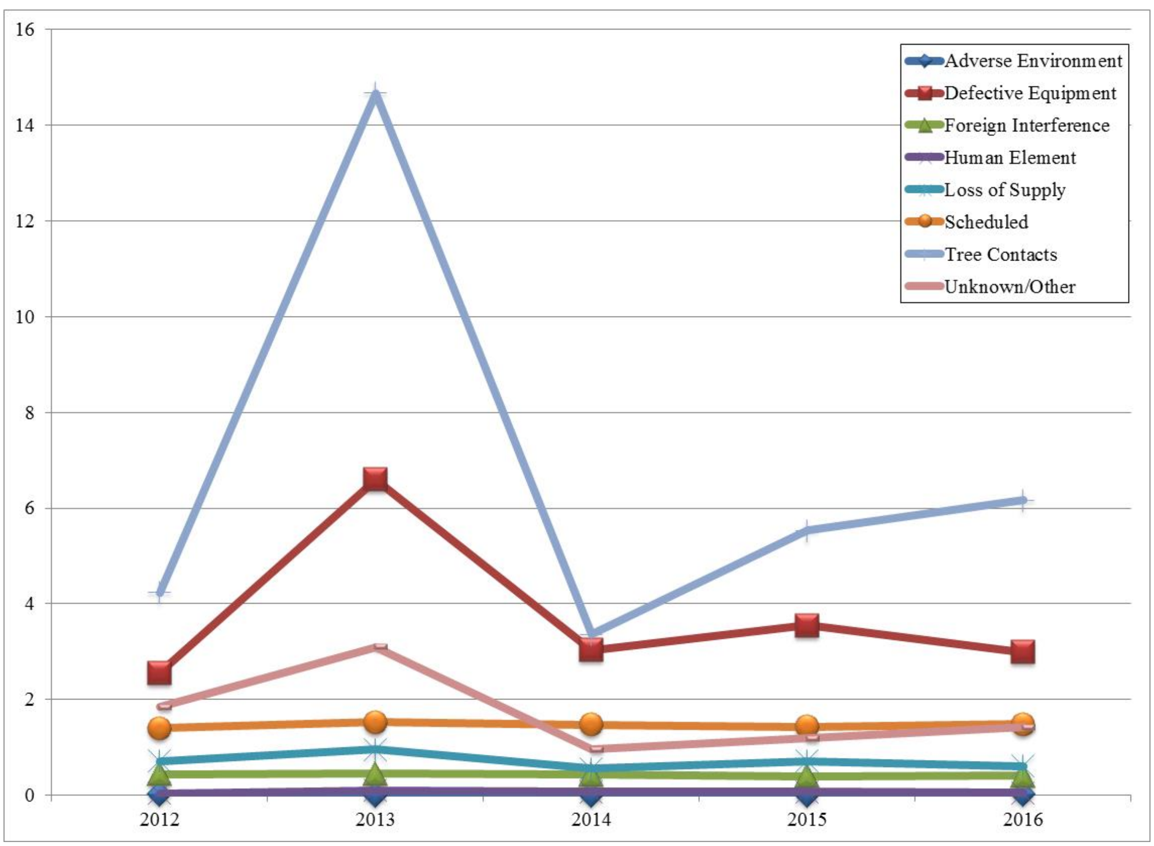


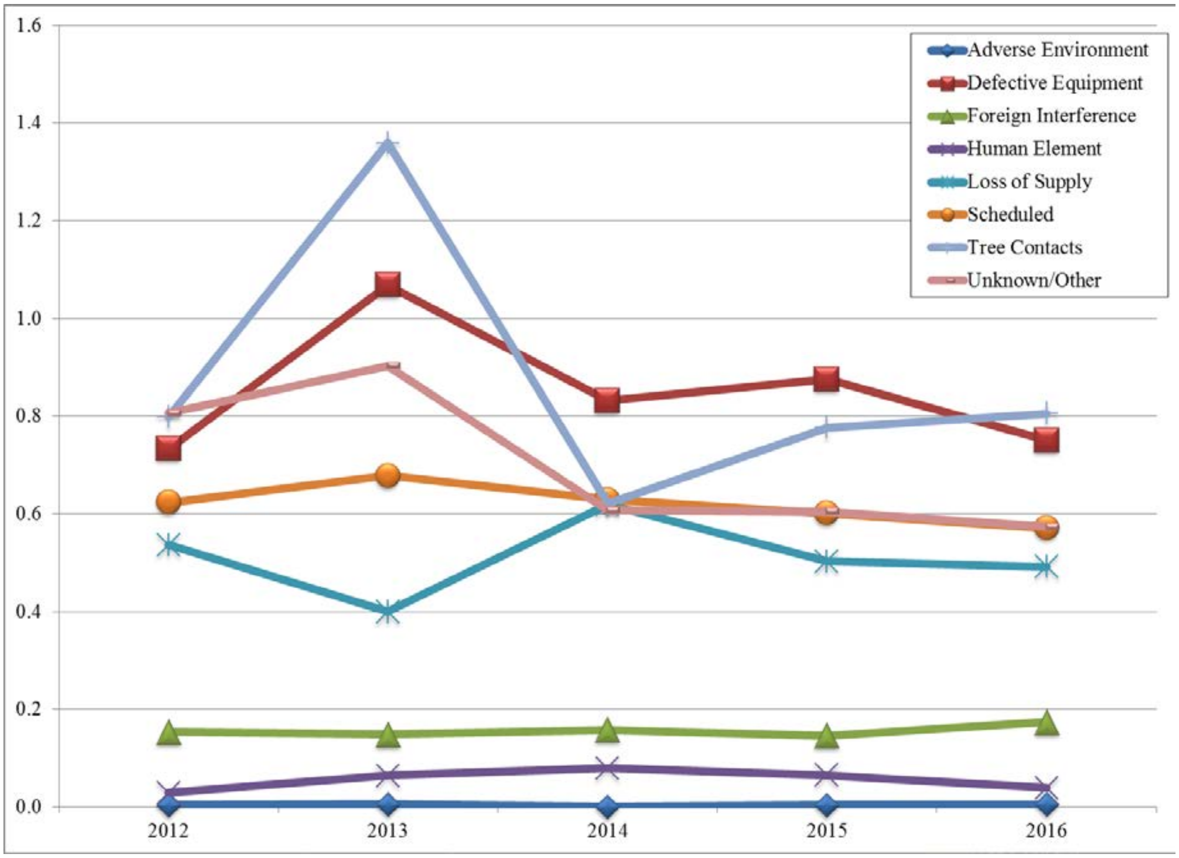
Figure 6 - Chart of SAIDI by Outage Cause

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

Table 14 - SAIFI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.00	0.01	0.00	0.00	0.00
Defective Equipment	0.73	1.07	0.83	0.88	0.75
Foreign Interference	0.15	0.15	0.16	0.15	0.17
Human Element	0.03	0.06	0.08	0.07	0.04
Loss of Supply	0.54	0.40	0.62	0.50	0.49
Scheduled	0.62	0.68	0.63	0.60	0.57
Tree Contacts	0.80	1.36	0.62	0.78	0.81
Unknown/Other	0.81	0.90	0.61	0.60	0.57

Includes outages due to Loss of Supply and Force Majuere

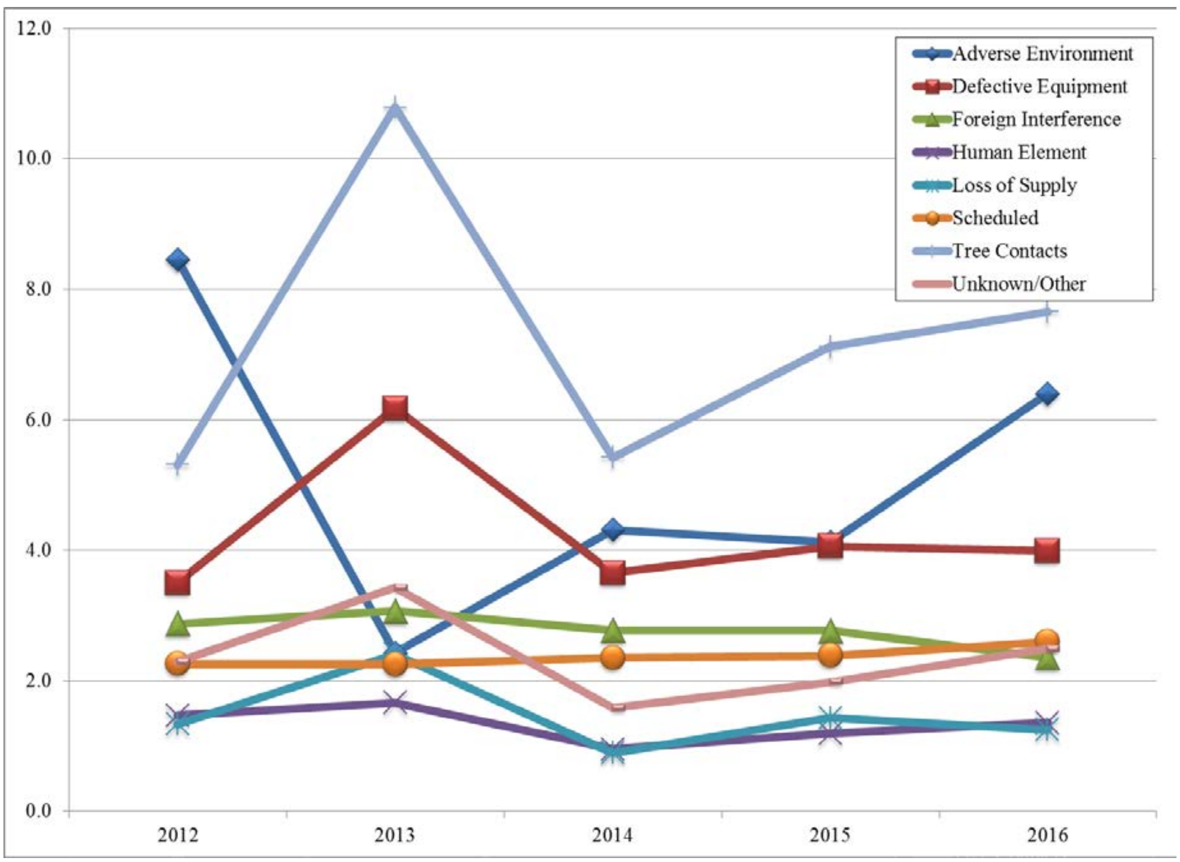
1 

2 **Figure 7 - Chart of SAIFI by Outage Cause**

1 **Table 15 – CAIDI* by Outage Cause**

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	8.46	2.43	4.32	4.12	6.40
Defective Equipment	3.50	6.17	3.65	4.06	3.99
Foreign Interference	2.87	3.07	2.77	2.77	2.36
Human Element	1.47	1.67	0.96	1.20	1.36
Loss of Supply	1.34	2.41	0.90	1.43	1.25
Scheduled	2.26	2.25	2.35	2.38	2.60
Tree Contacts	5.31	10.79	5.42	7.12	7.66
Unknown/Other	2.29	3.43	1.59	1.98	2.49
Includes outages due to Loss of Supply and Force Majuere					

2



3

4 **Figure 8 - Chart of CAIDI* by Outage Cause**

5 ** CAIDI provides the average outage duration that a typical customer would experience in any given year.*
6 *CAIDI is equal to SAIDI divided by SAIFI.*

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

1.4.3 (5.2.3 C) HOW THE PLAN REFLECTS PERFORMANCE MEASUREMENT AND OUTCOME MEASURES

The productivity and outcome measures discussed above are used to drive continuous improvement in asset management planning, work execution, and in customer oriented performance. The table below summarizes the alignment of Hydro One's performance measures with its Business Objectives and the corresponding RRF Outcomes.

Table 16 - Hydro One Business Objective Alignment with Performance Measures

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences	Improve current levels of customer satisfaction	• Handling Unplanned Outages Satisfaction % • Call Centre Customer Satisfaction % • My Account Customer Satisfaction % • New Residential/Small Business Services Connected on Time • Scheduled Appointments Met On Time • Telephone Calls Answered On Time • First Contact Resolution • Billing Accuracy • Customer Satisfaction Survey Results
	Engage with our customers consistently and proactively	• Used to inform outcomes
	Ensure our investment plan reflects our customers' needs and desired outcomes	• Used to inform outcomes
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Actively control and lower costs through OM&A and capital efficiencies	• Total Cost per Customer • Total Cost per km • OM&A per Customer • OM&A per km of Line • Pole Replacement –Cost per Unit • Vegetation Management – Cyclical Cost per km Line Clearing • Station Refurbishments – Cost per MVA

RRF Outcomes	Hydro One Business Objectives	Performance Measures
	Achieve and maintain employee engagement	• Drives company culture leading to improved Operational Effectiveness
	Drive towards achieving an injury -free workplace for employees and the public	• Drives company culture leading to improved Operational Effectiveness • Level of Public Awareness • Level of Compliance with Reg 22/04 • Number of General Public Incidents
	Provide reliability consistent with customer requirements.	• Average Number of Times that Power to a Customer is Interrupted • Average Number of Hours that Power to a Customer is Interrupted • Rural and Urban SAIFI • Rural and Urban SAIDI • Large Customer Interruption Frequency • Number of Substation Caused Interruptions • Number of Vegetation Caused Interruptions • Number of Line Equipment Caused Interruptions • Distribution System Plan Implementation Progress
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in	Ensure compliance with all codes, standards, and regulations	• Monitored by the applicable business unit(s)
	Partner in the economic success of Ontario	• Monitored by the applicable business unit(s)

RRF Outcomes	Hydro One Business Objectives	Performance Measures
legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Sustainably manage our environmental footprint	• Net cumulative energy savings • Renewable Generation Connection Impact Assessments completed on time • New Micro-embedded facilities connected on time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Achieve the ROE allowed by the OEB	• Current Ratio (Current Assets/Current Liabilities) • Return on Equity (deemed) • Return on Equity (achieved) • Total Debt to Equity

INVESTMENTS DRIVING BUSINESS PERFORMANCE

The following sections demonstrate how the planned investments will enable Hydro One to achieve its Business Objectives and the corresponding targets set for its productivity and outcome measures. The impact of each material investment within the DSP is summarized below by OEB Performance Outcome and corresponding Hydro One Business Objectives.

1.4.3.1 CUSTOMER FOCUSED PROJECTS

The RRF Customer Focus Outcome aligns with Hydro One's business outcomes to improve current levels of customer satisfaction, engage with our customers consistently and proactively, and ensure our investment plan reflects the Company's customers' needs and desired outcomes. Hydro One has historically measured the degree to which it is meeting the objective of increasing customer satisfaction with the OEB scorecard measures:

- New Residential/Small Business Services Connected on Time;
- Scheduled Appointments Met on Time;
- Telephone Call Answered on Time;
- Customer Satisfaction Survey Results;
- First Contact Resolution; and
- Billing Accuracy.

In addition to the OEB scorecard measures, Hydro One has added four additional measures to better measure the level of customer satisfaction:

- Customer Satisfaction – Perception Survey %;
- Handling of Unplanned Outages Satisfaction;
- Call Centre Customer Satisfaction; and
- My Account Customer Satisfaction.

The following investments are targeted at improving customer satisfaction and are expected to positively impact the measures used to monitor customer satisfaction.

Worst Performing Feeders ISD SS 06.

This investment will facilitate capital works to improve performance on Hydro One's feeder performance outliers. The strategy for this investment is to focus on distribution system areas that are reliability performance outliers. This approach will keep system performance statistics stable and control capital costs by deferring other investments with less impact on performance. This investment is expected to increase the reliability of the distribution network for customers that have been experiencing poor performance by reducing the average frequency and duration of power outages. This is expected to positively impact the **Customer Satisfaction Survey Results**.

Customer Self Service Technology ISD GP 16.

This investment addresses the need to enhance customer experience through additional self-service tools and functionality. This investment is expected to improve customer engagement by providing a convenient mechanism through which customers can interact with Hydro One. This investment also provides customers with a streamlined online experience that allows them to better understand their bills. This investment is expected to improve the **My Account Customer Satisfaction** and **Customer Satisfaction Survey Results** measures.

Call Centre Technology ISD GP 28.

This investment addresses the need to replace a system that has reached end-of-life. The investment also addresses the need to improve customer satisfaction and operational efficiencies at the call centre, especially for commercial and Industrial customers. This investment is expected to positively impact the **Customer Satisfaction Survey Results, Call Centre Customer Satisfaction, First Contact Resolution** and **Telephone Call Answered on Time** measures.

Customer Service Billing Investments ISD GP 29.

This investment will provide Non-Energy Billing Integration and will also produce a redesigned and improved bill for customers in 2022. This investment is expected to improve **Customer Satisfaction Survey Results**.

Customer Data and Analytics ISD GP 32.

This investment will upgrade several customer analytic tools provided by Hydro One. This investment is required to improve customer satisfaction through implementing alerts and analytics functionality. This investment is expected to improve **Customer Satisfaction Survey Results** as customers would have access to tools to help them manage energy usage.

Customer Service Complaint Management Tool ISD GP 33.

This investment will integrate the Complaint Management System with our SAP Customer Information System. This investment addresses the need to improve customer satisfaction through better handling, tracking and resolution of customer complaints. This investment is expected to improve **Customer Satisfaction Survey Results** and **Call Centre Customer Satisfaction.**

Smart Meter Network Investments ISD GP 34.

This investment will upgrade several meter reading systems and processes. This investment will reduce the number of customers who receive estimated bills, thereby improving **Customer Satisfaction Survey Results** and support Hydro One's efforts to meet the Ontario Energy Board's **Bill Accuracy** target of 98%.

1.4.3.2 OPERATIONAL EFFECTIVENESS INVESTMENTS

The OEB Operational Effectiveness Outcome aligns with Hydro One's Business Objectives as illustrated in Table 16. The measures that align with these business objectives and the material investments that impact the performance of these measures are discussed below.

Actively Control and Lower Costs Through OM&A and Capital Efficiencies

Hydro One has historically measured the degree to which it is meeting the objective to actively control and lower costs through OM&A and capital efficiencies with the following productivity measures:

- Cost/customer
- Cost/km
- OM&A/customer
- OM&A/km

- Pole replacement -unit cost
- Vegetation Management - unit cost
- Station refurbishments transformer bank- unit cost

The following investments are intended to actively control and lower costs through OM&A and capital efficiency gains and are expected to positively impact the measures used to monitor cost efficiency.

Remote Disconnection / Reconnection Program ISD SS 01.

The investment will result in the installation of meters with Remote Disconnect/Reconnect ("RDR") capabilities. Installing RDR capable meters will reduce the number of truck rolls required for disconnection and reconnection of service, required for customer needs such as move in and move out. Over the period 2018to 2022 planning period, 55,625 RDR capable meters will be installed.

Collection Enhancements ISD GP 31

This investment will enhance Hydro One's collections processes and functionality and implement pre-paid metering. This investment will improve collections and reduce bad debt expense at Hydro One leading to an increase in operational efficiency.

Corporate Performance Reporting ISD GP 07

The new Corporate Performance Reporting ("CPR") application will replace third-party software that requires support from an external vendor. The new application will be internally supported leading to reduced vendor costs. It will also be integrated with Hydro One's SAP system allowing for greater flexibility to meet reporting requirements.

Transport and Work Equipment (TWE) Capital Requirements ISD GP 01

This investment will replace transport and work equipment that is deemed to be at the end of its expected service life resulting in an optimal fleet composition that meets industry standards. This investment will maintain or improve operational efficiency by minimizing maintenance costs, shortening vehicle downtime, and increasing fleet availability.

Work Management & Mobility ISD GP 10

This investment will result in a refresh of the mobile technology used by Hydro One Distribution. The investment will eliminate or automate a significant amount of manual work and improve workforce effectiveness through better scheduling. In addition to the overall cost measures, this investment will have a positive impact on several distinct measures including pole replacement unit cost, vegetation management unit cost and station refurbishments – cost per transformer bank.

Business Process Consolidation ISD GP 12

This investment will allow the expanded use of the SAP Business Planning and Consolidation tool to add functionality such as integrated investment planning, business planning and forecasting capability. The added functionality will improve accountability and planning accuracy, shorten cycle times and allow for period books to be closed faster. This investment will yield operational and process efficiencies and improved decision-making capabilities.

Human Resource (HR) & Pay Related Technology Investments ISD GP 13

This investment will implement various process and tool enhancements to Hydro One's HR and Pay operations. This investment will improve efficiency/productivity in the HR & Pay area. These tool and process enhancements will increase operational efficiency.

Warehouse Scanning Device Replacement ISD GP 14

This investment will upgrade the bar coding devices used to manage warehouse inventory. This investment will enable Hydro One to monitor its inventory more efficiently, accurately and at reduced cost, all outcomes that increase operational efficiency.

SAP Treasury ISD GP 15

This investment will replace the Treasury system that has reached the end of its useful life and will no longer be supported by the vendor. The investment will implement the SAP Treasury & Risk Management System. Integration with enterprise SAP self-service tools results in savings attributable to better processes and more timely financial data. This investment improves business performance through using standard SAP automated processes for cash management, reducing manual entries for wire and ETF payments, and providing timely updates of bank data and transactions.

S4 HANA for Finance and Enterprise Asset Management ISD GP 17

This investment involves the replacement the SAP enterprise reporting platform with a new system, S4 HANA for Finance and Enterprise Asset Management. Implementation of the new system will improve decision-making with real time reporting, process simplification, better data quality, and a more effective interface. The new system will also increase processing speed and system performance. This investment will yield operational efficiencies.

Station Spare Transformer Purchases, ISD SR 03

This investment will result in the purchase of spare transformers for distribution stations as needed to support the in-service population. Operating with current proposed Mobile Unit Substation (MUS) fleet size requires spare transformers to be available to eliminate the 6 to 12 month transformer lead time. Hydro One has optimized its inventory of spare transformers required by moving toward a more standardized fleet of in-service transformer banks. This investment will also lower cost by reducing the need for expansion of the MUS fleet that would otherwise be necessary to support long transformer lead times.

Manage Public Safety Risk

Managing Public Safety Risk involves assessing the risks to the public from Hydro One's business operations, assessing the probability of an event and the severity of that event, and assessing the costs to mitigate identified risks. The following investments are expected to have a positive impact on Hydro One's Business Objective to manage public safety risk and are expected to drive improvement in the measures used to monitor this objective.

Station Security Upgrades, ISD GP 24

This investment provides for the installation of upgraded security measures at distribution stations to mitigate break and enter occurrences and prevent thieves from stealing copper grounds and neutral conductors. This investment is expected to improve public safety by mitigating the public's exposure to compromised grounding systems and station perimeters, positively impacting the number of general public incidents. In addition, this investment is expected to reduce maintenance costs associated with repairing the damage caused to distribution stations as a result of break and enters.

Component Replacement – Submarine Cable ISD SR 11

This investment will replace or refurbish submarine cables that are damaged or exposed at the shoreline and present a risk to public safety and are at an increased risk of failure. The public expects Hydro One to manage these safety risks. This investment is expected to mitigate public safety risks posed by damaged submarine cables and positively impact number of general public incidents.

Providing Reliability Consistent with Customer Requirements

Most of Hydro One's customers expect the level of system reliability to be maintained while large customers expressed a desire for improved reliability and a reduction in the frequency of outages. Hydro One will measure the degree to which it is meeting the objective of providing reliability consistent with customer requirements with the following measures:

- Substation-caused interruptions;
- Vegetation-caused interruptions;
- line equipment-caused interruptions;
- OEB Scorecard SAIDI;
- OEB Scorecard SAIFI;
- Rural SAIFI;
- Rural SAIDI;
- Urban SAIFI; and
- Urban SAIDI.

The following investments are targeted at providing reliability consistent with customer expectations and are expected to positively impact the measures used to monitor Hydro One's reliability performance.

Distribution Station Component Planned Replacements Program ISD SR 04

This investment replaces station equipment components that are at the end of their useful life and are not otherwise planned to be addressed by the station refurbishment program. By replacing these components before they fail, this investment will help maintain the substation-caused interruptions measure.

Distribution Station Recloser Upgrades ISD SR 05

This investment, which is part of an ongoing program, proactively installs new station reclosers at feeders where the existing protective device has become insufficient to meet electrical requirements. The new reclosers have lower maintenance costs, can be monitored and controlled remotely and have a longer service life. The quantity and funding for recloser upgrades is expected to be in line with historical levels to help maintain substation-caused interruptions within the historical range.

Distribution Station Refurbishments ISD SR 06

This investment, which is part of an ongoing program, replaces or refurbishes distribution stations at the end of their useful life before they fail. This investment is expected to help maintain substation-caused interruptions within the historical range.

Pole Replacement Program ISD SR 09

This program addresses replacement of wood poles and associated hardware that are at the end of their useful life. By replacing these poles before they fail, this investment is expected to maintain line equipment-caused outages within the historical range.

Distribution Line Component Replacements ISD SR 10

Hydro One performs assessments to identify distribution line components that are near the end of their useful life. This program addresses replacement of those line components. By replacing these components before they fail, this investment is expected to maintain line equipment-caused interruptions within the historical range.

Reliability Improvements ISD SS 03

This investment provides targeted reliability improvements in areas where customers have expressed concerns about the performance of the existing distribution network. Based on the currently identified projects targeted for reliability improvement in this DSP, overall SAIDI and SAIFI numbers are not expected to change materially from the historical range due to the local and limited size of these projects relative to Hydro One's system. However, this investment is expected to positively impact the Large Customer Interruption Frequency measure.

Worst Performing Feeders ISD SS 06

The strategy for this investment is to focus on distribution system areas that are reliability performance outliers and defer investments with less impact on performance. This investment aligns with customer preferences to sustain reliability and positively impact costs. This investment is expected to positively impact reliability of the feeder performance outliers and sustain the proposed SAIDI and SAIFI measures.

1.4.3.3 PUBLIC POLICY RESPONSIVENESS INVESTMENTS

The OEB Public Policy Responsiveness Outcome aligns with Hydro One's Business Objectives to ensure compliance with all codes, standards and regulations, partner in the economic success of Ontario and sustainably manage our environmental footprint. A significant portion of Hydro One's material investments are non-discretionary and are driven by the need to adhere to these business objectives. These investments do not directly align with specific performance measures but are critical to Hydro One's compliance with OEB Public Policy Responsiveness outcomes and the Company's corresponding Business Objectives. These non-discretionary investments are listed below.

- Life Cycle Optimization & Operational Efficiency Projects ISD SR 13;
- Distribution Lines Trouble Calls & Storm Damage Response Program ISD SR 07;
- AMI Network Expansion ISD SA 03;
- System Upgrades Driven by Load Growth ISD SS 02;
- Joint Use and Line Relocation Program ISD SA 01;
- Meter Inventory Sustainment ISD SA 02;
- AMI Hardware Refresh ISD SR 14;
- New Load Connections, Upgrades and Cancellations and Metering ISD SA 04;
- Generation Connections ISD SA 05;
- Enterprise Content Management (ECM) - Phase C ISD GP 09;
- Customer Service Regulatory Changes and Pricing Options ISD GP 30;
- Distribution Line PCB Equipment Replacement Program ISD SR 08;
- Leamington TS Capital Contribution ISD GP 25;
- Hanmer TS Capital Contribution ISD GP 26;
- Enfield TS Capital Contribution ISD GP 27;
- Demand Investments ISD SS 04;
- Distribution Station Demand Program ISD SR 01; and
- Distribution System Modifications ISD SS 05.

Details on each of the investments listed are available in the corresponding ISD in Section 3.8.

1.4.4 ATTACHMENTS: PERFORMANCE MEASURES AND OUTCOME MEASURES

Attachment	Name
1	Productivity Reporting Governance Document

Productivity Reporting Governance Document

February 17th, 2017

Contents

Productivity Reporting at Hydro One

Hydro One's goal is to be a best-in-class customer-centric commercial utility with a culture of continuous improvement and excellence in execution. Successful execution and performance measurement are critical to achieving this goal and will allow Hydro One to deliver incremental Value to customers in the coming years.

Hydro One will track and document the collective effort of all organizations to improve the Value provided to customers for program spending. The reporting of these efforts will drive increased accountability for management to achieve Productivity gains and will provide a transparent view for the regulator and our customers that Hydro One has adopted a culture of continuous improvement.

Definitions

Value

Value for the purposes of Productivity reporting can be defined as the service level provided to customers relative to the cost they pay through electricity rates. Customers assign different levels of importance to the services provided by Hydro One but it is clear through customer engagement that customers place the most Value in having a low cost electricity distributor without sacrificing performance in maintaining a safe, reliable electricity system. Creating Value for customer's means improving the service level provided while lowering the relative cost to provide those services.

Productivity

Productivity gains are the result of improved planning or execution of work that increases Value to the customer. This Value can be measured through output/input metrics which often are based on the cost per unit of output in a given work program. These metrics are measured over time to show the increasing Value to customers for program spending. Savings from new technologies and process innovations will naturally impact these metrics as they reduce costs to the customer while providing consistent or improved service levels. Productivity is quantifiable and can be measured through dollars or other numerical units.

Savings

There are many initiatives in place or under development that specifically target cost reductions in work programs and corporate support services. These Savings are tracked and reported to gauge the success of the initiatives and to find new ways to build upon their success. However, ultimately Productivity will be measured using metrics that demonstrate increasing Value to the customer rather than total Savings achieved.

Avoided Cost

Through Hydro One's business planning process, future cost increases can be identified in time to develop a strategy to mitigate or eliminate the increase. Avoided Costs are by their nature difficult to quantify as the conditions that would have caused the cost increase were prevented from occurring. These avoided costs will not be included in Savings tracking or Productivity reporting, but do impact the Value being generated for customers.

Performance Outcomes

In order to ensure that Hydro One is achieving its Productivity and cost efficiency goals it has aligned its planning, execution and reporting functions around performance outcomes. These outcomes are based upon the Renewed Regulatory Framework (RRF) that the Ontario Energy Board (OEB) has implemented for use in both Transmission and Distribution regulatory proceedings. The RRF outcomes are designed to provide additional transparency into the performance of Hydro One in these four areas:

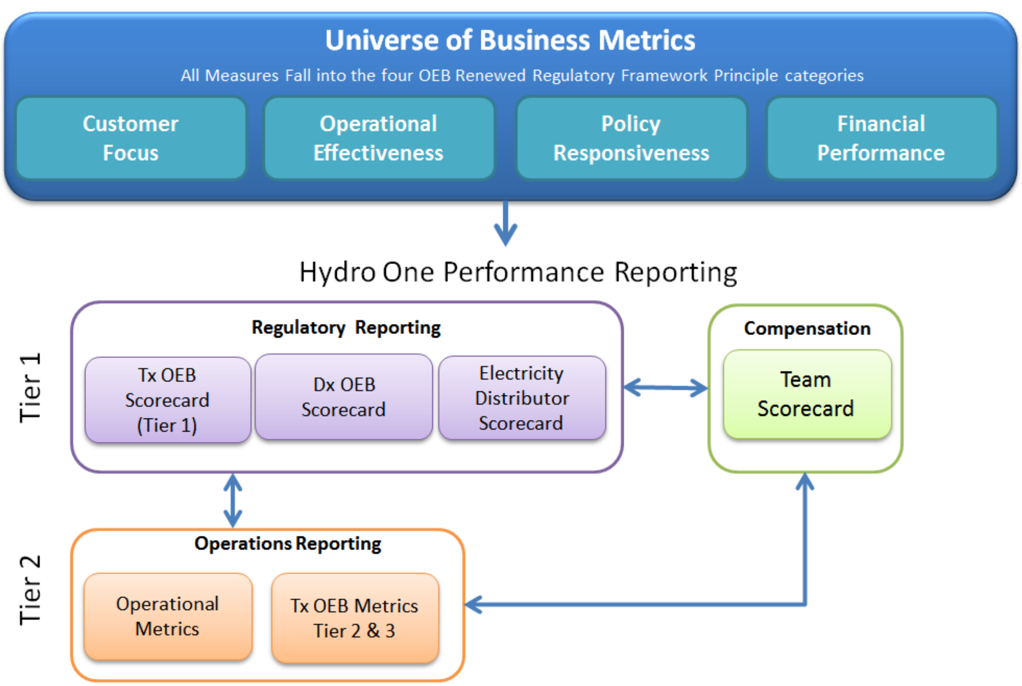
1. Customer Focus,
2. Operational Effectiveness,
3. Policy Responsiveness, and
4. Financial Performance

A direct correlation can be drawn between Hydro One's business objectives and the RRF performance outcomes.

Performance Scorecards

Hydro One primarily reports its performance through regulatory scorecards and the Team Scorecard which is used for the Short Term Incentive Plan award. These four scorecards comprise the Tier 1 scorecards that are reported internally and externally. The Tier 2 scorecards were designed for operational reporting to help managers effectively run the business. The measures on these scorecards often overlap, and at a minimum support the achievement of the Tier 1 goals, to ensure management at all levels are working towards the same goals.

The illustration below provides a view of the relationship between the RRF principles, the universe of business metrics and the scorecards used for reporting.



Performance Metrics

The regulatory scorecards and the Team Scorecard are composed of metrics that are designed to demonstrate the increasing Value to customers for program spending. The most evident of these are the cost per unit metrics that aim to reduce the cost of putting a standardized unit into service. Cost per unit metrics are impacted by both a reduction in costs (inputs) as well as the total number of units put into service (outputs). Increasing the number of units put into service will provide Value to the customer by improving service levels such as reliability. By showing an improvement in these metrics over time, Hydro One is demonstrating that it is providing an improved service level relative to the cost of providing the service.

For example cost per unit for the Wood Pole Replacement program is a metric where Value for the customer can be generated by maintaining service through reliability while reducing the cost of the pole through labour and material efficiencies. If the same standardized unit of pole is being replaced at a lower total cost then the customer will realize the Value through their electricity rates.

The reliability and customer service metrics on the scorecards are examples of metrics that are focused on the service level side of the equation (outputs). Since these service levels are very broad and cover many work programs and customer service efforts, they must be measured relative to other cost metrics (inputs) included on the scorecards such as OM&A per customer and OM&A per line km. These high level metrics will show the trend in spending that when viewed with the service level performance metrics will illustrate the Value that customers are receiving relative to spending over time.

Authorities & Accountabilities

Lines of Business

Each line of business is accountable for developing a Productivity strategy including targets and forecasts for the business planning period. This strategy should be aligned with Hydro One's business objectives and will focus on providing additional Value to customers. Lines of business will be responsible for executing their Productivity strategy and achieving the targets that are imbedded in the Productivity plan.

Business Planning

Business Planning will support LOB's in designing Productivity metrics to measure the effectiveness of the organizations Productivity strategy. The Productivity team will also review the data governance and reporting methodology for all metrics used in reporting (both internal and external).

Finance

Finance is the owner of the Team Scorecard and is accountable for reporting the results based on the internal reporting schedule.

Regulatory

Regulatory is the owner of the regulatory scorecards and is accountable for reporting based OEB requirements.

Deliverables and Stakeholders

Productivity reporting has two primary customers, including the Executive Leadership Team and the OEB. The OEB requires annual reporting to ensure performance levels are being maintained as well as for rate setting purposes during regulatory proceedings. The Executive Leadership Team requires monthly and quarterly reporting in order to successfully manage the business and achieve the business objectives.

Scorecard	Ontario Energy Board	Executive Leadership Team	Operations Managers
Regulatory			
Tx OEB – Tier 1	Annual	Quarterly	Monthly
Dx OEB	Annual	Quarterly	Monthly
Electricity Distributor Scorecard	Annual	Quarterly	Monthly
Compensation			
Team Scorecard	Upon Request	Monthly	Monthly
Operational Reporting			
Tx OEB – Tier 2 & 3	Not Provided	Quarterly	Monthly
Operational Reporting	Not Provided	Not Provided	Monthly

1.5 (5.2.3) PRODUCTIVITY AND CONTINUOUS IMPROVEMENT

As reflected in its Business Objectives, Hydro One is committed to continuous improvement and achieving Distribution system outcomes that are valued by customers, including cost efficiency. This commitment is central to the planning and execution of work programs across the Company.

Hydro One has undertaken a number of initiatives to reduce costs while maintaining service quality and work outputs. Quantifiable improvements are included in the business plan with clear accountabilities for delivering the savings.

Hydro One will use the performance metrics described in Section 1.4 to establish a baseline of its historical performance, track current progress, and establish new targets for future periods. These performance measures provide visibility to the progress of initiatives to deliver outcomes valued by customers.

1.5.1 PRODUCTIVITY SAVINGS IN THE PLAN

The key to providing customers with value is creating a business plan that aligns customer preferences, responsible stewardship of the system and rate impacts. Developing initiatives and approaches that make the Company more productive and more efficient define Hydro One's plan. The savings driven by these initiatives have been included in detailed OM&A and Capital plans. A summarised forecast of productivity savings for 2018-2022 is outlined in Table 17.

Table 17 – Detailed Productivity Savings Forecast

$Millions	**2018**	**2019**	**2020**	**2021**	**2022**
Move to Mobile	10.3	10.5	10.7	10.7	10.7
Procurement	14.2	15.3	19.1	20.2	20.8
Telematics	1.0	1.0	2.4	2.8	3.1
Total Capital	**25.5**	**26.8**	**32.2**	**33.7**	**34.5**
Move to Mobile	2.7	2.8	2.9	2.9	2.9
Operations	20.0	23.1	24.1	25.4	28.0
Procurement	2.2	2.1	2.5	2.7	2.8
Customer Service	1.8	2.6	3.2	4.1	4.8
Telematics	0.8	0.8	1.4	1.3	2.2
Information Technology	7.3	9.3	9.3	9.3	9.3
Total OMA	**34.8**	**40.7**	**43.4**	**45.8**	**50.0**

$Millions	2018	2019	2020	2021	2022
Procurement	1.8	1.8	1.8	1.8	1.8
Administrative	1.4	1.5	1.5	1.5	1.5
Total Corporate Common	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**
Total Savings	**63.5**	**70.8**	**78.9**	**82.8**	**87.8**

1.5.1.1 MOVE TO MOBILE

When Hydro One crews are working in the field, they could be anywhere inside a 640,000 sq. km area. Equipping these crews with technological resources that will help them perform work more effectively and find solutions faster will lead to savings. The goal of the Move to Mobile ("M2M") project is to improve operational efficiency in the field by using technology. The project is designed to apply industry best practices to Provincial Lines major business processes in the areas of Customer, Maintenance and Project work in addition to integrating mobile technology with the Company's existing suite of work management tools. An upgrade to the existing PCAD Scheduling Tool and associated process improvements will result in a 5% increase in field productivity and a reduction of eight clerical/administrative positions managed through attrition. The elimination of the current paper-based processes will result in an additional 21 clerical/administrative positions, also managed through attrition.

Other significant benefits that are realised by linking the Company's scheduling to real-time data that can be accessed by field crews via mobile devices will include improved Customer Service through timely and accurate meter setup, improved data accuracy and additional supervisory time in the field, which is critical to improving both safety and productivity. Implementation will be completed on a staged approach with completion scheduled for April 2017. Following successful implementation of this program to Provincial Lines, expansion to Forestry Services will be considered.

1.5.1.2 OPERATIONS

Hydro One forecasts productivity savings of over $120 million in Operations over the course of the 2018-2022 planning period. These savings demonstrate Hydro One's commitment to identifying and implementing efficiencies and minimizing expense before passing on costs to customers. Many of these savings have been realized by initiatives that leverage new technologies and processes, and in some cases drive a significant change to the way that Hydro One completes work. Cable Locates and Forestry are two significant sources of Operations savings.

Cable Locates

Hydro One forecasts $39.6 million in savings over the 2018-2022 planning period as a result of changes to execution of cable locates work. Beginning in September 2015, a pilot area was selected to source underground distribution locates through external service providers. The scope was expanded across the province over the following six months so that the majority of locates, excluding emergencies and some remote areas of the province, are outsourced. Savings are now being realized due to a competitive price and a multi-utility discount from these locate service providers that also perform the same service for other infrastructure owners.

To achieve the savings, Hydro One joined the Locate Alliance Consortium (LAC) to facilitate the transition to outsourced locates. LAC utilizes a One Call One Locate model in which multiple utilities use the same Locate Service Provider and share in the costs. This allows a decrease in the cost of an individual locate for each facility owner depending on the number of LAC members included on the locate request. Since Hydro One's territory is shared with a number of other LAC members this method has been successful in reducing the cost per locate.

A further initiative to lower locate costs is through reducing locate volumes through the implementation of Alternate Locate Agreements ("ALA") between Hydro One and excavators. An ALA outlines specific terms and conditions determined by the utility and agreed to by the excavator that allow the excavator to dig without receiving a traditional marked field locate. Improved GIS mapping in conjunction with planned system upgrades at Ontario One Call in late 2017 will result in further savings by avoiding locate requests where Hydro One does not have infrastructure within, or in close proximity to, the excavation area.

The overall savings forecast from changes to the Cable Locates work is provided in the Table 18.

Table 18 – Cable Locates Savings Forecast

$**Millions**	**2018**	**2019**	**2020**	**2021**	**2022**
OM&A Savings	7.6	7.8	7.9	8.1	8.2

Forestry

Hydro One forecasts $69 million in savings over the 2018-2022 planning period as a result of savings in vegetation management related work on the Distribution system. The Forestry Services department ("Forestry") is continuously looking to reduce costs and increase productivity. The following initiatives have been included in the business plan:

Inclement Weather Initiative: Forestry utilizes a significant amount of temporary staff to complete its annual work program. Changes to work practices and management of shifts have allowed for increased flexibility of staff levels during inclement weather. The cost savings expected as a result of this change have been included in the business plan.

Brush Control Optimization: Historically, brush control has been achieved through multiple approaches of manual cutting and herbicide application in the same location. A review of the program has concluded that costs can be reduced through operational changes without compromising the results of the program. These changes include a reduction of multiple treatment methods and instead utilize a one-touch approach wherever possible. Herbicides are now applied to standing brush to reduce follow-up cutting and processing. In locations where herbicide or mechanical brush cutting cannot take place, the brush will be trimmed at a reasonable height. This results in less aggressive re-growth and costs considerably less than trimming at ground level as previously done.

Customer Notification Optimization: Forestry is using various means to reduce the costs of notifying customers on upcoming work. This includes utilizing automated technology and BASC staff to make preliminary notification phone calls and having technicians collect field data on feeders scheduled for vegetation management within a three-year period. This approach would cover 60-70% of work plan requirements and would be more efficient, freeing technician time to notify customers where exceptions are necessary on the feeder. Forestry is also considering other measures to reduce expense including leveraging GIS and SAP data for feeder length calculation, reducing tree counting to determine density by using various sampling techniques, reducing marking of trees slated for removals and, when considering large removals, determining if trimming would suffice to minimize time without compromising safety and reliability.

Muskoka / Parry Sound Initiative: The Muskoka/Parry Sound region is a high priority region in terms of vegetation management, especially in light of frequent storm activity. Work volume in this area requires resources to be temporarily relocated from various areas across the province. Hydro One has created a broader project-based approach, integrating Forestry and Lines projects in planning and execution. This approach allows for the achievement of synergies in crew mobilization, project oversight and work reporting. This approach is expected to continue throughout the Application period.

Forestry Switching and Grounding: Currently, Forestry Regional Maintainers are required to wait for qualified Lines staff to switch and ground lines before commencing work activities. However, by employing a number of qualified foresters, who are trained to open switches and apply grounds in certain voltage and line configuration situations, forestry work can proceed without delays. This will result in more efficient utilization of Lines and Forestry resources as well as improved storm restoration times.

Labour Optimization: Forestry is working to optimize the number of high-skilled regular work staff to the level required to complete core work programs. Temporary workers will be utilized to perform the additional work in the applicable areas, allowing for additional flexibility in Hydro One's labour expense. In addition, Forestry is working to outsource low skilled brush control work at reduced expense to Hydro One. Both of these initiatives are expected to develop throughout the Application period (2018-2022).

Table 19 – Forestry Savings Forecast

$**Millions**	**2018**	**2019**	**2020**	**2021**	**2022**
OM&A Savings	10.0	12.9	13.8	14.9	17.4

Additional operational savings of approximately $2.4 million per year are included in the plan, primarily from two programs related to trouble calls and meter reading. The planned reduction in trouble call expense is the result of the deployment of Fault Current Indicators, which allow for faster identification of the location of outages, which aides in reducing in restoration time and expense. Planned reductions in meter reading expenses are the result of the Flexible Bill Window program, which was created to extend the billing window in order to obtain actual meter reads and reduce estimated bills. As part of that program, Hydro One's SAP system can update manual meter read schedules for unanticipated electronic meter reads, thereby eliminating the manual meter read expense. In addition, meter reading routes are adjusted on a real time basis to ensure that routes are optimized for driving distance, demand and resource constraints in order to reduce drive time.

1.5.1.3 PROCUREMENT

Subsequent to the Company's IPO, Hydro One's Supply Chain division has made several changes to its sourcing processes to increase productivity and reduce expenses, as described in Exhibit C1, Tab 3, Schedule 1. Hydro One forecasts more than $100 million in embedded savings over the 2018-2022 planning period as a result of procurement enhancements. The following enhancements are under development:

- **Bundling/Volume Discounts** – Renewed view of sourcing categorization by grouping materials/services supplied by like-suppliers to maximize savings and volume discount opportunities, and addressing multiple sub-categories at once. Bundling multiple contracts with a single supplier, and negotiate volume discounts across multiple categories and contracts.
- **Feedback Rounds** – Maximize competitive pressure through multiple feedback rounds on rates, with an opportunity for vendors to improve their proposals.
- **'Lean' RFPs** – Emphasize leaner, "bidder-friendly" scope and value in RFP formats with fewer onerous requirements and redundancies.

- **Standardization of Specifications** – Standardize requirements to allow direct, like-for-like comparisons across bidders. Move towards industry-standard specifications where reasonable, rather than Hydro One specifications, to reduce unnecessary costs.
- **Streamlined Evaluation** – Compress timelines and streamline evaluation process to meet business needs and accelerate the realization of negotiated savings.
- **Cost Transparency** – Increase knowledge of bidders' prices and composition to improve Hydro One's ability to challenge and negotiate competitive pricing.
- **Transition Pricing** – Where contracts are being renegotiated with incumbent vendors, implement new negotiated rates before the renegotiated contract execution.

Table 20 lists spending categories and the forecast procurement savings that have been embedded in the business plan over the 2018-2022 planning period.

Table 20 – Distribution Procurement Productivity – Category Overview

Category	Embedded Savings 2018-2022	Potential Approach/Levers
IT Software & Hardware	$13 M	• Renegotiate IT software contract(s) • Conduct broad RFP with telecoms and networks carrier services spend to leverage scale
Professional Services	$44 M	• Conduct RFP's to establish competitive rate cards and preferred suppliers(s) through multiple feedback rounds • Lock-in prices with preferred suppliers including volume discount agreements
Materials & Equipment	$23 M	• Conduct broad RFP's to consolidate spend with preferred suppliers with provincial capacity using multiple feedback rounds, thus increasing volume discount potential • Conduct RFP's to lock-in equipment rental rates while bundling other services as part of the RFP process
Back Office	$4 M	• Evaluate market alternatives and renegotiate office supplies

Category	Embedded Savings 2018-2022	Potential Approach/Levers
Telecom	$5 M	• Consolidate bulk of spend with fewer preferred suppliers to lower cost
Fleet	$22 M	• Renegotiate Fleet Management contract, including a broad RFP with multiple feedback rounds

1.5.1.4 CUSTOMER SERVICE

As Hydro One strives to become a customer-centric commercial entity focussed on improving customer satisfaction, the Company's business plan includes a number of initiatives that forecast Customer Service savings over $16 million.

Hydro One's new eBilling solution, launched in December 2016 via Hydro One's self-service website, is expected to increase ebilling penetration. Over 500,000 customers are expected to sign up for e-billing by 2022, reducing the volume of paper bills and associated expenses, including postage.

1.5.1.5 TELEMATICS

Telematics integrates telecommunications, including global positioning systems (GPS) and informatics systems that provide location of vehicles, and live vehicle operation and performance data. The Telematics project was successfully rolled out to all fleet vehicles and equipment at the end of 2016 and provides analytics that will allow Hydro One to realize productivity efficiencies for the 2018-2022 investment planning period. In 2017, Fleet Services will leverage the telematics vehicle data to define the baseline metrics with respect to equipment utilization, non-productive idling and reduction in speeding. The data gathered will enable Fleet Services to reallocate resources to other areas to prevent the need to purchase additional resources and reduce spending without compromising service quality to operating divisions. By using 2017 as the baseline year, targets for the specific metrics will be established for the 2018-2022 investment planning period. Please refer to Exhibit C1, Tab 3, Schedule 1, Attachment 2 for additional Telematics project information.

1.5.1.6 INFORMATION TECHNOLOGY

The following OM&A initiatives are designed to reduce costs without impacting the services provided.

Backup and Storage Optimization

Based on an assessment of industry best practices and project and application support requirements, Hydro One has identified opportunities to change its practices regarding frequency of full and incremental backups. This improvement has resulted in savings of disk space and staff time. For no material change in risk profile, this change resulted in a decrease of Hydro One's monthly storage requirement.

Environment Optimization and Decommissioning Initiatives

Hydro One has consolidated IT environments and, in some cases, decommissioned them. This has resulted in a reduction in monthly service fees paid to its third-party service provider. Also, after an assessment of IT infrastructure components and databases, Hydro One began decommissioning servers and databases that had low utilization. To date, 138 servers and 38 databases have been decommissioned, with plans to decommission an additional 67 servers and three databases by early 2017. This has reduced Hydro One's monthly server and database fees. An ongoing review process has been implemented to ensure that unused infrastructure is decommissioned in a timely manner.

Implementation of Cloud Infrastructure

Hydro One is implementing secure, cloud-based platforms into its IT environment. This will result in reduced costs due to a reduction in infrastructure resources, ongoing management and support.

IT Contract Renegotiation

A comprehensive review of all third-party contracts, including Hardware, Software, Personnel, and Telecom/Network Assets, was performed to determine opportunities for renegotiation based on overall cost and current contract renewal timelines. Hydro One is continuing its analysis of other third-party contracts and opportunities for renegotiation.

1.5.1.7 ADMINISTRATIVE

Hydro One has renewed its focus on reducing administrative and back office costs and plans, through a mixture of staff optimization and leveraging new technology, to reduce costs by $7.5 million over the Application period.

One of the drivers of these savings is implementing a new SAP-based expense management tool that allows for a reduction of corporate charge cards and optimization of the expense management processes leading to a reduction in costs of $5.4 million over the planning period.

1.6 (5.2.3) BENCHMARKING

In the Decision in Hydro One's last Distribution Rate Application for the 2015 to 2019 rates (EB-2013-0416), dated March 12, 2015, the OEB found that the proposed plan showed limited prospects for continuous improvement, lacked externally imposed improvement incentives, included limited cost and productivity benchmarking support, and failed to demonstrate value to customers commensurate with the forecast spending. To address the perceived shortcomings in the application, the OEB directed Hydro One to undertake several studies and submit reports.

The undertaking of these studies and reports presented Hydro One with the opportunity to demonstrate continuous improvement by different means: comparison to self; comparison to others; and unit cost trending analysis. This will assist Hydro One align its performance outcomes with those of the RRF.

Hydro One also challenged itself, venturing further ahead than just undertaking the studies and reports asked of it by the OEB. Hydro One identified other studies that would help it perform more efficiently, develop a culture of continuous improvement and stay on the path to excellence in execution.

1.6.1 (5.2.3 A) BENCHMARKING STUDY OVERVIEW

Benchmarking is increasingly being referenced as a means of monitoring company performance, especially when used in combination with specific cost drivers and other sources of utility performance information, as these allow for an overall assessment of a utility's cost and outcome performance. These studies address the expressed interest to better understand the cost of Hydro One's work by providing a high-level set of benchmarks that compare Hydro One's relative position to other North American utilities.

To secure the most technically qualified proponents with in-depth knowledge of the industry, market experience, and the ability to perform quality studies, Hydro One issued Requests for Proposal ("RFP") in accordance with the company's competitive bid process. Hydro One held stakeholder sessions for the productivity studies to gain input and endorsement from stakeholders and OEB staff regarding the study approach, peer comparators and metrics. Further information on the stakeholder sessions is available in Section 1.3.

The studies also presented Hydro One with a baseline to allow assessment of its own performance year over year. Exploration of cost variations and associated best practices will be beneficial for Hydro One to analyze potential cost efficiencies within its distribution business and will provide an opportunity to investigate industry best practices for the company's lines of business. Hydro One therefore also added its own objectives to the studies. The sections below outline the specific objectives for each of the studies.

Pole Replacement and Station Refurbishment Program Studies

The Pole Replacement and Station Refurbishment Programs were areas where Hydro One requested significant increases in Capital and OM&A expenditures over the three year test period of 2015 to 2017. Studies were directed to conduct a trend analysis of year over year unit costs, investigate variations, and explore best practices that can be adopted to realize value.

The Pole Replacement and Distribution Station Refurbishment Program Studies were awarded to Navigant Consulting in partnership with First Quartile Inc.

Vegetation Management Program Study

Vegetation Management was another area where Hydro One had increased expenditure levels in the test years. The OEB directed Hydro One to undertake a comprehensive trend analysis of the vegetation management program to show year over year comparisons in unit costs and a best practices study similar to the 2009 CN Utility study. The Vegetation Management Program Study was awarded to CN Utility Inc.

IT Budget Assessment Study

Hydro One conducted its own benchmarking study to collect relevant input that would craft a five-year strategy for its IT organization with sustainable efficiencies and continuous improvements. The study, which was not mandated by the OEB, was awarded to Gartner Consulting

Total Factor Productivity Study

In the *"Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board"* issued on November 21, 2013 and as corrected on December 19, 2013, the OEB's expert, Pacific Economics Group (PEG), performed, *"TFP "backcasts" and statistical tests which showed that Hydro One and Toronto Hydro were having a statistically significant impact on the industry's TFP trend, thereby providing the empirical rationale for eliminating these companies from the sample used to set the productivity factor for the electricity distribution industry"*.

In Hydro One's Distribution Rate Decision (EB-2013-0416), all parties saw value in Hydro One measuring its TFP over time to be able to demonstrate improvement in productivity to its customers and the OEB. Therefore, Hydro One was directed to determine its preferred TFP study methodology and subsequently awarded the contract to undertake a TFP Study to Power System Engineering Inc.

Total Compensation Study

Hydro One was directed by the OEB to undertake a compensation study similar to the study filed as part of the last distribution rate application to allow benchmarking to comparable companies. The study showed that on an overall weighted basis, compensation was fourteen per cent higher than industry comparators at the market median. Details and discussion regarding the findings of this study are contained in Exhibit C1, Tab 2, Schedule 1.

Total Cost Benchmarking Study

Hydro One conducted a further study in order to measure the Company's total cost performance relative to its peer group. The study showed that Hydro One is above the market median on an overall basis. Details and discussion regarding the findings of this study are contained in Exhibit A, Tab 5, Schedule 2.

1.6.2 (5.2.3 A) SUMMARY OF BENCHMARKING FINDINGS AND RECOMMENDATIONS

This section summarizes the key findings and recommendations from the benchmarking studies. How these key findings and recommendations are reflected in the Distribution System Plan can be found in Section 1.6.3.

1.6.2.1 POLE REPLACEMENT PROGRAM STUDY

The primary findings of the Pole Replacement Program Study are found in Table 21. The best practice recommendations are summarized in Table 22. The study report can be found as Attachment 1 in Section 1.6.4.

Table 21 - Pole Replacement Program Study Primary Findings

#	Primary Finding	Study Reference
1	Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles.	Section 3.1
2	Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections with some light physical inspections, while the others typically perform more rigorous physical inspections and testing.	Section 3.2
3	The replacement rate for Hydro One is slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest; on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group.	Section 3.3

#	Primary Finding	Study Reference
4	Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone premature replacement of poles.	Section 3.4

Table 22 - Pole Replacement Program Study Recommended Actions

#	Recommended Actions
1	Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2	Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria.
3	Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4	Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

1.6.2.2 DISTRIBUTION STATION REFURBISHMENT PROGRAM STUDY

The primary findings of the Distribution Station Refurbishment Program Study are included in Table 23. The best practice and implementation recommendations are summarized in Table 24. The contents of the study report can be found in Attachment 1 of Section 1.6.4.

Table 23 - Distribution Station Refurbishment Program Study Primary Findings

#	Primary Finding	Study Reference
1	Station refurbishment activities are varied within and across utilities.	Section 4.1
2	Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.	Section 4.1
3	As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.	Section 4.1
4	Navigant and First Quartile Consulting believe Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.	Section 4.2
5	Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.	Section 4.3
6	Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.	Section 4.4

Table 24 - Distribution Station Refurbishment Program Study Recommended Actions

#	Recommended Actions
1	Consider implementing a formal data governance process for equipment performance and maintenance data and incorporating that information into the asset condition scoring and project planning process.
2	Enhance cost and work completion reporting for individual projects and implement a formal change control process.

Witness: Darlene Bradley / Lyla Garzouzi

#	Recommended Actions
3	Develop and implement more comprehensive key performance indicators, including in-progress project cost performance measures, assessments of project/program impacts on substation reliability, maintenance costs, and overall asset health.

1.6.2.3 VEGETATION MANAGEMENT PROGRAM STUDY

The best practice and implementation recommendations found in the Vegetation Management Program Study are summarized in Table 25. The study report can be found as Attachment 2 of Section 1.6.4.

Table 25 - Vegetation Management Program Study Recommendations

#	Recommendation	Study Reference
1	Bring the whole distribution system to a four to eight-year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule. This will enable a more effective herbicide program, better off-ROW tree risk management, and reduce workload over the long term. Reduce the current backlog over the next decade through innovations, automation and changes in labour mix. See Recommendations 2, 3, 4, 6, and 9 (below).	Sections 4.1 - 4.3, 4.6, 4.8
2	Improve through innovation the mechanization and automation of the Utility Vegetation Management ("UVM") program. This will improve understanding of the workload and it will enable more effective work planning and cost/resource predictions.	Sections 4.3, 4.4
	Improve data analytics and predictive modeling through automated data collection of key UVM activities.	Sections 4.3.1, 4.3.2
	Use technology such as LiDAR to improve measurements, condition assessments, and accuracy of data collection.	Sections 4.3.2

Witness: Darlene Bradley / Lyla Garzouzi

#	Recommendation	Study Reference
	Increase ROW clearing capacity and safety through innovations in mechanical equipment and routing technology.	Section 4.4.1
	Improve customer knowledge, communication, and involvement by merging UVM data with the customer service system.	Sections 4.3.3 – 4.3.5
3	Improve productivity and control costs by utilizing higher percent of Hiring Hall and contract workers to perform lower safety and liability risk activities such as work planning, herbicide applications, and brush-clearing. This will lower unit costs.	Section 4.4.2
4	Strategically increase herbicide usage for cost-effective results. This will ensure ROWs stay clear between shorter cycles of management and lower the long term cost.	Sections 4.1.3, 4.2.5, 4.2.7, and 4.3.1
5	Develop a vegetation management outage investigation protocol that expands on the current cause codes and utilizes UVM personnel. This will improve capability to predict tree failure modes and guide future tree risk mitigations.	Section 4.5.3
6	Synchronize the annual asset inspections with the UVM work planning program to quantify system vegetation conditions based on performance metrics for maintaining air space around conductors. This will improve workload understanding and provide annual performance metrics for system conditions.	Section 4.3.1
7	Improve and increase the Tree Risk Assessment Program to reduce outages caused by off-ROW trees. This will, with the help of lessons learned through outage investigations, improve reliability by reducing outages caused by trees or branches falling into overhead lines.	Sections 4.3.1, 4.5.3, 4.7 and Appendices F and G

#	Recommendation	Study Reference
8	Identify fixed cost increases and overheads allocated to UVM to ensure cost effects of changes to the program are portrayed accurately. This will enable a better understanding of improvements to production and other cost reduction measures.	Sections 4.1 (4.1.1, 4.1.3, 4.1.4) and 5
9	Improve equipment and personnel utilization. This will lower unit costs by improving efficiency and optimizing equipment availability.	Section 4.4 (4.4.1, 4.4.2)

1.6.2.4 IT BUDGET ASSESSMENT

Hydro One conducted its own benchmarking study to collect relevant input that would craft a five-year strategy for its IT organization with sustainable efficiencies and continuous improvements. The study, which was not mandated by the OEB, shows Hydro One's commitment to increasing productivity before asking customers to pay more. Awarded to Gartner Consulting, the "**IT Budget Assessment"** analyzed enterprise-level metrics and the distribution of IT spending relative to industry peer groups. The study showed that Hydro One spends a similar amount on IT compared to the peer group, but there are differences in how the dollars are spent.

The IT Budget Assessment's key findings are summarized in Table 26. The best practice recommendations are summarized in Table 27. More details and discussion regarding the findings and recommendations of the IT Budget Assessment are available in Section 1.6.4. The study report can be found in Attachment 3 to Section 1.6.4.

Table 26 - IT Budget Assessment Key Findings

#	Key Findings	Study Reference
1	Hydro One uses more outsourcing than the peer group.	Sections - Summary of Metrics
2	Hydro One spends half of the peer group average on hardware and software.	Sections - Summary of Metrics
3	Capital IT spending is lower. Significant factor is Hydro One's minimum capitalization threshold of $2M compared to the peer group average of $250K-$500K	Sections - Summary of Metrics
4	Hydro One expenses are higher for Enterprise Computing (Servers and Storage), End User Computing (laptops and desktops) and applications support. Voice and data are both lower than the peer group.	Sections - Summary of Metrics
5	Hydro One in-house and contractor full-time employees ("FTE") are focused primarily in management and applications roles.	Sections - Summary of Metrics

Table 27 - Assessment Recommended Actions

#	Recommended Actions
1	Optimize enterprise computing and storage costs and increase server virtualization.
2	Reduce materiality threshold for IT capital expenditure.
3	Review IT organization structure and identify any duplication between roles and responsibilities of retained staff and outsourced service provider.

1.6.2.5 TOTAL FACTOR PRODUCTIVITY STUDY

Hydro One's Total Factor Productivity study can be found at Exhibit A, Schedule 3, Tab 2, Attachment 1. The key findings regarding that studied are summarized in Table 28.

Table 28 - Key Findings - Total Factor Productivity Benchmarking Study

#	Key Findings	Study Reference
1	2002-2015 TFP without safety or reliability adjustments declined by 1.4% per year.	Sections 6.1 and 8
2	2002-2015 TFP with adjustments declined by 0.9% per year which is the same as the Ontario industry decline from 2002-2014 of 0.9%.	Sections 6.1, 6.2.3, 7.1 and 8
3	Hydro One's TFP has been improving since 2010. After adjustments, Hydro One has shown positive TFP of 0.5% from 2010-2015, compared to -1.8% from 2002-2010	Section 6.2.3
4	With no adjustments, using only billing determinants as outputs, TFP was -0.4% in the recent period and -2.1% in the earlier period	Section 6.1
5	Based on the empirical evidence of declining industry TFP and the OEB's 4th Generation IR decision to set the productivity factor at 0.0%, PSE recommends setting Hydro One's productivity factor no higher than 0.0%.	Section 1.3

1.6.3 (5.2.3 C) HOW THE PLAN REFLECTS THE BENCHMARKING FINDINGS AND RECOMMENDATIONS

The pole replacement and station refurbishment benchmarking studies generated findings and recommendations that have had an impact on DSP investments. This section summarizes impacts of the benchmarking studies on the distribution system plan stemming from some key recommendations and findings.

The key recommendations from the Total Factor Productivity study are included in Exhibit A, Schedule 3, Tab 2.

Listed below, by recommendation/finding, are the actions currently being taken by Hydro One in response to the results of the benchmarking studies.

1.6.3.1 POLE REPLACEMENT PROGRAM STUDY

Recommendation 1: Pole Inspection Process

The benchmarking study recommended performing more comprehensive but less frequent pole inspections. The study recommended extending the inspection frequency from the current three and six years mandated by the Distribution System Code to a more comprehensive but less frequent 10-year inspection cycle. As a result of the recommendation, Hydro One will re-evaluate its pole inspection program frequency and comprehensiveness.

The study recommended approaching the OEB to extend the inspection frequency. Once potential changes to the frequency and comprehensiveness of the pole inspection process have been formalized, Hydro One may redesign the pole inspection process and approach the OEB for approval to implement a new inspection frequency.

Recommendation 2: Program Management

The study recommended expanding the centralized pole replacement selection reducing the amount of pole replacements identified by the local operations centres. Hydro One has implemented a centralized pole selection process with all pole replacements being selected based on identical criteria with data inputs from the inspection results of the Line Patrol Program. From the list of poor condition poles a subset of poles is selected and released to the field for replacement. When releasing these poles to the field, a timeline of one to three years is given for completion. If a pole is in urgent need of replacement, the field will be asked to replace it within the next year. For all other poles the field will be given the flexibility to replace it within the next one to three years to optimize the work execution.

There are currently a large number of poles that are in poor condition. These poor condition poles will take at least five years to be replaced.

The flexible replacement schedule allows the field to optimally schedule replacement in conjunction with other work in the area for increased efficiency. In order to determine the appropriate pole replacement design and technical requirements, Hydro One's field staff visit the pole replacement sites. During this visit, field staff may identify additional poles that have deteriorated since the last condition data was collected. Once members of field staff identify a pole that is deteriorating, they are required to submit updated condition data such that those poles are considered for inclusion in the pole replacement program. If they are deemed to require replacement, then they are replaced in conjunction with the previously identified poles.

Recommendation 3: Pole Replacement Crew

The study recommended considering use of dedicated pole replacement crews when geography and/or pole density permit. When geography and pole density conditions make the use of dedicated crews desirable, Hydro One will consider this option.

Recommendation 4: Pole Refurbishment Program

The study found that most of the peer group perform pole refurbishment. The study recommended refurbishing poles where possible. Hydro One will investigate the feasibility and cost benefit analysis of this option and its impact on work methods. The results of this analysis will determine if Hydro One will implement a pole refurbishment program.

Recommendation 5: Pole Replacement Rate

The benchmarking study found that Hydro One's pole replacement and maintenance costs are approximately average for the North American industry, with low unit costs for inspections and average costs for pole replacement. The study also found that the replacement rate has been slower than for the peer panel and, as a result, Hydro One's pole inventory is the oldest in the comparison group. This finding supports the need to increase the pole replacement rate as proposed in the DSP, see ISD SR-09 for more details on proposed pole replacement rates.

1.6.3.2 DISTRIBUTION STATION REFURBISHMENT PROGRAM STUDY

Recommendation 1: Project Planning Process

The study recommended implementing a formal data governance process for equipment performance and maintenance data, and to incorporate that information into the asset condition scoring and project planning process. The study also recommended incorporating test results and maintenance history data for switching and protection equipment and relays into the asset condition scoring and project planning process.

Hydro one is working towards improving its data governance process for equipment performance. Hydro One Station refurbishment projects are driven by major component replacement needs, (e.g., transformers, breakers, reclosers, and structures). Asset condition data on these major components drives station asset condition scoring and subsequently determines station refurbishment projects. Switching and protection equipment, and relays do not drive this program, however they are addressed under the station centric refurbishments.

Recommendation 2: Project Management Execution

The study recommended enhancing cost and work completed reporting for individual projects, and implementing a formal change control process. Hydro One currently employs cost and work completed reporting for individual projects, but has moved to improve it going forward. Substation refurbishment projects will now be managed individually with comprehensive tracking of costs, progress and a formal change control process for each project.

Recommendation 3: Key Performance Indicators (KPIs)

The study recommended developing a more comprehensive set of key performance indicators, including project cost performance measures and assessments of project impacts on substation reliability, maintenance costs and overall asset health. Hydro One is exploring the development of KPIs for station projects to incorporate aspects of cost and system impact measures.

Recommendation 4: Station Refurbishment Approach and Rate

The study found that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory. This finding supports Hydro One's approach to continue the expansion of its station-centric refurbishment investments as proposed in the DSP. For more details, see Distribution Station Refurbishments (ISD SR-06) and Station Spare Transformer Program (ISD SR-03).

The study found that Hydro One's power transformer age profile ranks in the older end of the peer group distribution. The study also found that Hydro One's "Expected Service Life" for power transformers is somewhat higher than the peer group average. Given that Hydro One's expected service life is reasonable and given its relatively old transformer age profile, this supports the level of station refurbishment investment as per the DSP, which is expected to maintain the current condition profile and corresponding reliability over the DSP period. Based on Hydro One's station service life profile and supported by the benchmarking study finding, it is expected that there will be an increased rate of distribution station deterioration that will require an increase in the level of station refurbishment investment beyond 2022. Complete details on the proposed increase in Hydro One's station-centric refurbishment programs can be found in Distribution Station Refurbishments (ISD SR-06) and Station Spare Transformer Program (ISD SR-03).

1.6.3.3 VEGETATION MANAGEMENT PROGRAM STUDY

Hydro One Forestry Services is committed to demonstrating improvements in the areas of productivity and cost efficiency. Hydro One is addressing some key recommendations made in the Vegetation Management Program Study as follows:

Recommendation 1: Technology Innovation Project

Hydro One is currently engaged in the early stages of a technology innovation project that is focused on upgrading the systems and processes that manage the vegetation programs. This project will consider options to address the following recommendations:

- Improvement through innovation and the mechanization and automation of the UVM program to enable more effective work planning and cost/resource predictions;
- Improve data analytics and predictive modeling through automated data collection of key UVM activities;
- Improve customer knowledge, communication, and involvement by merging UVM data with the customer service system;
- Synchronize the annual asset inspections with the UVM work planning program to quantify system vegetation conditions based on performance metrics for maintaining air space around conductors to improve workload understanding;
- Identify fixed cost increases and overheads allocated to UVM to ensure cost effects of changes to the program are portrayed accurately to enable a better understanding of improvements to production and other cost reduction measures; and
- Improve equipment and personnel utilization to lower unit costs by improving efficiency and optimizing equipment availability.

In 2016, Hydro One Distribution completed a pilot study on using LiDAR technology to improve program planning. LiDAR and other remote sensing technologies are in scope of the technology innovation project.

Recommendation 2: ROW Clearing Productivity

Hydro One is exploring and integrating new mechanical equipment into their work practices to improve productivity. The use of Feller Bunchers and Kershaw Sky Trimmers, and the introduction of a greater variety of grinding equipment are having a significant impact on backlog feeder clearing and brush control efficiencies. Further productivity improvements in the areas of vehicle telematics usage, route optimization, and schedule optimization are being investigated in the scope of the technology innovation project. Storm restoration efficiencies have also been gained through Forestry staff becoming qualified to provide their own work protection to provide safe work conditions.

To improve unit prices, Hydro One strives to optimize resource allocation while abiding by the terms of its Collective Bargaining Agreements. Current approaches include utilization of Hiring Hall Technicians for work planning and additional seasonal workers.

Recommendation 3: Increased Herbicide Usage

Herbicide is one tool used in Hydro One's integrated vegetation management program. The use of herbicides is sought where appropriate. Advances in the herbicide industry are closely tracked by our Herbicide Advisory Committee. Hydro One will continue to pursue the judicious use of herbicide where appropriate, including current and expanding mid-cycle application programs to control regrowth after manual control.

Recommendation 4: Outage Investigation Protocol

Hydro One has implemented a detailed outage investigation process to collect more root cause data and drive improvements in mitigating outages through planned investments.

Recommendation 5: Tree Risk Assessment Program

All programs within the vegetation management program contain elements of tree risk assessment. However, to reduce outages caused by off-ROW trees, Hydro One will be conducting a review of the International Society of Arboriculture's Tree Risk Assessment program to identify improvements in current assessment protocols and will apply these findings to the outage investigation process.

More discussion on the incorporation of the findings and recommendations of the Vegetation Management Program Study are in the exhibit entitled Sustaining OM&A, Exhibit C1, Tab 1, Schedule 2.

1.6.3.4 IT BUDGET ASSESSMENT

Recommendation 1: Rationalize Enterprise Computing Costs

The study recommended Hydro One work with internal stakeholders and an outsourcer to rationalize enterprise computing costs and review opportunities to increase server virtualization. The study also recommended Hydro One evaluate data management policies and roles at the business level to optimize storage costs.

As a result of the recommendation, Hydro One has developed a detailed 2017-2022 costs savings program, listed as IT Productivity Initiative. Included in the program are initiatives to increase server virtualization, enhance existing data management policies, optimize storage and reduce storage costs.

Recommendation 2: Reduce Capitalization Policy

The study recommended Hydro One work with internal business leadership and Finance to review the current capitalization minimum threshold of $2M and determine whether there is an opportunity to align with the peer group capitalization threshold of $250K-$500K.

As a result of the recommendation, Hydro One Finance is reviewing the current capitalization policy of $2M and will be making a decision in the near future on a potential reduction of the minimum threshold.

Recommendation 3: Review Current Organization Design

The study recommended Hydro One review the organization design to understand roles and responsibilities of retained in house IT staff and identify any overlaps (or duplication) with the service provider. The study also recommended determining whether roles should be retained or outsourced and reviewing how work is managed among the parties.

As a result of this recommendation, Hydro One is in the process of reviewing the current IT organizational structure and the roles and responsibilities of internal staff and the main outsourcer.

1.6.4 ATTACHMENTS: BENCHMARKING STUDIES

Attachment	Name
1	Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile
2	Vegetation Management Program – CN Utility Inc.
3	IT Budget Assessment Study – Gartner Consulting

Distribution Unit Cost Benchmarking Study

Pole Replacement and Substation Refurbishment

Prepared for

Hydro One Networks Inc.

Submitted by:
Navigant
Bay Adelaide Centre | 333 Bay Street
Suite 1250 | Toronto, ON M5H 2Y2

+1.416.777.2440 main
+1.416.777.2441 fax
navigant.com

Reference No.: 182699

October 19, 2016

TABLE OF CONTENTS

LIST OF FIGURES

EXECUTIVE SUMMARY

In the Ontario Energy Board's (OEB's) decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, the Board directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". Hydro One was also directed to "report on the results of this work with the corresponding analysis as part of its next rates application". Through a competitive procurement process, Hydro One Networks Inc. (Hydro One) engaged the consortium of Navigant Consulting Ltd. (Navigant) and First Quartile Consulting (1QC) to conduct this benchmarking study.

This report provides an overview of the approach, including the processes of selecting and recruiting utilities to participate in the study, assembling appropriate performance metrics, and gathering and analysing the data. The study provides insights into both the costs incurred by Hydro One and the practices used for the execution of pole replacement and substation refurbishment. Primary findings from the study for both the pole replacement and station refurbishment activities are presented below.

Pole Replacement

1. Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles.
2. Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections with some light physical inspections, while the others typically perform more rigorous physical inspections and testing.
3. The replacement rate for Hydro One is slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest; on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group.
4. Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone premature replacement of poles.

Substation Refurbishment

1. Station refurbishment activities are varied within and across utilities.
2. Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.
3. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.
4. Navigant and First Quartile Consulting believe that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.
5. Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.
6. Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.

Recommended Actions

In its request for proposals, Hydro One indicated that the study should produce recommendations that Hydro One could act upon to close gaps to best practice and improve the efficiency of its operations. Several recommendations were developed for each of the two areas under study.

Pole Replacement

The key recommended actions for pole replacement are outlined below.

1. Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2. Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria
3. Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4. Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

Substation Refurbishment

The key recommended actions for substation refurbishment are outlined below.

1. Consider implementing a formal data governance process for equipment performance and maintenance data, and incorporating that information into the asset condition scoring and project planning process.
2. Enhance cost and work completion reporting for individual projects, and implement a formal change control process.
3. Develop and implement a more comprehensive set of key performance indicators including in-progress project cost performance measures and assessments of project/program impacts on substation reliability, maintenance costs and overall asset health.

1. INTRODUCTION

In the OEB's decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, it directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". Hydro One was also directed to "report on the results of this work with the corresponding analysis as part of its next rates application".

1.1 Study Objectives

Hydro One engaged Navigant and First Quartile Consulting to design and implement a robust and replicable benchmarking study of Hydro One's distribution costs.

The benchmarking study was designed to:

- Include an appropriate group of utilities to compare Hydro One against, taking into account a number of characteristics, including asset demographics, geography, customer characteristics, etc.;
- Quantify and evaluate Hydro One's practices and unit costs for distribution pole replacement and distribution substation refurbishments and substation replacements relative to the comparison utilities, taking into account cost drivers and differentiating characteristics;
- Ensure a common understanding of the comparison criteria through the use of clear definitions;
- Make recommendations on practices that could be augmented or adopted to improve efficiency; and
- Engage stakeholders in regards to the comparison group selection criteria, comparison metrics, and preliminary findings and recommendations.

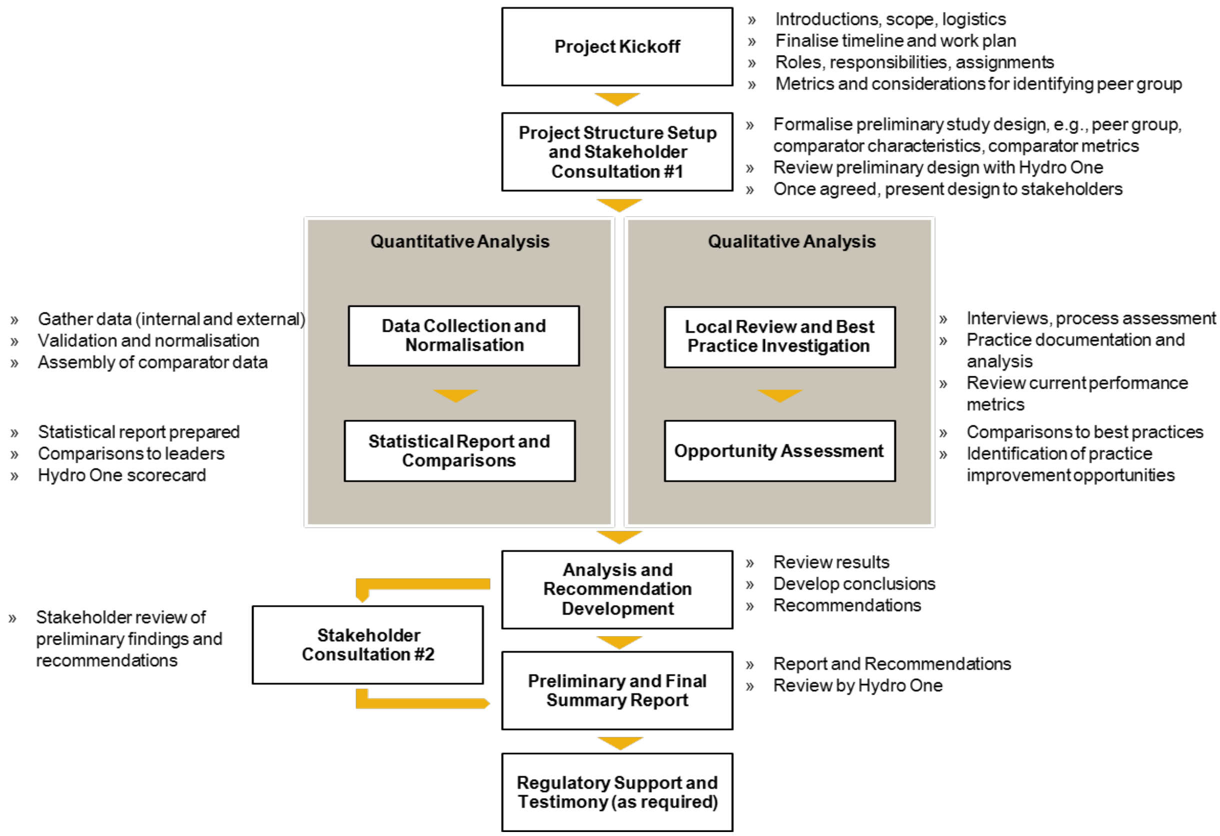
1.2 Overview of Approach

The approach to the engagement included two analyses: a quantitative analysis and a qualitative analysis. Figure 1 provides a pictorial overview of the approach used for the project. As part of the study, the evaluation team determined which business and operational demographics were relevant to identify a representative comparison group given Hydro One's vast and disparate service territory. This work leveraged First Quartile Consulting's existing transmission and distribution benchmarking program participants as well as additional companies recruited specifically for this study.

Through the quantitative analysis, the evaluation team identified and collected the necessary data from Hydro One and the comparison utilities, normalised the data, and assembled statistical reports and comparisons. Through the qualitative analysis, the evaluation team explored cost variations, identified current and best practices, and identified gaps that ultimately led to recommendations on processes and practices that Hydro One could adopt to realise efficiency gains.

The study engaged and included stakeholders. Hydro One consulted with stakeholders regarding the terms of reference for this study. Stakeholders then had the opportunity to review and provide comments at the beginning of the study on the proposed methodology and selection of the comparison group. Finally, they commented on the preliminary results, prior to the evaluation team finalising the study.

Figure 1. Overview of Benchmarking Approach



1.3 Content of Report

This report is organised into five sections and two appendices.

- Section 1: Introduction, provides an overview of the study objectives, and approach.
- Section 2: Benchmarking Process, provides an overview of the process, information collected, comparison group selection, and normalising factors used.
- Section 3: Pole Replacement Benchmarking Results, summarises cost performance, along with details associated with replacement and refurbishment of poles.
- Section 4: Substation Refurbishment Benchmarking Results, summarises the results for refurbishment and rebuilding of distribution substations
- Section 5: Recommendations, identifies practices that could be augmented or adopted to realise efficiency gains.
- Appendix A: Detailed Comparison Group Statistics, provides demographic data for the utilities that participated in the study.

2. BENCHMARKING PROCESS

The benchmarking process is the means by which data is collected and analysed in a standardised fashion. This process provides transparency into Hydro One practices and lends itself to identifying strengths as well as areas for improvement. This section covers four topics.

1. **Overview:** Outline of the benchmarking process from start to finish.
2. **Information Collected:** Description of the data collected.
3. **Comparison Group Selection:** Characterisation of the Canadian and U.S. distribution utilities included in the study.
4. **Normalising Factors:** Normalising factors were chosen to allow comparison of costs across utilities on a common basis. In the case of poles, the normalising factor most often was the number of poles or the number of poles touched (i.e. inspected, refurbished, and/or replaced). For substations, MVA of capacity, number of transformers, and number of substations were all used as normalisers.

2.1 Overview

This benchmarking study provides a balanced evaluation of Hydro One's pole replacement costs and approach versus other utilities, and a similar comparison of the unit costs for substation refurbishment. This analysis considers total cost and operations across the company's operating territory, rather than examining regional variations or providing regional recommendations. The benchmarking process consisted of the following steps for each of the two areas of study:

1. **Project structure setup:** Determine comparison group, comparator characteristics and comparator metrics, and present design to stakeholders.
2. **Quantitative analysis:** Gather data (internal and external), validate and normalise, and assemble the data; create a statistical report; and create a Hydro One scorecard.
3. **Qualitative analysis:** Review performance metrics, interview Hydro One staff, compare Hydro One practices to comparison utility and industry best practices, and identify practice improvement opportunities.
4. **Analysis and recommendation development:** Review results, develop conclusions and recommendations, and present them to stakeholders.

2.2 Information Collected

To best characterise Hydro One's costs and operating practices, the project team collected data about demographics, overall and unit cost performance, program performance and replacement/refurbishment rates for Hydro One and the comparison utilities. This data and the areas covered by the data that was collected for 2012, 2013, and 2014 operation years (the most recent complete periods), are summarised in Figure 2 and Figure 3.

Figure 2. Data Collected from Hydro One and Comparison Utilities for Pole Replacement

Demographic Information	Practice Information	Cost Performance Data
• Service territory square miles/km • Number of in-service poles by material type and age profile • Pole footing conditions (soil vs. rock vs. swamp) • Pole accessibility (on-road vs. off road) • Pole framing (single phase vs. multi-phase/circuits) • Average crew travel time to pole work sites	• Planned Service Life for different pole types • Inspection methods, trigger ages and time cycles • Average months to complete non-urgent pole inspection recommendations • Refurbishment methods used • Replacement process information (# trips, crew sizes, equipment complements, person-hours required) • Cost categorization (O&M vs. Capital) for different work activities • Regulatory requirements • Agreements with joint-use utilities regarding pole removals	• 2012 to 2014 pole inspection volumes, costs and hours • 2012 to 2014 results of inspections • 2012 to 2014 pole refurbishment volumes, costs and hours • 2012 to 2014 program pole replacement volumes, costs and hours • 2012 to 2014 emergency pole replacement volumes, costs and hours • Breakdowns of 2012 to 2014 labor costs for inspection, refurbishment and replacement by type (company vs. contractor)

Figure 3. Data Collected from Hydro One and Comparison Utilities for Substation Refurbishment

Demographic Information	Practice Information	Cost Performance Data
• Service territory square miles/km • Number of distribution substations by size (# power transformers) and service territory density served (urban vs. suburban vs. rural) • Number of distribution power transformers by high side and low side voltage • Current in-service age profiles of major substation components • Average power transformer loading at non-coincident peak % for past 12 months	• Planned Service Life for major substation components • Criteria for using different substation refurbishment approaches (component-focused vs, station-centric vs. full station rebuild) • 2010 to 2019 number of actual and planned refurbishment projects by approach • Component evaluation processes to determine need for replacement or repair/reconditioning • Component replace vs. repair/recondition criteria • Use of integrated (multi-component) modules • Regulatory support for refurbishment program funding	• Data on recently completed distribution substation refurbishments including: • Refurbished substation demographics • Refurbishment project type (component-focused vs. station-centric vs. full station rebuild) and high level work scope • Detail on major components replaced/installed • Total project costs and costs associated with major component installations • Year when majority of work was performed • Breakdowns of labor resource costs by function (engineering & design vs. construction vs. commissioning) and type (company vs. contractor)

2.3 Comparison Group Selection

The goal of the comparison group selection is to find utilities that represent the industry, with both similarities and differences from Hydro One. Similar utilities provide the opportunity for direct comparisons of outcomes (costs, service levels, etc.) while dissimilar utilities offer the opportunity to investigate a broader array of practices that might be beneficial for Hydro One. Companies across North

America were identified and evaluated for their usefulness as part of the comparison group. As a result, 29 North American Utilities were approached to participate in the study.

Figure 4. Comparison Utilities Targeted for Participation

8 Canadian Utilities	21 U.S. Utilities
• Large provincial utilities from across Canada • Mix of local distribution companies in Ontario	• Large utilities • Previous willingness to participate in similar studies

Responses (combined) were received from 20 organizations. Those not responding cited various reasons for not participating:

- Lack of interest;
- Insufficient resources; and
- Competing priorities.

Not all of the utilities agreed to participate in both parts of the study. A few contributed data only for the pole replacement part of the study, a few participated only in the substation refurbishment part, while the majority participated in both portions. Together, they provide a reasonable representation of the North American utility industry, and a viable comparison group for Hydro One.

A concerted effort was made, as requested by stakeholders, to include more Canadian utilities. However, because there is no requirement for them to participate, and the effort for them to participate is significant, only a few Canadian utilities agreed and provided data for the study. As shown in Figure 5, the utilities in the comparison group are located throughout Canada and the U.S. There are several large companies, some smaller ones, with regulatory circumstances and weather patterns similar and different from Ontario. The net result is a reasonably representative and useful comparison group.

Figure 5. Comparison Utility Service Territories

Appendix A provides a list of the comparison group companies, along with some demographic details, including number of customers, number of poles, and number of distribution substations.

2.4 Normalising Factors

Because the comparison group includes both U.S. and Canadian utilities, the first normalisation step was to convert all cost figures into Canadian currency. All charts and tables showing dollar values are based on Canadian dollars. The conversion rate used for data submitted by U.S. companies was the average currency exchange rate in effect during the year in which the work was performed. The shift in the exchange rate in 2014, the Canadian companies look slightly more cost effective, despite any change in their actions. All values are presented in nominal dollars, and costs were not adjusted for inflation when taking an average or aggregating across multiple years.

The figure below shows the exchange rates used for this study.

Figure 6. Exchange Rates Used in the Study

	2010	2011	2012	2013	2014
CAD:USD	0.9700	0.9987	0.9995	1.0300	1.1043

Source: http://www.federalreserve.gov/releases/g5a/current/

Within the individual areas of focus, different normalising factors were appropriate. In particular, for the pole replacement investigation, the number of poles served as the primary normalising factor. It varied depending on what the team was considering, meaning the total number of poles on a company's system was used for lifecycle cost analysis for all poles, and the number of poles touched (or treated) was used as the normaliser for the unit costs of specific activities (i.e., inspections, replacement, and/or refurbishment).

For substation refurbishment, unit costs were built around the total number of stations, the number of transformers, transformer banks, and the capacity in terms of MVA. No single normalising factor is ideal for comparing the unit costs, so a portfolio of normalisers was used to reach the appropriate conclusions. Additional comparisons were made using breakers and switches as normalisers, where the subject of cost analysis was the breakers or switches, to provide a comparison point for those companies who do component-based replacements/refurbishment rather than station-based work.

3. POLE REPLACEMENT BENCHMARKING RESULTS

The key findings of the pole replacement benchmarking study are provided below.

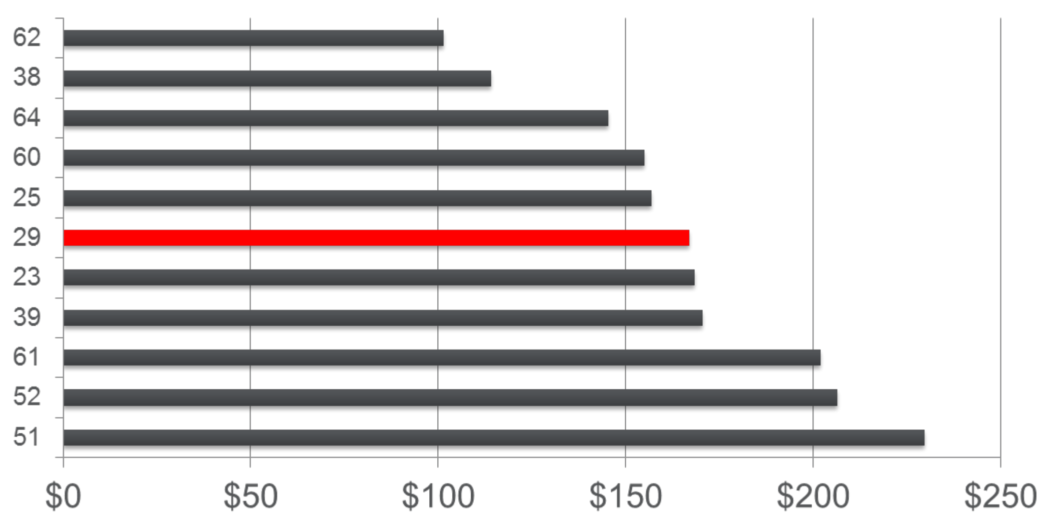
1. Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles
2. Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections, while the others typically do more rigorous physical inspections
3. The replacement rate has been slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest, and on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group
4. Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone replacement of poles, and reduce lifecycle costs.

3.1 Cost Comparisons

The cost analysis portion of the study looked at pole replacement from several aspects – lifecycle costs per pole across all poles, unit costs per pole worked on in a year, and then costs of individual aspects of the pole program such as inspection costs, replacement costs, and refurbishment costs. Each of these is summarized below in a series of charts showing the resulting cost figures.

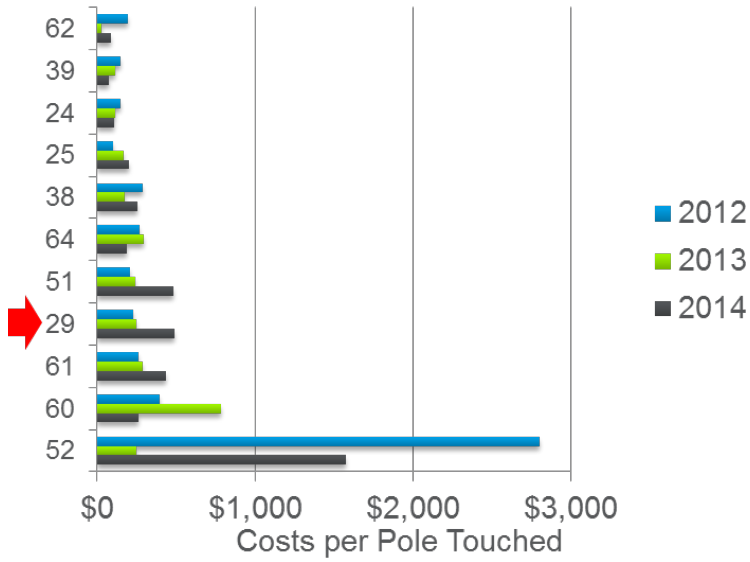
As shown in Figure 7, Hydro One demonstrates average life cycle costs. The most important factor in the life cycle cost is the original installation cost, but other factors such as the cost of inspections, the time between inspections, expected pole life, and others have influence as well.

Figure 7. Actual Annualized Life Cycle Costs per Pole per Year



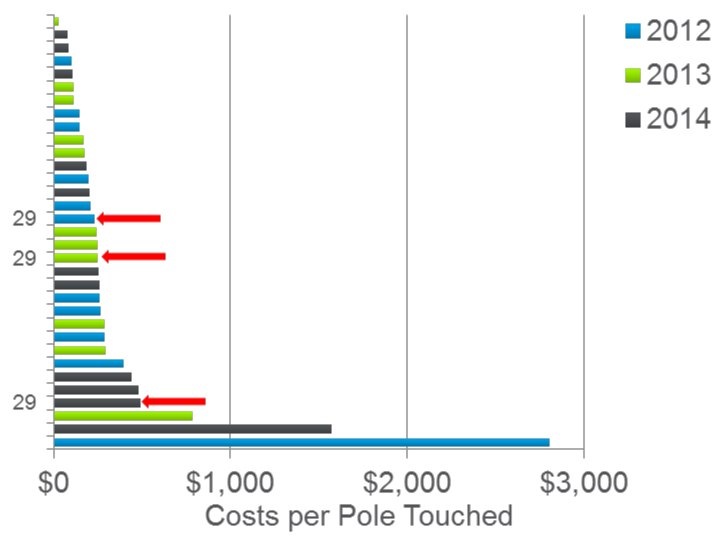
Another way to view pole program costs is through the unit cost of the poles touched (or treated) during an individual year. This is affected by the choices of how many poles to work on during a year, and what is done to those poles. "Poles touched" in this case is those inspected, refurbished, or replaced during the year, so depending on the mix of work done, the costs can vary year to year for an individual company. Three years of data were gathered for each of the participating companies, to allow understanding of these potential shifts from year to year. As with the life-cycle costs shown above, in this comparison, Hydro One again falls very near the mean of the comparison group.

Figure 8. Pole Program Costs Per Pole Touched Grouped by Company



Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

Figure 8. Pole Program Costs Ranked by Annual Spend



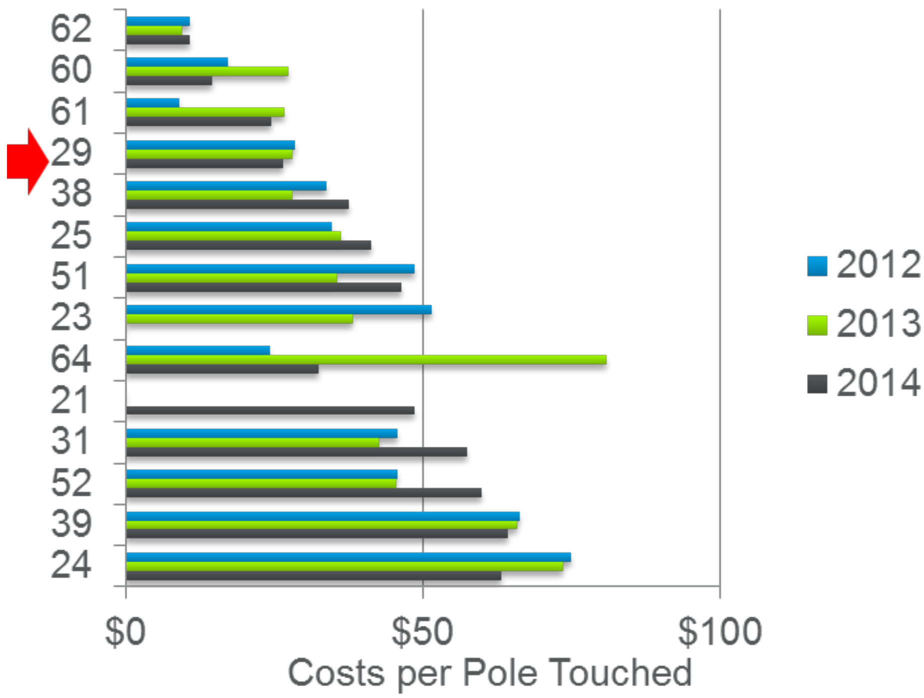
Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

3.2 Pole Inspection Costs and Frequency

Inspection costs are a function of what is done during the inspection. For example, is it a visual inspection, sound and bore, or other more complex physical inspection. Hydro One performs visual and light physical inspections on a shorter interval than most other companies (three to six years compared to 10 for the panel). Hydro One is the only company that does not use bore, excavation or ultrasonic methods on a dedicated schedule (seven to 20 years).

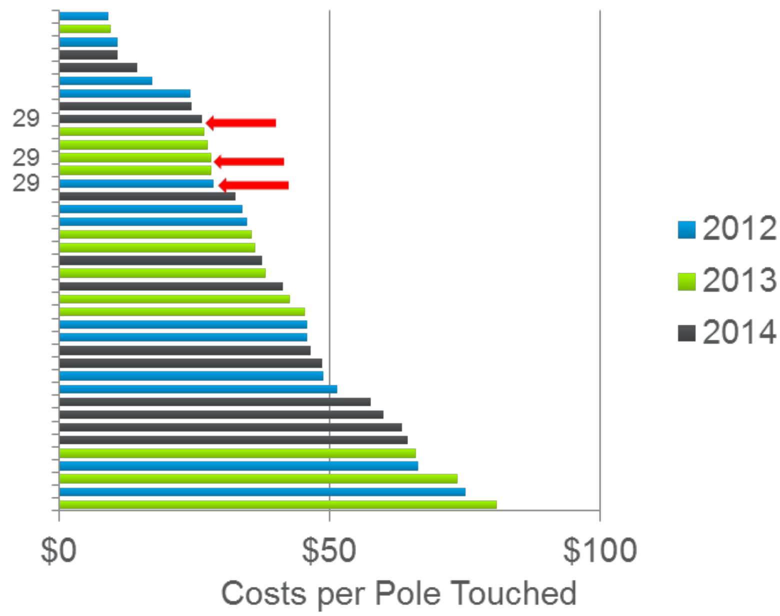
Overall, Hydro One conducts its inspections at a cost that is below the average of the comparison group. Hydro One costs are $27.60 per pole inspected, which is 29% lower per inspection compared to the mean of the panel.

Figure 9. Pole Inspection Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles inspected.

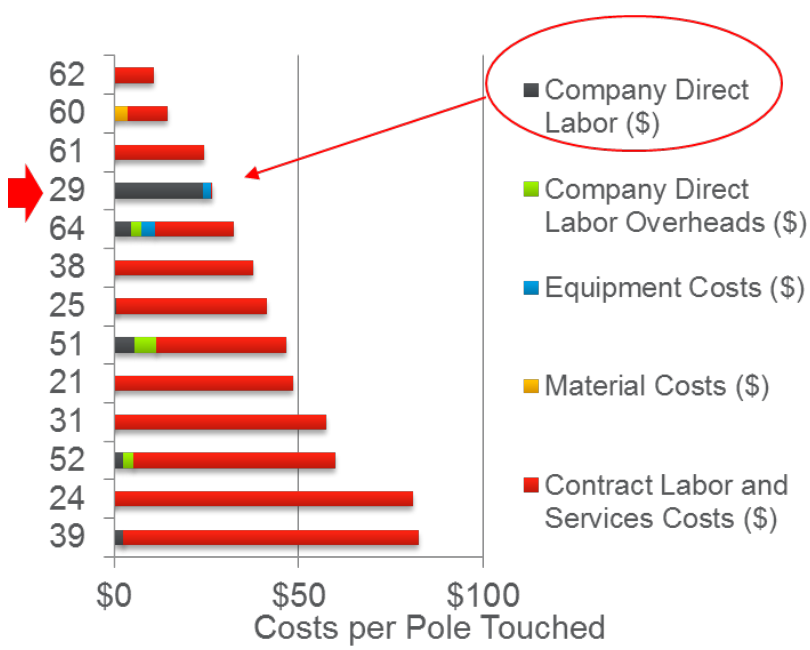
Figure 10. Pole Inspection Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles inspected.

Hydro One is the only company that performs more than 95% of inspections with in-house crews as compared to near 100% outsourced in other companies.

Figure 11. Pole Inspection Costs by Category

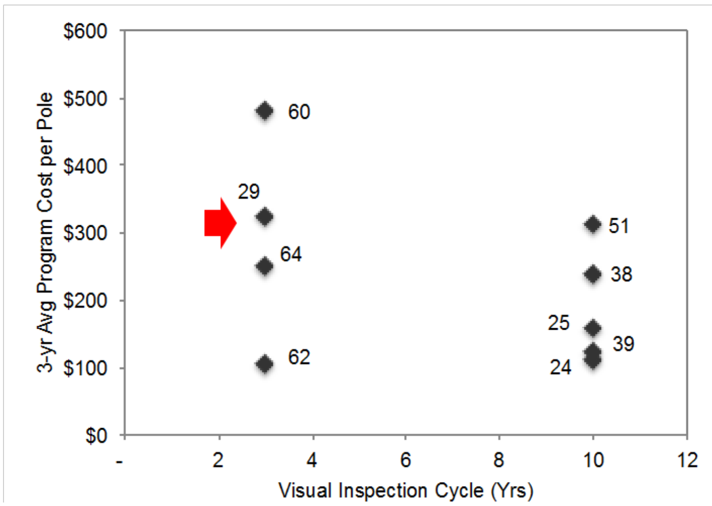


Note: In this comparison, pole touched means the total number of poles inspected.

3.2.1 Visual Inspection Cycle Time

Figure 12 shows the relative frequency of visual inspections and its impact on total pole replacement program costs. Where companies provided a range, the lower end of the range is represented in the figure. The frequency of inspections has only a modest impact on total program costs, since the majority of program costs are driven by pole replacements.

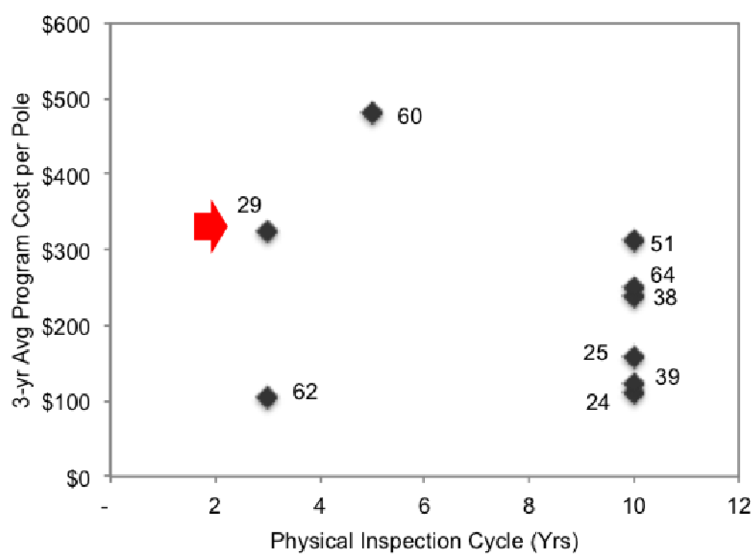
Figure 12. Visual Inspection Cycle Frequency



3.2.2 Physical Inspection Cycle Time

Though Hydro One doesn't have a comprehensive program for physical inspections, for those that are done, the cycle time is relatively short in comparison to the benchmark panel.

Figure 13. Physical Inspection Cycle Frequency



3.3 Replacement Rates and Pole Age

Hydro One has historically replaced its poles at a slower rate than other utilities. This fits with its planned longer life of the poles than other utilities in the comparison group. The net result is that the average age of Hydro One's wood poles is the oldest in the panel, at 37 years.

Figure 14. Age Profile of Wood Poles

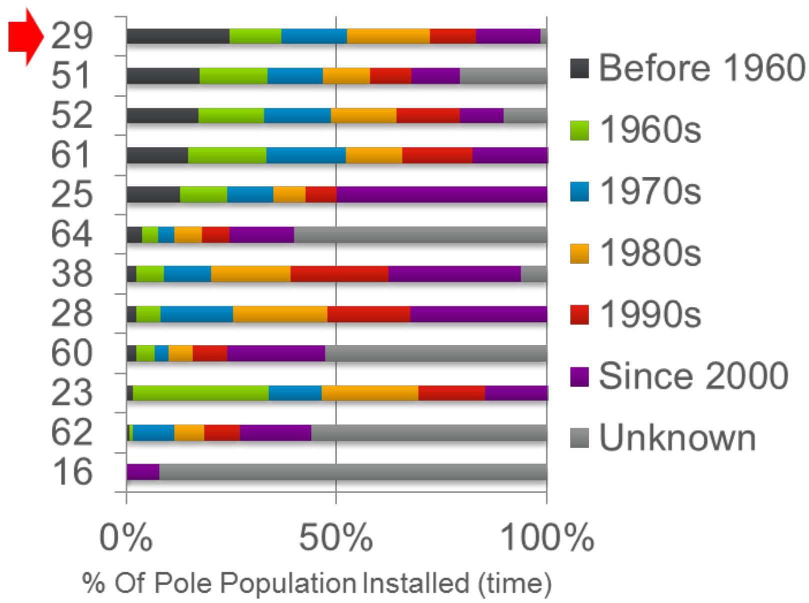
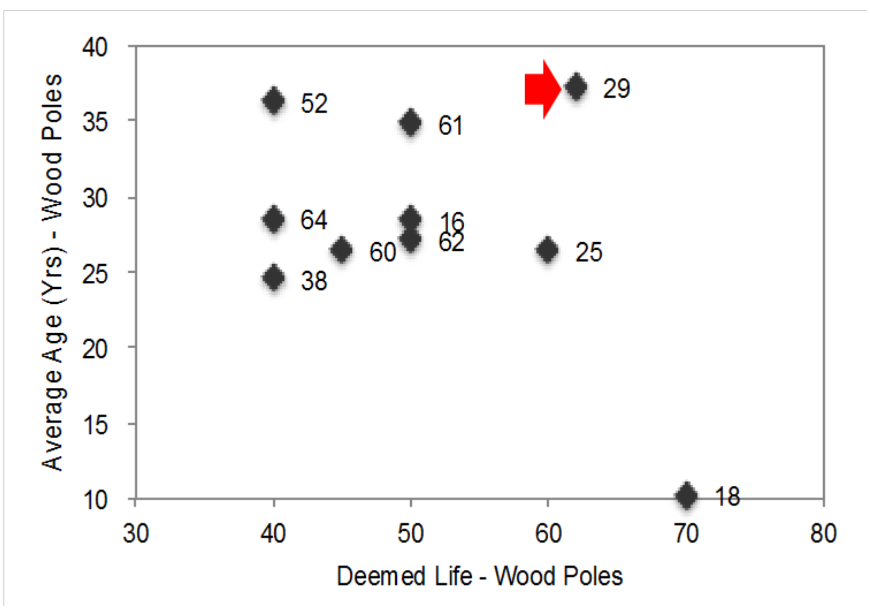


Figure 15. Average Age versus Planned End of Life

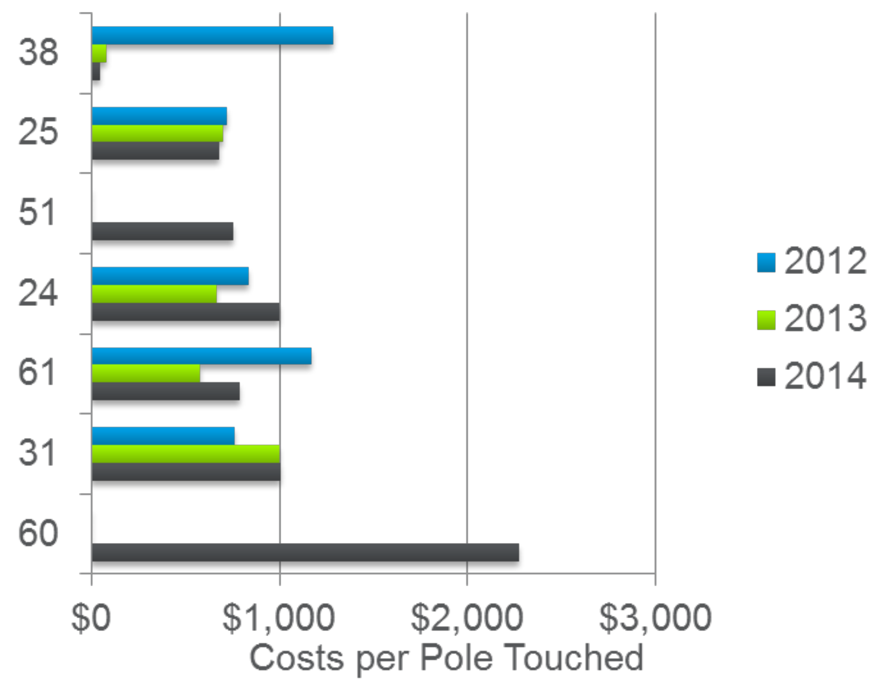


3.4 Pole Refurbishment Costs

Most North American utilities (13 of 17 in the study) have a formal distribution pole refurbishment practice in place to deal with poles that fail prematurely. Hydro One currently does not have such a refurbishment program, electing to replace poles that fail, rather than refurbish them. The fact that Hydro One has experienced a long life for its poles is one indicator of the reasonableness of this approach. At the same time, organizations with refurbishment practices in place are able to demonstrate that their lifecycle costs have improved due to the refurbishment practice.

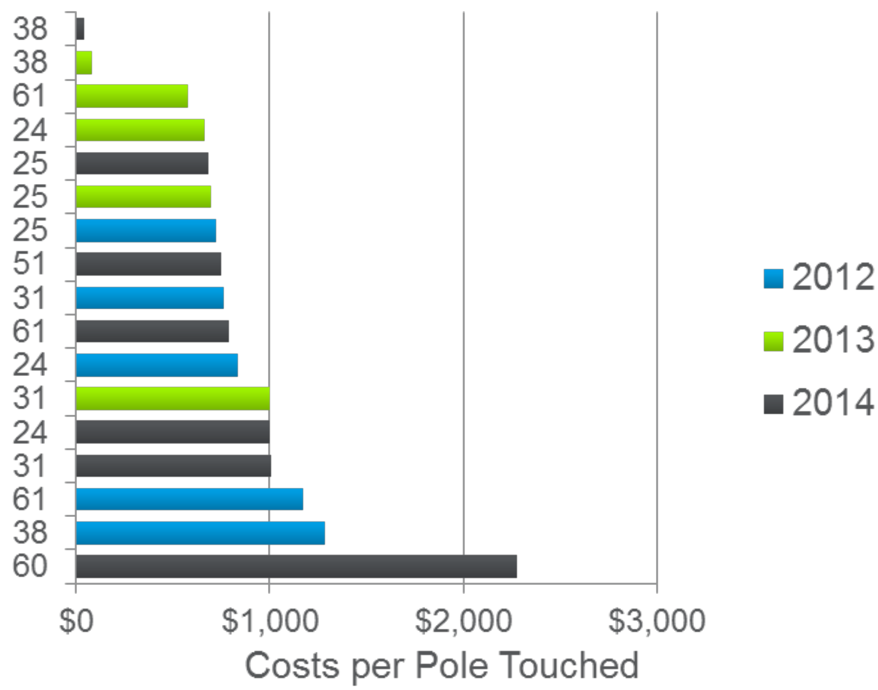
Figure 16 and Figure 17 show the unit costs for pole refurbishment for those companies who track and could report those costs. The mean cost to refurbish a pole is $947.

Figure 16. Pole Refurbishment Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles refurbished.

Figure 17. Pole Refurbishment Costs Ranked by Annual Spend



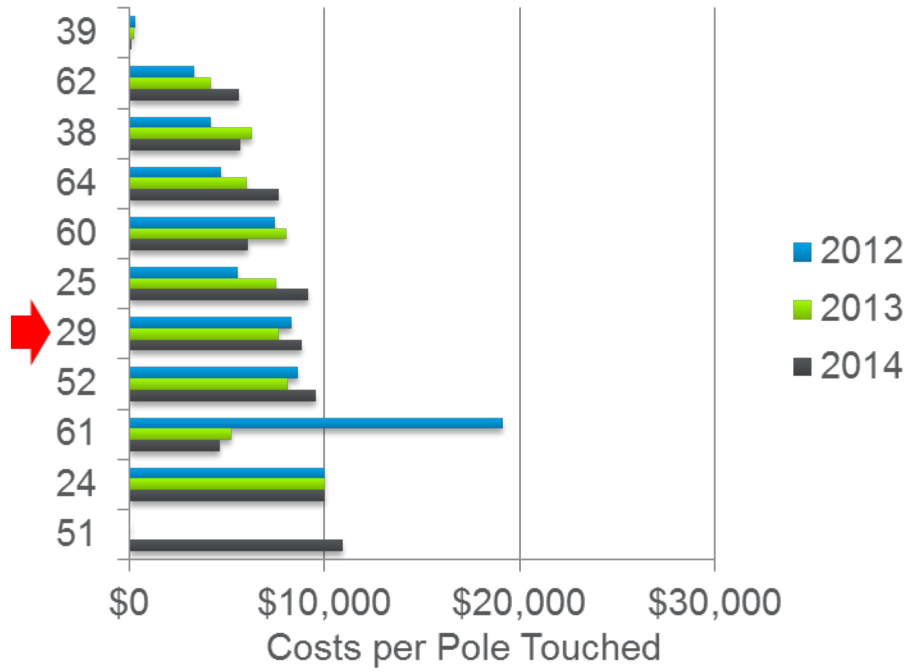
Note: In this comparison, pole touched means the total number of poles refurbished.

3.5 Pole Replacement Costs

As poles reach the end of their useful life, they must be replaced. All utilities have systematic programs for replacing those poles, with the goal of getting the longest useful life without allowing the poles to stay in service until their failure. Across the comparison group, the average cost to replace a pole is $7,105. For Hydro One, that cost is $8,266, or 16% higher than the mean.

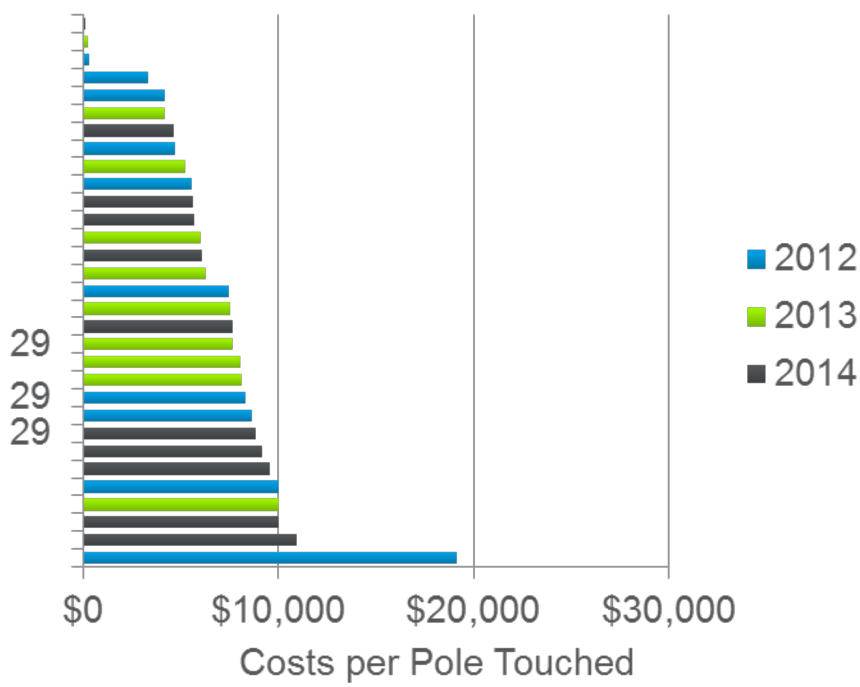
In the course of the study, a number of factors were investigated for their impact on the cost of replacing poles. This analysis revealed that these demographics had little impact on the overall results. Elements investigated include the planned life of the poles, the percent of poles installed off-road, the percent of poles installed in soft soil, the average travel time to get to poles, and average age of poles.

Figure 18. Pole Replacement Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles replaced.

Figure 19. Pole Replacement Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles replaced.

3.6 Refurbishment versus Replacement Costs

The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately 7x more expensive, where refurbishment is an option. Refurbishment is not an option in all cases. For example, it wouldn't make sense to refurbish a 50-year-old pole when its useful life is planned for 60 years. Refurbishment makes the most sense when a pole is found to be failing early in its planned life. Refurbishment has the possibility of extending the life of the pole by 20 to 40 years. In any scenario where a refurbishment can extend the life of the pole by over 20 years, then the economic benefit of refurbishment tends to be clear.

4. SUBSTATION REFURBISHMENT BENCHMARKING RESULTS

The six key findings of the station refurbishment benchmarking study are provided below.

1. Station refurbishment activities are varied within and across utilities.
2. Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.
3. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.
4. Navigant and First Quartile Consulting believe that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.
5. Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.
6. Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.

4.1 Cost Analysis

The analysis compared costs of substation refurbishment and rebuilding in several different ways. Since companies take different approaches to substation refurbishment, it was necessary to group the refurbishment work into several categories – full station rebuild projects, substation-centric projects, and component-based projects.

Hydro One's costs for station centric and full substation rebuild refurbishment projects fall within a reasonable range compared to comparison utilities. As with other companies, Hydro One's unit costs for individual projects vary from first quartile to fourth quartile.

Across all types of projects, Hydro One's per unit installation costs for major substation components are generally lower than those of other comparison utilities due to Hydro One' s use of less expensive, lower capacity equipment.

4.1.1 Full Substation Rebuild Projects

A limited number of companies completed a full station rebuild in the past three years. The costs associated with these projects were compared on a per-transformer bank basis and a per-MVA basis.

Figure 20. Cost per Transformer Bank Refurbished

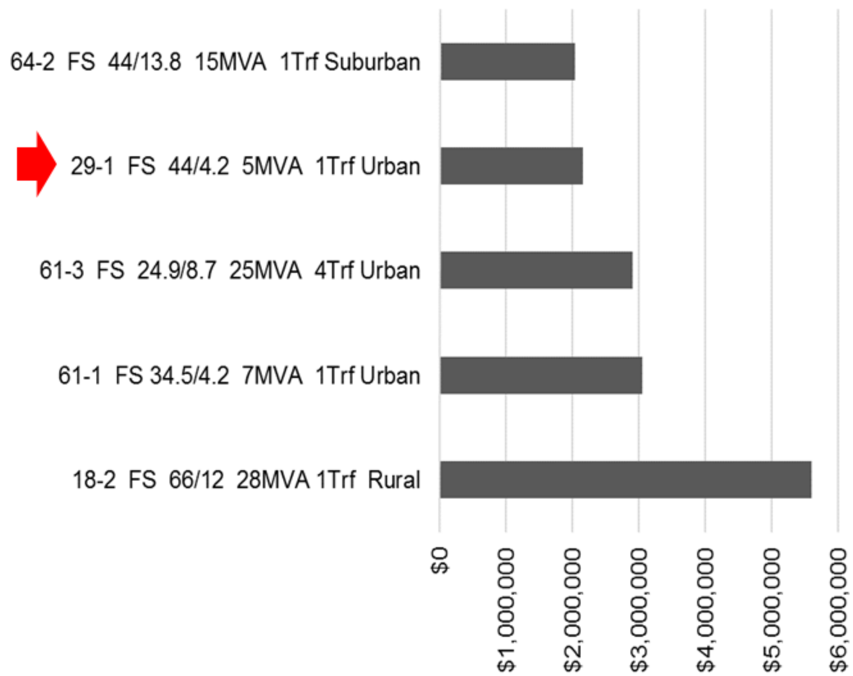
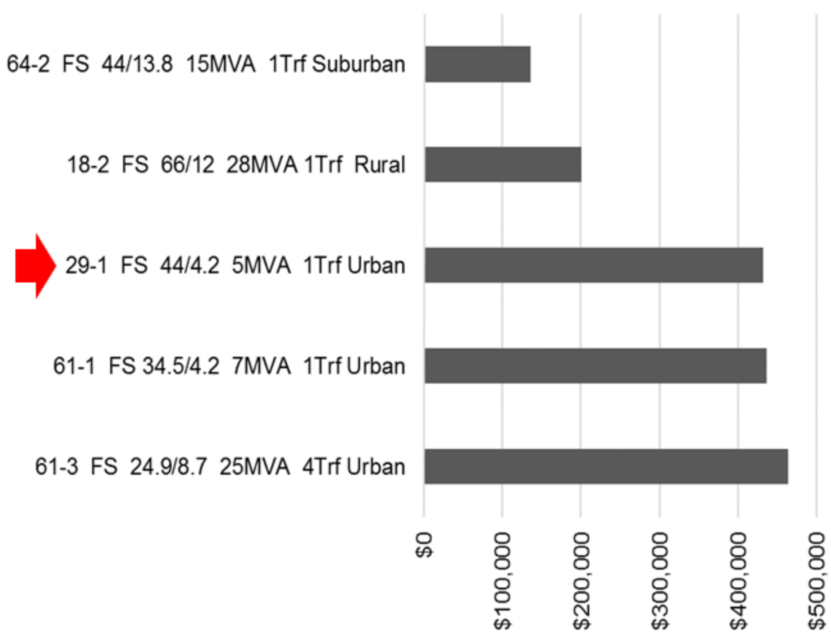


Figure 21. Cost per Substation MVA Refurbished



4.1.2 Substation-Centric Projects

A higher volume of substation-centric projects was available for analysis. As shown in Figure 22 and Figure 23, Hydro One's projects represent several of these, and they fall at different points within the comparative cost spectrum, whether measured on a per-transformer or a per-MVA basis. As before, all of the Hydro One stations in the comparison are single-transformer stations, typically at a distance from a work site.

Figure 22. Cost per Transformer Bank Refurbished for Substation-centric Projects

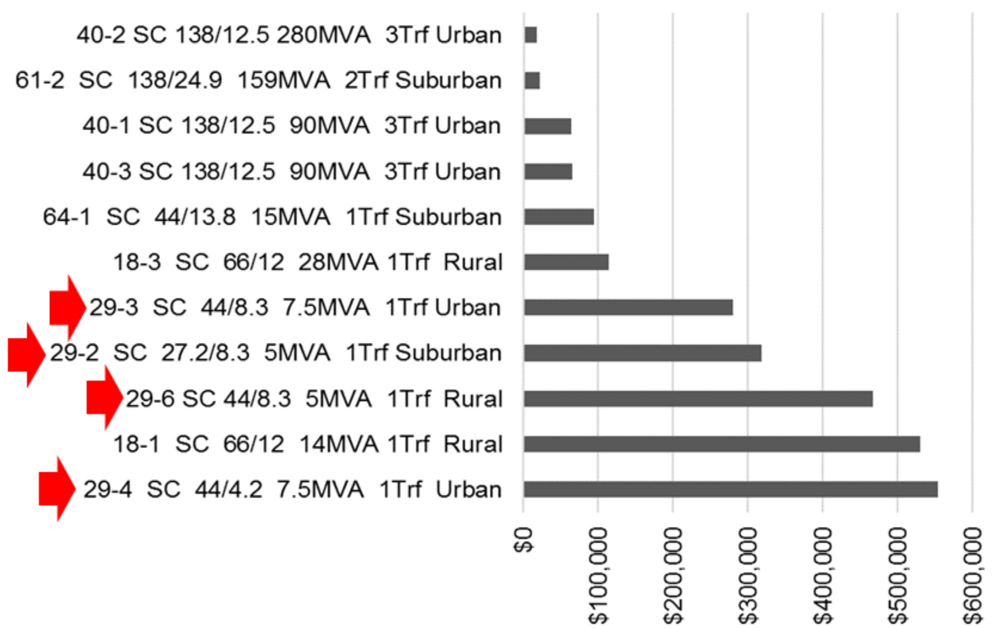
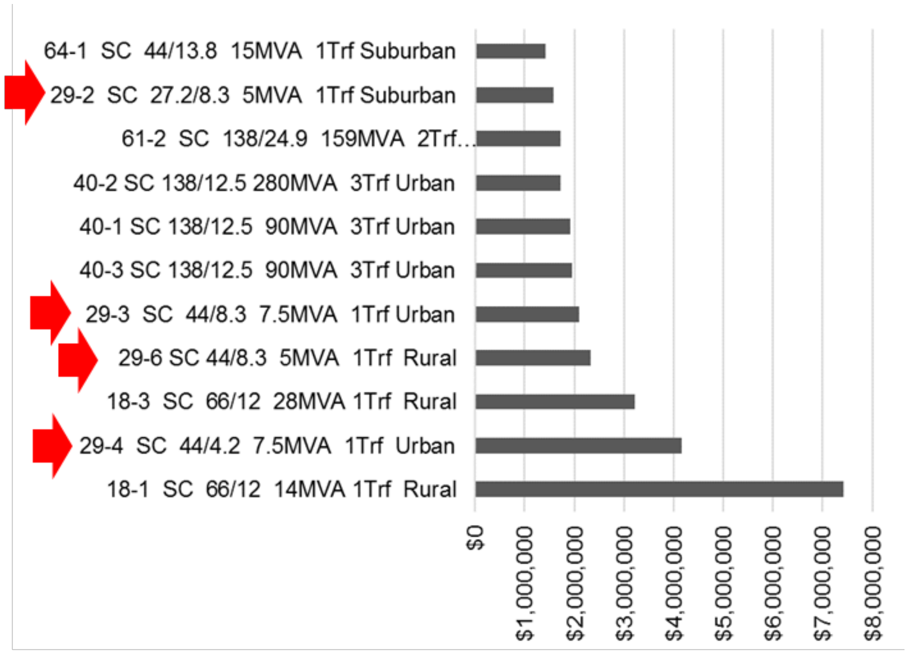


Figure 23. Cost per Substation MVA Refurbished



4.2 Operating Approach to Refurbishment

Hydro One's current emphasis on station centric and full station rebuild projects is not unique within the comparison group and is related to several demographic factors that distinguish Hydro One:

- Higher than average transformer loadings at non-coincident peak;
- An older age profile for in-service power transformers;
- Highest percentage of single transformer substations; and
- Second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile).

The demographics of the electric system, and specifically the substations, help drive the decision-making with respect to refurbishment activities. Age, condition, and planned life all influence what type of maintenance and refurbishment activities are appropriate, for individual components and for entire stations. Also important is the configuration of the system, i.e. the range of stations that have multiple transformers (or not), whether or not they are looped or structured with a radial design.

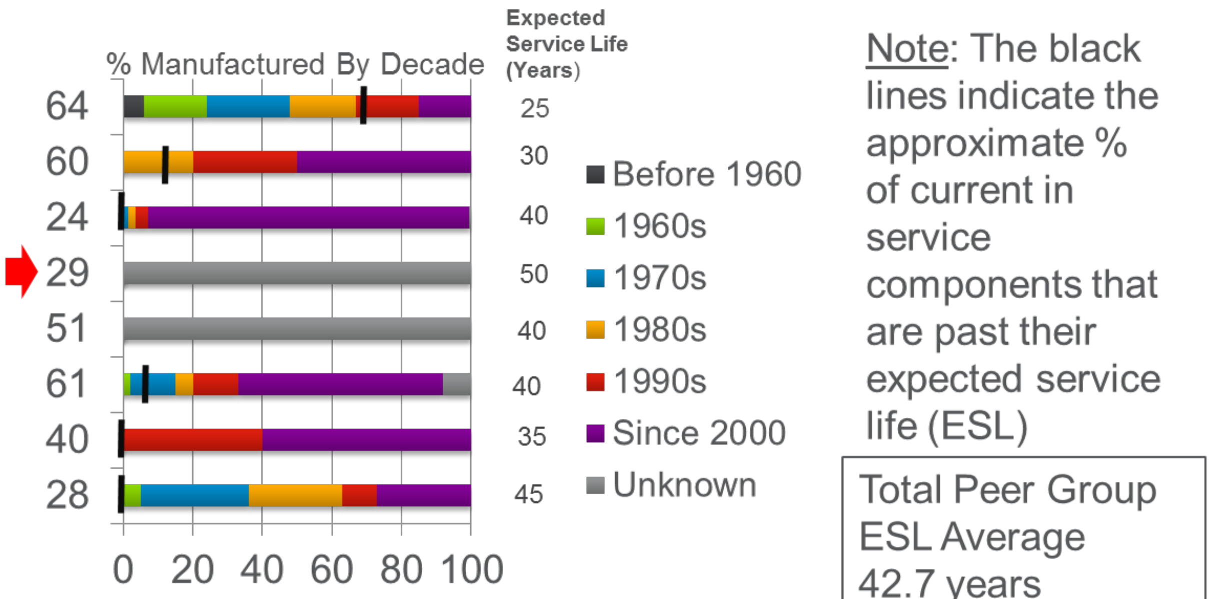
In this section, we present information about the age of the various station components, along with some information about the system configuration. While these findings aren't a measure of performance, they do have an impact on the costs and appropriate practices associated with the substation refurbishment activities.

While Hydro One's focus on station-centric and full-station refurbishment is not unique, several of the comparison companies primarily or exclusively rely on component-based refurbishment programs.

4.2.1 High Side Switching and Protection Equipment

Hydro One's expected service life for high side switching and protection equipment is higher than the comparison group average. It's actual age profile for these components is unknown.

Figure 24. Expected Service Life for High Side Switching and Protection Equipment

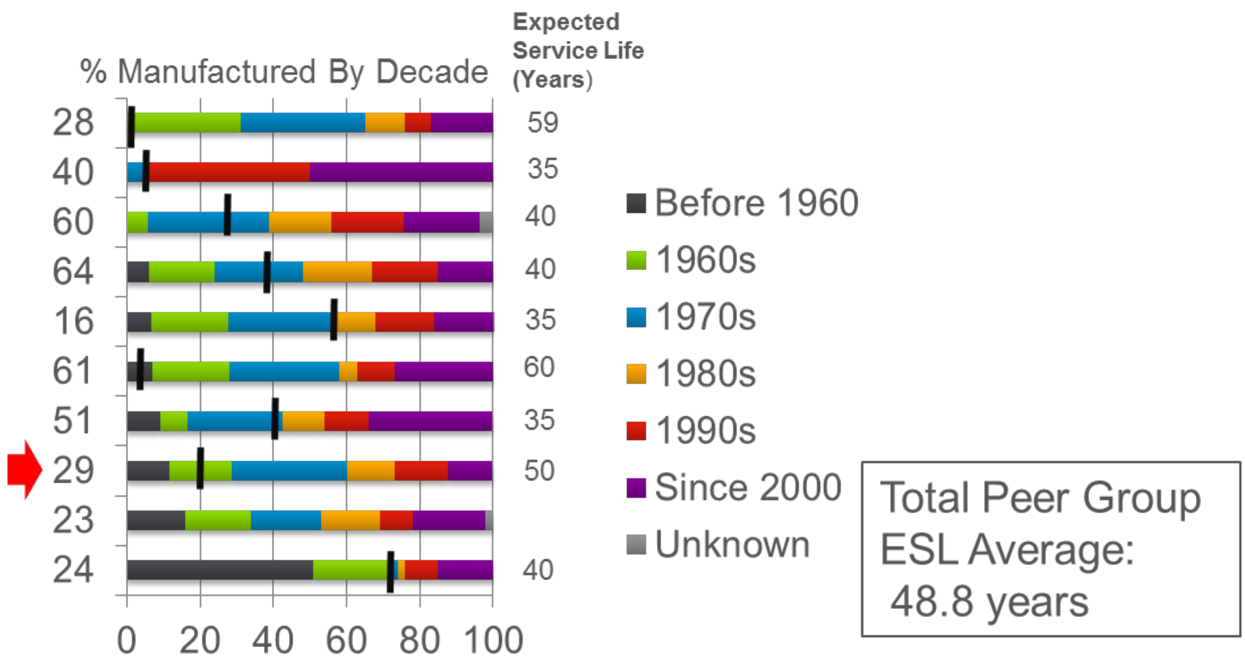


Source: Questions A3 and A4

4.2.2 Power Transformer Demographics

Hydro One's power transformer age profile ranks in the older end of the comparison group distribution. It's expected service life for power transformers is also somewhat higher than the group average, as shown in Figure 25.

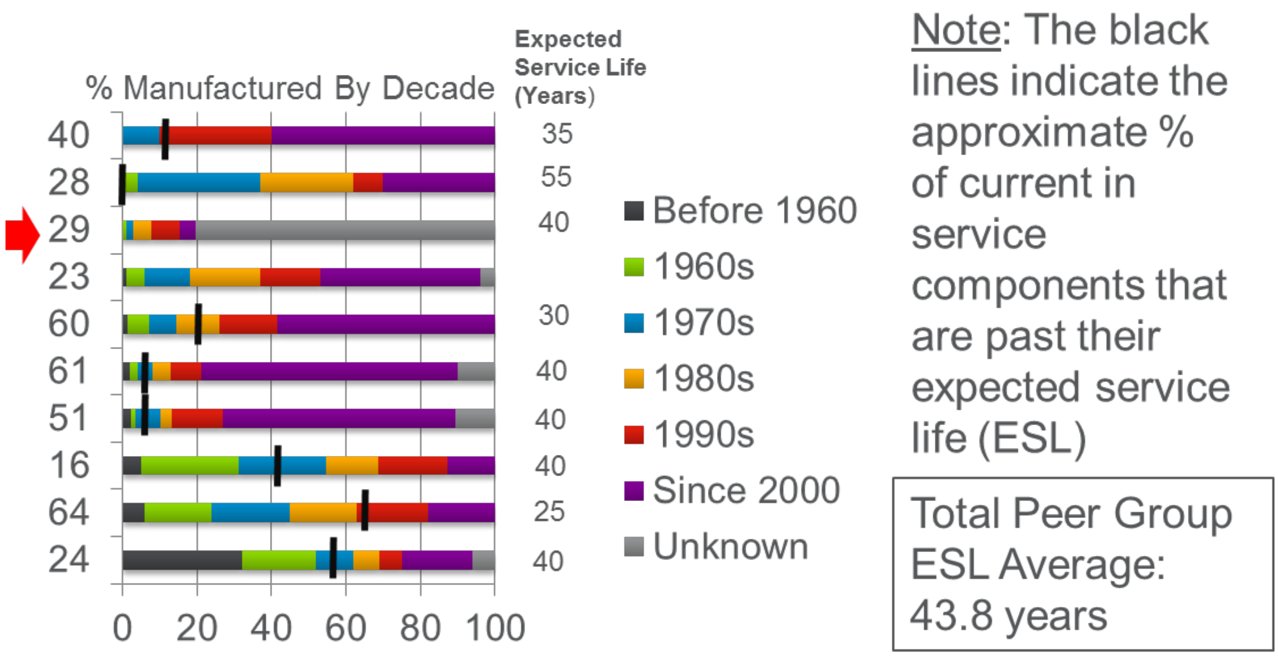
Figure 25. Expected Service Life of Power Transformers



4.2.3 Low Side Switching and Protection Equipment

Hydro One's expected service life for low side switching and protection equipment is somewhat lower than the comparison group average. Most of its actual age profile for these components is unknown.

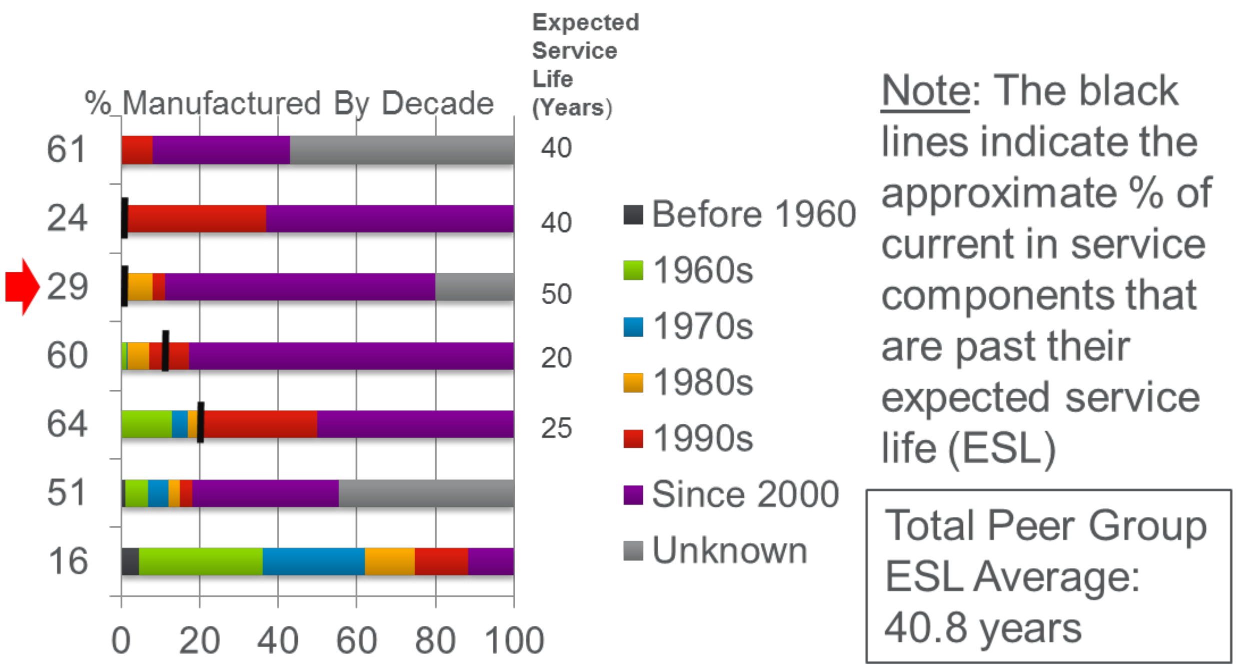
Figure 26. Expected Service Life for Low Side Switching and Protection Equipment



4.2.4 Relays and Control Wiring Demographics

Hydro One's Expected Service Life for in-service relays and control wiring is higher than the comparison group average. Most companies were not able to furnish a complete age profile for these components.

Figure 27. Expected Service Life for In-service Relays and Control Wiring



4.2.5 Substation Profiles

Hydro One has the highest percentage of single transformer substations within the comparison group. It also has a very high % of rural stations (stations serving areas that have 50 or fewer customers per square mile), meaning there are many stations with single transformers in remote locations.

Figure 28. Percent of Substations by Number of Power Transformers

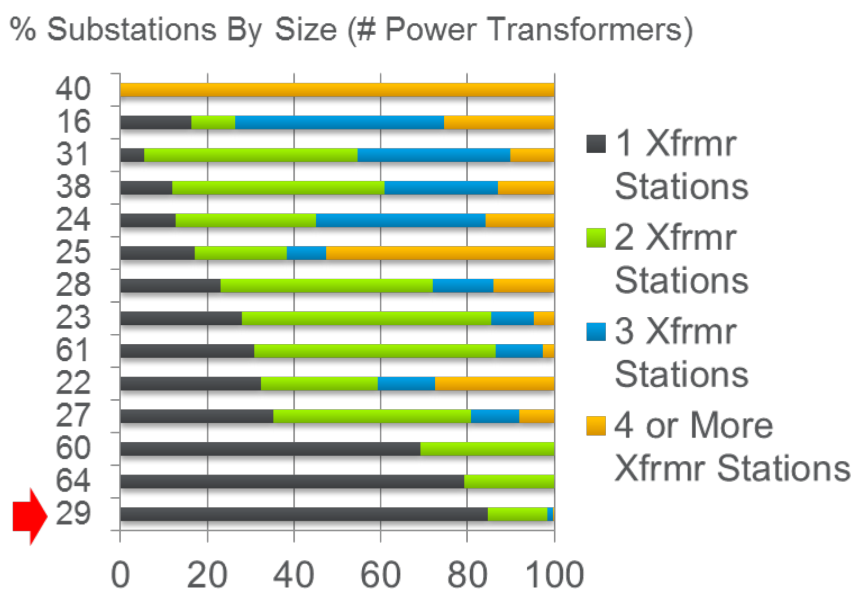
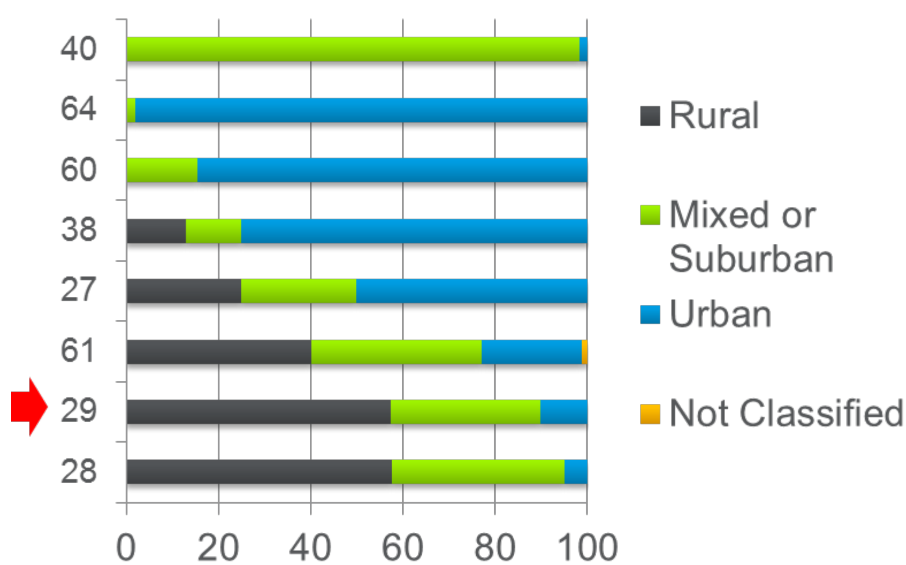


Figure 29. Percentage of Substations by Area: Rural, Urban and Mixed



4.3 Use of Testing Results and Maintenance History Records

The processes that Hydro One follows to evaluate the condition of switching equipment, protection equipment and relays appear to differ from those of most other comparison utilities.

Equipment Type	Hydro One Practice	Leading Practice
Switchgear	Visual inspections, or safety concerns	Visual inspections, testing, current and forecasted loading, maintenance history & costs
Breakers and Bus Ties	Visual inspections, current and forecasted loading, inoperable or poor performance, safety concerns	Visual inspections, testing, current and forecasted loading, maintenance history & costs
Relays and Control Wiring	Poor Performance	Visual inspections, testing, maintenance history & costs

The key difference between most comparison utilities and Hydro One is that Hydro One does not evaluate testing results and/or maintenance history records as a primary driver when making replace versus repair decisions for switching and protection equipment or relays.

Hydro One is one of only two companies in the comparison group that listed safety concerns as an important evaluation factor when evaluating switching and protection equipment.

4.4 Performance Measurement

Hydro One's performance measurement and reporting is limited, focusing only on the numbers and average costs of completed projects by type (conventional refurbishment projects versus refurbishment projects using an integrated modular substation).

Subject Area for Tracking	Hydro One Practice	Leading Practice
Age and usage history data for existing equipment	Limited tracking and available data	Complete data, including installation dates, maintenance activities, other investment
Periodic reporting of progress on individual projects while ongoing.	Reporting of program costs across year, but not individual station projects	Regular reporting of individual station project costs, completion % by work type (advanced practice is Earned Value)

5. RECOMMENDATIONS

The four key recommended actions for pole replacement are:

1. Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2. Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria
3. Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4. Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

The three key recommended actions for substation refurbishment are:

1. Consider implementing a formal data governance process for equipment performance and maintenance data, and incorporating that information into the asset condition scoring and project planning process.
2. Enhance cost and work completion reporting for individual projects, and implement a formal change control process.
3. Develop and implement a more comprehensive set of key performance indicators including in-progress project cost performance measures and assessments of project/program impacts on substation reliability, maintenance costs and overall asset health.

APPENDIX A. DETAILED COMPARISON GROUP STATISTICS

A total of 29 Canadian and U.S. utilities were contacted to participate in the comparison group. These companies include those summarized in Figure 30, as well several others who declined to participate. The Navigant and First Quartile Consulting team followed up with the utilities multiple times to clarify the data needed, and answer questions about reporting. The comparison group is a good cross section of the North American electric utility industry.

Figure 30. Comparison Group Demographics

Company	Number of Distribution Customers	Service Territory (sq. km)	Number of Distribution Poles	Number of Distribution Substations
Atlantic City Electric	547,145	7,166	226,111	61
Austin Energy	439,402	1,131	153,375	190
BC Hydro	1,970,950	68,201	907,000	208
CenterPoint Energy	2,348,517	12,950	924,275	216
Commonwealth Edison	3,927,204	29,598	1,523,715	746
CPS Energy	786,442	3,924	320,476	92
Delmarva Power	514,942	14,030	164,037	149
Essex Powerlines	28,000	105	6,251	0
Hydro One Networks	1,300,000	650,000	1,571,384	1,000
Hydro-Québec	4,038.114	1,365,128	2,642,700	NR
Kansas City Power & Light	910,155	46,420	549,728	265
Oncor Electric Delivery	3,358,029	138,484	1,840,087	735
PECO Energy	1,590,478	5,439	390,000	409
PEPCO	842,335	1,658	146,597	110
Public Service Electric & Gas	2,510,729	3,237	842,922	151
PowerStream	380,000	825	39,330	65
Southern California Edison	4,967,691	129,500	1,414,720	655
Tucson Electric Power	417,140	2,603	77,585	88
Veridian	119,000	640	31,010	53
We Energies	1,148,805	25,845	656,422	364
Westar Energy	699,390	26,159	545,616	518

NR = Not reported

FORM A

Proceeding:...........................

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ..Benjamin Grunfeld.............(*name*). I live at ...Toronto......... (*city*), in the ..Province............ (*province/state*) of ...Ontario................ .

2. I have been engaged by or on behalf of ..Hydro One Networks(*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....02/27/17....................

Signature

FORM A

Proceeding:

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Ken Buckstaff....(*name*). I live at ....Manhattan Beach.... (*city*), in the ....state.... (*province/state*) of ....California.... .

2. I have been engaged by or on behalf of ....Hydro One.... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

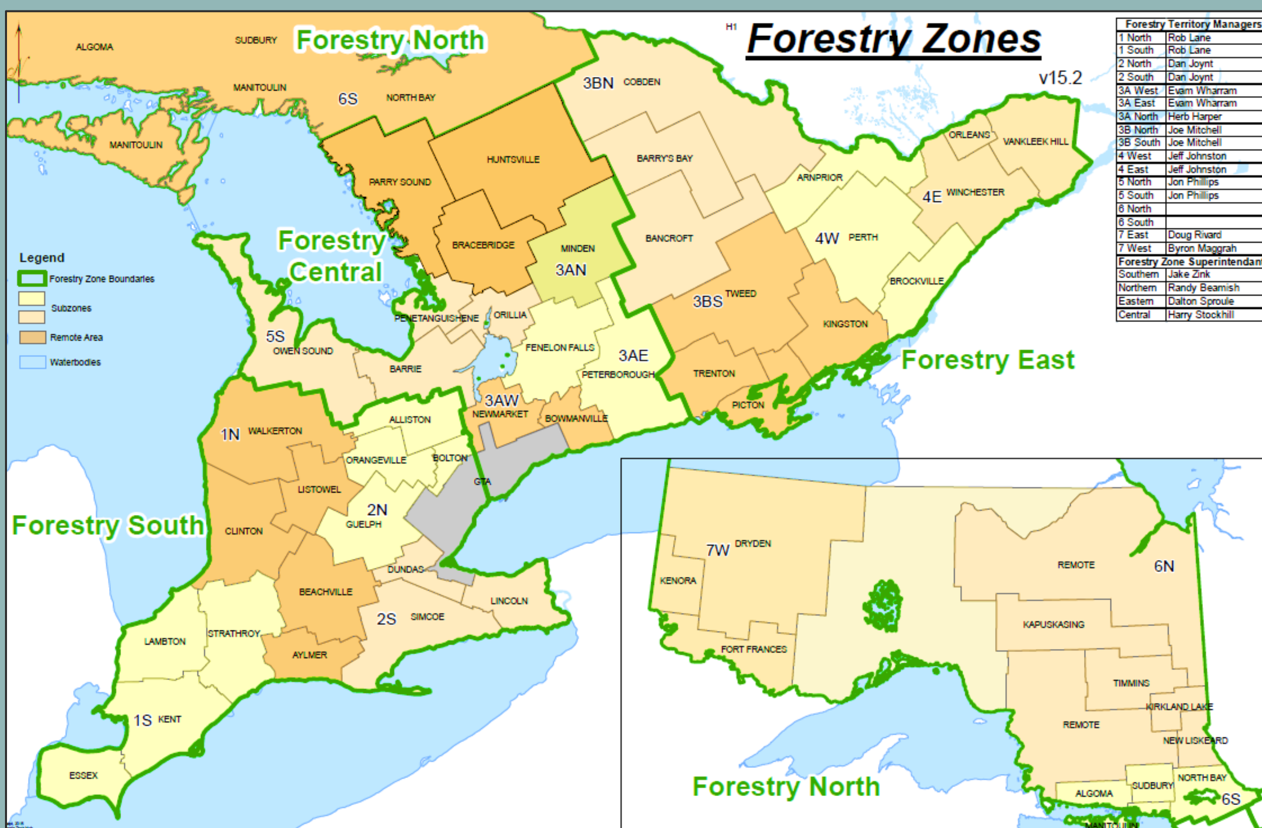
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....February 24, 2017....

Signature

HYDRO ONE VEGETATION MANAGEMENT STUDY 2016



October 2016

Prepared by:
CN Utility Consulting, Inc
5930 Grand Ave
West Des Moines, IA 50266

TABLE OF CONTENTS

TABLE OF FIGURES, TABLES AND MAPS

Disclaimer

The information collected through benchmark surveys and other data sources is offered as guidance to the readers of this report. How this data is interpreted is subject to many variables and potential biases. CNUC reviews benchmark data for errors and omissions and analysis is performed to advance positive recommendations and outcomes but makes no claims and does not take responsibility for interpretation or submitted survey information that is inaccurate or incomplete.

1 EXECUTIVE SUMMARY

1.1 STUDY PURPOSE

Hydro One was instructed by the Ontario Energy Board (OEB) in March 2015 to perform a trend analysis of the utility vegetation management (UVM) program. Specifically, the Ontario Energy Board (OEB) requested:

> *• A comprehensive trend analysis of the vegetation management program showing year over year comparisons in unit costs.*
> *• A best practices study, if undertaken, for vegetation management similar to the CN Utility study filed in EB-2009-0096.* (OEB, March 2015, p. 61)

In response, Hydro One contracted CN Utility Consulting (CNUC) to conduct a benchmark survey of North American UVM programs and perform trend analysis.

1.2 OVERVIEW OF THE HYDRO ONE SERVICE TERRITORY

Operating one of the largest North America distribution systems in vast remote and rural areas, dense forests and harsh winters, Hydro One maintains over 100,000 kilometres of rights-of-way (ROW) to keep trees away from powerlines. The service territory includes most of Ontario with the exception of the metropolitan areas around Lake Ontario and rural communities served by local distribution companies. The extreme northwestern region of the province (the Hudson Bay Lowlands) is also not included in the service territory.

Hydro One's geography presents several challenges to vegetation management. Although the majority of the powerlines are along roadways, one-third of the lines are off-road. These are rigorous to work and require special equipment, including heavy equipment, all-terrain vehicles, and boats. In addition, the system is large, sprawling and dense with vegetation as well as prone to ice-storms and wind events. In many areas the customers are scattered and separated by long distances. The number of customers per square kilometre is one of the lowest for all utilities compared and the number of trees managed per customer is one of the highest. On a cost per customer basis, these facts express the need for a highly efficient vegetation management program.

In general, electric systems start with high-voltage supply lines that divide and step-down into networks of lower voltage lines. For the Hydro One distribution system, the highest voltage lines are called M-Class feeders and are operated at 44,000 volts (44kV), 27,600 volts (27.6kV) and 25,000 volts (25kV) depending on the area. The rest of the network is comprised of F-Class feeders operated at lower voltages that consist of three-phase, two-phase, and single-phase lines. Of the 102,000 km of overhead line, 52,000 km are lower voltage feeders and two-phase and single-phase lines. The higher the voltage, the more customers are affected by an outage. M-Class feeders are a high priority for vegetation management. However, all overhead lines are managed to prevent vegetation encroachments. Although the higher voltage lines are more important to the system, vegetation needs to be managed for safety and reliable service, down to the lowest voltage.

There are three main forestry eco-zones within Hydro One's service area:

- The Boreal is mainly conifers
- The Great Lakes/St Lawrence Forest Zone is mixed conifer/deciduous forests
- The Deciduous Forests Zone has the greatest diversity of tree species

Hydro One's distribution system is divided into four forestry management regions: North, South, Central and East. The Central and East Regions have similar dense forestry conditions and require the greatest amount of vegetation management on the system. The North Region has dense forests, is mostly conifer, and has the least amount of line. In contrast, the South has scattered forests, is predominately agricultural, and has the most kilometres of line.

Expansive and large forests, harsh winters, frequent storms, and rugged and remote ROWs with long travel distances are realities that characterize forestry management for Hydro One.

1.3 Progress and Performance of Hydro one's Vegetation Management Program

Over the period of this study, 2011-2015, Hydro One increased their efforts to reduce the number of trees managed on their system. However, when the number of trees managed is almost eight million, it takes more than five years to experience a significant reduction in the workload. Since work is performed infrequently, a cycle of 9.5 years on average, it is difficult to make progress as trees are growing faster than they are managed. Until the backlog of work and the cycle length are reduced, Hydro One needs to continue to improve progress.

Hydro One has maintained the high level of efficiency that was discovered in the 2009 study. More trees are managed per hour than most peer utilities. In spite of all their challenges, Hydro One has fewer outages per kilometre of line than most peer companies. Even though the conditions are rugged and sometimes harsh, Hydro One has an excellent safety record in comparison to peers. Overall, Hydro One ranks high for performance in safety, reliability, and productivity.

Hydro One's costs per unit of work are very high in comparison to peers. Although many of Hydro One's costs are fixed costs, such as wages, benefits, equipment depreciation and overhead costs, there are some opportunities to decrease spending. Hydro One has been diligent at finding ways to improve efficiency and to lower labour costs. Continued efforts to employ new technologies, automation, mechanization, routing and scheduling, and outsourcing more of the labour will result in lower overall costs.

Hydro One's record shows a serious effort to reduce production costs and improve performance and progress. They have shown measurable headway in their performance over time. However, this progress has not been sufficient to effectively decrease the total workload.

Although most of the peer group has lower costs than Hydro One, it is not always due to better performance than Hydro One. This is because fixed costs are higher. Some companies do show that cost per unit can be lower. In fact, one company maintains their system three times during the same time period that Hydro One maintains their system once and the cost for three cycles is still less than Hydro One's single cycle. (See p. 39 for more details)

1.4 Best Management Practices

The following examples of vegetation best management practices (BMP) are based on industry standards and current industry practices.[1]

1.4.1 Best Management Practice Strategies

1. Perform consistent, compliant, and cost-effective ROW corridor management to maintain clearances between conductors and vegetation using industry-approved practices targeted to ensure reliable electric service, environmental quality, customer satisfaction, and safety for workers and the public.
2. Provide sufficient funding and resources to measurably achieve UVM program objectives. “A stable and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best practice (National Grid 2015).”
3. Build greater safety awareness and education for anyone who enters a ROW zone for any reason and measure success by using leading performance indicators, such as safe ROW environment metrics, safe work place metrics, and program features.
4. Define, measure, and audit the barrier space between conductors and vegetation.
5. Establish a cycle of inspection and maintenance that is sufficiently flexible to address a variety of vegetation management conditions but regular enough to anticipate conflicts before they occur.

1.4.2 Best Management Practice Tactics and Key Measures

1. Maintain 50-75% of distribution ROWs using industry-approved herbicides.
2. Cultivate and measure positive customer involvement with UVM.
3. Automate the UVM Program. See 4.3.2 for details
    a. Improve routing, deployment and management of crews through telematics technology and scheduling.
    b. Use predictive analytics and modeling to improve performance and achieve best management practices.
4. Perform detailed outage investigations by forestry personnel and model data to promote understanding of tree conditions and failure modes.
5. Convert the majority of distribution ROW to low-growing shrubs and herbaceous plants.
6. Assess ROW edge trees routinely for risk and replace hazardous trees with appropriate vegetation.
7. Improve adjacent off-ROW vegetation to ensure desired percent of tree cover to provide appropriate benefits and protections. Trees provide vital ecosystem services and having the right trees adjacent to powerlines requires appropriate planting and maintenance strategies.
8. Establish common goals and maintain action-based relationships with various provincial and community forestry units that foster a reduction in necessary line clearing activities: Align various vegetation management activities in province of Ontario

[1] Industry practices were derived from the benchmark survey conducted for this project and a literature review

9. Develop wood utilization programs as an organizing principle for sustainable harvesting and recycling of off-ROW trees before they become hazards. Trees provide many products and utility clearing can be a source of raw materials for wood products.
10. Develop land use programs such as food crops, pollinator habitats, recreational, emergency access, transportation, and other various land uses that are appropriate and beneficial for distribution ROWs.

1.5 Peer Group Criteria and Selection

The study included five Canadian companies, Hydro One and its four regions, and thirty-one US utilities for a total of forty-one companies. Based on selection criteria, four Canadian companies and twenty-three US companies were used in peer group comparisons. The remaining nine companies were used only in general industry comparisons. Peer companies were selected on the basis of geographic region, tree density, customer density and territory demographics, and whether the utility was a peer in the 2009 Hydro One Study.

All companies in the peer group have UVM programs aligned with the objective to deliver safe and reliable electricity. They have formal vegetation management programs, are directed by an employee of the utility, and operate year-round. Practices include aerial hand-pruning and tree removal with bucket trucks and climbing arborists, mechanical pruning and clearing with heavy equipment, and the application of herbicides to prevent stump sprouting and to terminate small trees and whips.

See Appendix C for further details on Peer Selection

1.6 Benchmarking and Year-over-Year Trending Metrics

For this project commonly collected performance and progress metrics were analyzed. In general, benchmarking are comparisons between Hydro One and the peer companies. Year-over-year trends (time-studies) for Hydro One and its regions were compared to the peer-average trends. System kilometres are the total number of overhead (OH) right of way kilometres in the distribution system. Managed kilometres are the number of overhead (OH) lines managed on an annual basis.

1.6.1 Unit Costs

Unit costs provides a basis for comparison and year-over-year analysis

1. **Cost per system kilometre:** Normalizes costs differences caused by variable cycle lengths
2. **Cost per managed kilometre**: Measures cost-efficiency and ability to control fixed costs
3. **Cost per tree:** Measures cost-efficiency and workload prioritizations

1.6.2 Labour Hours Expended

Labour Hours (LH) expended normalizes differences in fixed costs

1. **Labour Hours per system kilometre:** Normalizes LH differences caused by variable cycle lengths
2. **Labour Hours per managed kilometre:** Measures work-efficiency and workload reduction
3. **Labour Hours per tree:** Measures work-efficiency and workload prioritizations

1.6.3 Workload and Performance

Measuring workload is a baseline for improving performance

1. **Tree Density and Ingrowth:** Reductions indicate workload management improvements. Increases occur when the cycle of management is long. Disturbance from mowing and manual cutting can influence density of ingrowth especially in the absence of herbicide controls and long cycles.
2. **Tree Risk Assessment and Extent of Implementation:** Measures off-ROW risk reduction efforts
3. **Percent of System Kilometres Managed Annually:** Measures improvements on management cycles and enables industry comparisons

1.6.4 *Cost Efficiency*

Measures control over fixed costs

1. **Personnel Costs and Labour Mix**: Changes in labour costs were analyzed and compared to peers
2. **Equipment Costs and Usage:** Fleet management, usage rates and right-sizing were analyzed

1.6.5 *Reliability*

Measures the effect of UVM on electric reliability (See Appendix B for discussion on appropriate use of reliability metrics)

1. **Tree related outages per system kilometre:** Effective measure of UVM reliability performance
2. **IEEE Tree-Related Reliability Metrics:** SAIDI, SAIFI are customer density biased
3. **Storm Impact Prevention and Response:** Measures the impact of UVM on storm resiliency
    - **Major Event Day (MED) outages:** Changes indicate performance of UVM program
    - **Non-MED outages:** Helps to distinguish between asset improvement need vs UVM

1.6.6 *Safety*

Safety and reliability are ranked the most important UVM objectives by utility companies. Safety has a lack of leading indicator metrics. Accident incident rates are unevenly reported and are lagging indicators.

1. **Annual OSHA Incident Rates:** Rate of recordable accidents reported per 100 workers
2. **Annual Lost-Time Incident Severity Rate:** Rate of lost days per 100 workers
3. **Employee Turnover Rates:** High severity rates correlates well with employee turnover rate in this study and across industries

1.7 Key Findings

Each finding is followed by a section number where detailed discussion can be found.

1.7.1 *Unit Cost*

Hydro One reports high unit costs compared to the peer group. The high costs are due to heavy workloads associated with long cycle lengths, higher cost of labor and equipment, and better reporting of overhead costs by Hydro One as a result of having an in-house vegetation management program. (4.1).

1.7.1.1 System Unit Cost

UVM costs are increasing across the industry. Hydro One’s costs, in contrast, are remaining relatively steady with a decrease in 2015. (4.1.2)

1.7.1.2 Managed Unit Cost

Hydro One's cost per managed kilometre and per managed tree was high compared to the peer group, but the percent increase in cost from 2011-2015 was not as high as the peer average increase for both units. This statement also holds true when comparing 2011-2015 averages to 2006-2008 averages (2009 study). (4.1.3)

1.7.2 Labour Efficiency

As shown in the 2009 study for the OEB, Hydro One continues to perform UVM at or below the average for number of labour hours expended per managed kilometre of overhead line. The result is a decade of efficient UVM performance. See Section (4.2)

1.7.2.1 Labour Hours per System Kilometre

All of the Hydro One regions performed better than the peer average in this measurement. Rather than demonstrating work-efficiency, this metric is an indicator that Hydro One is under-resourcing their program and more work needs to be done. This is true because tree density, the number of trees managed per kilometre, is increasing and Hydro One has not been able to decrease the length of its cycle. (4.2.1)

1.7.2.2 Labour Hour per Managed Unit

Hydro One outperforms the peer group with low labour hours per tree and is close to the average for labour hours per kilometre for 2011 - 2015. (4.2.2)

- **Labour hours per managed km:** In spite of increasing tree densities and long cycle lengths, Hydro One's tree crews have been able to stay close to the peer average of labour hours per managed kilometre for 2011-2015. (4.2.2.1 - 4.2.2.2)
- **Labour hours per tree:** Hydro One's labour hours per tree has stayed relatively constant from 2006 – 2015, while the peer group has increased by 60%. (4.2.3)

1.7.3 Tree Density, Ingrowth and Tree Risk Controls

Tree density has increased on Hydro One service territory over the last decade. This increase is the result of a program on a long cycle, which increases in-growth, workload, and off-ROW risk. (4.2.4)

Insufficient management controls include:

- Herbicide control of ROW in-growth
- Tree risk assessment for off-ROW edge trees
- Removal and pruning of hazardous off-ROW trees

(4.2.5 - 4.3.1)

1.7.4 Work Planning (4.3)

1.7.4.1 Automation

Hydro One has a comprehensive work planning program, and it performs well especially in regards to customer communication and the sheer size of the territory. However, it is insufficient in the areas of technological innovation and automation of data collection, data analysis, work management, auditing and predictive modeling. Hydro One has initiated digital automation to the UVM program, but, like its peers, is challenged by transitions, knowledge transfers and change management that accompany new technologies. For detailed discussion see 4.3.1-4.3.2

1.7.4.2 Customer Service

Hydro One provides better customer service and communication than the industry at large. For detailed discussion see Sections 4.3.3 – 4.3.5.

1.7.5 *Equipment and Personnel (4.4)*

1.7.5.1 Equipment

- Hydro One's utilization rate of their equipment is lower than their peers.
- Hydro One has a continuous improvement program for the efficient use of equipment through logistics and mechanization.

(4.4.1)

1.7.5.2 Personnel (4.4.2)

- Hydro One's labour burden for in-house employees is double the cost of Hiring Hall employees and is more than three times the average of the peers' contractor charge-out rates.
- Hydro One employees on average have more than double the years of experience of peer contractor employees.
- The increase in UVM cost is not a matter of efficiency or increased workload; rather it is a result of increases in cost per labour hour, including wages, benefits, equipment, fuel expenses, and other overhead and administrative costs.

(4.1.4 and 4.4.2)

1.7.6 *Reliability (4.5 and Appendix B)*

- Hydro One is well below the peer group average for tree-related outages per system kilometre and this measurement has been improving since 2003 (See Appendix J analysis). This metric is preferred for measuring the performance of UVM over the standard reliability metrics because it is more closely related to the system workload and it more appropriately measures the performance on downstream facilities.
- Hydro One compares unfavorably with peers in the area of the standard reliability metrics, SAIDI and SAIFI. These metrics are biased when applied to Hydro One where there are no high customer density areas on a very large service territory. Low customer density, as well as six other factors common to Hydro One, is known to negatively impact reliability metrics. (4.5.1-4.5.2)

1.7.6.1 Storms are Hydro One's Greatest Challenge

- Hydro One's outage per system kilometre metric is an achievement given the length of management cycles, high tree densities, system size, and the propensity for storms in the South, Central, and East Regions.
- A high percent of outages, especially during storms are caused by trees on the Hydro One system.

(4.5.1-4.5.4 and Appendices B, E, and J)

1.7.7 Safety as a Priority (4.6)

- Hydro One is distinguished from the peer group by having a more experienced and stable workforce that is in-house and is more directly connected to safety monitoring and initiatives promoted within the company.
- Hydro One's lost-time safety incident severity annual rate (SR) for 2013-15 is 7.90 lost days/100 FTE compared to the peer group average of 31.36. Compared to the industry-wide fatalities over the past three years and the peer group's incident SR, Hydro One shows clear evidence of a more successful record of tree worker safety.
- Hydro One's safety incident average rate for 2013-15 is 3.90 incidents/100 FTE compared to the peer group average of 2.46. It should be noted that there are problems with accident under-reporting and OSHA has instituted a new rule effective in 2017 to improve accident reporting.

(4.6.1 & 4.6.2)

1.7.8 2022 Model Cost Projections

Four models with varying degrees of risk and workloads are proposed by CNUC with projections of cost out to 2022. The initial 2017 costs are Current Risk Model A, $150.2 million; Moderate Risk Model B, $166.5 million; Lowest Risk Model C, $174.9 M; and Best Management Practice Model D, $192.9 M. It is expected that SAIDI and SAIFI will improve under all three models. Under Model A outages per kilometre will likely increase and public and worker safety risks will increase. With Model B the number of outages per kilometre will probably not increase but reductions are likely to be minimal. The workload will improve at a slow pace. Model C would be the most likely model to secure some reductions to the workload, to long-term cost, and to safety risk. Model D would move Hydro One towards a cycle closer to best management practices in the industry and secure significant reductions to the workload. These predictions assume resource cost will be reduced by employing Hiring Hall or contracted labour for all work on one and two-phase lines and it does not account for improvements from innovations and new technology. The recommended labour mix, employing contracted labour for only lower risk activities, would increase all modeled estimates by approximately 10 – 15%.
The assumptions behind these models are discussed in Section 4.8 and in Appendix D.

1.8 Recommendations: Improvements, Best management practices and Innovation

The following are recommendations in the order of importance:

*ST means Short-Term and indicates a onetime change; LT means Long-Term and will require continuous improvement or will take many years to implement. When both LT and ST are indicated, periodic improvements will be needed to update a short-term improvement

1. **Bring the whole distribution system to a four to eight-year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule. This will enable a more effective herbicide program, better off-ROW tree risk management, and reduce workload over the long term.** (LT)* See Sections 4.1 - 4.3, 4.6, 4.8

   a. **Reduce the current backlog over the next decade through innovations, automation and changes in labour mix** (LT)* See Recommendations 2, 3, 4, 6, and 9 (below), Section 4.1 (intro)
2. **Improve through innovation the mechanization and automation of the UVM program. This will improve understanding of the workload and it will enable more effective work planning and cost/resource predictions.** See Sections 4.3, 4.4
   a. **Improve data analytics and predictive modeling through automated data collection of key UVM activities.** (ST, LT)* See Sections 4.3.1, 4.3.2
   b. **Use technology such as LiDAR to improve measurements, condition assessments, and accuracy of data collection.** (ST,LT)* See Sections 4.3.2
   c. **Increase ROW clearing capacity and safety through innovations in mechanical equipment and routing technology** (ST,LT)* See Sections 1.4.2 and 4.4.1
   d. **Improve customer knowledge, communication, and involvement by merging UVM data with the customer service system**. (ST)* See Sections 4.3.3 - 4.3.5
3. **Improve productivity and control costs by utilizing higher percent of Hiring Hall and contract workers to perform lower safety and liability risk activities such as work planning, herbicide applications, and brush-clearing. This will lower unit costs.** (LT)* See Section 4.4.2
4. **Strategically increase herbicide usage for cost-effective results. This will ensure ROWs stay clear between shorter cycles of management and lower the long term cost** (LT)* See Sections 4.1.3, 4.2.5, 4.2.7, and 4.3.1
5. **Develop a vegetation management outage investigation protocol that expands on the current cause codes and utilizes UVM personnel. This will improve capability to predict tree failure modes and guide future tree risk mitigations.** (ST)(LT)* See Section 4.5.3
6. **Synchronize the annual asset inspections with the UVM work planning program to quantify system vegetation conditions based on performance metrics for maintaining air space around conductors**. **This will improve workload understanding and provide annual performance metrics for system conditions.** (ST)* See Section 4.3.1
7. **Improve and increase the Tree Risk Assessment Program to reduce outages caused by off-ROW trees. This will, with the help of lessons learned through outage investigations, improve reliability by reducing outages caused by trees or branches falling into overhead lines.** (LT)* See Sections 4.3.1, 4.5.3, 4.7 and Appendices F and G
8. **Identify fixed cost increases and overheads allocated to UVM to ensure cost effects of changes to the program are portrayed accurately. This will enable a better understanding of improvements to production and other cost reduction measures.** (ST)* See Sections 4.1 (4.1.1, 4.1.3, 4.1.4) and 5
9. **Improve equipment and personnel utilization**. **This will lower unit costs by improving efficiency and optimizing equipment availability.** (LT)* See Section 4.4 (4.4.1, 4.4.2)

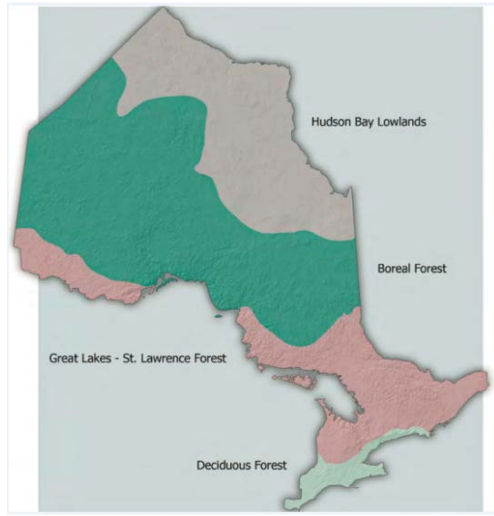
1.9 Conclusion

Hydro One has established over the last decade the capacity for safely managing dense vegetation on one of the largest service territories of the peer comparators. This accomplishment is highlighted above and is noteworthy considering the long cycles of management and financial constraints. Hydro One has achieved a below average number of outages per kilometre, but has high SAIDI and SAIFI. Budgetary constraints on UVM resources, insufficient innovation, incomplete digital automation of work management, and a long cycle have limited Hydro One's ability to convert ROWs to compatible plant communities. This has resulted in high costs of mechanical and manual intervention throughout the system. However, Hydro One has demonstrated improvements in numerous areas such as increased usage of herbicides, mechanization, and automation of planning and work management processes. To expand and sustain these efforts, longer-range goals for improving the management of the 52,000 kilometres of single and two-phase lines should be studied. Without this effort, the probability that outage numbers will increase should be expected. While the IEEE reliability metrics may show improvement under the current scheduling, they should not be viewed as a definitive performance metric for UVM. A minimum percent of tree-related outages should be investigated by arborists using root-cause analysis. Reliability is the center of UVM performance and there is a plethora of reliability data to gauge it. In the discipline of quality management, too much reliance on a single set of data can be misleading and the UVM program currently relies heavily on IEEE reliability metrics. Conversely, Hydro One's low accident severity rate and low employee turnover rate are evidence of a successful program, but the dataset is limited and is composed of lagging indicators. Equally important UVM objectives, such as safety, compliance to regulations, environmental quality, and customer satisfaction should be measured through improved data collection and included as key performance indicators, both leading and lagging.

2 INTRODUCTION

2.1 STUDY BACKGROUND

Hydro One was instructed by the Ontario Energy Board (OEB) in March 2015 to perform a study similar to the *Hydro One 2009 - Vegetation Management Benchmark Study*, which analyzed Hydro One's relative efficiency. Central to the current project is a distribution utility vegetation management (UVM) survey conducted by CN Utility Consulting (CNUC) in February, March and April of 2016 with Hydro One and 35 electric utility companies throughout North America. The following statements by the OEB and the Ontario Auditor General have influenced this project:



MAP 1: FOREST REGIONS OF ONTARIO

> *The OEB also directs Hydro One to present in its next rates application a comprehensive trend analysis of its vegetation management program showing year-over-year comparisons in unit costs. Further, the OEB encourages Hydro One to explore best practices in vegetation management with other distributors and transmitters, similar to the CN Utility Study filed with the OEB in the EB-2009-0096 proceeding, and file any resulting study in its next rates application.* (OEB, March 2015)
>
> *Explore best practices in vegetation management, considering changes in labour mix and innovation opportunities, as well as conduct a trend analysis of the vegetation management program showing year-over-year variations in unit costs.* (Office of the Auditor General of Ontario, 2015)

2.2 BENCHMARK STUDY PURPOSE AND LIMITATIONS

This report is for the purpose of determining the level of efficiency that Hydro One has achieved in carrying out its mission to manage vegetation that impairs or potentially could impair the reliable and safe operation of their expansive distribution system, which serves over 1.3 million customers and requires management of over 7 million trees. The efficiency level is determined by comparing the productivity, costs, and measurements of reliability and safety for each Hydro One business unit (region) and Hydro One with a group of peer utilities across North America. Analysis includes longitudinal studies of the different metrics, particularly for Hydro One. Given the peer group level of efficiency, the question can be asked whether enough work is being performed by Hydro One to meet a standard of care. Regulations, policies and behaviors that establish a performance standard include the various decisions made by the utility and the regulator, the normative behavior of the industry at large, and the industry consensus standards that are applied to UVM. These are the gauges to determine whether the efficiency of Hydro One's performance is sufficient to manage the UVM workload and whether it meets a best management practice criteria.

2.3 Goals and Objectives of the Benchmarking Study

Based on the five obstacles to success in business enterprise (Deming, 1984), this project:

- Looks for inconsistencies, especially in the UVM planning process
- Evaluates whether long-term goals are receiving adequate attention
- Reviews the performance evaluation system with a focus on whether some metrics are relied on too heavily because the data are the easiest to obtain
- Looks at whether the customer is driving the quality of the program
- Examines the safety and liability risks and whether they are managed adequately

It is hoped that some changes can be implemented that will streamline processes and ease burdens. For utilities to succeed in the 21st century, they will have to create a new philosophy for UVM by envisioning it in a new framework that customers will appreciate. With the customer on board, improvements can move forward with leadership inspired to empower an advanced culture of positive and freely-exchanged knowledge, whether it is for productivity, technology, safety, reliability, customer service or the environment.

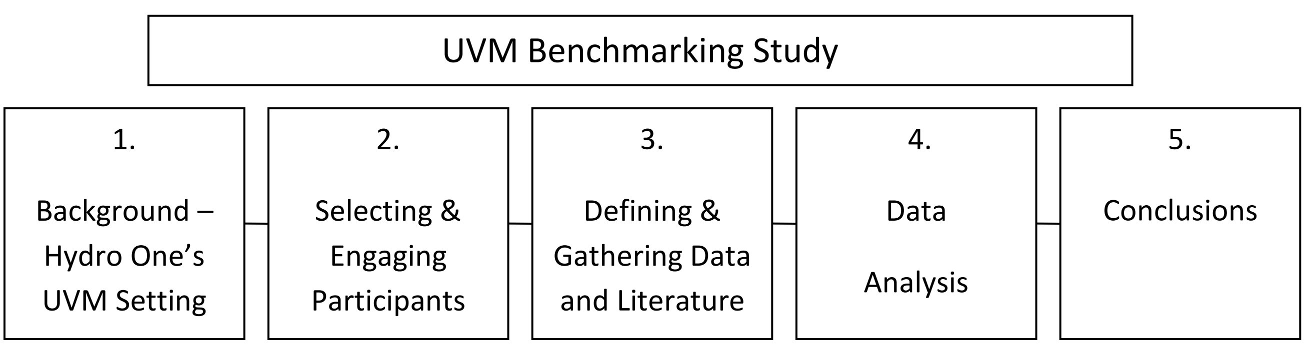
2.4 The Benchmark Report Team

CNUC was selected as an independent third-party consulting team to execute Hydro One's 2016 Vegetation Management Benchmarking Study. CNUC has extensive experience in both Utility Vegetation Management (UVM) and in benchmarking. This combination of expertise is unique in North America and is evidenced by experiences and achievements that CNUC brings as a consulting team.

Details about CNUC's project team can be found in Appendix A of this report.

3 Benchmark Study Framework

3.1 Benchmark Study Data Collection and Analysis Methodology

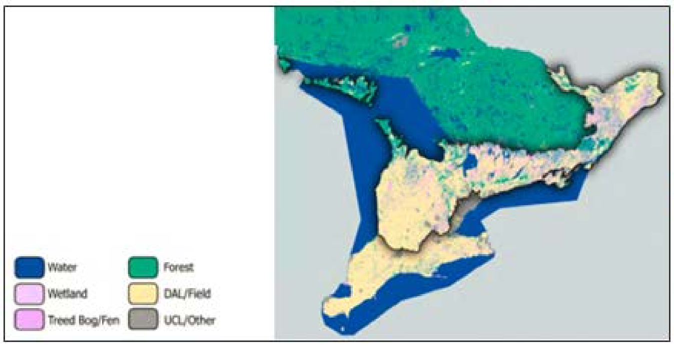


See Appendix I: Benchmark Study Process Chart for details

See Appendix D: Statistical Methodology and Model Development for details on analysis

3.2 Forests in Ontario

The South is mostly agriculture and has a small percent of deciduous forests scattered throughout. The East and South and Central are predominantly privately owned. Parts of the East and Central Regions, however, are heavily forested with large conifer, deciduous and mixed forests. The concentration of forested areas, particularly conifer, is the greatest in the North in the boreal forest. The land north of Lake Superior and Lake Huron/Georgian Bay is another ecoregion within the North Region that also contains many mixed and deciduous forests. It is in the East and Central where the density of customers is greater than the North but there are heavy and scattered forests. The Central incurs more tree-related reliability issues than the other regions, having many settlements in forested areas. The East is not far behind, but has more agricultural areas that reduce the tree populations in some areas and risks of tree-related outages.



Map 2 Urban Agriculture and Dense Forests

Map 3 Hydro One Regions Map

By comparing the yellow and green areas in Map 2 with the Hydro One regional boundaries in Map 3, one can see that about fifty percent of the Central and East Regions are densely forested. The North region (only partly shown in Map 2) is practically all dense forests. The East and Central regions also have significant areas that are agriculture, wetlands, scattered forests and many populated areas.

Forestry and customer demographics play a key role in UVM program implementation and performance results. The North Region is the largest area but only contains 18% of the system kilometres and 14% of the customers. The North Region is heavily forested and has the highest percent of kilometres (29%) that have limited or difficult access. The North region of Hydro One is roughly 512,600 km^2 with 190,000 customers. This vast area contains only 18,000 km of line. The South region has the largest number of distribution lines at 32,000 km and Central and East regions are roughly equal at 26,000 km.

3.3 Hydro One's UVM Environment and System Attributes

Peer Stats: Customers per Square Km					Peer Stats: Customers per OH System Km			
Sample Size	27	Q3	74.5		Sample Size	27	Q3	42.2
Average	57.1	Min	0.9		Average	37.7	Min	6.7
Q1	11.0	Max	293.9		Q1	21.2	Max	141.1
Median	27.5	SD	71.3		Median	28.9	SD	27.7
Hydro One Networks					Hydro One Networks			
Hydro One	2.1	HO Central	8.8		Hydro One	13	HO Central	14.3
HO North	0.4	HO East	8.7		HO North	10.6	HO East	15.3
HO South	9.2				HO South	11.3		

Table 1: Customers per Square Kilometre and Customers per Distribution Overhead System Kilometre

With the exception of one other North American company, Hydro One has the lowest average customer density by land area. Even the South Region, the most densely populated of the four Hydro One regions, has only 9.2 customers per square kilometre (km^2) (Table 1, above left). *This is six times less dense than the average of the peer group*. Of the twenty-seven companies in the peer group, only three have fewer customers per overhead (OH) system kilometre than the East region, which has 15.3 customers per km, the highest of Hydro One's four regions (See Table 1, above right). Hydro One manages forty-one percent of the electric distribution equipment in Ontario, while it only serves twenty-five percent of the customers (OEB, 2015). All Hydro One Regions are in quartile 1 (Q1) for lowest customer density per km of line.

Customer density is important when analyzing the cost to the customer and reliability. In 2011-2015 each Hydro One customer spent on average $99.36 for UVM. Although this is above the average ($35.13 in 2015) for utilities in their peer group, it is important to note some extenuating circumstances that contribute to higher cost for Hydro One customers:

- Hydro One manages 76 trees per system km compared to the average for the peer group at 68 trees per km.
- Hydro One has nearly the lowest number of customers per km^2 and per km of line; therefore it has fewer customers to pay for the cost of UVM.
- On Hydro One's system there are significantly greater distances between customers than peer companies. Low customer density contributes to higher logistical costs for maintenance and longer response times for emergencies.
- Low customer density increases the difficulty of prioritizing work to achieve consistent reliability performance improvements uniformly across the system.
- Low customer density reduces the reliability improvement impact of any single UVM effort
- Wages are higher for Hydro One than for most of the peers.
- Hydro One's service territory has a higher than average number of storms, especially in winter, that damage the distribution system on a regular basis.
- Vegetation management is performed infrequently (9.5 year intervals).
- 30% of Hydro One's system is difficult to access because of terrain, lack of roads, water and other access issues. In the North and East regions, 75% of off-road locations are difficult to access.
- With the exception of the South Region, Hydro One has one of the coldest minimum average winter temperatures in the peer group, making winter time work challenging and sometimes less cost-effective. Lake-effect snow accumulations and snow that persists for much of the winter makes forestry work difficult to perform in some areas. Additionally, the window for applying herbicides is limited.

3.4 Selection of Peer Utilities

The study had a total of forty-one companies, including six Canadian companies as well as Hydro One's four regions. Twenty-seven peers were selected to be comparators to Hydro One and are referred to as the peer group. The peer group includes four Canadian companies and twenty-three US companies. In some comparisons, non-peer companies are included. The response sample size of each question is noted with each graph and if the non-peer group is included it is noted under the graph title. Peer companies were selected on the basis of geographic region, tree density, customer density and territory demographics, and whether the utility was a peer in the 2009 Hydro One Study.

All companies in the peer group have UVM programs aligned with the objective to deliver safe and reliable electricity. They have formal vegetation management programs, are directed by an employee of the utility, and operate year-round. Practices include aerial hand-pruning and tree removal with bucket trucks and climbing arborists, mechanical pruning and clearing with heavy equipment, and the application of herbicides to prevent stump sprouting and to terminate small trees and whips.

See Appendix C for further details on Peer Selection

3.5 Differences between 2009 study and 2016 study

- In 2009 CNUC distributed the survey only to companies who were deemed to be potential peers. In 2016 companies were invited to participate regardless of their peer potential and the peer group was selected after preliminary analysis of several factors, which resulted in a larger peer group sample size (14 peers in 2009 vs. 27 in 2016).
- Non-peer companies were included in the analysis for some industry-wide comparisons in 2016, whereas in 2009 all of non-peer data was discarded.
- Survey questions were changed, revised and clarified. The scope of the survey was expanded to ensure coverage of target areas and to include some topics not covered in the past.
- More intensive literature review was performed on laws and regulations, reliability and climate impacts on UVM.
- More correlational and predictive analysis was used to draw conclusions. A future UVM cost model for Hydro One was developed.

4 Findings and Discussion

4.1 Unit Cost Introduction

Cost is relative to production, efficiency, labour and equipment management, program stability, sufficiency, and risk acceptance. Cost is a measurement that incorporates many variables when making comparisons. It represents regional and local economics, monetary exchange rates, union membership costs and wage agreements, taxation differences, and the scope and interval of work. It is difficult to always know what is included in cost. Differences may be arbitrary, based on perceptions of valuation and where overhead costs are assigned. Cost comparisons in this report shouldn't be taken necessarily as a measure of efficiency or productivity but rather a measure of cost variables.

Annual cost is usually understood as an annual input that can positively or negatively influence future annual inputs. Variations in annual cost over the long-term are influenced by the frequency of maintenance. A stable annual UVM cost is achieved by having an optimum interval of maintenance that comports with the workload. The workload is determined by ingrowth, the annual accumulations of growth on existing trees, and the desired reductions in risk associated with off-ROW tree and branch failure.

UVM workload is managed through vegetation clearing activities and logistics. If the interval of maintenance is too short, then long-term logistical cost will increase unnecessarily. If the interval of maintenance is too long, then risk will rise above the acceptable level and annual vegetation-clearing cost will increase. If quality of work and duration of vegetation clearances aren't specified and audited, then financial constraints on a UVM program can result in a longer cycle of routine maintenance. At some point, as the cycle length increases, it will become more and more difficult or impossible to maintain acceptable risk including safety, reliability, adequate storm response, and fire protection. At some point when a long cycle is getting longer, a workload barrier is formed in which it will take extraordinary short-term measures to achieve even minor reductions to cycle length, and improvements to reliability and efficiency. Achieving a stable, consistent and desirable cycle length with maximum cost efficiencies is a long-term project. *In Hydro One's case it will take at least a decade of accelerated and highly productive UVM to reduce the cycle of management by two to four years.*

4.1.1 Routine UVM Maintenance Cost per System Kilometre

Long-term cost comparisons with the peer group are made by normalizing the cycle lengths and comparing the annual cost per kilometre. The term for this is **cost per system kilometre** and it compares what companies spend annually on UVM relative to the size of their system:

Routine UVM Cost per system kilometre = Annual Routine UVM expenditures ÷ Number of OH kilometres in the system

Cost per system kilometre compares what companies spend per kilometre regardless of the frequency of management. Hydro One spends more per system kilometre than the average of the peer group. This is because its annual clearing costs are significantly higher than the entire peer group. Hydro One's long cycle length is driving up the annual unit cost increment. However, there are more variables that affect cost and Hydro One would still spend more per system kilometre than their peers if the cycle was shortened.

In combination with other variables, such as tree density, labour burden, or overhead/administrative costs, system kilometre cost is a way to compare productivity costs. The following graph (Figure 1 below) compares Hydro One's system km cost with its peers.

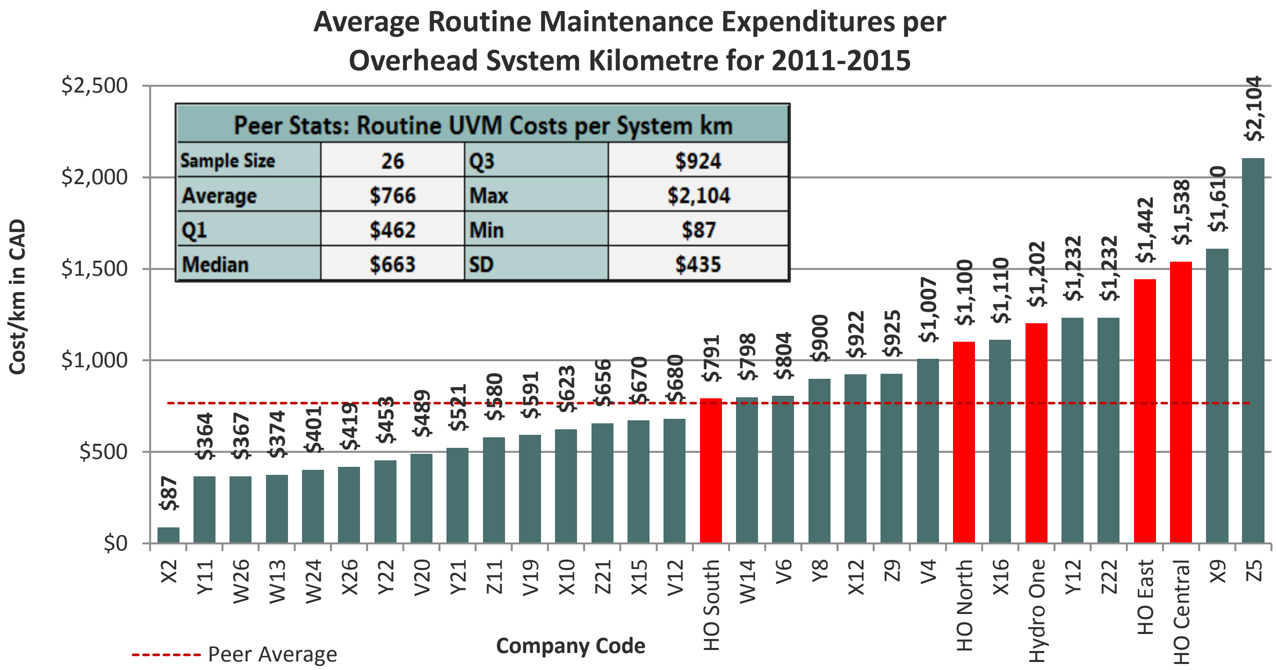


FIGURE 1: ROUTINE MAINTENANCE COSTS PER SYSTEM KILOMETRE

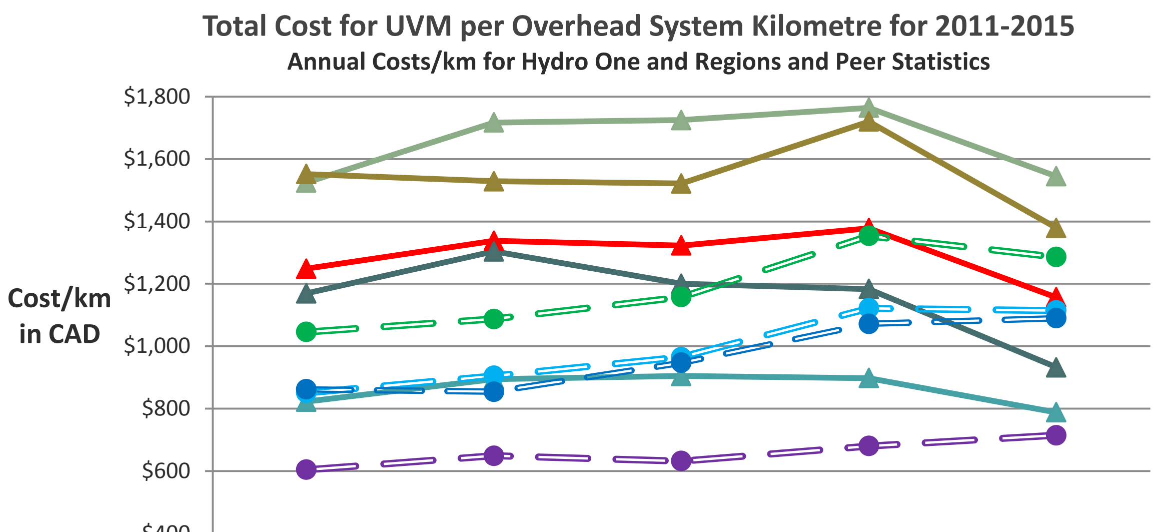
Hydro One is in quartile four for average cost per system km for routine maintenance 2011-2015. Hydro One is paying a high rate per km of UVM and the cost must be spread over one of the lowest number of customers per km. This makes the cost evaluation problematic and sensitive. Routine maintenance system kilometre costs at Hydro One are one standard deviation *above* the peer average.

In 2006-2008 Hydro One's routine system kilometre costs were also much higher than the peer average and it was attributed to significantly higher wages and benefits than the peer group. The current study finds that higher routine system kilometre cost is still a matter of hourly costs but is not solely a matter of higher wages and benefits. In fact, the cost of UVM per labour hour has increased significantly since 2011, while the number of labour hours actually decreased after 2012. System kilometre cost increases were due to hourly cost escalations which include administrative and equipment costs as well as labour burden. Hourly cost increases are discussed further in 4.1.4 below.

The peer group has a consistent ratio between labour burden and basic wage rates (about *17:10* for line clearance personnel). This ratio is much larger for Hydro One (about *29:10* for line clearance personnel). Hydro One UVM personnel are company employees who earn a higher wage than contract workers employed by peer companies. Furthermore, Hydro One includes significant administrative costs in their total UVM spend, whereas the peer companies outsource UVM and do not include administrative costs other than the personnel costs for the UVM department. Hydro One UVM hourly costs increased between 2011 and 2015 by $14 for line clearing, $18 for Brush Clearing and $25 for work planning. These increases represent fixed costs unrelated to efficiency and productivity and only a part of the increases are due to increases in wages and benefits. These increases are discussed further in the following sections.

4.1.2 *Total UVM Cost per System Kilometre Year over Year*

Another cost per system kilometre that can be compared is the total cost for UVM, which includes routine, reactive and storm costs. From 2011 to 2014, Hydro One increased the UVM expenditures by $130/system kilometre. In 2015, the cost per system kilometre was scaled back by $221/system kilometre. This reduction was achieved by modifying the work scope and schedule, which resulted in a $22.5 million budget decrease, only $3 million above the average spend in 2006-2008. In contrast, the peer group average system kilometre cost *increased* by $272/km from 2011 to 2014, more than double the increase of Hydro One during this time period. In 2015 Hydro One's system kilometre cost was only $42 above the peer average. Figure 2, below, highlights this fluctuation dynamic between Hydro One and the peer group. Hydro One's cost is split between high cost per system km in the East and Central Regions and low cost per system kilometre in the North and South Regions.



	2011	2012	2013	2014	2015
HO Central	$1,525	$1,717	$1,725	$1,764	$1,544
HO East	$1,552	$1,528	$1,521	$1,720	$1,379
Hydro One	$1,248	$1,338	$1,323	$1,378	$1,157
HO North	$1,170	$1,304	$1,200	$1,183	$932
HO South	$822	$895	$904	$898	$788
Peer Average	$850	$905	$965	$1,122	$1,115
Peer Q1	$604	$649	$632	$680	$714
Peer Median	$862	$854	$947	$1,072	$1,090
Peer Q3	$1,046	$1,087	$1,157	$1,354	$1,286

Figure 2: Year over Year System Kilometre Cost Comparisons

4.1.3 Routine Cost per Managed Kilometre

4.1.3.1 Average Cost 2011-2015 Comparisons

Another ratio for comparing cost is calculating the cost per managed kilometre. Managed kilometre is different from system kilometre. System kilometres are the number of overhead (OH) kilometres in the distribution system. Managed kilometres are the number of OH lines managed on an annual basis. The high cost for Hydro One vegetation management is apparent when measured by the cost of a managed kilometre (Figure 3, below). The routine average cost per managed km in the Central Region is nearly double that of the South Region and over four times the cost of the peer average. These costs are the result of:

- The accumulated biomass and heavy workload after a long interval between maintenance cycles. The management of in-growth after a long cycle is more expensive than treating a converted ROW on a short cycle with herbicides to prevent ingrowth.
- A higher cost of labour and equipment compared to the peer group, nearly all of which outsource UVM program implementation. A qualified line clearance arborist at Hydro One earns \$5/hour more than the highest paid peer company contract arborist. The labour burden is \$55 more. For the peers the average labour burden is 1.7 times greater than base wage. For Hydro One the labour burden is 3.0 times greater than the wage for field personnel, except for trainees (2.6 times) and temporary employees (1.6 times), which is closer to the contract crews. Hydro One's labour burden is loaded with associated UVM costs such as equipment and indirect administrative costs. The peer group labour burden is lower because wages and benefit costs are lower, but also because administrative/overhead costs are lower or they are not fully reported.
- Hydro One reports administrative/overhead costs better than their peers, since they are completely in-house. The peer group does not report indirect costs on the UVM program. They only report the direct costs to run the UVM department plus the cost of the contractor.

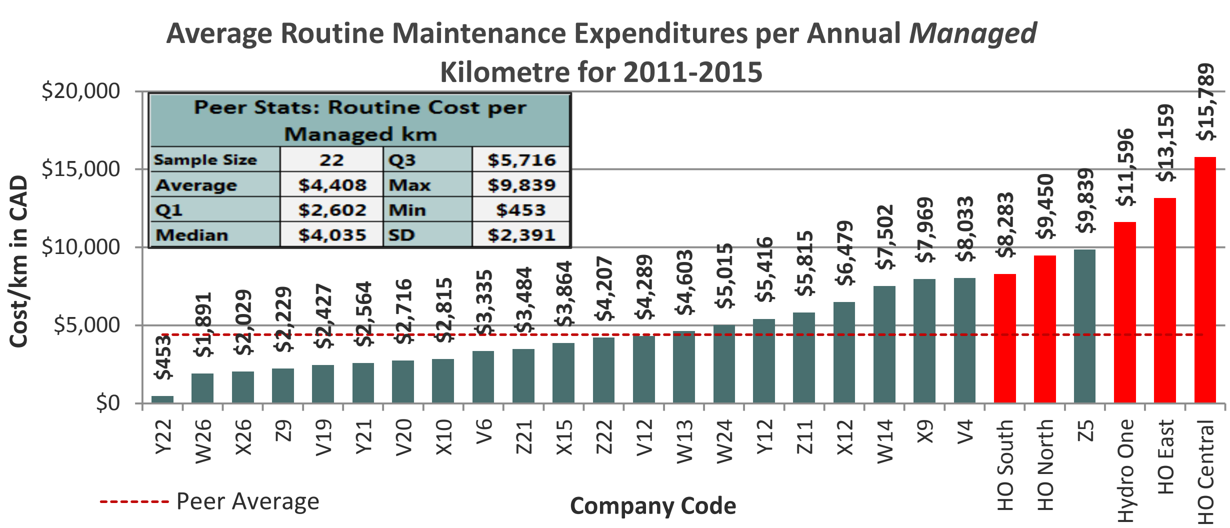
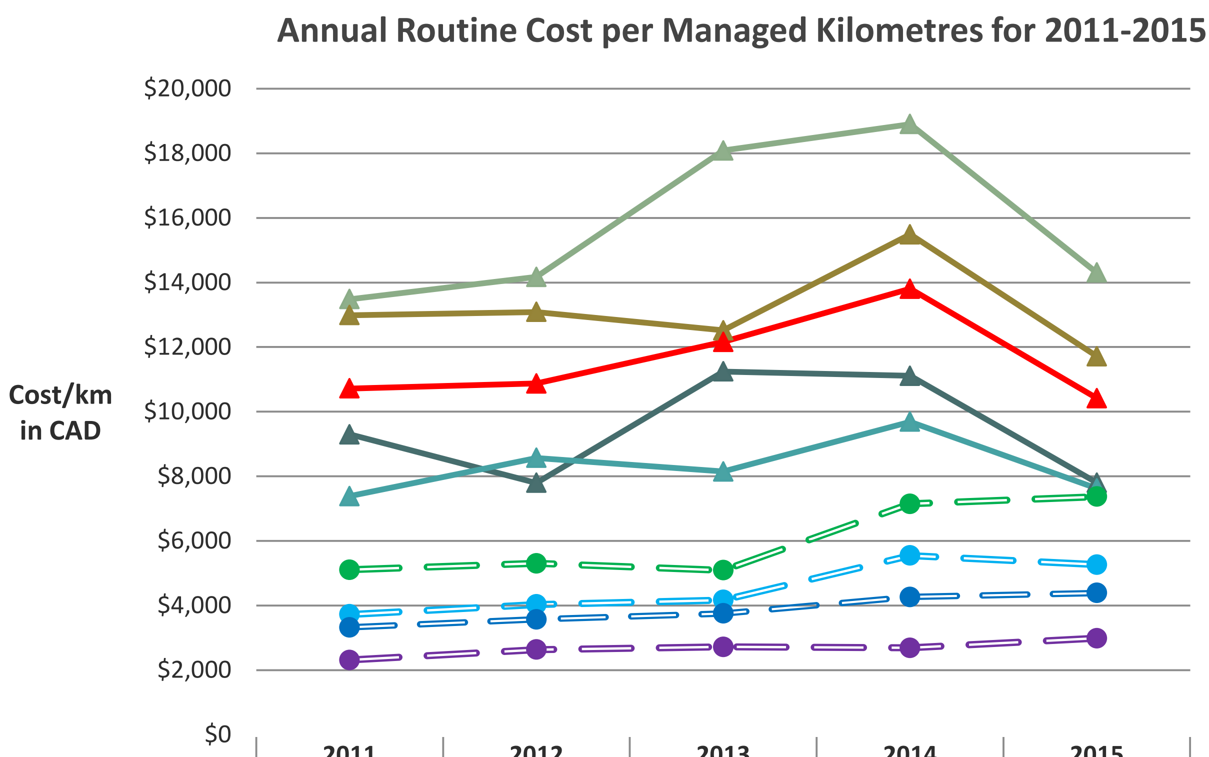


Figure 3: Routine Maintenance per Managed Kilometre

4.1.3.2 Longitudinal Cost per Managed Kilometre

Hydro One's 2011-2015 average cost per managed kilometre was a 22% increase over its average cost in 2006-2008 compared to a 25% increase for the peer group. Hydro One's 2015 cost per managed kilometre was only 13% over its 2006-2008 average compared to the 49% increase for the peer group. Also, Hydro One significantly reduced the cost per managed kilometre in 2015 over 2014 by 25% compared to the peer group average which was reduced by only 5% (See Figure 4, below). This reduction in cost was a result of targeting the 2015 schedule on M-Class feeders which are managed on a shorter cycle 6-8 years. The cost reduction in 2015 illustrates the cost savings possible when work is performed on-cycle and on a shorter cycle than in the past. It does not, however, show the cost reductions that could be achieved through herbicide use which requires a shorter cycle length to be effective.



	2011	2012	2013	2014	2015
HO Central	$13,483	$14,172	$18,084	$18,901	$14,303
HO East	$12,986	$13,087	$12,515	$15,487	$11,717
Hydro One	$10,721	$10,875	$12,163	$13,807	$10,417
HO North	$9,297	$7,795	$11,245	$11,112	$7,800
HO South	$7,388	$8,568	$8,150	$9,688	$7,624
Peer Average	$3,725	$4,034	$4,169	$5,547	$5,265
Peer Q1	$2,311	$2,633	$2,719	$2,688	$2,986
Peer Median	$3,326	$3,573	$3,756	$4,265	$4,391
Peer Q3	$5,107	$5,307	$5,092	$7,148	$7,370

Figure 4: Annual Routine Cost per Managed Kilometres for 2011-2015

4.1.4 Hydro One UVM Cost Increases are due to rates more than production

Total cost increases over time at Hydro One can be explained in part by variations in the number of trees treated per km or the amount of brush treated. Much of the cost increase is independent of tree densities or numbers of kilometres completed. It is the annual cost per unit of labour that has increased steadily since 2011 by nearly $20/hour (Figure 5, below). The number of labor hours increased in 2012 but decreased each year 2013-2015. The largest decrease was in 2015. The UVM cost increase is not a matter of efficiency or increased workload. It is due to increases in wages, benefits, equipment, fuel expenses, and other overhead and administrative costs. By reviewing Figure 5, the extent of the annual labour burden increase from 2011-2015 can be seen, irrespective of labour hours expended. In mid 2014 the labour pool was reduced by a large percent. When Hydro One was questioned about the increase in cost per labour hour, the following explanations were provided:

- $9 million cost centre administration costs
- $4.5M health and safety costs
- $1.5M BASC Costs
- $0.2M Central tools
- $0.35M shared services
- Wage increases
- Changes in the mix of full time employees and temporary hiring hall employees.
- Other labour burden increases

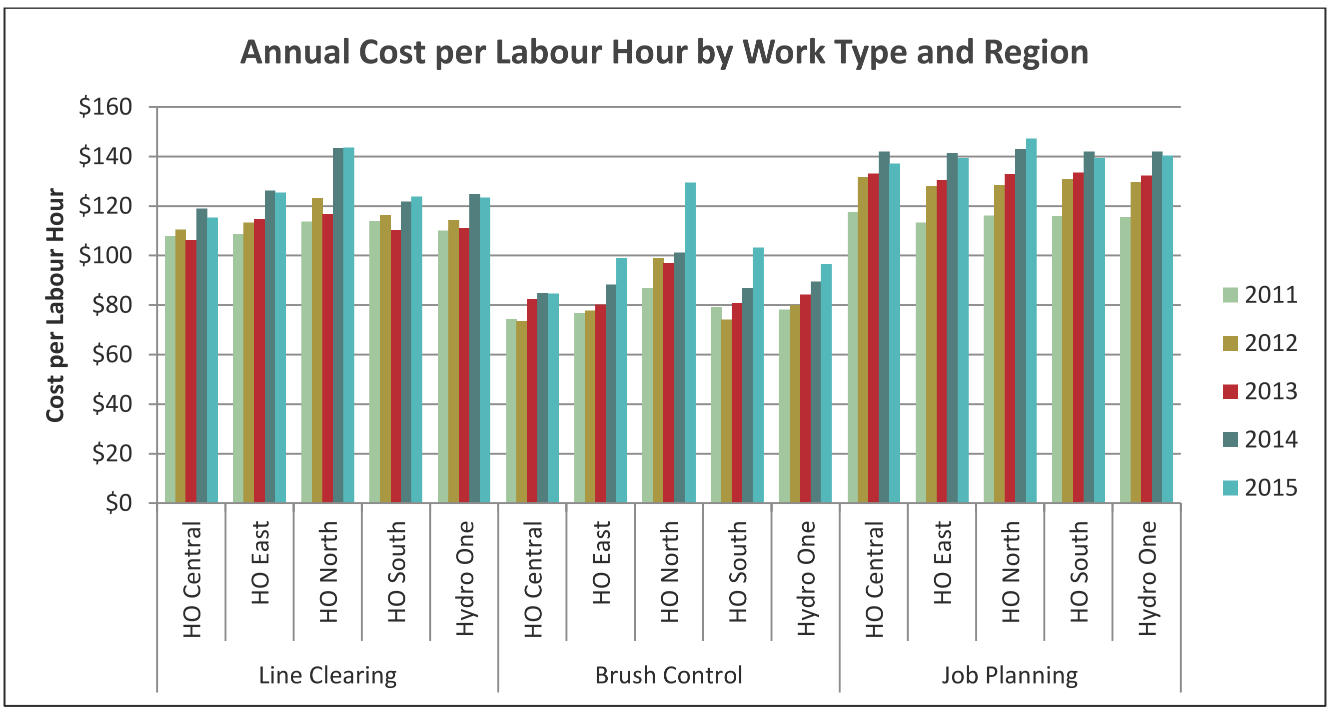


Figure 5: Hydro One Annual Cost per Labour Hour by Work Type and Region

The increases in hourly costs should be separated from the variations in productivity costs. The peer group typically reports less than 1% of costs related to administration or overhead compared to Hydro

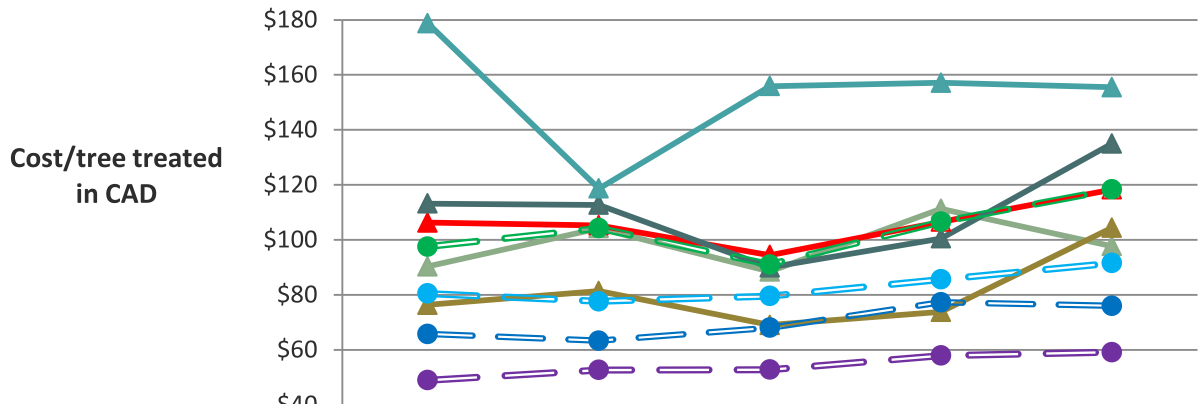
One whose administrative costs are closer to 8%. This is a significant difference. The peer group may not report all in-house costs associated with the UVM department.

4.1.5 Cost Per Tree Treated

Trees treated are the same as managed trees and include both prunes and removals. Hydro One has maintained an above average cost (third quartile) per tree treated (Figure 6, below). This ratio is moderate in comparison to the cost per managed kilometre, which is high for Hydro One due to high tree density. The average cost per tree increased by $11 for the peer group and $12 for Hydro One over the five years. For Hydro One the rise in cost per tree represented increases in fixed cost rather than changes in work scope or productivity. In contrast, the peer group's cost increase was due to a greater emphasis on off-ROW tree risk, mitigating emerald ash borer (EAB), and hardening distribution systems against more frequent and intense storms, all of which require more off-ROW removals of larger trees. The average labour hours per tree did increase for the peer group by 9%. Labour efficiency is analyzed in section 4.2.

Hydro One's average cost per tree treated in 2011-2015 increased by only 3% over the 2006-2008 average compared to the peer group which rose by 97%.

Annual Cost per Tree Treated for Routine UVM for Years 2011-2015



	2011	2012	2013	2014	2015
Hydro One Central	$90.37	$104.22	$88.51	$111.31	$97.74
Hydro One North	$76.37	$81.39	$69.07	$73.85	$104.43
Hydro One	$106.26	$105.28	$94.47	$106.55	$118.33
Hydro One East	$113.18	$112.76	$90.01	$100.55	$135.03
Hydro One South	$178.76	$118.66	$155.89	$157.11	$155.48
Peer Average	$80.51	$77.68	$79.58	$85.62	$91.54
Peer Q1	$48.96	$52.69	$52.84	$57.94	$59.14
Peer Median	$65.82	$63.34	$68.07	$77.29	$76.01
Peer Q3	$97.58	$104.22	$91.07	$106.55	$118.33

Figure 6: Year over year Changes in Cost per Tree Treated

4.1.6 COST AND TREES PER CUSTOMER

"The OEB notes that the 2011-2012 CN Utility Benchmarking analysis showed that Hydro One had the highest vegetation management cost per customer relative to its peers. This benchmarking comparison emphasizes the need for Hydro One to provide detailed and thorough evidence substantiating its spending requirements and how it intends to continuously improve in this activity (OEB, March 2015)." Figure 7, Annual UVM Cost per Customer, below, confirms Hydro One's high relative cost that was discovered in 2012. This measurement is an average. It does not account for the variations in electric usage which affects cost per customer, but it does show that a Hydro One customer has a measureable stake in the performance of the UVM program, and that there may be a customer expectation that costs should be closer to that of peers.

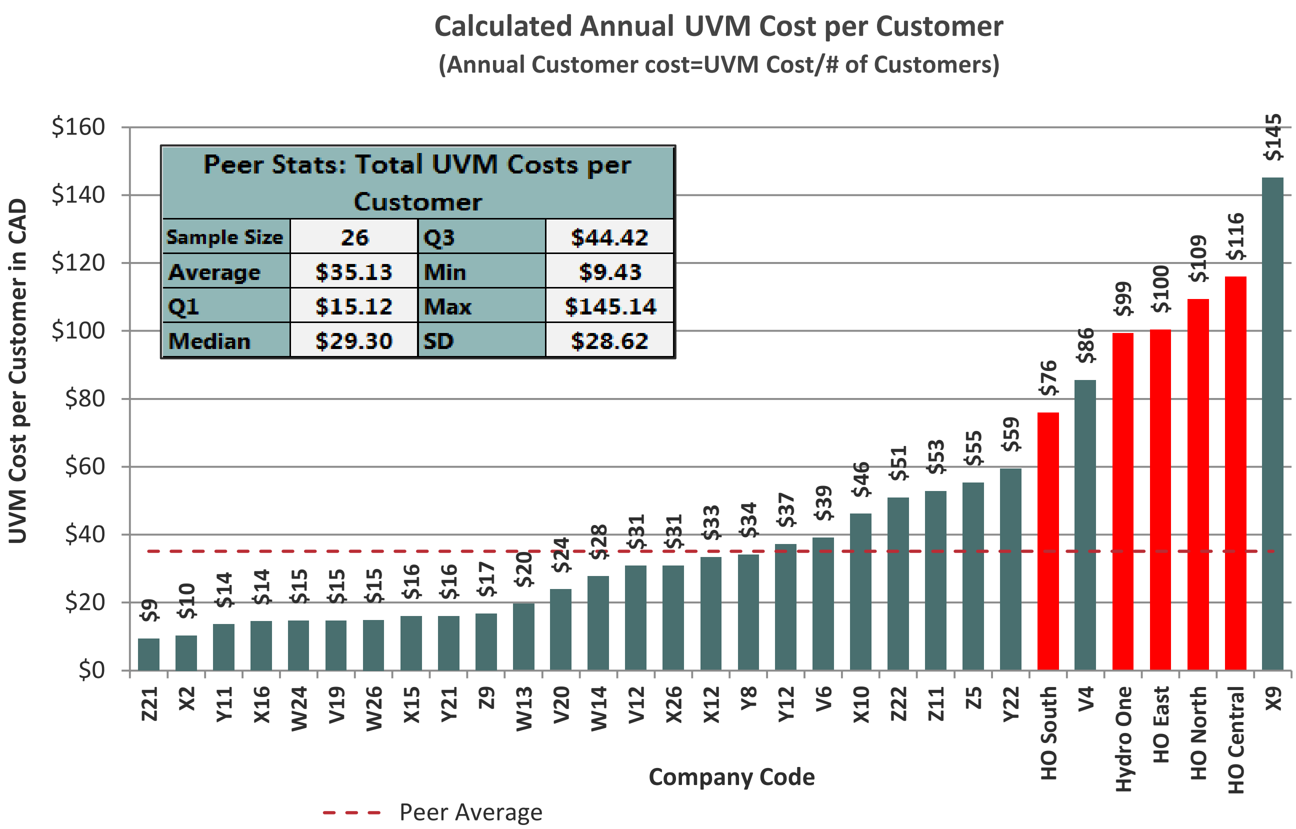


FIGURE 7: ANNUAL UVM COST PER CUSTOMER

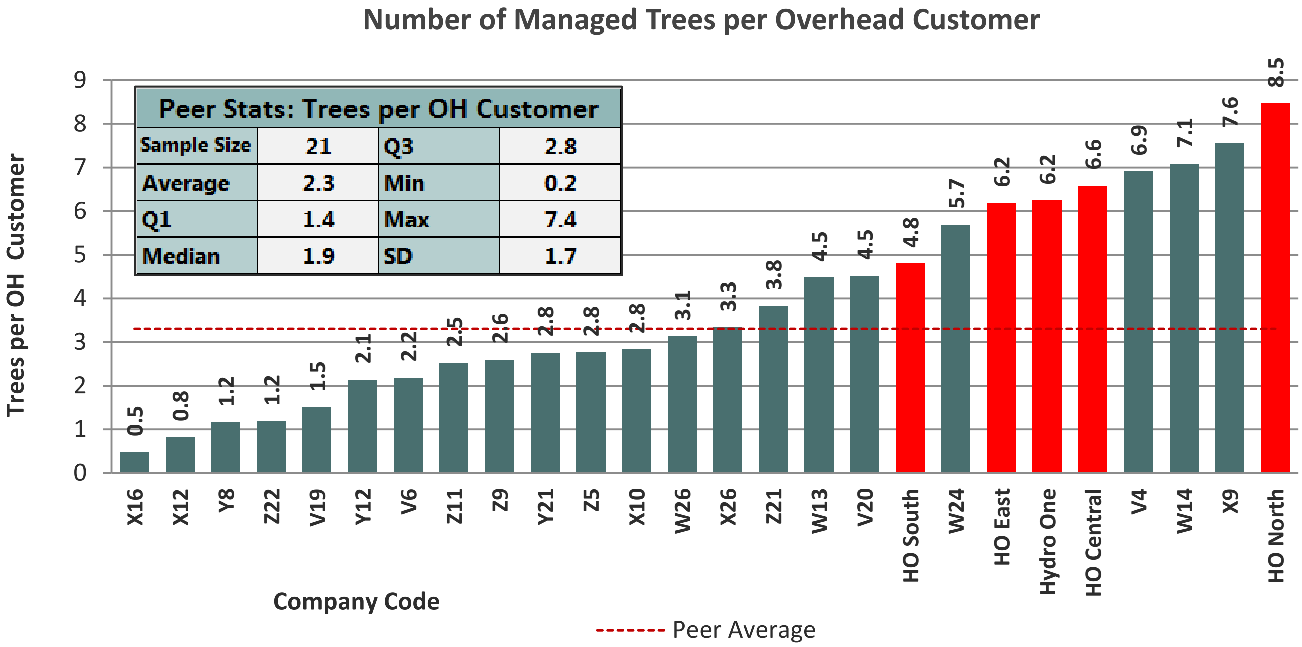


Figure 8: Number of Managed Trees per OH Customer

Another way to compare the customer's cost is to compare the workload per customer. The average number of trees per customer is calculated by dividing the total number of trees managed by the total number of customers. Since residential customers make up 90% of the total customer base, the calculations for trees per customer in Figure 8 (above) should be close the actual average (unlike the cost per customer, which is weighted to the industrial and commercial customers). There are wide variations of trees from one property to the next, but each Hydro One customer on average have 6.2 trees that must be managed compared to the peer and non-peer group average of 2.3. This is a cost factor that helps to explain a higher cost for Hydro One in terms of total cost and cost per customer.

4.2 Labour Efficiency

Another way to compare companies is to focus on the time units required to perform UVM. This is a more universal measurement (hours) for comparing the relative efforts of each company in the peer group. Hydro One compared favorably with the peer group in the 2009 study and again in the current study.

4.2.1 *Routine Labour Hours per System Kilometre*

When routine labour hours per system km are compared, a different picture of relative efficiency emerges in comparison to cost (Figure 9, below). Hydro One's labour hours per system km is nearly one standard deviation *below* the average. This could indicate the work is being performed as or more efficiently than the majority of companies in the comparison group. All of the Hydro One regions performed better than the peer average labour hours per system kilometre. However, rather than demonstrating work-efficiency, this metric is an indicator that Hydro One is under-resourcing their program and more work needs to be done. This is true because tree density, the number of trees managed per kilometre, is increasing and Hydro One has not been able to decrease the length of its cycle.

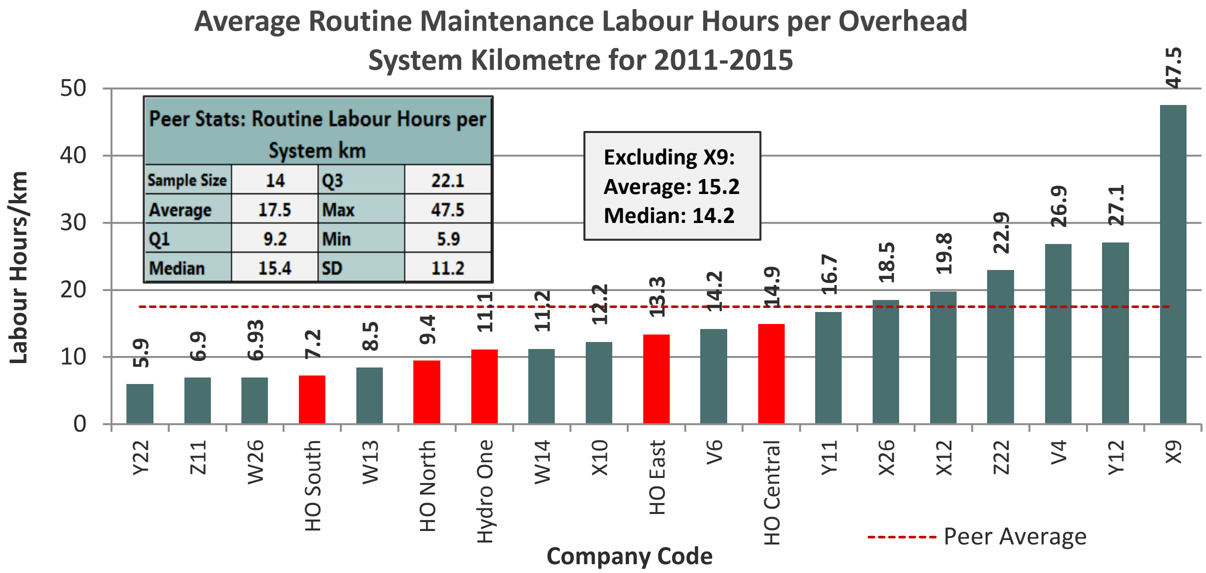


FIGURE 9: ROUTINE MAINTENANCE LABOUR HOURS PER SYSTEM KILOMETRE

4.2.2 LABOUR HOURS PER MANAGED KILOMETRES

4.2.2.1 Establishing Work Efficiency

The following discussion will establish that Hydro One has an efficient workforce relative to the peers. Figure 10, below more accurately depicts Hydro One's performance in labour hours per managed kilometre (LH/managed km) in comparison to peers by including tree density and cycle length for each company. Hydro One, W13 and W14 show similar measurements for all three metrics. All three have high tree densities, long cycle lengths and similar labour hours per kilometre. (**Gray bars = labour hours per km**; **Blue dots = trees per km**; **Green squares = calculated cycle length**). W13 and W14 have better ROW access than Hydro One regions with the exception of Hydro One South. This comparison with three different metrics lined up together shows how Hydro One compares evenly with other companies. Given a fourth metric, ROW accessibility, Hydro One compares more favorably with W13 and W14 because of the greater amount of access issues challenging the work at Hydro One.

The other companies with high tree densities, V4 and X9, expend significantly more labour hrs/managed km than Hydro One. Although their systems are on a shorter cycle than Hydro One, both V4 and X9 are under recent regulatory mandates that require increases in vegetation management. The remaining companies in Figure 9 have lower tree densities and shorter cycle lengths than Hydro One.

Work efficiency is reinforced by the higher tree density found on much of Hydro One's system. Hydro One also has a significant number of access issues to their system and it is typically in a state of heavy growth after nine to ten growing seasons. In conclusion, although Hydro One is close to the average for LH/km, they are in fact working UVM at a higher rate of efficiency in comparison to the peer group.

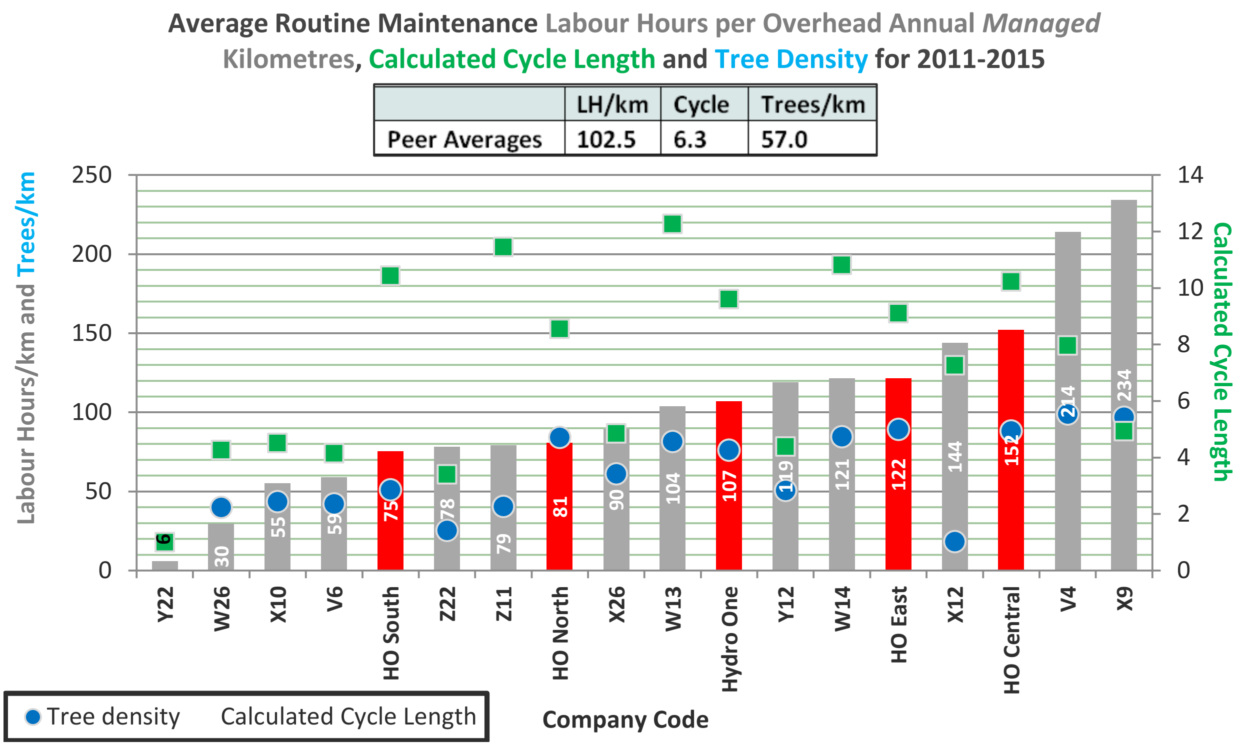


Figure 10: Routine Maintenance LH/Managed km, Cycle Length, and Tree Density

4.2.2.2 Tree Density and Managed Labour Hours

Figure 10, above is also a visual representation of the relationship between tree density and labour hours. In fact, there is a good correlation ($R= 0.66656$, $p < 0.005$) between tree density and labour hours for the peer group. As is expected, labour hrs/managed km increase as tree density increases. Hydro One's managed tree population has been enlarging for many years as a result of a long cycle length. Hydro One has had to work more efficiently to meet this rising demand. Hydro One's policy is to clear the ROW thoroughly in hopes of reducing outages, reactive work, and future workloads. When applied to circuits that have not been managed for many years (more than eight years), it is difficult to maintain efficiency. In order to sustain efficiency and reliability, in 2015 Hydro One modified the schedule to achieve shorter cycle lengths on M-Class feeders. At the same time, fewer kilometres of single phase and two-phase were worked. The change in labour hours per managed kilometre in 2015 can be seen in Figure 11 (below). This is evidence that shorter cycles will result in lower tree densities and less work and longer cycles will result in higher tree densities and more work.

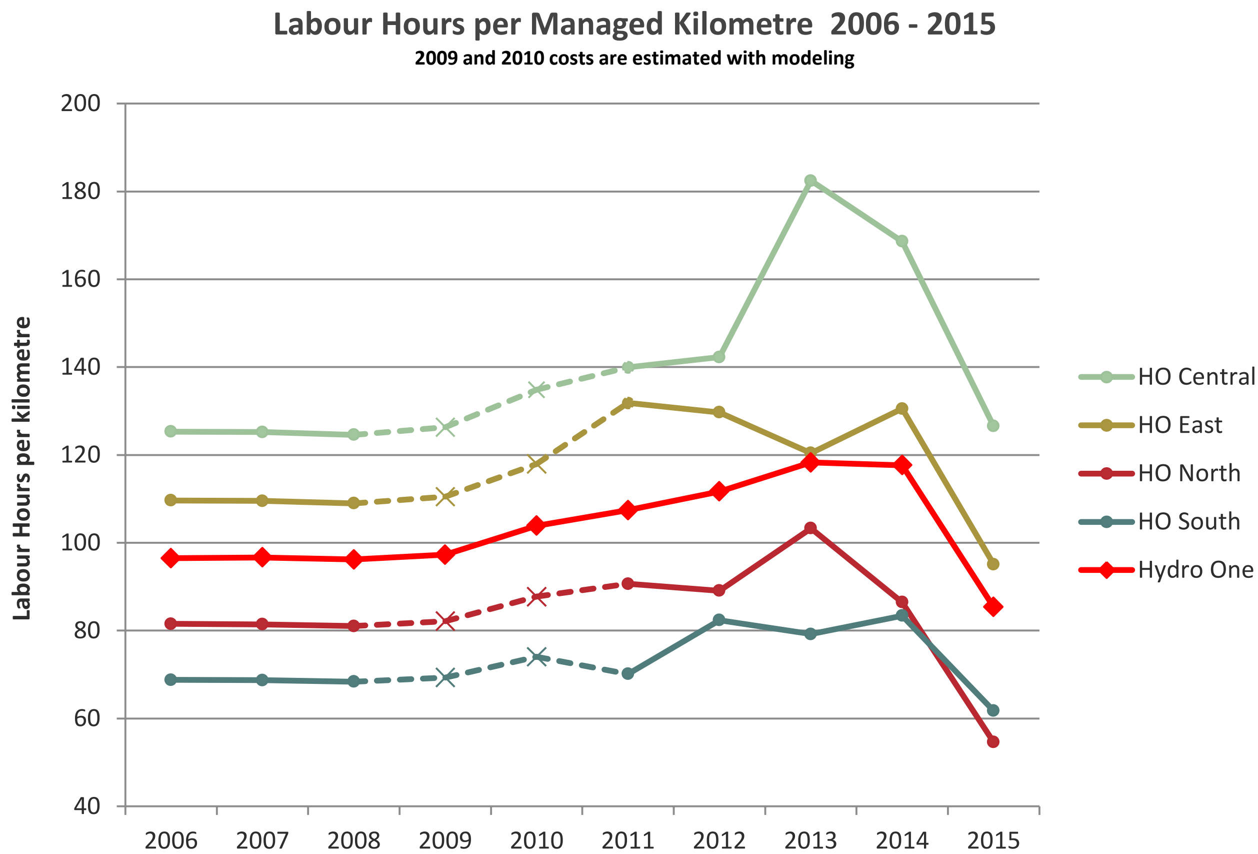
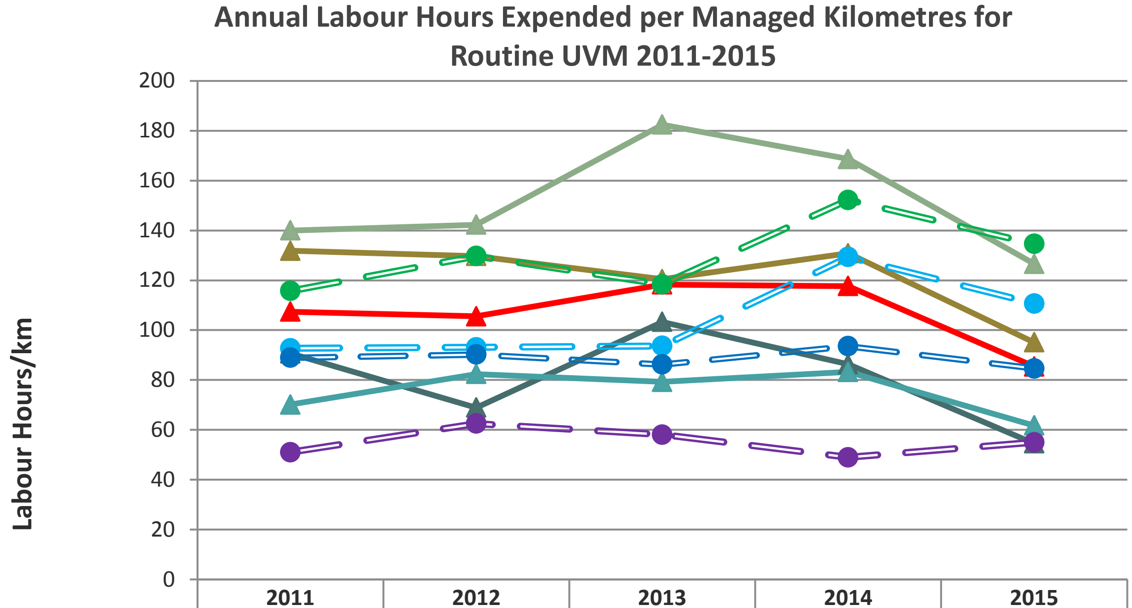


FIGURE 11: HYDRO ONE LABOUR HOURS PER MANAGED KILOMETRE 2006-2015

The following graph (Figure 12) is the same as the one above but it is limited to the labour hours per managed km of 2011-2015. The peer group average, median and 1st and 3rd quartiles are also represented. The peer average surpassed Hydro One in 2014 when both were at the highest number of labour hours per managed kilometre over the five years. It is easy to see in this graph that tree densities of the East and Central Regions are driving the annual labour hr/managed km output for the whole company. The North is managing a similar tree density with a much smaller labour output per km.

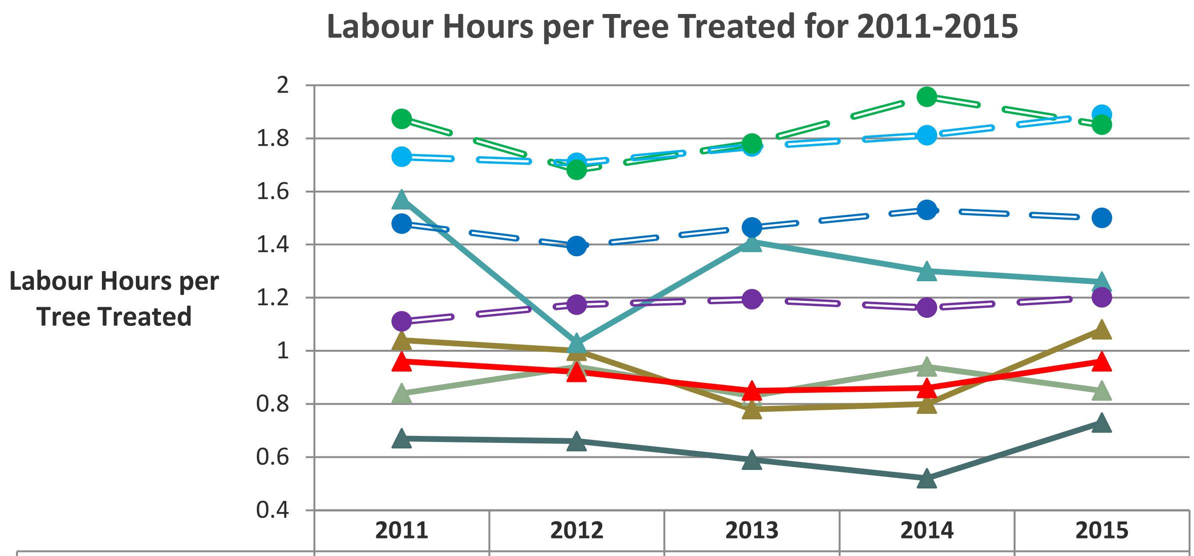


	2011	2012	2013	2014	2015
HO Central	139.96	142.26	182.41	168.63	126.56
HO East	131.83	129.68	120.43	130.79	95.09
Hydro One	107.42	105.52	118.30	117.67	85.40
HO North	90.66	68.91	103.29	86.30	54.60
HO South	70.14	82.38	79.23	83.26	61.74
Peer Average	92.7	93.1	93.7	129.3	110.7
Peer Q1	51.0	62.5	58.1	49.0	55.0
Peer Median	88.9	90.2	86.2	93.6	84.7
Peer Q3	115.8	129.7	118.3	152.2	134.6

Figure 12: Annual Labour Hours Expended per Managed Kilometres for Routine UVM 2011-2015

4.2.3 Labour Hours per Tree Treated

In contrast to the cost per tree treated, Hydro One's labour hours per tree treated are near the best-in-class (see Figure 13, below). In fact, the North Region is best-in-class all five years. If tree density was not so high, Hydro One could also be best-in-class at labour hours per kilometre. The South, which has the lowest labour hours per managed kilometre and per system kilometre of Hydro One's four regions, has the highest labour hours per tree. As previously mentioned, this is due to a longer growing season, a greater number of large trees, greater species diversity, and lower tree density. These conditions require moving personnel and equipment more frequently. The tree density in the North, Central and East Regions should be reduced to a level closer to the South Region, where possible.



	2011	2012	2013	2014	2015
Hydro One Central	0.84	0.94	0.83	0.94	0.85
Hydro One East	1.04	1	0.78	0.8	1.08
Hydro One	0.96	0.92	0.85	0.86	0.96
Hydro One North	0.67	0.66	0.59	0.52	0.73
Hydro One South	1.57	1.03	1.41	1.3	1.26
Peer Average	1.73	1.71	1.77	1.81	1.89
Peer Q1	1.11	1.17	1.19	1.16	1.20
Peer Median	1.48	1.39	1.46	1.53	1.50
Peer Q3	1.87	1.68	1.78	1.96	1.85

FIGURE 13: YEAR OVER YEAR LABOUR HOURS PER TREE TREATED FOR 2011-2015

4.2.4 TREE DENSITY IS A FUNCTION OF CYCLE LENGTH

In general, tree density is a natural phenomenon of the environment. For the purposes of UVM and this study, tree density is the average number of trees treated per kilometre each year. Consequently, tree density is not an independent variable. For example, although forested areas tend to have higher tree density than agricultural areas, tree density for UVM is still a function of management. Less management allows tree density to become a function of the environment. Consequently, companies with long UVM cycles (less management) tend to have higher tree densities (Figure 14 below). When Hydro One changed the UVM scheduling in 2015 and began focusing on M-Class, the tree density decreased because these lines have been managed more frequently. Hydro One's data shows that other non-M-Class backlogged circuits have greater tree density.

In Figure 14 the cluster of companies that have shorter cycles (left side of scatter plot) follow the correlation between tree density and cycle length more closely, because tree density increases with minor increases in cycle length. Companies with long cycle lengths correlate less well and the points are more scattered across both cycle length and tree density. The probable reason for this is that when the management cycle is long, environmental conditions begin to influence tree density more and changes in cycle length have a weaker relationship with changes in tree density. In other words, the shorter cycle UVM programs are lined up with a steep slope of tree density against the cycle length axis, whereas the long cycle companies are spread out and tree density is less oriented to the length of the cycle. Only one company in the long cycle group has less tree density than the short cycle group. Since Hydro One's cycle is already long, there is not as much change in tree density if the cycle is extended by another year or two. New trees, re-sprouted stumps, and increased growth from existing trees have already saturated the space.

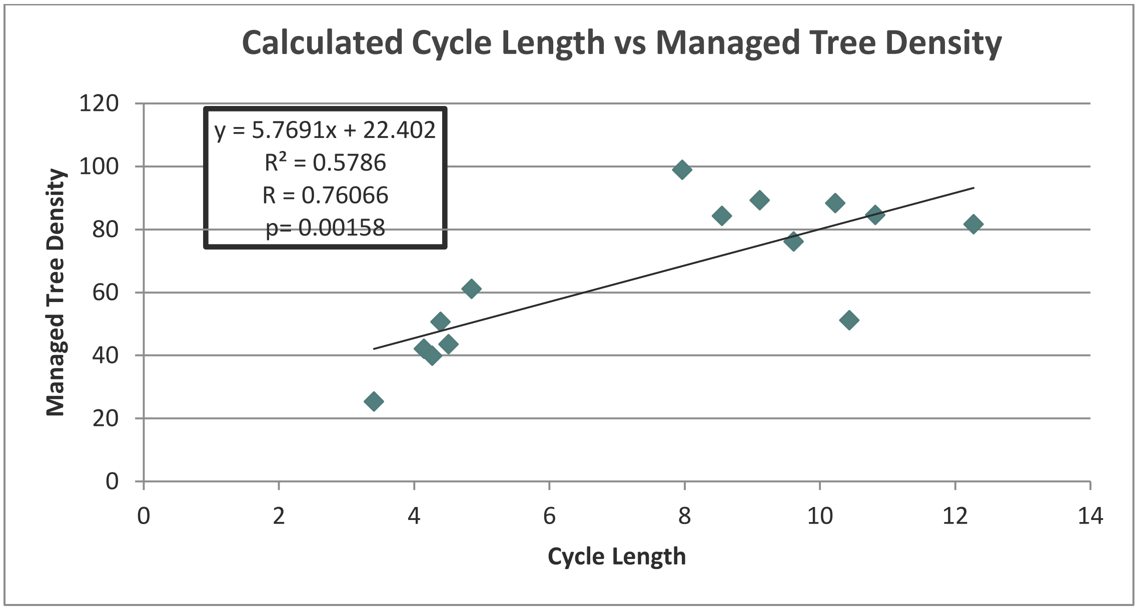


Figure 14: Tree Density is a Function of Cycle Length

The measuring and definition of tree density is also changing. Traditionally, tree density has been defined as the number of trees managed for UVM. Some companies have come to recognize that off-ROW trees cause many, if not the majority of reliability risks. A few companies have begun collecting data that expands the scope of their management to off-ROW risk trees. If this trend continues, the measurements of tree density will be higher than in the past for reasons other than long cycle lengths. Like Hydro One, the field of peer companies has not established a best management practice that balances cost, cycle length and tree density. This is evident in the wide range of tree densities matched to a wide range of cycle lengths and labour outputs.

4.2.5 *Tree Density Controls*

The conditions on parts of the Hydro One system at the time of maintenance are a considerable challenge to workers faced with multitudes of trees that are in contact or nearly contacting conductors and with trees that are overhanging conductors that must be roped down or pruned one small piece at a time. Tree workers are also faced with ROWs that are overgrown with dense invasive plant growth. Utility companies have a certain amount of control over tree density:

- If on-ROW trees are removed;
- If ROWs are treated with herbicides frequently enough to prevent ingrowth

- If off-ROW trees are removed where possible according to tree-risk assessment

Another term for controlling tree density is "controlling in-growth" and this control is natural for a maturing UVM program. Programs on long cycles such as Hydro One may *not* be controlling in-growth. Such programs are accumulating biomass in the ROW faster than it is managed. Several years can pass in this condition if there is not a programmatic effort to limit how many tree are encroaching conductors. This long cycle approach increases safety and reliability risks, but by applying selective tree work and having a well trained workforce as well as making other technical improvements to the distribution system, reliability metrics can improve in spite of increasing in-growth, at least in the short-term (See Appendix B).

The path to a shorter cycle is blocked by high costs to reclaim ROWs and the added cost in subsequent years of reworking ROWs with herbicides to get a stable plant conversion established. Figure 11 (p. 27) shows the increased effort to reclaim ROWs, particularly in the Central Region, where labour hours per km went from 124 in 2008 to 140 in 2011 to 182 in 2013. The effort to reclaim ROWs will result in vigorous regrowth without a follow-up herbicide program.

4.2.6 *Regional Costs Indicate Varied Forestry Conditions and Management Challenges*

The following are a few facts that illustrate the varied conditions in the Hydro One regions for the years 2011-2015:

- The Central, East and North Regions have similar tree densities, which are approximately 1.7 times greater than the South
- The South has nearly one-third of Hydro One's line kilometres
- The cost per tree treated in the South is 30% higher than in the Central Region
- The need to improve forestry conditions is the greatest in Central Region, followed by the East
- The Central Region's reliability performance is the worst of the four regions, having the highest number of outages/km
- North is removing over 70% of the trees managed

The above facts indicate Hydro One UVM program needs varied approaches in order to reduce and control the workload. For example, the South needs to devise strategies to reduce cost per tree treated. This could be accomplished with specialized equipment, pruning practices, scheduling and routing. The East and the Central need to decrease the tree density. This might be accomplished by educating customers, tree risk assessment to identify higher risk trees, and similar tactics recommended for the South could be used. The North, and where applicable in the other three regions, could reduce tree density by applying herbicides on a shorter cycle than the line-clearing cycle. Each region needs a customized approach to reducing the workload.

4.2.7 *Integrated Vegetation Management (IVM)*

Integration Vegetation Management or IVM's ". . . ultimate goal is to maintain a desirable plant community with available tools, emphasizing biological and ecological control (Miller, 2014)." Using IVM to make planning decisions, Hydro One should endeavor to convert ROWs to more appropriate plant communities. Initially, it is recommended treat a higher percent of distribution kilometres with industry-approved herbicides or other land management applications that effectively reduce or eliminate mechanical-cutting. Treating 50 – 75% of ROWs is recommended, although this amount may vary depending on property owner acceptance.

IVM is considered the most universal of Best Management Practices by system foresters, vegetation managers, academic research, the Environmental Protection Agency, and many other environmental groups. It has been championed by the *ROW Stewardship Accreditation Program* and is the chosen methodology of many in the arboricultural, forestry, and landscape industries. It is also known as integrated pest management (IPM). IVM advocates a rational approach to managing vegetation that is environmentally beneficial, cost-effective and meets the approval of various stakeholders, such as property owners, regulators and other involved parties. A key component in current IVM methodology is the use of approved herbicides to control inappropriate plant species early, before more invasive and expensive manual and mechanical methods are necessary. This means the vegetation must be treated when it is small brush and before it reaches the smallest class size of tree. This is not possible when the cycle of management is too long. IVM also encourages conversion of the ROW to appropriate low growing plant communities. IVM is a best management practice for achieving safety, reliability and customer satisfaction objectives of UVM while reducing the workload and environmental impacts. In general, IVM prevents substantial in-growth in a cyclical management program.

One of the primary tools advocated in IVM is the use of herbicides to prevent ingrowth. Table 2 (below) provides the percent of distribution kilometres that are treated with herbicides by utility companies. IVM is one of the most effective tools for managing vegetation, but it is the most inconsistently applied tool. In a six-year study, EPRI determined herbicide control could reduce stem counts of trees in the ROW by 70% compared to manual cutting methods which increased stem counts and mowing which didn't significantly reduce stem counts. (EPRI 2000)

Peer Group Herbicide Use					
Sample: 21	**GENERAL (Foliar, Basal)**	**STUMP**		**GENERAL**	**STUMP**
Hydro One	**14%**	**7%**	**Q3**	75%	98%
Average	35%	66%	**Max**	100%	99%
Q1	9%	21%	**Min**	0%	0%
Median	20%	93%			

TABLE 2: HERBICIDE USE

The Ontario Pesticide Act is designed to provide safety to the applicator, the public and the environment. However, it is used as a constraint by many who do not understand its benefits and who are more comfortable with traditional mechanical controls or favor the absence of control. Consequently, Hydro One compares poorly with many of the peer group in the percent of distribution system managed with herbicides through IVM. Only about 14% of the Hydro One system is managed with general herbicide methods such as foliar or basal treatments. Only 7% of stumps are treated. A more widespread use of herbicides would be necessary for Hydro One to reduce the cost, equipment, and human resources currently required to provide management of distribution ROWs. Once a succession of appropriate stable plant communities is allowed to populate ROWs, the volume of needed herbicide applications would decrease. This is the ultimate goal of IVM- stable plant communities in the ROW that suppress ingrowth of incompatible tree species. Estimates for an IVM cost benefit ratio over traditional manual and mechanical treated ROW are 3:1 or better (Finley Engineering 2010).

Hydro One's best effort to utilize herbicides is in the North Region, where 22% of the managed kilometres are treated with herbicide. Although this is a higher percent than the other Hydro One regions, it is not nearly enough to be cost-effective. If a decade passes before the ROWs are treated again, they will need to be fully cleared before herbicides can be reapplied, which is not cost-effective. The Central Region is the furthest from ROW conversion to appropriate and stable plant communities. Only 6% of Central ROW kilometres are treated with herbicides. For much of Hydro One, applying herbicides is not cost-effective because the interval between applications is so long that the ROW must be re-cleared. Hydro One currently is increasing their use of herbicides.

4.3 Work Planning, Customer Notification and Scheduling

4.3.1 *Work Planning and Cycle Length*

The following (Figure 14) is a representation of the consequence of not being on cycle as cited by survey respondents. Overwhelmingly, UVM managers believe that getting behind in the maintenance schedule has negative effects on cost, reliability, and safety.

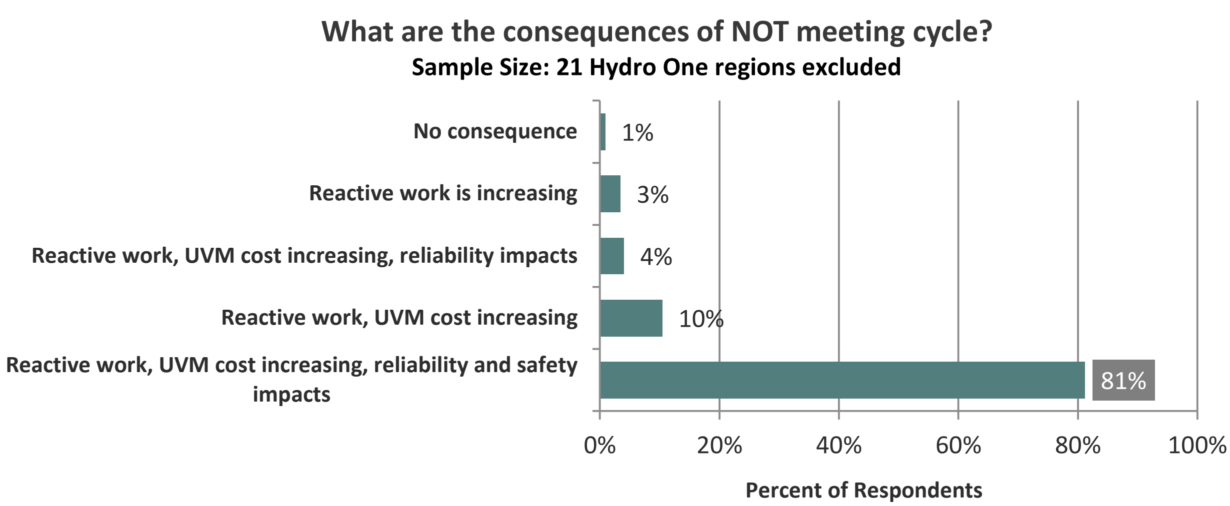


Figure 15: Consequences of NOT Meeting UVM Cycle Targets

The following are recommended practices for work planning at Hydro One. Included are some features that would enhance Hydro One's cyclical management of distribution corridors:

- **Cyclical survey of vegetation:** Document beneficial and unwanted vegetation conditions on the ROW. Hydro One only documents offending vegetation. 17% of system is inspected each year by non-vegetation management personnel trained to recognize the most obvious vegetation issues. Approximately 12% of the system is inspected by a qualified vegetation management pre-inspection planner. The 17% may overlap with the 12%. These inspection programs could be strategically synchronized to better capture tree risk that is out of reach of the routine program and to audit the success of the program. Improve, consolidate, and synchronize the current required asset inspections and the UVM work-planning inspections to add value and economies of scale to the planning program. Workload documentation should be more thorough at the circuit level to improve cost-planning, productivity, and quality management.
- **Cyclical survey of specific tree hazards off-ROW (Tree Risk Assessment) followed by prescribed work:** Hydro One has a formal Tree Risk Assessment Program that is a part of the pre-inspection program. The funding for this program is a small percent of the routine maintenance. It could be a more integral part of the UVM program if the responsibility was more clearly defined regarding trees off-ROW.
- **Management interval that is flexible based on actual conditions in the field and regular enough to prevent vegetation encroachment:** The M-Class and three-phase feeders are on a target for 4-8 years. The rest of the system should be managed similarly (See Table 3, below).
- **Establish performance metrics for maintaining air space around conductors**. Employ innovative data collection and leading performance indicators, such as safe ROW environment metrics, safe work place metrics, tree-risk assessment data, advanced outage investigation documentation, and other program features. These metrics will enhance and build greater safety awareness and education for anyone who enters and performs activities in a ROW zone for any reason.
- **Quality-driven IVM program that ensures ROWs are populated with beneficial plants and kept clear of inappropriate vegetation with a minimum of cutting, chemical application and soil disturbance:** Hydro One cannot cost-effectively apply herbicides until the cycle of UVM including herbicide applications is a shorter interval. The six-year cycle for M-Class and three-phase are sufficiently short if the herbicide applications are timed properly (Table 3).
- **Involvement of significant stakeholders, such as electric customers, regulators, governing jurisdictions, property owners, land agencies, media and the public:** Under equitable conditions the burden of liability risk would not be 100% on the utility company as they do not own the trees. Some stakeholder actions, such as property owners who are opposed to vegetation management, constrain the utility from performing UVM at standard industry levels. The pre-planners and utility foresters should be trained in customer communications and regulatory matters in order to build a future where carefully crafted incentives shift some of the financial and legal responsibility for trees away from the utility and toward property owners and local jurisdictions.

- **Database documentation of activities and favorable outcomes:** Hydro One has electronic data capture. Data transfers from paper to electronic and across various electronic formats should be streamlined so there is a seamless automation.
- **Use of innovation and technology to enhance effectiveness and efficiency of UVM program to achieve stated measureable objectives for reliability, safety, customer satisfaction and environmental quality:** Hydro One has a continuing commitment to innovation. More emphasis should be placed on R&D.

Variable Cycle Statistics [Peers plus Hydro One Networks]								
Cycle Type	General Target	General Actual	Urban & Suburban Target	Urban & Suburban Actual	Rural Target	Rural Actual	Remote Target	Remote Actual
Sample	25	25	11	11	11	11	8	8
Average	4.6	5.3	3.6	4.5	5.0	6.4	4.9	6.6
Q1	4.0	4.0	3.0	4.0	4.0	5.5	4.0	6.0
Median	4.0	5.0	4.0	4.0	4.0	6.0	4.5	6.5
Q3	5.0	6.0	4.0	4.5	6.0	7.0	6.0	7.3
Max	8.0	10.0	6.0	9.5	10.0	11.5	8.0	9.5
Min	1.0	1.0	1.0	2.0	1.0	3.0	2.0	3.0
STDEV	1.7	2.0	1.4	2.0	2.5	2.5	1.8	1.9

Table 3: Variable UVM Cycle Statistics

In Table 3 (above), target cycles and actual cycles are listed for demographic divisions. Descriptive statistics of the responses are given, including standard deviation from the norm. This table illustrates how the majority of the distribution UVM industry operates behind schedule, and has for many decades. The yellow highlighted numbers are recommended cycle lengths for Hydro One based on what is realistic for the average company and given the fact that a majority of Hydro One' system is rural or remote and that the North, Central and East Regions have harsher climates than most of the peers in this study. The variation in cycle lengths could be applied to the different regions or as needed to reduce risk. Similar cycle lengths have been cited by personnel at Hydro One during interviews about ideal cycle lengths.

Can a company, that is on schedule, has a proactive reliability program to reduce the risk of tree failures, and has a history of top-tier reliability, be spending less than Hydro One on a per km basis? A simple comparison of cost per system km shows the difference. One company (Y8) that is at the minimum cycle length (one-year inspection cycle and a three-to-four-year maintenance cycle) spends $900/system km for routine maintenance while Hydro One Central spends $1,538 per system km and is on a 9.5-year cycle (Figure 1, p.17). In other words, it is costing the Central Region almost twice as much to manage a km of line one time as it costs Y8[2] to manage a km of line three times. Even for the complete Hydro One system it cost more to manage it once than it does for Y8 to manage its system 3-4 times. Y8 inspects

[2] Y8 did not supply their labour hours which would have provided a more normalized comparison

their entire system once every year and only manages what is necessary. Hydro One Central may be clearing the full width of the ROW, but since the interval of maintenance is so long the workload stays the same. With a more frequent management, the workload (cost) could be reduced because vegetation is managed at a smaller stage of growth. This is not to say a three to four-year interval would be cost-effective for Hydro One, but it does establish that a more frequent interval could be more efficient. Inspecting the system more frequently than it is maintained also ensures a quality of management and increases the ability to discover hazardous trees.

4.3.2 *WORK PLANNING AUTOMATION*

Survey participants were asked to name three technologies they have introduced into their program. The most frequently mentioned technology was software for planning, work management, and mapping. This technology adoption is not immediate or without challenges. Planning UVM work is less standardized than line clearance maintenance work, so software automation projects are unique and emergent. Only about 27% of companies have comprehensive work planning over 100% of their distribution system. Another 15% are formally planning at least 50% of the system. 36% of companies are conducting less formal summary planning over their entire system. The variations in data collection present challenges to adding value with electronic systems.

Hydro One conducts comprehensive work planning over 100% of their distribution system. There are 48 notifiers and five work planners. Although every tree is not documented and evaluated for treatment, tree-counts are estimated through samples and all customers are notified. Herbicide treatments require a signed permit. Although Hydro One has introduced custom software to the UVM program, there are still many challenges to effectively improving the efficiency of the program with data.

Hydro One administers the UVM program using several formats. Most of Hydro One’s UVM administrative activities are done partly on paper, with the exception of the workload inventory database. Mapping is electronic but crews do not have access to it. Many activities are done in multiple formats such as paper, Microsoft office products, and various types of in-house or vendor software. Activities such as crew dispatch or work plans are done purely on paper. Time sheets are done on paper and in-house enterprise software. Production is on paper, on excel, and on in-house custom software. Invoices are on paper and electronic.

UVM administration and documentation activities performed in multiple formats are likely to have extra layers of data input and opportunities for error. Much of modern life is conducted electronically and increasingly outmoded paper formats are reviewed and verified less than in the past, making them more dysfunctional than when they were the primary transaction format. Paper today presents fewer opportunities to create summaries, because most calculations are currently performed in databases. Therefore, paper information has to be input to the database before calculations can be made. A best management practice (BMP) is to fully automate administration and documentation of the UVM program with the least amount of data input repetition and maximum integration within the UVM department and across other departments and stakeholders.

The following are work planning automation statistics with 33 companies providing data:

- 42% of companies reported that they use more than one format to collect work planning data.
- 55% use one format
- 18% use paper *only*
- 54% use paper
- 36% use paper with another format such as excel or a proprietary software
- 21% use excel, word or pdf only
- 9% use in-house software only
- <1% use vendor software only

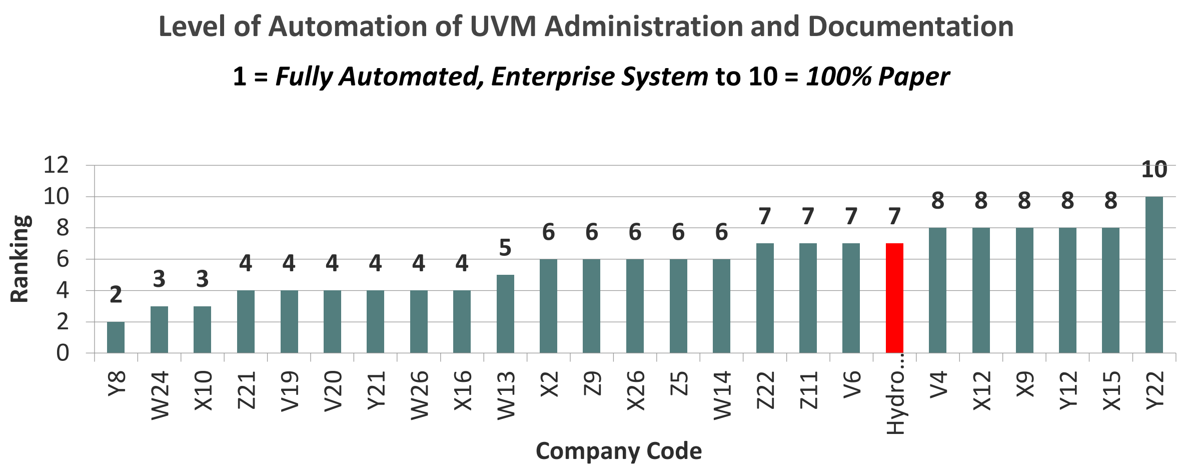


Figure 16: Level of Automation of UVM Administration and Documentation

A rough scoring was devised to compare Hydro One with other utilities based on how well each company has adopted electronic processes and how far they have progressed through transitions that require multiple formats. Figure 16 (above) shows the scores for each company. A fully automated and integrated UVM system would receive a score of one and a system that still performs all administrative and documentation activities on paper received a score of ten. No company received a one and only one company was scored at ten. The majority of companies is attempting to transition away from paper and has been since the last time a similar survey question was posed in 2009. The progress can be seen in how much paper has been transitioning to electronic processes, but it is more difficult to see how efficient the various electronic systems are performing, particularly in transition with multiple formats in use. Full transition to the field crew level is likely to take a few more years for many companies.

Automation should continue to be pursued and improved on all fronts. For example, the following work management activities would benefit from automation:

- Electronically documented measurements and assessments of ROW conditions
- Professional prescriptions
- Electronic work order transmission to crews
- Crew electronic time keeper submitted back with verification that work plan was completed with any modifications
- Documentation of production

- Records automatically generated for audits, payroll, invoicing, data analysis, and financial planning.
- Monthly and quarterly reports tracking progress and exceptions to plans
- Statistical process control calculator to determine weekly production that is two and three standard deviations above norm with investigative follow-up and corrective action when appropriate
- Data collected from the above activities can be used to develop predictive models

The use of remote sensing such as LiDAR to quantify and accurately measure vegetation conditions will improve Hydro One's ability to model appropriate, economical, safe, environmentally beneficial, climate-change aware UVM programs that help deliver optimum electric reliability.

4.3.3 *Customers and UVM*

Hydro One reported their "Customers are becoming more aware of their trees and more environmentally conscious, while not very aware of the hazards of powerlines and trees." The path to a rational and sustainable distribution ROW management begins with customers, who need to take some responsibility for their vegetation encroachments and their vegetation-caused damages to the infrastructures they depend on. This is no easy task since the ROW crosses over or is at the edge of customer property. If the utility is willing to manage the problem, then the customer should be willing to accept cost-effective management or plan to pay for management that is customized for their purposes. A rule such as this exists in Illinois where communities that require costlier UVM practices than what the utility prescribes have to pay the difference. Is reliability and the customer a *Catch-22* or an opportunity to know your customer? Most companies don't know much about their customers and rely on field workers to be good representatives for the company. Data on the customer is not impactful to decision making and policy. An improved UVM program would do a better job of understanding and educating the customer.

4.3.4 *Company Customer Service*

Hydro One is more customer service oriented compared to the peer and non-peer group. Hydro One personnel:

- negotiate with customers on work specifications
- negotiate with customers who refuse work
- get permission to remove trees
- notify every customer of impending work
- respond to focus groups
- get permission access property
- get permission to apply herbicides
- respond to complaints
- call property owners who don't live on the property

Hydro One does most of these customer service activities using multiple resources, including notifiers and other supervisory personnel. Although many companies provide these services, not as many do it at multiple levels and often the core of customer communication is conducted by the same people who are cutting the trees.

4.3.5 *How well are UVM departments connected to the utility customer service equation?*

The key to knowing the customer from a planning perspective is dependent on the data collected and how that data is leveraged in future customer services. 58% of companies, including Hydro One, keep a record on customers who respond to notifications. 92% of companies said they think there is 'a disconnect' between industry standards and what customers/property owners and local agencies require when UVM is performed on their properties. Hydro One has a customer refusal tab in their Tech notification software (*Forestry Application Production*), where information about customer refusals is captured. Figure 17 (below) illustrates the lack of knowledge about customers that may be at the root of why there is a disconnect between customers and the industry standards. Only 5% of companies store vegetation data on the customer service system (CSS) and less than half of UVM departments and/or UVM planners/notifiers can access the CSS database. As one survey respondent commented, one of the most important factors for UVM efficiency is customer relations.

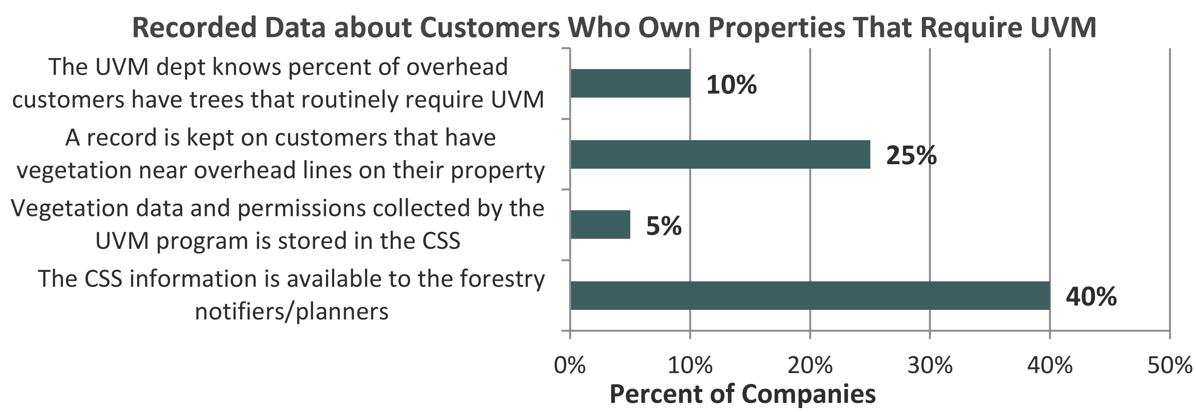


Figure 17: Knowledge about Customers Who Own Property Where UVM Is Required

4.4 Equipment and Personnel

4.4.1 *Equipment*

Hydro One named three items that are key to the efficiency of their UVM program:

- Logistics
- Labour Rates
- Mechanization

Two of these: logistics and mechanization, involve equipment. One is for transportation and the other is equipment for performing work. Under logistics a subcategory of utilization could be included that maximizes the efficiency related to having the right equipment and people in the right place at the right time. Hydro One expects each local area to develop strategies based on local geographical knowledge. Beyond the prioritization of circuits, there isn't a company-wide approach for scheduling crews or pooling resources. Hydro One is developing GIS telematics to monitor crew locations, manage fleet maintenance and enhance emergency response. This technology could be used to improve routing of crews to minimize drive times and fuel consumption. This is an area of technology R&D that should be coordinated centrally to ensure high level planning prioritization feeds into routing optimization and to ensure storm response is enabled to decrease the current high number of MED SAIDI minutes.

To economize fuel and travel time, crews meet at temporary work headquarters that are remote from the local operations centres. Training is conducted on inclement days and in the winter to ensure blue sky days are utilized. Hazard trees are managed at the same time that routine work is performed to eliminate duplicate trips. Hydro One spends on average 6.4% (of routine + reactive work) on travel intensive reactive work to correct emergency system problems. This is lower than the peer average of 8.8% reactive expenditures. 40% of customer calls are resolved without a crew site visit. The UVM department only receives 15,000 calls per year out of the 2M customer calls made annually to the Hydro One call center. If this ratio were to increase, the productive utilization of labour and equipment would decrease. Customer satisfaction is important to the level of efficiency for a UVM program.

Hydro One made the following statement in the 2013 rate proceeding: "Equipment utilization averages have increased from approximately 65 percent in 2001 to approximately 80 percent in 2012. The 2012 average equipment rate is $21.38 per hour; this is established by averaging total annual fleet equipment costs over total annual fleet utilization hours." (EB-2013-0416 Exhib. C1 Tab 4, 2013) Hydro One reported in the benchmark survey that on average equipment is utilized 63% of the time. On average 60% of Hydro One employees are stood-off for at least three months of the year, which idles equipment. The savings in lost productivity due to weather extremes and short days and the winter wear on equipment may offset some of the utilization losses. Hydro One depreciates equipment at standard rates, which are based on year around utilization and this may prolong the time it takes to fully depreciate equipment. The excess pool enables equipment to be replaced when taken out of service for repairs and it enables quicker deployment to locations where the equipment is needed. The forestry department meets with the fleet department to decide the future equipment needs and which pieces to sell and replace. *This process could be incentivized to maximize utilization and optimize the life-cycle of useful equipment, while replenishing and rightsizing the fleet for maximum productivity, safety and environmental quality.*

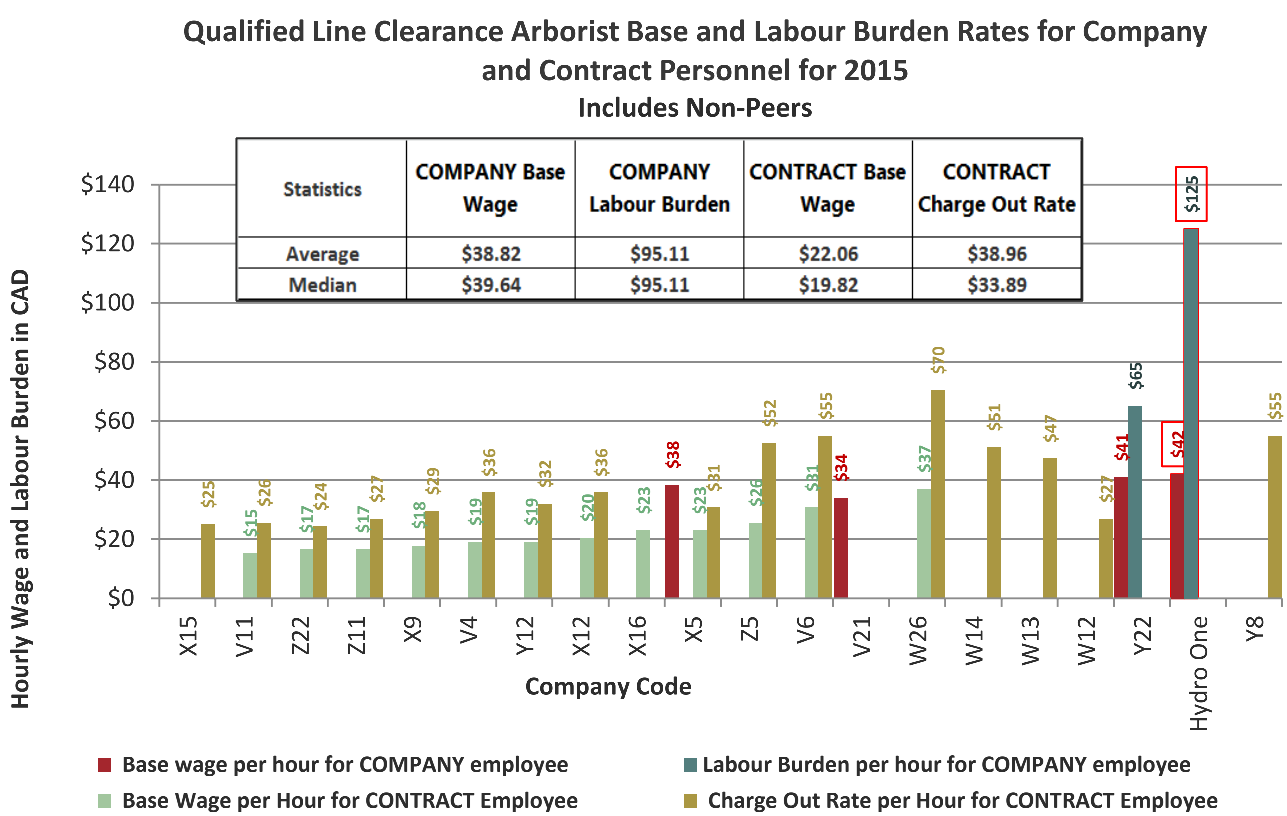
The peer and non-peer groups did not report equipment utilization percent except for one company that reported 95%. Most companies (83%) said they rely on their contractor to have serviceable equipment. 22% of 36 companies reported they require contractor equipment to be not older than five years on average. 66% of companies said their contractors' trucks are tracked with GPS locators (Telematics). 36% of companies said crews are allowed to add workers whose equipment is being repaired.

Although an argument can be made for lack of utilization of equipment throughout some periods of the year, having a consistent and adequate budget to accomplish clearly established objectives is a more effective way to ensure a fleet is optimized and rightsized than simply penalizing a department for underutilizing equipment purchased when funds were more available. The increases in cost of equipment accounted for only a small percent of the increase in expenditures for UVM over the 5 years. Mechanization and new technology is necessary for forestry services as its importance grows.

Improvements can be made by focusing more resources in the North during the warmer months of the year and shifting resources to the South Region during the coldest months of the year. Productivity could be improved and labor costs reduced by increasing the deployment of crews when working conditions are optimal and discontinuing deployments during the harshest weeks/months of the year. Forestry staff deployment strategies and technology should also be tailored and coordinated to improve preparedness and restoration response to reduce outage durations.

Customers are becoming more aware of the value of their trees. Provided the right messages they will become more aware of the efforts and effective forestry practices required to have power system corridors crossing through many forests.

4.4.2 *Personnel*



Statistics	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$38.82	$95.11	$22.06	$38.96
Median	$39.64	$95.11	$19.82	$33.89

Figure 18: Line Clearance Arborists Base Wages and Labour Burden Comparison

The primary driver for the cost of UVM at Hydro One is the cost of labour. The base wages for Hydro One are in the fourth quartile (Figure 18 above) and they are about 1.9 times higher than the average of the peer group contract labour. The $125 charge-out rate for a Hydro One crew leader or qualified line clearance arborist combined with $67 for an apprentice is also about 1.9 times higher than the cost of a two-person aerial lift contract crew including typical line clearance equipment.

There are large differences between labour burden rates for in-house arborists, Hiring Hall line-clearance workers and contractors (Figure 18, above). Changes in the labour mix could improve productivity and control costs. These improvements can be made by utilizing a higher percent of Hiring Hall and contract workers to perform lower safety and lower liability risk activities such as work planning, herbicide applications, and brush-clearing. To maintain current level of lower safety risk, the more experienced and highly-trained in-house arborists who perform line-clearing activities should not be replaced with less experienced and less trained workers common to contractors and the Hiring Hall.

The turnover rate at Hydro One is at 5% compared to 32% for the peers. The table below shows the result of low turnover rates. For example, on average, Hydro arborists have 20 years of experience compared to 6.5 years for peer group companies that contract out line clearance activities (See Highlighted cells in Table 4, below). Since these are averages per company, it is evident some peer group contractors employ more people with minimal experience.

Number of Years Line Clearance Employees Have Been Working at the Utility					
Average, Max, and Min Exclude Hydro One		Peer Average	Hydro One	Peer Max	Peer
Supervisor	Company	13	25	24	5
	Contract	11.7		25	5
General Foreman	Company	5	15		
	Contract	10		18	5
Crew Leader	Company	5	20		
	Contract	8.7		20	3
Arborist	Company	8.75	20	15	5
	Contract	6.5		15	4
Arborist Trainee	Company	1.75	4	3	1
	Contract	3.1		7	1
Other Field Personnel	Company	3	15		
	Contract	5.5		15	1

TABLE 4: EMPLOYEE TENURE COMPARISONS

4.5 RELIABILITY PERFORMANCE

As a measure of performance, reliability metrics have been developed to help utilities prioritize work to provide optimum improvements to the expansive and aging overhead electrical grids that matured many decades ago and are now in various stages of renewal, rebuild and replacement. The metrics commonly known as the IEEE 1366 methodology have provided a way to triage complex systems that are vulnerable to dozens of minor and major interrupting events each year. It is not uncommon for large utilities to experience in excess of 10,000 outages every year, but most utilities have reduced the frequency that feeder lines fail and they have reduced the number of affected customers by inserting loops and breaks to isolate interruptions down to the fewest possible number of customers. Much of this effort has been the answer to storm events that are increasing in frequency and intensity. However, these efforts, while mitigating impacts, do not reduce the vegetation management workload. If anything they have allowed utilities to postpone UVM and to reallocate funds to other efforts that are more successful at improving the reliability metrics. Appendix B offers more details about the impact of IEEE 1366 reliability metrics on UVM programs.

A majority, 54%, of companies, are using SAIFI (System Average Interruption Frequency Index) as a measure of performance in their UVM programs. Other indexes are used to a lesser extent. Recently, over the past decade, regulators started requiring utilities to report reliability metrics as a way to measure the performance of regulated utilities. 83% of utilities in the CNUC survey are reporting SAIFI to their regulator. Of particular interest to UVM are the separation of customer interruptions into Major Event Days (MED) and Non-MED. The threshold for MED is T_{MED} which is calculated with the Beta Method equation which involves the average of MED over a five-year period. Not all companies use this method, including Hydro One, who uses 10% of customers interrupted as the threshold for a MED. The following variables have a negative influence on reliability metrics and(Pacific Economics Group 2010) are all very common to Hydro One:

- **Weather**— South, East and Central regions are in path of common storm tracks in all seasons
- **Vegetation density**— 76 trees per km, which is above the peer average, nearly highest number of trees per customer (6 trees/customer)
- **Low percent of underground**—94% overhead
- **Low customer density**—lowest in peer group
- **Difficult terrain** –20-30% off road and 55% of off road is difficult to access
- **Industrial and Commercial Customer Influence** – Lowest percent of commercial and industrial customers in peer-group. Larger commercial and industrial commercial customers will pay a premium for better reliability and thus improve reliability of the system
- **Age of network**—high percent is beyond replacement age

This section provides comparisons of reliability metrics with peer groups, but any reliance on these comparisons should bear in mind the disadvantage that Hydro One has in regards to reliability metrics and that reliability metrics are a lagging indicator for performance in vegetation management, which is less cost effective to address after trees have encroached conductors and are causing more outages.

4.5.1 Tree-Related Outages per System Kilometre

The following graph, Figure 19, below, shows a less common reliability measurement that is more appropriate to UVM, although it is still a lagging indicator: outages per kilometre.

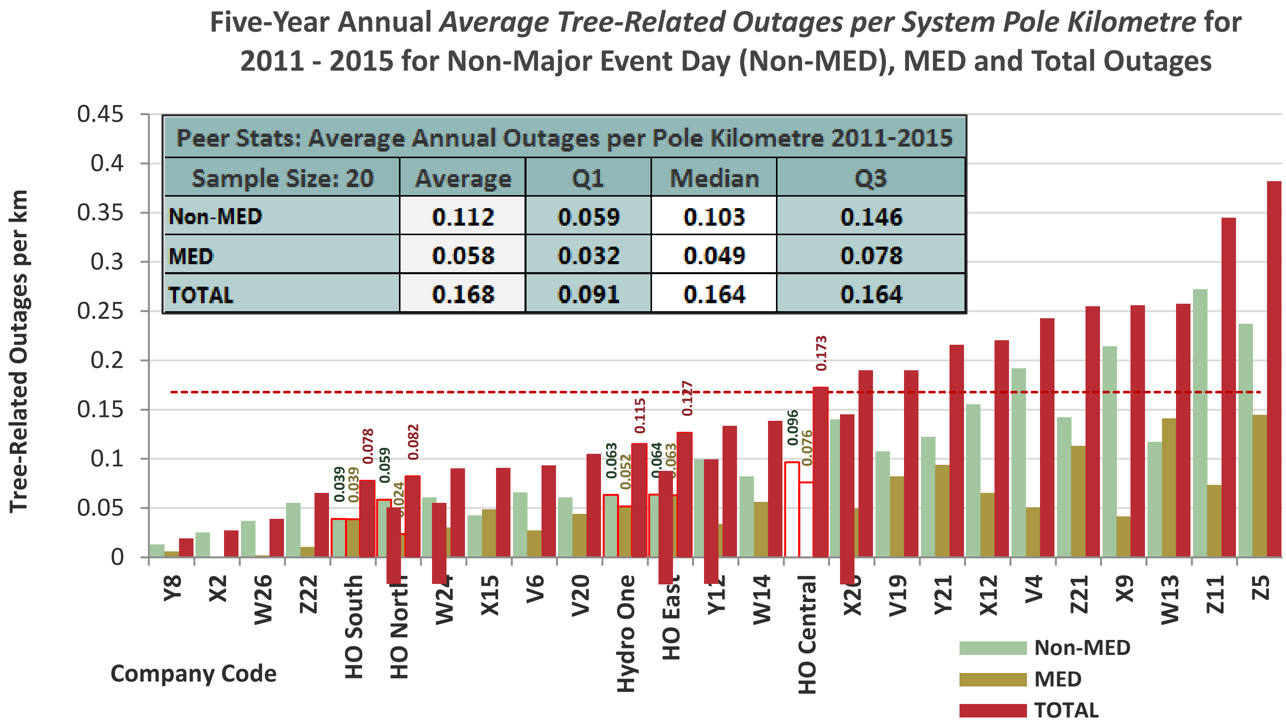


FIGURE 19: TREE-RELATED OUTAGES PER SYSTEM KILOMETRE

This measurement indicates Hydro One is doing a better than average job of reducing the risk of trees causing outages across the Hydro One System. This Figure is analyzed and discussed further in Appendix E.

4.5.2 *IEEE RELIABILITY METRICS FOR TREE-RELATED OUTAGES*

The measurements for tree-related SAIDI (Figure 20 and Figure 21) and SAIFI are not as reassuring. Hydro One is in the fourth quartile in both non-MED SAIFI and SAIDI. Hydro One has improved from 2.9 hours (174 minutes) in 2003 to 2.3 hours (138 minutes) in 2015 for Non-Major Event Day (Non-MED) tree-related System Average Interruption Duration Index (SAIDI). This improvement has remained relatively steady since 2008 with a 2009-2015 average of 2.1 hours (126 minutes). In spite of improvements Hydro One still compares unfavorably with peers in the area of standard reliability metrics. Hydro One's 126 minute SAIDI average is more than twice as high as the peer average of 50 minutes for 2011 -2015.

Hydro One is currently scheduling UVM work to improve tree-related SAIDI and SAIFI. However, the prioritization of workload to accomplish reliability metrics improvement will not necessarily improve total UVM performance. See Appendix B for in-depth analysis of relationships between reliability metrics and UVM.

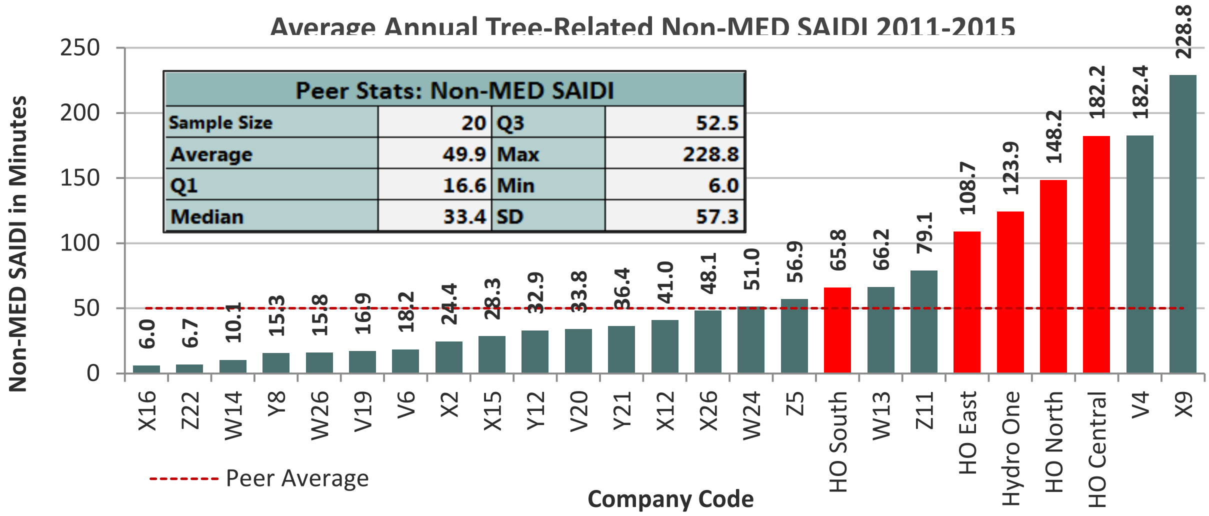


FIGURE 20: TREE-RELATED NON-MED SAIDI

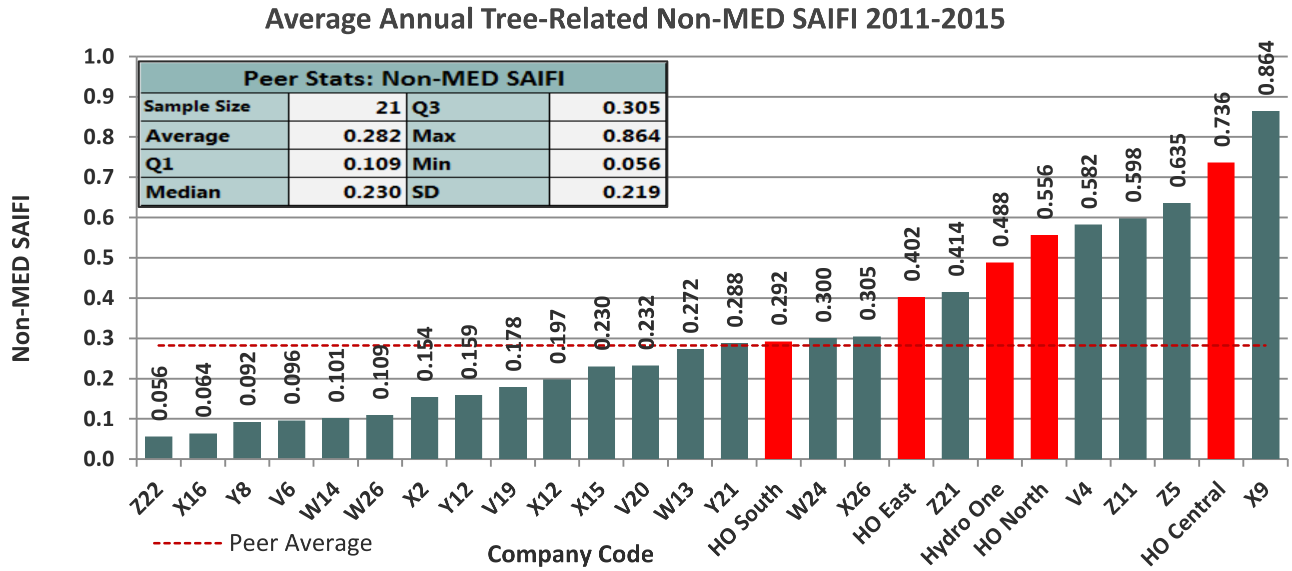


FIGURE 21: TREE-RELATED NON-MED SAIFI

There are other metrics that can be used as indicators of the reliability performance of a UVM program. For example, utility companies were asked whether they record what percent of trees are in contact. Few companies could produce this data. Trees in contact and trees overhanging conductors are condition-based metrics. Most companies estimate these measurements, but a few utilities record locations where trees are in contact or overhanging the conductors to better understand their workload and to measure the performance of the cyclical clearing work. This data also provides information about the growth characteristics associated with species, time of year pruning, local site differences and eco-regions, failure modes etc. Tree condition data can be correlated with reliability data to better understand proximity influences on reliability, particularly during ice and wind events. Lidar has been introduced most recently to provide tree condition data on distribution systems. Unmanned Aircraft Systems (UAS) hold promise for collecting Lidar data on distribution networks which have many times more kilometres than linear transmission, where Lidar measurement data has been collected with helicopters for nearly a decade.

The following graph (Figure 22) shows how important it is to recognize that vegetation management could be the leading edge in any program that seeks to reduce the reliability risk during storms. This is especially dramatic when comparing with the percent of Non-MED outages that are tree-related -- a dramatically lower percent of total outages (Figure 23 below). These are five-year averages and clearly the Central Region has a significant influence on both metrics. The effect of each region can be seen in the next section with longitudinal measurements (Section 4.4.3). The most striking finding in this is how vegetation becomes so much more relevant to reliability when there is a major event day. It suggests that better strategies should be developed for UVM resiliency against storms.

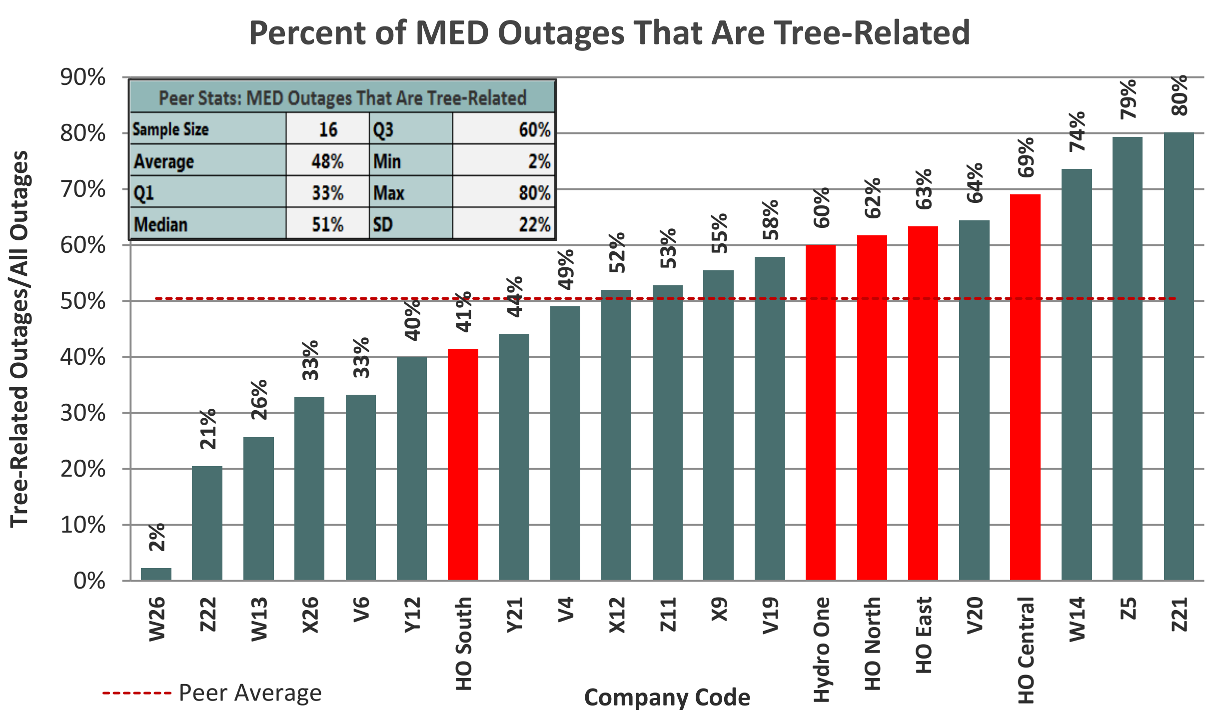


FIGURE 22: PERCENT OF MED OUTAGES THAT ARE TREE-RELATED

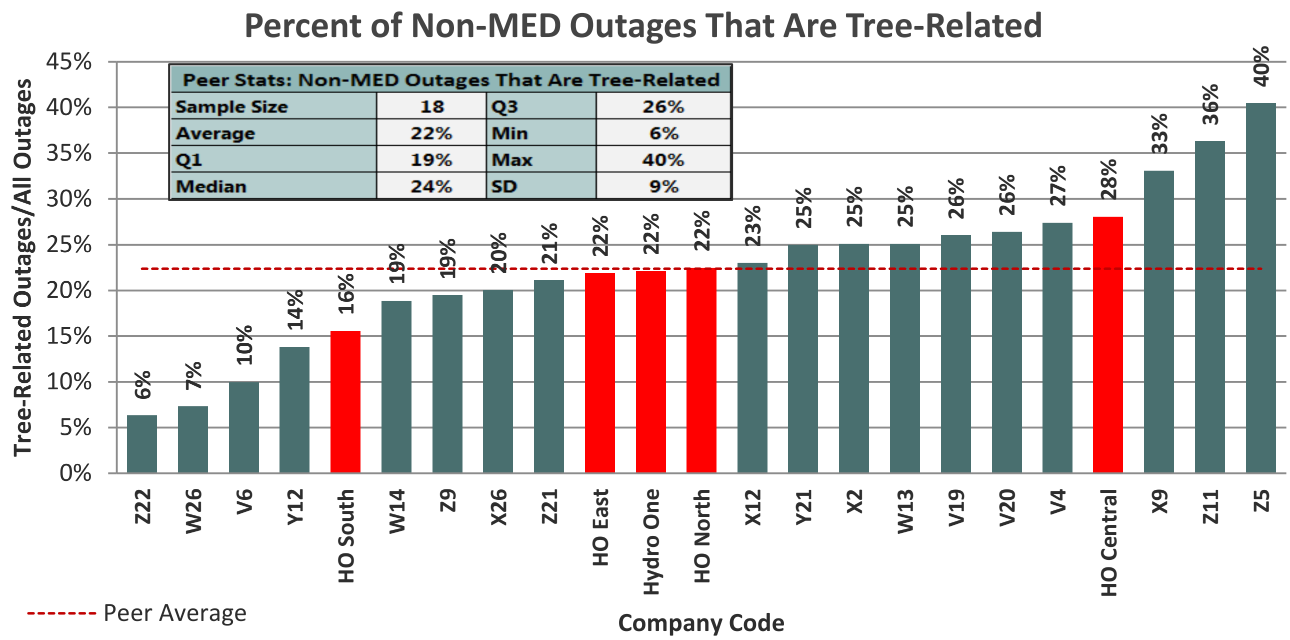


FIGURE 23: PERCENT OF NON-MED OUTAGES THAT ARE TREE-RELATED

4.5.3 INDUSTRY AND LONGITUDINAL COMPARISONS

Figure 24 (below) shows that the ratio of Non-MED tree-related outages to company outages has remained relatively static from 2011 to 2015. Although Hydro One and the peer average are similar performances in this metric, the Hydro One regions are not very consistent, with the exception of the South Region which has done well to keep the company at the average. Central is consistently a poor performer in regards to reliability and it would do well to fully evaluate its strategy for vegetation management.

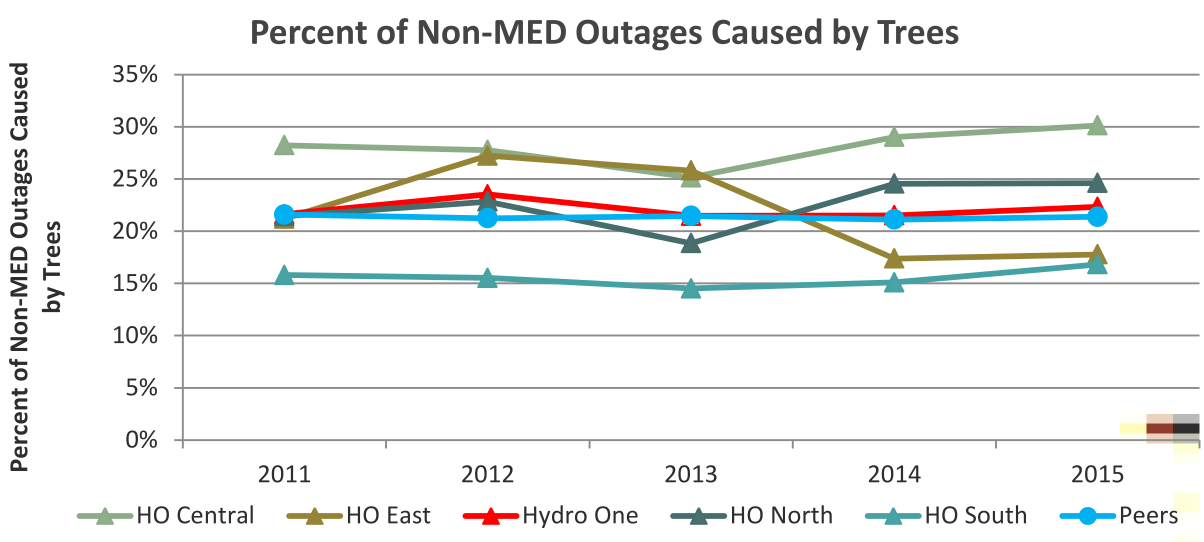


FIGURE 24: PERCENT OF NON-MED OUTAGES CAUSED BY TREES ON THE HYDRO ONE SERVICE TERRITORY 2011-2015

The percent of MED outages caused by trees (Figure 25 below) has also remained constant at Hydro One. It is an indicator that when a storm blows through the majority of restoration will involve distribution facilities damaged and interrupted by trees. In this measurement the peer group on average is improving from 51% down to 40% --an 11% improvement over the five-year period. Hydro One stayed much higher than the peer group at 64% of MED outages caused by trees. Central region has not been able to improve over the five years and nearly 70% of MED outages in the Central region are caused by trees. None of the regions are below the 2015 level of the peer group. Although Hydro One has a below average percent of outages per km caused by trees and the Non-MED tree-related outages are close to the peer average, MED tree-related outages are a high percent of the total and they are not improving. Major Event Day (MED) outages have dominated the worst years of Hydro One's tree-related outages, which escalated to as many as 17,200 in 2006 and 2013. In years with low MED outages, Hydro One has not been able to drop below 8,000 outages. Since Hydro One does not compare favorably with peers in either MED or Non-MED reliability metrics SAIDI and SAIFI, but has below average outages per km compared to peers, it will need to adjust its program to build more resiliency to storms while keeping the raw number of outages per km from increasing.

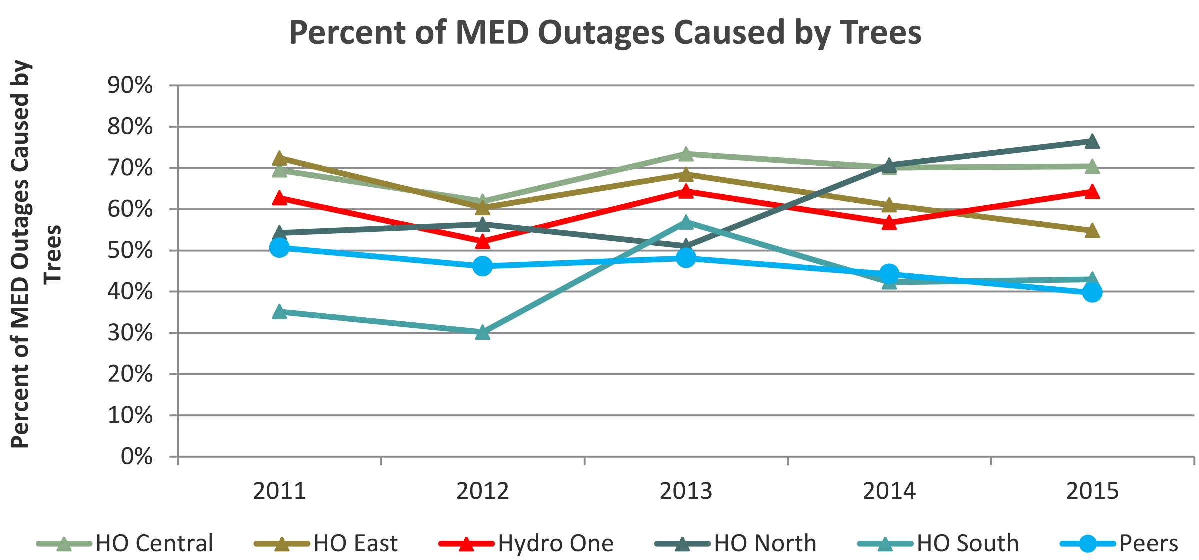


Figure 25: Percent of MED Outages Caused by Trees on the Hydro One Service territory 2011-2015

Although Hydro One compares favorably using the metric of outages per kilometre, it will have to make improvements in reliability performance for the foreseeable future. First and foremost, the *UVM department* should be investigating tree-caused outages. Hydro One is the only utility in the survey where the vegetation management department does not investigate tree-related outages. It is also unknown how many tree-related outages are categorized as unknown or weather-related.

Outage investigations should be performed by trained forestry personnel and should be stored in a database. Areas of data capture and database development should include species, age, size, site conditions, tree failure modes beyond whole tree, branch and growth, measurements of ROW, whether tree is on or off ROW, description and condition of adjacent vegetation, investigation and analysis of external causes such as local weather and wind information. This program could be piloted on a stratified random selection of outages to limit costs and accentuate the focus on both high priority feeder outages and the variety of outage settings found on infrequently managed single and two-phase lines. A modeling program based on the outage investigation database will help identify tree failures before they happen and this will be more effective than removing all suspected trees in and off the ROW. The models should be used to improve the tree risk assessment program.

4.5.4 Reliability Improvement Targets

Hydro One was asked to explain the poor relative reliability performance in Central Region and they supplied the following response:

- The Central Region is covered by heavy tree density.
- Most of operation centers in the Central Region have radial distribution lines, which means lack of alternate feeding and switching capability compared to other regions
- The Central Region is in the path of normal storms that goes through Ontario
- Other design, planning, protection, and control issues

Given the metrics provided are accurate; Hydro One should focus on resiliency improvements to the Central Region where reliability issues are more prevalent.

4.6 Safety as a Priority

For the purposes of this report safety is evaluated as a performance metric and as elements of program design. Hydro One's performance in the field is compared with the peer group and the industry at large. Hydro One's UVM program is also compared to peers for how well safety risks are minimized to the public and line clearance workers.

4.6.1 Safety Performance

In general Hydro One's performance over the past five years falls short of the perfect incident rate (0 accidents) recorded in 2008 when CNUC performed a benchmark survey. However, some indicators suggest Hydro One's program is less likely to incur lost time accidents than other programs. Hydro One maintained a low accident severity rate and zero fatalities. Hydro One has one of the lowest employee turnover rates of the peer group. An extensive training program also is evidence that Hydro One reduces the risk of accidents occurring. Several studies have found that accidents increase proportionally to employee turnover and disproportionally to employee tenure: "[T]he weight of research evidence seems to overwhelmingly show a relationship between job tenure and accidents (Burt, 2015)." A high percent of incidents involves employees in their first year and many leave the line clearance industry because they perceive it to be too unsafe.

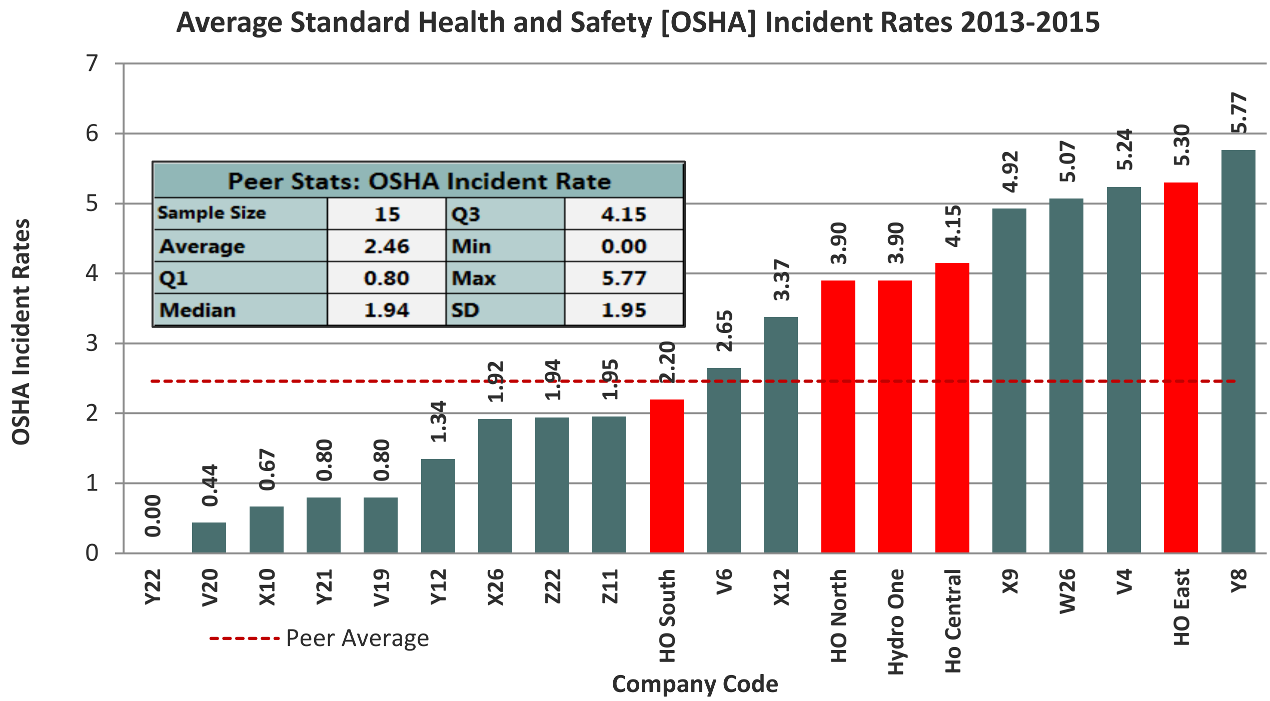


FIGURE 26: OSHA INCIDENT RATE COMPARISONS 2013-2015

Hydro One has succeeded in minimizing the turnover rate and this can be associated with the zero accident frequency and severity rates that were reported in the 2009 study for the OEB. The current survey found the average turnover rate for the peer group is 32% for line clearance personnel compared to Hydro One which is 5%. Hydro One's incident rate was 3.90 incidents/100 FTE for 2013-15 (East region reported 5.30 incidents/100 FTE) (Figure 26 above). The average for the peer group was 2.46 incidents/100 FTE. However, recent statements and actions by OSHA in the US indicate incident rates may not be accurate for the tree care industry, which includes line clearance. Beginning in November 2016, new rules apply to incident reporting that are designed to improve accuracy of reporting. Accident Severity Rates were not reported by many survey participants. Of the nine peer companies who did report, the average severity rate 2013-2015 was 31.36 lost days/100 FTE (Figure 26 below). If companies reported rates for multiple contractors the worst rate was used for this comparison. Hydro One's severity rate was 7.9 lost days/100 FTE average for 2013-2015. It should be noted that regression analysis of employee turnover rate and incident severity rate for these nine companies showed a high correlation ($R^2 = 0.643$, $R = 0.802$, $p < 0.001$). This finding is also supported by multi industry studies which have found high correlations between accident rates and employee tenure.

Combined, the Hydro One incident rate and severity rate indicate some need for improvement at achieving the benchmark for limiting injury accidents. However, the low severity rate at Hydro One indicates there is still a high level of safety on the job. The accident frequency rate for the South region is below the average for the peer group and North Region is above average and is at the low-end of the third quartile. More problematic for Hydro One is the Central Region accident frequency and severity rates. The Central Region severity rate, 21.6 lost days/100 FTE, is below the peer average, 31.36 lost days/100 FTE, but it is still an indicator that safe work improvements are needed. The incident rate for

Central Region is at the upper end of the third quartile and the East Region, which is the second highest on the chart. Why has there been an increase in the incident rate over the period of this study,

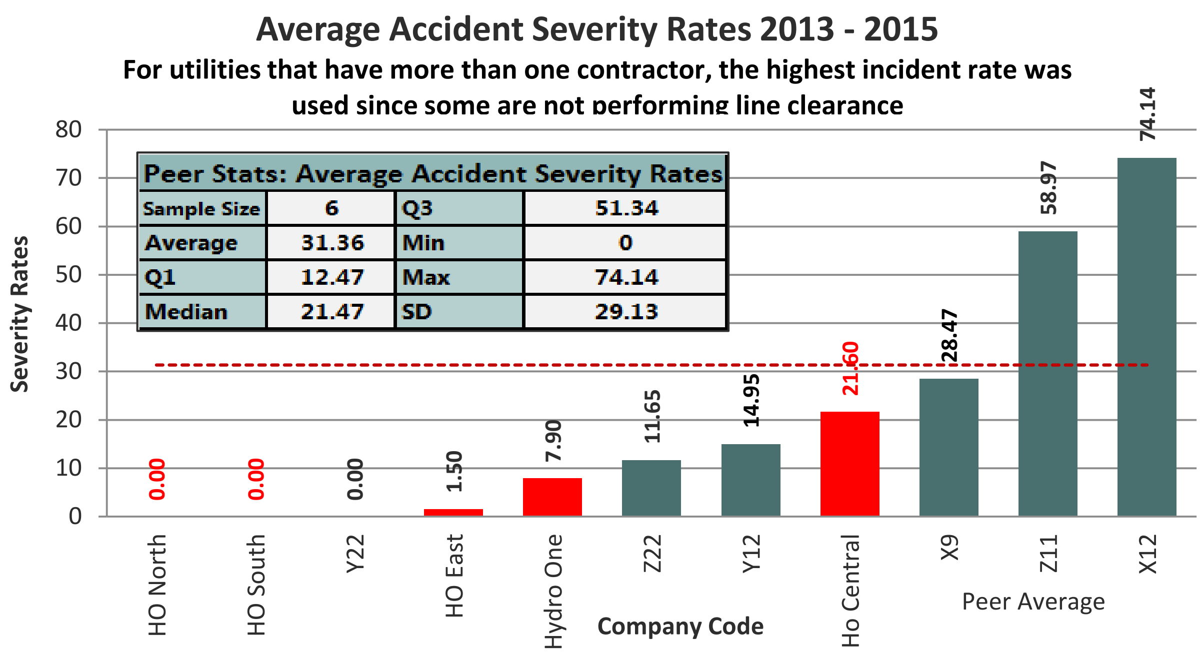


FIGURE 27: AVERAGE ACCIDENT SEVERITY RATES 2013-2015

particularly for the East and Central Regions? First, there has been greater reliance on temporary employees and a decreased reliance on in-house trained personnel. However, the safety data is not comprehensive or conclusive. Second, Hydro One stepped up the effort to decrease the cycle length through greater numbers of inexperienced employees and higher expectations for production, particularly in the Central and East regions. Fluctuating budgets changes the employee count and increases potential for some employees not to consider the employment permanent, which may have a negative influence on the safety culture. Higher stress levels with employees who are required to move around the province to maintain M and F class feeders on a more frequent basis. Increases in the number of backlogged kilometers worked each year that are past the target cycle length. Worker safety is affected by program changes. We recognize program improvements designed to improve safety in the work place, but we are not always cognizant of the unintended consequences of program changes that affect safety.

Hydro One is required to report the number of serious electrical incidents that occur on their system each year. An average of six per year was reported to the OEB for 2010-2014. Although the survey requested information related to vegetation and electrical contacts, only two peer companies could provide information. One company stated 0 incidents occurred over the past five years. Another stated no more than one to two per year and that these incidents are usually the fault of the victim, not the result of poor maintenance or system defects. Hydro One could not state whether contacts involving vegetation occurred on their system. 67% of peer companies report the rate of occurrence is unknown. 71% of companies, like Hydro One, do provide many public service announcements that discourage removing trees or branches near powerlines. 19% of companies provide electrical hazards awareness training to non-line clearance arborists. Hydro One did not report they provide this service. Another 19% said they do not frequently and/or effectively communicate safety concerns of trees and powerlines. Hydro One was not in this group.

Many companies in the survey consider safety to be the business of their contractors and a few said they supplement the contractor's programs with company-initiated safety training. Hydro One has 40-50 hours of safety training for their employees, which is more training hours than any participant in the survey reported for in-house or contractor employees.

92% of peer utilities plus Hydro One reported that they track safety metrics. The following are metrics tracked:

- All companies: Accidents, contractor-caused outages, vehicle incidents, and non-reportable incidents are included in their statistics
- Six companies: Web-based program that contractors use to enter incidents and calculate safety statistics
- Most companies: have quarterly meetings and contractors submit accident logs
- Two companies: Utilize near-miss reports.

Three companies in the survey (Hydro One, one peer, and one non-peer) had more extensive monitoring. These include frequent safety audits, internal safety specialists, and frequent departmental safety meetings. Hydro One is distinguished by having an in-house workforce that is more directly connected to safety monitoring and initiatives promoted within the company.

4.6.2 UVM Program Safety

The most important safety monitoring metrics and arguably a best management practice for documenting a successful program are leading indicators that measure safety in performance. Documented completion of specific task-oriented and performance-based training programs are an example of a leading indicator. Other examples could be certification and continuing education units through a third-party administered safety training program; new employee apprenticeship programs that audit the trainers and ensure new employees receive consistently adequate hands-on training and documented proficiency measurements; ongoing hazards and skills training that is specific for the work that the employee performs and appropriate training provided when an employee changes job duties.

Other leading indicator safety metrics are policies that specify the activities of the UVM program. Based on the responses of the peer group and a few of the non-peer group, there is a direct and positive relationship between UVM program policies regarding clearances between vegetation and conductors and the safety of the public and utility arborists.

Is a tree in contact with a powerline a safety issue? The following language is from Ontario Infrastructure Health and Safety Association (IHSA) of which a Hydro One employee was a board member at the time of this publication.

> ***The Line Clearing Operations Safe Practice Guide*** *(Infrastructure Health and Safety Association 2008)*
> *Should a limb still attached to a tree be found in contact with a conductor energized above 750V:*
> - *the tree should not be climbed directly from the ground*
> - *clearing should be done using live line equipment from the ground, from an aerial device or portable non-conductive ladder*
> - *the circuit should be isolated and de-energized prior to limb removal*

From a safety and economic perspective, preventing trees from being in contact with conductors should be a best management practice. The alternative is that trees *could* be climbed by a line clearance worker or someone else, when it is in contact, that a utility tree worker's electrical hazard exposure is increased by trees in contact, and that to follow proper protocols by de-energizing the line would be more expensive.

The topic of maintaining clearances is discussed in several places in this report with compelling arguments for why it is important, but there is probably no data that is as compelling as the 90% of survey respondents reporting that they believe a required airspace around conductors would be a *significant* improvement to the safety of the distribution system. A third of these UVM experts, who collectively manage a significant percent of the kms of distribution lines in North America, stated they have a requirement for airspace and it has improved worker safety significantly. A smaller percent, but a solid majority, 64%, of respondents said that clearance duration requirements play a role in over-all program safety. Multiple commenters stated that longer cycle lengths increase the probability of an incident.

4.7 Recommendations for Measuring and Determining a Risk Acceptance Level

In the future, it is recommended that a standard of care be documented that provides the acceptable level of risk reduction from vegetation conflicts with powerlines. It is also recommended that customers be notified of what responsibilities they have relative to the risk reduction. Some metrics should be introduced that measure the performance of UVM in achieving objectives. The following are suggestions for metrics, analysis, data collection, and databases:

- Create a tree-related outage database and analyze types of tree failure and weather conditions to support annual reliability report.
- Set a target percent limit for trees in contact found during annual audit inspections with corrective action measures.
- Create a customer vegetation transaction record that defines workload per customer.
- Keep a record of customers who refuse standard UVM work for pruning, removing trees or applying herbicides.

- Use a statistical process control calculator to continuously monitor km productivity with corrective action plans for work that falls outside of two standard deviations.
- Have a target percent reduction of tree density measured for each km (or by circuit) over each cycle of management with a corrective action plan if density is increasing.
- Create an annual reliability report for tree-related outages delineated by outage risk. Metrics such as tree-related SAIDI and SAIFI that are biased to customer densities should be evaluated cautiously because Hydro One's system has very a low customer density, which biases IEEE reliability metrics, and reliability performance is also related to other measures. Outage data statistics could include at-risk customers, heavy load circuits, outages on circuits with a long duration response time, time since last UVM maintenance for each tree-related outage, frequency and interval averages for outages by circuit. The report should be scored as 'improved' or 'not improved' over previous year(s) based on a variety of metrics.
- Publish an annual report of innovation and initiatives which is effective at bringing stakeholders and customers into partnership with UVM objectives. There should be a net reduction of tree density involved plus an enhanced environmental quality and a customer satisfaction metric.
- Document the Tree Risk Assessment Program that targets hazardous trees at the edges and beyond the ROW with target outage reductions by circuit and voltage class.

4.8 2022 Model Cost Projections

See Appendix D: Statistical Methodology and Model Development - Projections of Unit Costs for Hydro One for details on model development

Three different budget projections were developed based on levels of risk.

- **Risk Model A:** This model is at the *highest risk* level. It is a model built on the current scheduling methodology, which targets M-Class feeders and three-phase (3Ø) lines. This methodology will get the high priority lines on schedule, but the single and double phase will fall farther behind resulting to a 14.9 year cycle on average for this part of the distribution system.
- **Risk Model B:** This model is a *moderate risk model*. This model expands the Risk Model A by continuing the backlog and cyclical work on the M-Class and 3Ø lines, but will also increase the work on the single-phase and double-phase lines to keep this part of the system closer to the 9.5 year (on average) cycle.
- **Risk Model C:** This model carries the *least risk* and produces a more storm resilient system. It gets all of circuits on target cycles by obtaining an eight-year cycle (ten in the North region) for single and double-phase circuits.
- **BMP Model D:** This model produces a more storm resilient system with greater returns. It gets all of circuits on target cycles by obtaining a six-year average cycle for single and double-phase circuits.

4.8.1.1 Budget Projections for Each Model

MODEL	Risk Model A Highest Risk Model		Risk Model B Mid-Risk Model		Risk Model C Lowest Risk Model		Model D BMP Model	
	Annual Cost Projections	Annual Kilometres Completed	Annual Cost Projections	Annual Kilometres Completed	Annual Cost Projections	Annual Kilometres Completed	Annual Cost Projections	Annual Kilometres Completed
2017	$150,217,259	12,000	$166,458,286	13,973	$174,912,181	15,000	$192,914,780	17,167
2018	$152,725,887	12,000	$169,238,140	13,973	$177,833,215	15,000	$196,136,456	17,167
2019	$155,276,410	12,000	$172,064,417	13,973	$180,803,029	15,000	$199,411,935	17,167
2020	$157,869,526	12,000	$174,937,892	13,973	$183,822,440	15,000	$202,742,115	17,167
2021	$160,505,947	12,000	$177,859,355	13,973	$186,892,275	15,000	$206,127,908	17,167
2022	$163,186,396	12,000	$180,829,606	13,973	$190,013,376	15,000	$209,570,244	17,167

TABLE 5: BUDGET PROJECTIONS THROUGH 2023 FOR RISK MODELS A, B, C, AND D

Note: All four models were developed using exclusively Hiring Hall or contract labour for single and double-phase work. It is recommended that the lower safety risk work (planning, brush, and herbicide) be performed by contracted labour and that the higher safety risk work continue to be performed by in-house crews. *The costs for Risk Models B-D would increase by between 10% - 15% with the suggested labour mix.*

5 CONCLUSIONS

Hydro One's routine maintenance costs measured by system kilometre are one standard deviation *above* the peer average. Hydro One's expended labour hours per system km is nearly one standard deviation *below* the peer average. This differential is the result of the following factors (the first three explain the cost deviation and the last three explain the labour efficiency):

- The accumulated biomass and heavy workload after a long interval between maintenance cycles.
- A higher cost of labour and equipment compared to the peer group, all of which outsource UVM program implementation, with the exception of one other company.
- Hydro One reports overhead/administrative costs better than their peers, since they are completely in-house. The peer group does not report indirect costs on the UVM program. Comparators only report the direct costs to run the UVM department plus the cost of the contractor.
- Hydro One management organizes work and crews perform ROW maintenance more efficiently than the majority of the peer companies.
- Hydro One's long cycle of maintenance has resulted in fewer labour inputs per system kilometre than shorter cycle programs.

- The historical practice of clearing the full width of the ROW, a shorter growing season in 50-75% of the system, and a third of the system is in agricultural areas where tree density is low are all factors that contribute to a more labour efficient management.

The result of Hydro One's UVM program is 32% fewer outages per kilometre than the average of the peer group. Hydro One did not report a history of fires caused by powerline contacts, electrocution accidents involving trees and power lines, or other incidents related to the close proximity of powerlines and trees. The absence of such incidents and the employee safety record are testaments to the success of their program.

Despite the positive results of Hydro One's UVM program, there are areas that are in need of improvements, because:

- Some aspects of the program are not sustainable over the long-term
- Risk is increasing on parts of the system, and
- The environment and the customer are driving UVM programs to a higher level of performance than the past.

The positive outlook is that 50% of the system is targeted for a consistent schedule (4-8 year cycle) of maintenance that includes the highest priority and largest load kilometers on the system, M-Class and non-M-class feeders. Over the next six years all of the backlog of work for this half of system will be brought up to date. This requires 8,500 kilometres of M-Class and non-M-class feeders to be managed each year.

The areas that are in need of improvement are the other half of the system, which is composed of single and two-phase lateral primaries and associated secondary lines that feed residential and commercial customers. Under the current plan only 3,500 kilometres of these lines will be managed each year for the next six years. This will put the second half of the system further behind and the annual increment of work will be the equivalent of a 15-year cycle of management. This is a rational approach to cope with a reduced budget. Although greater efficiencies can improve the execution of the program, it will not be enough to offset the reductions in program expenditures. Additionally, the new schedule will increase the risk of outages occurring on the single and two-phase lines.

The highest priority recommendation from this study is that Hydro One should strive to bring all of its system to a 4-8 year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule. The current plan to prioritize the M-Class and feeder system is appropriate if sufficient attention can be given to the rest of the system. This may require greater expenditures in the future and an increase in the number of lower cost hiring hall or contract personnel. In the short-term, the single and two-phase system should be worked on an eight to nine-year cycle of management instead of a 15 year cycle. This would require increasing the annual increment from 3,500 to approximately 6,000 kilometres. The program could be ramped up 500 kilometres each of the six years after which additional resources can be reassigned from the M-Class and feeders. These will be managed under a six-year IVM cycle and require fewer resources to keep cleared.

6 LIST OF APPENDICES

7 ACRONYMS AND GLOSSARY

7.1 ACRONYMS

22/04: Ontario Regulation for Electrical Distribution Safety

ATV: All-Terrain Vehicle

BMP: Best Management Practices

CAD: Canadian Dollars

CAIDI: Customer Average Interruption Duration Index

CNUC: CN Utility Consulting

DBH: Diameter Breast Height

FERC: Federal Energy Regulatory Commission

FTE: Full-time employees

IEEE: Institute of Electrical and Electronics Engineers

IEEE-1366: IEEE Electrical System Reliability Indices (e.g. SAIDI, SAIFI, CAIDI, etc.)

IPM: Integrated Pest Management

IVM: Integrated Vegetation Management

km: Kilometre

km^2: Square kilometre(s)

M: Million

MED: Major Event Days

NERC: National American Electric Reliability Corporation

Non-MED: Non-Major Event Days

O&M: Operation and Maintenance

OEB: Ontario Energy Board

OH: Overhead

PIM: Performance Incentive Mechanism

PPE: Personal Protective Equipment

R&D: Research and Development

ROW: Right-of-Way, Rights-of-Way, Right-of-Ways

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

T_{MED}: Major Event Day Threshold

TRA: Tree Risk Assessment

UG: Underground

USD: United States Dollars

UVM: Utility Vegetation Management

7.2 GLOSSARY

Barriered: "Barriered" means separated by clearances, burial, separations, spacings, insulation, fences, railings, enclosures, structures and other physical barriers, signage, markers or any combination of the above (OEB, 2004)

Cause code: Code for reporting the initiating condition for electrical interruption

CAIDI: Customer Average Interruption Duration Index

$$\text{CAIDI} = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ interruptions} = \frac{SAIDI}{SAIFI}$$

DBH: Diameter Breast Height as a measurement of the size of a tree

FAC-003: Electric Transmission Vegetation Management Regulation in North America

F-Class: 27.5 kV, three-phase feeders

In-growth: The volume of new trees growing into the minimum dbh size class during the measurement period [cycle]

IVM: A systematic integrated approach to managing vegetation, which includes controlling vegetation in the ROW by removal of inappropriate species, discouraging re-growth or in-growth, and planting and maintaining of appropriate tree species

OSHA RECORDABLE INCIDENT RATE (IR): a mathematical calculation that describes the number of employees per 100 full-time employees that have been involved in a recordable injury or illness.

$$\text{OSHA RECORDABLE INCIDENT RATE} = \frac{Number\ of\ OSHA\ Recordable\ Cases\ x\ 200{,}000}{Number\ of\ Employee\ Labour\ Hours\ Worked}$$

M-Class: 44kV feeders, sub-transmission

Managed kilometres: The number of overhead (OH) lines managed on an annual basis.

Trees treated: The same as trees managed and includes both trees pruned and trees removed

SAIDI: System Average Interruption Duration Index

SAIDI= $\frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customers\ served}$

SAIFI: System Average Interruption Frequency Index

SAIFI= $\frac{sum\ of\ all\ customer\ interruptions}{total\ number\ of\ customers\ served}$

System kilometres: The number of overhead (OH) kilometres in the distribution system.

Tree Density: Tree density = Average number of trees managed per kilometre each year.

Work Planning: Same as Pre-Planning

8 BIBLIOGRAPHY

Become Accredited. (n.d.). Retrieved from Right-of-Way Stewardship Council: http://www.rowstewardship.org/become_accredited

Burt, C. D. (2015). *New Employee Safety - Risk Factors and Management Strategies.* Switzerland: Springer International Publishing.

CNUC. (2014). *2011-2012 Distribution CN Utility Distribution Benchmark Survey Analysis Updated 2014.* Sebastopol, California.

CNUC. (2015). *Distribution Benchmark Survey Results 2014.* Sebastopol, CA: CN Utility Consulting.

Deming, W. (1984). The 5 Deadly Diseases. Retrieved from https://deming.org/theman/theories/deadlydiseases

Finley Engineering. (2010). *Cost Analysis for Integrated Vegetation Management Plan.* Carroll Electric Cooperative. Retrieved from http://www.carrollecc.com/files/pdf/cecc_finley_cost_study.pdf

Hydro One. (2015). DM103_18193.

IHSA. (2008). *Line Clearing Operations - Safe Practice Guide.* Ontario, Canada: Infrastructure Health & Safety Association. Retrieved from https://www.ihsa.ca/PDFs/Products/Id/SPG8.pdf

Larsen, P. H. (2015, August). *Assessing Changes in the Reliability of the U.S. Electric Power System.* Retrieved from Berkley Lab Electricity Markets and Policy Group.

McLoughlin, K. T., Nowak, C., Ballard, B., & Charlton, P. (2000). *Long-Term Right-of-Way Effectiveness: Update 2000.* Palo Alto, CA: EPRI.

Miller, R. H. (2014). *Integrated Vegetation Management Best Management Practices* (2nd Ed ed.). (W. Kocher, Ed.) Champaign, IL, USA: International Society of Arboriculture.

National Grid. (2015). *Electric Infrastructure, Safety, and Reliability Plan FY2017 Proposal.* Warwick, RI.

OEB. (2004). *Ontario Regulation 22/04: Electrical Distribution Safety.* Toronto. Retrieved from https://www.ontario.ca/laws/regulation/040022

OEB. (2015, July 31). *2014 Yearbook of Electricity Distributors.* Toronto. Retrieved from http://ontarioenergyboard.ca/oeb/_Documents/RRR/2014_Yearbook_of_Electricity_Distributors.pdf

OEB. (March 2015). *EB-2013-0416/EB-2014-0247.* Toronto: Ontario Energy Board.

Office of the Auditor General of Ontario. (2015). *Annual Report 2015.* Retrieved from http://www.auditor.on.ca/en/content/annualreports/arreports/en15/2015AR_en_final.pdf

Ontario Energy Board. (2015). *EB-2013-0416/EB-2014-0247 Decision March 12, 2015.* Retrieved from Ontario Energy Board: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0416&sortd1=rs_dateregistered&rows=200

APPENDIX A: CNUC TEAM QUALIFICATIONS AND EXPERIENCE

PROJECT TEAM MEMBERS:

William Porter, Project Lead and Chief Consultant

Nina Cohn, Data Analyst

Both project team members participated in the Hydro One 2009 UVM benchmark project

WILLIAM PORTER, PROJECT LEAD AND CHIEF CONSULTANT

- Director of Research, Development and Industry Intelligence (RDII) at CN Utility Consulting, Inc. (CNUC)
    - CNUC consults internationally with utility companies, vendors, lawmakers and regulators on all issues related to utility vegetation management (UVM)
- With more than 25 years of experience in the utility vegetation management (UVM) industry, Porter has direct knowledge of all aspects of UVM work
- Directed program and compliance reviews and special projects
- Performed analysis on a wide range of UVM metrics
- Principal author of the 2010 *CN Utility Consulting Utility Vegetation Management Benchmark and Industry Intelligence*
- Often presents on UVM benchmarking and LIDAR projects and other industry topics in the U.S. and abroad.
- Continuously monitors and evaluates legal and regulatory changes, as well as issues and trends related to UVM around the world.
- Led a research project for the Centre for Energy Advancement through Technological Innovation (CEATI) on *Data Analytics and Modeling Tools Applied to UVM Programs.*
- Serving on a task group to revise the ANSI Standard Z133, the *American National Standard for Arboricultural Operations – Safety Requirements*.
- Provides support to legal cases for CN Utility Consulting, tracks legal cases involving UVM in the U.S. and has participated in several legal cases as a witness.
- Has 15 years of line clearance experience, starting as a ground-person and advancing to supervising crews for 11 of those years. He was employed for Davey Tree and Wright Tree Service in Colorado and Iowa for most of these years, as well as supervising storm restoration throughout the US.

EDUCATION AND TRAINING

Education

Attended arboricultural and utility vegetation management seminars over the last 22 years

2003	General Foreman's School, Wright Tree Service
1997	Davey Institute of Tree Sciences
1976-1986	Post Graduate Studies at University of Illinois and University of Colorado
1975	Bachelor's Degree, University of Illinois, Urbana, Illinois

Certifications

1997-2009	Certified Pesticide Applicator
2006	Certified Proctor of ISA Certification Exams

2003	ISA Certified Utility Specialist
1996	ISA Certified Arborist International Society of Arboriculture: Certification # MW-0620AU

PARTIAL LIST OF PUBLICATIONS

1. Porter, W. (2016, June). *The Measure of UVM*. Transmission & Distribution World: Vegetation Management Supplement, pp. 14 – 19. http://tdworld.com/td-world-magazine/2016-03-31-0

2. Porter, W. (2015, May/Jun). *Regulatory Changes to Utility Vegetation Management in the US*. Utility Arborist Newsline, 6(3), pp.24-28.

3. Porter, W. H., & Cohn, N. L. (2014, October). *A Study of Data Analytics and Modeling Applied to Utility Vegetation Management Programs*. Montreal, Quebec, Canada: CEATI International, Inc.

4. Porter, W. (2014, June). *Higher Expectations Drive UVM Mandates*. Transmission & Distribution World: Utility Vegetation Management, 14-16 (104-106). http://tdworld.com/june-2014#104

5. Porter, W. (2014, May/Jun). *Career Advancement for Consulting Utility Foresters*. Utility Arborist Newsline, 5(3), 33-35. http://viewer.epaperflip.com/Viewer.aspx?docid=9f3e2a95-f5d6-4c66-ae33-a35b00e56ffe#page=33

6. Porter, W. (2014, Jan/Feb). *UVM for the Modern Electric Grid: A Review of the Presidential Report on Economic Benefits of Avoiding Outages Related to Severe Weather*. Utility Arborist Newsline, 5(1), pp. 1-4.

7. Porter, W. (2013, Sep/Oct). *FAC-003-2: A "Zero Tolerance" Approach to Transmission Vegetation Management*. UAA Newsline, 4(5), 26.

8. Porter, W. (2013, March/April). *How the Circle of Safety Reliability and Regulations Impacts Vegetation Management for Electric Cooperatives*. UAA Newsline, 4(2), p. 16.

9. Porter, W. (2013). *A Study of UVM Planning and Implementation with a LIDAR Information Matrix*. Environmental Concerns in Rights-of Way Management 10th International Symposium. Champaign, IL: International Society of Arboriculture.

10. Porter, W. (2012, Nov/Dec). *The Future of Transmission Vegetation Management: A Review of the 2011 FERC/NERC Northeast US Storm Report*. UAA Newsline, 3(6), p. 28.

11. Porter, W. (2012, Sep/Oct). *Customer Communications Emerging as Top Priority*. UAA Newsline, 3(5), p. 26.

12. Porter, W. (2012, June 1). Public Relations. T&D World, p. 24. http://tdworld.com/vegetation-management/public-relations

13. Porter, W. (2012, May/June). *Customer Service and FAC-003*. UAA Newsline, 3(3), p. 27.

14. Porter, W. (2011, Jan/Feb). *Creating a Standard for Performing Transmission Vegetation Management Inspections*. UAA Newsline, 2(1), p. 12.

15. CNUC. (2010). *Utility Vegetation Management Benchmark & Industry Intelligence*. Des Moines, IA: CN Utility Consulting.

16. CN Utility Consulting, Inc. (2009). *Hydro One 2009 - Vegetation Management Benchmarking Study*. http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2009-0096/Exhibit%20A/A-15-02_Attachment_1.pdf

NINA COHN, DATA ANALYST

- Nina Cohn, Senior Analyst for CN Utility Consulting, provides data and statistical analysis for reports.
- Cohn earned degrees in Mathematics and Sciences with work experience in entomology research, biochemistry research, and mathematics instruction.
- She taught Mathematics for over 14 years at Community Colleges in Denver, Colorado and Des Moines, Iowa.
- Cohn began working in the utility vegetation management field in 2009 by analyzing benchmark data for the publication, *"CN Utility Consulting Utility Vegetation Management Benchmark and Industry Intelligence."*
- The current benchmark report, *2011-2012 Cumulative Distribution CN Utility Consulting Benchmark Survey Report,* is co-authored by Nina Cohn and William Porter.
- Her statistical analysis has also been utilized in a Canadian rate case, consulting projects, numerous utility vegetation management (UVM) program reviews, and reports conducted for CNUC.
- Cohn co-authored a 2014 research project for the Centre for Energy Advancement through Technological Innovation (CEATI) on *Data Analytics and Modeling Tools Applied to UVM Programs.*
- Cohn's background in the math and sciences lends a distinctive skill-set to the UVM industry.

EDUCATION AND TRAINING

- University of Illinois, 1975
  Bachelor of Science in Physiological Psychology, Minor in Chemistry

- University of Colorado at Denver,1987
  Mathematics Degree and Teacher Certification in Mathematics and Sciences

PARTIAL LIST OF PUBLICATIONS

1. *Fluidity of LM cell membranes with modified lipid compositions as determined with 1,6-diphenyl-1,3,5-hexatriene.* Reid Gilmore, Nina Cohn, Michael Glaser. *Biochemistry*, 1979, 18 (6), pp 1042–1049.
2. *Rotational relaxation times of 1,6-diphenyl-1,3,5-hexatriene in phospholipids isolated from LM cell membranes. Effects of phospholipid polar head-group and fatty acid composition.* Reid Gilmore, Nina Cohn, Michael Glaser *Biochemistry*, **1979,** *18* (6), pp 1050–1056.
3. Acknowledged in several articles in *Biochemistry, Journal of Biological Chemistry,* as well as articles in Entomology and Physiological Psychology.
4. CNUC. (2010). *Utility Vegetation Management Benchmark & Industry Intelligence.* Des Moines: CN Utility Consulting.

5. CNUC (2014) *2011-2012 Cumulative Distribution CN Utility Consulting Benchmark Survey Report.* Des Moines: CN Utility Consulting.

Utility Vegetation Project Portfolio (Partial List)

William Porter was the Lead on all these projects. All Projects Included a Written Report.

1. Hydro One
   - Performed benchmark analysis for *Hydro One 2009 - Vegetation Management Benchmarking Study.* Retrieved from http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2009-0096/Exhibit%20A/A-15-02_Attachment_1.pdf
2. United Illuminating
   - Sorted and cleaned LIDAR data supplied by LIDAR acquisition company to make field ready. These sorts were done to desired clearances and rights-of-way (ROW) widths
   - Developed methods to determine how many trees were represented and to eliminate duplicate LIDAR information
   - Developed methods to input data into field software to aid inspectors in organizing field work
3. Connexus Energy
   - Organized and analyzed data supplied by Connexus to answer specific questions posed by the utility
   - Analysis proved crucial to presenting a business case to increase the UVM budget
4. Reports for Internal and External Stakeholders
   - Produced numerous statistical reports on specific topics for utilities and for use by CNUC personnel
5. The Centre for Energy Advancement through Technological Innovation (CEATI)
   - Co-author and co-researcher of *A Study of Data Analytics and Modeling Tools Applied to UVM Programs,* a research project funded by CEATI (William Porter primary author)
   - Performed a Literature Review for the research project
   - Helped develop a survey for the project
   - Analyzed the data collected from the survey
   - Developed a template for UVM managers to aid in the incorporation of data analytics into UVM programs
6. Greencoat Capital
   - Benchmark Study of LiDAR use in North America and the United Kingdom
   - Helped develop a survey for the project.
   - Analyzed the data collected from the survey.
   - Performed market research.
   - Co-authored final report (William Porter primary author)
7. Ameren Illinois (AIC) Project One
   - Benchmark Study of UVM programs in North America
   - Helped develop a survey for the project.
   - Analyzed the data collected from the survey.
   - Secondary author of final reports (William Porter primary author)
8. Ameren Illinois (AIC) Project Two
   - Researched and analyzed data for three white papers for AIC's UVM program
   - Modeled return on investment and capitalization of UVM program enhancements
   - Secondary author of final reports (William Porter primary author

Appendix B: A Study of Reliability Metrics' Influence on UVM Programs

A decade ago, utility vegetation management (UVM) subject matter experts were encouraging utility executives to realign their UVM programs for measureable reliability benefits. It was suggested this realignment would result in lower costs and bring UVM out of the industrial age and into the technological realities of modern business management. The most significant and clearest measure of reliability improvement has been with extra high voltage transmission, because the internationally mandated FAC-003 standard has spurred utilities to achieve specific results. FAC-003 affected transmission lines, which account for about 3% of the total miles of overhead power lines in the US, but what about the other 97% of miles of overhead T&D electric lines in the US?

Although the bright light of business models, including economies of scale and process management, has been shined into the voids of UVM performance, there is no consensus that the industry has given birth to the golden age of utility arboriculture. Young arborists, some freshly trained on UVM, are still put to daily task to work around lethal conductors engulfed in vegetation. Utility arborists, scolded by the public for being butchers, continue to wonder why the industry does things the way it does them. Every year, a few go to work and never return. Many more tree workers lose their lives or are injured because they made contact with electrical energy, often not knowing the wires were there.

Studies conducted to evaluate how UVM has conformed to reliability data revealed several interesting findings:

- Reliability improvement is correlated with increases in customer density .
- Reliability-centered maintenance (RCM) applied to UVM may shift focus away from other objectives, such as safety, fires, environment and the customer.
- When UVM programs are prioritized to improve reliability metrics, long-term UVM workloads are likely to increase
- An increase in tree-related outages can occur at the same time reliability is improving.

The need to apply computer-enabled technology to UVM has coincided with the adoption of IEEE-1366. The Interruption Cost Estimate (ICE) calculator designed by the Department of Energy (DOE) reinforces the nexus between data-driven UVM and a burgeoning growth of reliability data. It would be imprudent to discourage actions that prevent outages that affect large electric loads. However, it is also important to recognize that the priorities of electric system reliability are not the only motivation for performing UVM. The consequences of applying electric system reliability metrics to UVM should be fully vetted. Is it okay that RCM encourages UVM policies that increase the frequency that outages occur? Improvements for relative reliability and improvements for absolute reliability are two separate outcomes that both require adequate planning and resources to achieve.

The following discussion demonstrates the theory, the logic, and the empirical evidence that the industry should be supporting UVM beyond the current reliability-centered maintenance (RCM).

Theory:
In *theory*, UVM programs operate upon a set of objectives that are established to support a mission and vision for a utility company. These objectives are collectively the driver and benchmark upon which the program is measured and implemented in a continuous spiral of improvements. Objectives provide the theoretical framework behind UVM. Without such a framework UVM would be reactions to system failures and liability. The cost alone of reactive UVM has driven UVM programs to become more preventative. To be preventative one must have a plan based on a theory of objectives, strategies and results.

Logic:
Once the theory behind UVM is established, then logical steps are taken to achieve the framework of objectives. Theory may be the the lodestar, but logic is the navigation system and it has to adjust to stay on course. For example, a UVM program must show a return on investment, but what logic gets you there? UVM has sought cost-effective ways to manage high risk, but in order to maximize return on investment, it has bypassed managing smaller risks and made compromises and adjustments. This strategy has allowed UVM departments to show success by using IEEE reliability metrics. Managers can report success if the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI) are reduced. For upper management, this provides a reduced cost burden achieved through reliability improvements.

Unfortunately, the marriage of UVM risk and reliability metrics has also meant performance for other objectives and risks could be reduced, ignored or transferred away from UVM departments. Worker safety liability has been shifted to contractors. Reliability performance shows UVM is performing what is reasonable and shields utilities from public liabilities. State regulatory compliance validates this idea by requiring reliability metrics. Other objectives like fire prevention, environmental quality, and customer service have become weak objectives.

Regardless of relative ranking, each objective should have key performance indicators. Strategies and tactics should be formulated to support measureable achievements and improvements. Some objectives, such as reliability and safety, may be more important, but a program ought to be balanced. A single objective, such as reliability, should not be the only characteristic of quality service. For example, UVM, from a customer perspective, is an inconvenient intrusion onto private property where vegetation is negatively altered in order to complete an electric system correction. Asset corrections protect equipment and ensure reliability, which is misconstrued as the primary if not only element of customer service. Why shouldn't UVM be a customer service activity in which the customer perceives they are receiving a benefit to their property or vegetation and their community? Perhaps we have come to accept adversarial relationships with rate-paying customers.

Empirical Evidence:
While logic is necessary to navigate, we need empirical evidence - an analysis of readings from our instrument cluster - to support and measure the performance of our logic. The following four sets of data are readings from the current era of UVM, and they suggest that there is a need to change our theoretic lodestar or reevaluate the logic used to navigate our UVM programs.

1. **Reliability is a UVM problem, but Reliability-Centered Maintenance is an asset management strategy**

   Reliability-centered maintenance (RCM) from an asset perspective is designed to address the vast majority of failure modes that are likely to occur during normal operating conditions. RCM is integral to the life-cycle of assets, which includes constructing, maintaining, extending, and finally replacing. Since abnormal conditions are usually an "event" such as weather, IEEE devised a statistical method to exclude certain outages in reliability performance metrics.

   The IEEE- 1366 2012 defines a Major Event as one *"that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day (MED)."* A T-MED is a calculated threshold for excluding outages in reliability metrics. It provides a limit beyond which a utility should not be expected to perform within expected reliability parameters.

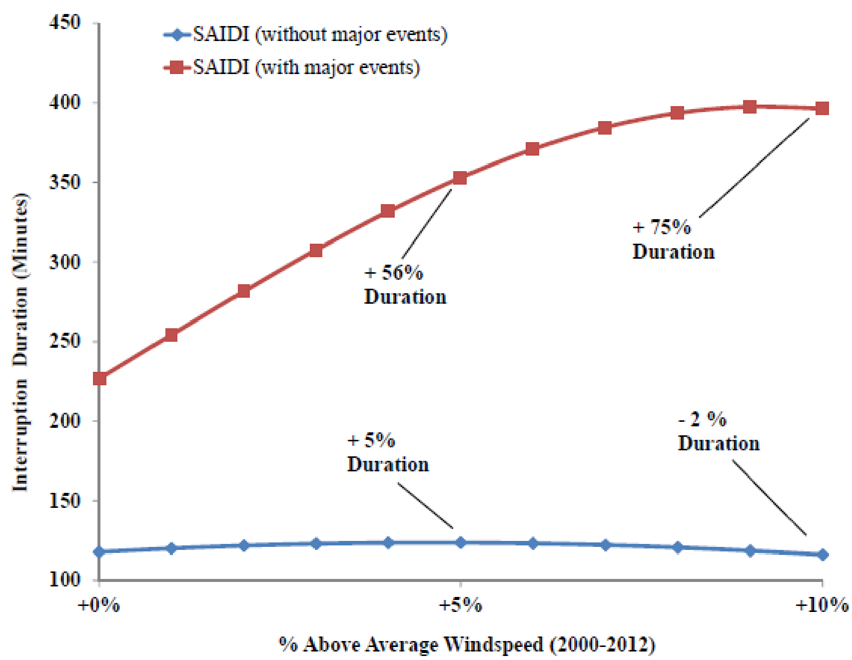


Figure 28: Above-average wind speed and duration of interruptions (SAIDI) (Larsen, 2015)

Berkeley National Laboratory (BNL) has performed cumulative statistical research on utility reliability data collected over the past thirteen years. Some specific variables are associated with measureable improvement in SAIDI and SAIFI. T&D expenditures, percent of underground, hot weather, and increases in customer density were found to correlate with lower SAIDI and SAIFI. Other variables such as wind are associated with increases in SAIDI and SAIFI (Larsen, 2015). Although the BNL research does not differentiate wind-caused outages between tree and equipment failures, CN Utility Consulting (CNUC) benchmark surveys have found at least 43% of outages during major event days (MED) are tree-related (CNUC, 2015). Wind-event data were studied at BNL, including and excluding MED. If MED are included, a 10% increase in average annual wind speed is correlated with a 75% increase in SAIDI. In contrast, if MEDs are excluded, a 10% increase in average annual wind speed is correlated with only a 2% increase in SAIDI (Larsen, 2015) (See Figure 1). This data analysis is significant to UVM since the majority of tree-related outages are caused by wind and other loading events. Without actionable knowledge of the life-cycle of trees and their failure modes and without a reliability system designed around the effective management of right-of-way (ROW) land and nearby trees, RCM is not likely to address tree-related reliability nearly as well as it can guide asset management.

2. Reliability Performance is not measured the same from one company to the next

The CNUC benchmark surveys found that 88% of responding companies track tree-related SAIFI, SAIDI and CAIDI, and 74% of companies are using this information to make planning and resourcing decisions for the UVM department (CNUC, 2014). Additionally, 59% of companies have not strictly used the IEEE-1366 guidelines for separating major event days (MED) from non-MED (CNUC, 2014). In fact, the 1366-2012 revisions left the door open for companies to adopt their own specific definition of a catastrophic storm. Some companies may have to comply with a state commission definition. Differences in MED definitions and thresholds may effectively increase or decrease the number of events which become MEDs and subsequently influence the threshold for determining MED. When one major event is excluded, the average used to determine the T-MED is also lowered, which causes additional events to be classified as major. Consequently, the measurement of reliability performance is inconsistent and possibly misleading, because SAIFI and SAIDI numbers vary significantly depending on whether outage events are included or excluded.

3. Reliability is worsening, according to SAIDI

Despite the reported improvements to non-MED SAIDI, the most current research into reliability data indicates that distribution system SAIDI measurements are worsening by 10% annually over the 13-year period of study (Larsen, 2015). In recent years, major storm events have become a critical reliability issue, and tree-related outages are the chief contributor. A comparison of the ratios of tree-related to system SAIFI revealed Non-MED tree-related SAIFI was, on average, 24% of system non-MED SAIFI. In contrast, MED tree-related SAIFI was 43% of the system MED SAIFI (CNUC, 2015). This difference underscores the significance of the SAIFI amplitude that vegetation causes during MEDs compared to other distribution system failure modes.

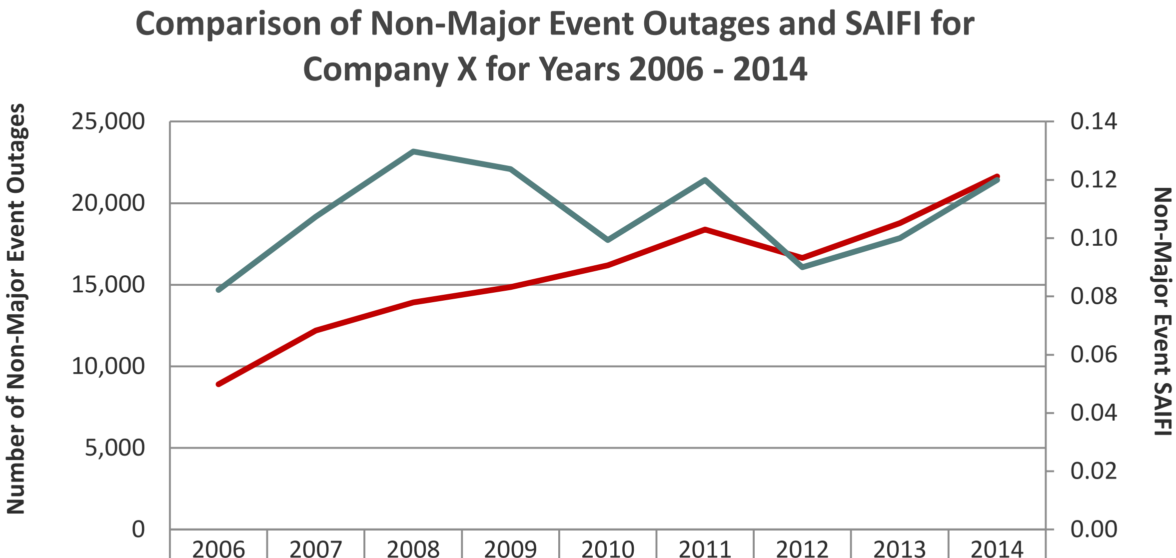
The risk factor for MEDs is greater for UVM than it is for equipment failure in the absence of tree damage. The Larsen study, which has many interesting findings, also found a 10% decrease in precipitation is correlated with a 3% increase in SAIFI (Larsen, 2015). It has been thought that drought conditions may contribute to tree-related outages.

4. **A Case Study**

The following is a comparison study between SAIFI, SAIDI, and tree-related outages per pole mile between three companies (X, Y and Z). The UVM programs for these utilities represent a reliability-centered maintenance program (Company X), a compliance-based program (Company Y) and a company (Company Z) that had favorable reliability performance but was dissatisfied with its UVM program. All three companies were excellent performers based on SAIDI and SAIFI. Company Z initiated the study with CNUC by asking the question, “How is it possible that we achieve best-in-class reliability when we know the UVM program is not meeting best management practices?”

By comparing the metrics from the three companies within a field of other companies, CN Utility Consulting (CNUC) found several revealing facts that demonstrate the limitations for using reliability metrics as a measure of the standard of care for UVM.

Company X almost doubled the number of tree-related outages on its distribution system in five years (2008-2012) and still showed significant improvements in SAIFI (31%) for the same years (See Figure2, below). By focusing UVM efforts on high customer density feeder lines while deferring maintenance on single-phase lines with lower customer density, X was able to report almost best-in-class metrics in 2012. An increase in SAIFI in 2011 could have been an anomalous year given the return to dropping SAIFI values in 2012. Subsequent years, 2013 and 2014, suggest something else is happening. Potentially, there is an upper limit of tree-related outages at which point SAIFI will also increase (2012-2014 in Figure 2).



	2006	2007	2008	2009	2010	2011	2012	2013	2014
Outages	8,906	12,194	13,918	14,865	16,197	18,379	16,636	18,774	21,633
SAIFI	0.08	0.11	0.13	0.12	0.10	0.12	0.09	0.1	0.12

Figure 29: SAIFI improves whilevegetation-related outages increase

Another interesting aspect of the reliability metrics occurs when SAIFI increases faster than SAIDI, then customer average interruption duration index (CAIDI) will actually improve, in spite of an overall worsening of the other metrics. This is another example of how reliability metrics may be misleading. A company could show exemplary reliability - in comparison to industry averages - by only focusing on non-major events, even while vegetation-related SAIDI, SAIFI and outages are increasing.

Outstanding reliability is a product of interpreting statistics and focusing on the bigger picture of utility reliability, which include other failure modes such as equipment failure and generic categories such as non-major weather events. If asset improvements are made – such as replacing equipment, adding isolating fuses, monitoring with sensors and making equipment more resistant to weather, vegetation, and animals – then reliability will improve and vegetation appears to be under better control. In reality, it is the asset that is improved, not the vegetation management.

In a comparison of reliability indices for the three companies of interest (X, Y, and Z), all three utilities show excellent metrics when compared with the UVM industry in general (See Figures 3 and 4, below). If the graphs only included peer utilities (companies with similar key characteristics), all three companies are best-in-class among their comparators. These two figures also show that X and Z, RCM companies, compare well with Y, the compliance-based program. Of note, a majority of the other companies that are in the first quartile have cycle-mandated programs (regulatory-based programs).

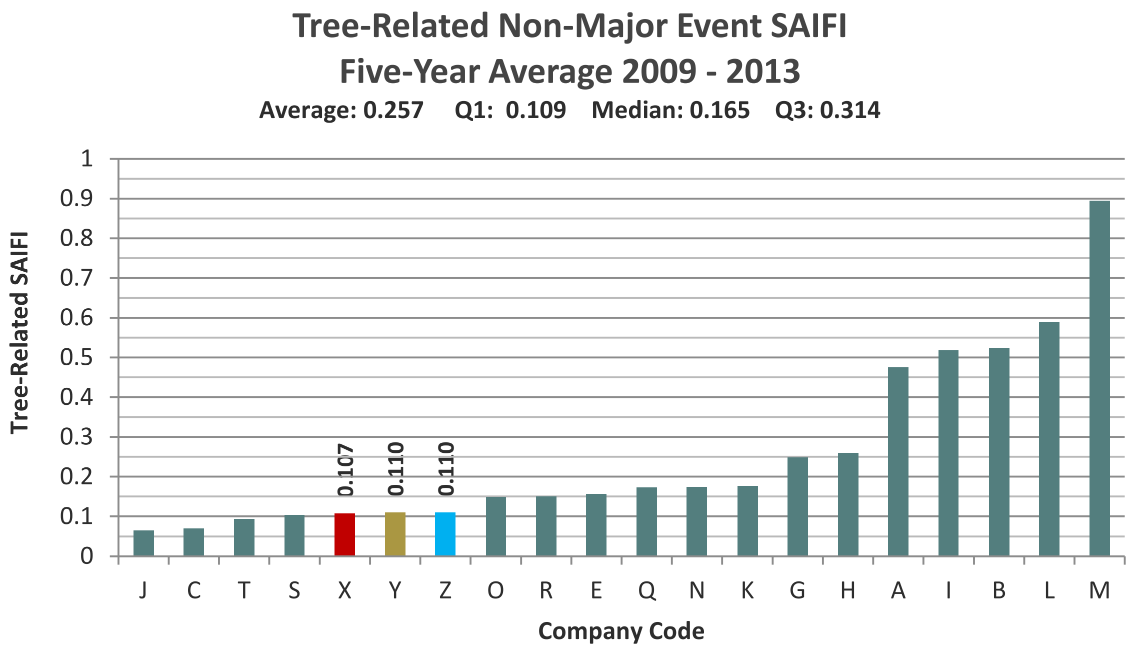


Figure 30: Utilities X, Y, and Z have different UVM strategies but similar SAIFI

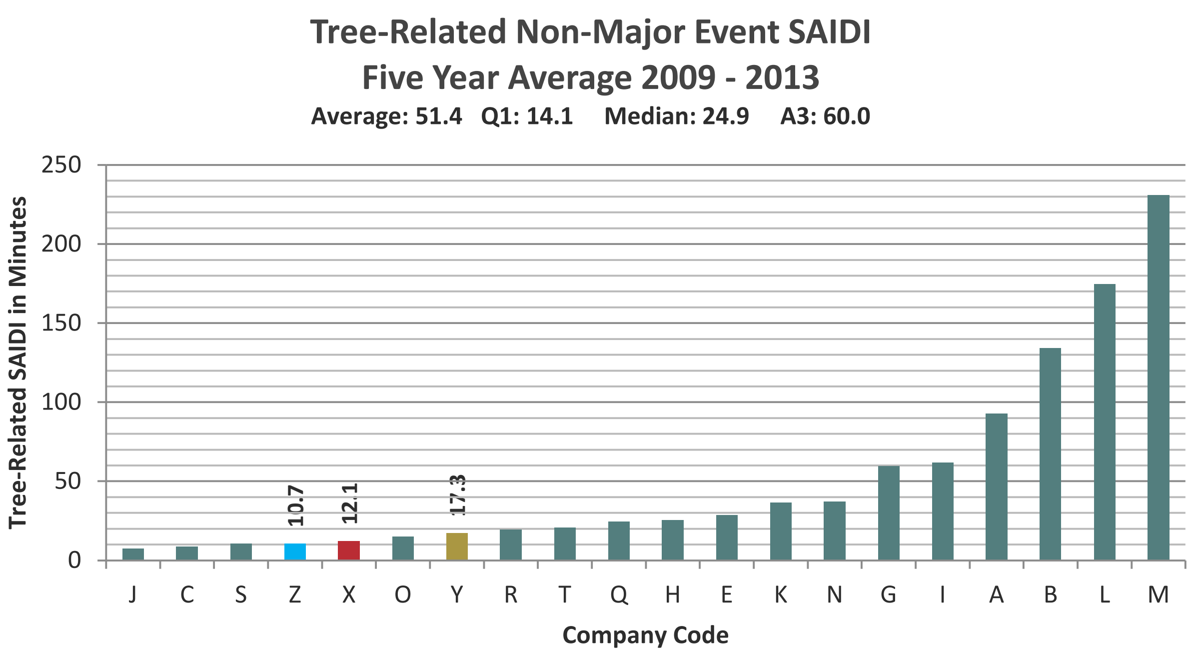


Figure 31: Company Y has a slightly higher SAIDI byt program is focused on the bigger picture

As noted above in Figure 2, company X is able to achieve a high reliability performance as measured by SAIFI, while the absolute number of outages has increased 143% over a nine-year period. Company Z knew that there was something misleading about their best-in-class tree-related reliability metrics, because the increases in the percent of trees in contact with powerlines and the increases in the percent of reactive maintenance were not represented by these measurements.

What was unclear to company Z was the relative value of SAIFI and SAIDI. In other words, IEEE metrics are customer-density dependent and UVM is tree-density dependent. When comparing companies X, Y and Z with peers using an absolute rate (outages per mile), a different picture emerges (Figure 5, below). Company Y, which is focused on regulatory mandates, achieves similar SAIDI/SAIFI but much better outage prevention performance that the RCM utility, X, while meeting other objectives as well. These objectives include public and worker safety, fire risk reduction, and environmental quality. As figure 5 shows, this inclusive strategy also results in best-in-class reliability when measured as an absolute rate.

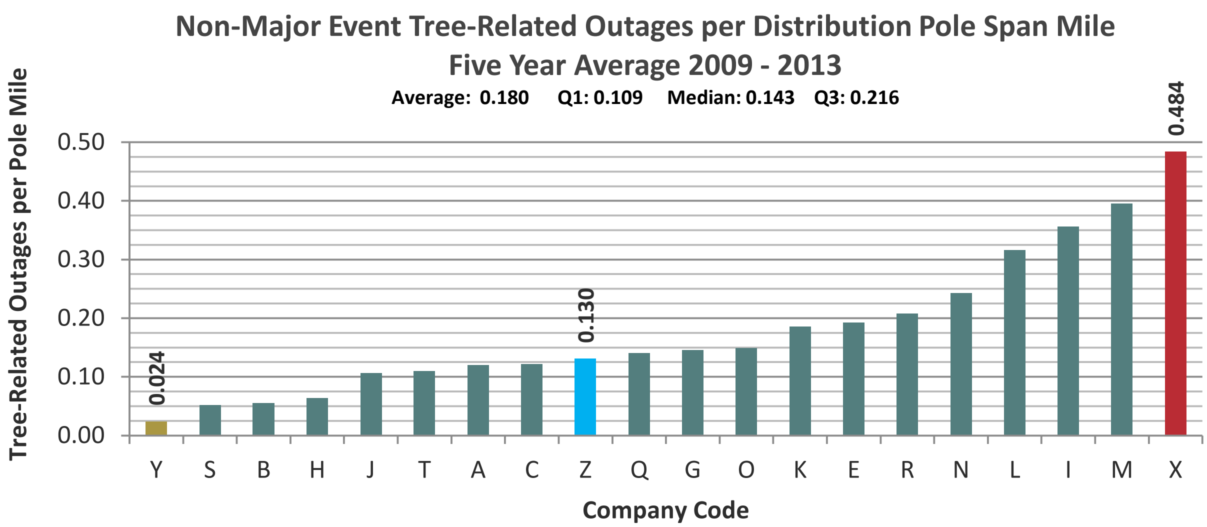


Figure 32: Absolute Reliability Rates

Conclusion:

Reliability is a major objective, especially as we enter into an era when climate changes are a significant threat to utility operations. However, effective vegetation management is not a direct response to conditions that negatively impact reliability. The reliability metrics that currently guide vegetation management do not measure or recognize the full extent of the UVM workload or forestry conditions. It is not the incremental tree growth that impacts reliability but rather the accumulative growth which leads to branch and tree failure. Nonetheless, it is still growth that UVM must control in order to prevent interruptions. This growth component must be managed in a cost-effective way and UVM must be performed to satisfy other objectives besides reliability. The use of reliability metrics as a measurement of UVM efficacy is pressuring utilities to practice reliability-measured UVM rather than sustainable

UVM that adheres to principles of forestry and urban arboriculture. All vegetation near power-lines must be managed at some point, regardless of its impact on reliability. Delaying maintenance to serve improvements to reliability metrics compromises all of the objectives and creates a greater long-term risk. This research was performed to demonstrate the shortcomings of reliability-centered maintenance and offer some alternatives to steer UVM in the direction of a more balanced approach that includes multiple objectives.

Works Cited:

Become Accredited. (n.d.). Retrieved from Right-of-Way Stewardship Council: http://www.rowstewardship.org/become_accredited

Burt, C. D. (2015). *New Employee Safety - Risk Factors and Management Strategies.* Switzerland: Springer International Publishing.

CNUC. (2014). *2011-2012 Distribution CN Utility Distribution Benchmark Survey Analysis Updated 2014.* Sebastopol, California.

CNUC. (2015). *Distribution Benchmark Survey Results 2014.* Sebastopol, CA: CN Utility Consulting.

Deming, W. (1984). The 5 Deadly Diseases. Retrieved from https://deming.org/theman/theories/deadlydiseases

Finley Engineering. (2010). *Cost Analysis for Integrated Vegetation Management Plan.* Carroll Electric Cooperative. Retrieved from http://www.carrollecc.com/files/pdf/cecc_finley_cost_study.pdf

Hydro One. (2015). DM103_18193.

IHSA. (2008). *Line Clearing Operations - Safe Practice Guide.* Ontario, Canada: Infrastructure Health & Safety Association. Retrieved from https://www.ihsa.ca/PDFs/Products/Id/SPG8.pdf

Larsen, P. H. (2015, August). *Assessing Changes in the Reliability of the U.S. Electric Power System.* Retrieved from Berkley Lab Electricity Markets and Policy Group.

McLoughlin, K. T., Nowak, C., Ballard, B., & Charlton, P. (2000). *Long-Term Right-of-Way Effectiveness: Update 2000.* Palo Alto, CA: EPRI.

Miller, R. H. (2014). *Integrated Vegetation Management Best Management Practices* (2nd Ed ed.). (W. Kocher, Ed.) Champaign, IL, USA: International Society of Arboriculture.

National Grid. (2015). *Electric Infrastructure, Safety, and Reliability Plan FY2017 Proposal.* Warwick, RI.

OEB. (2004). *Ontario Regulation 22/04: Electrical Distribution Safety.* Toronto. Retrieved from https://www.ontario.ca/laws/regulation/040022

OEB. (2015, July 31). *2014 Yearbook of Electricity Distributors.* Toronto. Retrieved from http://ontarioenergyboard.ca/oeb/_Documents/RRR/2014_Yearbook_of_Electricity_Distributors.pdf

OEB. (March 2015). *EB-2013-0416/EB-2014-0247.* Toronto: Ontario Energy Board.

Office of the Auditor General of Ontario. (2015). *Annual Report 2015.* Retrieved from http://www.auditor.on.ca/en/content/annualreports/arreports/en15/2015AR_en_final.pdf

Ontario Energy Board. (2015). *EB-2013-0416/EB-2014-0247 Decision March 12, 2015.* Retrieved from Ontario Energy Board: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0416&sortd1=rs_dateregistered&rows=200

APPENDIX C: PEER SELECTION

In 2009 CN Utility Consulting (CNUC) conducted a Distribution Vegetation Management Benchmark Survey for Hydro One and performed a comparative analysis of program efficiencies with utilities that had been selected as peers. The current study is a continuation of this analysis.

The selection of peer utilities in 2009 was based on the following criteria:

- Vegetation Cover and Density
- Weather Considerations
- Distribution System Characteristics (i.e. Customer Density, Size of Service Territory, Percent of Overhead (OH) Lines and Off-Road Lines)

The current peer selection expanded upon the 2009 criteria. There are several departures in the 2016 study design that allowed CNUC to select peers based on a larger set of criteria and to limit bias. These departures were:

- The survey was distributed to utilities that wanted to participate regardless of whether they were perceived as a possible peer to Hydro One.
- Comparative analysis of system characteristics and vegetation cover was performed on all survey participants before selecting peers.

Once the preliminary analysis was done, CNUC gave weights to the importance of each characteristic. These weights were assigned partly on regression analysis and correlational studies. The order of importance is as follows:

1. Peer in the 2009 study
2. Geographic location and proximity to Hydro One
3. Tree density and managed tree characteristics
4. Customer Density (i.e. Customers per sq km, customers per system km, customers per OH km and OH customers per OH km, Urban versus Remote)

Peer in 2009:

2009 peers were automatically selected as peers to give the current study continuity to the previous study. A majority of the 2009 peer utilities are represented in the current study.

Geographic location and proximity to Hydro One:
Utilities in Northern United States as well as Canada had similarities to Hydro One in several areas. Canadian companies not only had geographical proximity to Hydro One, they had comparable regulatory oversights that may vary from US utilities. Canadian utilities were given greater scrutiny for this reason. Most of the survey participants that are Canadian companies were chosen as peers, although not all. Northern US, excluding the Northern Great Plains utilities, has comparable climate and tree populations.

Tree density and managed tree characteristics:
Tree density and tree characteristics are of major importance, since it is really trees that are managed by the UVM department, not kilometres of line. A kilometre of line that is heavily treed will require more work than one with few trees. The tree species make-up will also affect the amount of time required for management.

Customer density:
Customer density was the last factor that was used for peer selection. Customer density was viewed from several perspectives, since each viewpoint gave insights into comparability of different utilities.

Customer density was calculated as followed:

- *Customer density by land area*: customers per square kilometre
- *Customer density per system circuit kilometre*: customers per overhead (OH) and underground (UG) distribution system circuit kilometre
- *Customer per pole kilometre*: Customer per OH distribution system kilometre
- *Service Territory Descriptions*: Percent of Urban, Suburban, Rural and Remote

This selection process allowed a larger sample set than the 2009 study and afforded the different territories comparators that had similar characteristics. It also eliminated some assumptions about comparability of UVM programs.

APPENDIX D: STATISTICAL METHODOLOGY AND MODEL DEVELOPMENT

UNIT CONVERSION

NUMERICAL DATA

All numerical data was converted to metric if necessary. Survey participants stated the units they used and appropriate conversions and calculations were done.

FINANCIAL DATA

United States dollars (USD) were converted to Canadian dollars (CAD).

- Statistics on financial graphs that used five-year averages or year-over-year trends were converted using the average of the annual exchange rates for years 2011 – 2015. This rate is: 0.9343524 (USD to CAD). This method was selected to smooth out the anomalous variation in the exchange rate.
- Statistics that only used only 2015 financial information (e.g. wages) employed the 2015 exchange rate (0.782992)

NORMALIZATION

Data was normalized by:

1. Filtering by peer group selection
2. Dividing by distribution system overhead (OH) kilometres
3. Dividing by annual managed kilometres
4. Dividing by number of electric customers
5. Focus on labour hours expended as a proxy for cost
6. Using percents
7. Selective comparisons of peer group

Given the complexity of the utility vegetation management (UVM) industry, calculations using weighted adjustments were not employed since they would mostly likely introduce bias. If there had been only one or two variables affecting differences between UVM programs, it would have been an appropriate approach. Multivariate analysis proved one factor could not be selected for weighted adjustment over another. Therefore, root-cause analysis was used to explain variability.

EXPLORATORY DATA ANALYSIS

Comparative investigation was based on an exploratory data analysis (EDA) approach. Simply put, the key data was summarized visually and by descriptive statistics before hypotheses were formulated.

REGRESSION AND MULTIVARIATE ANALYSIS

The relationship between UVM program cost and productivity components was explored using graphical visualization and by regression analysis. For example, tree density (trees/managed km), cycle length, and cost per managed kilometre were charted on one graph using the secondary axis to view all three variables simultaneously.

Regression analysis was done with some of the variables to see if relationships exist between factors. When more than two variables were being explored, multivariate analysis was done. Analysis was performed using JMP software, which is an exploratory statistical software. JMP allowed the researchers to perform a variety of tests and provided best fit analysis.

This exploration was done to build hypotheses about efficiencies, especially when identifying best management practices (BMP).

PROJECTIONS OF UNIT COSTS FOR HYDRO ONE

Hydro One is unique in three major ways with regard to the peer group:

- Line clearance, brush control, and job planning is performed by in-house crews using company-owned equipment
- The UVM program costs include administrative costs that other utilities do not include
- Hydro One employs seasonal workers that are hired from the Hiring Hall at lower labour burden rates

These differences make it difficult to use information from peer utilities to estimate costs for the model. Therefore, all projections were made using Hydro One's past spending records as a basis for setting cost estimates.

Hydro One experienced a major funding cut in 2014. This compelled them to change their UVM program in terms of equipment utilization, scheduling, and labour mix. Therefore, historical data of costs and production took a sharp turn beginning in 2014. Long-term cost modeling had to be based on the current budget, which has a larger cost per labour hour, but total expenditures are similar to pre-2011. This decision was determined through consultations with Hydro One UVM strategists.

Variables that affect the predictions:

- Fixed Variable Cycle Lengths

- Number of kilometres managed annually
- Annual Inflation
- Tree Density
- Cost per Labour Hour
- Employee Resource Mix (Hiring Hall vs FTE)

Three models were built:

1. **Risk Model A:** This model is at the highest risk level. It is a model built on the current scheduling methodology, which targets M-Class feeders and three-phase (3Ø) lines. 8,500 km of 3Ø (~one-sixth of the 3Ø system) will be done annually, including approximately 7,083 km of backlog work. Only 3,500 km of single-phase (1Ø) and double-phase (2Ø) will be done annually on a case-by-case basis and will be performed by Hiring Hall employees. There are 52,000 kilometres in this category and this will put this part of the distribution system on a 14.9 year cycle. 1Ø, 2Ø scheduling will be triggered by reliability problems. This scheduling methodology will take approximately six-years to get all the M-Class and the 3Ø feeders on the desired target variable cycles (four, six, and eight-year dependent on reliability considerations). This approach will get the high priority lines on schedule, but the single and double phase will fall farther behind.
2. **Risk Model B:** This model is a mid-risk model. This model expands the Risk Model A by continuing the backlog and cyclical work on the M-Class and 3Ø lines, but will also increase the work on the single-phase and double-phase lines to keep this part of the system closer to the 9.5 year (on average) cycle. This will increase the number of km for 1,2Ø lines to 5,473 km/year (13,973 total km managed annually). This increased work on the 1Ø will be done by Hiring Hall or contracted labor.
3. **Risk Model C:** This model carries the least risk and produces a more storm resilient system. It gets all of circuits on target cycles by obtaining an eight-year cycle (ten in the North region) for single and double-phase circuits. This requires that 6,500 km (1,2Ø) and 8,500 km (3Ø) be managed annually for the next six-years, a total of 15,000 km a year. The single and double – phase circuits will again be performed by Hiring Hall or contracted labor.
4. **BMP Model D:** This model produces a more storm resilient system with greater returns. It gets all of circuits on target cycles by obtaining a six-year average cycle for single and double-phase circuits. This requires that 8,687 km (1,2Ø) and 8,500 km (3Ø) be managed annually for the next six-years, a total of 15,000 km a year. The single and double –phase circuits will again be performed by Hiring Hall or contracted labor.

Once these models have cycled through the six-years, it is anticipated that the cost of maintenance on the scheduled work will decrease due to improved forestry conditions. Anticipated cost savings in each model:

- **Risk Model A** will see improvements only for the M-Class and 3Ø. At the same time, the single-phase will have accumulated a greater workload. This model will possibly see little to no improvements in the cost of maintenance due to half the system falling into greater arrears. In fact, it may make the work on the single-phase circuits more expensive and time-consuming. The time and money saved on the three-phase system will need to be funneled into the single-phase work after six-years.

- **Risk Model B** will see improvements only for the M-Class and 3Ø, but the single-phase system will have maintained its present conditions. This should produce reduced costs and labour hours for work done on the 3Ø. This will allow concentration on the single-phase. Once again, the time and money saved on the three-phase system will need to be funneled into the single-phase work.
- **Risk Model C** will see improvements on all circuits in the system and there should be a reduction in costs. These savings will not only come from reduction in workload, but also from increased storm resilience and a decrease in reactive work. It will take many years beyond the six year time-frame to establish an appropriate plant community and ROW conditions and to realize cost-savings.
- **BMP Model D** will see improvements on all circuits in the system and there should be a reduction in costs. These savings will not only come from reduction in workload, increased storm resiliency, and a decrease in reactive work. There will also be a reduction in the need for line clearance personnel and an increase in the herbicide and planning personnel. This change in labour mix will also be a cost-savings. It will take many years beyond the six year time-frame to establish an appropriate plant community and ROW conditions and to realize cost-savings. The long-term gains for this model will be greater than Risk Model C, since cycle lengths will be closer to best management practices.

The following elements and assumptions were built into all models:

- Units completed for Line Clearing, Brush Control, and Job Planning were equalized to account for the large differentials experienced in 2014 and 2015.
- 2015 costs were projected to be the best indicator of labour burden rates for the future by Hydro One. These unit rates were adjusted to include equal units completed for all three work types.
- The South's 2015 costs per managed km were thought to be a target for a system in control by Hydro One. The cost per kilometre was adjusted to include equal units completed for all three work types. Since all the regions in the Hydro One territory vary in terms of what will be required once on schedule, it is possible that this may need to be adjusted after several years of data has been collected on the new scheduling and work-force implementation.
- The M-Class feeders are mostly in control. It was assumed that the rest of the three-phase and F-Class feeders would get on schedule by 2022-2023
- East's costs per km were used to represent costs when circuits are in arrears or backlogged. Although the Central region has higher costs, the East was chosen to be a better estimate to account for regional differences. . Since all the regions in the Hydro One territory vary in terms

of what will be required to address backlog, it is possible that this may need to be adjusted after several years of data has been collected on the new scheduling and work-force implementation.

- An annual inflation rate of 1.67% - calculated from the current ten-year average for Canada.
- Hiring Hall/Apprentice and FTE mix is unpredictable at present. An approximation of the effect this mix will have on costs was established in the following way. Since, on average, the labor burden for hiring hall/apprentice personnel runs about 59% of a FTE, this ratio was used to model costs on the single and two-phase circuits. Presently, Hydro One will dedicate the use of hiring hall employees to the single and two-phase work. Since this mix has not been established and will change due to attrition, all calculations using this variable are subject to variation.
- An average of approximately $10M was added on each year to the projected costs. This represented the difference between routine maintenance and total cost of UVM. This includes reactive and administrative cost and was calculated using the five-year average from 2011-2015.

Model Set-ups

Risk Model A: 8,500 kilometres were set for the M-Class and 3Ø, and the single and double-phase lines were set at 3,500 km. 1,417 km of M-Class/3Ø will be circuits already on cycle and it will be predicted that UVM costs (Planning, Brush and Line Clearance) could be approximated by the 2015 cost for the South Region. The rest of the 3Ø will uses an equalized 2015 rate for Hydro One East, since the brush control and job planning were decreased in 2015.

Risk Model B: 8,500 kilometres completed were set for the M-Class and 3Ø, and the single and double-phase lines were set at 5,473 km. The same costing rates were used for projections as Risk Model A.

Risk Model C: 8,500 kilometres completed were set for the M-Class and 3Ø, and the single and double-phase lines were set at 6,500 km. The same costing rates were used for projections as Risk Model A.

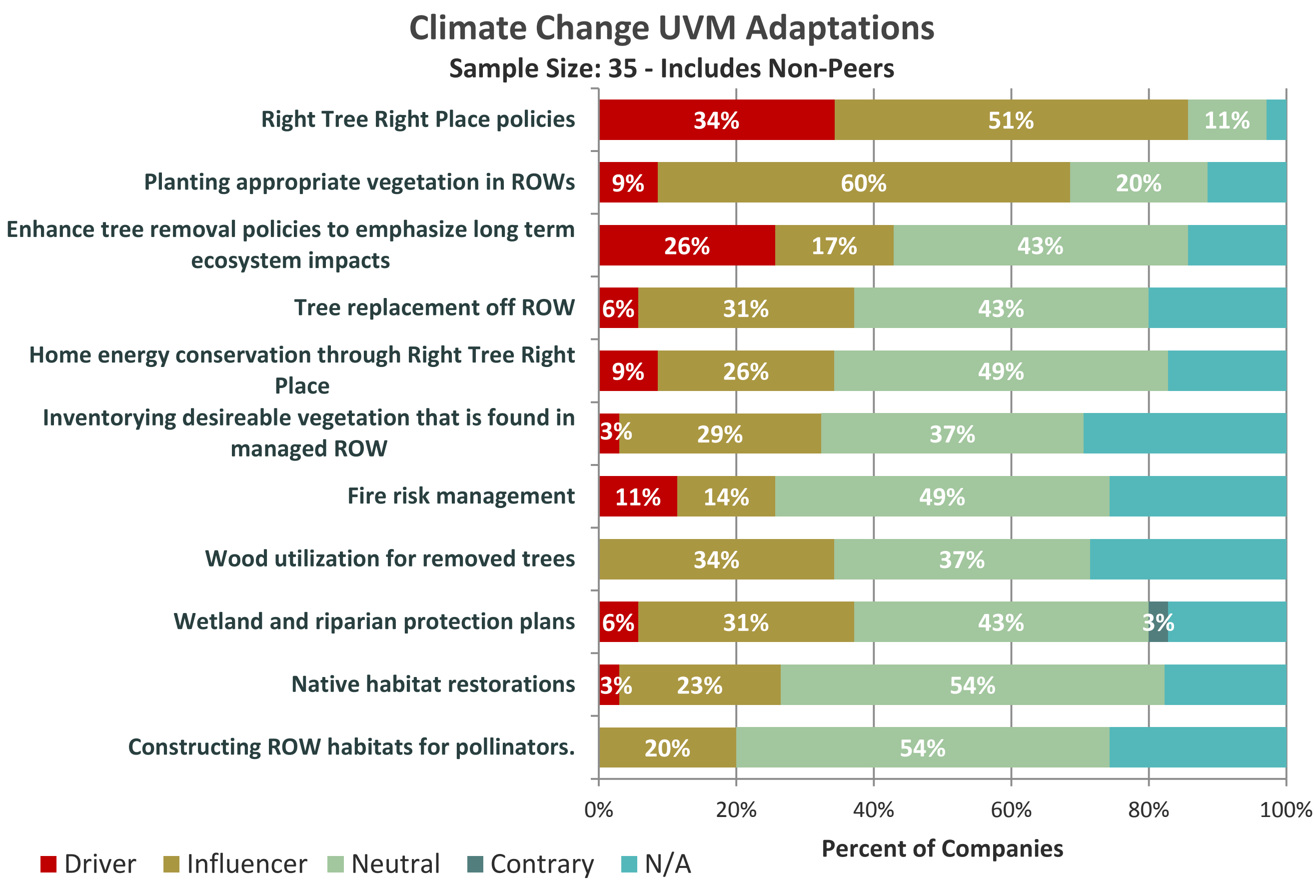
Model D: 8,500 kilometres completed were set for the M-Class and 3Ø, and the single and double-phase lines were set at 8,667 km. The same costing rates were used for projections as Risk Model A.

APPENDIX E: CLIMATE CHANGE AND STORMS

INTRODUCTION

This appendix addresses *Climate Change and Storms.* Of importance is not only the current storm severity but the impact on vegetation conditions due to climate change. A proactive approach to utility vegetation management (UVM) will most likely result in a long-term savings and mitigation of heightened risk from climate change.

Climate change adaptation will have its most aggressive opportunities in cycling trees out of the system before they become hazardous and entering trees into the system early enough to provide a sustainable canopy. UVM has to make this their mission in order to integrate with more global forestry efforts.



Graph 1: Climate Change Adaptation

Graph 1 (above) provides an analysis of how UVM policies are aligned with climate adaptive behavior. This is not an exhaustive listing of how UVM policy is or can adapt to climate change.

The models for climate change in Ontario indicate there may be significant increases in temperatures with the number of high temperature days (>30°C) doubling by 2050. Consider what this means to UVM at Hydro One. 2016-2050 is roughly 3.5 cycles of UVM for Hydro One. Heat waves are predicted to increase from the current “moderate/possible” (0-2.5 days) to “often” (1-5 days). The number of winter cold waves (≥ 3 days of <-10°C) will decrease from occasional to remote. Heavy rain days (>50mm/24hr) in southern Ontario are expected to increase from “moderate/possible” to “often.” Summertime precipitation is predicted to decrease by as much as 10-25% by 2050 in southern ON. The predictions for beyond 2050 escalate (CIMA 2014). Will the UVM department be able to respond effectively to a much different future, when it is challenged by the present growth conditions?

Adaptation to climate change could be a positive influence on UVM programs efficacy, efficiency and knowledge of the evolving conditions. Opportunities for the forestry and utility industries have already been manifested in a multitude of ways. Utilities have decreased their use of coal and other fossil fuels in favor of cleaner and ultimately cheap sources of energy such as wind and solar. Regulators are discovering ways to keep utilities successful while generating and distributing less electricity. End-users are getting more benefits while using less energy. Western Canadian timber companies have already salvaged the majority of useable lost timber from the Mountain Pine Beetle (MPB) devastation. These are winning, “no-regrets” adaptations that are helping to solve a problem. UVM could follow a similar pattern, by strategically planning for a future in which fewer resources will be needed to bring solutions for adapting to climate changes and improving electric reliability.

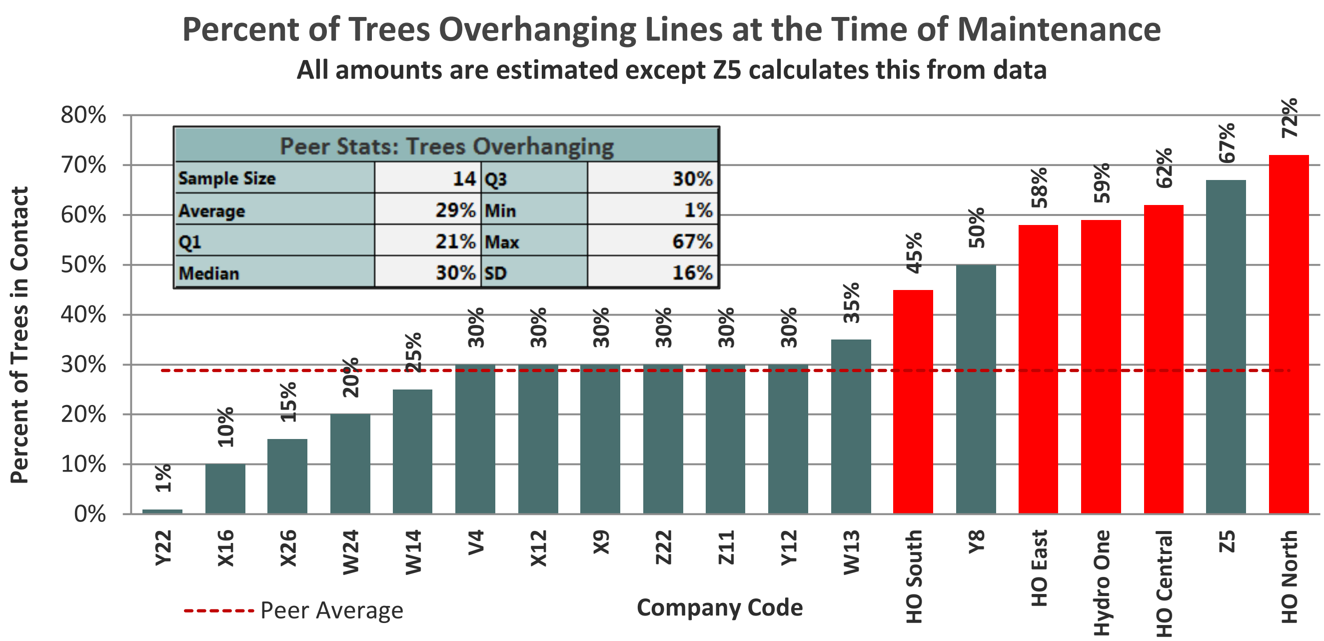
STORMS

CLIMATE CHANGE AND THE UVM RESPONSE TO STORMS

Reliability is the number one UVM objective for Hydro One. This is because Hydro One has been in the fourth quartile for system average interruption duration index (SAIDI) in peer performance comparisons for many years. Storms are a tree problem. Strategies for reducing damages that occur from storms are a priority for Hydro One’s UVM programs, because customers have come to expect electricity to be highly resilient to storms. Customers, the public, the media, elected officials, and regulators will judge utilities when major storms interrupt power for prolonged periods. Climate change has begun to cause catastrophic storms to happen more frequently and with greater intensity than in the past. Major storms have been happening ever since the first overhead system was built. In many ways storms already represent climate change because they are never the normal and they have always set new records. Distribution grids typically sustain heavy damage and require resources many times the size of the routine workforce that are brought in from long distances to work incredible hours in often dangerous conditions of unstable trees and broken equipment. Unfortunately for

UVM programs, the history of violent storms bringing down trees has not inspired society to want the utility to scientifically and effectively manage for reductions in damage. Perhaps for a short time, customers want to give up a tree to protect their part of a circuit, but soon the major event is historical and the risk of losing power again is not as important as the tree.

A realistic equation between tree benefits and cost-effective utility forestry strategies and best management practices has to become a part of the future environmental zeitgeist of the larger society that Hydro One serves. Not until overhead electrical equipment is afforded an appropriate space without vegetation will Hydro One be able to effectively manage the risk of failing trees during storms, particularly storms in the 21st century of climate change. Hydro One's *estimated* percent of managed vegetation that overhangs conductors is higher than nearly all of its peer group (Graph 2 below).



Graph 2: Percent of Trees Overhanging Lines at the Time of Maintenance

Without effectively managing to achieve a low percent of overhanging trees, particularly susceptible species, storm risk will remain dangerously high. This situation is likely to collide fatefully with the catastrophic storms predicted for the coming decades.

Proactive initiatives to increase system resiliency are happening at several utilities. Hydro Quebec, Manitoba Hydro, Consolidated Edison, Connecticut Light and Power, PSEG, FPL, and Entergy are a few utilities that have experienced multiple events over the last few years that have inspired them to respond to perceived impacts of climate change (CIMA 2014). They have implemented programs to harden their distribution systems against more frequent and more intense storms. Hydro Quebec has ramped up its efforts with a special pruning program in areas that are prone to freezing rain over 25mm. Identifying and removing hazardous trees is a key component to hardening a system.

The benchmark survey performed for this project probed whether UVM departments have linked their efforts to climate change prevention/adaptation policies and strategies adopted by the generation and grid operators they serve. The survey and literature review shows that while UVM departments are aware that climate change is already affecting their programs, there aren't strategies for adapting beyond meeting the current urgencies. 85% of companies view Right-Tree Right-Place policies as a driver or influencer to their program (see Graph 1, p.85), but it is unclear whether such policies and initiatives are being applied in a strategic response to climate change or if programs passively apply it because it would effectively reduce workloads. Right-tree right-place is the ultimate solution to UVM and many other urban forestry problems and it has been trending since the term was coined in the 1940's. However, unless it is applied more faithfully, right-tree right-place becomes little more than a wish and any place a tree grows is the right place. In the past we managed forests with fire to regenerate new forests and provide new food for wildlife. It is in a similar spirit of stewardship and benefits that a utility should maintain networks to provide reliable modern "fire" that powers our homes, cities and towns. 43% of companies who responded to the survey are adopting more assertive climate change adaptation by enhancing their UVM program tree removal policies to emphasize long-term ecosystem benefits (Graph 1). This is an alignment of UVM objectives, such as reliability, with more global forestry urgencies.

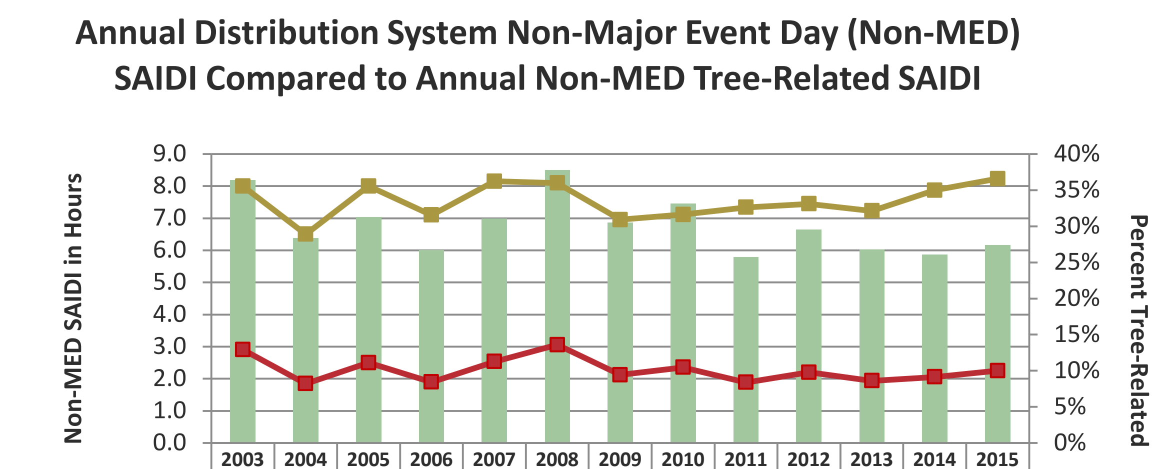
Storms and the Reliability

Out of the last thirteen years, Hydro One finished ten of them with greater than 60% of Major Event Day (MED) outages caused by trees (Graph 4, p.90). This poor performance during storms is a great challenge. When climate change effects intersect with long-term poor reliability performance, there is likely to be a catastrophic outcome.

Hydro One has had numerous ice storms and wind events that have resulted in a high number of outages. While lightning strikes and tornadoes may happen less frequently than in parts of the US, Hydro One faces many logistical challenges in managing storms that other companies in the study are better suited to handle. These challenges are evident in reliability data over the past decade. A few facts emerge when you look at the reliability (SAIDI) of the Hydro One Networks on Non-MEDs (Graph 3, p.89):

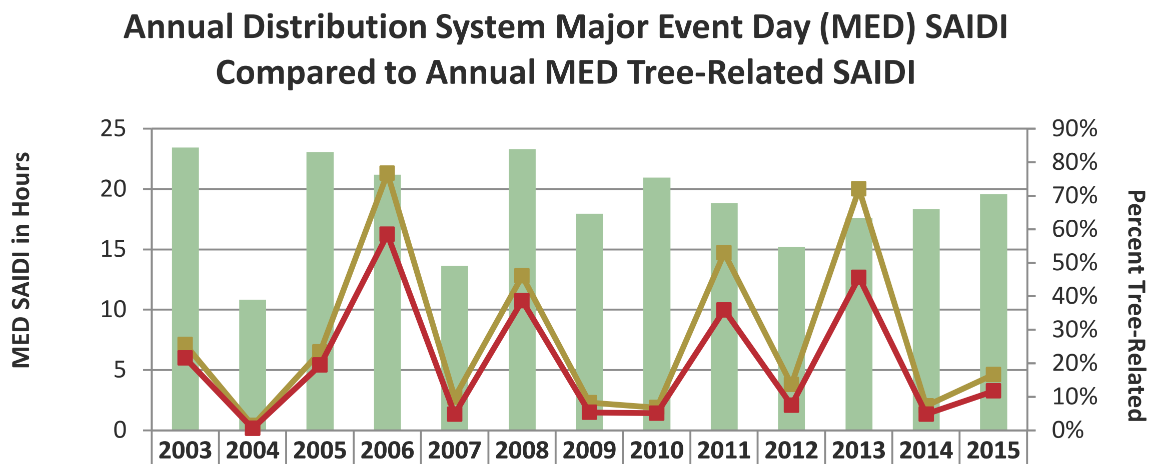
- Tree-related Non-MED SAIDI has improved for Hydro One since 2008. The improvement since 2003 is less significant.

- Other (non tree-related) causes of non-MED failure have been increasing steadily since 2009 so that SAIDI has increased nearly an hour during the last 6 years while tree-related SAIDI has remained relatively steady since 2009.
- *2011 through 2015 was the lowest five- year period of non-MED tree-related SAIDI for the last thirteen years*.
- Non-MED tree-related SAIDI has ranged between 26-38% of the company non-MED SAIDI for the last thirteen years.
- Non-MED SAIDI is probably a higher priority for asset improvements since on average more than two-thirds of it is not tree-related.
- The percent of SAIDI that is caused by trees during non-major event days (non-MED) is average in comparison to peers (see reliability section in main report).
- The contrast between non-MED performance and MED performance is striking and emphasizes the need for making the system more resilient (See Graph 4,below).



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	36%	28%	31%	27%	31%	38%	31%	33%	26%	30%	27%	26%	27%
Total Non-MED	8.0	6.5	8.0	7.1	8.2	8.1	7.0	7.1	7.3	7.5	7.2	7.9	8.2
Tree-Related	2.9	1.8	2.5	1.9	2.5	3.1	2.1	2.4	1.9	2.2	1.9	2.1	2.3

Graph 3: Hydro One Time Study of Non-MED SAIDI from 2003 – 2015

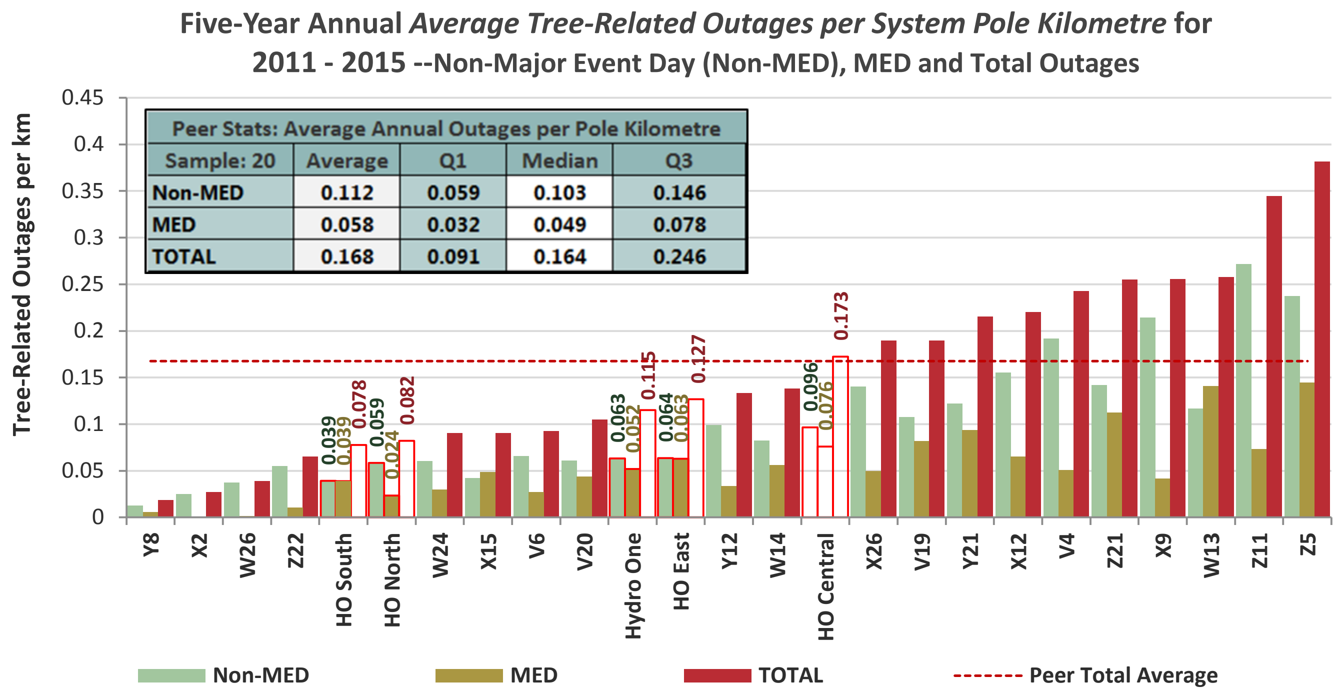


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	84%	39%	83%	76%	49%	84%	65%	75%	68%	55%	63%	66%	70%
Total MED	7.1	0.4	6.5	21.3	2.7	12.8	2.3	1.9	14.7	3.8	20.0	2.0	4.6
Tree-Related	6.0	0.2	5.4	16.2	1.3	10.7	1.5	1.4	10.0	2.1	12.7	1.3	3.3

Graph 4: Hydro One Time Study of MED SAIDI from 2003 – 2015

MED SAIDI is a different puzzle and trees are the culprit for the majority of cases. MED tree-related SAIDI was 70% of total MED SAIDI in 2015 (See Graph 4, above). The significant fact to recognize with these measurements is how much the ratio of tree related outages to asset failure increases during storms. A Department of Energy (DOE) study has noted that SAIDI is increasing throughout the US particularly when measured with major events. Even a slight increase in average annual wind speed of 10% correlates with a 75% increase in SAIDI (Larsen et al, 2015). The 2014 CNUC distribution benchmark survey found tree-related SAIFI accounted for more than 43% of total SAIFI during MED compared with 24% during non-MED. What this tells us is that UVM will have much greater success if it can reduce the outages that happen during major event days. It is the duration of interruptions during major events that have caught the attention of the public, the media and high level officials (White House 2013).

Hydro One performs relatively well when total outages are measured per kilometre of overhead line (See Graph 5, below). With the exception of the Central region, the five-year average of *total* outages per kilometre is below the average of their peers. The South and the North are in the first quartile. The whole company, performing at 0.115 outages per kilometre, is well below the average of 0.168. The ratio of Non-MED to MED outages is on average about 2:1 for the peer companies. However, for Hydro One East and South it is 1:1, Central is 5:4, and North is 5:2. With the exception of North, the ratio of MED to Non-MED outages is significantly less than peer companies. Since 2003, the majority of storm outages have been caused by trees nearly every year (See Graph 4, above).



Graph 5: Hydro One Comparison with Peers for Non-MED, MED and Total SAIDI 2011 - 2015

Hydro One's relative performance with outages in MED or Non-MED may be somewhat related to methodology in determining the MED, which does not follow the 2.5 Beta Method described in IEEE-1366. However, Hydro One's methodology would tend to keep small scale storm impacts in the Non-MED category because the bar is set sufficiently high for MED—10% of customers are disrupted. Most companies are able to remove catastrophic storms from the metric so that their Non-MED isn't an unrealistically low bar and if a company has no big storms the bar is automatically set at a level to allocate a fair proportion of outages to MED. Additionally, this data is smoothed by averaging over five years. In other words, storm events are frequently severe enough that 40% of Hydro One outages are MED. Hydro One Central is in the high end of the third quartile in peer comparisons of outages per km during storms, East is in the third quartile, and the company as a whole is close to the median (Graph 5 above). *Central and East should make storm resiliency a priority*.

Hydro One and all of its stakeholders would like to see an improvement in the reliability of the system, especially when storms blow through. A definite trend emerges for MED tree-related SAIDI (Graph 4, p.90). The data since 2003 has shown that storms have been worse every second or third year since 2003. The cause is unknown to CNUC, but it is worth noting from a planning perspective. The percent of SAIDI during storms attributable to tree failures is most interesting. From an engineering perspective, the asset failure causes are mostly happening during non-MED and could be solved with system upgrades and other condition-based refurbishments. Equipment failures that happen during storms may be the same failures that happen on non-MED days and the same maintenance processes will solve both reliability issues. The hardening of the system during storms is predominantly a single issue - trees. These are ostensibly not the same issues that are happening during non-MED outages, although a consistently applied improvement in routine maintenance would result in a substantial improvement to MED SAIDI. From a UVM perspective, if the right trees could be removed, then the system would be more resilient during storms, which is when it needs the most improvement (See Appendices F & G Tree Risk Assessment).

Typically on most systems the events that cause the greatest damage are wind events. A map of wind events from the Ontario Ministry of Community Safety and Correctional Services, Hazard Identification Risk Assessment (Figure 1, below) illustrates the relative potential for storms in the four Hydro One Regions. The South has the highest potential, but it has the lowest tree density and lowest number of outages per km. The Central has the second highest risk and it has high tree density and the highest number of outages per mile. The East has the second highest number of outages per km, but it has only a moderate risk of wind events. The North has the least risk in regards to wind events. Similar maps are included for tornadoes and freezing rain. The highest concentration of the most severe tornadoes are in the South (Figure 2, below). The East has the second highest risk for tornadoes and also has the highest risk for freezing rain (Figure 3, p.94). The South has the third highest risk for tornadoes and the southern part of the North region is fourth.

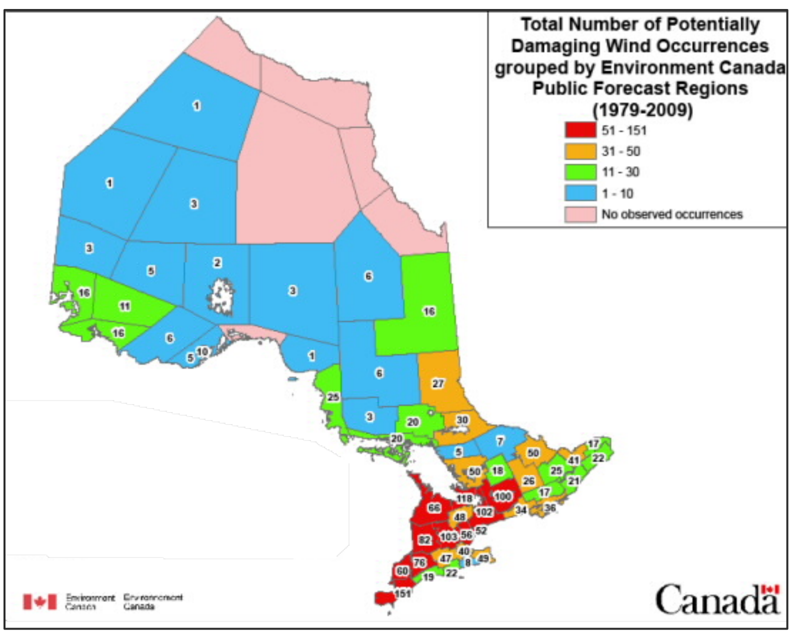


Figure 33: Historical Cumulative Number of Damaging Wind Events 1979-2009 (Hazard Identification Risk Assessment)

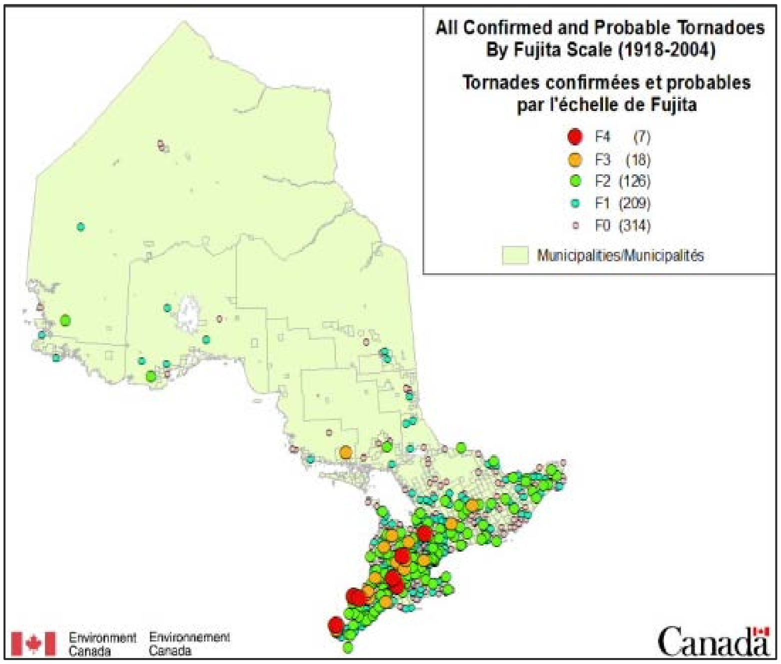


Figure 34: Total Tornado Occurrence in Ontario 1979-2004

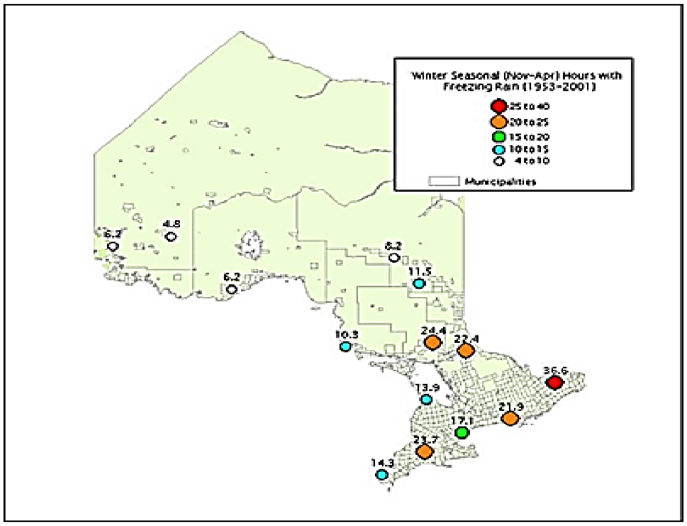
Wind damage has been cited as the largest cause of destruction to forested areas in Europe:

> *Tree species and average tree or stand dimensions, especially height, have been found to be the most important factors controlling [wind] storm damage in the forests typical of central Europe* (Hanewinkel 2013).

Tree defect, which is sometimes difficult to assess, is the most common attribute that an arborist in the US uses to determine the risk of failure. The collection of articles entitled Living with Storm Damage to Forests (Gardiner 2013) suggests there is an attribute elevating wind damage risk - tree heights - that can more easily be evaluated at the stand level instead of individual tree assessments. Other important factors affecting wind damage noted in this study were:

- Types of trees: Conifers are more susceptible than hardwoods
- Waterlogged soils with restricted rooting
- Acidic soils
- High final tree height and high target diameters are key factors for determining risk
- Early thinning at low heights increases diameter and reduces wind risk
- Slopes and valleys exposed to prevailing wind
- Thinning at latest stages of forest rotation increases wind throw risk
- New edges on a upwind side of stands increase wind damage risk
- Trees with highest taper are most wind resistant
- Thinning on exposed sites increases wind risk

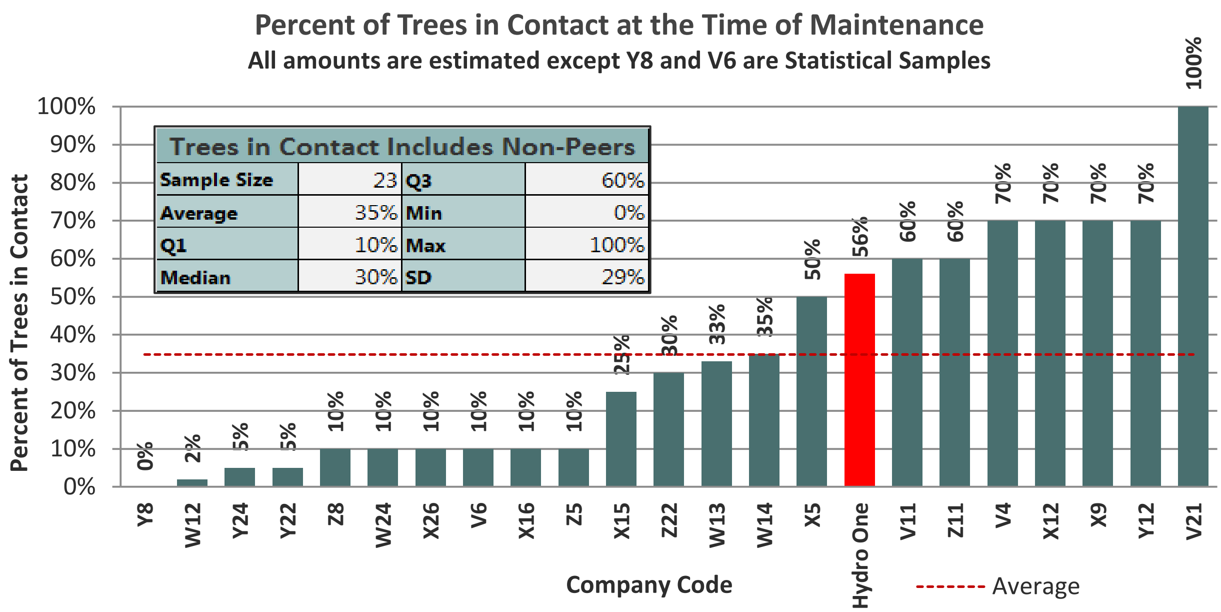
(Hanewinkel 2013)



Freezing rain is a frequent hazard in Ontario. Northern and Central Ontario experience the greatest number of days per year with freezing precipitation (Figure 5) with an average of over 17 days per year. Southern Ontario has fewer days per year with an average of just over 11 days. In Ontario, the most severe ice storms/freezing rain events usually occur from November to March with approximately one half occurring between the last two weeks of December and the first two weeks of January. In general, these have lasted between 12 hours and 1-2 days (Environment Canada, 2009). Freezing rain can be a small scale or a large scale hazard, depending on the size of the storm system.

Figure 35: **Average number of hours per year with freezing rain, based on data form 1953-2001**

Ice storms are not an uncommon occurrence in Ontario and, as noted by the Ministry of Community Safety and Correction, from 17-36 hours of freezing rain can occur annually in Hydro One's South and East regions and the southern part of the North region. Ice storm risk is increased by a considerable margin when trees are overhanging or in close proximity to conductors. The ice brings the branches into the conductors. Until ice-covered, broken, and permanently-bent branches are removed, the power cannot be restored. This is repeated for *every* tree that has not been managed for clearance from conductors. Unlike wind, there is less chance that trees from a further distance will be blown over into the conductor. Managing a system for permanent clearances is the greatest defense against ice storms, which are a frequent cause of disruption on parts of the Hydro One system. A similar case can be made for protection against heavy snows on conifer trees. When the percent of trees overhanging (Graph 2, p.87) and the percent of trees in contact (Graph 6, below) on the Hydro One system is considered, it is not surprising that wind, ice and snow events cause many MED outages for Hydro One.



Graph 6: Percent of Trees in Contact at the Time of Maintenance

Storm Case Study

In 2014 after Nova Scotia Power (NSP) experienced the aftermath of Post-Tropical Storm Arthur, the company entered into an investigative and rule-making proceeding with the Nova Scotia (NS) Utility and Review Board (UARB or "Board"). The jurisdictions of various stakeholders regarding vegetation management and storm hardening were the primary concern of the Board. Like Hydro One, the issue of vegetation management must be handled with stakeholder consultation. Organizations, such as the transportation authority, the union of NS Municipalities and Wood Lot associations, are included in the proceedings. A consulting company was hired to study NSP's preparations and response to the hurricane. The following activities have resulted from the proceeding:

- Improve the capability for weather forecasts on a local level
- Reclaim overgrown distribution ROW including widening of the ROW
- Prioritize three-phase feeders
- Execute multi-year performance evaluation for worst-performing circuits
- Widen ROW of sub-transmission lines (69kV)

Comments from intervenors regarding vegetation management were generally aligned with the independent recommendations, which were nearly all made into policy at NSP. Most of the letters from the public stated NSP should do more vegetation management (UARB 2014).

"*More than 90% of the power outages caused by Post-Tropical Storm Arthur were due to trees contacting lines and other equipment"* (NSPower 2014). In 2015, NSP filed with UARB a follow-up report in which they stated, "*There is approximately 10,875 km of distribution right-of-way remaining to reclaim throughout the province and at the current budget for vegetation management it is estimated to take approximately 32 years (at $3M per year) to get the program to a sustainable level"* (NSPower 2015 p. 18).

For Nova Scotia Power the measure of progress is the percent of ROW kilometres that are classified as sustainable with integrated vegetation management (IVM). NSP has begun widening the sub-transmission corridors and has submitted a plan for widening the remaining 40% of the distribution line kilometres at a cost of $8,500 per km (NS Power 2016). This plan should effectively bring the NSP distribution system to an optimum level of cost efficient management and reduced reliability and safety risk.

One of the issues that was reviewed at length after Post-Tropical Storm Arthur was the weather forecasting capabilities. This is an area of technology that is developing rapidly and many companies are now setting up local weather reporting systems to enable preparations and responses to impending storms. This will enable the utility's response to be more finely tuned to the timing, intensity and actual damages from a storm. These hyper-local forecasts can inform load planning as well as "ensure utilities know what weather will affect a specific point of their service area up to the minute and throughout the entire day, up to 72 hours in advance. They also can determine if high winds or rain will hit a portion of their service area, while other areas will be hit with ice and snow. This allows utilities to plan for outages before they happen and understand where their pain points will be" (Schneider Electric 2015).

CONCLUSION

The human-built world will have to adapt to changes that will not always be predictable. For an electric distribution company, it makes sense to take a "no regrets" approach (Figure 4, below) to protecting the grid against more frequent and more intense weather events. The win-win outcome will be to have a more reliable and safe system regardless of climate change and a more environmentally adaptable, safe and reliable system.

POTENTIAL REGULATORY SOLUTIONS FOR CLIMATE CHANGE ADAPTATION

Common Regulatory Commission Functions	Potential Enabling Roles for Adaptation
Determine the revenue requirement and utility rates	Guidance on eligibility of adaptation-related investments for rate reimbursement; Structure utility rates to enable demand responsiveness (Ex: dynamic pricing)
Set service quality standards and consumer protection requirements	**Require robust storm plans and conduct evaluations and drills.**
Oversee the financial responsibilities of the utility, including reviewing and approving capital investments and long-term planning	**Examine adaptation-related investment and require long-term planning take climate change impacts into account.**
Review and approve comprehensive supply resource plans	Require that resource plans are tested against future scenarios that include climate change projections and uncertainties; Provide opportunities for collaborative decision making.
Approve the entry of competitive retailers into the state's market	Allow microgrids and ESCOs to operate in utility service territory to provide customers with energy management options

Figure 36 : Potential Regulatory Solutions for Climate Change Adaptation (Higbee 2013)

Bibliography

Executive Office of the President. (2013). *Economic benefits of Increasing Electric Grid Resilience to Weather Outages.* Washington DC: US Department of Energy. Retrieved from http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Hanewinkel, M., Albrecht, A., & Schmidt, M. (2013). Influence of Stand Characteristics and Landscape on Wind Damage. In B. Gardinar, e. al, & L. Hetemaki (Ed.), *Living with Storm Damage to Forests* (pp. 39-41). European Forest Institute.

Larsen, P. H., LaCommare, P. H., Eto, J. H., & Sweeney, J. L. (2015). *Assessing Changes in the Reliability of the US Electric Power System.* Berkeley National Laboratories. Berkeley, CA: Department of Energy.

Nova Scotia Review Board. (2014). *Post tropical Storm Arthur - Review of NS Power's Storm Response.* Retrieved from http://www.nspower.ca/site/media/Parent/20140819%20Post-Tropical%20Storm%20Arthur%20-%20Review%20of%20NS%20Power's%20Storm%20Response%20-%20Report.pdf

Nova Scotia Utiity and Review Board. (2016). *Post-Tropical Storm Arthur.* Retrieved from http://www.nspower.ca/site/media/Parent/20160201%20NSPI%20to%20UARB%20Post-Tropical%20Storm%20Arthur%20Progress%20Report.pdf

Nova Scotia Utility Review Board. (2015). *Post-Tropical Storm Arthur - Vegetation Management.* Retrieved from http://www.nspower.ca/site/media/Parent/20150213%20NS%20Power%20Post-Tropical%20Storm%20Arthur%20Vegetation%20Management%20Stakeholder%20Consultation%20Report.pdf

OEB. (2015, July 31). *2014 Yearbook of Electricity Distributors.* Toronto. Retrieved from http://ontarioenergyboard.ca/oeb/_Documents/RRR/2014_Yearbook_of_Electricity_Distributors.pdf

OEB. (March 2015). *EB-2013-0416/EB-2014-0247.* Toronto: Ontario Energy Board.

Power Stream. (2014). *Hardening the Distribution System against severe storms .* Vaughan, Ontario: CIMA.

Schneider Electric. (2015). *Weather Stations: Providing business critical information.* Retrieved from http://oreo.schneider-electric.com/flipFlop/1427144232/files/docs/all.pdf

Appendix F: Tree Risk Assessment - A Best Management Practice

A Tree Risk Assessment (TRA) standard, ANSI A300 Part 9, has provided a framework for utilities to develop formal TRA programs. In a survey performed in February and March 2016 for Hydro One and the Utility Arborist Association TRA Best Management Practice (BMP) Working Group, 40 utility companies throughout North America gave their opinions and facts on their programs relative to tree risk and hazardous trees. The data from this survey is intended to help determine current practices and what would fairly represent a BMP for publication. This discussion will pose some questions and potential directions for a Best Management Practice as the basis for evaluating Hydro One's current practices. The cornerstones for determining tree risk are inspection, measurement, and record keeping. Some key practices include site and tree inspections, remote sensing, customer education, and data analysis.

An important aspect when making vegetation management decisions is understanding specific hazards in the context of populations of trees. An inspector looking for suspect trees rarely encounters a tree that is ready to fail. Instead, a decision to remove a tree may need to be based on a classification list that comports with a system-wide effort to reduce risk over the entire population of trees. It is different for an arborist about to commence work, who must inspect the tree for hazards as a matter of safe practice. If the tree has some hazards that the arborist considers a compromise to his or her safety, then a decision might be made to adjust the method of working the tree, including a recommendation that the tree be removed. Removal may be recommended if the tree cannot be worked safely, and so that the tree isn't left as a safety risk for the public, the property owners or future arborists assigned to work on the tree. The arborist decision process is valid, because it is vital to weigh out the probability of safety factors that are part of the exigent realities of working in the trees. However, these trees are typically expensive and risky to work on and it is unfair to arborists to expect such conditions to be the normal life-cycle of trees they work on. A better scenario involves deciding to remove trees before they become hazardous. Hence, there are significant benefits to be derived from a formal Tree Risk Assessment program.

There are also social and economic reasons for developing a formal process. The final decision to remove a tree may require assessments based on the probabilities for how many trees will be selected for removal versus how much resource is available to remove the trees. These are calculations that cannot be easily made, even by a trained, experienced inspector, armed with precision measurements and techniques for detecting signs that a tree should be removed.

Removing trees is a product-based event with a dramatic and permanent outcome; i.e. there is no longer a tree standing, there is substantial debris, and there are agreements and communications to make it happen. For these reasons, the process for permitting the removal of a tree, the time it takes to remove, particularly large trees (hazard trees are frequently mature trees), and the challenges related to debris disposal have made tree removals an expensive, onerous business for utilities. Waiting until trees become hazardous before removing them may be the most expensive mistake utilities have made over the last century. The following testimony highlights this assessment:

> *"The fact is that many of our outages that are caused by trees are actually from trees that are outside of our right-of-way. Limbs fall on our equipment or trees fall down: This is just a fact. If you look at our distribution system, the three largest causes of interruptions, in order, are tree contact, tree contact and tree contact. That's a fact."* (Hydro One recorded testimony 2016 Legislature)

There are few incentives for removing large trees adjacent to ROWs beyond a fear the tree is about to fail any minute. Even with the knowledge that a tree may be unsafe, it is unclear whose responsibility sits with a bad tree. In fact, only 11% of utility respondents to the Tree Risk Assessment survey stated their company has a clear idea of where their responsibility for risk ends and the property owner's begins. Consequently, a standard of practice for the utility industry is likely to be somewhat of a lowest common denominator, such as the arborist performing a job site analysis decides the tree is dangerous and the *only* way to work it is to cut it down. Otherwise, leave the tree standing until there is a more definitive assessment that the tree is going to fail. And then maybe the property owner will step up and take responsibility. Many trees are worked by arborists who have doubts about their structural integrity, but the external pressures for them to perform to a standard of productivity in spite of their doubts has led to a culture of risk-taking behavior. A standard or best management practice for evaluating tree risk could alleviate some of the danger of trees failing into high voltage distribution lines. In fact, this is occurring on regulated (FAC-003/NERC) transmission corridors and some distribution and sub-transmission corridors. The TRA survey identified the percent of companies that frequently inspect their lines:

- 18% of companies inspect 100% of their single-phase line annually
- 26% inspect 100% of their multi-phase primary lines annually
- 63% inspect 100% of their non-FAC-003 regulated lines annually
- 100% inspect 100% of their FAC-003 regulated lines annually

Of the companies that have separate TRA programs (17), 65% (11 companies) also have pre-inspection programs. Of the remaining six companies who have a separate TRA program, 83%

do inspections at the time of maintenance (one did not answer this question). These statistics indicate it is probable that formal TRA programs are better implemented as a subset of pre-inspections than added to the highly-focused and risk-intensive activities of aerial arborists. The skill levels of inspection and assessment and capabilities to analyze data are the current limits on how successful a TRA program can effectively pay for itself. Successive inspections and the use of historical data, as well as the growing database of outage root-cause analysis, will bring regular improvements to TRA. The TRA process is likely to remove some trees that in reality would not have failed in the near term. For utility purposes this is not as efficient as cutting down a tree that would have caused a significant amount of service disruption, damage, and customer dissonance. Nevertheless, benefits are derived because the tree does not have to be removed in the future and, since the tree is not fully decadent, it may have value as a wood product. Renewal of trees adjacent to the ROW offers an opportunity for changing the culture of land management to one that is more harmonious with infrastructure. Laura Cooke from Hydro One made the following statement about Hydro One's efforts:

> *Something else that we like to do is we like to work with communities to beautify a section on a right of way after we've done the work. We understand that in some communities, the rights of way and the greenery along the rights of way are the only green space some communities have, so they really, really want to protect that space. What we try to do is manage our obligations to reliability and manage our obligations to the community by trying to do some beautification work following some aggressive tree trimming.* (Hydro One recorded testimony 2016 Legislative Standing Committee)

Since inspections on distribution ROW for the majority of companies, 54-58%, is performed by the crew at the time of maintenance, there is little opportunity to fully engage the customer or plan a ROW conversion that is beneficial to both the customer and the utility. For the 43% of companies that do engage in a pre-inspection process, the most common way utilities make improvements on the properties they impact is to plant a new tree or shrub in an appropriate place. A few companies have begun offering to plant trees that provide energy conservation. Research from the University of Guelph indicates significant value to maintaining a high percent of canopy for human comfort levels to prevent heat islanding (Graham 2012). The peak load needs of summer heat waves are mitigated by tree canopy, thereby relating tree canopy to energy efficiency. It is expected that summer time heat waves in southern Ontario will increase as the effects of climate change intensify. Customer service via utility forestry services may be directly influenced by the nexus of energy, environment and conservation. It is apparent the utilities cannot operate forestry programs without integrating with the larger environmental concerns.

In general, a formal inspection program is a prerequisite for a TRA program. Arborists performing tree work could be expected to implement a formal TRA program, but there are many challenges to manage and it could result in cost escalations in areas where tree removals are indiscriminant or do not bring any reductions in tree-related outages and equipment damages. Utility reaction has been to limit the number of removals and allow only the smallest class trees to be selected without approval from forestry management. There are some questions to consider:

- Should a tree risk assessment program go beyond the effort of trying to find the trees that are imminently in danger of failing?
- Should aerial arborists who are charged with production expectations make decisions whether to remove trees that are not imminently hazardous but carry long-term financial and safety risks that could be mitigated?
- Should a utility have some level of understanding about the inventory of trees that are tall enough to strike distribution lines and have the risk for failure?
- Will the costs of measuring, collecting and analyzing data plus the additional work of removing trees bring a return on investment?

While these questions have been presented, they are exceedingly difficult to quantitatively answer. Studies have shown that deferring maintenance escalates cost and increases safety hazards. The North American UVM standard for transmission (FAC-003), California requirements for permanent airspace around conductors including managing hazardous trees, and a few states and provinces that have initiated reliability performance expectations have compelled utilities to manage hazardous trees. Beyond these regulations, there are few incentives for utilities to spend funds on removing anything other than the most obvious hazardous trees and the smallest class trees (in-growth).

The Auditor General for Ontario has noted the following concerning Hydro One's UVM program:

> *Hydro One's cycle for clearing vegetation (forestry) under, around and above distribution lines is more than twice as long as that of comparable utilities. Because trees are not trimmed back as often, Hydro One experiences more outages caused by fallen trees or tree limbs. We noted that line breaks caused by trees were the main cause of distribution outages from 2010 to 2014, responsible for 31% of all outages.*
>
> (Auditor General 2015)

One could argue that a few select removals on high- priority feeder lines could improve the reliability performance. On the other hand, this type of effort would divert resources from the already escalating problem of ROWs spiraling out of control with growth into the lines. This strategy has been tried and what has been learned is that it does improve reliability if select trees are removed.

While the survey has many measurements to consider and the UAA is in the process of designing a best management practice for the industry, a phased in approach with flexibility is appropriate for Hydro One to begin addressing the reliability, safety, cost, and customer service problems caused by a preponderance of off-ROW tree -related outages. The design of a TRA program could involve discussions with regulators and a public discourse to arrive at consensus of what a long-term approach would look like and where responsibilities and funding would be assigned. A TRA program should begin with baseline expectations for on-ROW management to ensure the effectiveness of the practice is not compromised by on-ROW growth and that the program is efficiently administered. Otherwise, the TRA program would not be a best management practice.

Works Cited

Committee Transcripts: Standing Committee on Public Accounts - 2016-Mar-23 - 2015 Annual Report, Auditor General: Ministry of Energy, Hydro One, Ontario Energy Board . (2015).

Graham, A. A. (2012). *The Impact of Design modifications to the Urban Landscape.* Guelph, Ontario: The University of Guelph.

Office of the Auditor General of Ontario. (2015). *Annual Report 2015.* Retrieved from http://www.auditor.on.ca/en/content/annualreports/arreports/en15/2015AR_en_final.pdf

Appendix G: Tree Risk Assessment Best Management Practices Survey Results

TABLE OF CONTENTS

INTRODUCTION

The following report represents the results of the *Tree Risk Assessment Best Management Practices Survey* deployed in March 2016. This report will be used by Utility Arborist Association (UAA) to develop a Utility Best Management Practice (BMP) for Tree Risk Assessment (TRA).

Work is currently underway to develop a Tree Risk Assessment (TRA) Best Management Practice (BMP) specific to the utility industry. The BMP will follow the general format and use the risk assessment constructs included in the current ISA TRA BMP (2012). The utility-specific BMP needs to reflect current practices within the industry and provide useful guidance on contemporary best management practices. The results of this survey will help guide development of the new BMP.

How to Navigate the Report

- The Table of Contents (previous page) has links to each graph and table
- All questions (as written in the survey) are given after the survey question number.
- Graphs and comment tables are shown after each question to report on the survey results.
- Responses to the questions are in brackets on comment tables. In other words, if the respondent answered, “Yes”, [Yes] will appear after their comment. This will be true for most comment tables in this report.
- Each participating utility has been given a unique code (Company Code)

CONFIDENTIAL PARTICIPANT INFORMATION

Question 1: Confidential Information. Results not available for publication

COMPANY AND UVM PROGRAM INFORMATION

All questions as written in the survey are given after the survey question number. Graphs and comment tables are shown after each question to report on the survey results.

Responses to the questions are in brackets on comment tables. In other words, if the respondent answered, “Yes”, [Yes] will appear after their comment. This will be true for most comment tables in this report.

Question 1: Please indicate the *Region* in which the majority of your T&D system is located. Note: Map included in survey to locate region in which the utility operates.

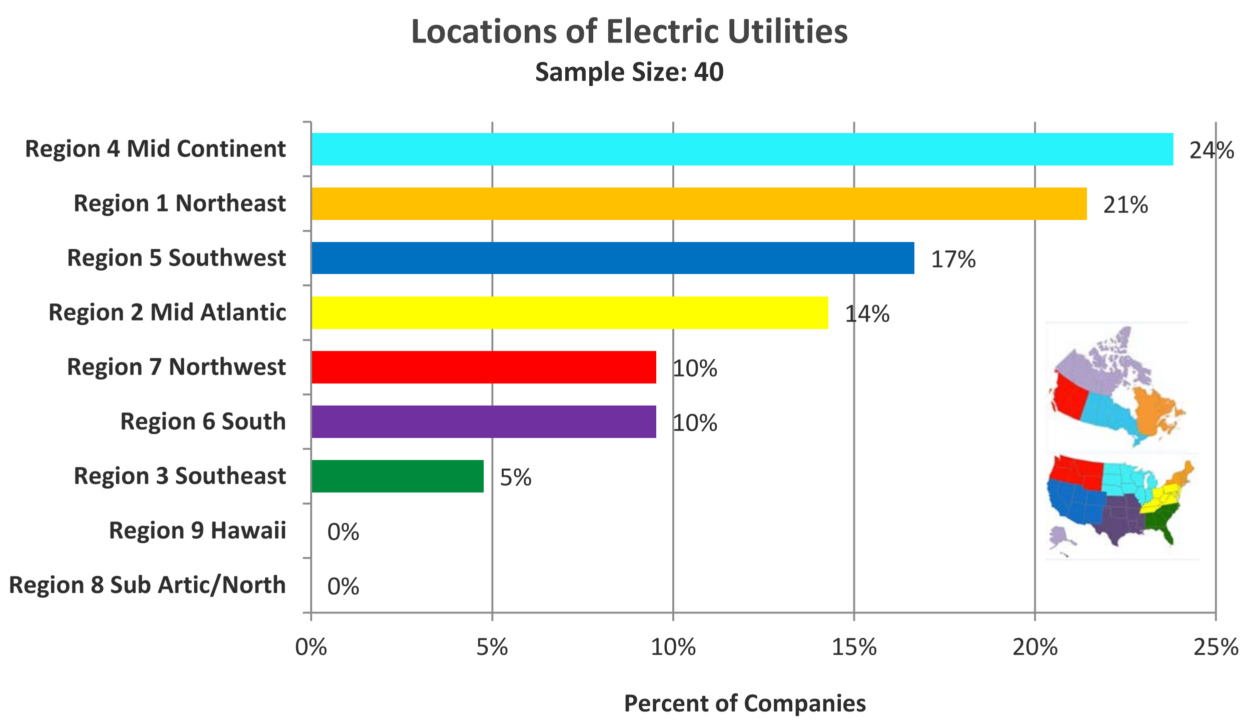


Figure 37: Locations of Electric Utilities

Three participants operated in more than one region and these additional regions are included in the above graph.

Question 2: Please select from your following choices to describe your company type

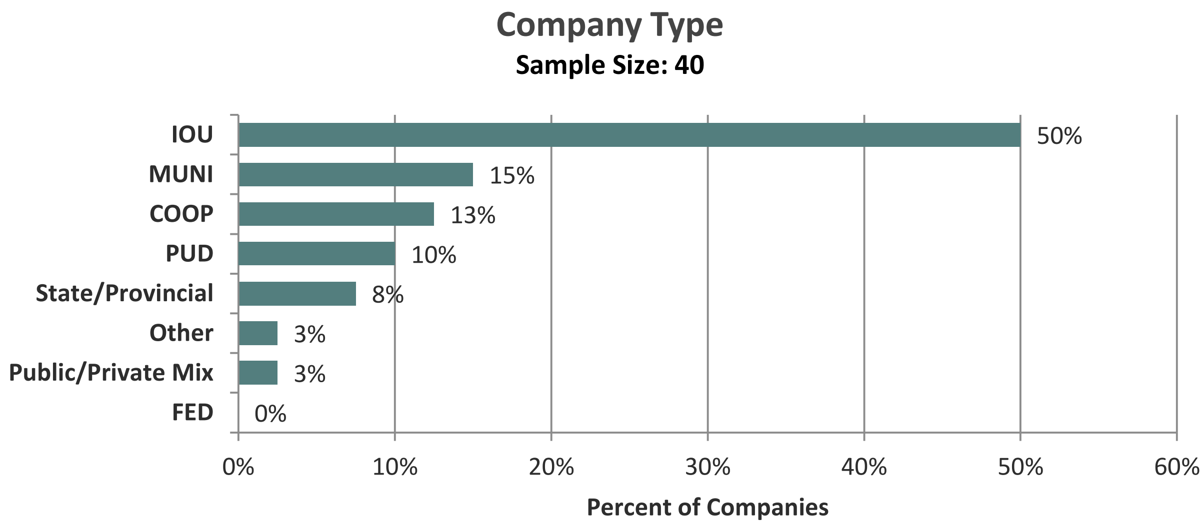


Figure 38: Company Type

Legend:

IOU: Investor Owned Utility

MUNI: Municipal Utility

COOP: Rural Electric Cooperative

PUD: Public Utility District

State/Provincial: State or Provincial Run Utility

FED: Federal Utility

Public/Private Mix: Quasi-Public and Privately Owned Utility

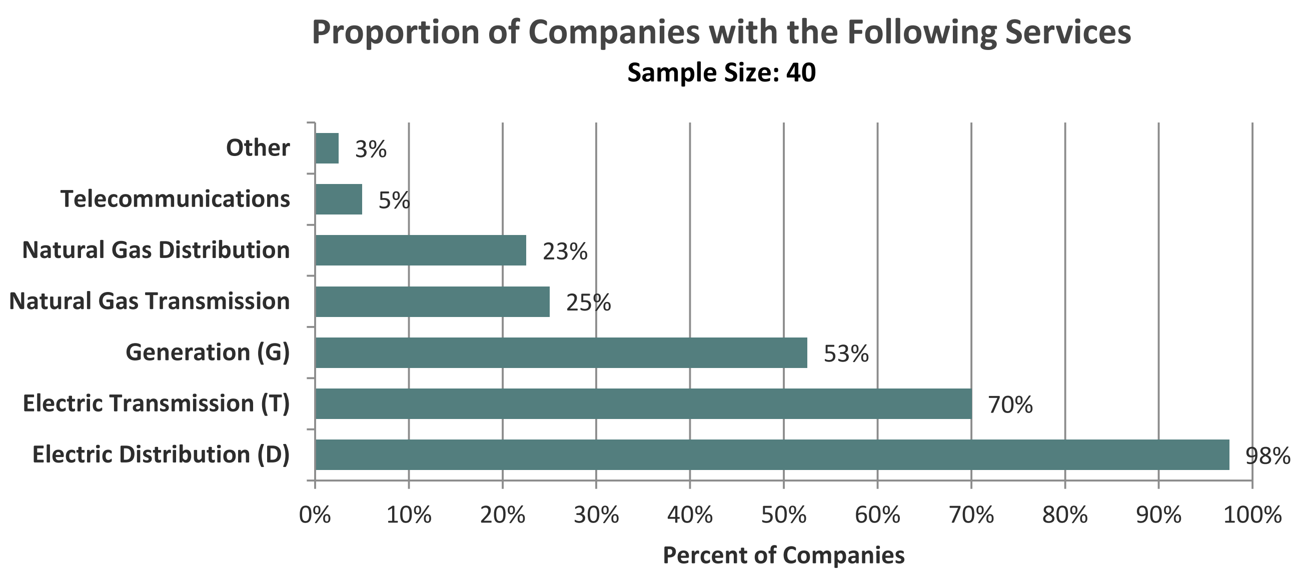


Figure 39: Proportion of Companies with the Following Services

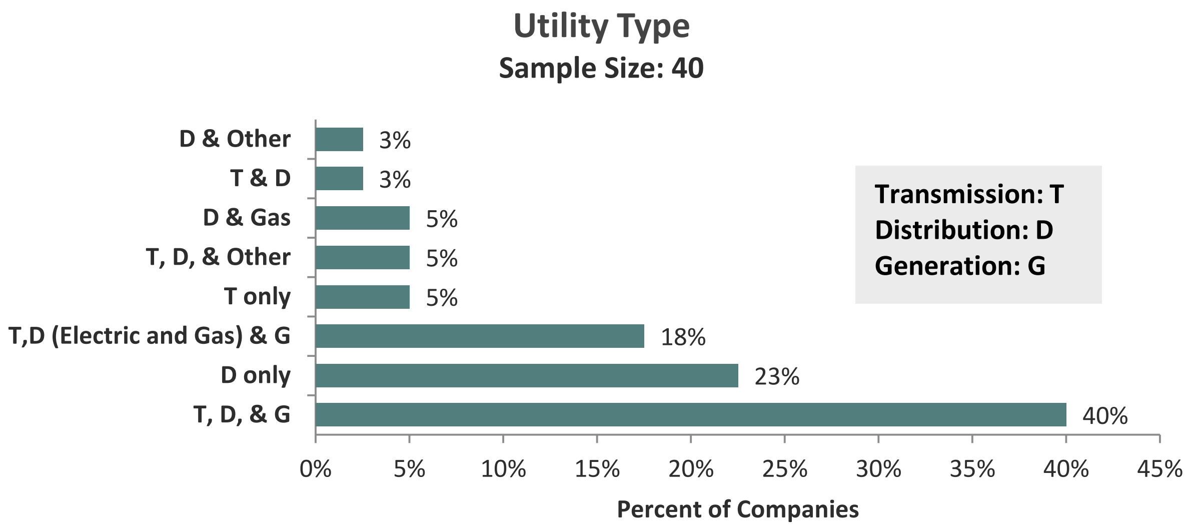


Figure 40: Utility Type

Question 3: How many circuit miles of overhead line in each line type are included on your overhead system within this region?

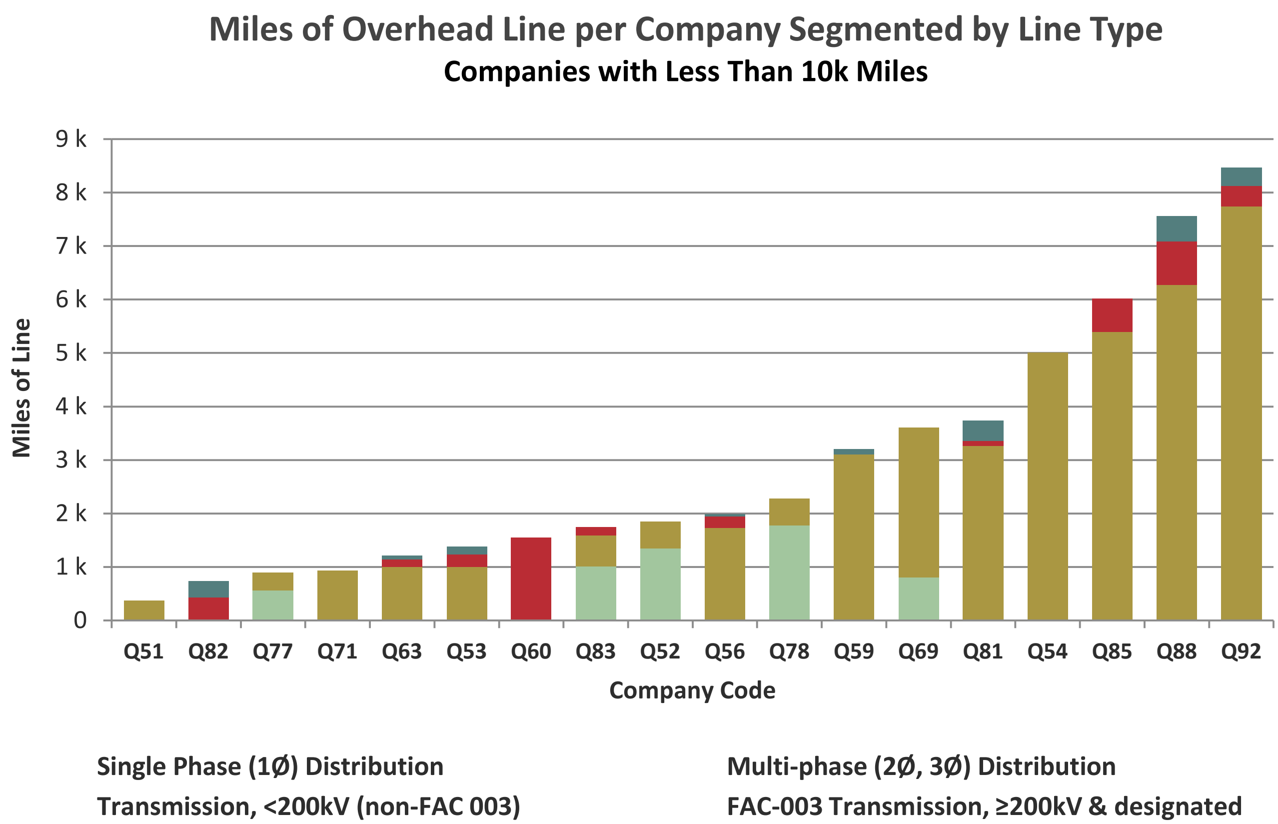


Figure 41: Miles of Overhead Line per Company Segmented by Line Type Companies with Less Than 10k Miles

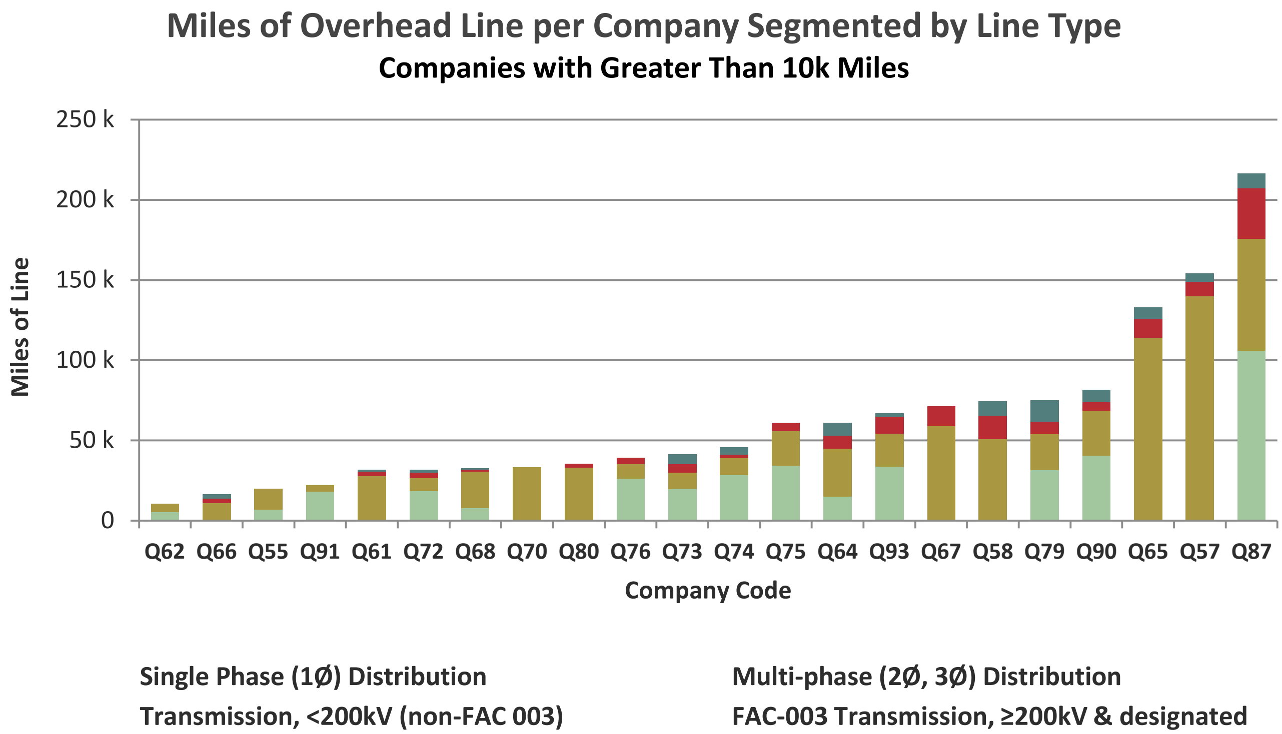
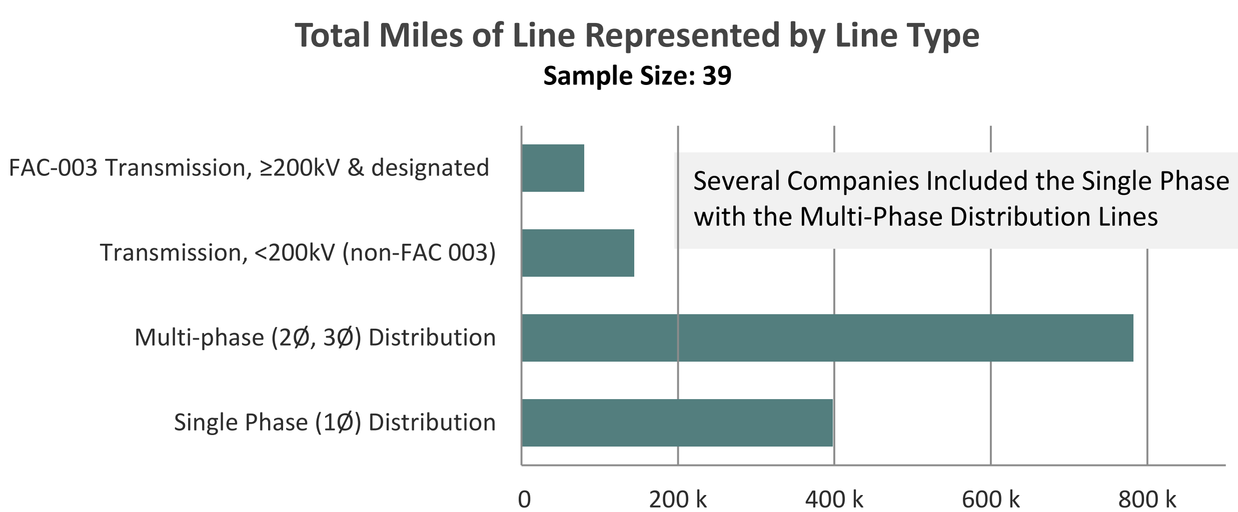


Figure 42: Miles of Overhead Line per Company Segmented by Line Type Companies with Greater Than 10k Miles



	Single Phase (1Ø) Distribution	Multi-phase (2Ø, 3Ø) Distribution	Transmission, <200kV (non-FAC 003)	FAC-003 Transmission, ≥200kV & designated
Miles of Line	398,254	782,276	144,207	80,208

Figure 43: Total Miles of Line Represented by Line Type

Question 4: Do you have a formal Tree Risk Assessment (TRA) program separate from routine maintenance for assessing and managing tree risk involving potentially hazardous trees? Comment on the nature of your Tree Risk Assessment program.

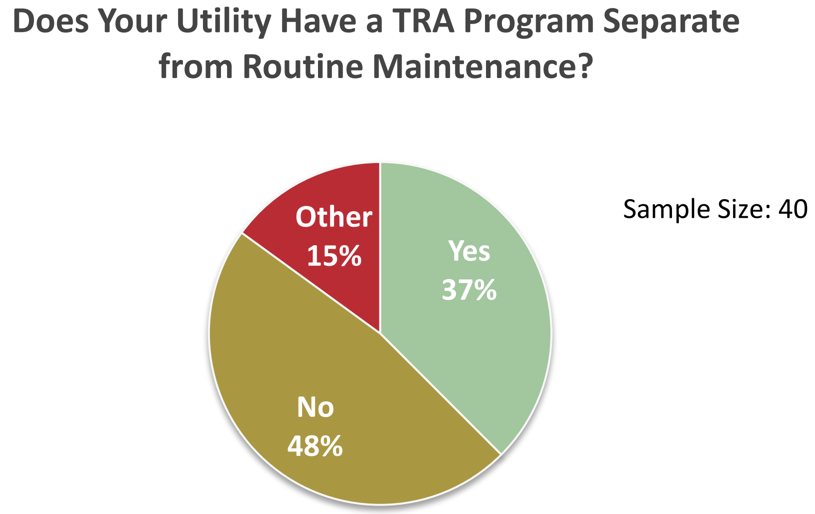


Figure 44: Does Your Utility Have a TRA Program Separate from Routine Maintenance?

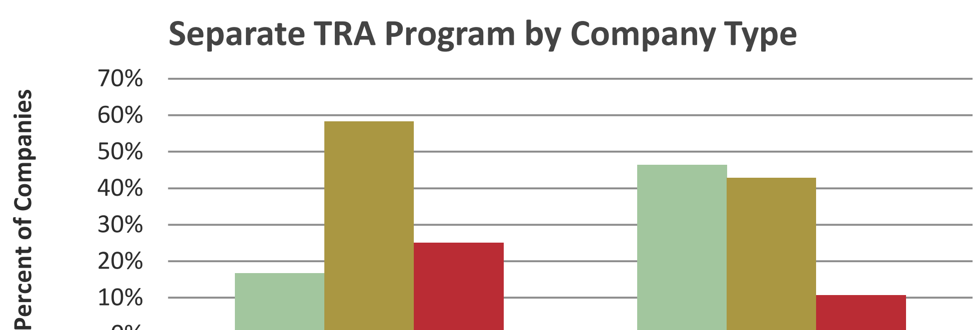
Responses to the questions are in brackets on comment tables. In other words, if the respondent answered, "Yes", [Yes] will appear after their comment. This will be true for all comment tables in this report.

TRA Program Descriptions
We have a mid-cycle vegetation patrol for obvious hazard trees [Other]
TRA is conducted as a critical component of routine maintenance [Other]
Yes for mountains of Colorado, focusing on trees killed by Mountain Pine Beetle and other insects in the 'epidemic area'. Otherwise hazard trees are mitigated as part of routine cycle maintenance in all other areas. [Other]
Distribution: Public Safety and Reliability Program addresses live trees with identified failure patterns. 2nd Patrol Program addresses dead or dying trees due to drought, beetle kill. Transmission: [Yes]
Aerial and Ground patrols [Yes]
For our Distribution program [Yes]
We have one of our [ ] foresters [are] train in hazard tree id and dedicate one day per week to looking for hazard trees. [Other]
Trees of a hazardous nature, posing either from limb, branch or tree position or state or decline, or positioning (leaning) are identified during foot patrol of transmission. [No]
We have a hazard tree program on both distribution and transmission systems. [Yes]
Level 2 risk assessment as part of prescriptive work planning [No]
While routine work is being completed, a trained job planner identifies hazard trees/limbs and these are removed at that time. [Other]

TRA Program Descriptions - continued
First we arrange our line in consideration of their outage number per kilometre (poor performing circuit). We patrol the worst fifth (20%) of these lines to detect 10 to 15 trees per km that show imminent risk of failure and we cut 40,000 trees per year. We detect and cut another 10,000 trees per year when patrolling line in the pruning and brush cutting cycle (15% of system about 17,500 Km/per year). We try to obtain owner authorization to cut all of those trees in respect of legal exigence. [Yes]
We complete an annual ground-based patrol and four aerial patrols of which Tree Risk is incorporated. [Yes]
Tree Risk Assessment Protocol built specifically for us based on ANSI Part 9 and TRAQ but modified for utility. [Yes]
Trees may exhibit potential threats to the facilities due to disease, damage, physical location, growth characteristics or environmental problems. Where these trees exist, the utility considers them high priority risks that need to be addressed and remediated. [No]
We have a program but it is very basic. Any dead, dying or significantly leaning trees are identified. We make a filed decision to remove or trim. This is only for our NERC/FERC facilities [Other]
The TRA is completed within the Asset Defect Program. [Yes]
Select potential hazard tree for removals [Yes]
Potential Danger trees identified during routine maintenance of circuits. Have utilized Intern to do Danger tree inventory on distribution. [Yes]
EHTM - Enhanced Hazard Tree Mitigation ranks circuits based upon customer count, miles of three phase bare wire, Tree exposure, & three year average for Customer Impacted per tree event and total customers impacted. Review Intensity is very robust from station breaker to 1st protection device. Intensity of review is reduced as progress moves beyond each protection device further out on a circuit. Customer count from protection device to end also dictates level of review. [Yes]

Comment Table 1: TRA Programs Descriptions

The following graph integrates the answers from Questions 3, 4, and 5.



	Distribution Only Companies: Sample 12	Distribution & Transmission and Transmission Only Companies: Sample 28
Have Separate TRA Program	17%	46%
Do NOT Have Separate TRA Program	58%	43%
Other	25%	11%

Figure 45: Separate TRA Program by Company Type

Question 5: Is your Tree Risk Assessment program modeled after Level 1 Tree Risk Assessment practices as described in ANSI A300 Part 9 and the current ISA TRA BMP?

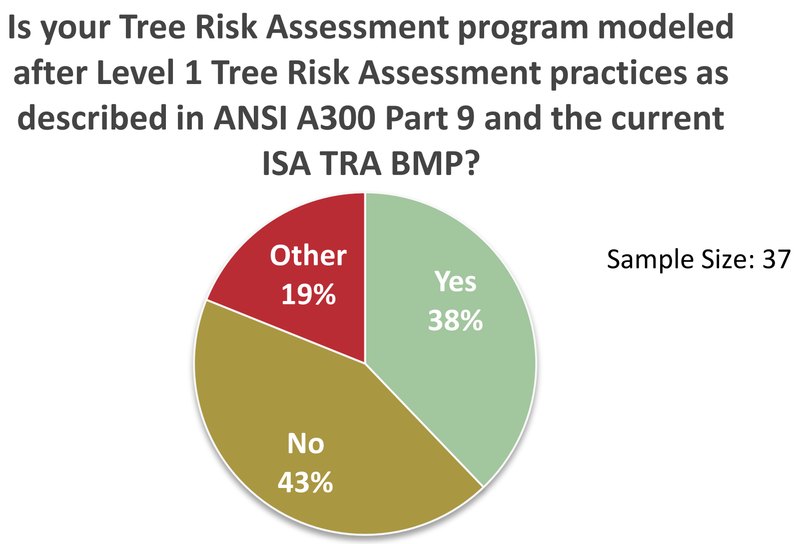


Figure 46: Is your Tree Risk Assessment program modeled after Level 1 Tree Risk Assessment in ANSI A300?

TRA Program Practices in Relation to ANSI A300 Part 9
We employ professional arborists who have qualifications such as college degrees in forestry, ISA arborist certified, utility arborist certified, and/or hold State tree expert certifications plus have on the job experience. Current vegetation management specifications require identification, evaluation and mitigation of trees as described in a Level 1 TRA. Today our current specifications do not reference ANSI A300 Part 9. [Yes]
[Province] has the "[Province] Reliability Standard" which is modeled from the NERC Standards. [Other]
Ours is based on the UAA Utility Best Management Practices Tree Risk Assessment and Abatement for Fire Prone States and Provinces in the Western Region of North America [Other]
To my knowledge our program is not modeled after others, but our guy, [ ], is using principals learned from a week long certification class attended last year. [Other]
Overhead inspection of 33% of the plant each year to identify hazards and high priority actions. [No]
Developed in-house [Other]
ANSIA300 part 9 is unknown here in [Province]. [No]
We use the same terminology for Level 1, visual and limited visual assessment. [Yes]
1. Visual Assessment While performing work on a circuit, contract crews shall conduct a visual assessment to identify trees with imminent and/or probable likelihood of failure inside and outside the right-of-way. The tree should be viewed from some distance away, if possible, to consider crown shape and surroundings. Any tree identified to be a potential imminent threat to a utility line shall be reported to the responsible forester. [Yes]
[Utility]'s Level 1 would be the most intense review including a 360 survey of each tree. This is from the station breaker to the first protection device or beyond depending on calculated customers served on the specific circuit. *** A [Utility] level 3 would equate to a level 1 per ANSI A300

Comment Table 2: TRA Program Practices in Relation to ANSI A300 Part 9

Question 6: Does your company have specified and formally documented procedures to elevate the level of inspection intensity of a tree or site from Level 1 to Level 2 and/ or Level 3?

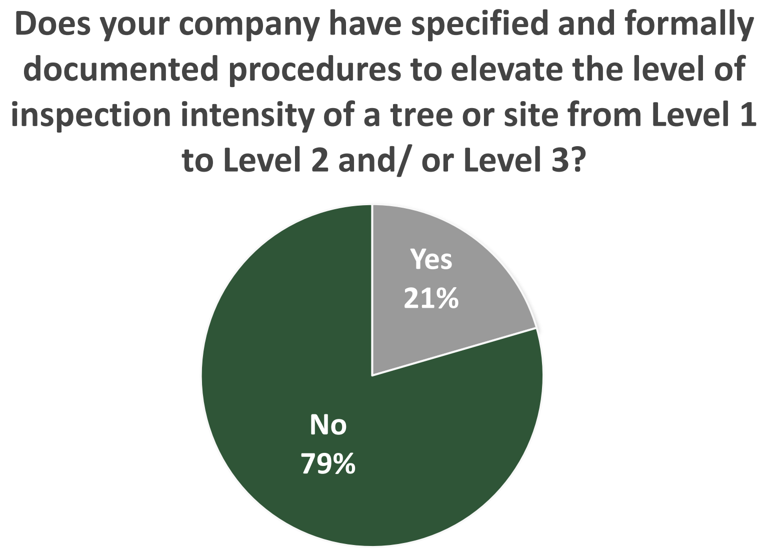


Figure 47: Does your company have procedures to elevate the level of inspection intensity?

TRA Level of Inspection Intensity
Due to the small size of our area, we inspect and complete any work identified in the same year. [No]
If hazard trees are identified in a level one assessment, inspectors are expected to look farther into the issue. [No]
Trees posing an imminent threat are reported immediately and removal is governed by timeline. Formalized program to manage trees of risk. [Yes]
We have developed inboard criteria. [Yes]
We state that we only elevate to Level 2 (we don't have the means for level 3). We have defined required action/assessment based on defect levels. [Yes]
Only to Level 2. Program is conservative and will take any trees that are a threat without the need of a Level 3 evaluation. [Level] 2. Ground Evaluation: If a Hazard Tree is identified during the visual assessment, a 360° ground evaluation shall be required. The evaluations should include an inspection of: * Tree crown * Trunk * Trunk flare * Above-ground roots * Site conditions around the tree in relation to targets. The Contractor shall report risk and mitigation options to the responsible utility forester. [Yes]
Our level 2 is a Moderate Inspection Intensity and is conducted beyond the first protection device out to a calculated customer service point or pre-determined number of customers served. Level 3 is an Imminent Risk Inspection. Again, a calculated customer service point determines the intensity of tree inspection. [Yes]

Comment Table 3: TRA Level of Inspection Intensity

Question 7: Do you use a Visual Tree Assessment (VTA) checklist or risk evaluation form that is intended to assign a numeric score to tree related risk?

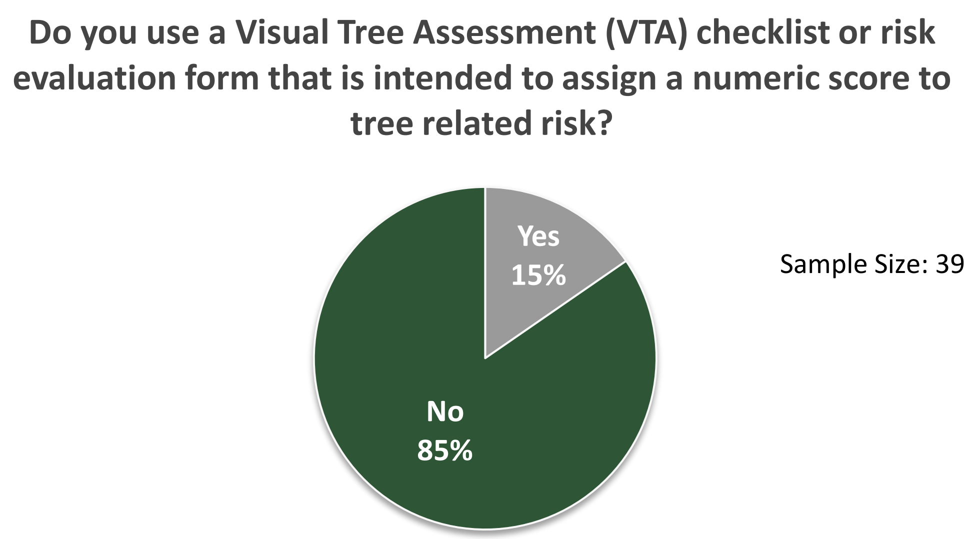


Figure 48: Do you use a Visual Tree Assessment (VTA) checklist intended to assign a numeric score to tree related risk?

Risk Evaluation Descriptions
Derived internally and incorporates circuit information and customer counts, site specific weather patterns, and common failure patterns derived from internal outage investigations. [Yes]
Some of us had the formation and we integrated the principle in our process. [Yes]
We do use a form, but it does not assign a numeric value. It leads you to an action based on a matrix. [No]
Numeric score is just prioritization depending on tree assessment and site conditions (voltage, type of construction etc.) [Yes]

Comment Table 4: Risk Evaluation Descriptions

Question 8: Which best describes the type of vegetation inspection(s) conducted on your system? Please enter an estimated percent (%) of total line miles inspected for each line type. *NOTE: Each graph for Question 8 is arranged by percent of lines inspected annually with the most on the right.*

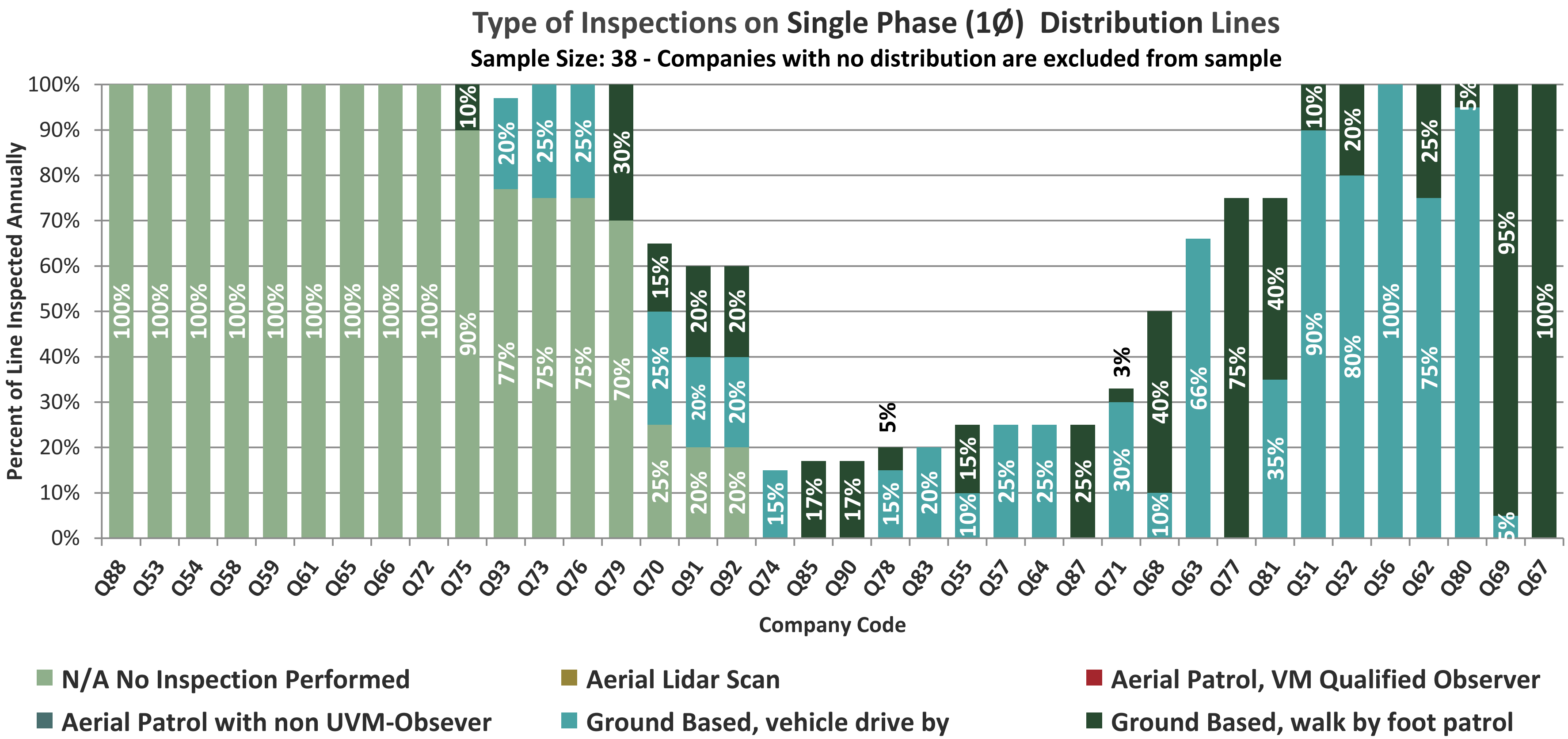


Figure 49: Types of Inspections Performed on Single Phase Distribution Annually

Statistics on Annual Inspection for Single Phase Distribution Lines:

- 18% Inspect 100% of the Single Phase Lines Annually
- 24% Do Not Inspect Any of The Single Phase Lines

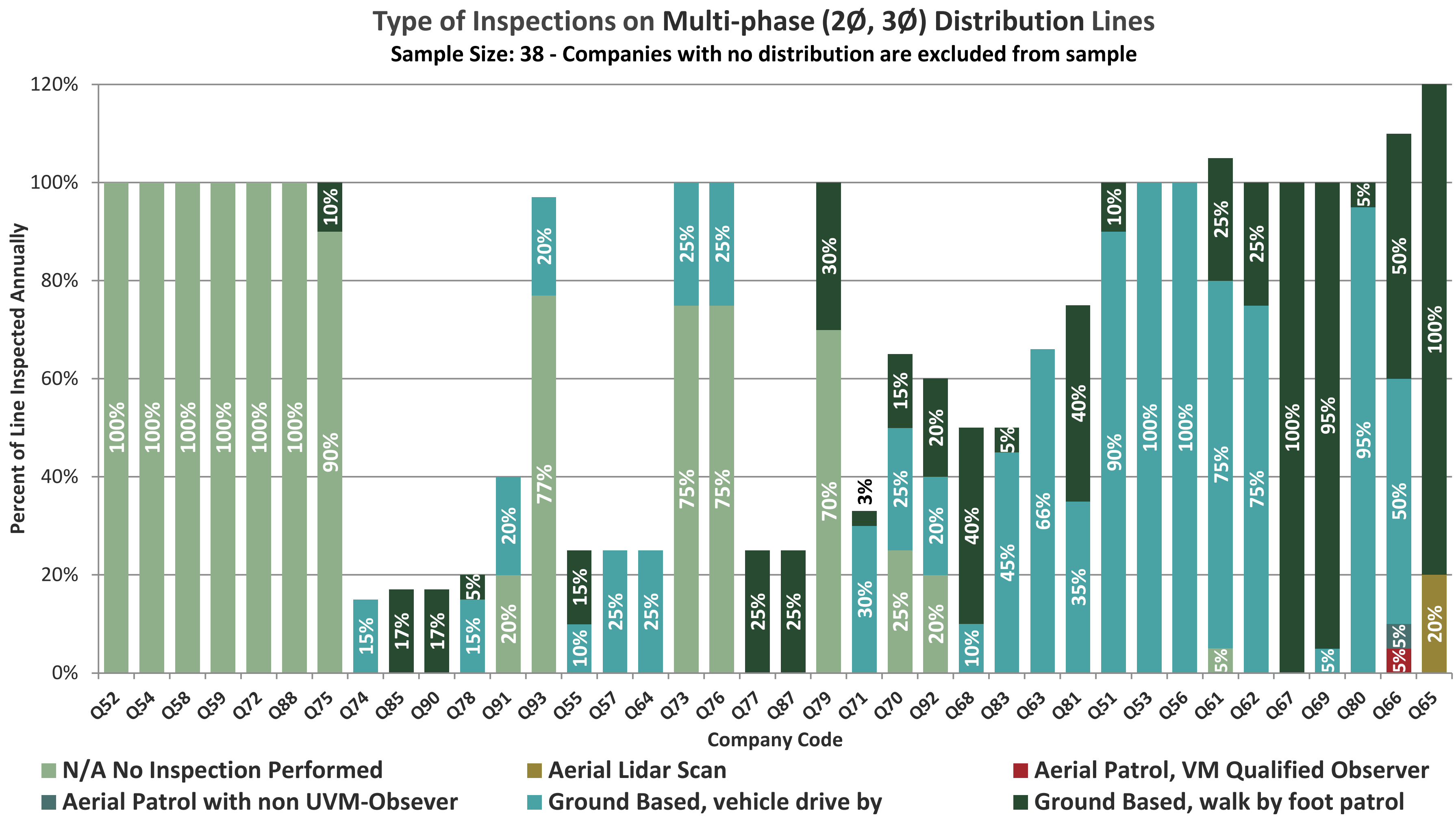


Figure 50: Types of Inspections Performed on Multi Phase Distribution Annually

Statistics on Annual Inspection for Multi-Phase Distribution Lines:

- 26% Inspect 100% of the Multi-Phase Lines Annually
- 16% Do Not Inspect Any of The Multi-Phase Lines

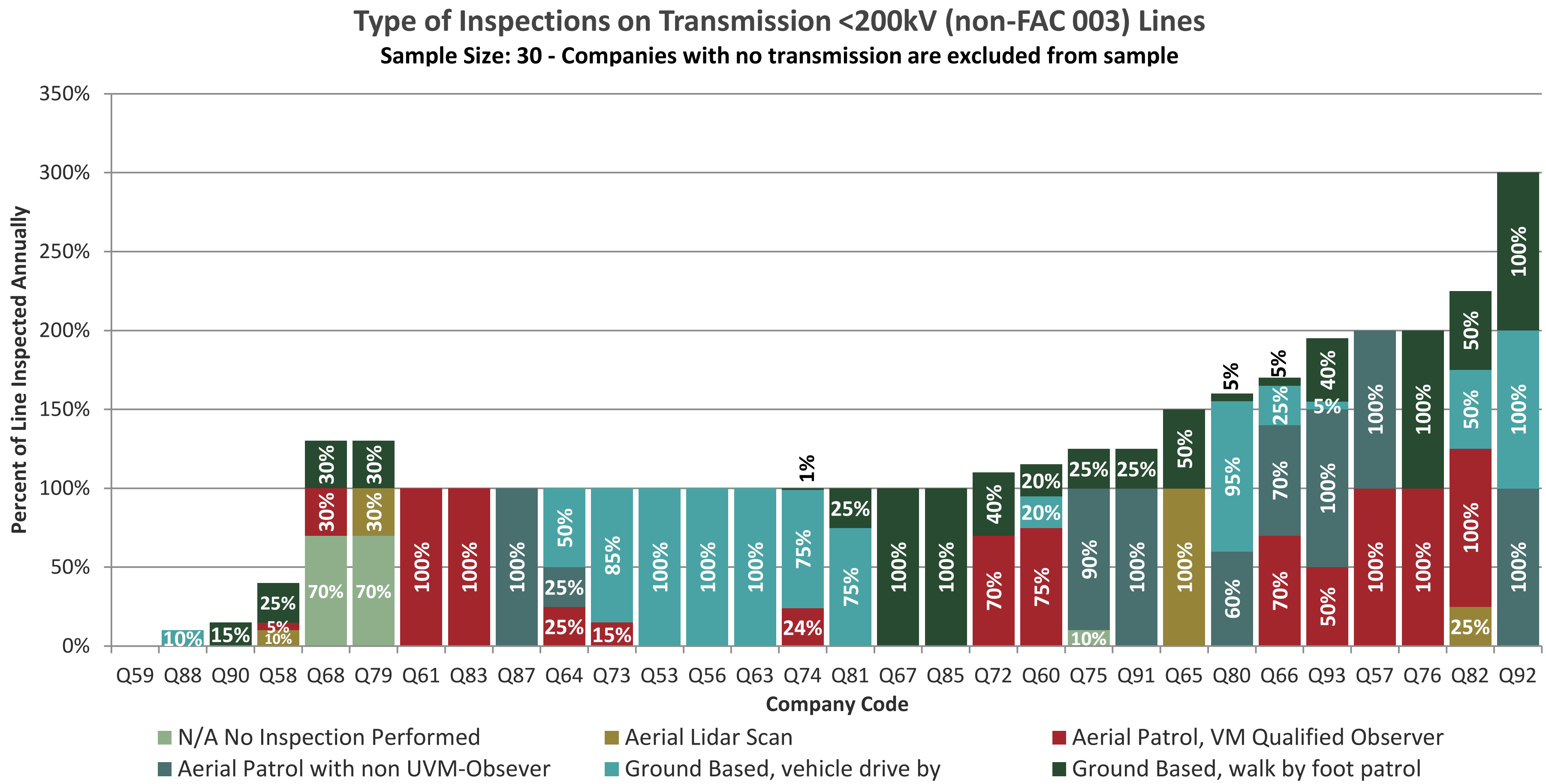


Figure 51: Types of Inspections Performed on Non-FAC-003 Regulated Transmission Lines Annually

Statistics on Annual Inspection for Non-FAC-003 Regulated Transmission Lines:

- 63% Inspect 100% of the Non-FAC-003 Regulated Transmission Lines Annually
- 3% Do Not Inspect Any of The Non-FAC-003 Regulated Transmission Lines

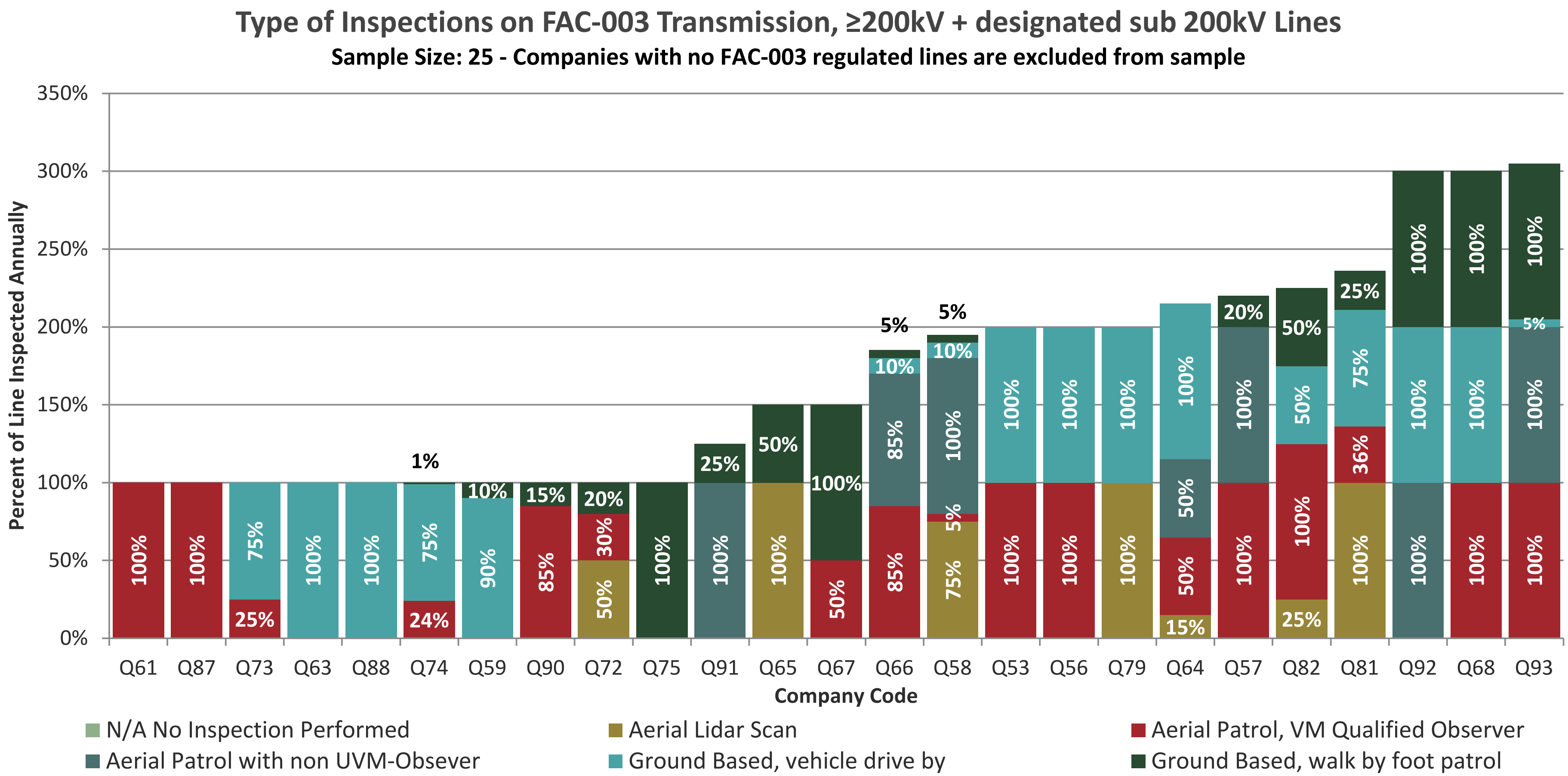


Figure 52: Types of Inspections Performed on FAC-003 Regulated Transmission Lines Annually

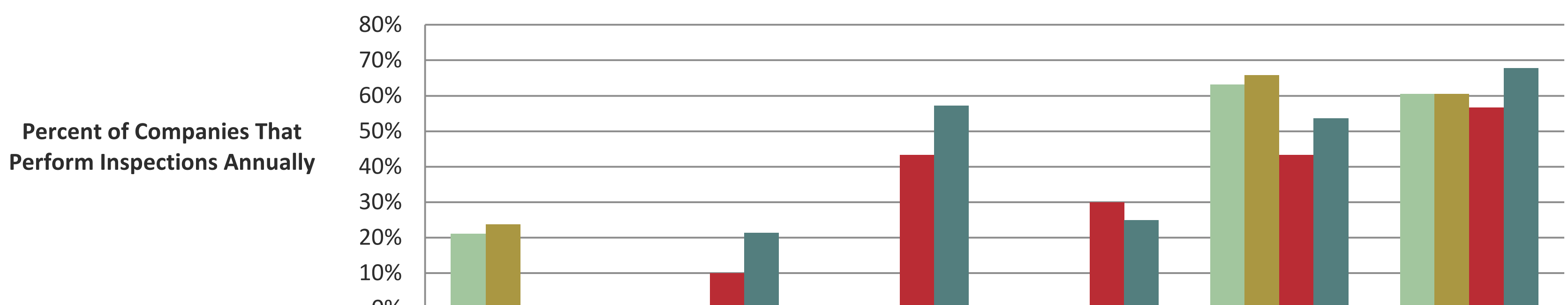
Statistics on Annual Inspection for FAC-003 Regulated Transmission Lines:

- 100% Inspect 100% of the FAC-003 Regulated Transmission Lines Annually
- 60% Use Multiple Methods of Inspection for Some of the FAC-003 Regulated Transmission lines

Comments on Types of Inspections
All distribution are patrolled (either vehicle or foot if private property) based on feeder classification. Urban is trimmed every 4 years, rural every 6 with each inspection at mid-point
fixed wing monthly on all BES by non UVM-observer
Some of the foot patrols are followed by aerial patrol.
100% of lines above 200kV are inspected annually
Line patrol for hardware and trees 5-year cycle
LiDAR is once every 5th year.
We patrol all 230kV facilities twice a year, should be 200% in the 230kv category
In 2015 we captured Lidar on all FAC 003-3 lines in one Jurisdiction including pending 115kV IROL circuits. To date it is not an annual inspection tool

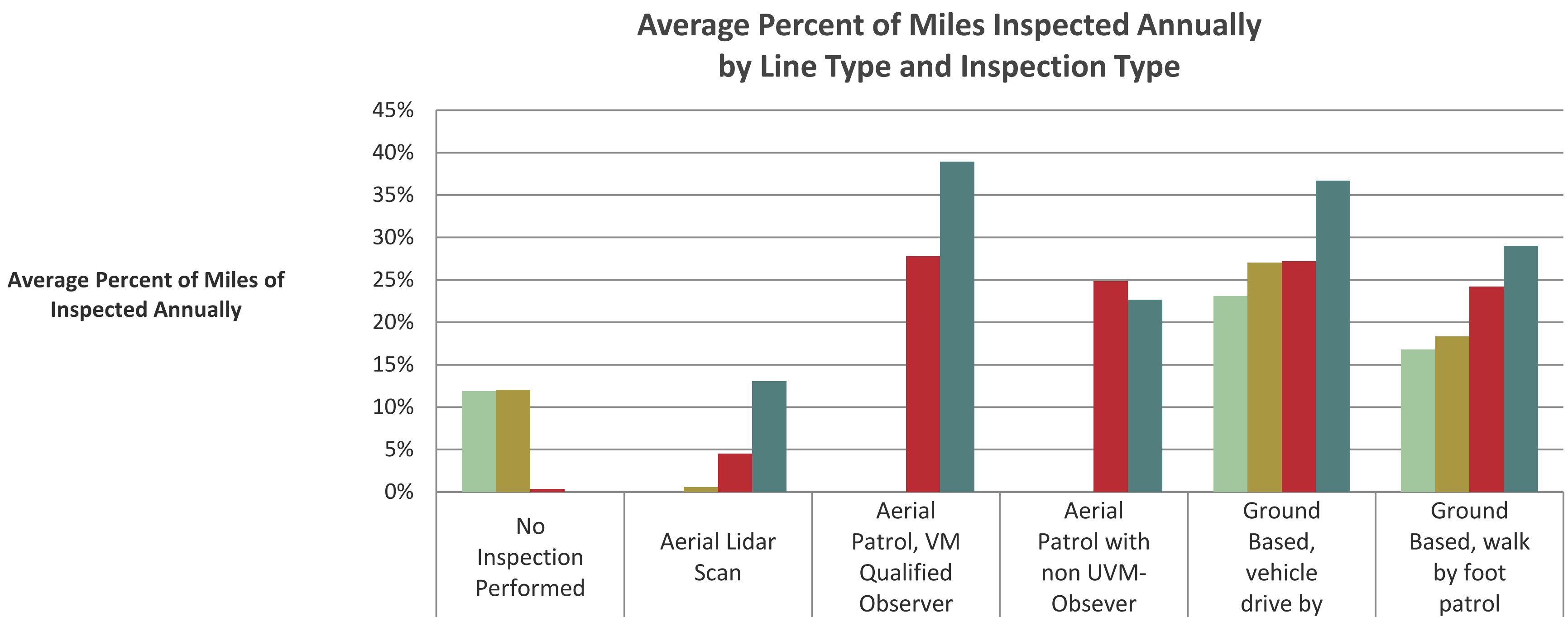
Comment Table 5: Comments on Types of Inspections

Percent of Companies That Perform Inspections Annually by Inspection Type



	No Inspection Performed	Aerial Lidar Scan	Aerial Patrol, VM Qualified Observer	Aerial Patrol with non UVM-Obsever	Ground Based, vehicle drive by	Ground Based, walk by foot patrol
1Ø Distribution (Sample 38)	21%	0%	0%	3%	63%	61%
2Ø, 3Ø Distribution (Sample 38)	24%	3%	3%	3%	66%	61%
Transmission, non-FAC 003 (Sample 30)	3%	10%	43%	30%	43%	57%
FAC-003 Transmission (Sample 28)	0%	21%	57%	25%	54%	68%

Figure 53: Percent of Miles Inspected by Line and Inspection Type



	No Inspection Performed	Aerial Lidar Scan	Aerial Patrol, VM Qualified Observer	Aerial Patrol with non UVM-Obsever	Ground Based, vehicle drive by	Ground Based, walk by foot patrol
1Ø Distribution (Sample 38)	12%	0%	0%	0%	23%	17%
2Ø, 3Ø Distribution (Sample 38)	12%	1%	0%	0%	27%	18%
Transmission, non-FAC 003 (Sample 30)	0%	5%	28%	25%	27%	24%
FAC-003 Transmission (Sample 28)	0%	13%	39%	23%	37%	29%

Figure 54: Average Percent of Miles Inspected Annually by Line Type and Inspection Type

Question 9: Which best describe the intended frequency of vegetation inspections completed as part of a deliberate inspection program (rather than informal, incidental inspection). Check all that apply

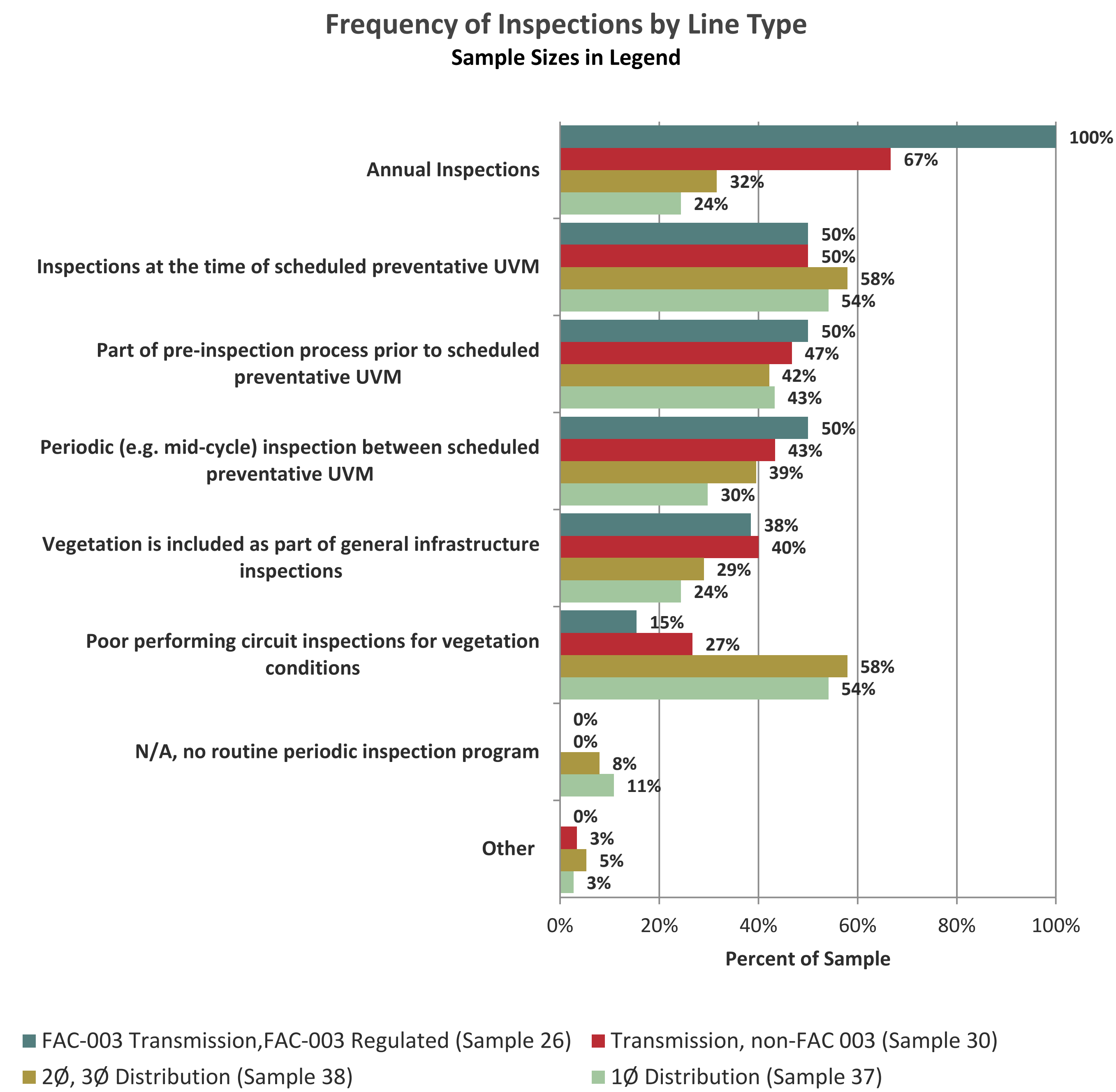


Figure 55: Frequency of Inspections by Line Type

Comments on Frequency of Inspections
For maintenance trimming, typically have a planner do a pre-inspection, crews perform inspections at time of trimming, and General Foreman does a post-trimming quality assessment.
DISTRIBUTION: random inspections by operations personnel for circuits of interest. Level 1 inspections by veg management of circuits experiencing significant general reliability issues or increased customer complaints.
Quarterly aerial patrols with qualified VM personnel of all 200kV and greater transmission corridors.
We added "Post Storm" inspections to our program a couple years. We usually find more risk trees per mile immediately after a major storm event. [Other]
We consider anytime that we are out looking at circuits that we are on inspection/ patrol
Line patrol 5-year cycle
100% post audit for all NERC VM control activities, and 7 to 8% post audit for everything else.
We patrol our 40 miles of 138kV and selected priority 69kV (tie line) facilities.

Comment Table 6: Comments on Frequency of Inspections

Question 10: Which best describes the qualifications of personnel who regularly perform Tree Risk Assessments (TRA)? If more than one category of Assessment Personnel is involved for a line type, please indicate the percent (%) of line miles inspected by each.

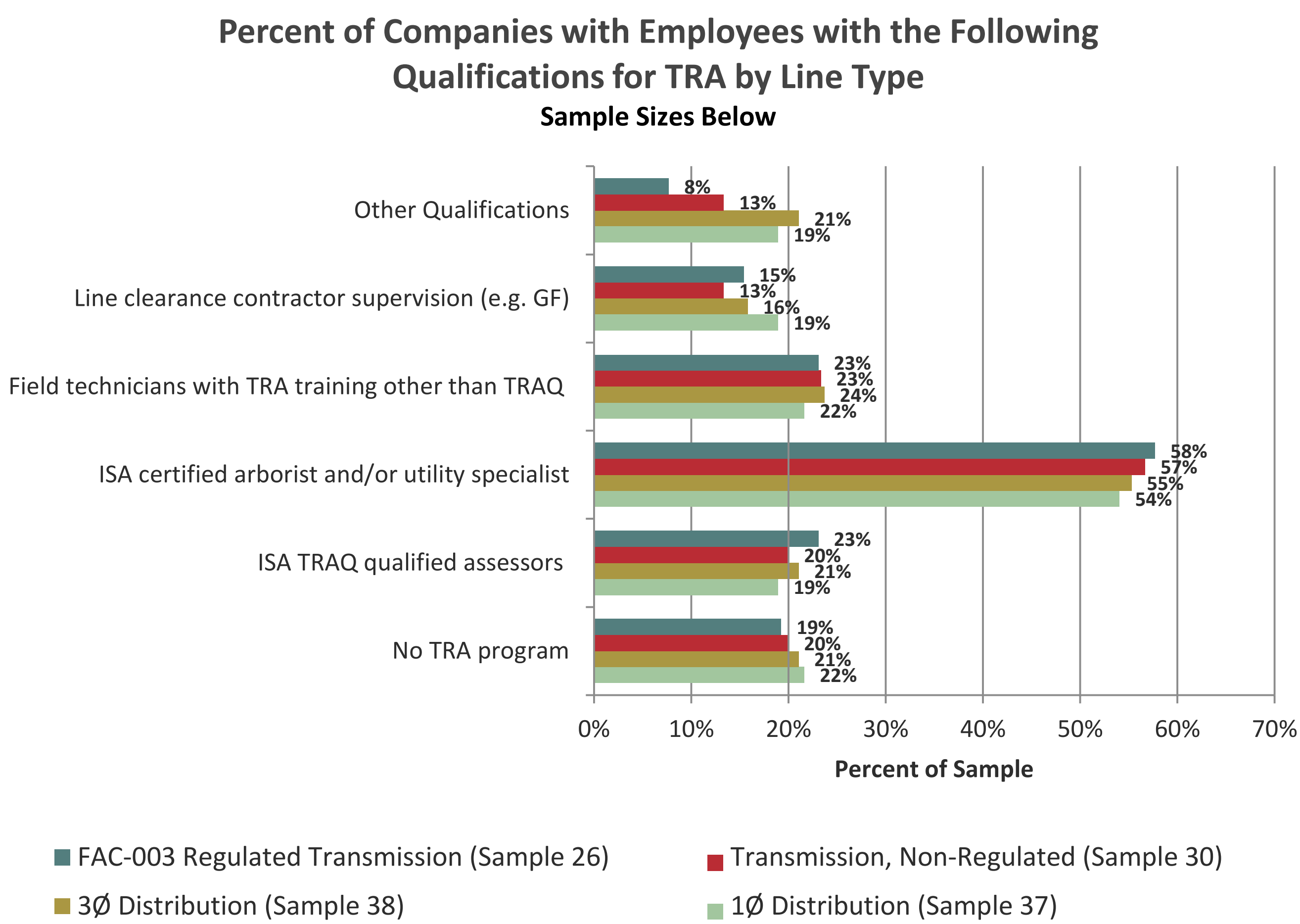


Figure 56: Percent of Companies with Employees with the Following Qualifications for TRA by Line Type

Other Qualifications for Inspectors
Our contract foresters have additional TRA training programs through their parent employer.
Internal risk tree assessment protocol training
Other qualifications are degreed foresters.
We do not have a separate TRA program, but we do have trained planners evaluating and looking for high risk whole tree failures and co-dominate branching during our VM cycle
It's an internal equivalent
We do not currently perform TRA.
Power Lineman
Forestry Technicians
Line clearance contractor supervision is also ISA certified arborists.
UVM contractor personnel with general working knowledge of obvious hazards; administered by dedicated utility forester.
Powerline Technician that is also a Safety Codes Officer

Comment Table 7: Other Qualifications for Inspectors

TRA Inspection Qualifications for 1Ø Distribution

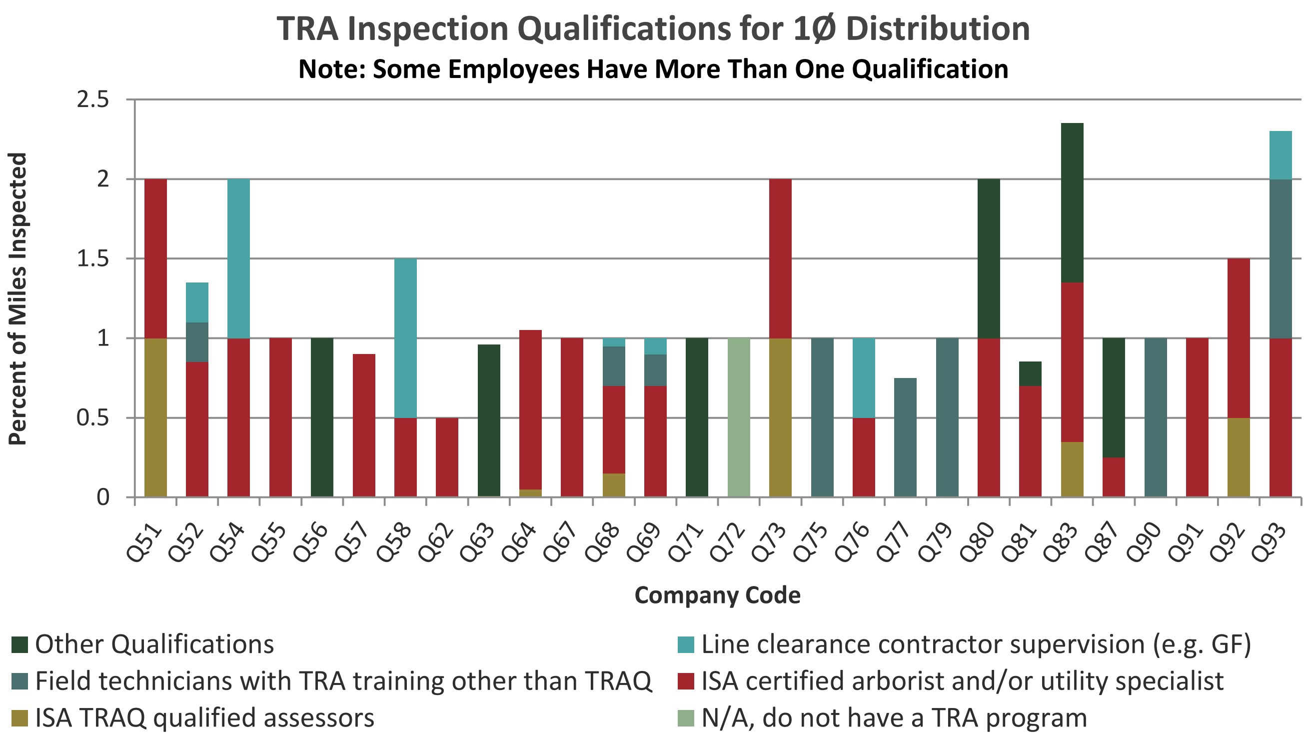


Figure 57: TRA Inspection Qualifications for 1Ø Distribution

Percent of Miles Inspected By Personnel with Given Qualifications For 1Ø Distribution						
Statistics	**No TRA program**	**ISA TRAQ qualified assessors**	**ISA certified arborist and/or utility specialist**	**Field technicians with TRA training other than TRAQ**	**Line clearance contractor supervision**	**Other Qualifications**
Sample Size	1	7	20	8	7	7
Average	100%	44%	82%	68%	46%	84%
Median	100%	35%	100%	88%	30%	100%
Q1	100%	10%	66%	25%	18%	85%
Q3	100%	10%	66%	25%	18%	85%
Max	100%	100%	100%	100%	100%	100%
Min	100%	1%	25%	20%	5%	15%

Statistics Table 1: Percent of miles inspected by personnel with given qualifications for 1Ø Distribution

TRA Inspection Qualifications for 3Ø Distribution

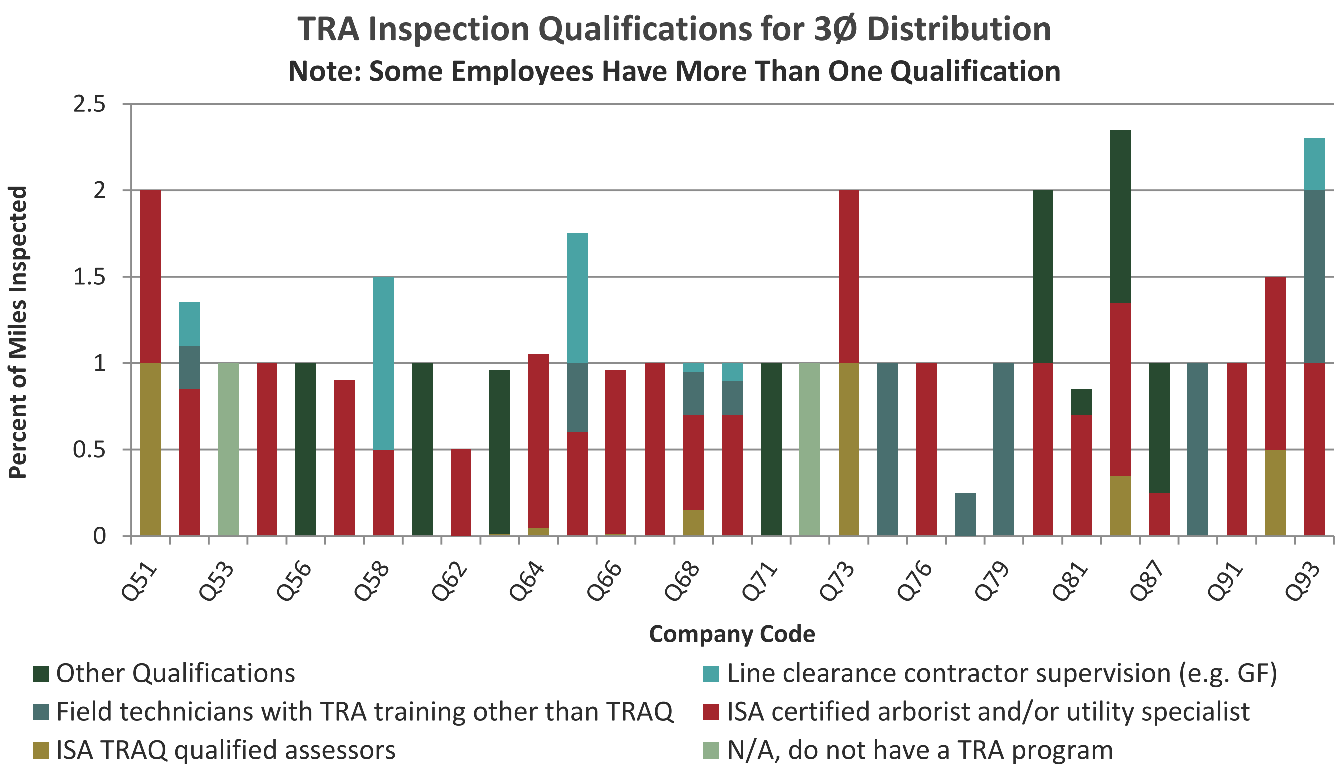


Figure 58: TRA Inspection Qualifications for 3Ø Distribution

Percent of Miles Inspected By Personnel with Given Qualifications For 3Ø Distribution						
Statistics	No TRA program	ISA TRAQ qualified assessors	ISA certified arborist and/or utility specialist	Field technicians with TRA training other than TRAQ	Line clearance contractor supervision	Other Qualifications
Sample Size	2	8	21	9	6	8
Average	100%	38%	83%	59%	41%	86%
Median	100%	25%	100%	40%	28%	100%
Q1	100%	4%	70%	25%	14%	90%
Q3	100%	4%	70%	25%	14%	90%
Max	100%	100%	100%	100%	100%	100%
Min	100%	1%	25%	20%	5%	15%

Statistics Table 2: Percent of miles inspected by personnel with given qualifications for 3Ø Distribution

TRA Inspection Qualifications for Non-FAC-003 Regulated Transmission

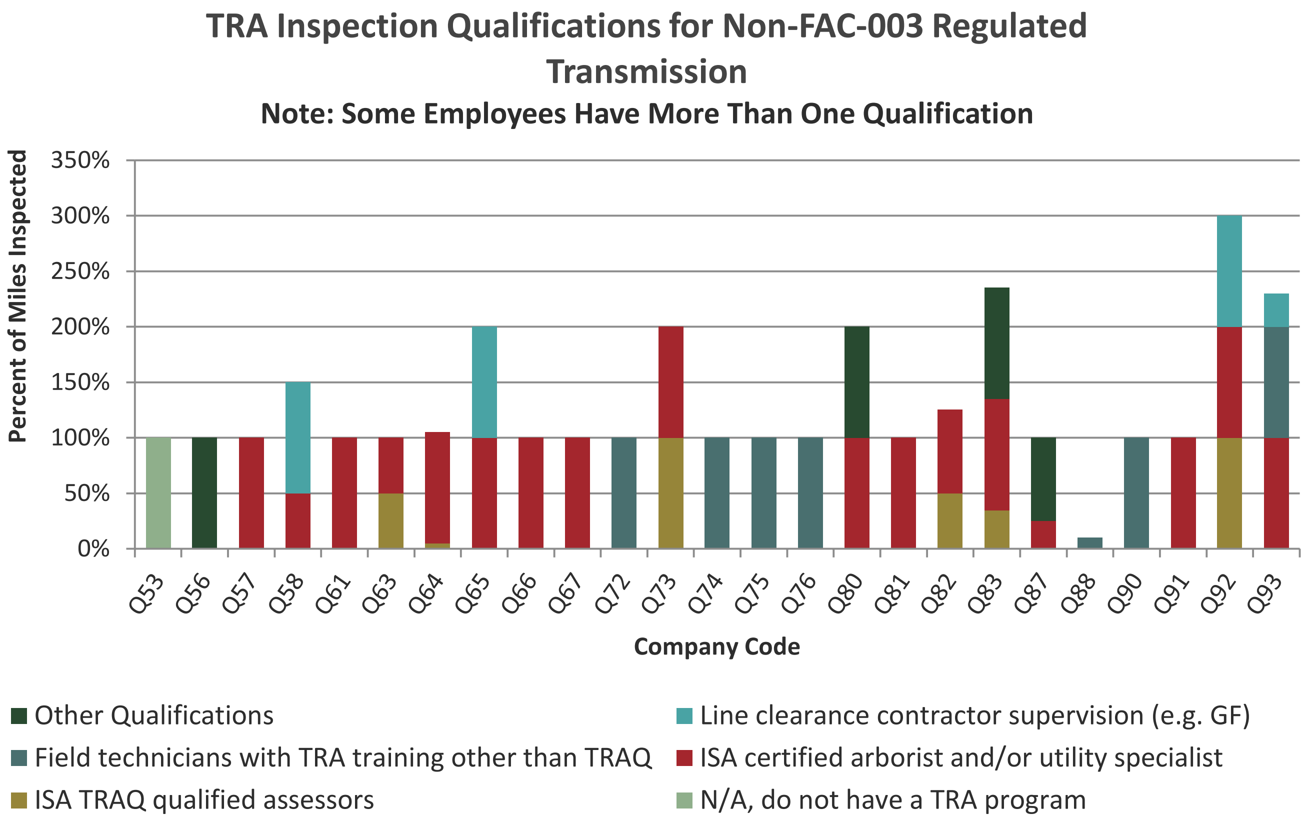


Figure 59: TRA Inspection Qualifications for Non-FAC-003 Regulated Transmission

Percent of Miles Inspected By Personnel with Given Qualifications for Non-FAC-003 Regulated Transmission						
Statistics	**No TRA program**	**ISA TRAQ qualified assessors**	**ISA certified arborist and/or utility specialist**	**Field technicians with TRA training other than TRAQ**	**Line clearance contractor supervision**	**Other Qualifications**
Sample Size	1	6	16	6	3	4
Average	100%	57%	88%	87%	83%	94%
Median	100%	50%	100%	100%	100%	100%
Q1	100%	39%	100%	100%	83%	94%
Q3	100%	39%	100%	100%	83%	94%
Max	100%	100%	100%	100%	100%	100%
Min	100%	5%	25%	10%	30%	75%

Statistics Table 3: Percent of Miles Inspected By Personnel with Given Qualifications for Non-FAC-003 Regulated Transmission

TRA Inspection Qualifications for FAC-003 Regulated Transmission

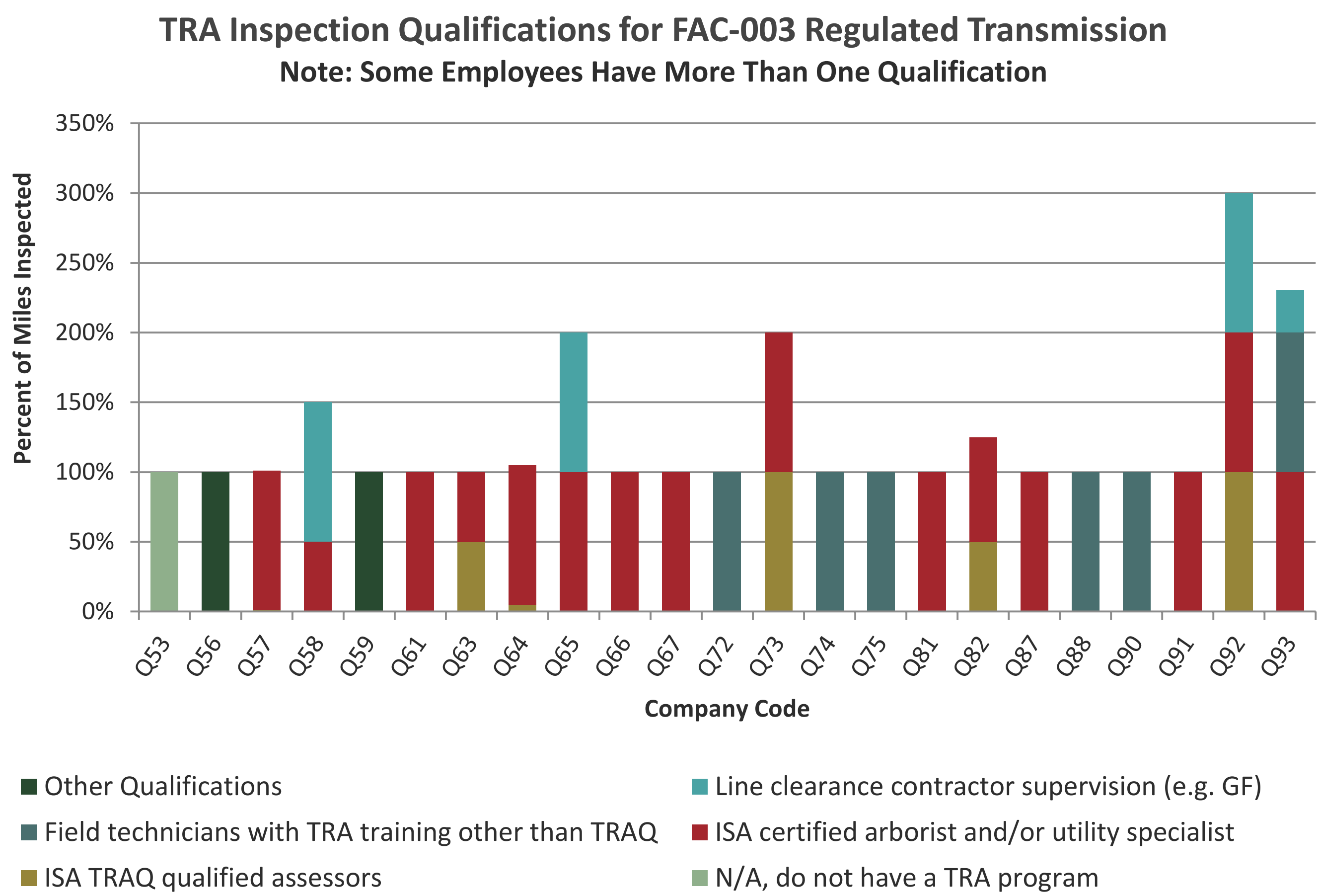


Figure 60: TRA Inspection Qualifications for FAC-003 Regulated Transmission

Percent of Miles Inspected By Personnel with Given Qualifications for FAC-003 Regulated Transmission						
Statistics	No TRA program	ISA TRAQ qualified assessors	ISA certified arborist and/or utility specialist	Field technicians with TRA training other than TRAQ	Line clearance contractor supervision	Other Qualifications
Sample Size	1	6	15	6	1	6
Average	100%	51%	92%	100%	100%	51%
Median	100%	50%	100%	100%	100%	50%
Q1	100%	16%	100%	100%	100%	16%
Q3	100%	16%	100%	100%	100%	16%
Max	100%	100%	100%	100%	100%	100%
Min	100%	1%	50%	100%	100%	1%

Statistics Table 4: Percent of Miles Inspected By Personnel with Given Qualifications for FAC-003 Regulated Transmission

Question 11: Do you have formal specifications that codify requirements for Tree Risk Assessment?

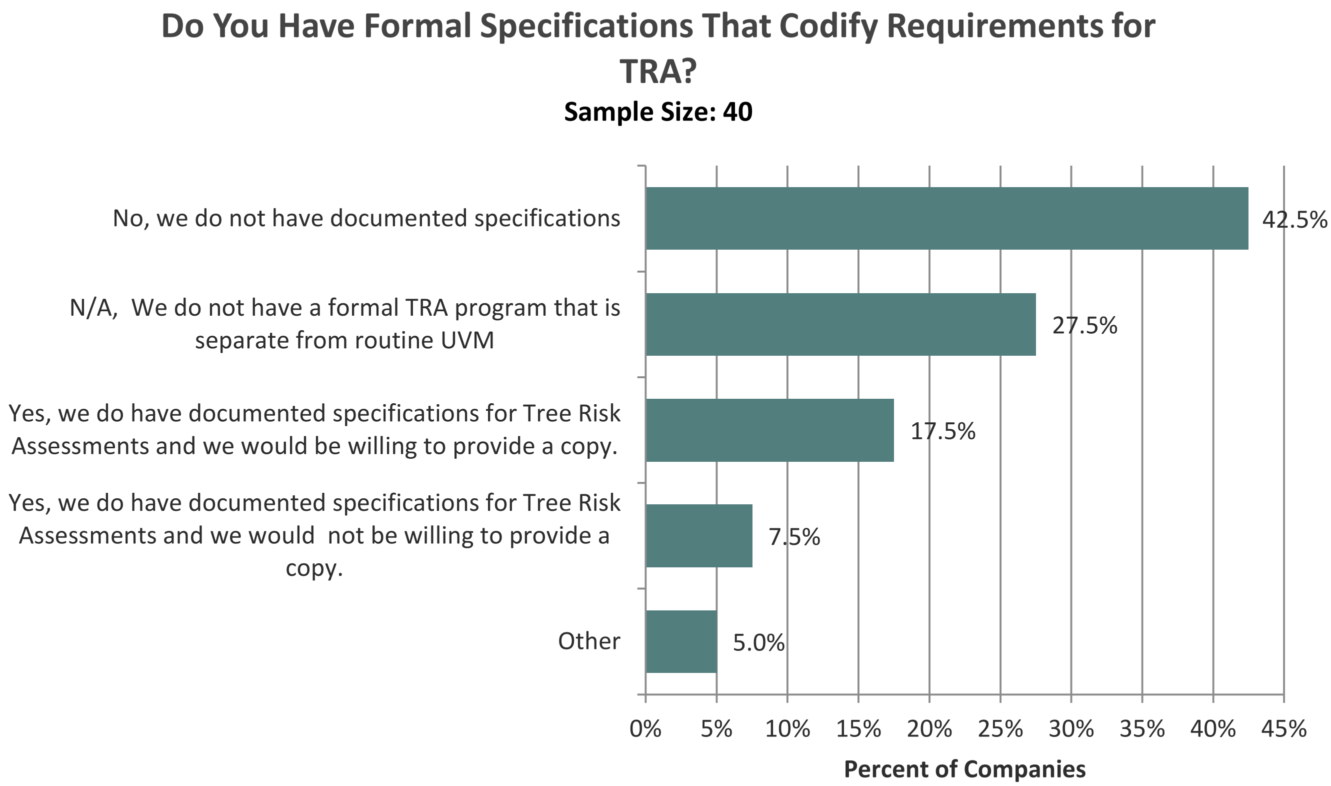


Figure 61: Do You Have Formal Specifications That Codify Requirements for TRA?

Formal Specification for TRA Comments
We have a general approach on risk vs target (voltage/facilities). For example a tree with slight risk for a single phase line would not be acceptable risk for sub-T radial feed [Other]
Experience and common sense is our guide! [N/A, No]
We do not have a formal TRA program that is separate routine UVM [N/A, No]
I would need approval from the vendor who helped us develop the material, as it is copyrighted. [Yes, will provide copy]
Specifications are specific to FAC-003 applicable lines. [Yes, will *not* provide copy]
As [we] gather more data we expect to craft specs. [N/A, No]
Most of TRA program is routine UVM, we are currently doing inspections and collecting danger tree inventory on Distribution. Transmission is done during annual and mid-cycle inspections [Other]
We craft our specs ourselves and we do inform our personnel. And our spécifications are in French. [Yes, will provide copy]
We have a section in our Vegetation Management Guidelines Book that refers to hazard tree expectations (section 2.2). [Yes, will provide copy]

Comment Table 8: Formal Specification for TRA Comments

Question 12: Do you provide or require training for Tree Risk Assessment assessors?

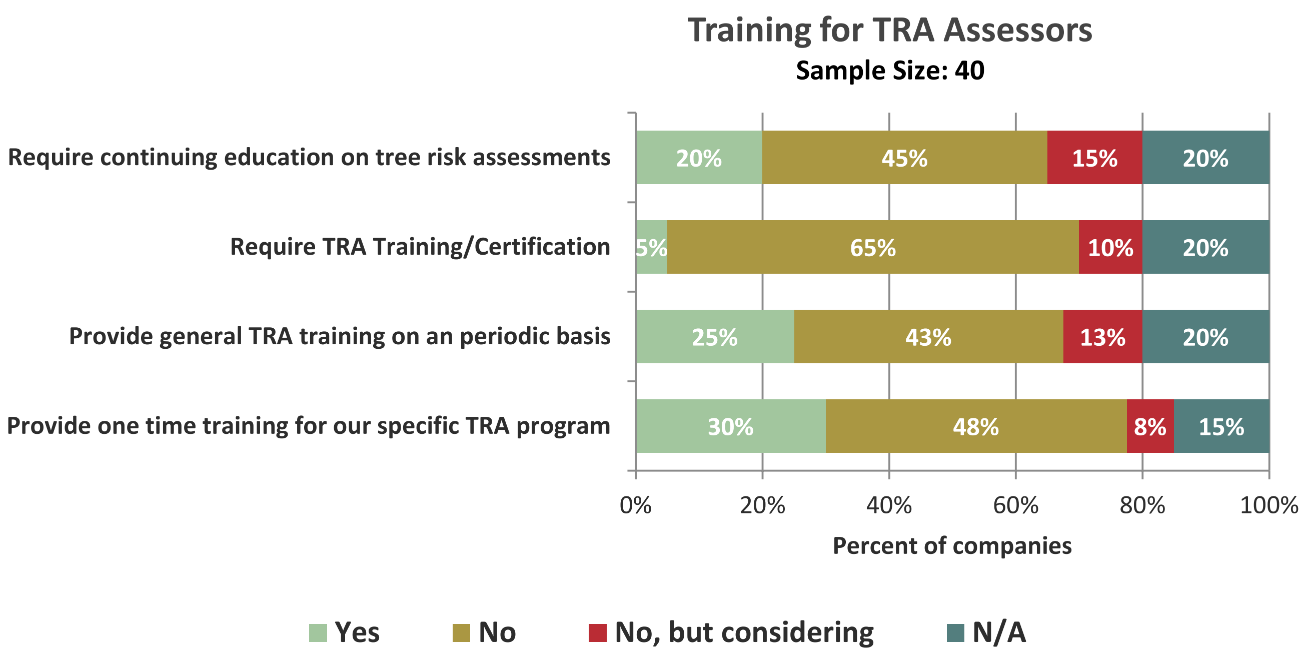


Figure 62: Training for TRA Assessors

Other Training Scenarios
Annual training along with specification review
Transmission specialist with an understanding of the Clearance requirements in the Alberta Reliability Standard.
Distribution: Review general expectations with available UVM contractor inspectors to identify trees that are obviously hazardous (i.e. dead trees, leaning, etc.); Transmission: Utilize experienced internal utility transmission foresters to perform aerial inspections, with subsequent follow-up ground assessments by contractor personnel if needed.
Contractor lead trainings
The ISA TRA requirement of re-testing and no CEUs is ridiculous. I will not be re-certifying when my certification expires.
[Inspection contractor] volunteered to have one of their foresters trained, which has proven very valuable to our informal TRA program
Annual training as an aspect of general orientation
We provide our on specific training for determining hazard trees and profession judgement
MN tree inspector license and MN first pest detector
Annual training for anyone involved with FAC003-3

Comment Table 9: Other Training Scenarios

Question 13: Which best describes the normal/expected location (viewing position) from which routine ground-based Tree Risk Assessment is conducted? Please indicate the one Assessor Location which best describes what is done on each type of line.

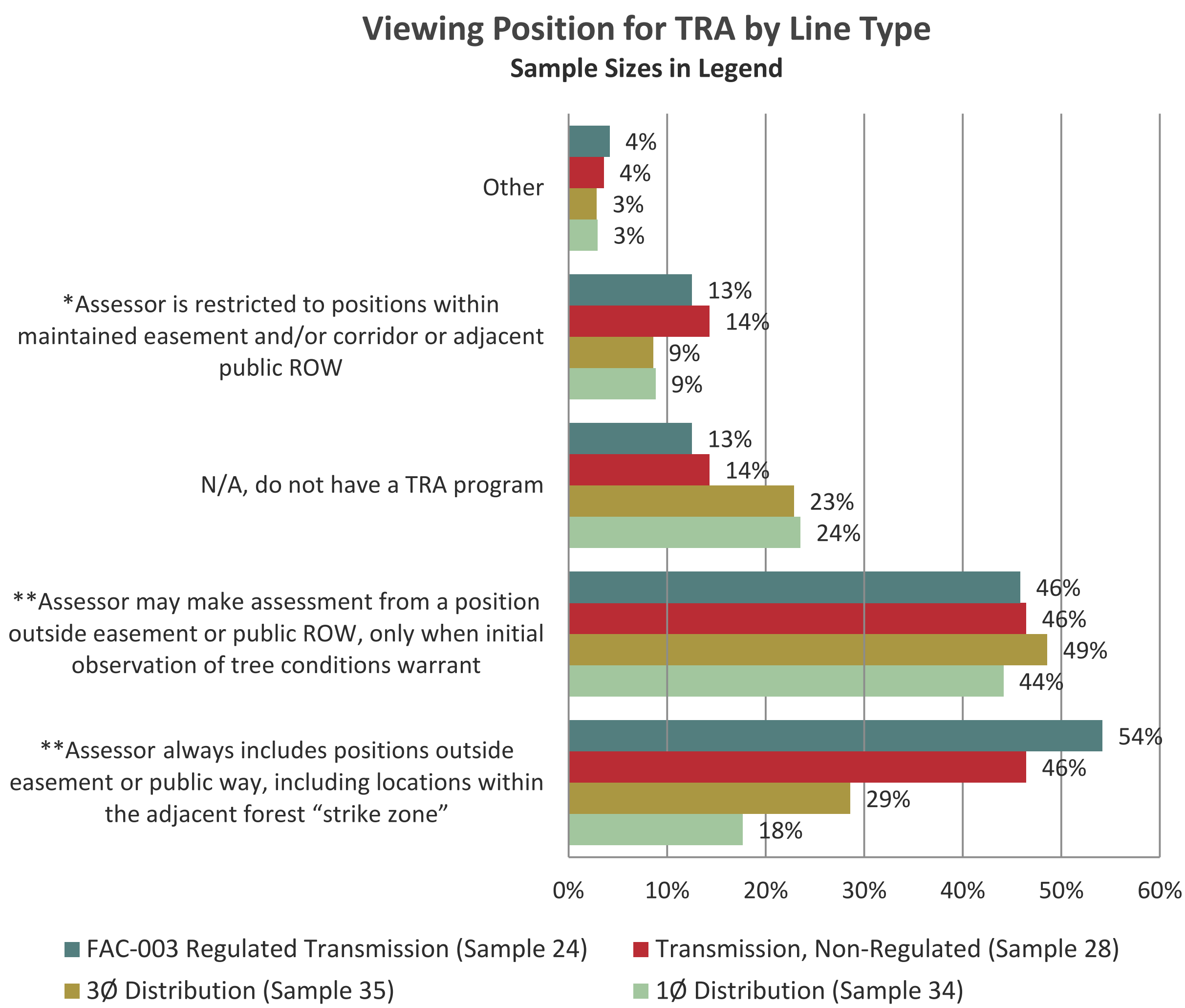


Figure 63: Viewing Position for TRA by Line Type

Three companies chose more than one response per multi-phase and transmission line types:

- *One company chose this response *and* the responses labeled ** and ***
- Two companies chose responses labeled ** and ***
- Therefore, these categories do not add to 100%

Comments

- We do not have any rule on observation positioning for our TRA program
- I don't understand what you're getting at with this question. We can inspect our lines from outside or inside the easement as needed and we do.

Question 14: Which approach best describes the primary area of focus for Tree Risk Assessment (TRA) on each of the four line types?

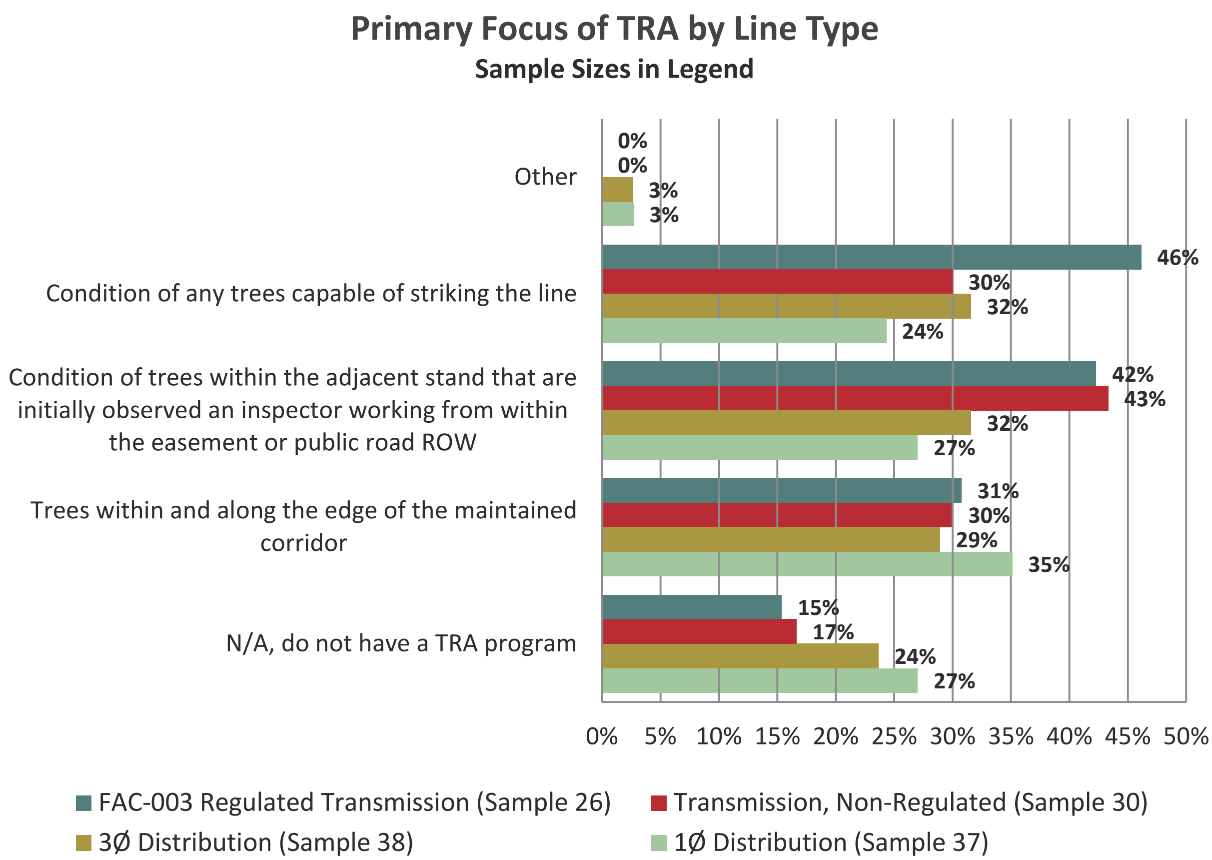


Figure 64: Primary Focus of TRA by Line Type

Other: Risk trees can be mitigated as far away from line as needed

Question 15: Please identify the types of rights you have to inspect and mitigate risks posed by Off ROW trees, by indicating the estimated percentage (% of total line miles) of Off ROW Rights for each line type.

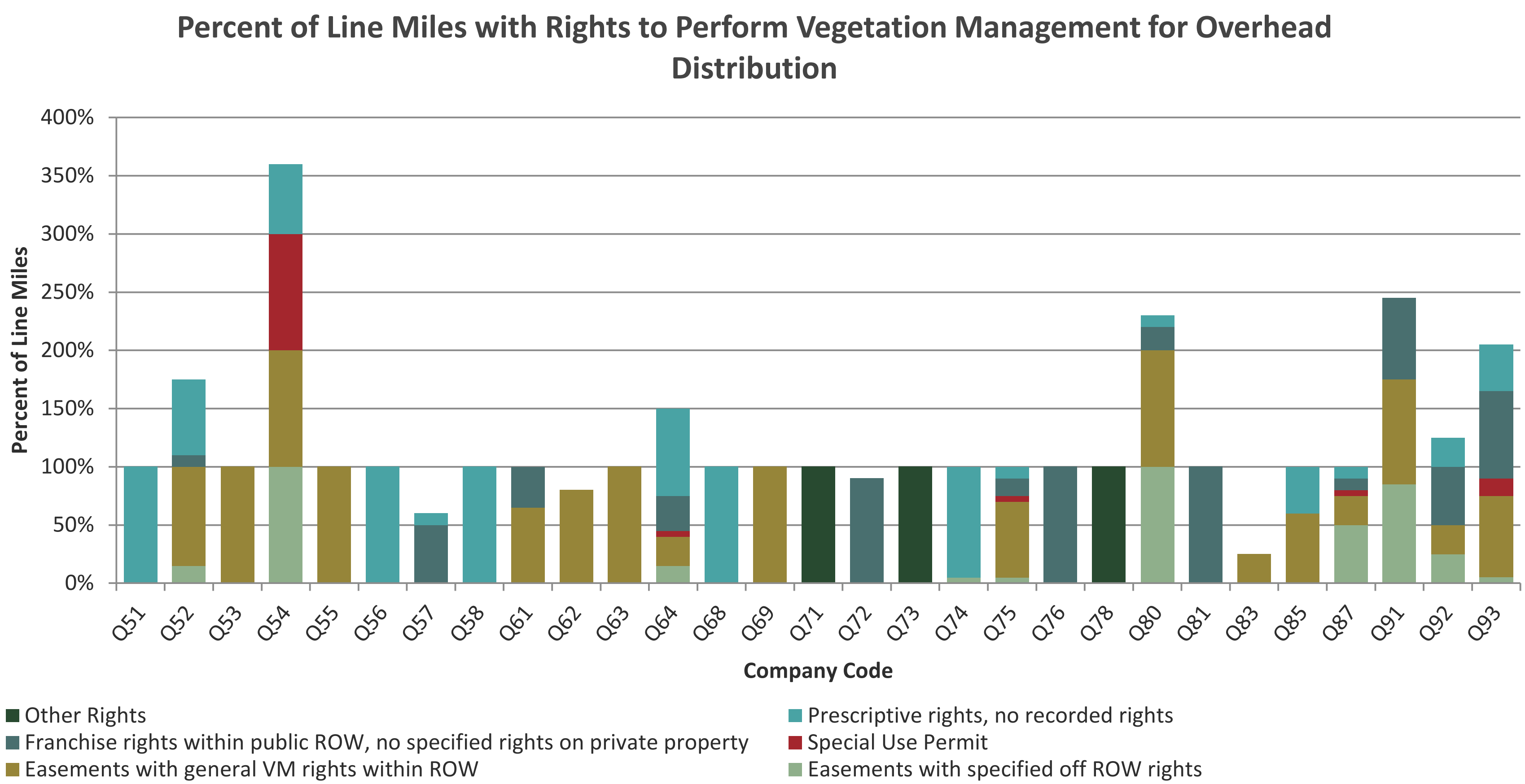


Figure 65: Percent of Line Miles with Rights to Perform Vegetation Management for Overhead Distribution

- **26% Reported 0% in all categories (Total Sample: 34)**

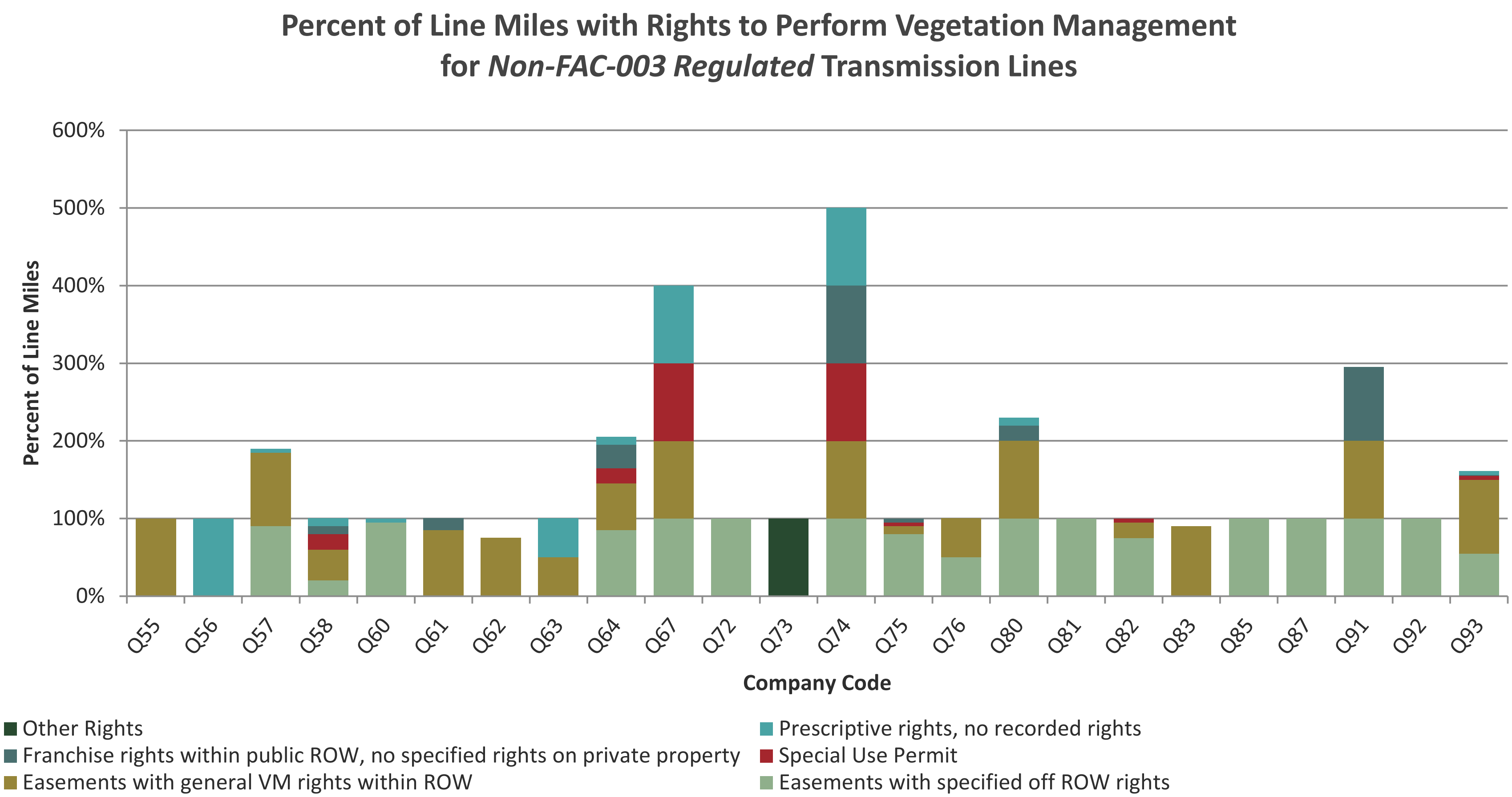


Figure 66: Percent of Line Miles with Rights to Perform Vegetation Management for *Non-FAC-003 Regulated* Transmission Lines

- **24% Reported 0% in all categories (Total Sample: 33)**

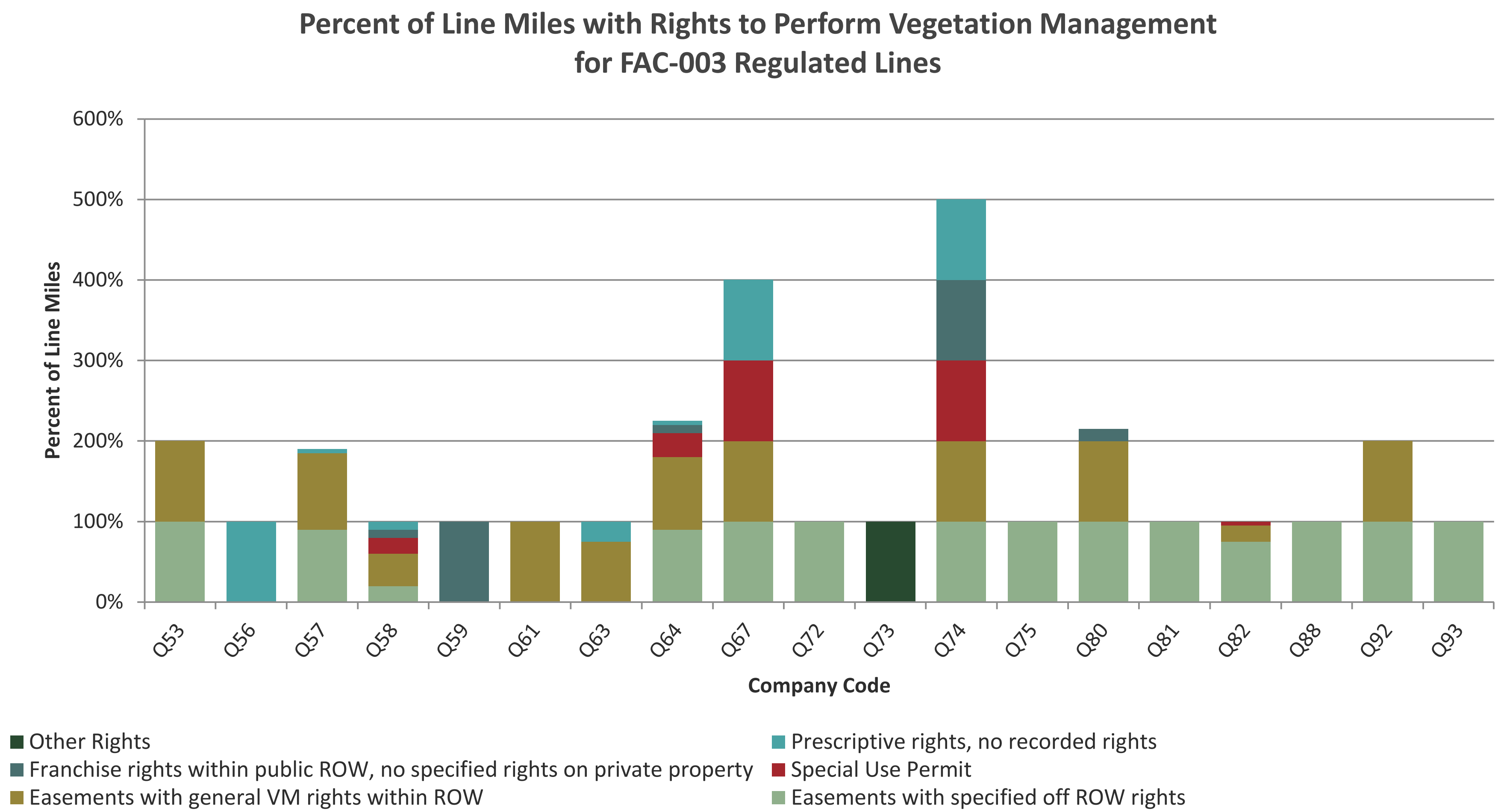


Figure 67: Percent of Line Miles with Rights to Perform Vegetation Management for FAC-003 Regulated Lines

- **34% Reported 0% in all categories (Total Sample: 29)**

Comments Rights on Off-ROW Trees
These are estimates [percent of miles]
We do not have any way to track this information by mileage.
Information not attainable.
We go wherever necessary.
Only cross country distribution line has easement rights but no off-ROW rights.
Under law, we have the authority to remove any vegetation that we deem hazardous to our electrical system
Prescriptive easement with general VM rights
We do not need right to inspect any trees; we need owner's authorization to cut risk trees.
Unknown, really a poor question. Rights or not, if we identify a tree that is a problem we will find a way to purchase the tree, work with the customer, etc. Really do not have all these easement rights categorized in this way.
We do not keep records of this as it relates to line miles.

Comment Table 10: Rights on Off-ROW Tree

Question 16: Are there any regulatory requirements in your service territory that specifically address the need to conduct periodic inspections of vegetation conditions? If so, please cite Regulatory agencies and titles of requirements in the comments box.

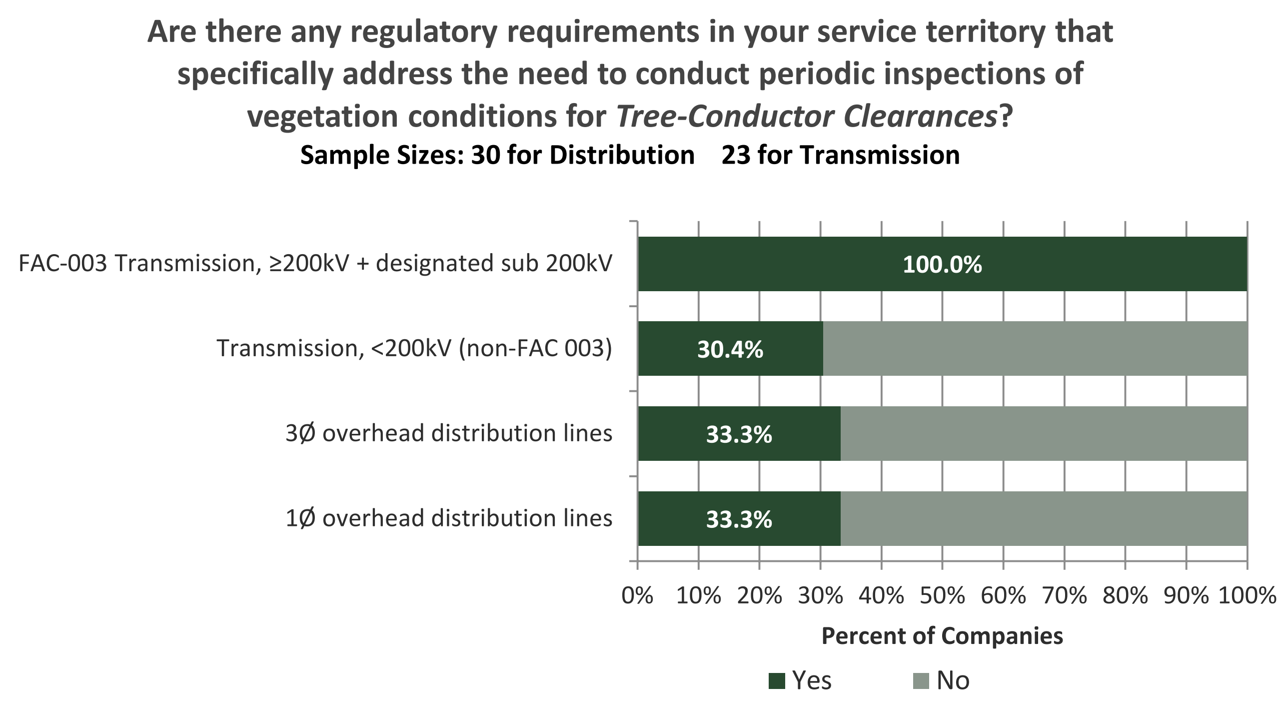


Figure 68: Regulation Requirements for Tree-Conductor Clearances

Are there any regulatory requirements in your service territory that specifically address the need to conduct periodic inspections of vegetation conditions for *Tree Condition, Likelihood of Failing and Striking the Line*?

Sample Sizes: 26 for Distribution

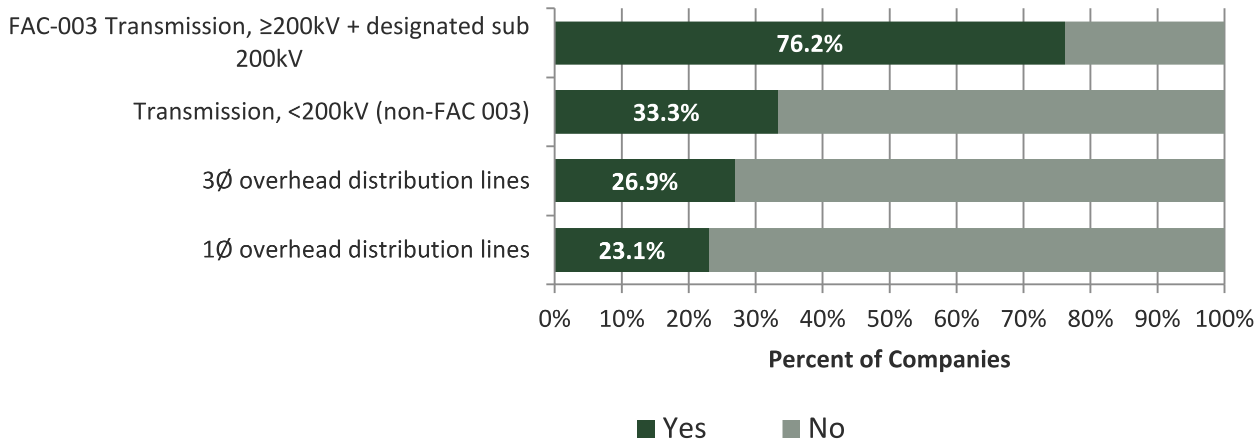


Figure 69: Regulation Requirements for Tree Condition, Likelihood of Failing and Striking the Line

Identify Regulatory Agencies and Titles of Regulations
CPUC NERC
General clearances are contained within PSC rule 4 CSR 240-23 along with all investor own filing of specific clearances for each programs.
New Jersey Administrative Code - 14:5 various Maryland RM43
FAC-003 on NERC lines ***(Cited 8 times as only regulation)***
Alberta Reliability Standard Alberta Utilities Commission
CA GO 95 R35 and PRC 4293 in addition to NERC standards for Transmission
FAC-003 WECC
California Public Utility Commission [CPUC], General Order #95 Rule #35, PRC 4292, and PRC 4293.
only NESC 218
ICC
Ontario Energy Board- Maintain historical practices- inspect 33% of the plant annually.
Manitoba Hydro Distribution Standards / Tree Trimming Clearance and Brush Clearing NERC/FERC
FERC, CT PURA, MA DPU, NH DPUC
NH PUC 3017.10
Régie de l'énergie du Québec
California Public Resource Codes 4292 and 4293
State of New York Public Service Commission, CASE 04-E-0822 Order Requiring Enhanced Transmission Right-of-Way Management Practices By Electric Utilities

Comment Table 11: Identify Regulatory Agencies and Titles of Regulations

Question 17: Do you have different standards or policies for tree risk assessment inspection in areas of potentially elevated risk (e.g. fire prone areas).

Sample Size: 40
Yes 27.5%
No 72.5%

Description of TRA in Areas of Elevated Risk
Extra patrols and clearance is required in [California Department of Forestry] CDF areas [Yes]
Fire [Yes]
Yes, our Mountain Pine Beetle program (this is a general program title which includes hazard trees created by insects other than MPB too) in Colorado. [Yes]
Area very small [No]
Emerald Ash Borer affected areas. Ash trees that shows any degree of decline caused by the Emerald Ash Borer is removed as a hazard tree. [Yes]
No different standards; however, have focused inspections on areas that have historically experienced higher mortality rates during enhanced drought conditions or elevated bark beetle infestations. This may increase the frequency of inspections for those specific areas. [No]
We inspect California Resource areas annually [Yes]
Conducting Redundant patrols in high fire risk areas [Yes]
More aggressive vegetation clearances and proactive tree removals where permitted to mitigate risk in high fire locations. [Yes]
We inspect fire prone or recent fire areas yearly until not needed. [Yes]
We have standards for hazard tree removal that define a process for "worst performing" circuits [Yes]
Higher focus on Backbones (un-fused portion of circuit) [Yes]
No, other than what is required for [inspections]. [No]
We have different standards of tree risk assessment for those circuits that meet our Storm Resiliency Program qualification [Yes]
If we ever did this it would be after the fact/event, after the fire in a specific area, after the storm, etc. [No]
Not a large fire risk [No]

Comment Table 12: Description of TRA in Areas of Elevated Risk

Question 18: Are there any regulatory requirements in your service territory that specifically address the risk of power-line-initiated wildfire, such as tree risk assessment?

Sample Size: 40
Yes 22.5%
No 77.5%

If yes, please cite regulatory agency and requirement title(s).
G.O. #95 and [California Department of Forestry] CDF High fire threat areas [Yes]
State [Yes]
Not applicable to our utility [Yes]
California Public Service Commission [Yes]
CA GO 95 R35 and PRC 4293 specify minimum clearance requirements and mitigation of potentially hazardous trees. [Yes]
California Public Utility Commission [CPUC], and PRC 4292 and PRC 4293. [Yes]
Wildfire Act [Yes]
Provincial Fire Smart Program - to negotiate with Manitoba Conservation [Yes]
Régie de l'énergie du Québec [No]
California Public Resource Codes 4292 and 4293 [Yes]

Comment Table 13: Regulatory Requirements in Service Territory That Address Powerline Initiated Wildfires

Question 19: Do you provide any training to staff specific to wildfires (e.g. prevention, limiting spread, evidence preservation)?

Sample Size: 40
Yes 25.0%
No 75.0%

Description of Fire Risk Training
Extreme dry conditions limit mowing work/all crews have fire extinguishers on vehicle and [are] trained. [Yes]
Monthly safety meeting [Yes]
Contractors conduct their own fire prevention training internally. [No]
Annual Fire Season Kickoff Meeting, training on prevention and practical exercises to familiarize with common tools such as fire rake, shovel, and water pack. [Yes]
Arizona Wildfire Academy [Yes]
General fire prevention and safe operating practices in high fire areas. [Yes]
Utility doesn't provide the training; we have Department of Natural Resources conduct periodic training. [Yes]
Contractors are required to provide annual training on fire prevention and response. [Yes]
Not really just for fire, but it is discussed. We annually review our Imminent threat process, this is general to all threats, but fire damaged tress, dead trees, wind throw trees, etc. [No]
Basic Fire awareness. [Yes]

Comment Table 14: Description of Fire Risk Training

Question 20: When evaluating trees for risk, do your Tree Risk Assessors document fire potential (e.g. fuel build up or the potential for tree wire contacts to occur, which could lead to wild land fire ignition)?

Sample Size: 40
Yes 5.0%
No 95.0%

If yes, could you briefly describe the assessment process?
- DNR & [utility] jointly generated form [Yes]
- Question may be N/A since we have no TRA program. [No]

The following graph compiles the information from questions 18 -21, which all relate to wildfire risk.

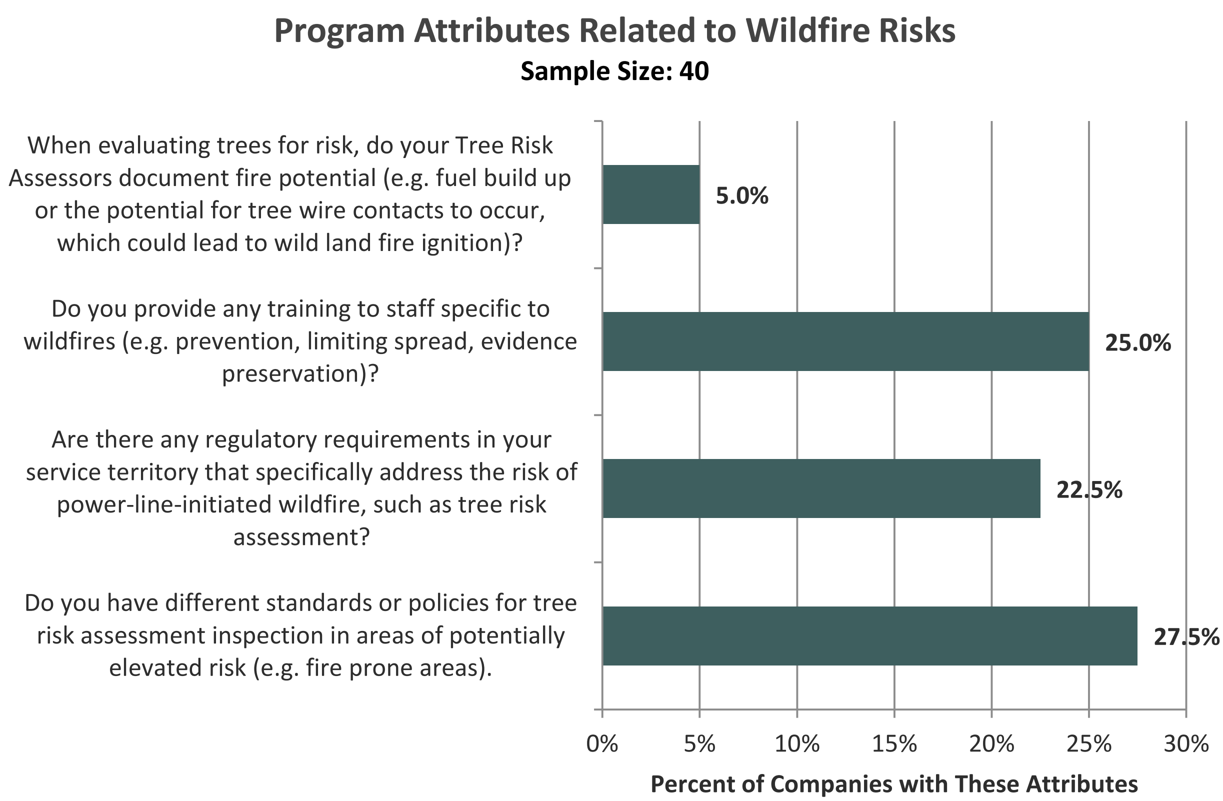


Figure 70: Program Attributes Related to Wildfire Risks

Question 21: Do your hazard tree inspectors pursue removal permits on large trees that appear to be in good health but could impact an important feeder line if they failed in a storm? If yes, how many such trees are removed each year? Choose all that apply

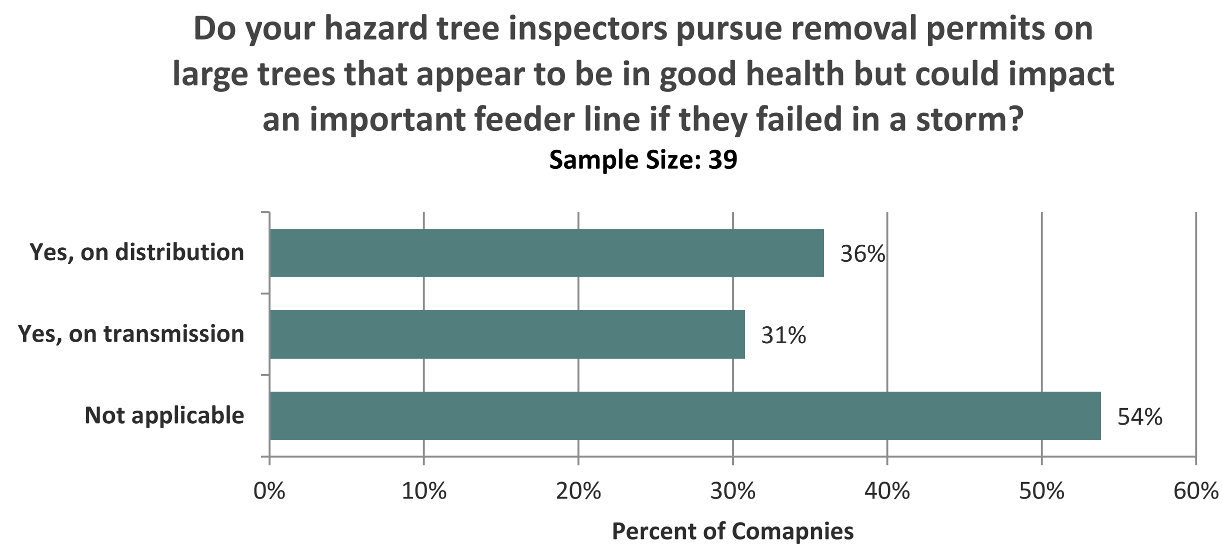


Figure 71: Pursue the Removal of Healthy Trees That Could Impact Important Feeder Lines

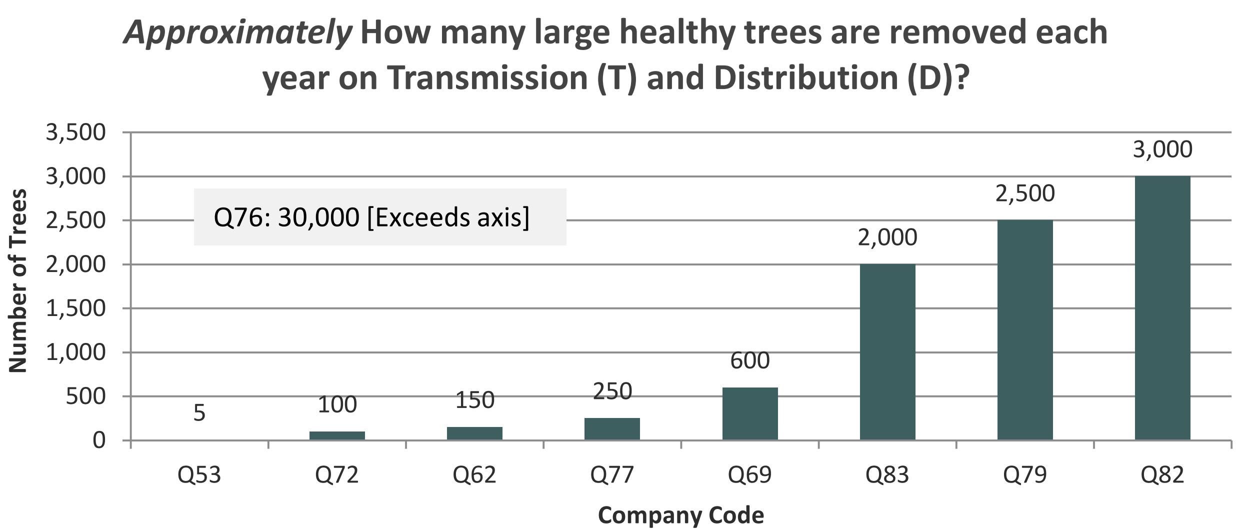


Figure 72: Number of Healthy Trees Removed per Utility

Approximately How many large healthy trees are removed each year on T and D?
Tree count does not distinguish between healthy vs hazard removals [Yes, on T & D]
If they are in good health, why would we take them down? [N/A]
Unknown [Yes, on T & D]
No on Dist. Pursue removals on Trans if on the easement (may or may not need a permit). Transmission off-ROW, if healthy, limited pursuit of removals. [Yes, on Transmission]
Starting with H[azard]&D[iseased] tree survey this year [N/A]
< 100 total; however, we capitalize widening activities on T&D annually. [Yes, on T & D]
5% of our 50 000 removals and it's recent [Yes, on Distribution]
On average 3000 [Yes, on Transmission]

Comment Table 15: Removal of Healthy Trees Comments

Question 22: When trees are assessed for risks, are targets other than powerlines considered (e.g. traffic, pedestrians, playgrounds, and backyards where children are present)?

Sample Size: 40
Yes 47.5%
No 52.5%
Other 0%

Are Other Targets than Powerlines Part of TRA?
NESC 218---we consider any tree on major highway crossings for removals. We consider any tree in school yard or backyard that is readily able to climb an issue. Any tree house within a tree in proximity to electrical wires would be an issue. [Yes]
While we are cognizant of such risks other than to our transmission lines, they do not factor into a decision to remove a tree that is not a threat to our lines. [No]
May observe/assess these risks during the course of normal work to identify any tree, healthy or hazardous, to determine if risk should be mitigated. [No]
We have a lot of internal discussion on how much responsibility lies with the property owner. We don't have an answer, but if we are unsure, we act to remove the tree at our ratepayer's expense. [Yes]
We take in to account the environment in order to prioritize when the work will be done. [Yes]
Public safety and reliability are our highest goals. [Yes]
We notify customers of potential risks from tree houses, playground equipment, etc. that are within minimum approach distances. [Yes]
Not officially part of the removal criteria but if they are a factor they can be used in discussing removal with the tree owner [No]
[We] got no TRA [No]
These factors may influence tree A versus tree B that are otherwise evaluated as a similar risk [Yes]
The potential hazards are articulated to the member [Yes]
We use those risk assessments to obtain owner authorization [Yes]
Public and employee safety [Yes]

Comment Table 16: Are Other Targets than Powerlines Part of TRA?

OPINIONS

Question 1: Please indicate whether you, strongly agree (SA); agree (A); have no opinion (No O); Disagree (D); or Strongly Disagree (SD), with the following statements:

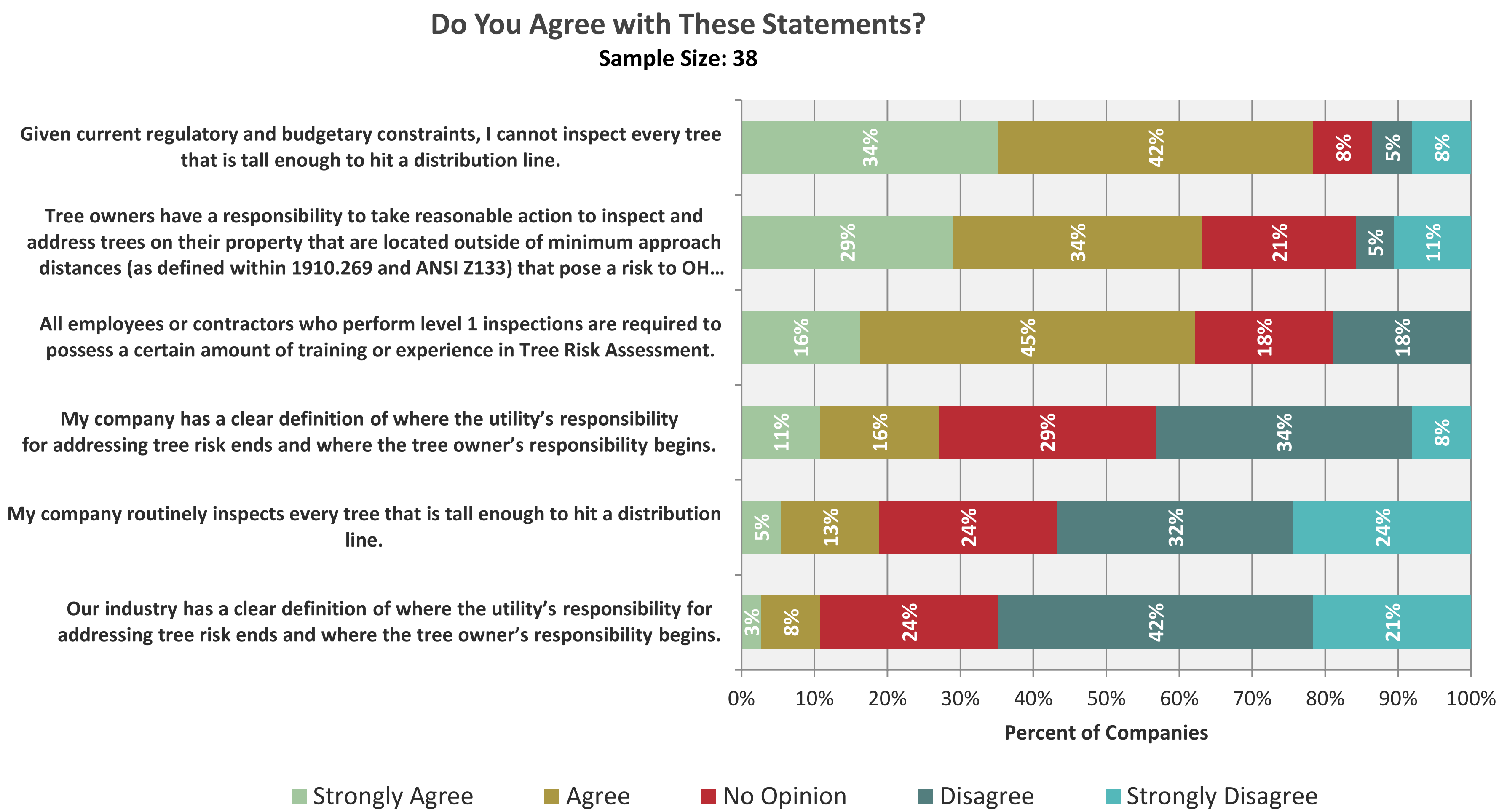


Figure 73: Do You Agree with These Statements?

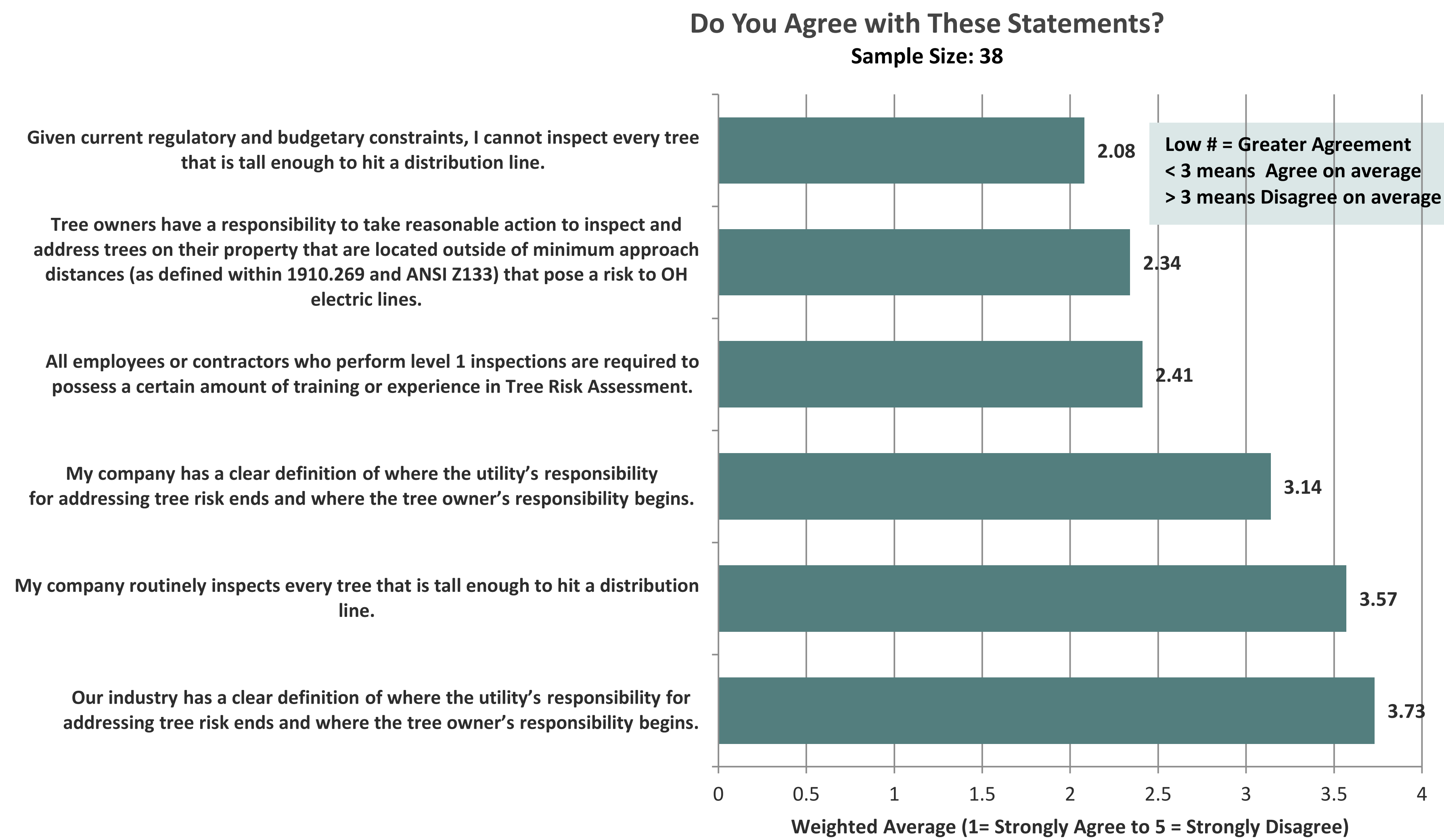


Figure 74: Do You Agree with These Statements? Analyzed with Weighted Averages

How is this Responsibility Established between the Utility and the Customer?
As a public utility we are all about customer service, but we will not remove stumps and [we] leave the wood for the customer whenever possible when removing trees. I would like to place the liability for the tree on the owner of the tree for refusals and danger trees.
Comes down to definition of inspection. Limited vantage point versus intense inspection.
The customer responsibility: it is on the service line from the last pole to the meter Panel and depending on the degree of hazard we may provide the service.
In my opinion, tree maintenance or mitigation responsibility and liability should shift significantly towards the property owner.
Municipal property is utility's responsibility, and private property is the responsibility of the property owner with the exception of easements (i.e. rear lot)
Owner has no responsibility
Distribution up to 14.4/24.9 kV out to 35 feet from centerline; 46 kV out to 80 feet from centerline; 138 kV and 345 kV out 40 feet from edge of cleared ROW
Tree risk assessment should be utility's responsibility, but addressing the risk should be owner's responsibility.
Again, this is a rather difficult question, funding, staffing, corporate value for this service are all factors.

Comment Table 17: How is this Responsibility Established between the Utility and the Customer?

Question 2: Do you have additional thoughts or opinions about a Best Management Practice for Tree Risk Assessment?

Additional Thoughts or Opinions

- Our company does not have an official TRA program in place. We assess risk trees while doing normal routine R.O.W. maintenance. We do offer incentives to property owners for removal of large trees on and off our ROW's that are a danger to our facilities. Our system arborist, (myself) has been certified in Tree Risk Assessment by the ISA for mitigating risk by tree's on and off our ROW.
- Tree risk assessment is an important part of conducting vegetation management to reduce tree related outages to utility facilities. A basic level of TRA should be required; however, [utility is] cautious about requiring high level of TRA on individual trees and on stands due to size of our utility, limited resources, limited qualified personnel etc.
- Due to our small size and limited vegetation, we do not have any additional comments.
- Our utility has chosen to widen distribution circuits to a new standard ROW width as well as 69kV. Trees of risk are removed on an individual basis on all rights-of-way no matter the voltage class.
- Dangerous road to go down as it introduces liability questions that have to be answered in court if something goes awry. Property law says property owner is responsible but development of a risk assessment standard can be used to say the utility has a duty of care beyond their easement rights with no formal permission to perform the work.

Appendix H: Distribution Survey Benchmark Results

INTRODUCTION

CN Utility Consulting conducted a benchmarking survey in January - April 2016. The participants included 36 companies (excluding Hydro One) and of this group 27 were selected as peers to Hydro One Networks. This peer group was used for making comparisons involving costs, reliability, and safety.

Peer companies were chosen to some degree by geographic proximity (see Appendix D for further details on how the peer group was selected). This proximity helps equalize variables that impact the functioning of a utility vegetation management (UVM) program such as tree species populations, economic factors, weather conditions, and regulatory oversight. Although all UVM departments and utilities are unique, benchmarking has value and all efforts have been made to normalize or analyze data to accommodate "fair" comparisons. "Company Profiles of Peer Companies," the first section in this appendix, highlights how the selected group varies on core elements. A list of companies that responded to the survey is shown in Table 1. In order to maintain confidentiality and anonymity, the peer group list will not be distinguished from this group.

List of Participating Utilities

Participating Utilities in the Hydro One Networks 2016 Benchmark Study	
AEP Texas	Liberty Utilities (New Hampshire)
Ameren Illinois Company	Lincoln Electric System
Appalachian Power Company	Manitoba Hydro
Arizona Public Service	Massachusetts Electric (National Grid)
Avista Utilities	Modesto Irrigation District
BC Hydro	Mount Pleasant Power System
City of Tallahassee	Narragansett Electric (RI) (National Grid)
Connexus Energy	Niagara Mohawk (National Grid)
Consumers Energy	Ohio Power Company
CoServ	Omaha Public Power District
Entergy Corporation	Pacific Gas and Electric
EPB (Electric Power Board)	Public Service of Oklahoma
EPCOR	Puget Sound Energy
Hydro Ottawa	Southern California Edison
Hydro-Québec	Southwestern Electric Power Company
Indiana Michigan Power	Tampa Electric (TECO)
Kansas City Power and Light (KCPL)	Turlock Irrigation District (TID)
Kentucky Power	Unitil

Table 6: Participating Companies

The data used to develop this appendix is important to the accuracy of the analysis in the report. In particular, the number of kilometres of overhead line is a key element of many of the calculations and models used for comparing utility vegetation management (UVM) programs. To ensure accuracy of elemental data, survey responses were verified with publically available sources, such as utility websites, legal dockets, the Energy Information Administration (EIA), Platts Directory of Electric Power Producers and Distributors, utility reports to regulatory entities, regulatory reports, and previous CN Utility Consulting (CNUC) survey responses. This process was used to "scrub" the data of erroneous data entry, missing data or misinterpretation of the question. Respondent communication was also a part of this data "cleansing."

Most graphs use data only from the peer group companies. *Data from **all** participants in the survey was used for information that is not regionally or workload dependent, such as what factors influence the utility vegetation management budget (UVM).* **Graphs that include non-peer companies will be indicated next to the sample size.**

Graphical Representation and Highlighting of Hydro One Networks

The graphs in this appendix highlight the data from Hydro One in the following ways:

- On graphs, Hydro one Networks' label is *Hydro One*.
- The South, East, Central and North region labels are *HO South, HO East, HO Central*, and *HO North*, respectively.
- A gray text box surrounding the data label indicates the group to which Hydro One belongs. This applies to bar graphs or pie charts.
- A red highlighted bar indicates Hydro One Networks and its regions for single column graphs, where individual utilities have their data represented with a bar or two variable stacked column graphs.
- Hydro One Networks and its regions are represented with a red outline for stacked or column cluster graphs, unless 'bright" colors can be used without losing clarity.
- All *Statistical Tables* in plot area of graphs are peer statistics and exclude Hydro One and its regions in the calculations.

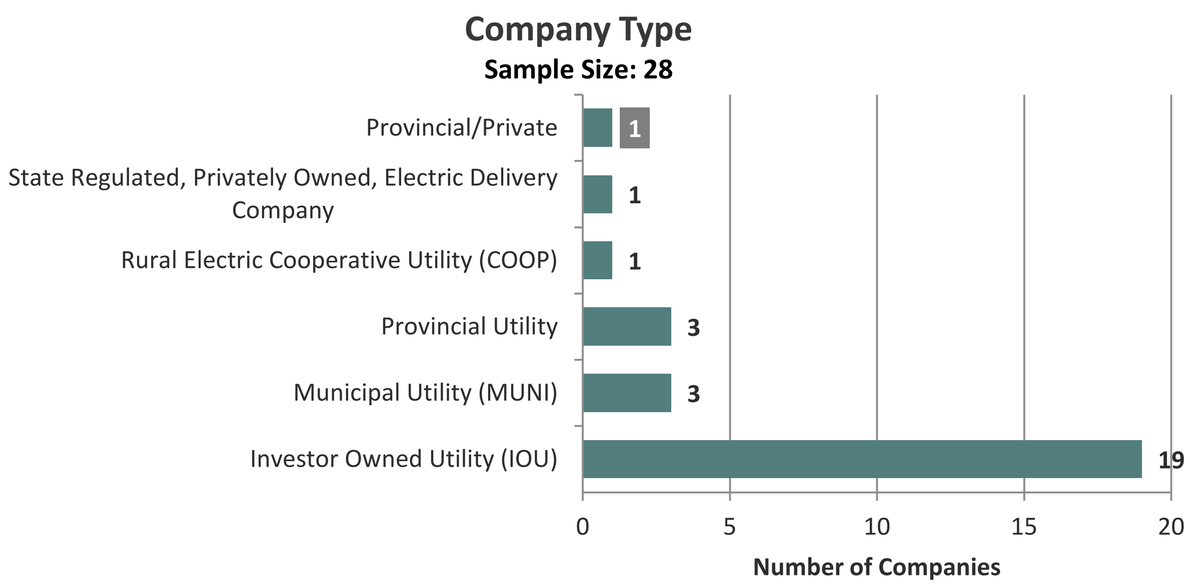
Graph and table numbers in this appendix vary from labels in the main report and other accompanying appendices.

Responses to the question are in brackets on comment tables. In other words, if the respondent answered, "Yes", [Yes] will appear after their comment. This will be true for most comment tables in this report.

COMPANY PROFILES OF PEER UTILTIES

The graphs in this section are comprised of general information about the peer group. They support the efficacy of the choice to include each utility in the target group for comparison with Hydro One.

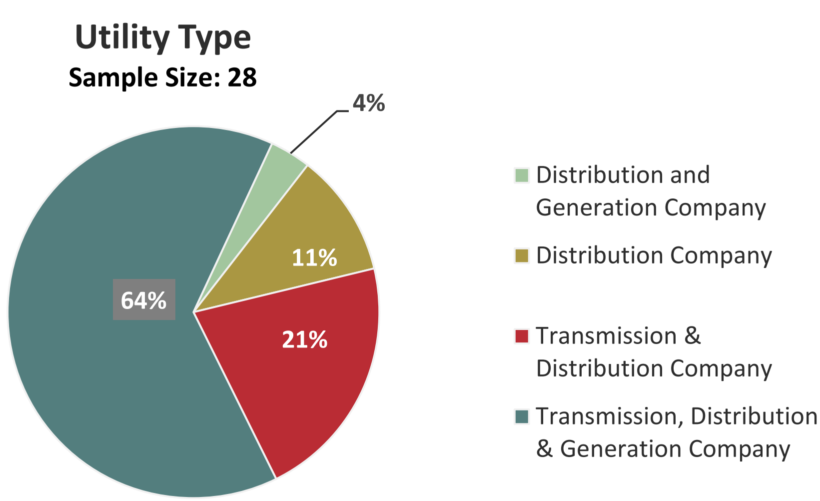
Company Type



Graph 7: Company Type

NOTE: Hydro One only counted as one company (not five) in graph above and below.

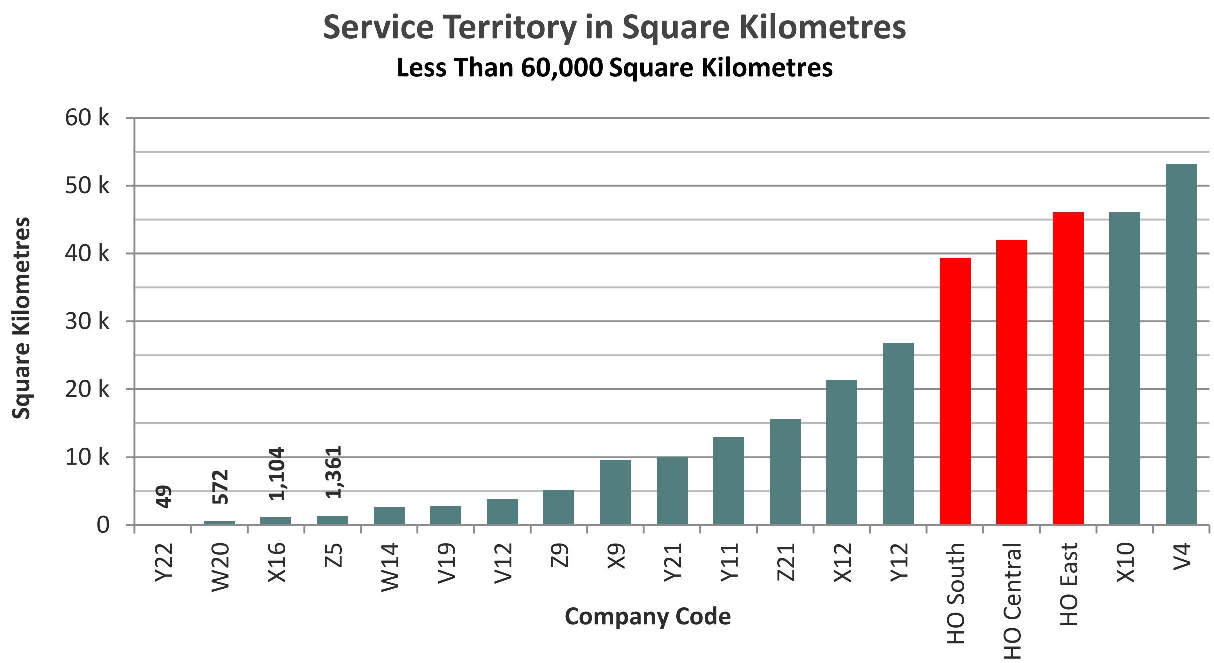
Utility Type



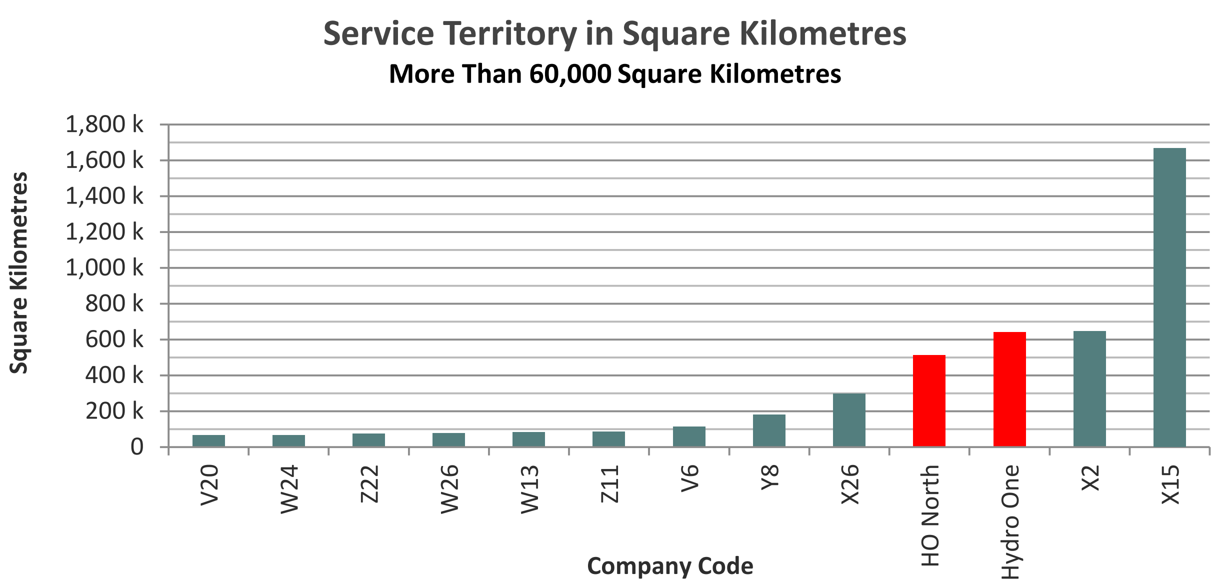
Graph 8: Utility Type

Service Territory in Square Kilometres (Land Area)

The peer group is shown on two graphs (*with different y-axis scales*), so that the range of service territory sizes can be distinguished.



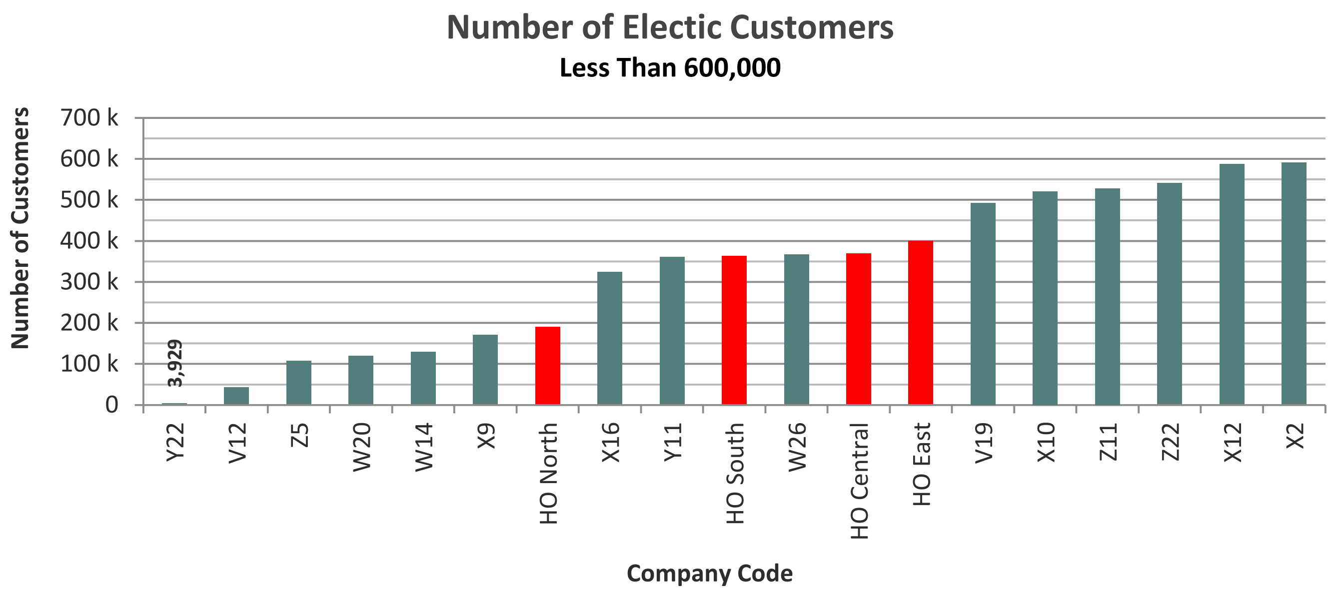
Graph 9: Service Territory in Square Kilometres – Companies with Less Than 60,000 Square Kilometres



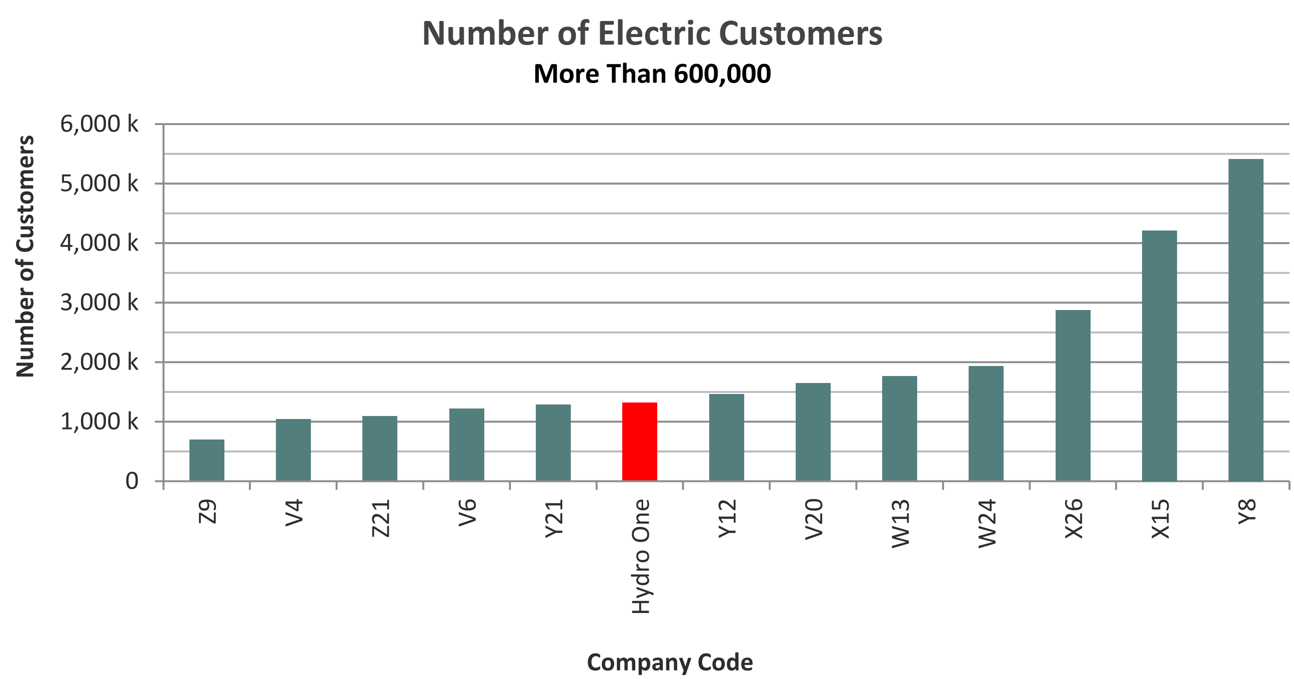
Graph 10: Service Territory in Square Kilometres – Companies with More Than 60,000 Square Kilometres

Number of Electric Customers

The peer group is shown on two graphs (*with different y-axis scales*), so that the range of customer count can be distinguished.

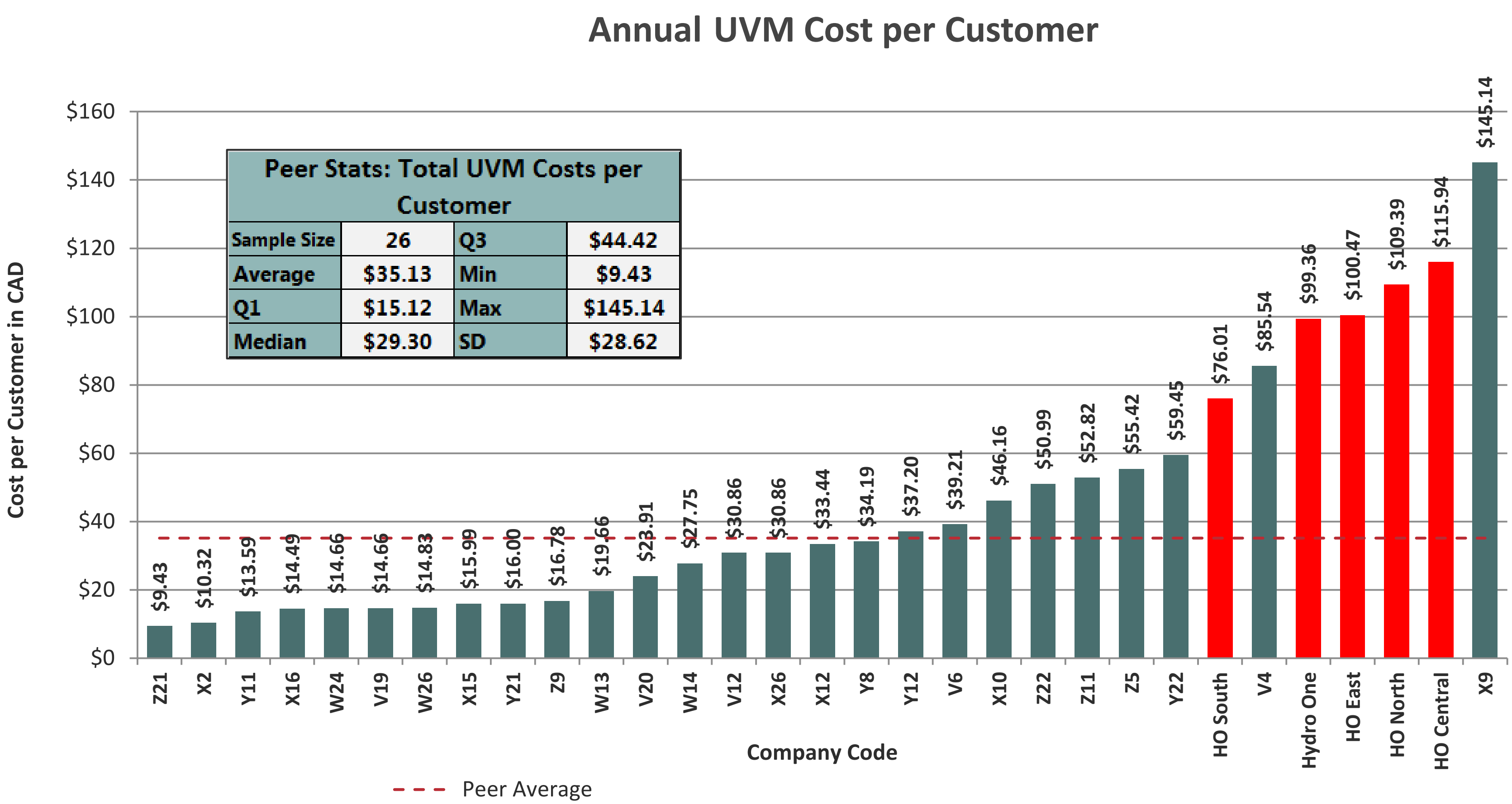


Graph 11: Number of Customers – Companies with Less Than 600,000



Graph 12: Number of Customers – Companies with More Than 600,000

Annual Cost per Customer



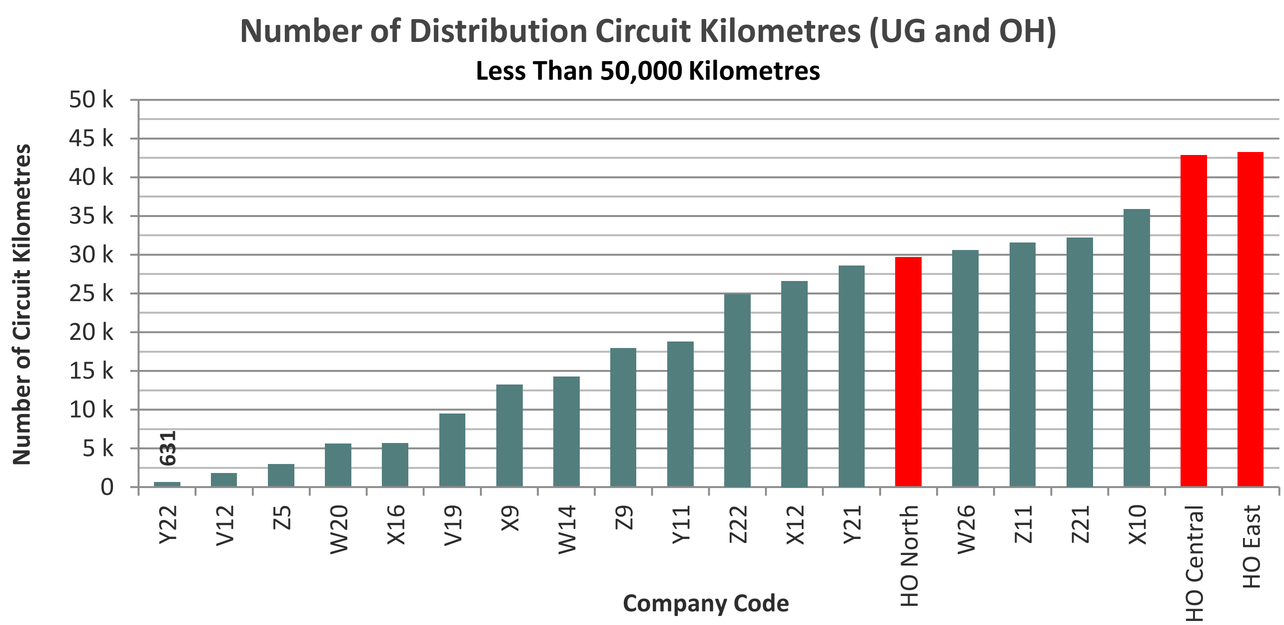
Graph 13: Annual UVM Cost per Customer

This rate was calculated by dividing Total Cost of UVM by number of electric customers, using 2015 numbers. Hydro One's UVM expenditures were an average of 2011-2015, since their 2015 total cost was significantly reduced from the previous years.

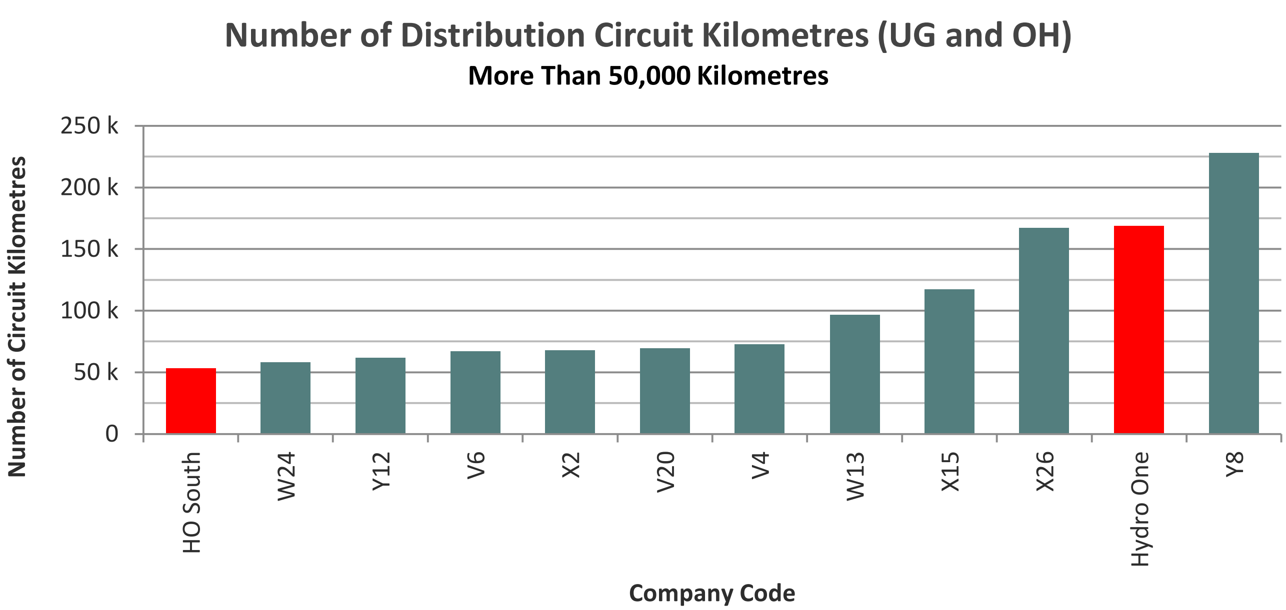
ELECTRIC DISTRIBUTION SYSTEM DESIGNS

Distribution System Circuit Kilometres

The peer group is shown on two graphs (*with different y-axis scales*), so that the range of circuit kilometres lengths can be distinguished. This includes all lines greater than 1kV and less than 60kV.



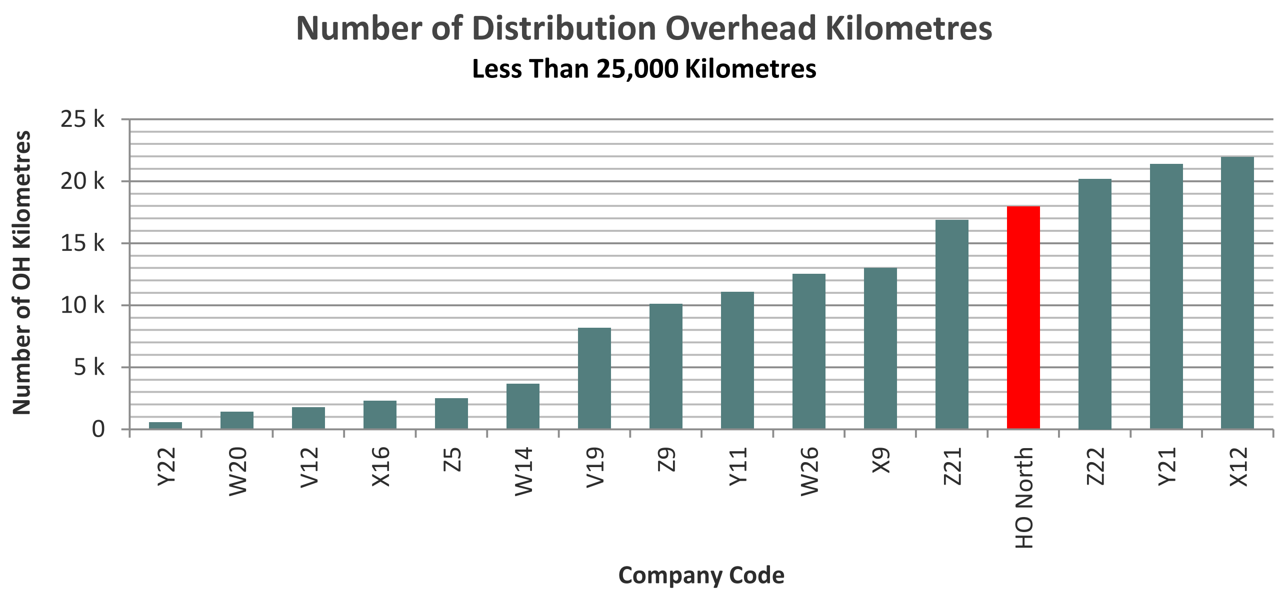
Graph 14: Number of Distribution Circuit Kilometres (UG and OH) – Companies with Less Than 50,000 Kilometres



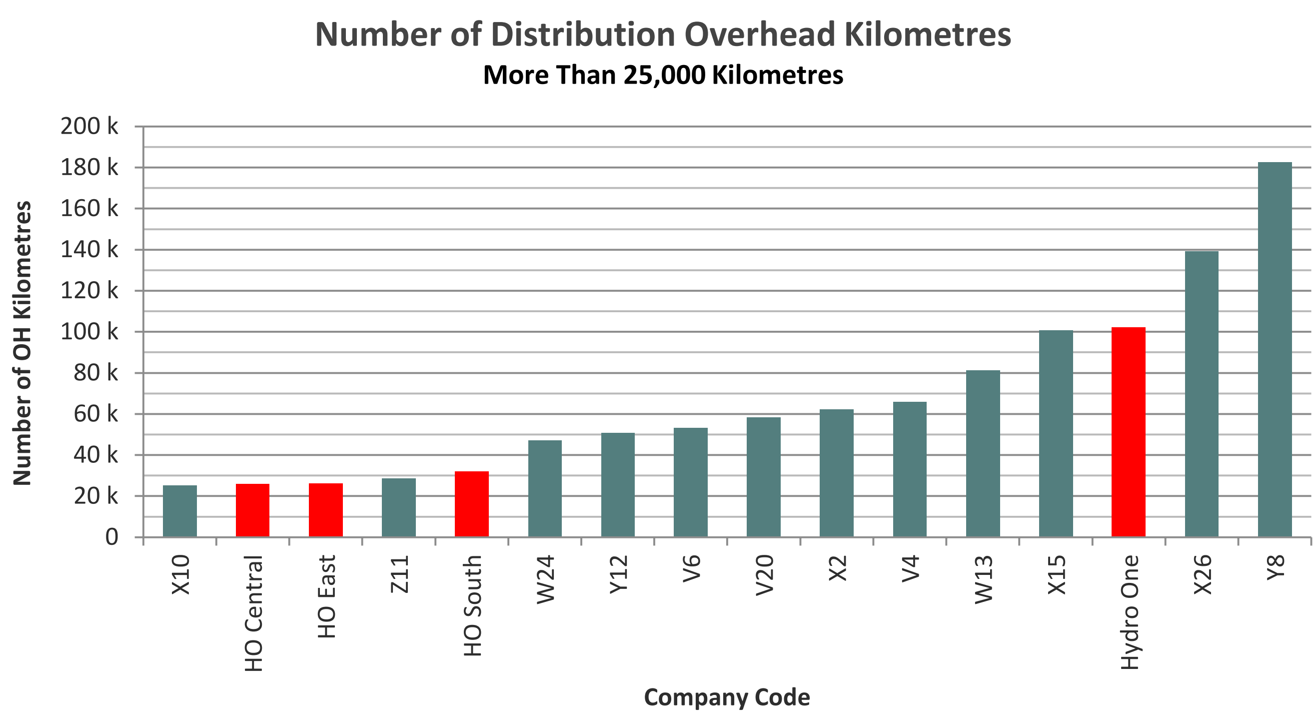
Graph 15: Number of Distribution Circuit Kilometres (UG and OH) – Companies with More Than 50,000 Kilometres

Distribution System Overhead Kilometres

The peer group is shown on two graphs (*with different y-axis scales*), so that the range of pole kilometres lengths can be distinguished. This includes all overhead pole kilometres greater than 1kV and less than 60kV.



Graph 16: Number of Distribution Overhead Kilometres – Companies with Less Than 25,000 Kilometres

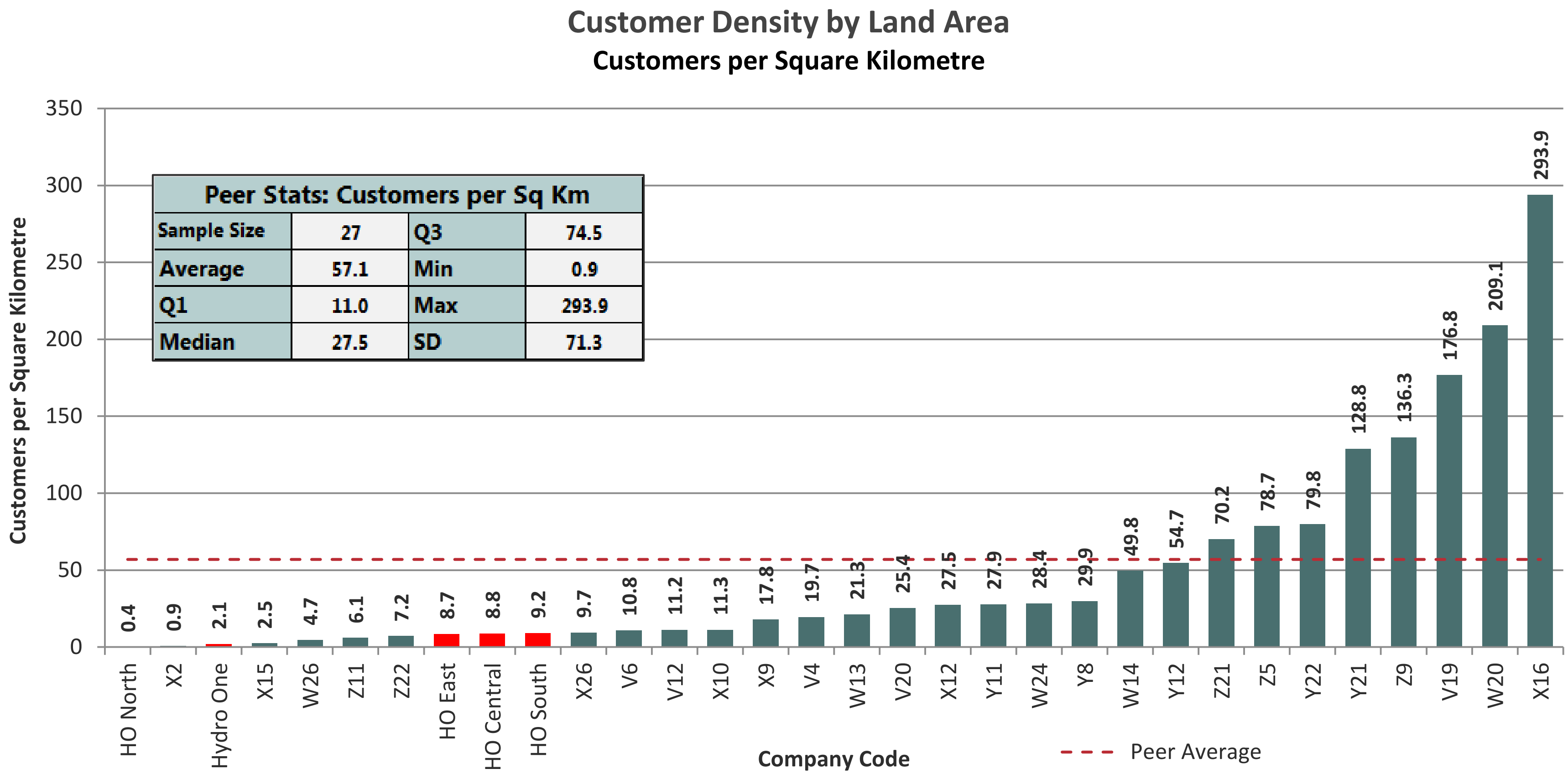


Graph 17: Number of Distribution Overhead Kilometres – Companies with More Than 25,000 Kilometres

COMPANY CHARACTERISTICS

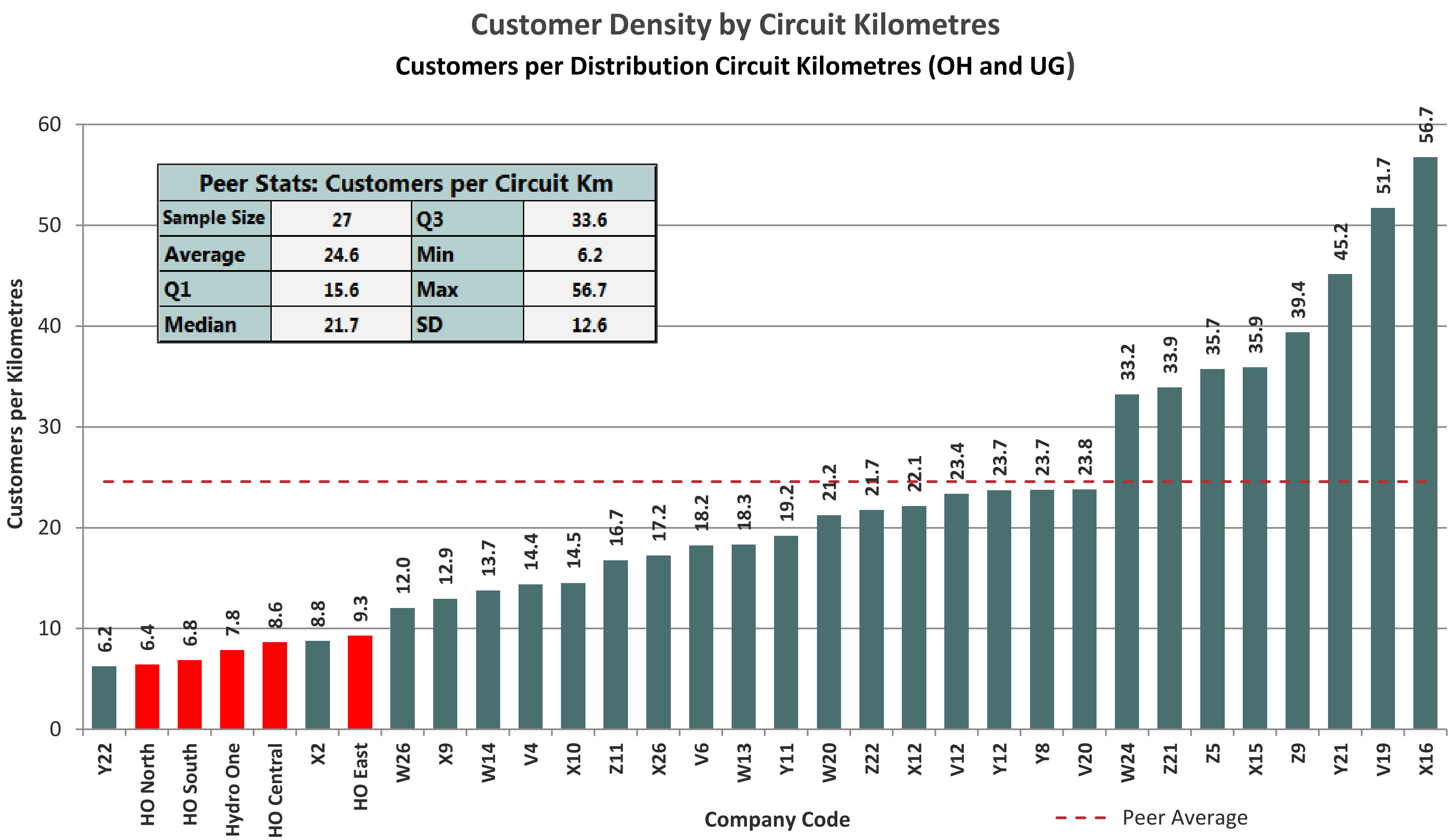
Customer Density

Electric Customers per Square Kilometre



Graph 18: Customer Density by Land Area - Customers per Square Kilometre

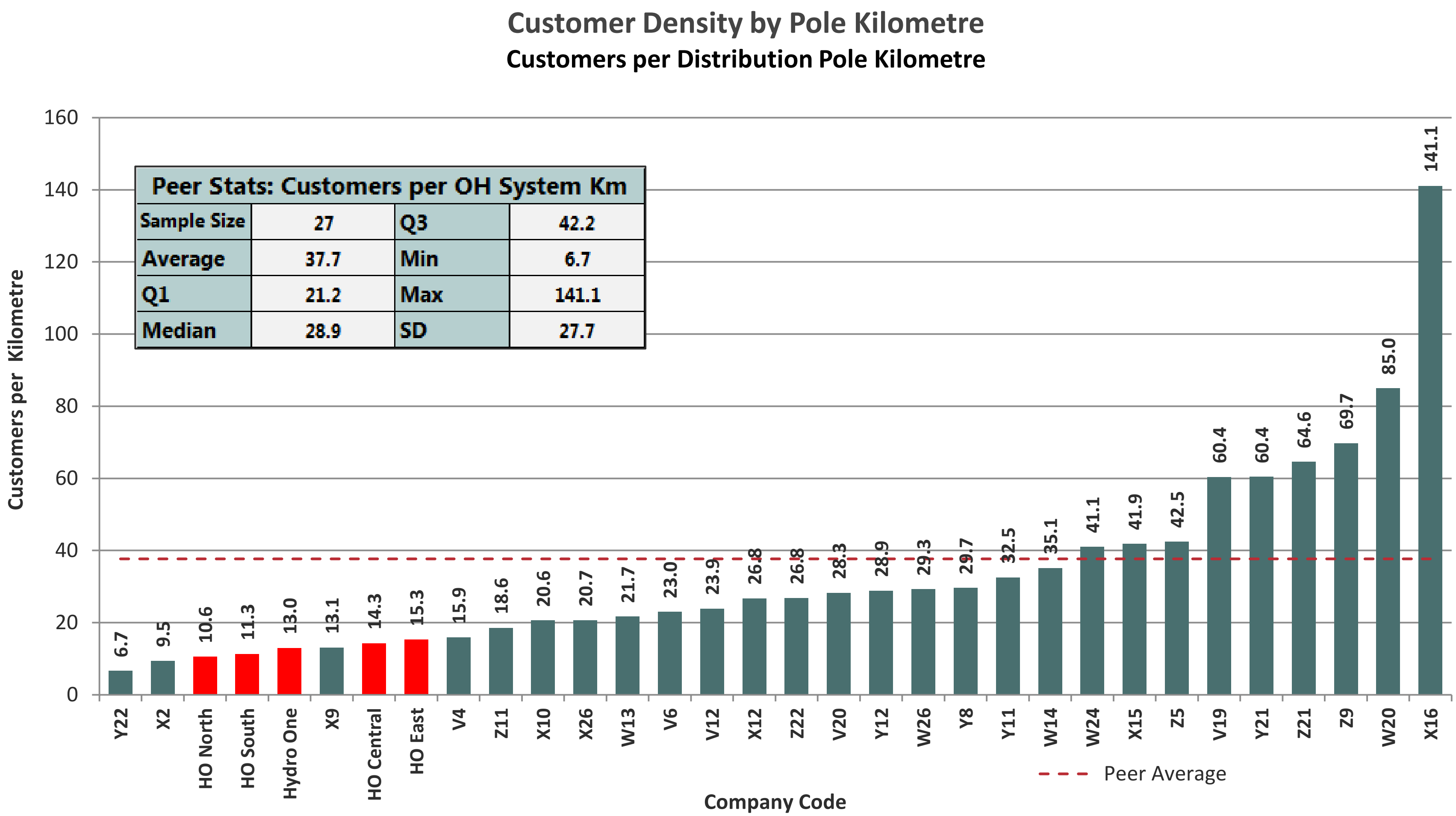
Customers per Distribution Circuit Kilometres



Peer Stats: Customers per Circuit Km			
Sample Size	27	Q3	33.6
Average	24.6	Min	6.2
Q1	15.6	Max	56.7
Median	21.7	SD	12.6

Graph 19: Customer Density by Circuit Kilometres - Customers per Distribution Circuit Kilometres (OH and UG)

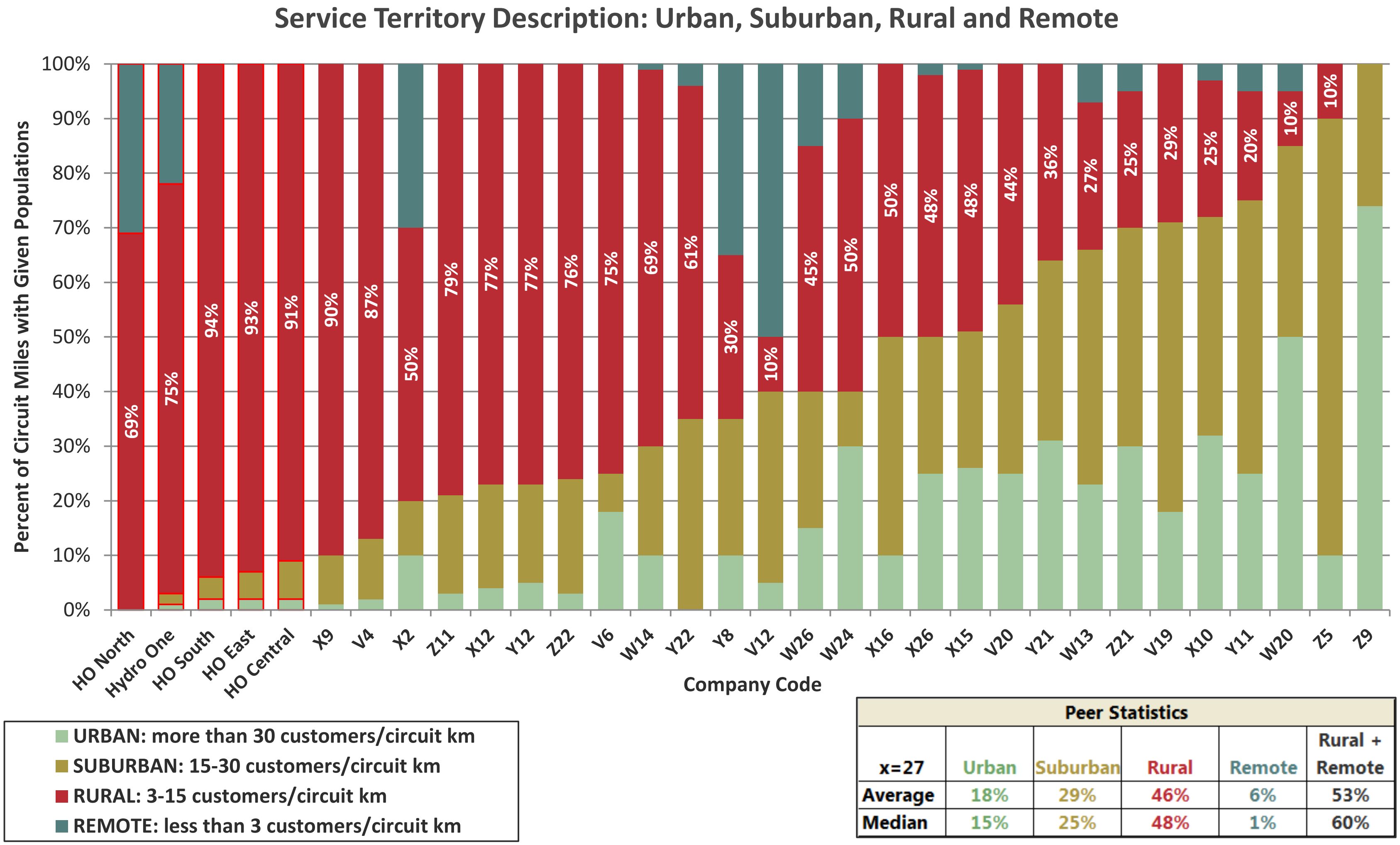
Customers per Pole Kilometre



Peer Stats: Customers per OH System Km			
Sample Size	27	Q3	42.2
Average	37.7	Min	6.7
Q1	21.2	Max	141.1
Median	28.9	SD	27.7

Graph 20: Customer Density by Pole Kilometre - Customers per Distribution Pole Kilometre

Service Territory Description by Customer Density

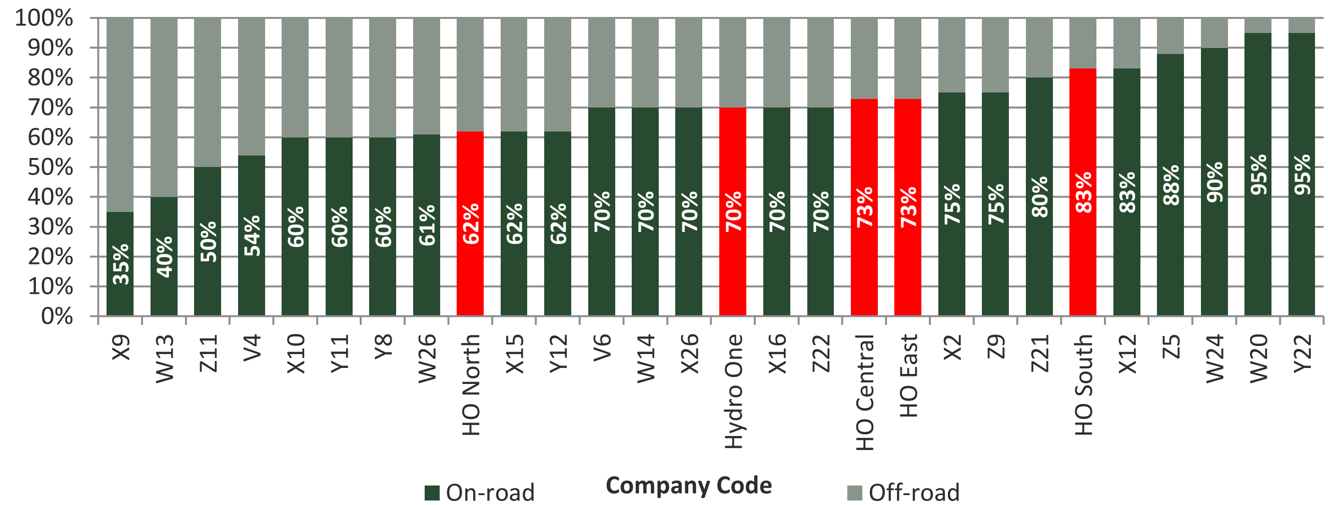


Peer Statistics					
x=27	Urban	Suburban	Rural	Remote	Rural + Remote
Average	18%	29%	46%	6%	53%
Median	15%	25%	48%	1%	60%

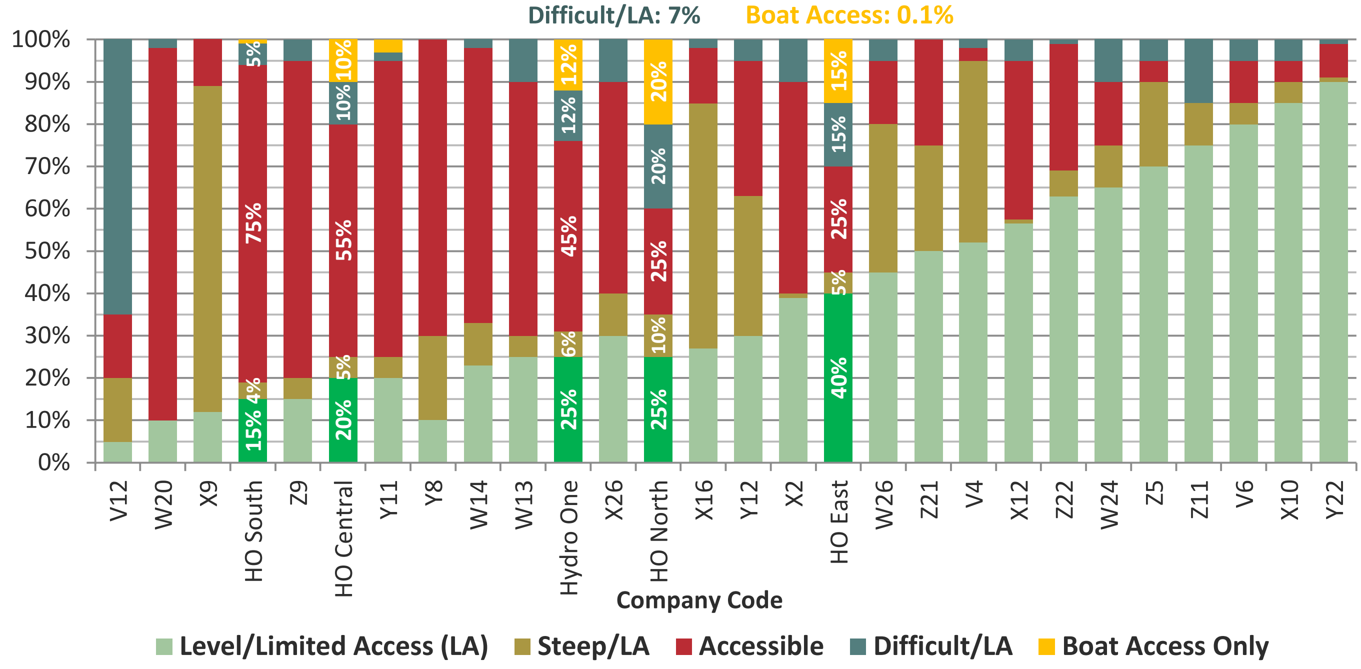
Graph 21: Service Territory Description: Urban, Suburban, Rural and Remote

Note: Graph sorted by combined rural and remote – largest to smallest; followed by urban – smallest to largest

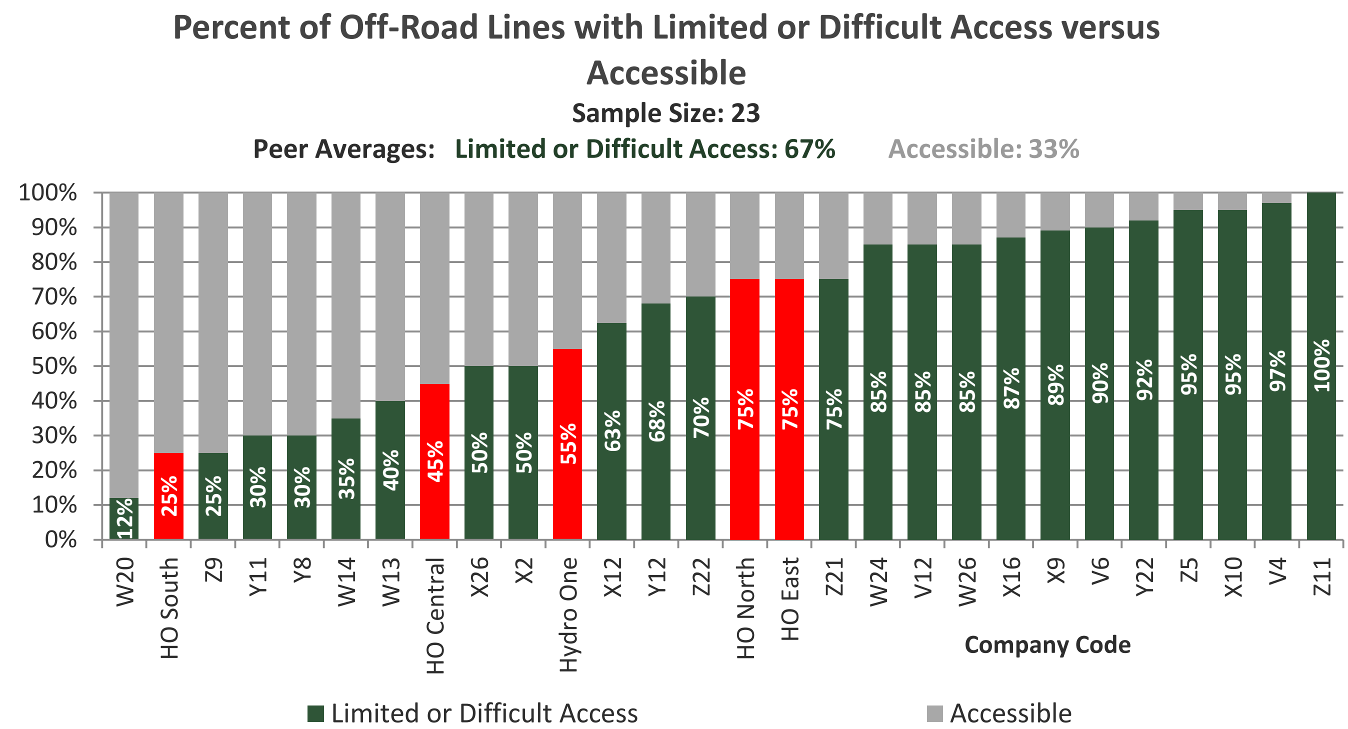
Accessibility



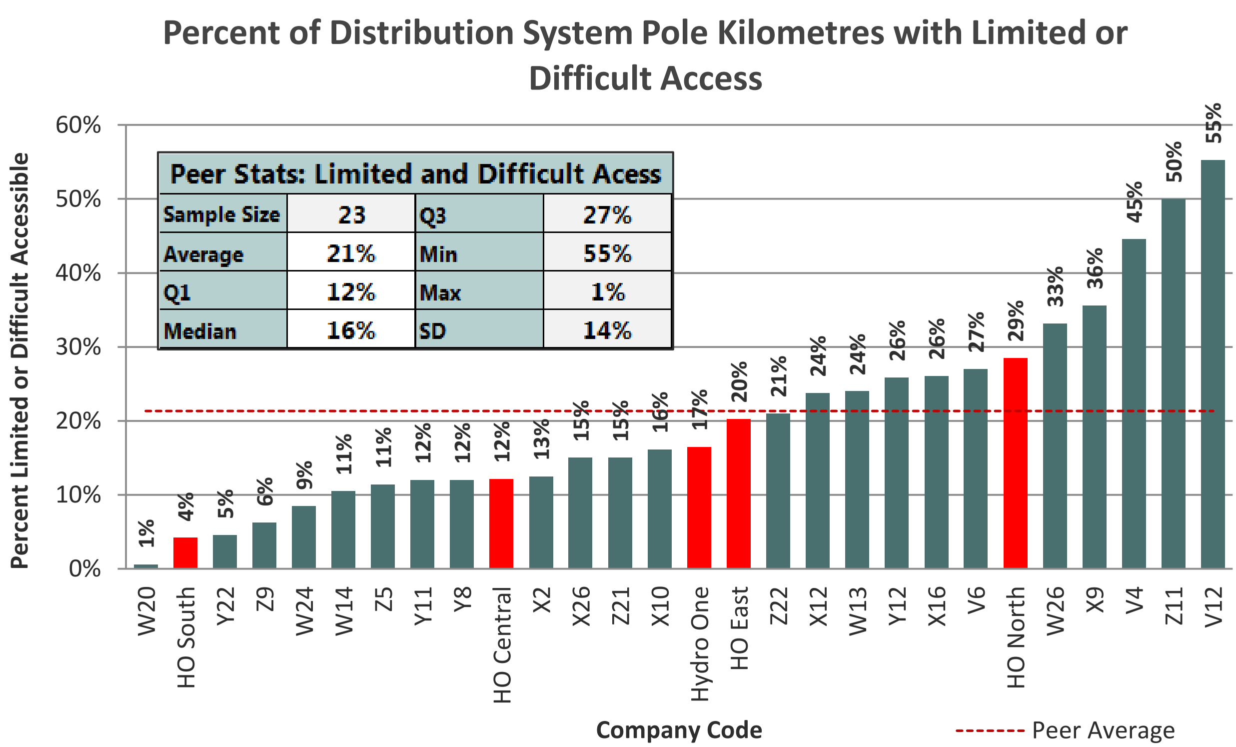
Graph 22: Percent of Overhead Pole Miles On-Road versus Off-Road



Graph 23: Description of Terrain of Off-Road Overhead Distribution Line Accessibility

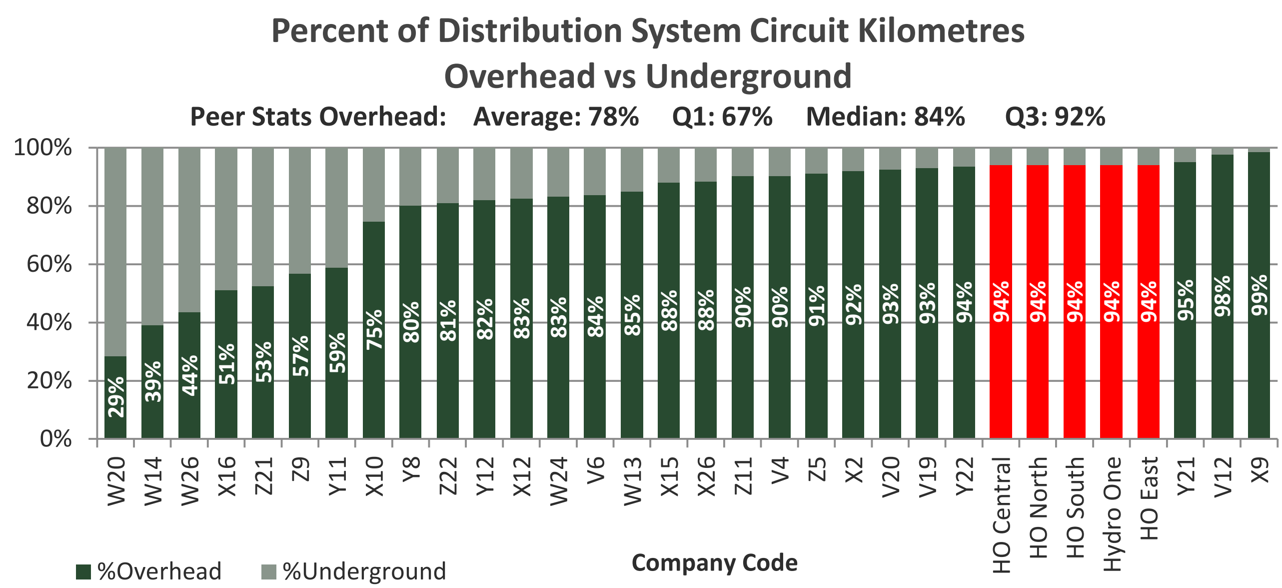


Graph 24: Percent of Off-Road Lines with Limited or Difficult Access versus Accessible



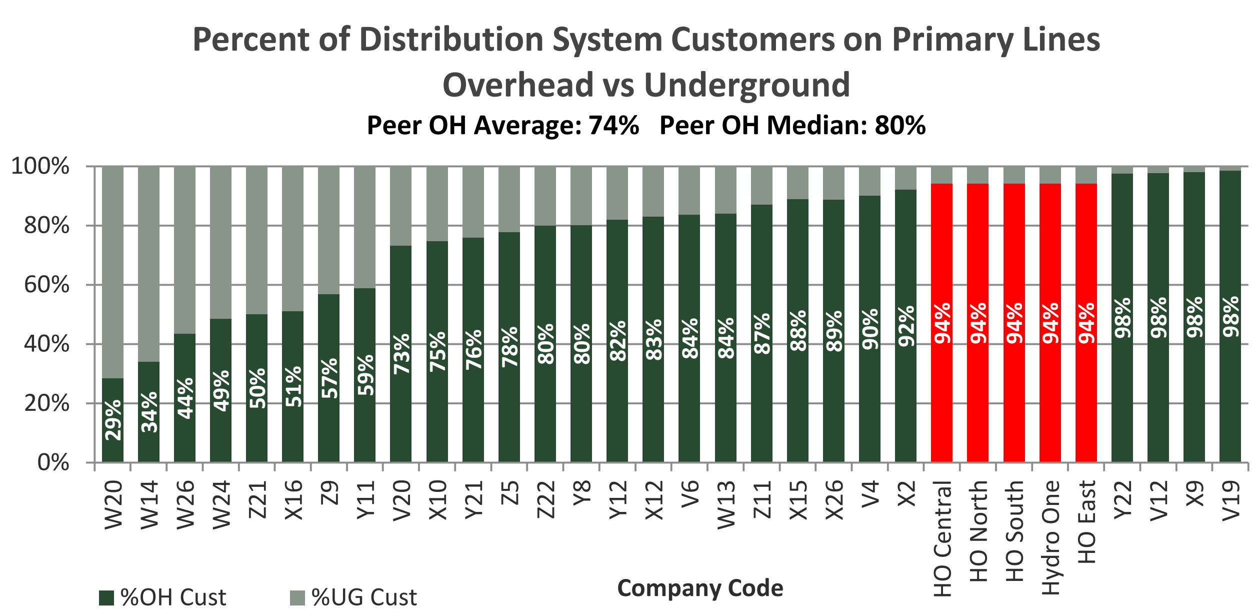
Graph 25: Percent of Distribution System Pole Kilometres with Limited or Difficult Access

Overhead versus Underground



Graph 26: Percent of Distribution System Circuit Kilometres Overhead vs Underground

NOTE: Customers on the distribution system that are on overhead primary lines versus underground primary lines follow a similar pattern for most of the peer group as the circuit kilometre breakdown.



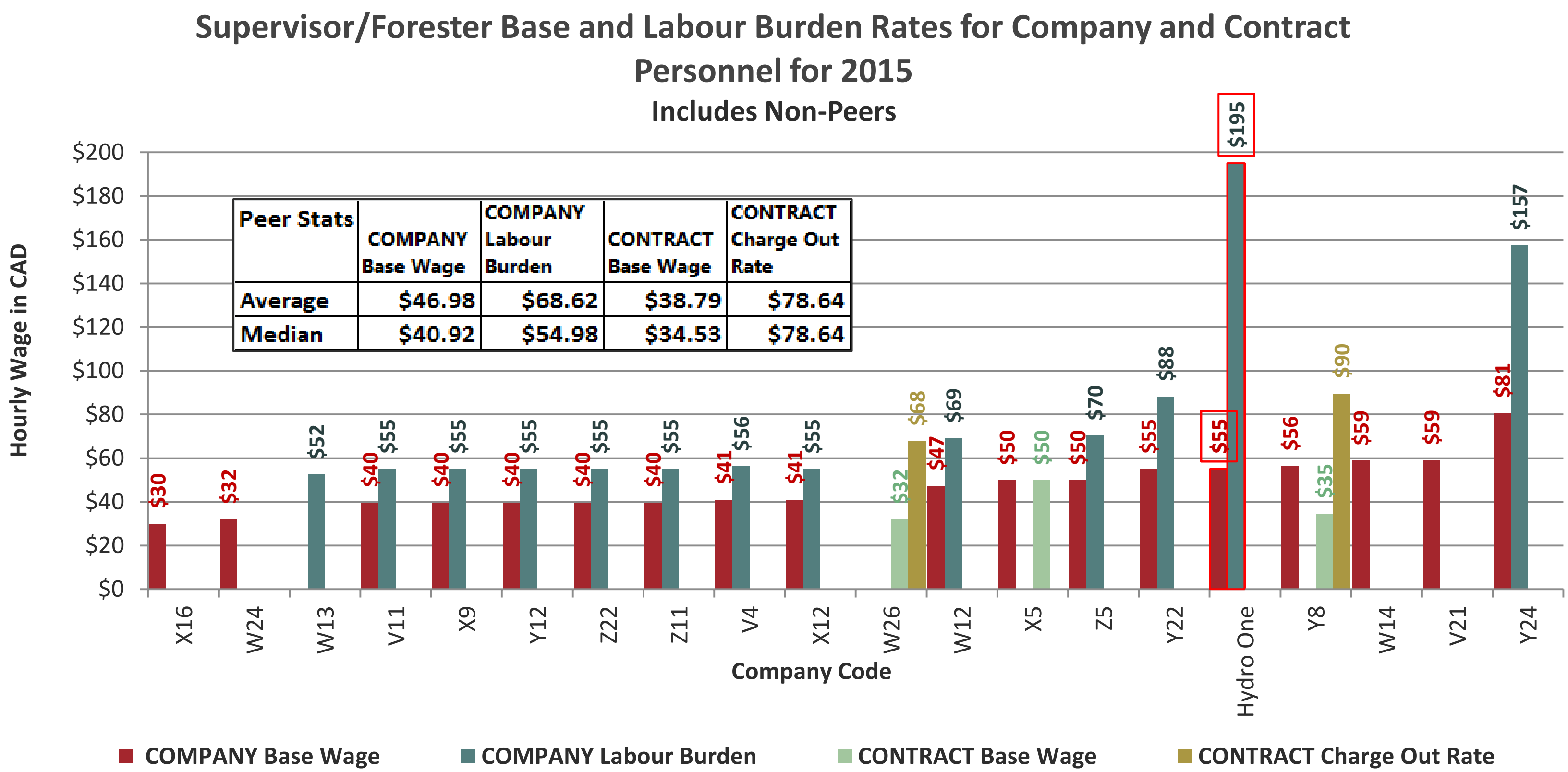
Graph 27: Percent of Distribution System Customers on Primary Lines Overhead vs Underground

WAGES AND MANAGEMENT RATIOS

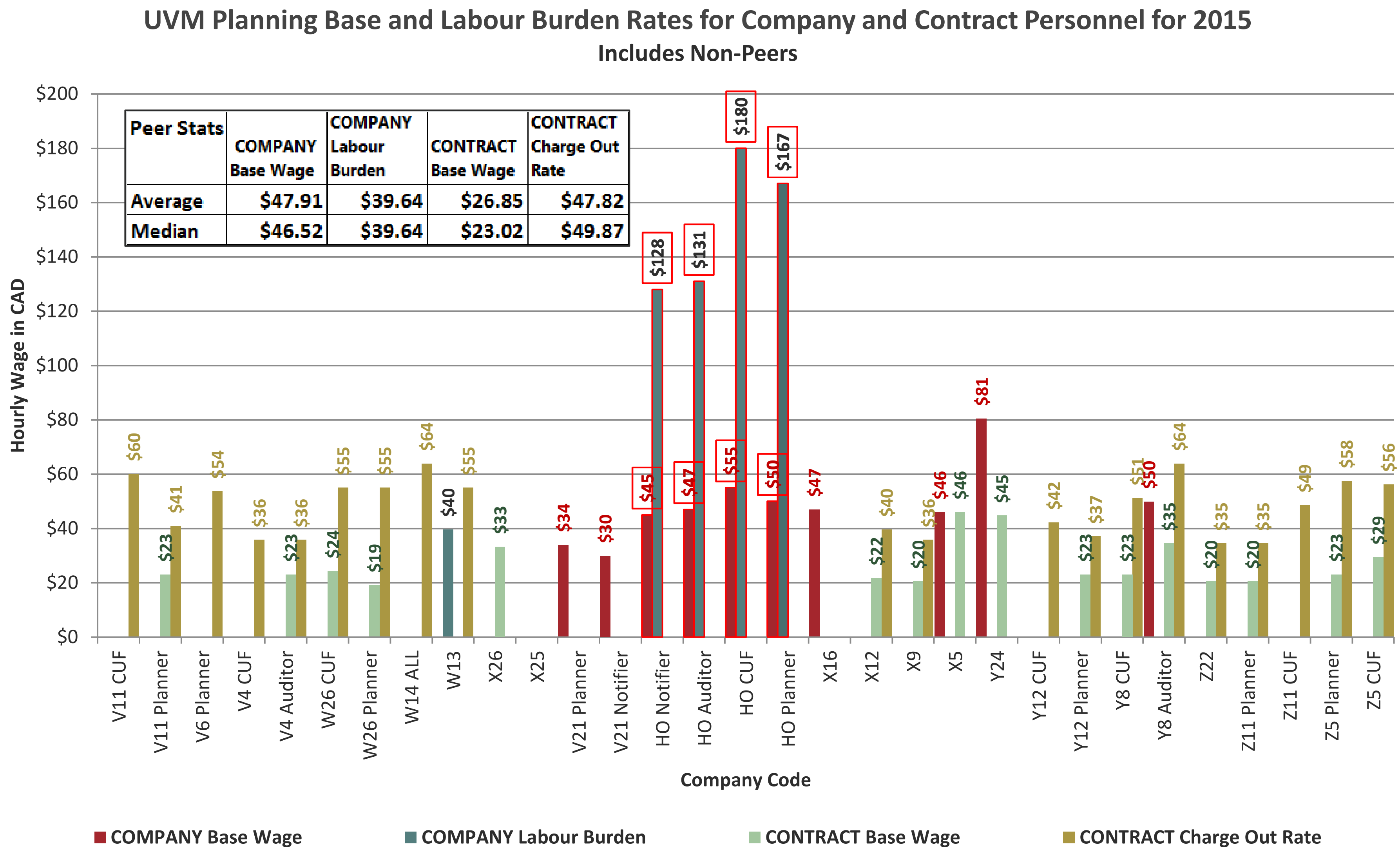
Wages

All the wage comparisons include Non-Peer Utilities and are in CAD using the 2015 annual exchange rate for USD to CAD, since this was the year for which the wages were given.

- Personnel Who Perform Work Planning and Quality Assurance



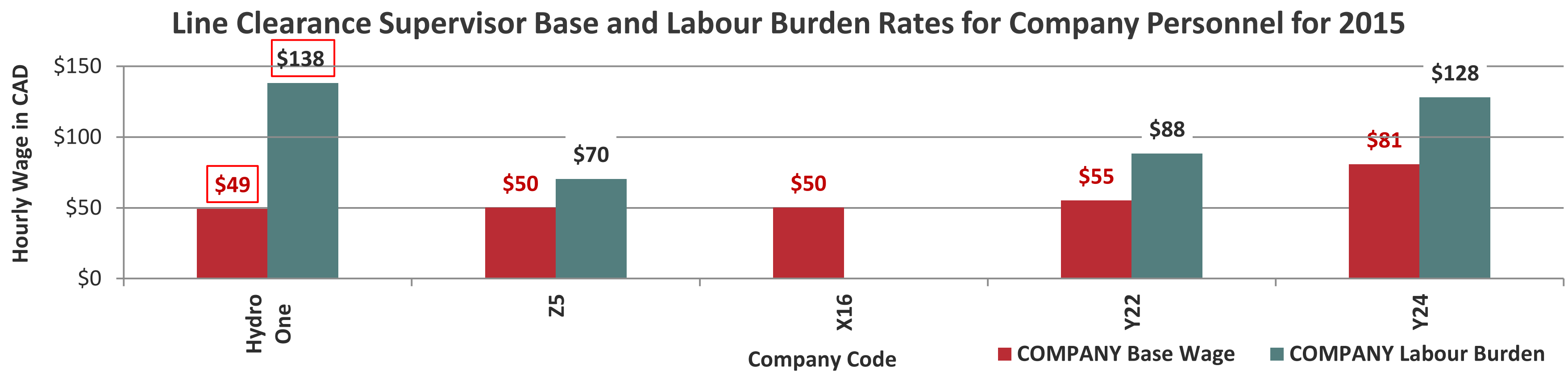
Graph 28: Supervisor/Forester Base and Labour Burden Rates for Company and Contract Personnel



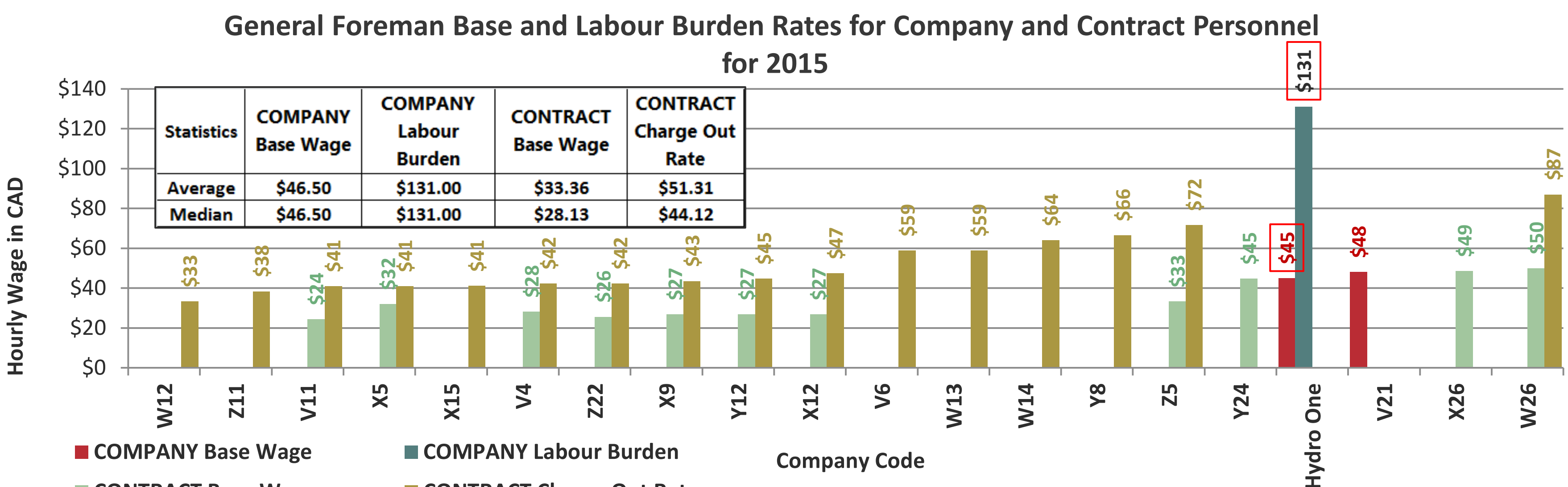
Peer Stats	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$47.91	$39.64	$26.85	$47.82
Median	$46.52	$39.64	$23.02	$49.87

Graph 29: UVM Planning Base and Labour Burden Rates for Company and Contract Personnel for 2015

Line Clearance Supervisory Personnel

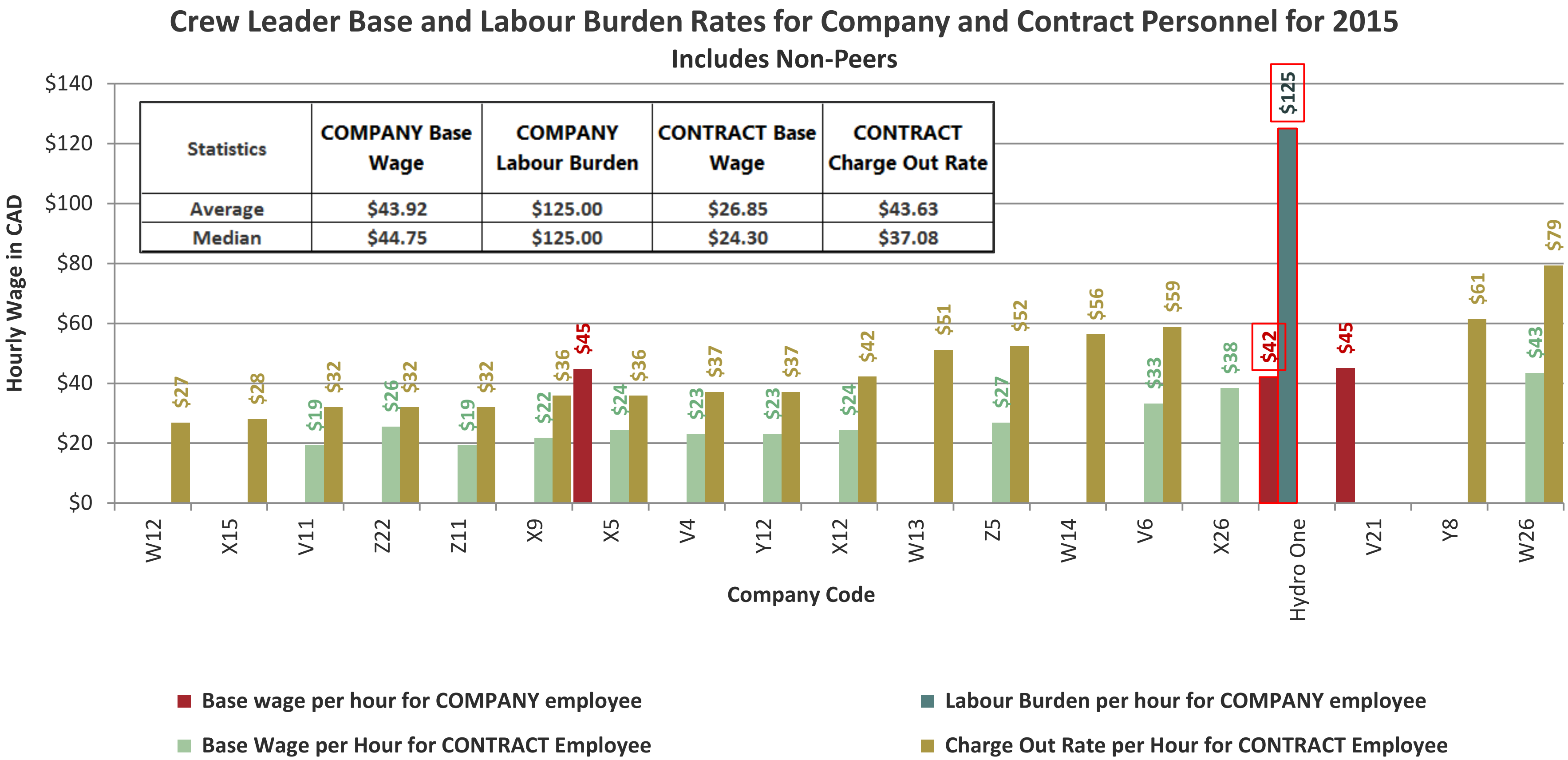


Graph 30: Line Clearance Supervisor Base and Labour Burden Rates for Company Personnel



Statistics	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$46.50	$131.00	$33.36	$51.31
Median	$46.50	$131.00	$28.13	$44.12

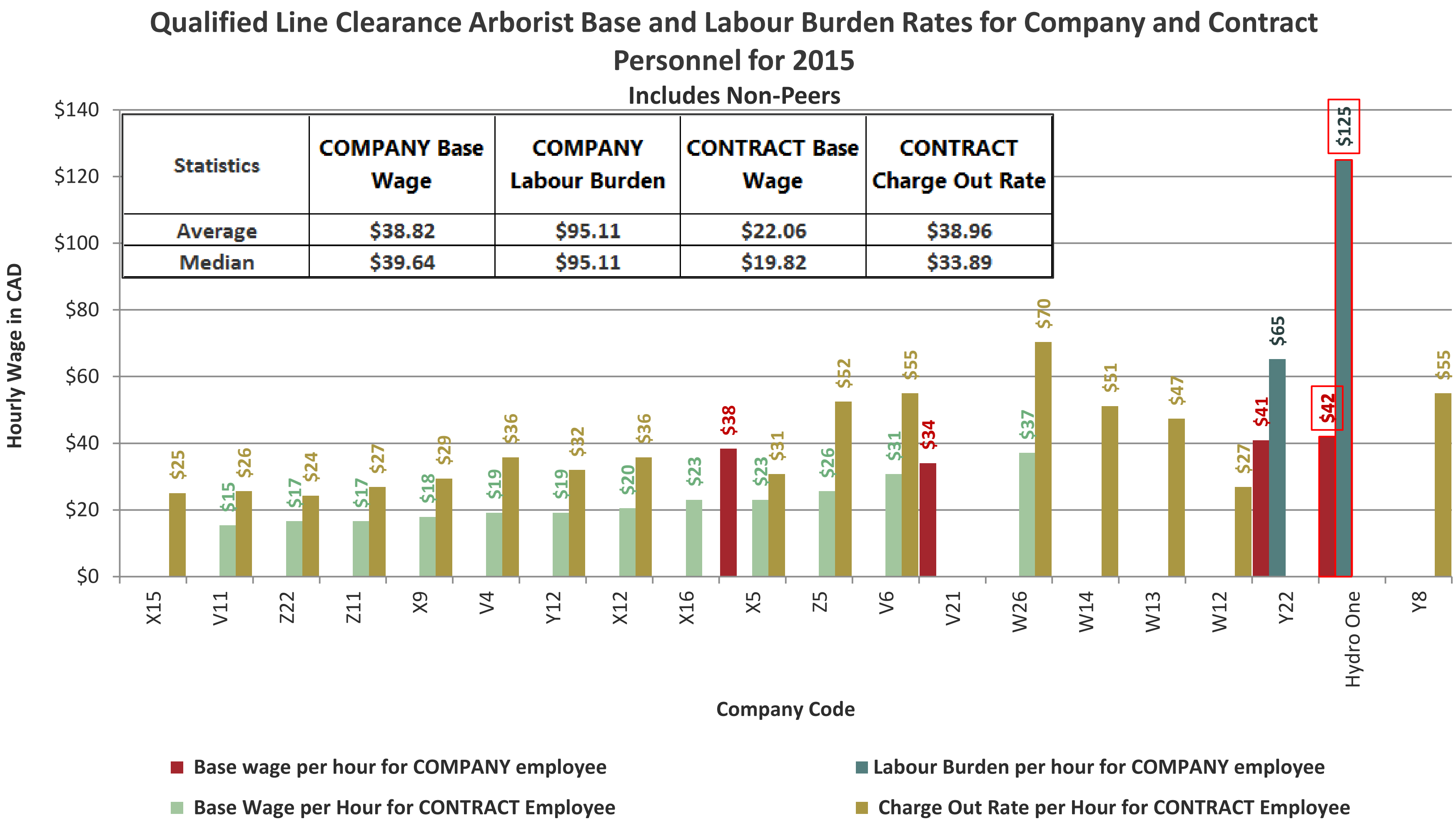
Graph 31: General Foreman Base and Labour Burden Rates for Company and Contract Personnel



Statistics	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$43.92	$125.00	$26.85	$43.63
Median	$44.75	$125.00	$24.30	$37.08

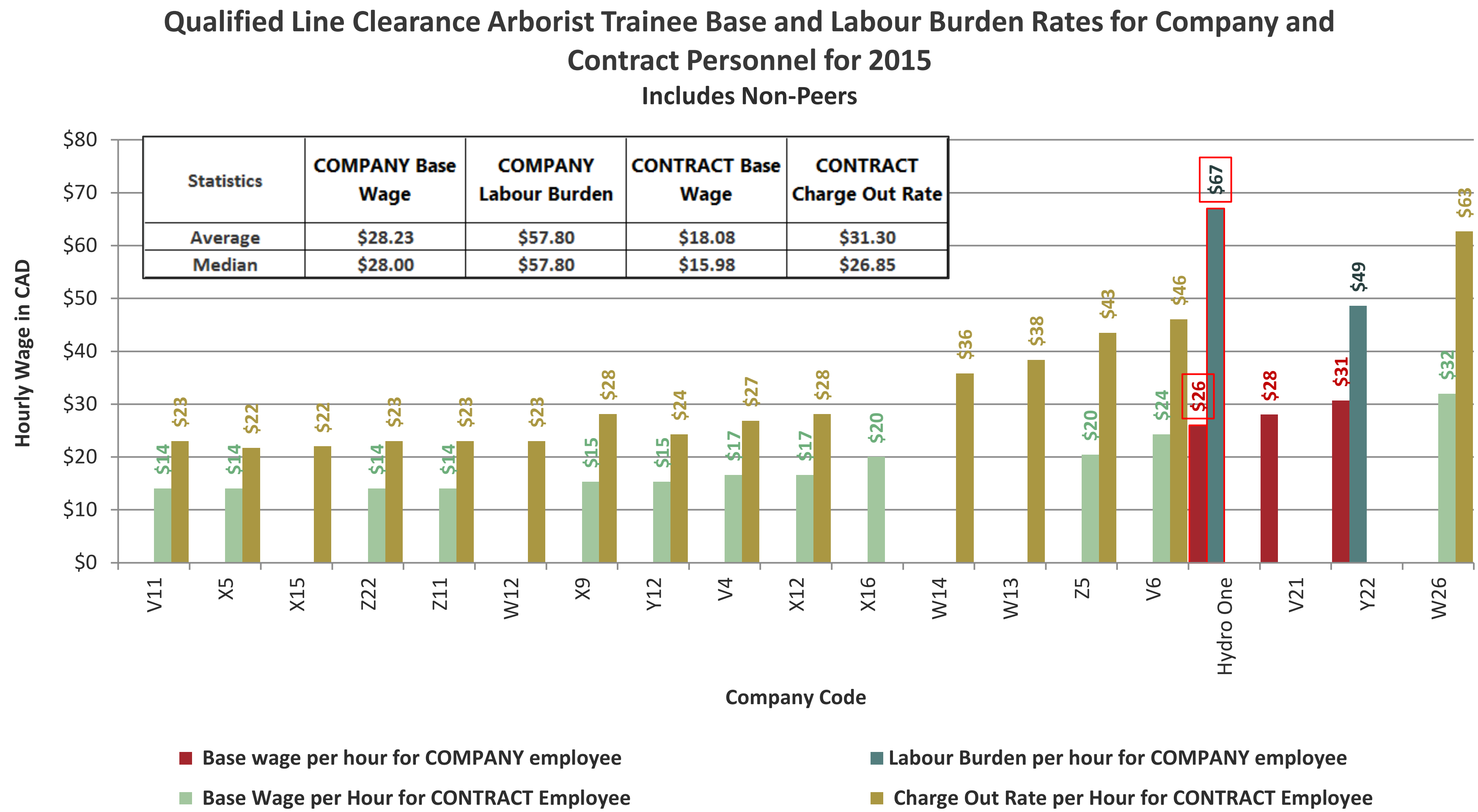
Graph 32: Crew Leader Base and Labour Burden Rates for Company and Contract Personnel

Line Clearance Field Personnel



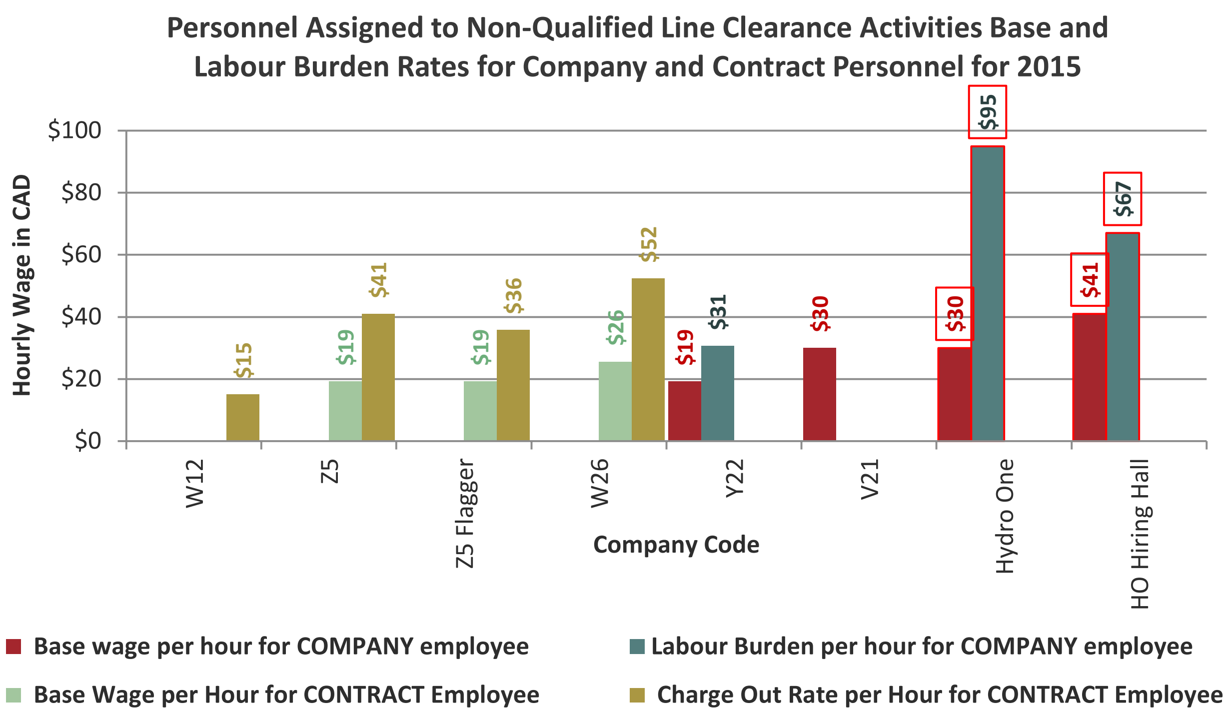
Statistics	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$38.82	$95.11	$22.06	$38.96
Median	$39.64	$95.11	$19.82	$33.89

Graph 33: Qualified Line Clearance Arborist Base and Labour Burden Rates for Company and Contract Personnel



Statistics	COMPANY Base Wage	COMPANY Labour Burden	CONTRACT Base Wage	CONTRACT Charge Out Rate
Average	$28.23	$57.80	$18.08	$31.30
Median	$28.00	$57.80	$15.98	$26.85

Graph 34: Qualified Line Clearance Arborist Trainee Wages for Company and Contract Personnel



Graph 35: Non-Qualified Line Clearance Activities Base and Labour Burden Rates

Number of Years Line Clearance Employees Have Been Working at the Utility					
Average, Max and Min Exclude Hydro One		Average Number of Years on Job	Hydro One	Peer Max	Peer Min
Supervisor	Company	13	25	24	5
	Contract	11.7		25	5
General Foreman	Company	5	15		
	Contract	10		18	5
Crew Leader	Company	5	20		
	Contract	8.7		20	3
Arborist	Company	8.75	20	15	5
	Contract	6.5		15	4
Arborist Trainee	Company	1.75	4	3	1
	Contract	3.1		7	1
Other Field Personnel	Company	3	15		
	Contract	5.5		15	1

Table 7: Average Number of Years on the Job

The maximums in all the contract categories are from a utility that has sole-sourced their work to the same contractor for over twenty years.

Base Wages versus Labour Burden or Charge-Out Rates						
Average, Max and Min Exclude Hydro One		Average Difference between Hourly Base Wage and Labour Burden [Times Greater]	Hydro One	Peer Max	Peer Min
Supervisor/Forester	Company	1.6	3.6	2.0	1.3
	Contract	2.4		2.6	2.1
UVM Planning Personnel	Company	1.6	3.3	2.0	1.4
	Contract	2.4		2.6	2.1
Supervisor	Company	1.5	2.8	1.6	1.4
	Contract				
General Foreman	Company		2.9		
	Contract	1.7		2.2	1.3
Crew Leader	Company		3.0		
	Contract	1.7		2.0	1.3
Arborist	Company	1.6	3.0		
	Contract	1.7		2.1	1.5
Arborist Trainee	Company	1.6	2.6		
	Contract	1.7		2.1	1.5
Other Field Personnel	Company		3.2		
	Contract Hiring Hall [HO]	2.0	1.6	2.1	1.9

Table 8: Base Wages versus Labour Burden or Charge-Out Rates

Note: Some companies only have the Supervisor/ Forester as the planning personnel

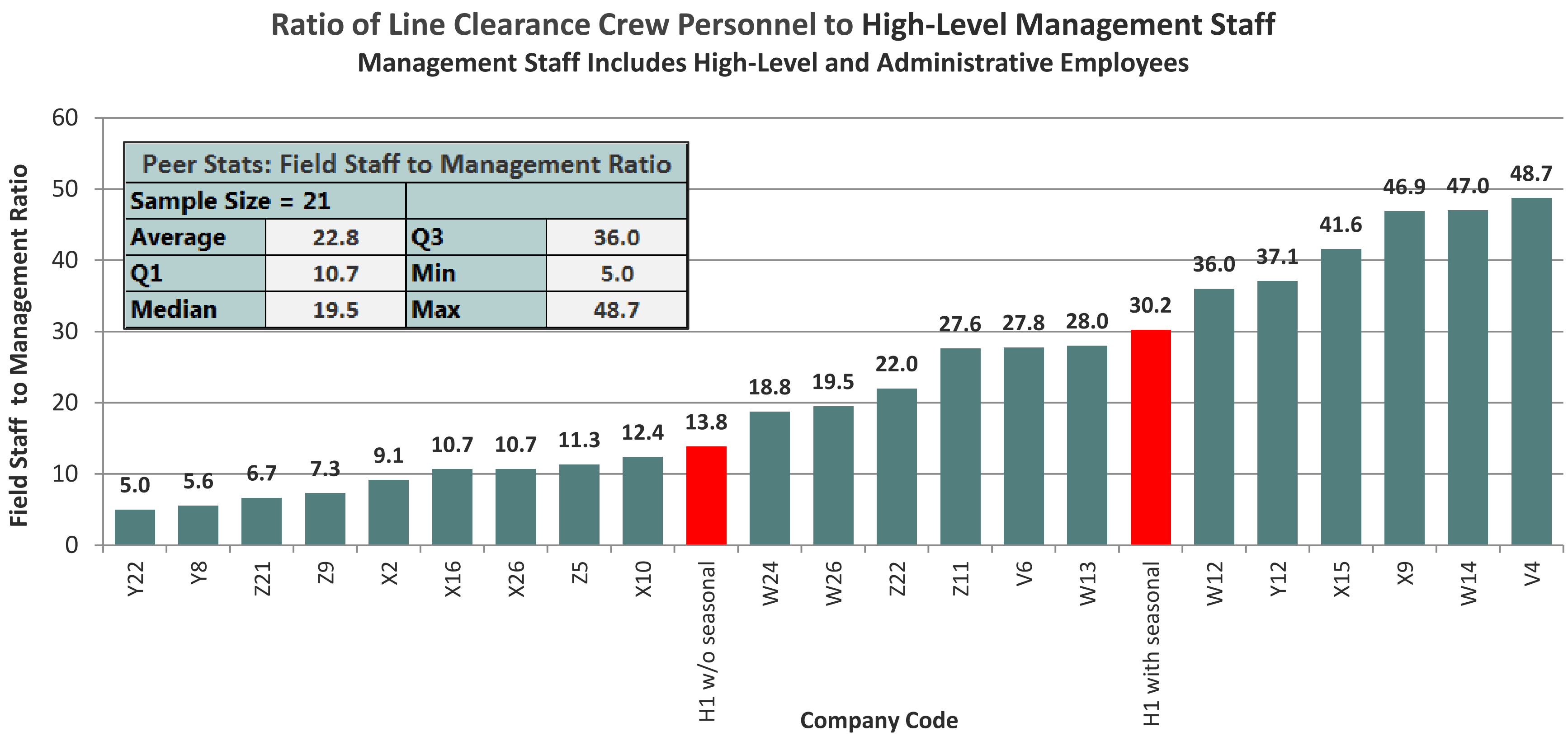
Management Staff to Line Clearance Crew Personnel Ratios

Utilities organize their UVM departments differently. Variations in position titles and duties, in-house to contract personnel ratios, and extent of work planning all impact the following study. It should also be noted that Hydro One is the only company in the peer group that uses temporary labour to any degree. As a result of these differences, Hydro One data are presented as an upper and lower range using the management staff reported and the number of full-time staff with and without seasonal labour.

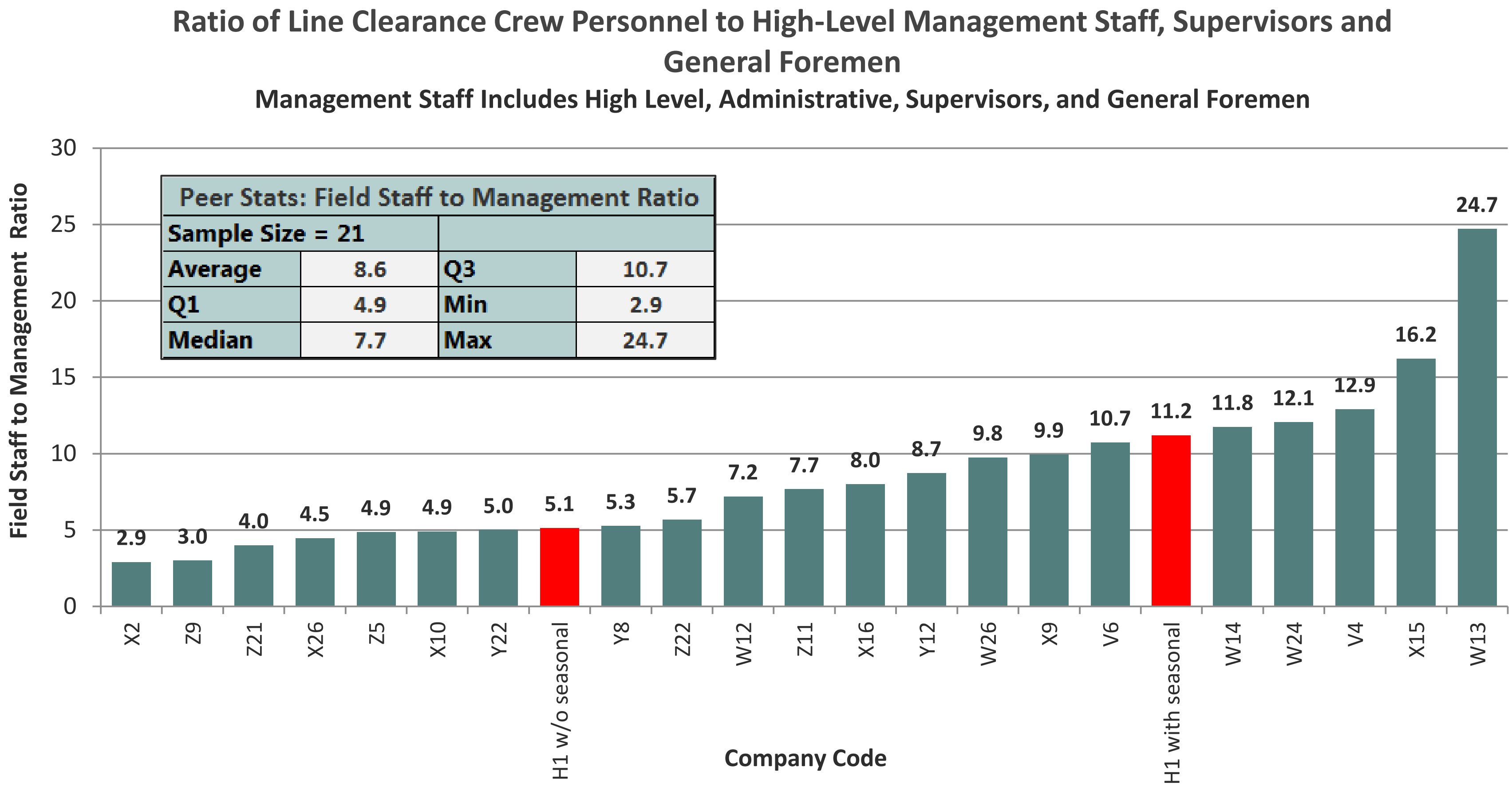
Management Staff was separated into three categories:

1. High-level and administrative
2. Line Clearance Supervisors and General Foremen
3. Work planning staff

Graphically, the above categories were grouped as follows: 1 only; 1 + 2; and 1 + 2 + 3

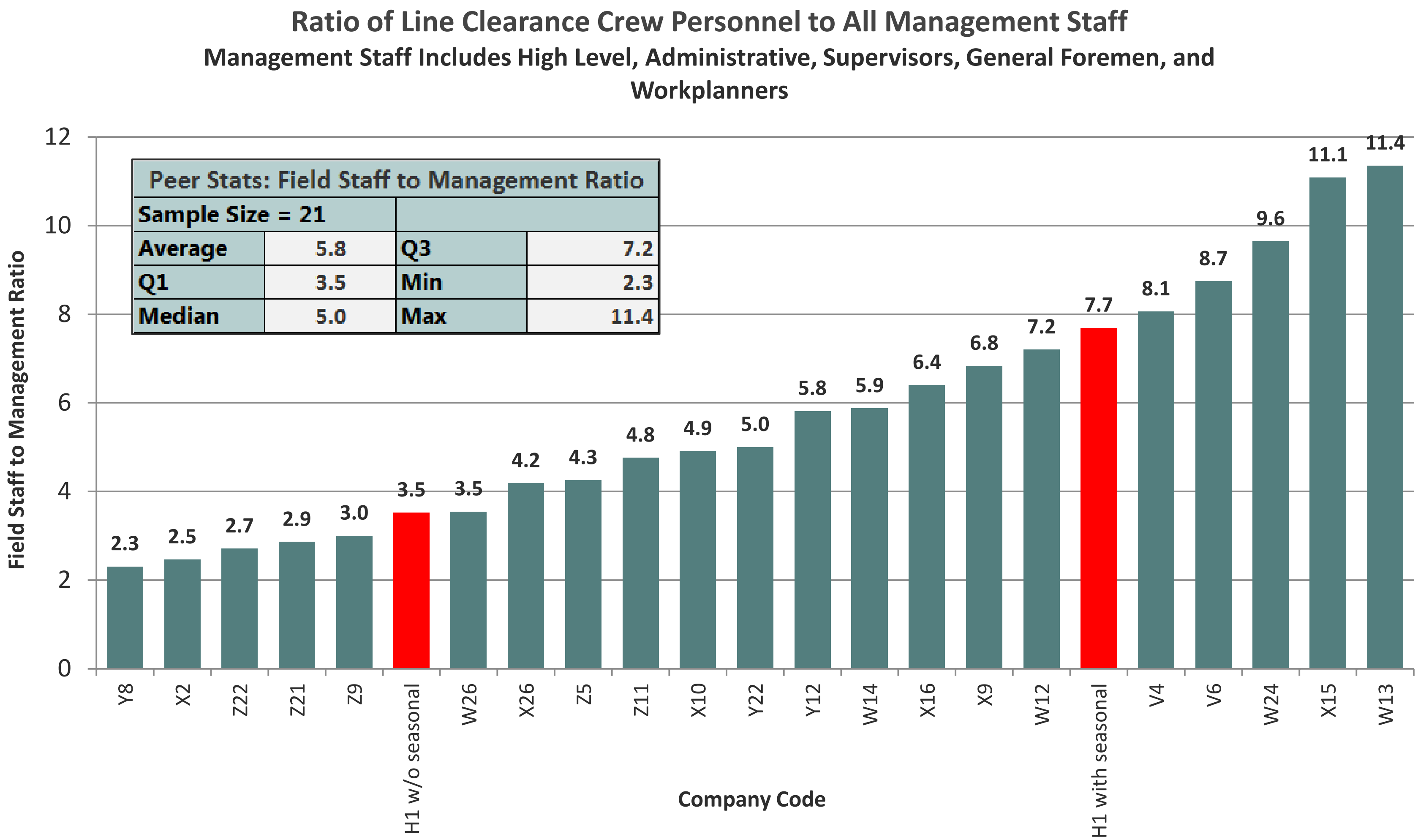


Graph 36: Ratio of Line Clearance Crew Personnel to High-Level Management Staff



Peer Stats: Field Staff to Management Ratio			
Sample Size = 21			
Average	8.6	Q3	10.7
Q1	4.9	Min	2.9
Median	7.7	Max	24.7

Graph 37: Ratio of Line Clearance Crew Personnel to High-Level Management, Supervisors and General Foremen

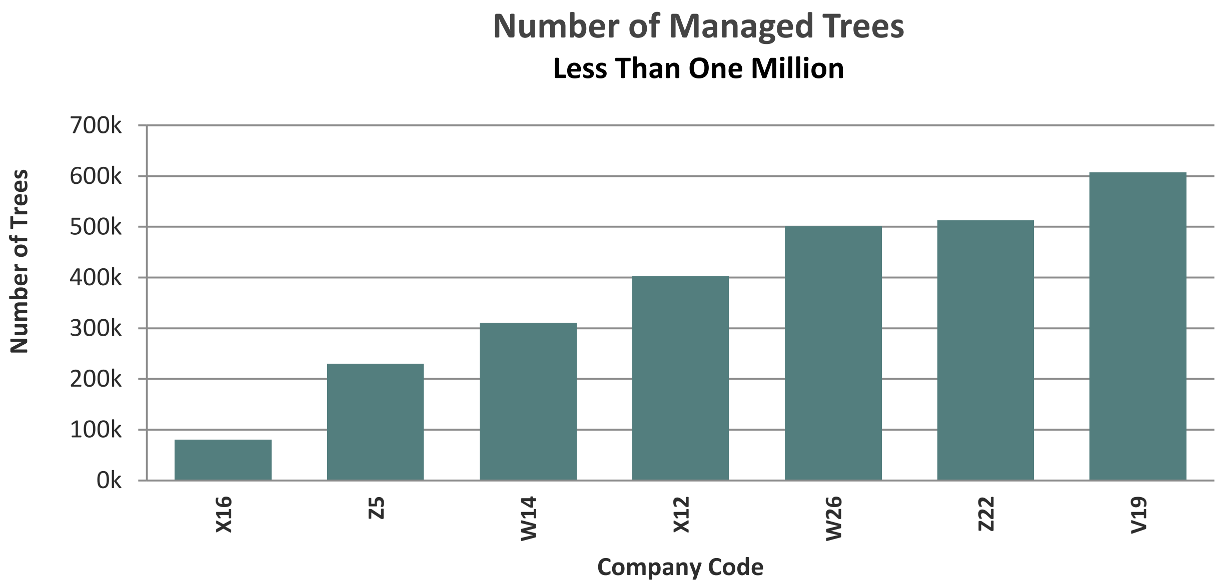


Graph 38: Ratio of Line Clearance Crew Personnel to All Management Staff

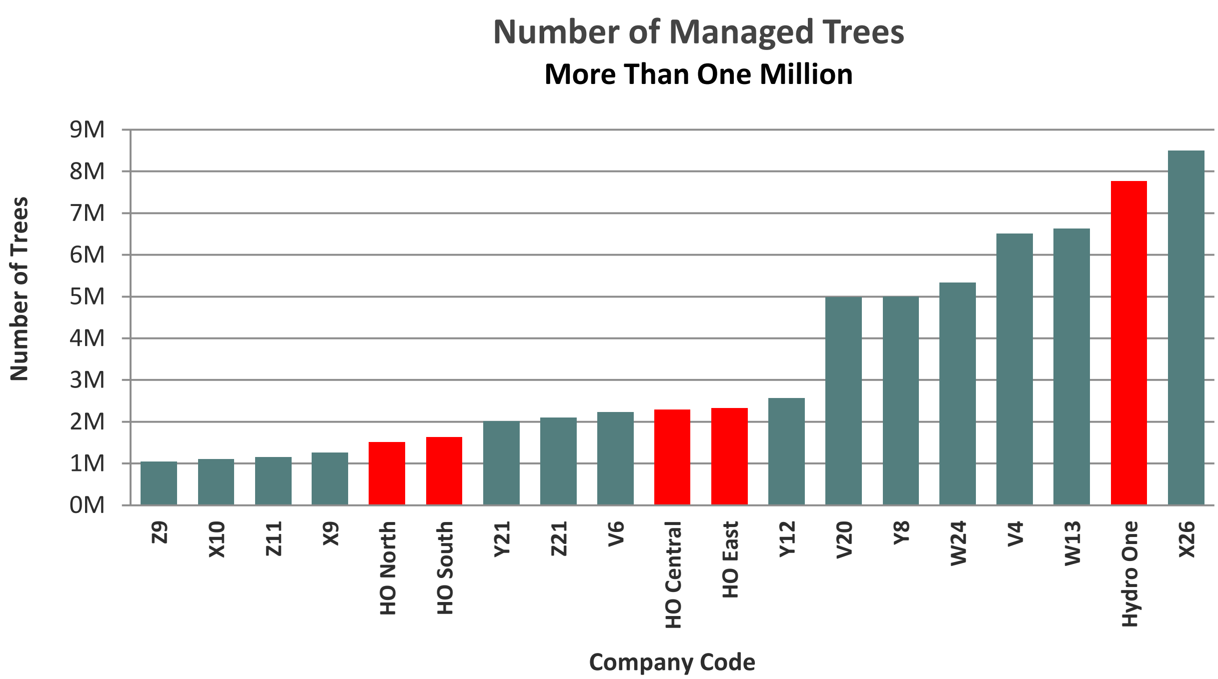
UTILITY VEGETATION MANAGEMENT WORKLOADS

Number of Managed Trees on Distribution System

The peer group is shown on two graphs (*with different y-axis scales*), so that the range of managed trees sizes can be distinguished.

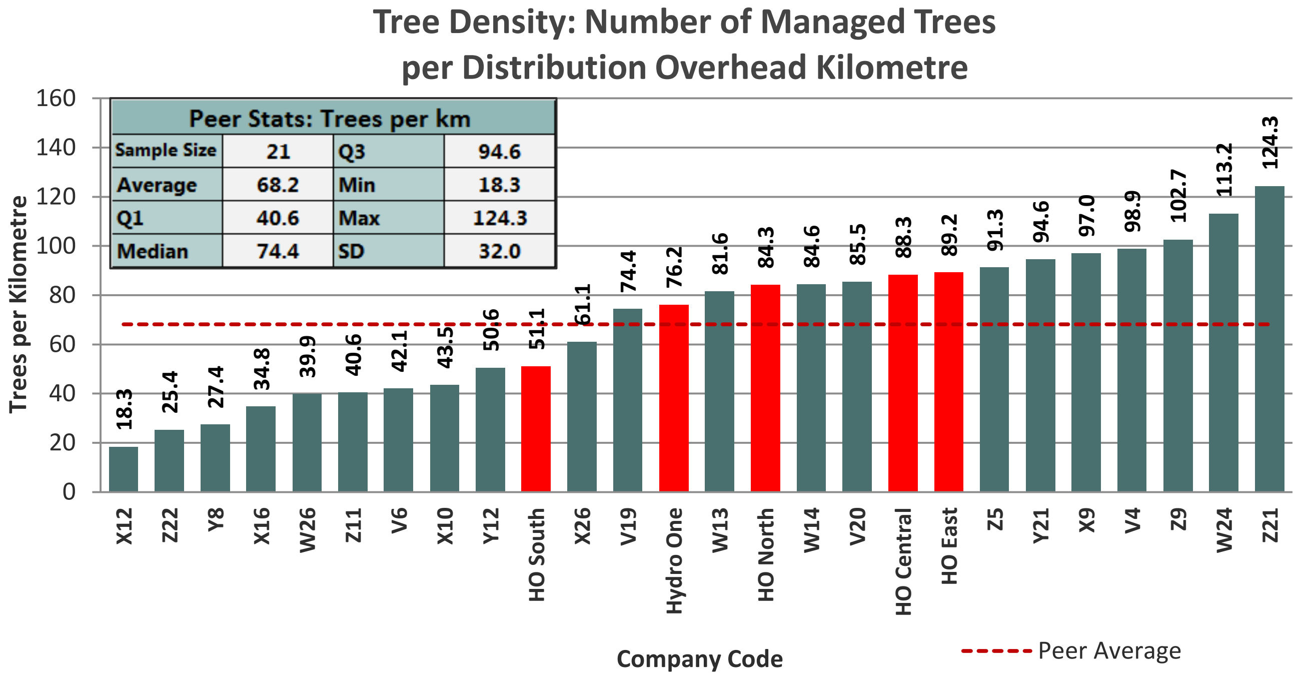


Graph 39: Number of Managed Trees – Companies with Less Than One Million

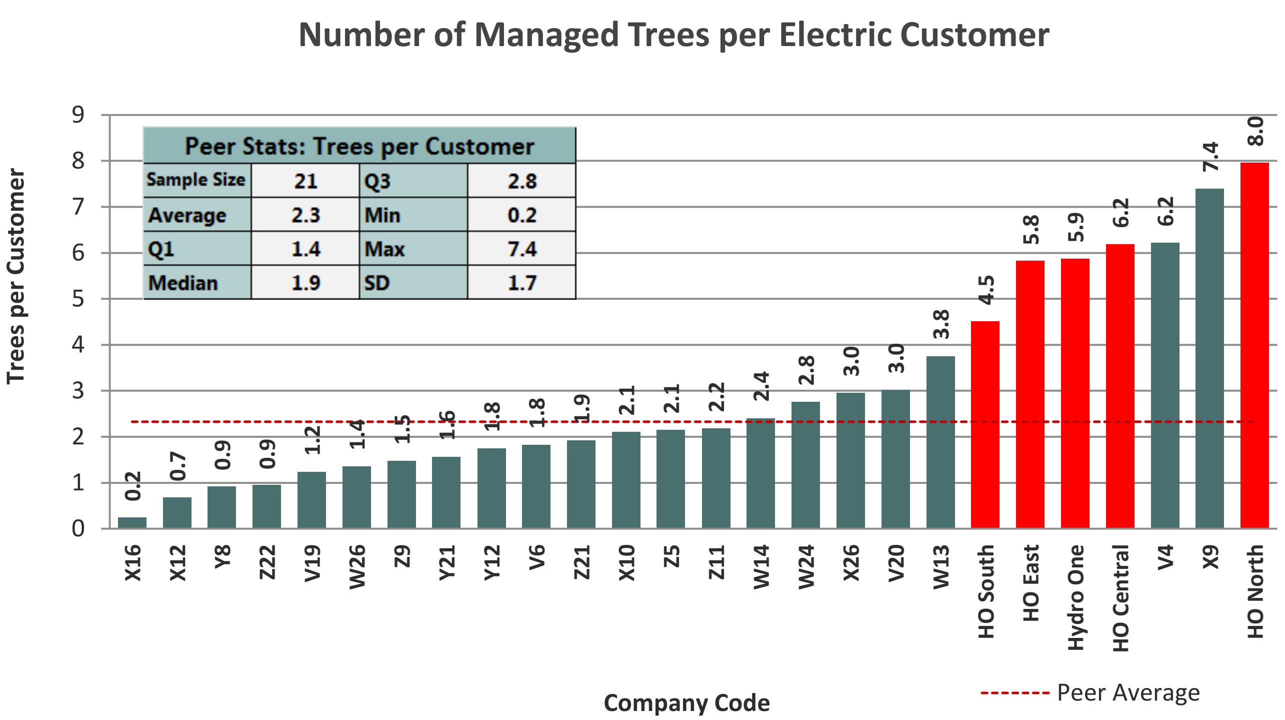


Graph 40: Number of Managed Trees – Companies with More Than One Million

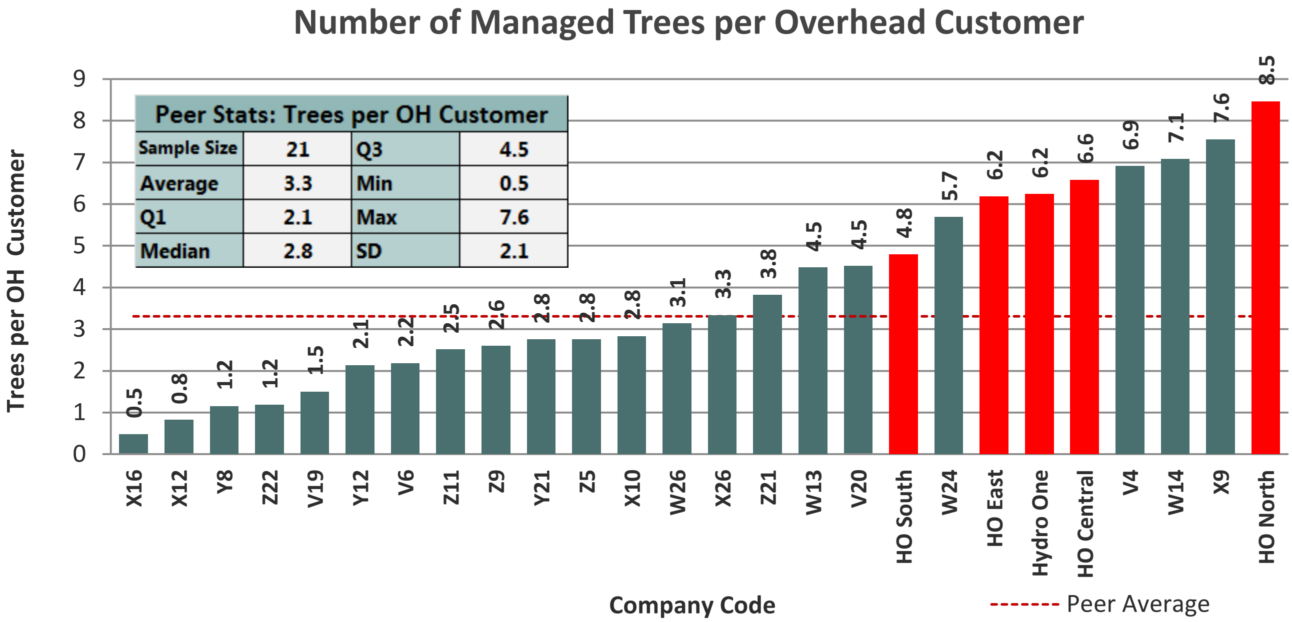
Tree Density



Graph 41: Tree Density: Number of Managed Trees per Distribution Overhead Kilometre

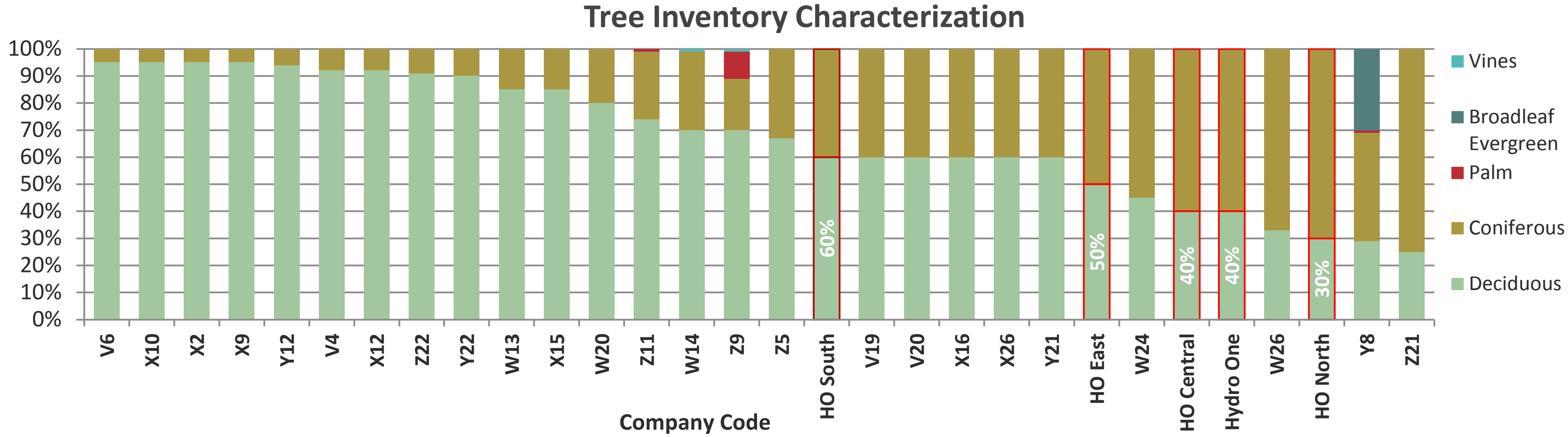


Graph 42: Managed Trees per Electric Customer

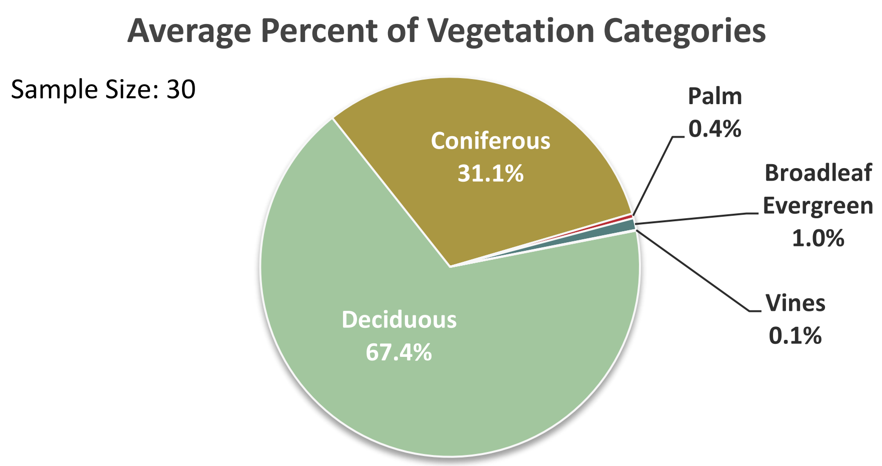


Graph 43: Managed Trees per Overhead Customer

Characterization of Managed Trees



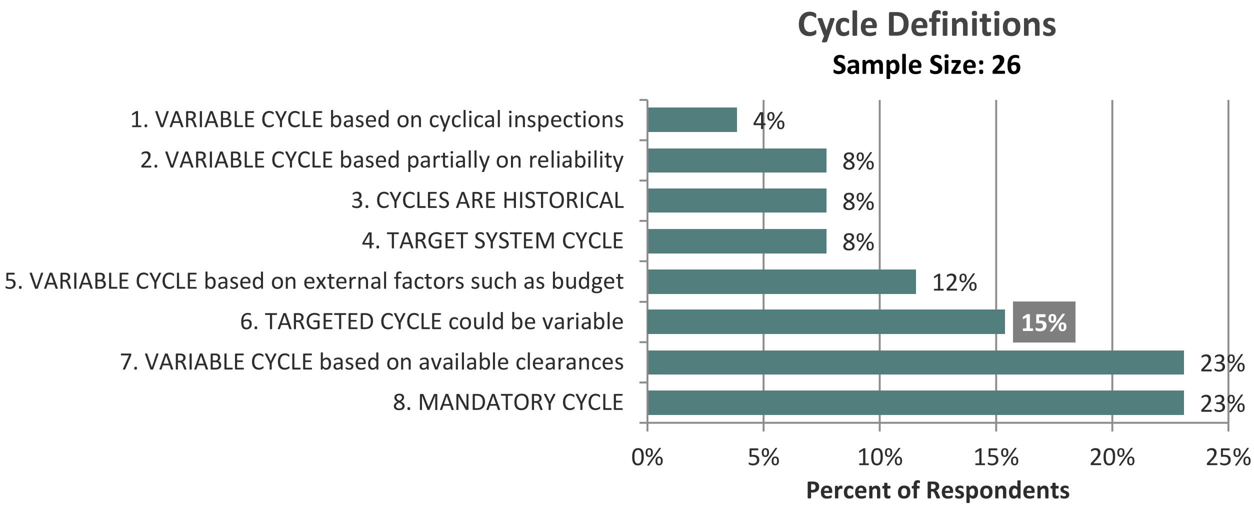
Graph 44: Tree Inventory Characterization



Graph 45: Average Percent of Vegetation Categories

CYCLES OF MANAGEMENT

Cycle Definitions



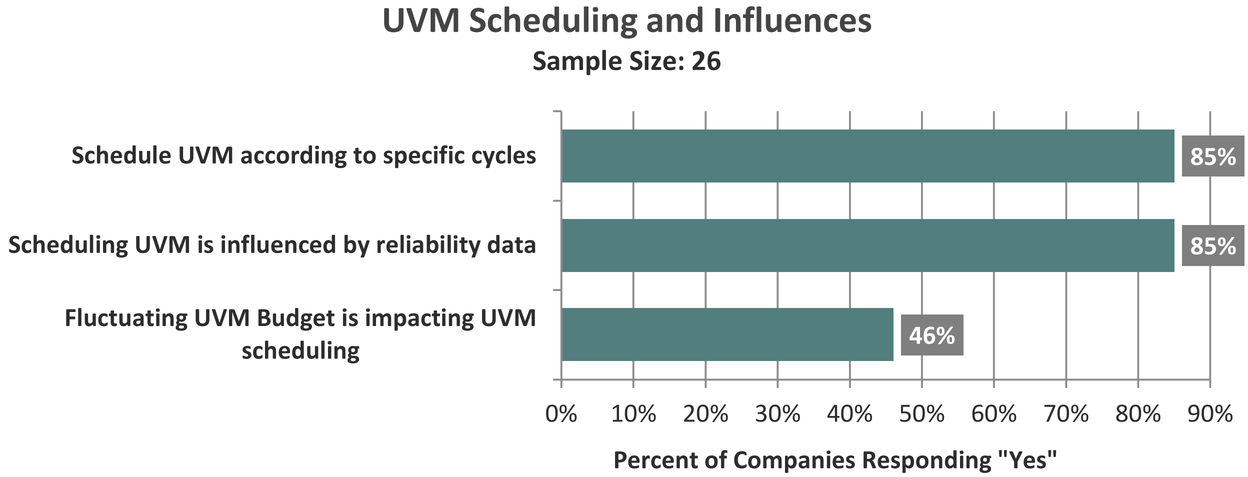
Legend: Complete Definitions
1. VARIABLE CYCLE based on cyclical inspections: A set SCHEDULE OF INSPECTIONS that determines which trees are in need of maintenance
2. VARIABLE CYCLE based partially on reliability
3. CYCLES ARE HISTORICAL: A measure of the time it takes to manage ALL of the trees, spans or miles in your distribution system ONE TIME
4. TARGET SYSTEM CYCLE: A SCHEDULE of maintenance applied to the entire distribution system
5. VARIABLE CYCLE based on external factors such as budget: The time between management of a SINGLE tree, span or mile in your distribution system
6. TARGETED CYCLE could be variable: PLANNED length between vegetation maintenance activities
7. VARIABLE CYCLE based on available clearances: A SCHEDULE based on the amount of clearance that can be realistically obtained as well as the expected growth rates of the trees on any given site
8. MANDATORY CYCLE: A PLANNED length of time that MUST be maintained between vegetation management activities
9. VARIABLE HISTORICAL CYCLES: The amount of time between SCHEDULED pruning operations

Graph 46: Percent of Companies with Given Cycle Definitions

Descriptions of Vegetation Maintenance Cycles
We run 4 and 6 year cycles on distribution. [7]
Working towards a cycle based on inspections [5]
Based on predictive model that forecasts tree related outages per mile of line and impact to SAIFI and SAIDI for the next 12 months [2]
Our UVM cycle is a four-year average (or effective) cycle. For example, we maintain 25% of our overhead UVM system miles annually. This is a reliability based, variable cycle. [2]
We are expected, by [State] Commerce Commission mandate, to perform full maintenance on each of our distribution circuits at least once every 48 months. We are also mandated to perform a mid-cycle patrol of every circuits the second year after full maintenance has taken place. [8]
Utility vegetation cycles are planned lengths of time attributed to every circuit of our system and are based on vegetation response to all factors influencing growth as well as customer density. These cycles should be maintained for each programmed interventions. [5]
Also agree that it is a planned length of time not only looking backwards, but forwards as well. But it is a measure of time to manage all trees, spans, or miles one time. [3]
Our tree program is driven by customer density and budget and reliability. 5-year cycle suburban 10-year cycle Rural [4]

Table 9: Descriptions of Vegetation Maintenance Cycles

Scheduling, Cycles, and Impacts



Graph 47: UVM Scheduling and Influences

Comments on Fluctuating UVM Budget
We set budgets according to the number of miles being maintained in a given year [No]
Due to program underfunding we are experiencing a backlog of work [Yes]
Depends upon the year and the budget. Over the years we have been successful in creating a more stable annual budget [No]
Yes and no. Maintaining 48-month compliance is first priority and we have been successful in achieving this despite budget fluctuations over the past few years. It affects us most in regard to how we approach the work. When resources are limited, we often have to just get by with the necessary clearance and move on. Often times we may not be able to address good removals (trees and brush), off - ROW trees/hazard tree conditions, overhang removal (beyond what our minimum specs require), etc. Essentially, we are not able to do the work that really improves reliability. Also, we sometimes are not able to do full maintenance on the isolated sub-t. We often have just been able to "hot spot" the sub-t. Limited resources also have an effect on fulfilling customer requests and reliability work. [Yes]
Our cycles are based on vegetation response to all factors influencing growth as well as customer density. These cycles should be maintained for each programmed interventions. They can be consider[ed] as objectives. Availability of resources impacted directly our scheduling. [Yes]
Beginning of 2014 we have a stable budget for the next 4-years [Yes]

Table 10: Comments on Fluctuating UVM Budget

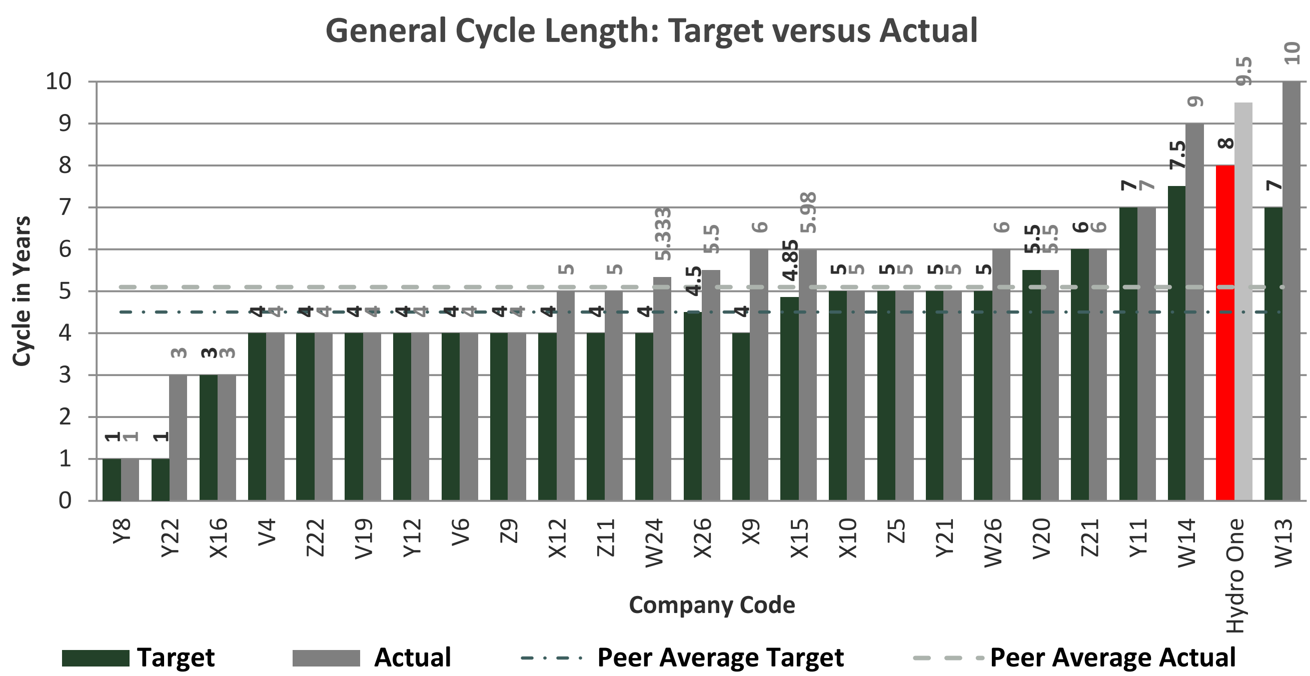
Explain How Reliability Measurements Influences Your UVM Scheduling
We schedule on a yearly basis and we'll often move circuits up in a given year to make sure the reliability benefits are realized as early as possible [Yes]
Priorities are based on targeting worst performing areas and/or feeders [Yes]
Previous 12 month vegetation coded outages have a great impact in the predictive model for forward 12 months [Yes]
[Enhanced Hazard Tree Mitigation] EHTM program is influenced by reliability [Yes - 3 companies]
Our routine operations are not influenced by this however we have a dedicated reliability program that incorporates this data to determine the SSDs that will be worked in a given year. [No]

Explain How Reliability Measurements Influences Your UVM Scheduling [Continued]
[Utility] Power Quality team tracks momentaries on poor performing circuits and will issue trim locations within circuit. [Yes]
Part of our rankings for determining EHTM circuits are based on reliability.
[Utility] utilizes the Davies Consulting Tree Trim Model (TTM), a sophisticated software program that projects a "Bang for Buck" approach, a balance of reliability and cost. [Yes]
Time between UVM activities may be in/decreased based on reliability. [Yes]
All circuits/feeders reliability is monitored throughout the year for vegetation outages. Circuits with poor performing reliability #'s are inspected and if it determined by the Forester/OC that the circuit is performing badly due to grow-in type vegetation outages, then the circuit will be added to the trim list for that coming year. This plays a role in the reliability metrics, but doesn't always effect scheduling. Scheduling the yearly trim plan is determined by the last trim year, distance of vegetation from conductor, and viewing outage data on that feeder. If the feeder is having a lot of grow-in outages it will be a good candidate for trim, where as a feeder that is performing badly from a SAIFI/SAIDI standpoint due to outside ROW Tree fall in's, the forester may not schedule that feeder to be trimmed but instead conduct a danger tree patrol or see if skylining certain parts of the feeder are feasible to alleviate the non-preventable outages. [Yes]
Poorly performing line segments are priority for line clearing [Yes - 6 companies]
Sometimes, but seldom. We may move a circuit up on the schedule (perform work before the circuit is actually due for full maintenance) if there are tree conditions present which warrant addressing, and may be causing reliability issues. In most cases, if there are issues, we will perform some hot-spotting to help alleviate problems before the next cycle trim is due. For worst performing circuits: On the vegetation side, I do not believe that we are actually REQUIRED to do anything. We do, however, take a closer look (through an inspection) at these circuits to see if there is any additional work (beyond what our program guidelines dictate) that could be done to improve reliability. We would look at possibly removing more overhang, removing "problem" trees, addressing off-ROW trees, etc. [Yes]
Reliability data is used as the driving force behind our composite risk index used to prioritize feeders for UVM treatments [Yes- Hydro One]
[Reliability data is used] for the tree removal program only. [Yes]
We do off-cycle trimming to mitigate urgent reliability issues. [No]
Annual work is prioritized in that year based on reliability ranking. Occasionally a cycle can be shortened (other(s) lengthened) to meet a reliability need. [Yes]
If we have a circuit that is having [outages] it will be given priority until reliability is successfully restored. [Yes]
If a section of line or circuit is experiencing an unacceptable amount of outages we will trim out area before the designated UVM cycle. (2013). The 10 worst performing circuits are reviewed and addressed on a yearly basis [Yes]

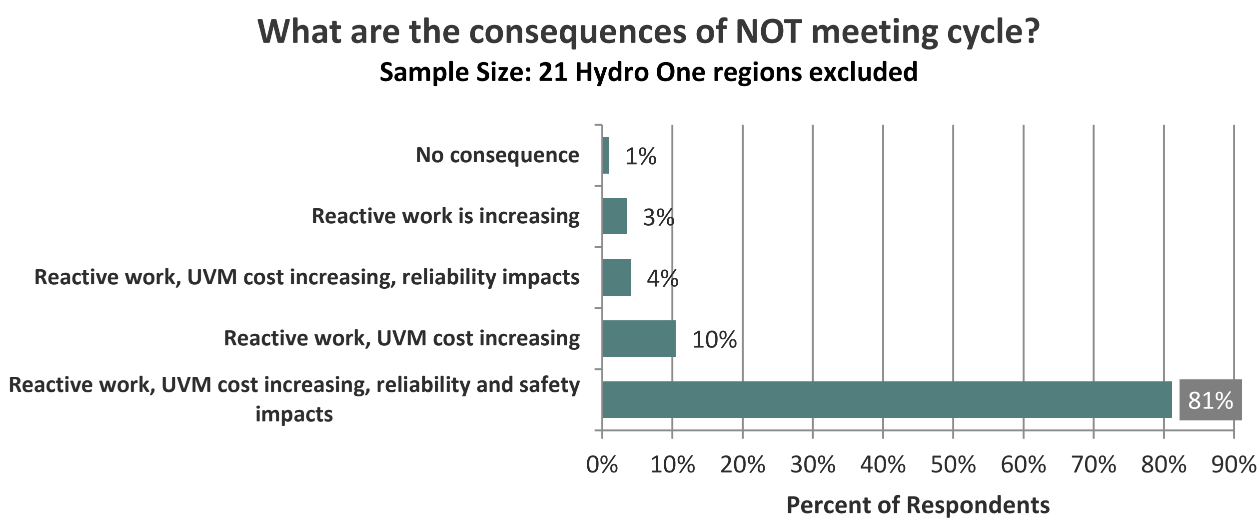
Table 11: Explain How Reliability Measurements Influences Your UVM Scheduling

Responses highlighted in tan prioritize poor or worst performing circuits.
Hydro One highlighted in rose.

General Cycle Lengths



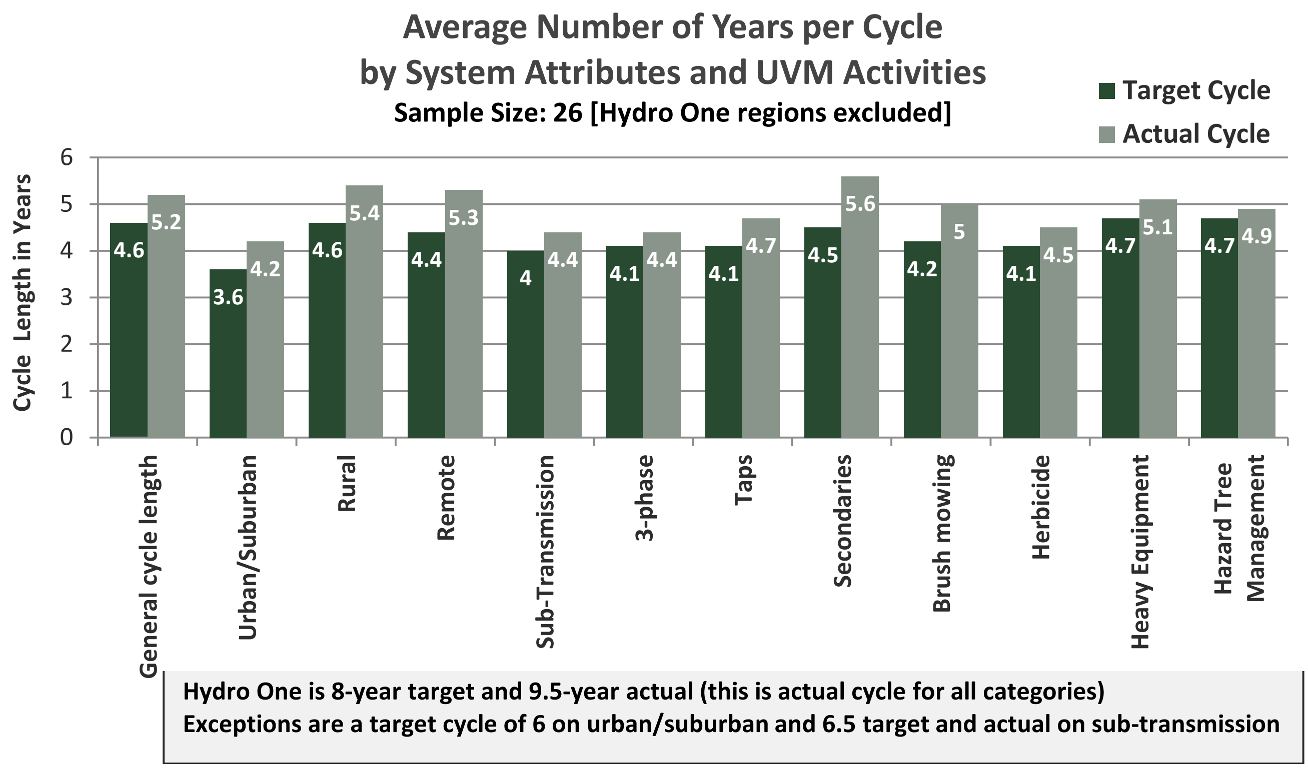
Graph 48: General Cycle Length: Target versus Actual



Graph 49: What are the consequences of NOT meeting cycle?

The graph (Graph 40) above is based on responses from the following twelve cycle categories: General, Urban/Suburban, Rural, Remote, Sub-Transmission, Three-phase, Taps, Secondaries, Brush mowing, Herbicide control, Heavy equipment work, and Hazardous tree management. The variation between the twelve categories was not significant, so all cycle types were averaged to derive the statistics in the graph.

Variable Cycles

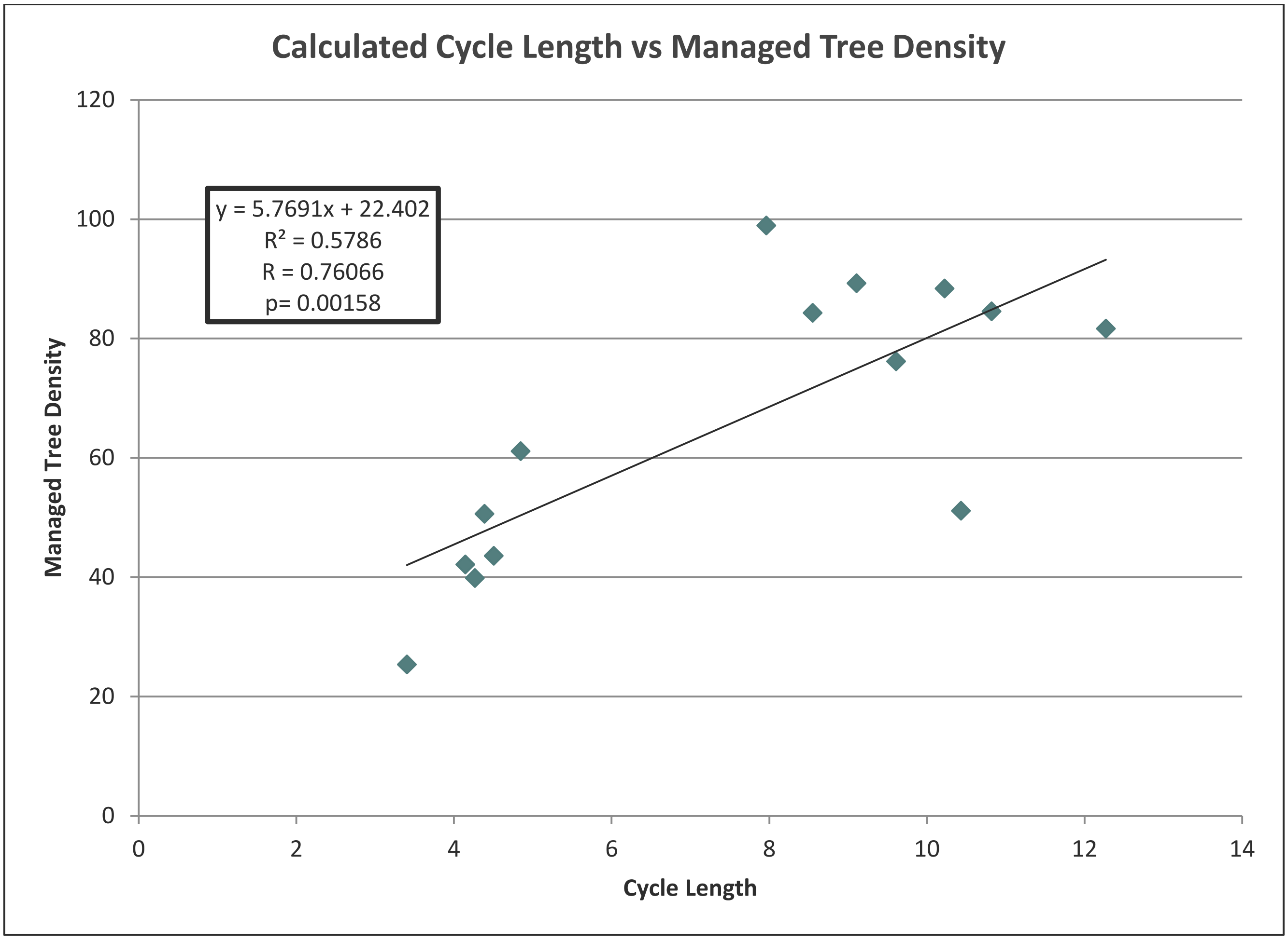


Graph 50: Average Number of Years per Cycle by System Attributes and UVM Activities

Variable Cycle Statistics [Peers plus Hydro One Networks]								
Cycle Type	General Target	General Actual	Urban & Suburban Target	Urban & Suburban Actual	Rural Target	Rural Actual	Remote Target	Remote Actual
Sample	25	25	11	11	11	11	8	8
Average	4.6	5.3	3.6	4.5	5.0	6.4	4.9	6.6
Q1	4.0	4.0	3.0	4.0	4.0	5.5	4.0	6.0
Median	4.0	5.0	4.0	4.0	4.0	6.0	4.5	6.5
Q3	5.0	6.0	4.0	4.5	6.0	7.0	6.0	7.3
Max	8.0	10.0	6.0	9.5	10.0	11.5	8.0	9.5
Min	1.0	1.0	1.0	2.0	1.0	3.0	2.0	3.0
STDEV	1.7	2.0	1.4	2.0	2.5	2.5	1.8	1.9

Statistics Table 5: Variable Cycle Statistics

Correlation between Cycle Length and Managed Tree Density

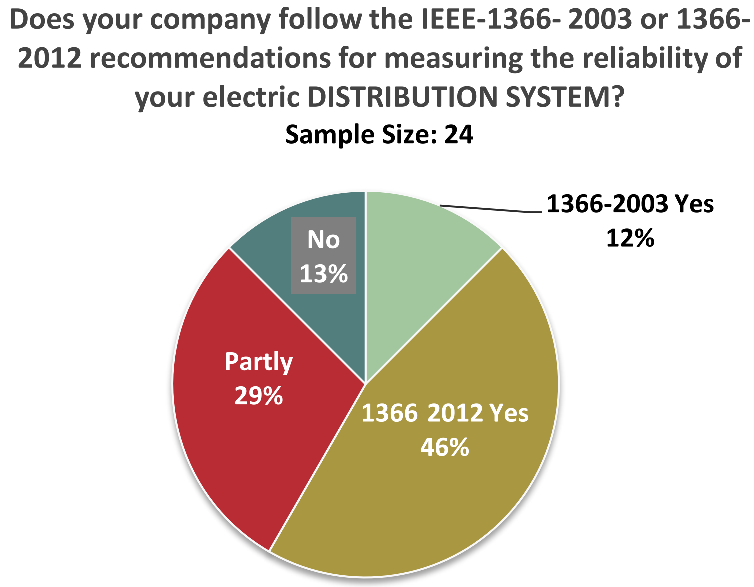


Graph 51: Calculated Cycle Length vs Managed Tree Density

R^2 = 0.5786 or 57.9% of the variance can be accounted for in the model. Simply, this indicates the strength of the model for prediction (This is adequately high)
R = 0.76066 is the correlation coefficient and it is an indication of the strength of the relationship (1 is perfect). This is a good correlation
p = 0.001582 or p-value loosely means 'how significant or repeatable is this result or model?' The smaller the p-value indicates that the probability that this model is a good predictor is high. In this case it is well below 1%

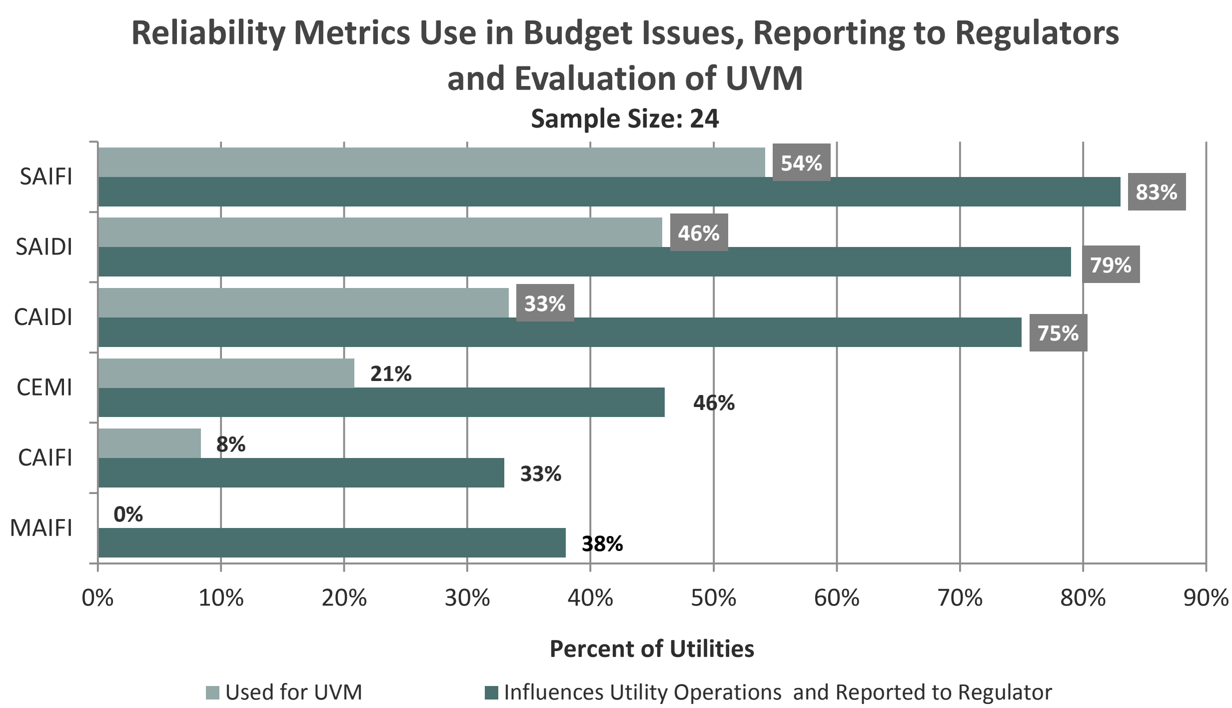
RELIABILITY

Calculating Reliability Metrics



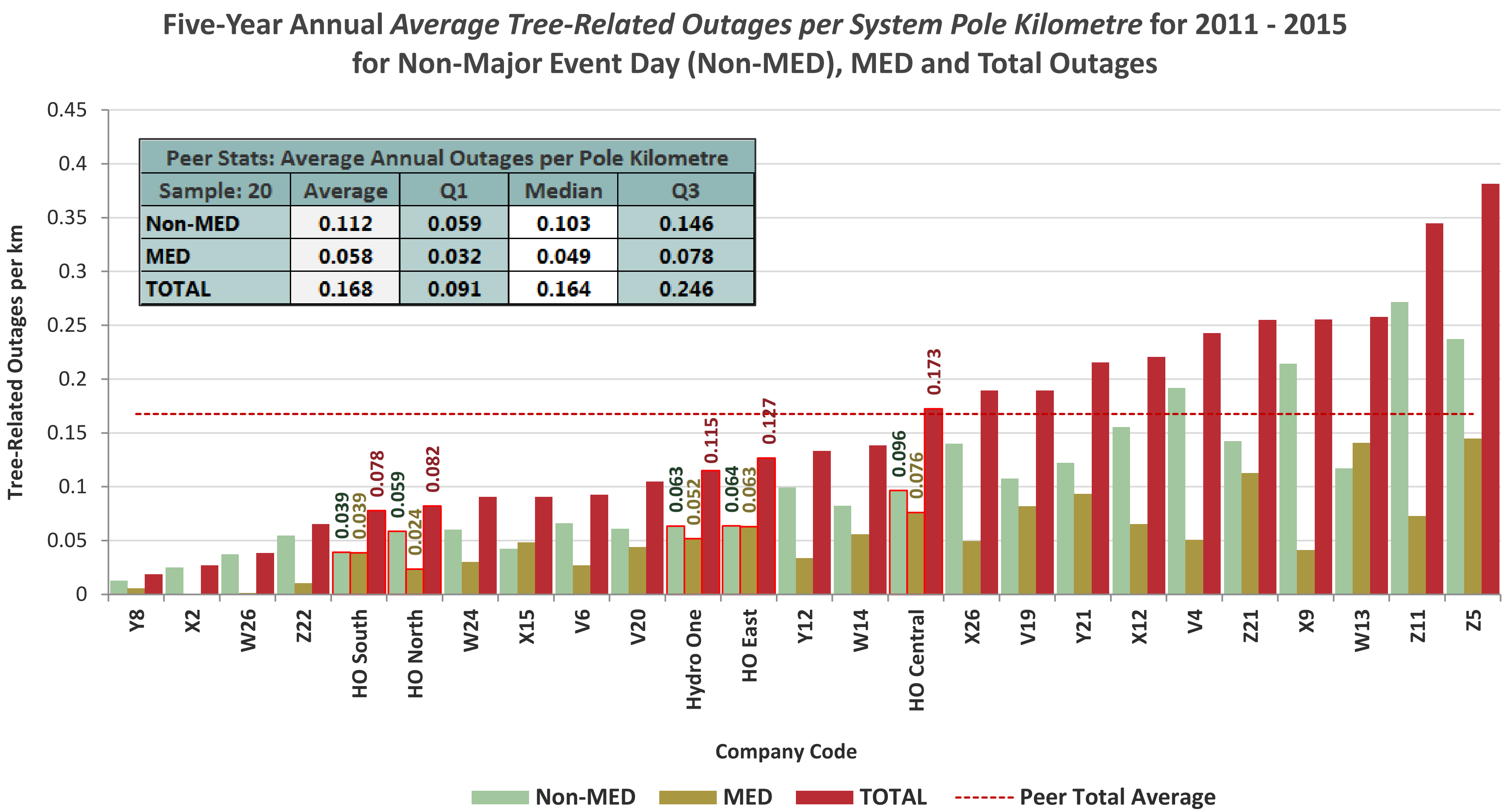
Graph 52: IEEE 1366 Usage for Calculating Reliability Metrics

Reliability Metrics Used for Evaluating the UVM Program



Graph 53: Reliability Metrics Used for Utility Vegetation Management

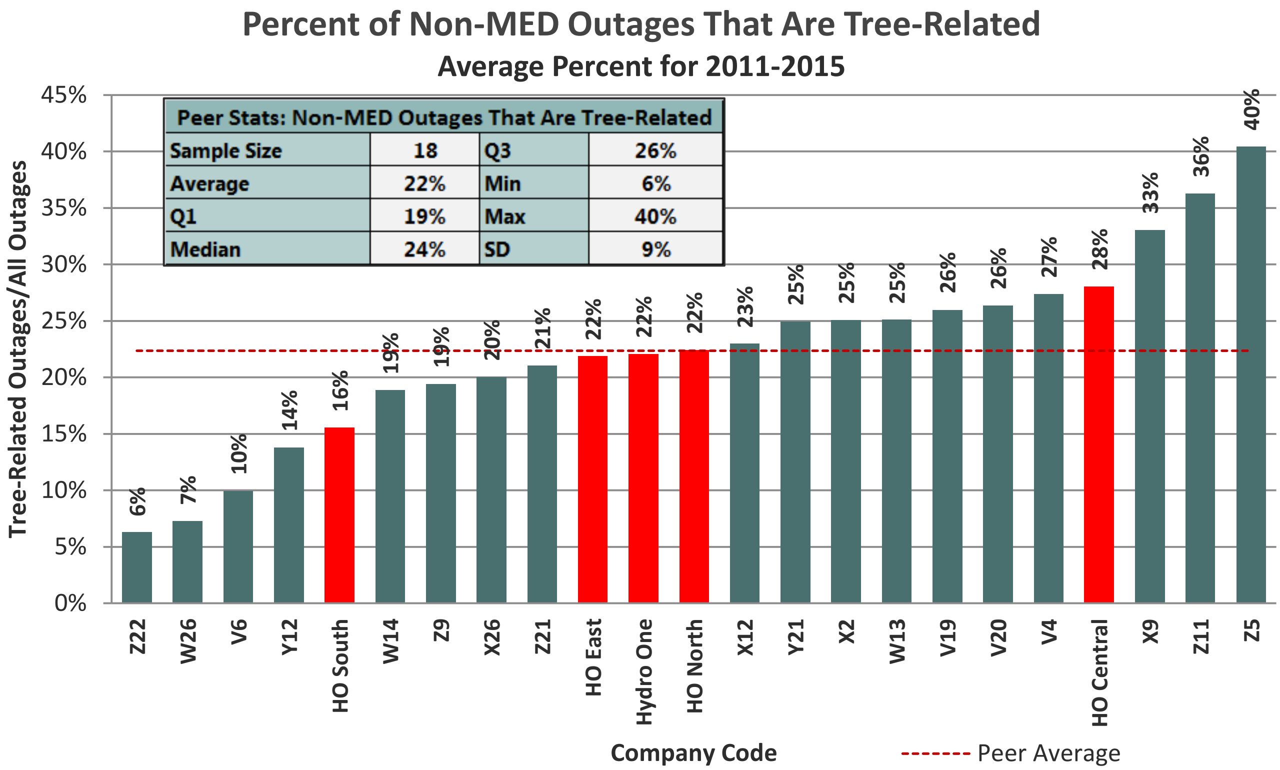
Tree-Related Outages per Kilometre of Distribution Overhead Line



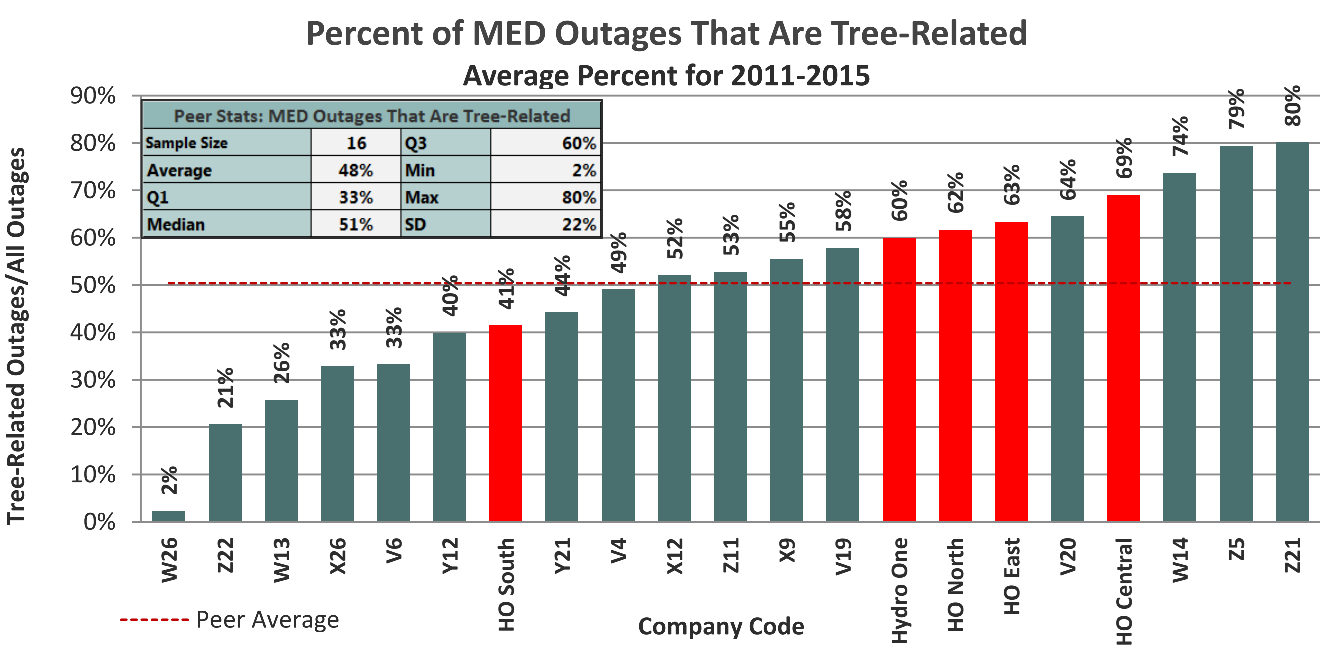
Peer Stats: Average Annual Outages per Pole Kilometre				
Sample: 20	Average	Q1	Median	Q3
Non-MED	0.112	0.059	0.103	0.146
MED	0.058	0.032	0.049	0.078
TOTAL	0.168	0.091	0.164	0.246

Graph 54: ***Average Tree-Related Outages per System Pole Kilometre*** **for Non-MED, MED and TOTAL Outages**

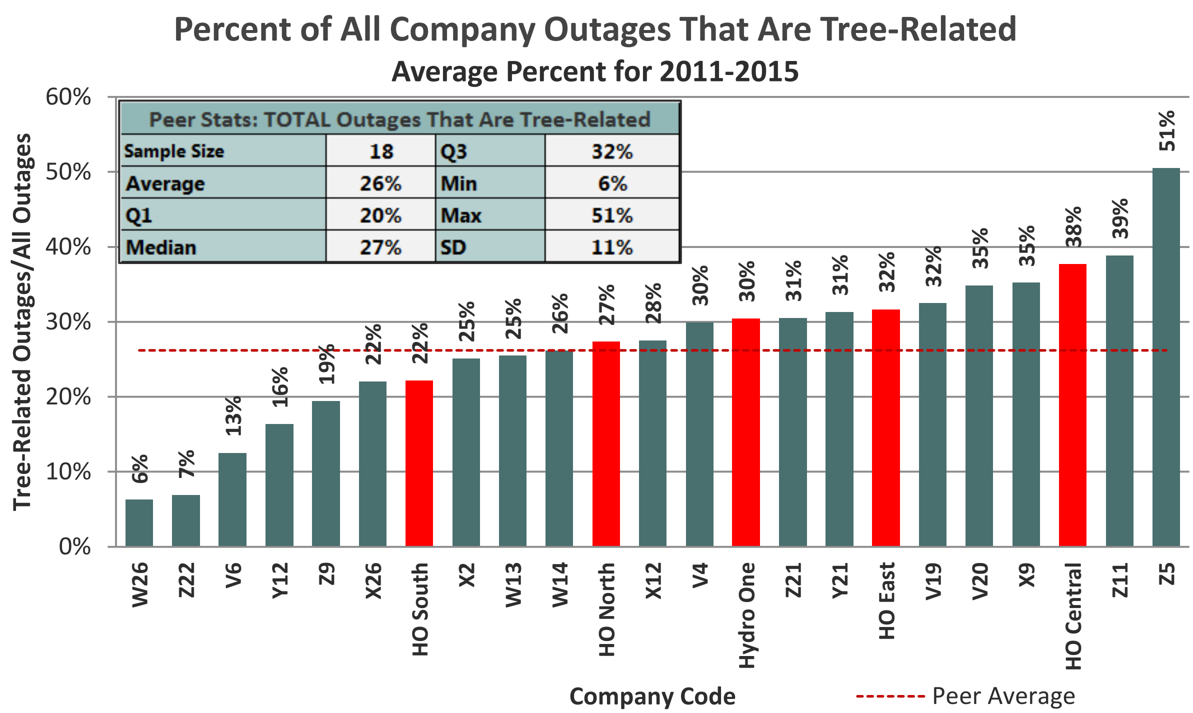
Percent of Outages That Are Tree-Related



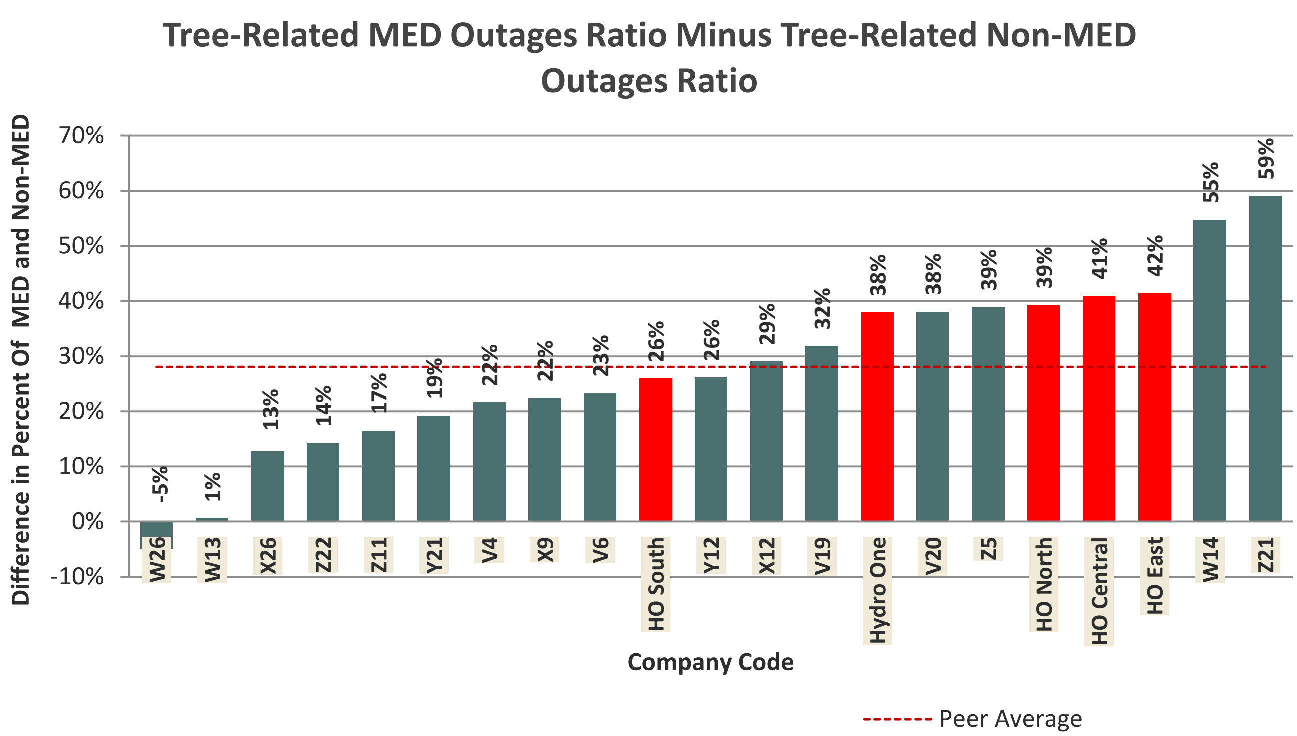
Graph 55: Percent of Non-MED Outages That Are Tree-Related



Graph 56: Percent of MED Outages That Are Tree-Related

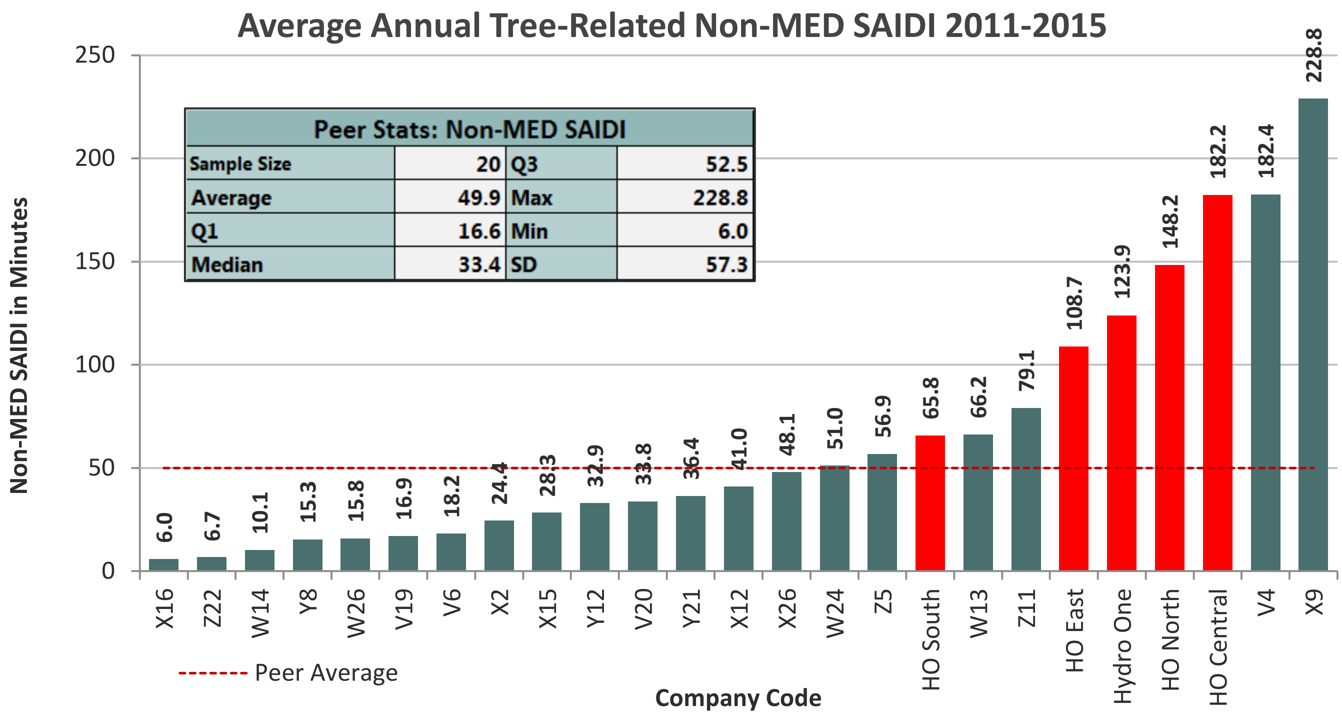


Graph 57: Percent of All Company Outages That Are Tree-Related

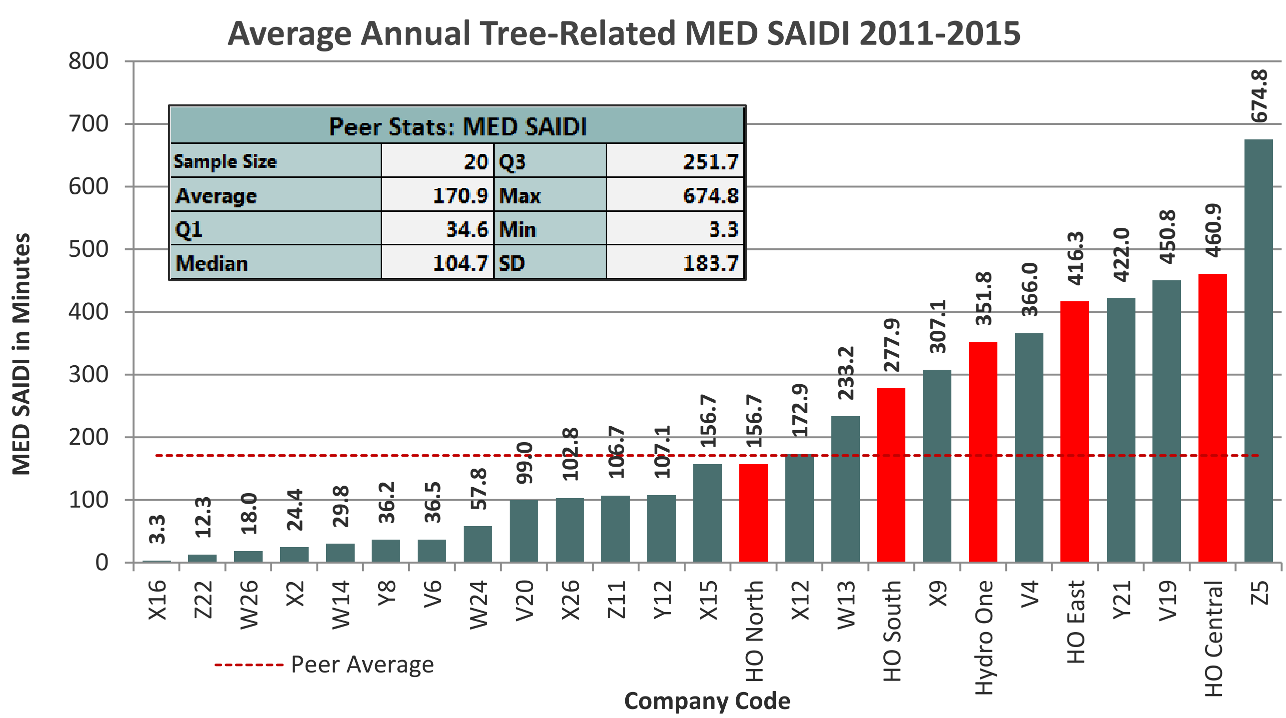


Graph 58: Tree-Related MED Outages Ratio minus Tree-Related Non-MED Outages Ratio

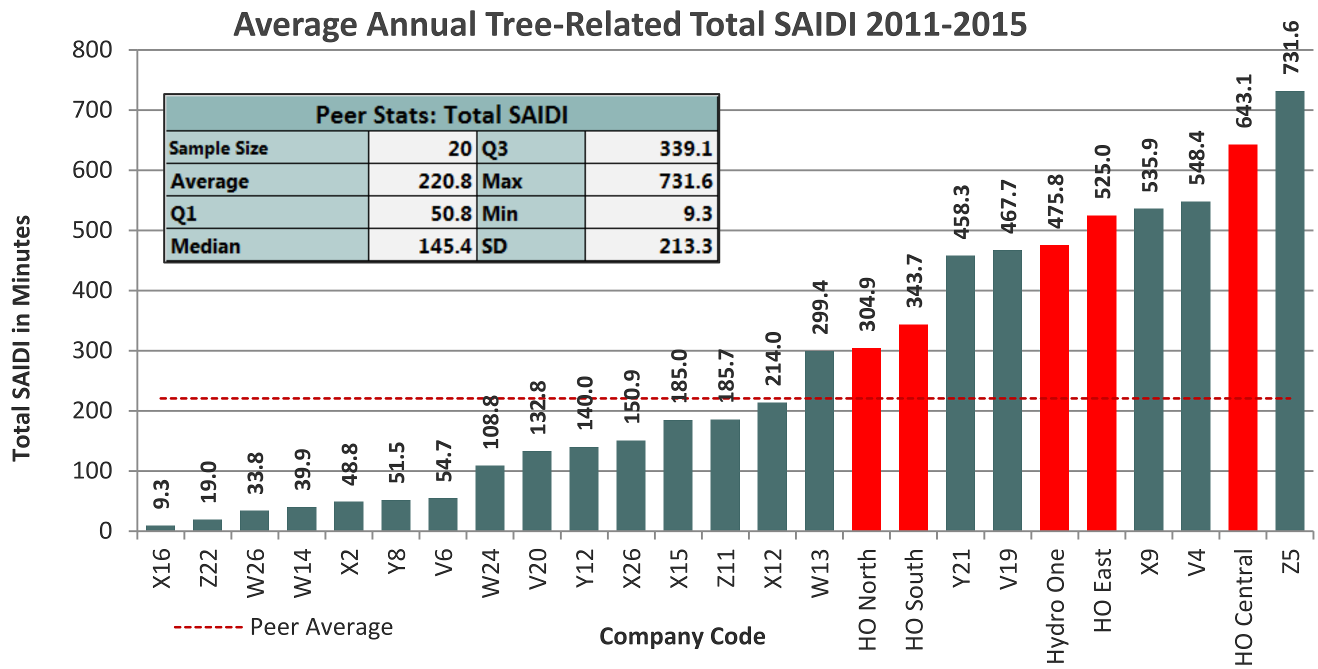
SAIDI Comparisons



Graph 59: Average Annual Tree-Related Non-MED SAIDI 2011-2015

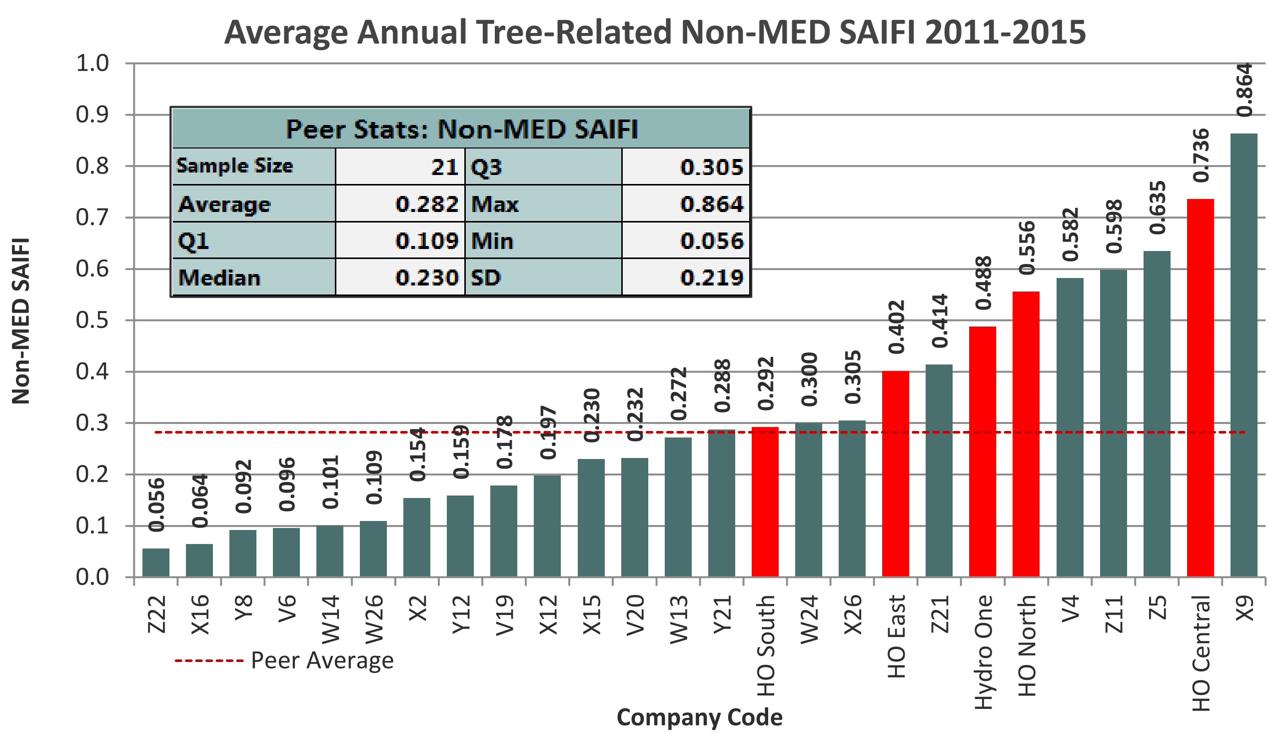


Graph 60: Average Annual Tree-Related MED SAIDI 2011-2015

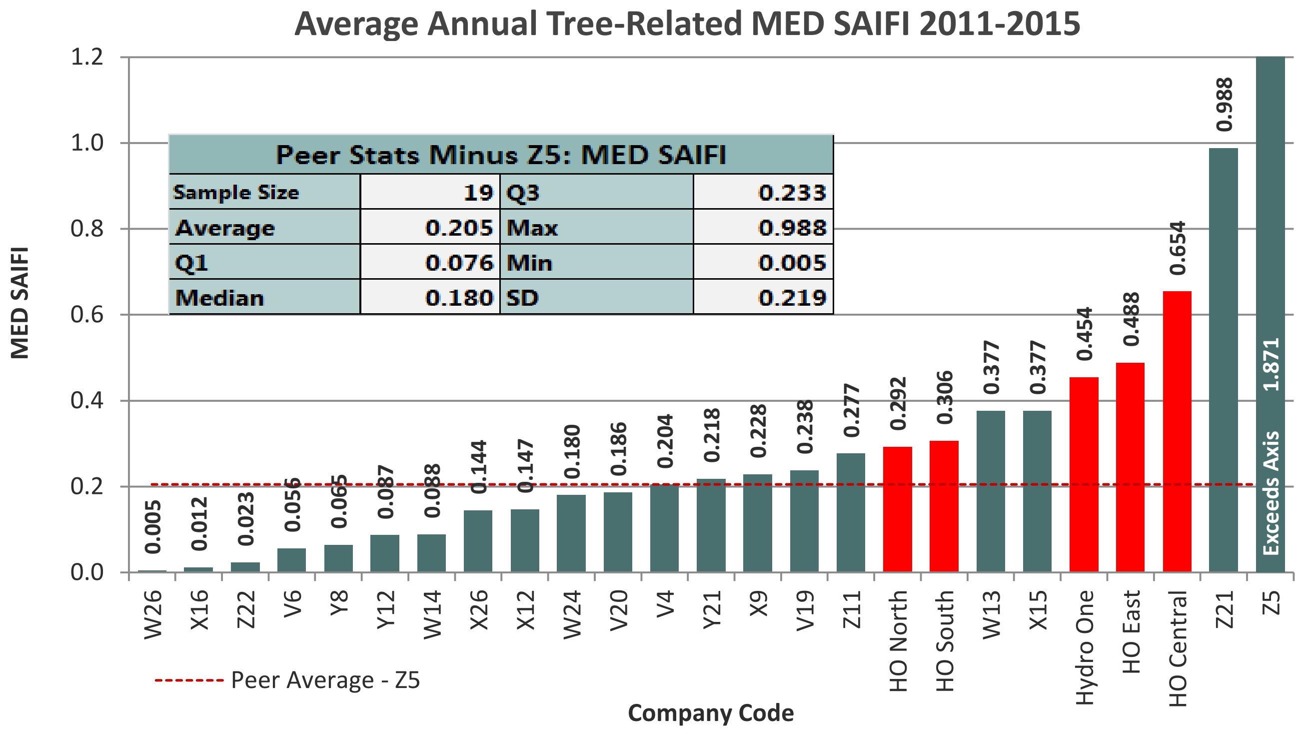


Graph 61: Average Annual Tree-Related Total SAIDI 2011-2015

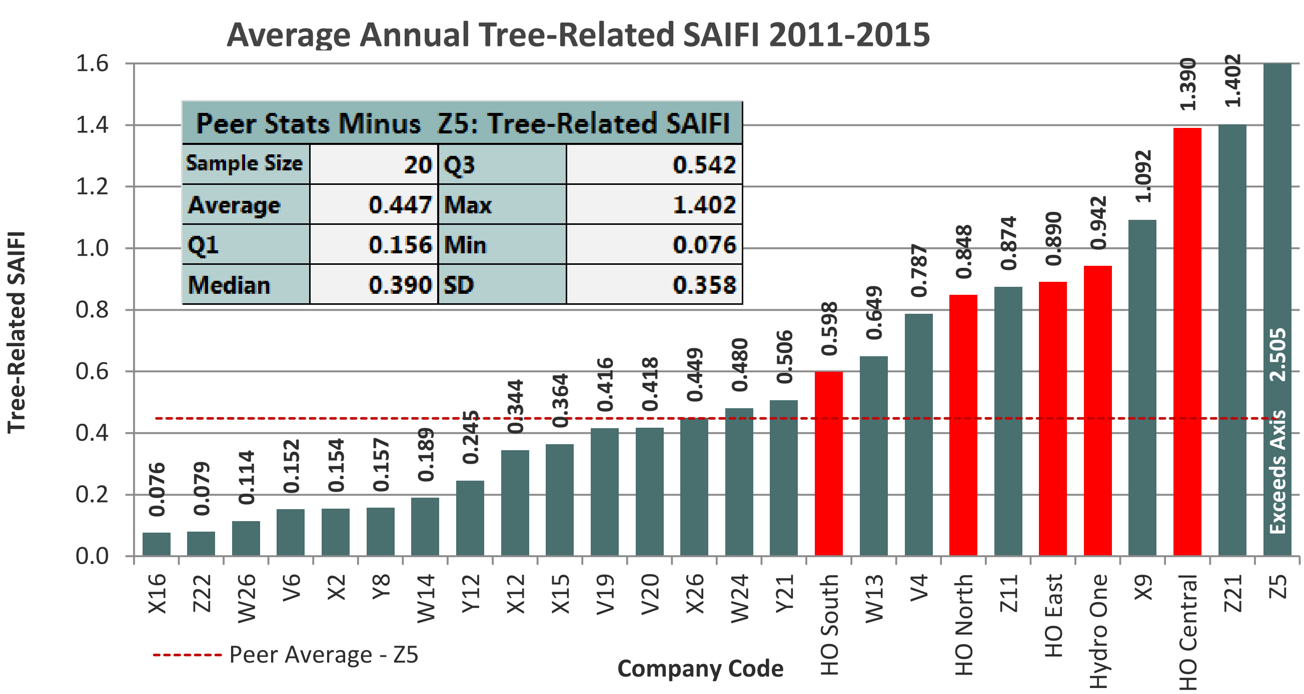
SAIFI Comparisons



Graph 62: Average Annual Tree-Related Non-MED SAIFI 2011-2015

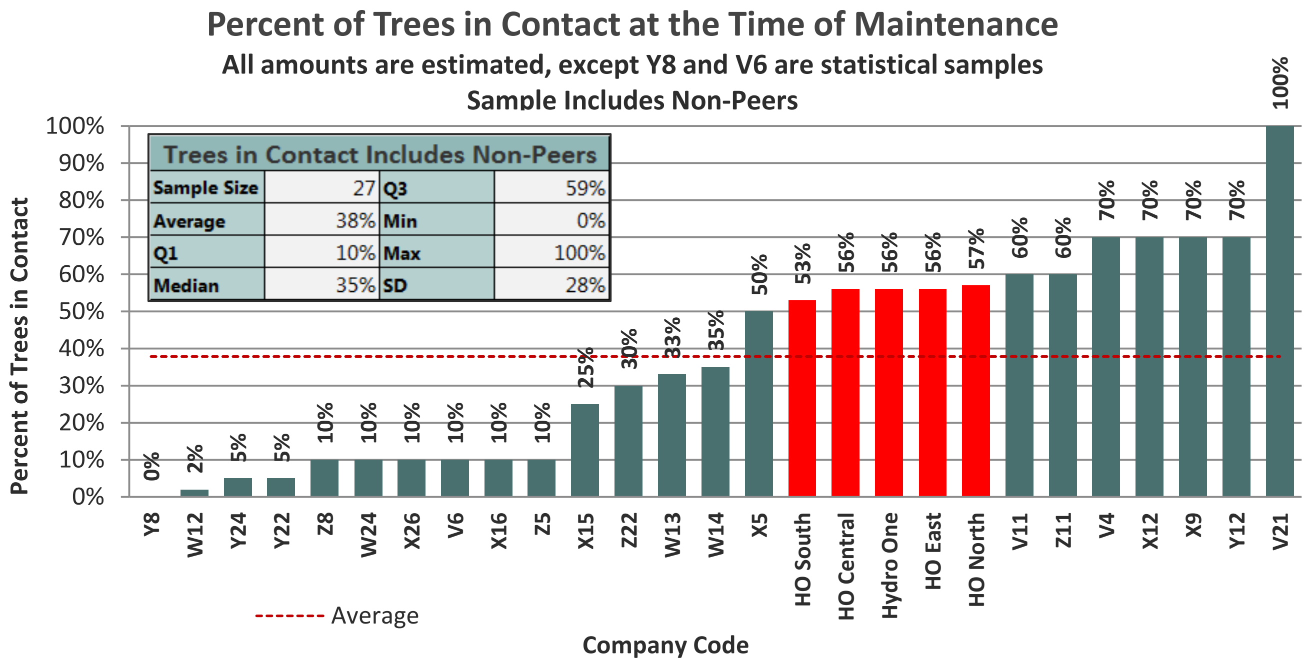


Graph 63: Average Annual Tree-Related MED SAIFI 2011-2015

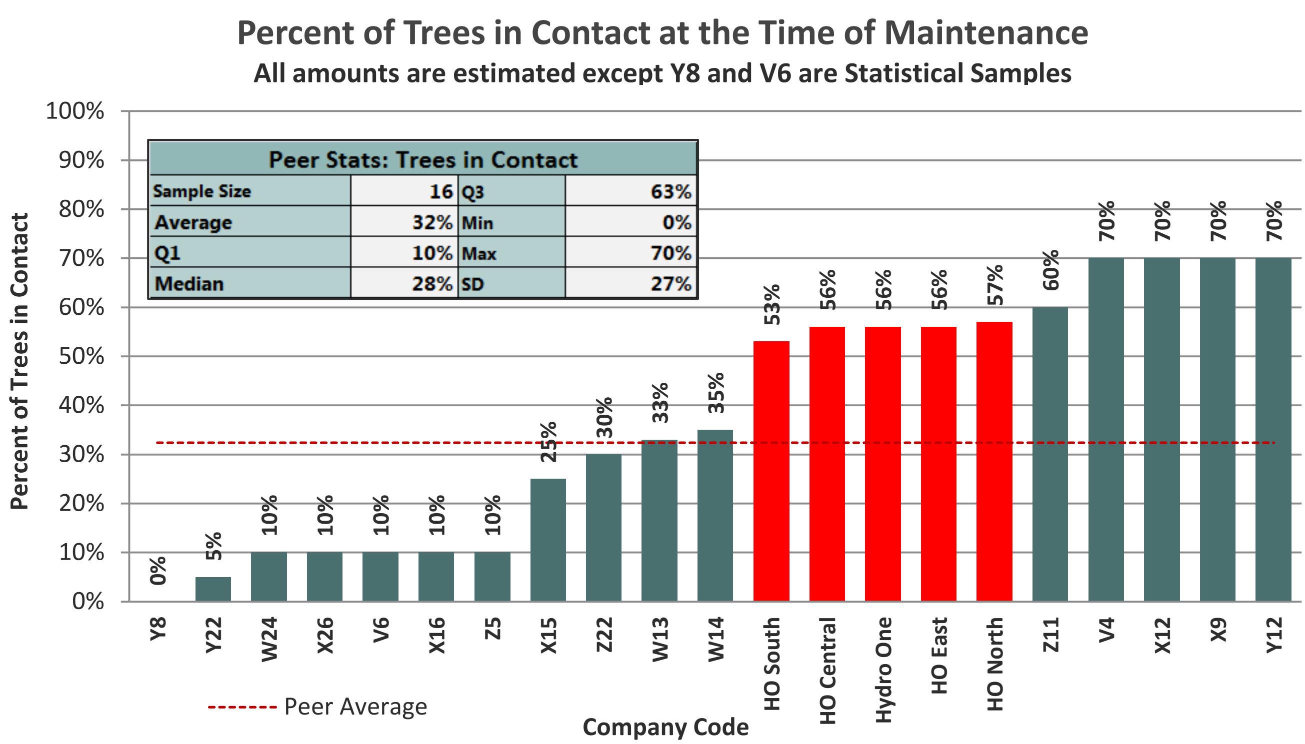


Graph 64: Average Annual Tree-Related SAIFI 2011-2015

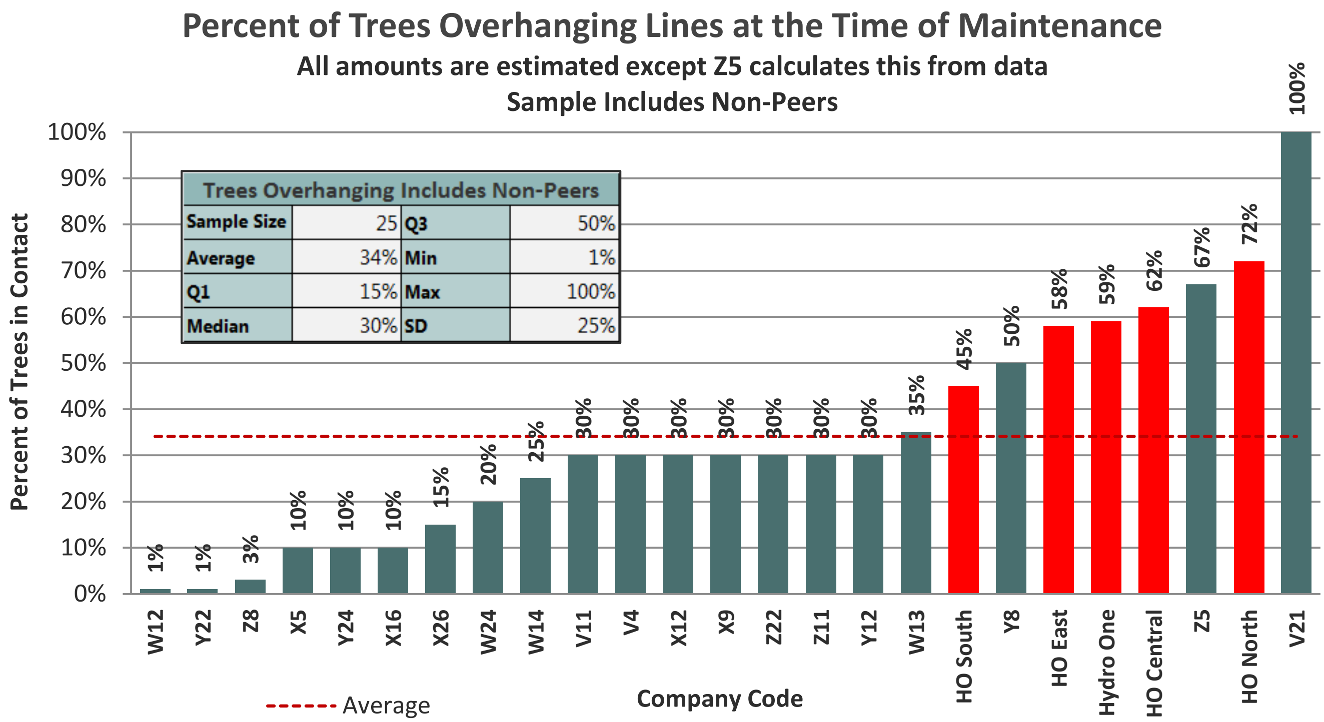
Vegetation Conditions at Time of Maintenance



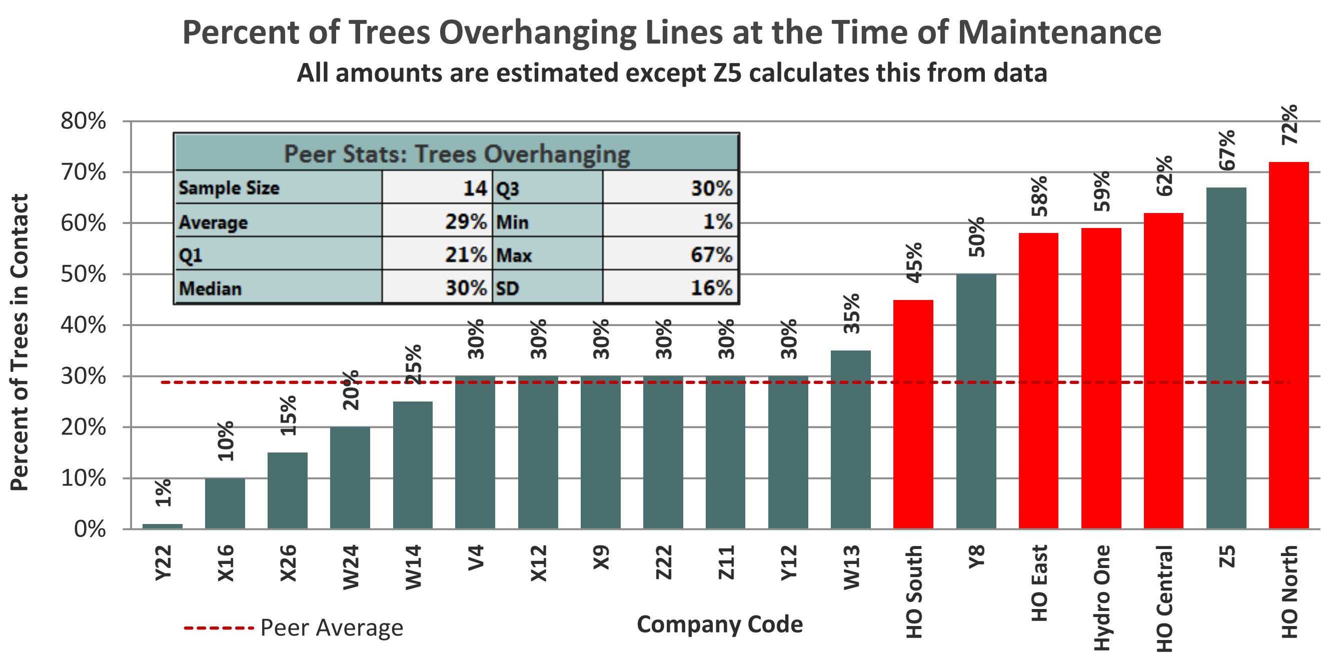
Graph 65: Percent of Trees in Contact at the Time of Maintenance – All respondents



Graph 66: Percent of Trees in Contact at the Time of Maintenance – Peers and Hydro One



Graph 67: Percent of Trees in Overhanging Lines at the Time of Maintenance – All Respondents

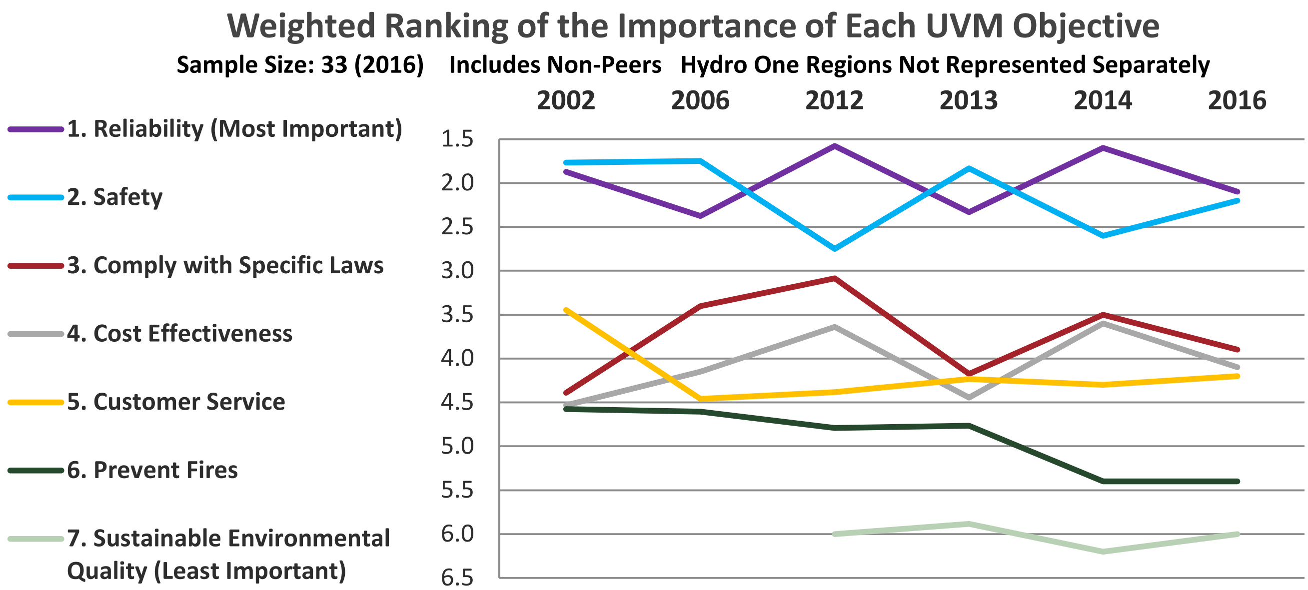


Graph 68: Percent of Trees in Overhanging Lines at the Time of Maintenance – Peers and Hydro One

UVM DRIVERS AND FUNDING

UVM Objectives

This graph was created from six different CNUC surveys given in 2002, 2006, 2009, 2014, and 2015 (the survey done for this project). The number of participants varied from year to year and the utilities were not the exact same set, although many participated in all five surveys. The order shown in the legend is the 2016 rankings.



Graph 69: Weighted Ranking of the Importance of Each UVM Objective

Hydro One's Rankings in order of importance were:

- Most Important: Reliability
- Cost-Effectiveness
- Customer Service
- Safety
- Sustainable Environmental Quality
- Comply with Specific Laws
- Least Important : Prevent Fires

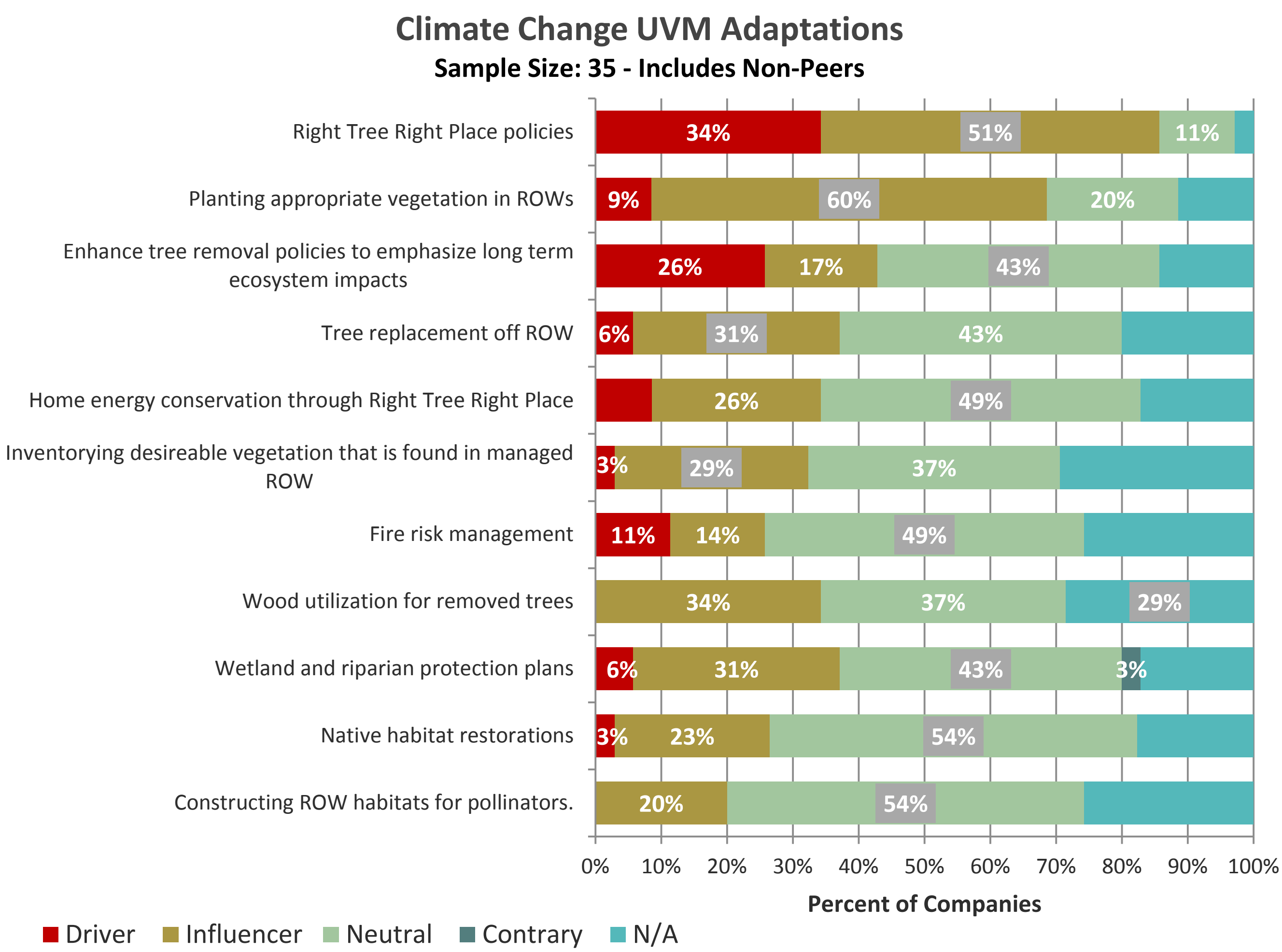
Of note is the Hydro One's ranking for Safety (4th), which is significantly lower than the industry; Compliance - 6th compared to the industry ranking of 3rd; and Cost-Effectiveness, which is significantly higher than the industry. Although much of the industry ranks preventing fires a lower priority, several rank it is as the second most important. These utilities are located in areas of high fire danger. Locations with higher fire danger are changing as changes in climate impact forest health and composition. The fires in Alberta in May 2016 may be an indication that Hydro One should consider incorporating fire prevention into their UVM program.

UVM Programs Contributions to Ecosystem Sustainability

The following question was posed to UVM managers:

OBJECTIVE: To determine the extent that distribution UVM programs are contributing and adapting to carbon free initiatives and ecosystem benefits.

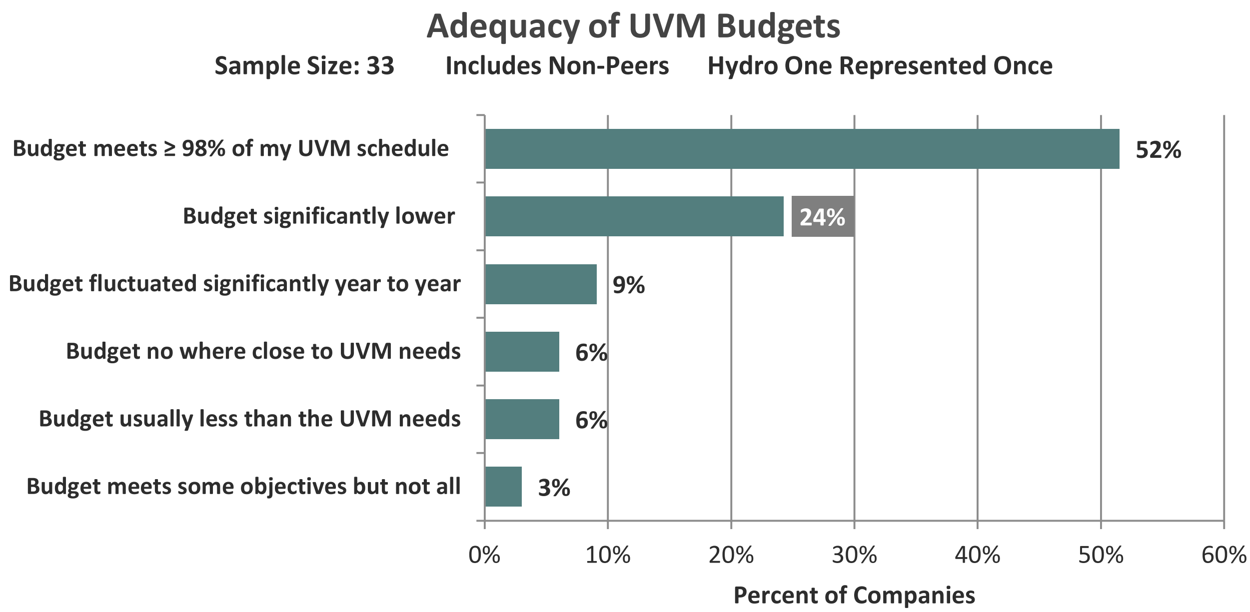
QUESTION: Evaluate whether the activities listed below are driving, influencing, neutral or contrary to your UVM program.



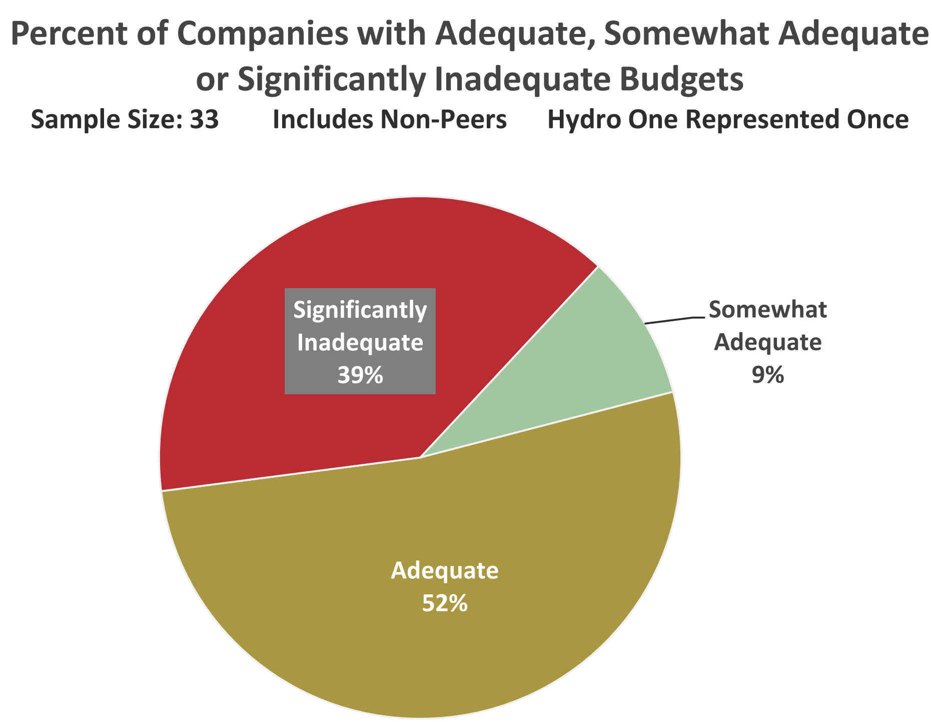
Graph 70: Climate Change UVM Adaptations

- One utility targets invasive species and this influences their UVM activities.

UVM Budget

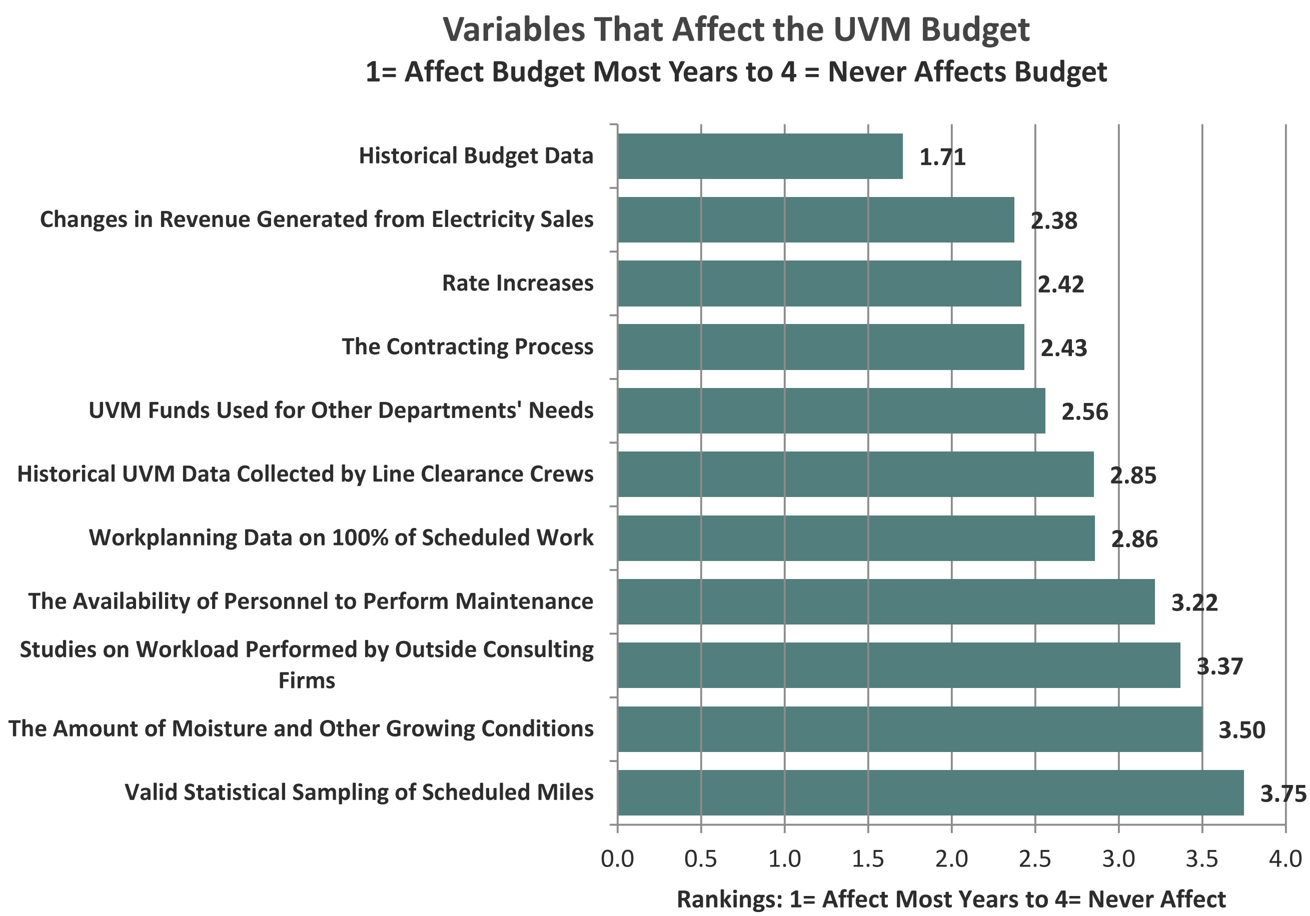


Graph 71: Adequacy of Budgets Meeting UVM Needs



Graph 72: Percent of Companies with Adequate, Somewhat Adequate or Significantly Inadequate Budgets

Variables That Influence UVM Budget



Graph 73: Variables That Affect the UVM Budget

Program Policies to Optimize Efficiency

These responses include **Non-Peer** utilities. 32 companies answered this question.
The survey asked:

> Do you have scheduling strategies or program policies that are designed to optimize efficiency and reduce non-productive costs resulting from transportation and related costs of the mobile work environment?

Included in this question were several sub-categories. A summary of responses follow.

What scheduling strategies are employed?

We ask [our contractor] to schedule work in the most efficient way possible. This is to their benefit as their contract is dependent on meeting quarterly production metrics
Planned feeder cycles, SAIDI, and routine patrols
An annual target for all compliance work is employed.
O&M program clearing work is coordinated with capital line work to maximize efficiency
Planning, inventory to plan maintenance schedule (3 similar responses)
Time of year (Seasons) coordinating work (maintenance and hazard tree programs)
Mainly try to put the right equipment in the right place at the right time. For example, get bucket trucks into farm fields before crops are planted.
Switched to Unit Price contract for planned maintenance work two years ago
Organized at a local level, no overall strategy [Hydro One]
Group circuits of a substation together in an annual plan (or group by local work area)
We try to concentrate all of efforts to a particular location and do all we can in that location until completed.

Table 12: Scheduling Strategies

What program features, such as cycle length, limit unplanned or reactive work?

Our cycle lengths are appropriate for our system, [the] grow[th] in outages are less than 10%. We have also had third party studies confirm that our cycle length is appropriate.
Two- year planned feeder cycles, targeting past outage areas
Cycle length does not affect unplanned/storm/reactive work. We are able to ramp up crews to meet unforeseen events along our powerline systems.
Relatively short and consistent cycle
Managing vegetation maintenance to a cycle (6 Companies)
Cycle length [and] increasing use of technology such as LiDAR.
Our mid-cycle program helps address issues that may result in unplanned work.
We have had to increase our Transmission pruning to stay compliant with NERC requirements and it had a negative impact on our routine pruning so I have implemented the use of topping machines and have been able to keep our regular crews on routine work.
Combine vegetation defect program with regular maintenance to avoid duplicate trips [Hydro One]
[Third party contractor] work inventory and prescriptions
Cycle length, mid-cycle review, Forestry driven reliability assessment work, Engineering driven reliability enhancement work

Table 13: Strategies to Limit Unplanned Work

Clearance and removal policies that limit future reactive work to optimize efficiency

We defer a lot of requested off cycle work, we mainly only do reactive work that really needs to be done.
We remove problem trees as much as possible
Aggressive removal of "cycle busters"
Maximize removals of trees inside and hazardous trees outside of the right-of-way
Aggressive removal policy (7 companies)
Data
Contractor incentives for reducing inventory
Remove if allowed
Remove trees vs just trim to eliminate future issues [Hydro One]
We attempt to clear 10-15' to all sides of the primary conductors to minimize growth into or close before the next cycle is due.
Corrective pruning and certain removals are performed on hourly T&M billing
Remove all dead, dying, defective branches in overhang (regardless of height)
We alter all scheduling for any and all tree removal near our facilities.

Table 14: Policies to Limit Future Work

Tree removal was the primary method to reduce future unplanned work. (53%)

Contract policies on travel time to optimize efficiency

Must be approved by [utility]
None. Our contracts are set up so that there are crews positioned in each respective district.
Contract crews locate pullouts within 15 minute drive of work locations (2 companies)
No charges for travel time.
No requirement - Unit Price contract

Table 15: Travel Time Policies

A vast majority (86%) of UVM departments do not have a policy for travel time.

Technology that monitors transportation to optimize efficiency

68% of the respondents (Hydro One is in this category) use a GPS-based monitoring system for tracking vehicle locations. One company mentioned having a two-way communication system included with their monitoring system.

Two responses that varied were:

- We are in the process of introducing a Work Force Management tool.
- [Contractor] uses Telogis to monitor crew travel and production.

Customer service activities and policies to optimize efficiency

Customer contact is handled by contractor representatives and by [utility] personnel to ensure 100% compliance and satisfaction.
Increased utilization of partnership with internal customer care department.
No debris clean-up after storms or damage from acts of nature, customer responsible for service
We try to do this ahead of time to minimize the impact on time.

Table 16: Customer service and policies

Parking locations for crews to optimize efficiency

This is always a challenge in our Urban areas
None. This is a contractor's responsibility. (2 companies)
At substation or farm or gas station within 15 min of work site (2 companies had 15 minute policies).
Various staging sites based on work plan (7 companies)
Yes we provide places for contractor trucks.
Encourage "show-up" locations close to circuit
Parking/staging locations are set up close to the work to minimize travel times. These are changed frequently to keep contractors close to the work. (3 companies)
Temporary work headquarters for jobs that are remote from the local operations centre. [Hydro One]
At local operating center for reactive work crews (none for bid work crews)

Table 17: Parking locations for crews

Lodging and per diem to optimize efficiency

Must be approved by [utility]
Only during storm work/emergent work
Only for peak workloads when utilizing out-of-state traveling resources
Per diem per designated distance from show-up as defined in contract (7 companies)
Very minimal; considered on a case-by case basis. Seldom utilized except in extreme circumstances.
Limited but union mandated when applicable
None (2 companies)

Table 18: Lodging and per diem

Large crews transported in one vehicle to optimize efficiency

On some jobs, yes
Organized at a local level, no overall policy [Hydro One]
Again, contractor's responsibility.

Table 19: Large crews transported in one vehicle

Training to optimize efficiency

We generally pay time for training, we ask [contractor] to cover the cost of conferences, etc.
Contractor provides training to all crews. We conduct an annual environmental sensitivity training for all contractor personnel.
Focus on winter and inclement weather days for crew training [Hydro One]
At least annual
Training is an ongoing process that we schedule around.
On the job

Table 20: Training

Other methods used to optimize efficiency

If conditions merit we may perform a mid-cycle maintenance cut (basically a planned and controlled hot spot cut)
Incentive/remedy program has increased productivity
Assigning contractors to specific geographic areas to reduce non-productive travel time
Smart phone with email, GPS, mapping for reactive work crews
Work is planned in advance; contractor is responsible for optimizing resources.

Table 21: Other optimizing methods

Compensating for Storm Disruptions

What adjustments to your schedule do you make to compensate for storm disruptions of the routine schedule?
None. If we have a storm the contractors try to add resources to get back on schedule. Not always successful. [8 companies similar responses including Hydro One]
Storms can be a big challenge; they interfere with getting maintenance work done. We will often have crews that are on storm standby go out and do maintenance work so they're not just sitting around.
Bump scheduled work as needed
Compliance tree crews are ramped up after a storm incident to be able to ensure compliance time-frame is on track.
Overtime based on length and severity of the storm (7 companies)
Depending on the severity of the storm and damage
Overtime may be authorized when significantly behind schedule. Work may be shifted from reliability to compliance pruning.
Adding crews, working overtime or both if possible.
We have been able to absorb storm costs without impacting the completion of our annual schedule
We can be flexible on the Target miles that contractors are to complete each quarter if they have worked numerous storm disruptions. In many cases we will not penalize them for being behind target on line mile production.
Circuit completion dates are reported as month/year, not an exact date. This means that you have until the last day of each month to complete a circuit. We schedule each of them to be completed by the 15th however to provide us with some breathing room in case of unforeseen circumstances. For instance, if a storm hit an area the last week of the month, and you had to take your crews of the circuit work to address the storm, you may not meet the end of the month deadline.
Increase Risk Tree assessments post storm to cover all affected areas -push out other maintenance work
Reactively adjust all scheduled activities
Bring in an extra crew or add Saturday work at straight time or OT, if necessary
Being an in house crew, routine UVM is restarted as soon as the disruption is resolved.
Our utility budgets an annual amount for storms
Add on additional crews if possible in order to meet our cycle goals

Table 22: Strategies for Storm Disruptions

Basically, companies use the following two strategies:

- Increase expenditures by adding overtime or extra crews to maintain schedule
- Keep target maintenance schedule flexible or readjust them

Elements of UVM Program That Optimize Efficiency

Name three things that are key to the efficiency of your UVM program:
1: Contractor continuity - [Contractor] has been here so long they know our system intimately. 2: We have several cycles' worth of cost data so we know how much each circuit should cost. 3: We run very low overheads (7.5%) so more funding goes towards tree trimming
Outage tracking, targeting tree type (faster growing to slower growing) and patrols
Accountability of the inventory personnel and tree crews, accurate work of such, and proper oversight and management of all contractors by [utility] personnel throughout the year.
100% audit of all vendor work, vendor flexibility in scheduling to maximize their productivity, incentives for exceptional on-time delivery of quality work.
Weather, Customer Relations, Equipment Reliability
1. Great contractor leaders and trained, dependable personnel; 2.   Small, but excellent internal team; 3. Sufficient budget funds to pay for quality contract help
Mowing the brush/trimming rather than chipping in the rural area mainly. The 55' back yard-lift to reduce manual climbing. Mini skid for removing brush/trimming from back yards and having the clam truck pick up brush rather than chipping. Job planners talking members rather than VM tree crew. -herbicides play a huge role.
1) Field-verify any unknown ticket work prior to crew dispatch. 2) Cycle customized to each VM area. 3) Assess VM areas several months prior to making a scheduled cut to allow for re-prioritizing based on actual field conditions
Targeted RE (time per primary tree unit includes associated brush & secondary) with quarterly payment adjustments Use of mowers and side trimmers where ever possible Backyard buckets and "bigfoot" aerial lifts to increase accessibility
Safety, planning, proper equipment (7 companies)
Adequate funding, quality work audits, resourceful management.
Inventory, safety and square meter contract
Getting consistency in all aspects of the program such as planning, work layout and end product delivery. Effective contracting strategy. Contractors that are committed to supplying resource to our programs.
Consistent workload over a year (number of trees consistent over the year). Long-term contracts (5 years). Incentive for reducing the number of trees that need to be pruned compared to a baseline quantity at start of contract. (reward for removal vs prune)
electronic inventory/prescription, electronic time keeping and invoicing, Google Earth mapping and pictures of work
Budget, inspections of work, and crews regularly
Close communication with the contractor, good supervision and well thought out planning
Adequate funding, quality work audits, resourceful management. (2 companies)
Contractor performance, Staff inspection of the work performed, Management of staff, contractors and budget
Pre-notification Incentive/Remedy Program Consistent workforce

Continued next page
(1) Receiving funding to meet our target Trim cycle, (2) Adequate funding to our Danger Tree Program (3) Knowledge transfer from retirees to new hires.
Logistics, labour rates, mechanization [Hydro One]
Weather, Resources and Planning
1) Accurate estimation of the resources needed to complete the 48-month work. 2) The right contractor management folks in place to make sure the work is managed most effectively/efficiently. 3) Experienced work force in regard to the tree workers themselves.

Table 23: Three things that are key to the efficiency of your UVM program

New Technologies Used in UVM Program

What new technologies have you introduced to your UVM program?
Unfortunately we are not a technology forward company.
Use of SAIDI information and outage tracking
We introduced at the start of the year a new GIS tree inventory program utilizing handheld iPad units that enables the inventory patrolmen to digitally inventory the tree with GPS placement, updated inventory count, pertinent notes related to the site, and GIS mapping capability for QC work of the tree crews in real-time.
Mechanized hazard/danger tree removal, use of Hiring Hall crews, LiDAR trial [Hydro One]
Electronic work planning (7 companies)
GPS data collection for patrol inventory of vegetation
Electronic data (computer and GIS based work management systems.
LiDAR is being used for transmission inspection, and we are testing its use for distribution.
Trying to get away from Paper maps. We are attempting to email all maps to GF's in the field. Many of our Company Forester's can make updates to the map in the field and send directly to our contractors. All OC's have mobile offices in their trucks and we're looking at going to a tablet.
Pilot TGR program. Electronic timesheets and production trackers. New UVM software to be introduced possibly late in 2016.
Electronic inventory/prescription, electronic time keeping and invoicing, Google Earth mapping and pictures of work
Work management system, electronic invoicing, new equipment technology (new type of whole tree chipper, new type of mower, cranes. etc) herbicide application (plus starting TGR in 2016)
Lateral Pruning, Herbicide Treatment
1. Skid-steer with forestry cutter; 2. Mini back yard Jaraffe; 3. Organized herbicide program; 4. Clear, simple expectations
Inventory software - back yard lift 55'- Quick trim where possible

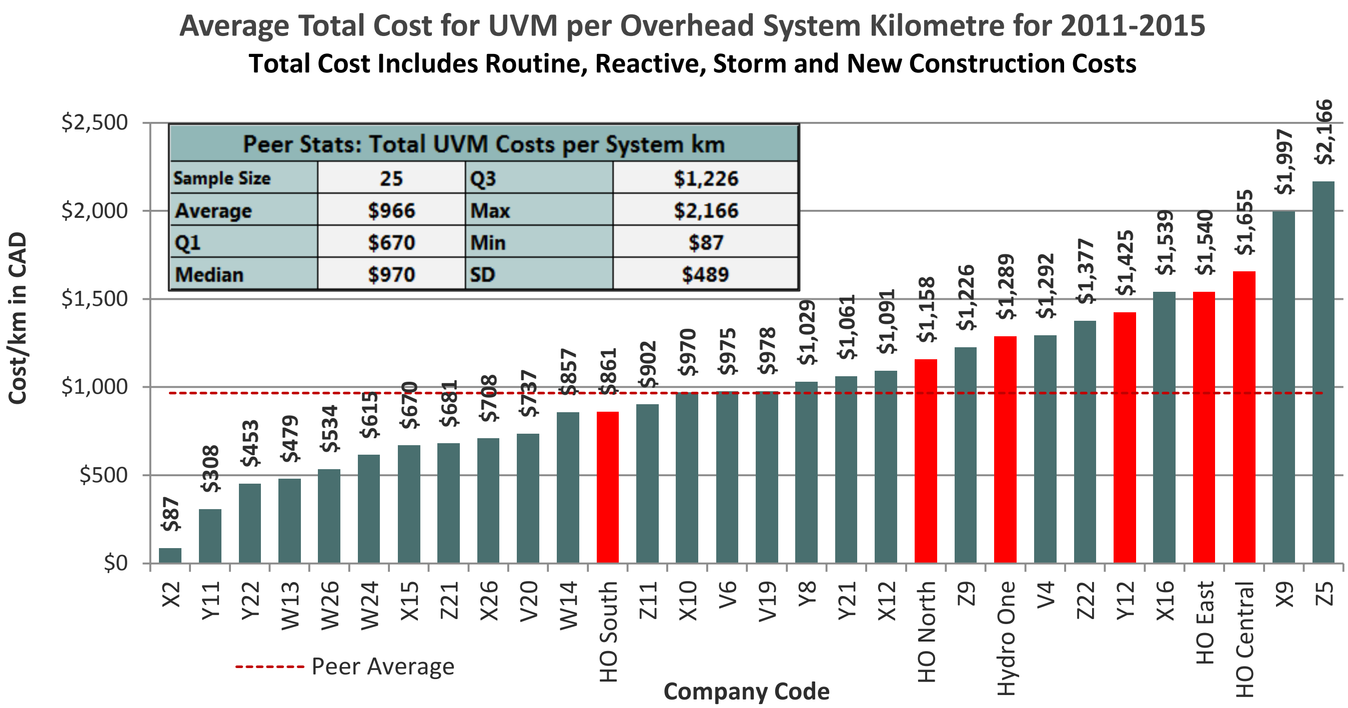
Table 24: New Technologies

Predominate New Technologies in the order of times mentioned:

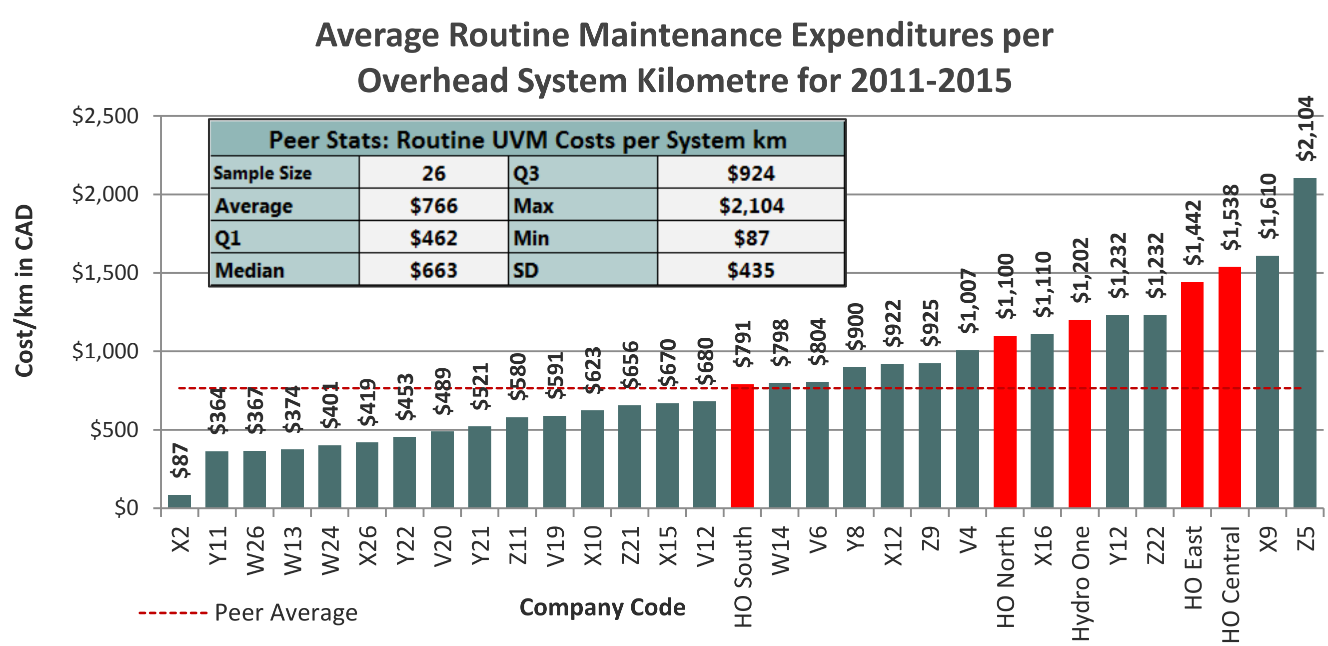
- Software for data collection, inventory, and work-planning, which may also include electronic mapping capabilities
- Mechanization and UVM equipment technologies
- LiDAR and remote sensing technologies
- Herbicide

FINANCIAL AND LABOUR HOUR COMPARISONS

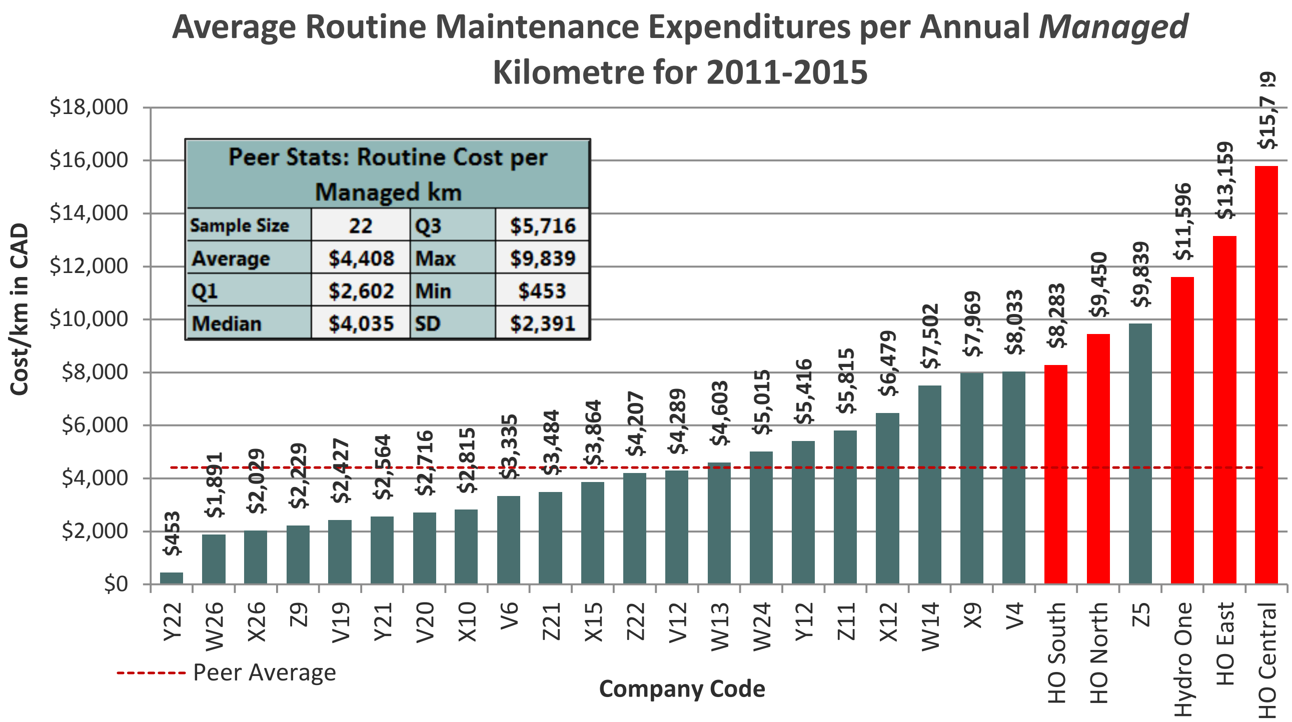
UVM Expenditures



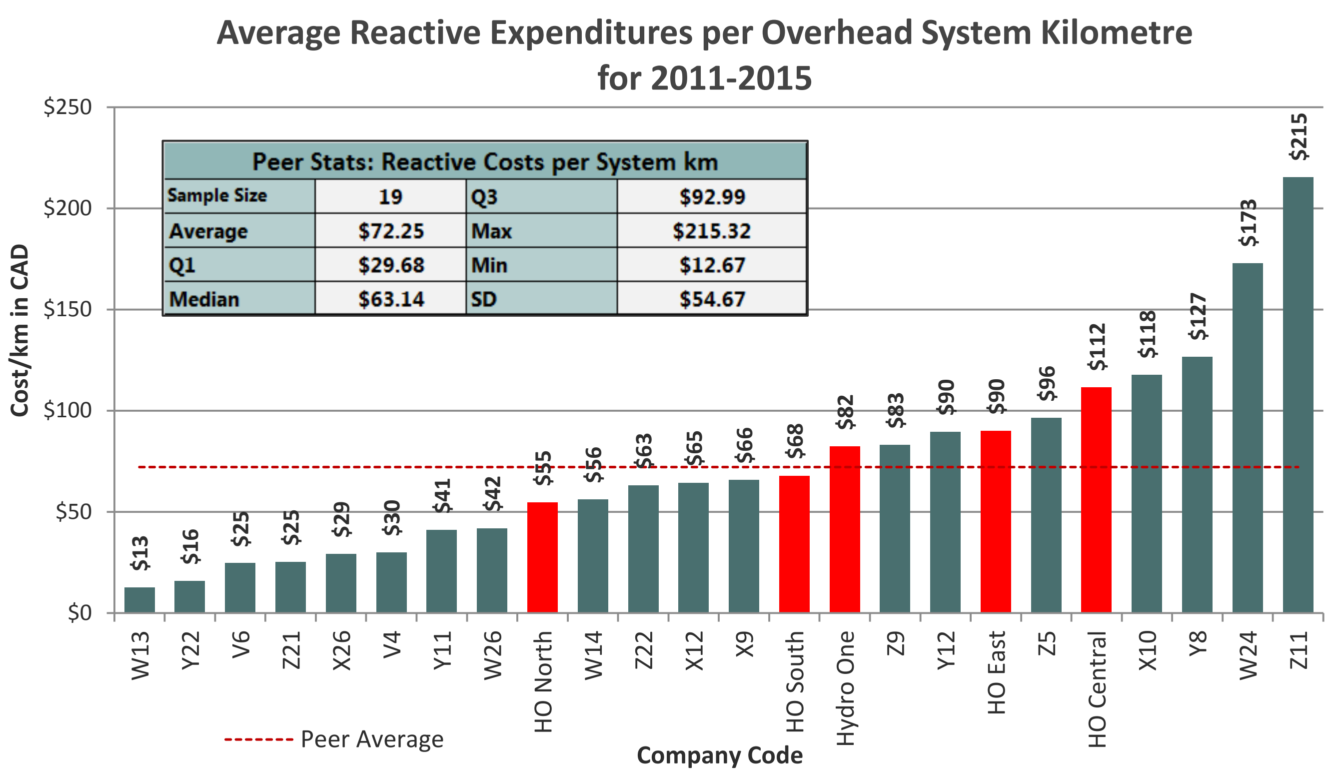
Graph 74: Average Total Cost for UVM per Overhead System Kilometre for 2011-2015



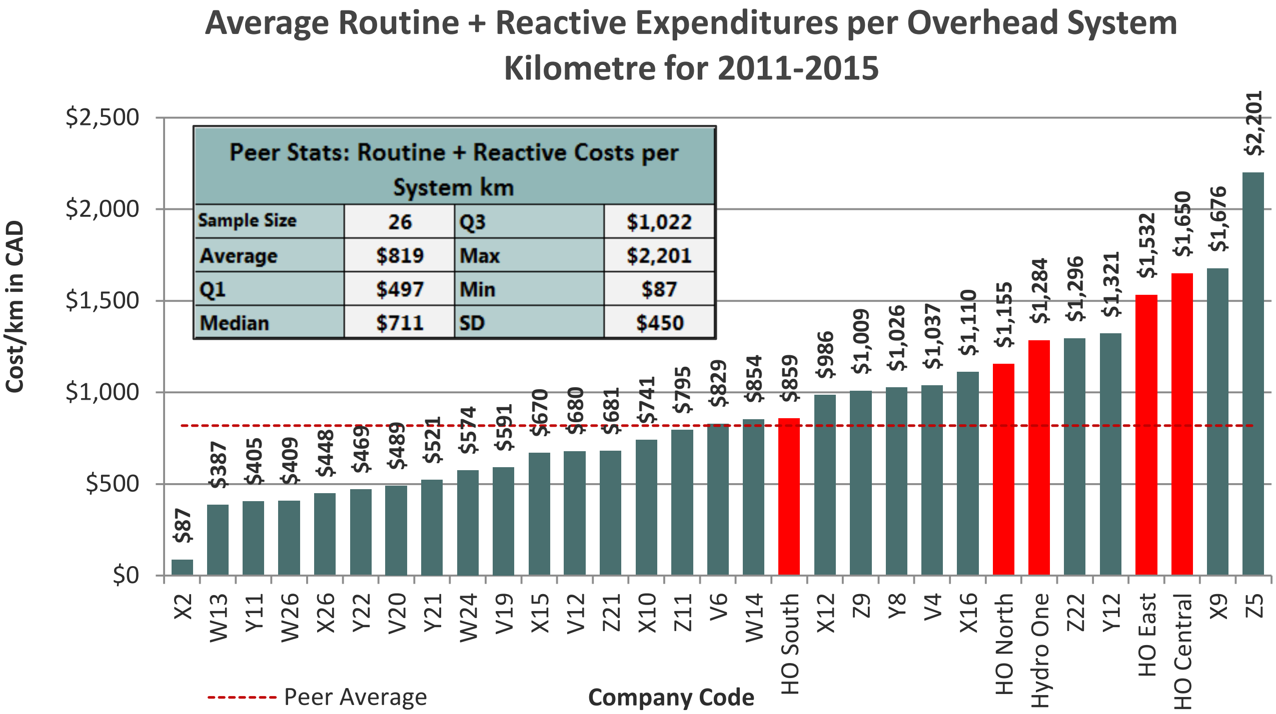
Graph 75: Average Routine Maintenance Expenditures per Overhead System Kilometre for 2011-2015



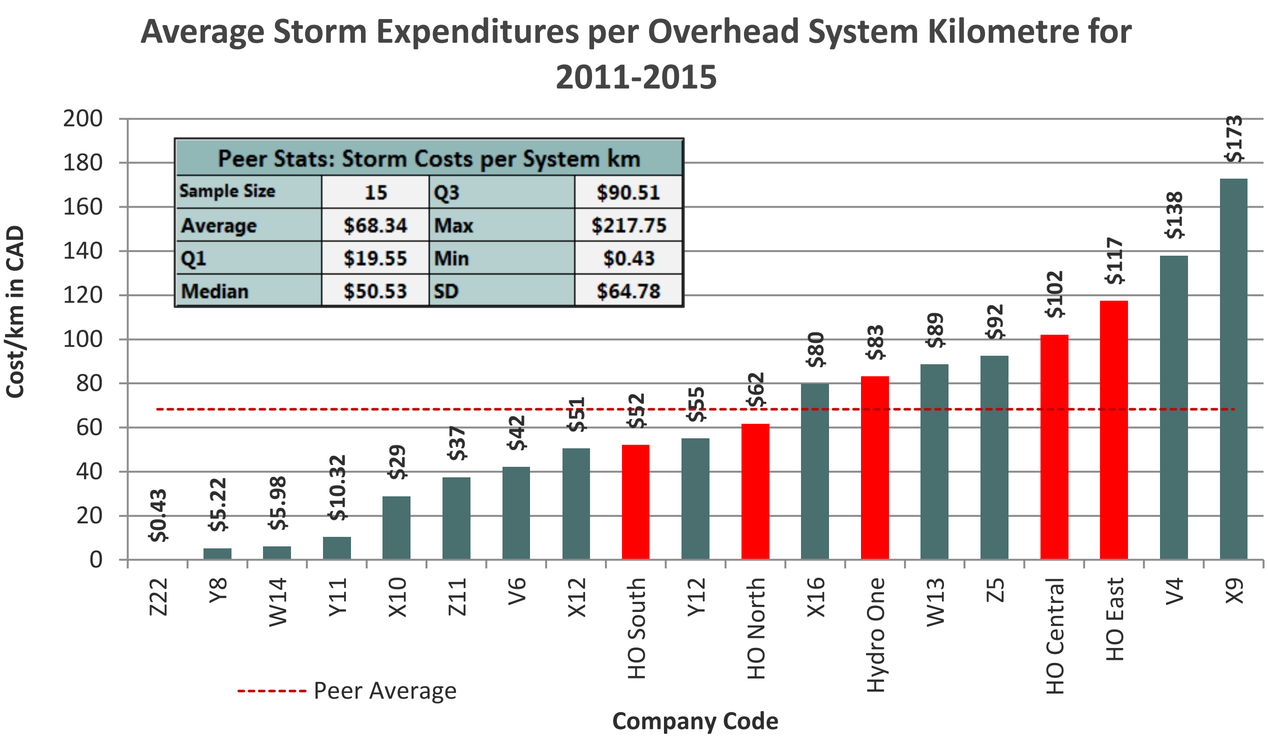
Graph 76: Average Routine Maintenance Expenditures per Annual *Managed* Kilometre for 2011-2015



Graph 77: Average Reactive Expenditures per Overhead System Kilometre for 2011-2015

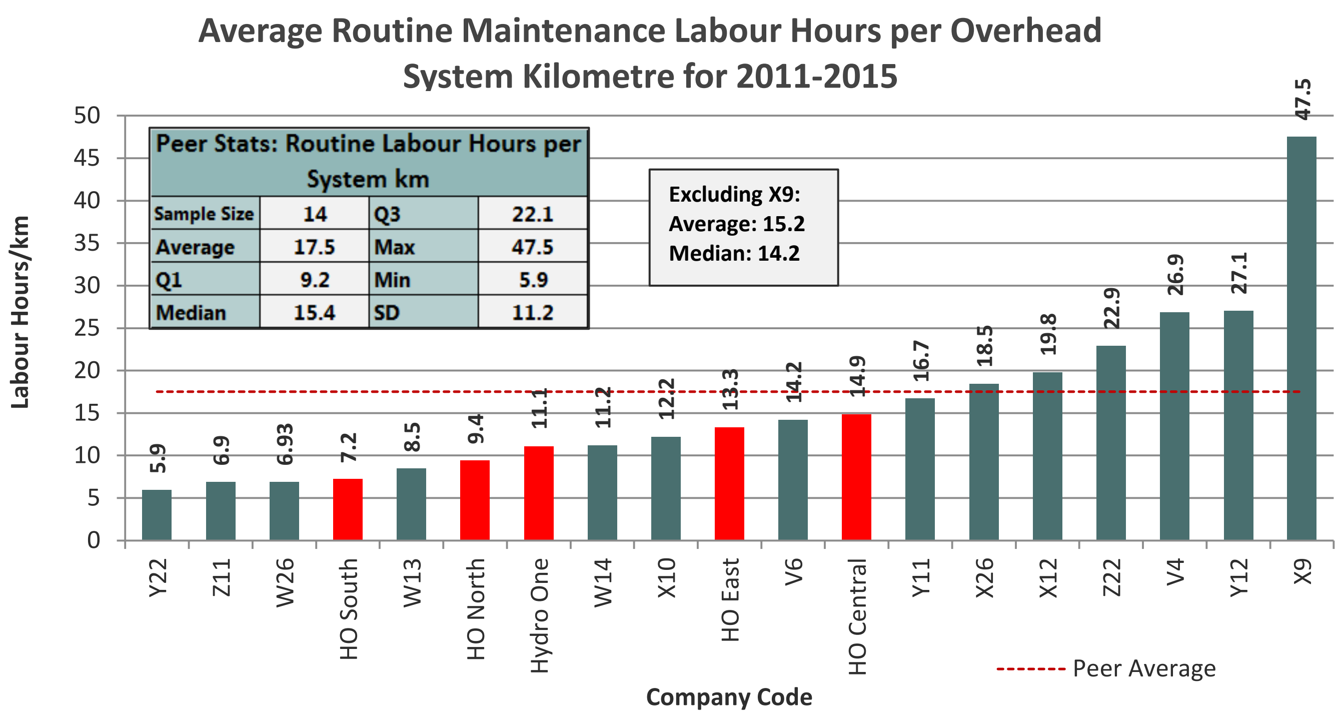


Graph 78: Average Routine + Reactive Expenditures per Overhead System Kilometre for 2011-2015

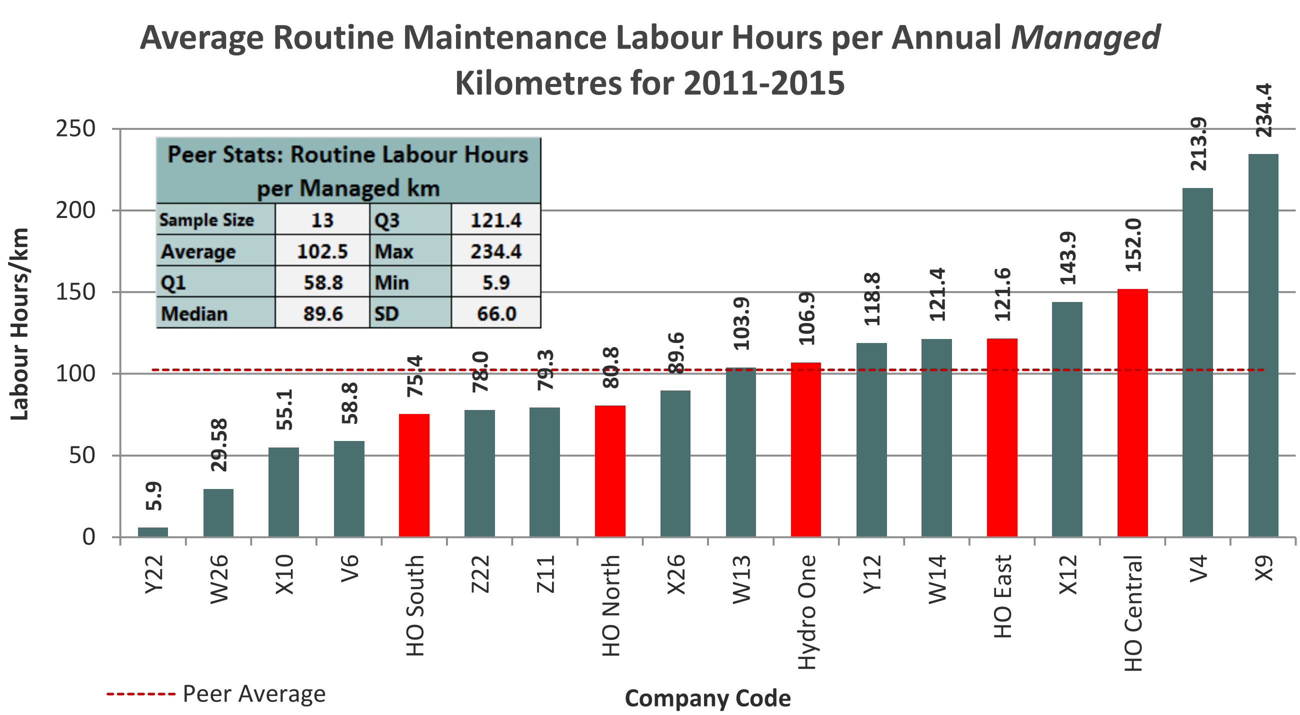


Graph 79: Average Storm Expenditures per Overhead System Kilometres for 2011-2015

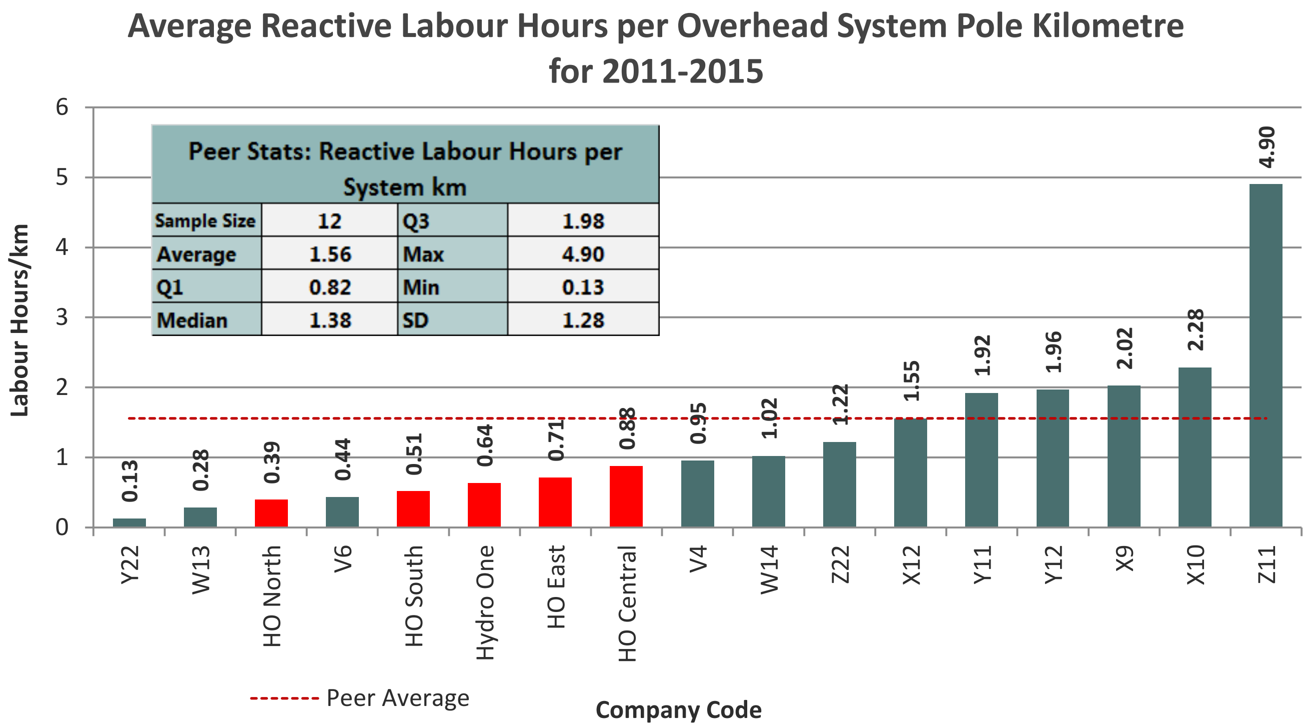
Labour Hours Expended on UVM



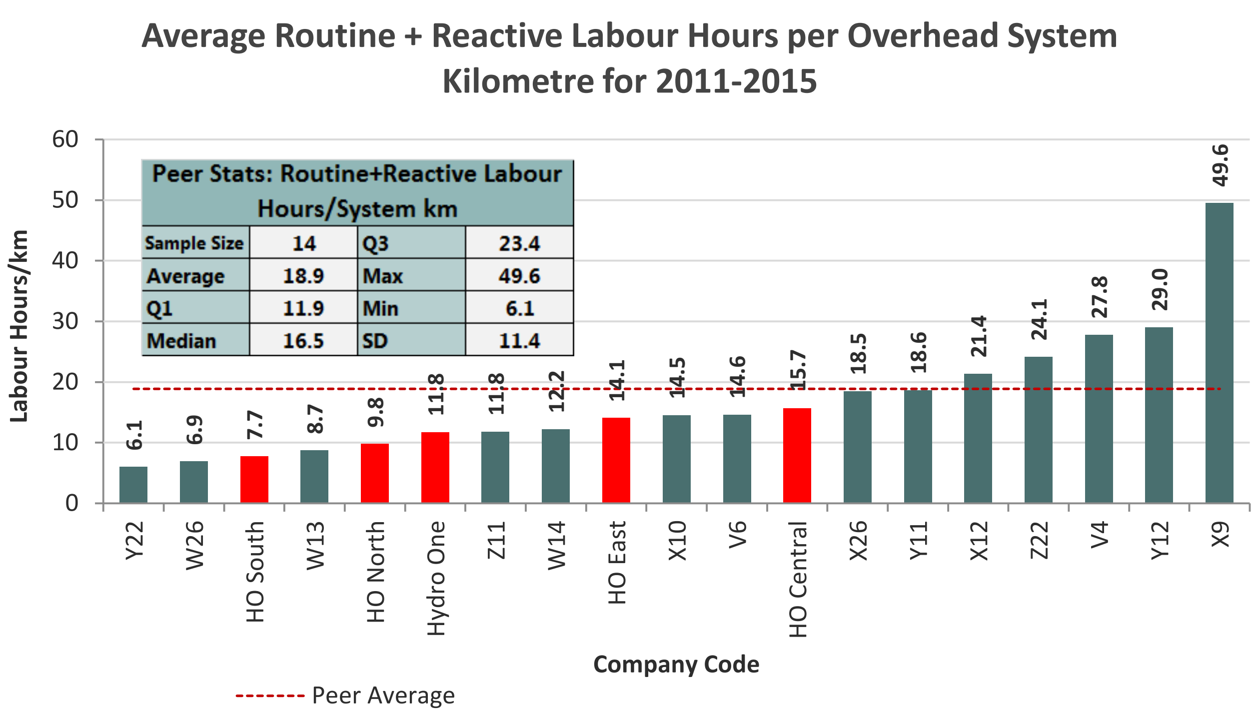
Graph 80: Average Routine Maintenance Labour Hours per Overhead Distribution System Kilometre for 2011-2015



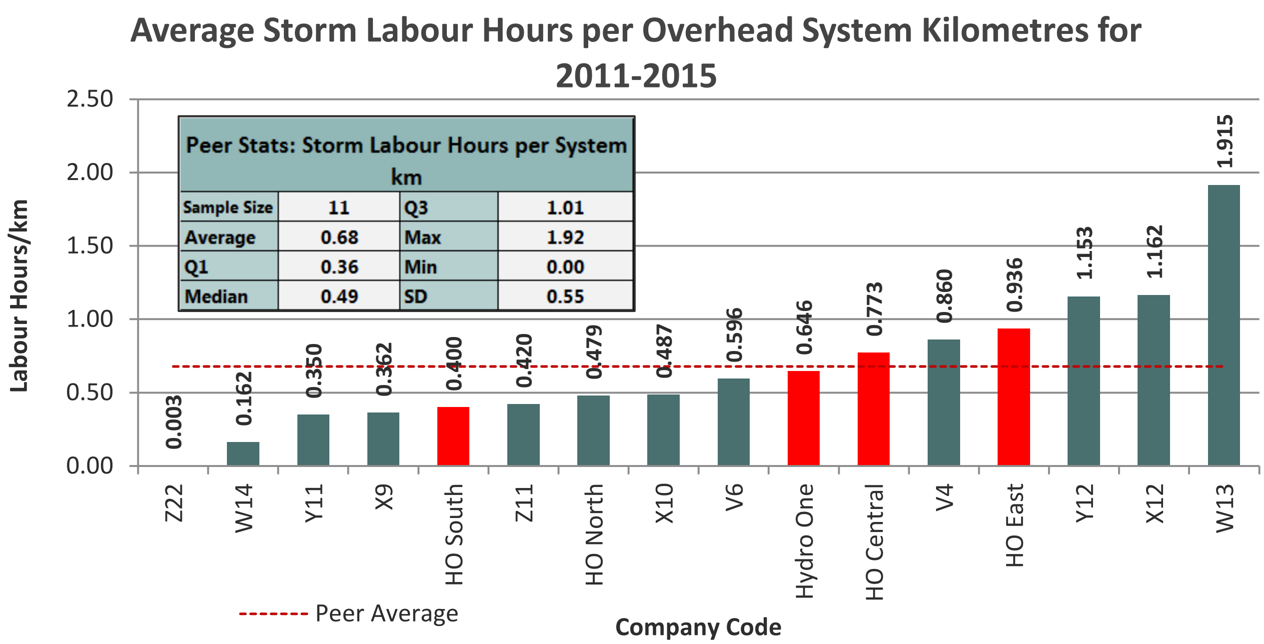
Graph 81: Average Routine Maintenance Labour Hours per Annual *Managed* Kilometres for 2011-2015



Graph 82: Average Reactive Labour Hours per Overhead System Kilometre for 2011-2015

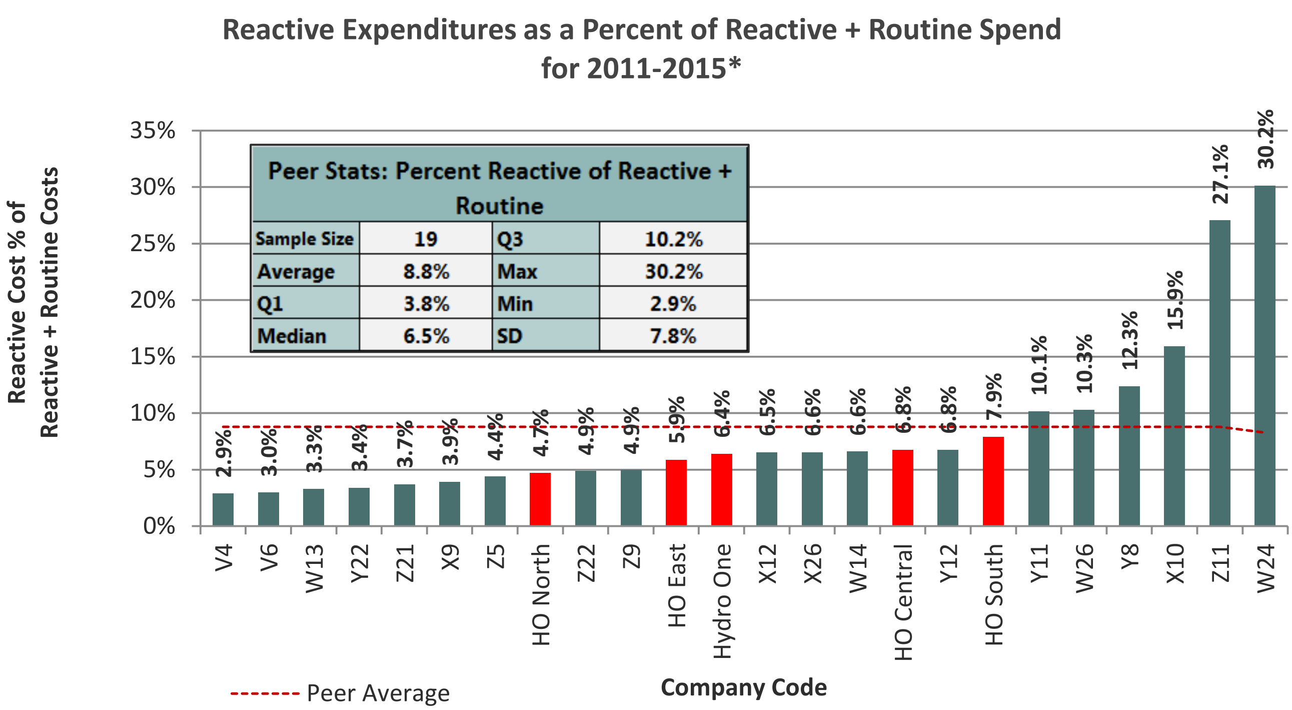


Graph 83: Average Routine + Reactive Labour Hours per Overhead System Kilometre for 2011-2015



Graph 84: Average Storm Labour Hours per Overhead System Kilometres for 2011-2015

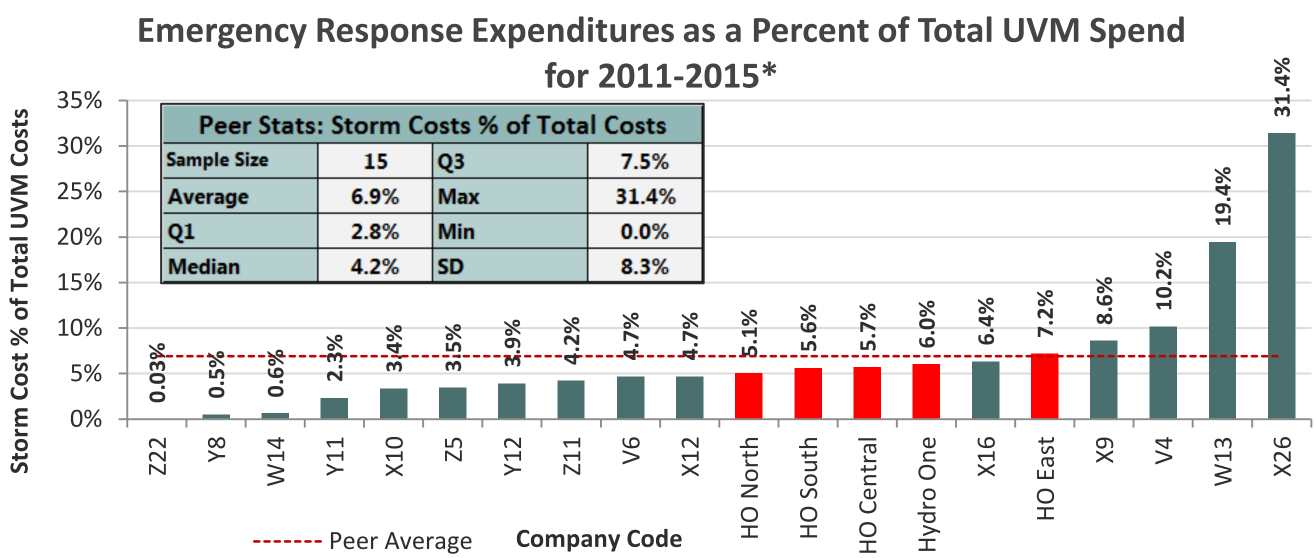
Reactive Work Expenditures as a Percent of Reactive and Routine Maintenance Costs



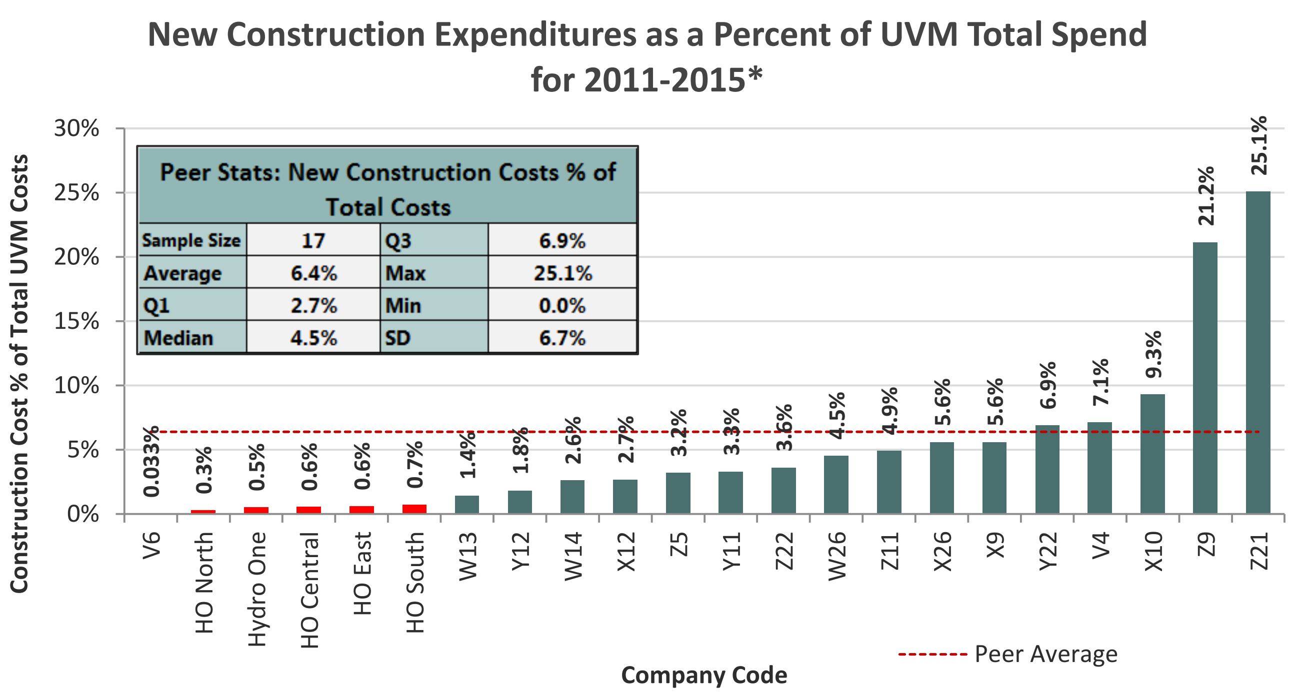
Graph 85: Reactive Expenditures as a Percent of Reactive + Routine Spend for 2011-2015

Percent of Total UVM Spend

*The following graphs were derived by adding the reported expenditures *for Routine Maintenance, Reactive, Emergency Response,* and *New Construction Work* costs to derive the "Total Spend." This "total" may vary from reported *Total UVM Expenditures* reported by the respondents due to the way costs are accounted for each utility. Some utilities included overheads, excluded storm and/or new construction since these expenses are not part of the UVM budget. Therefore, to equalize "Total Spend", CNUC added the costs of each work type.

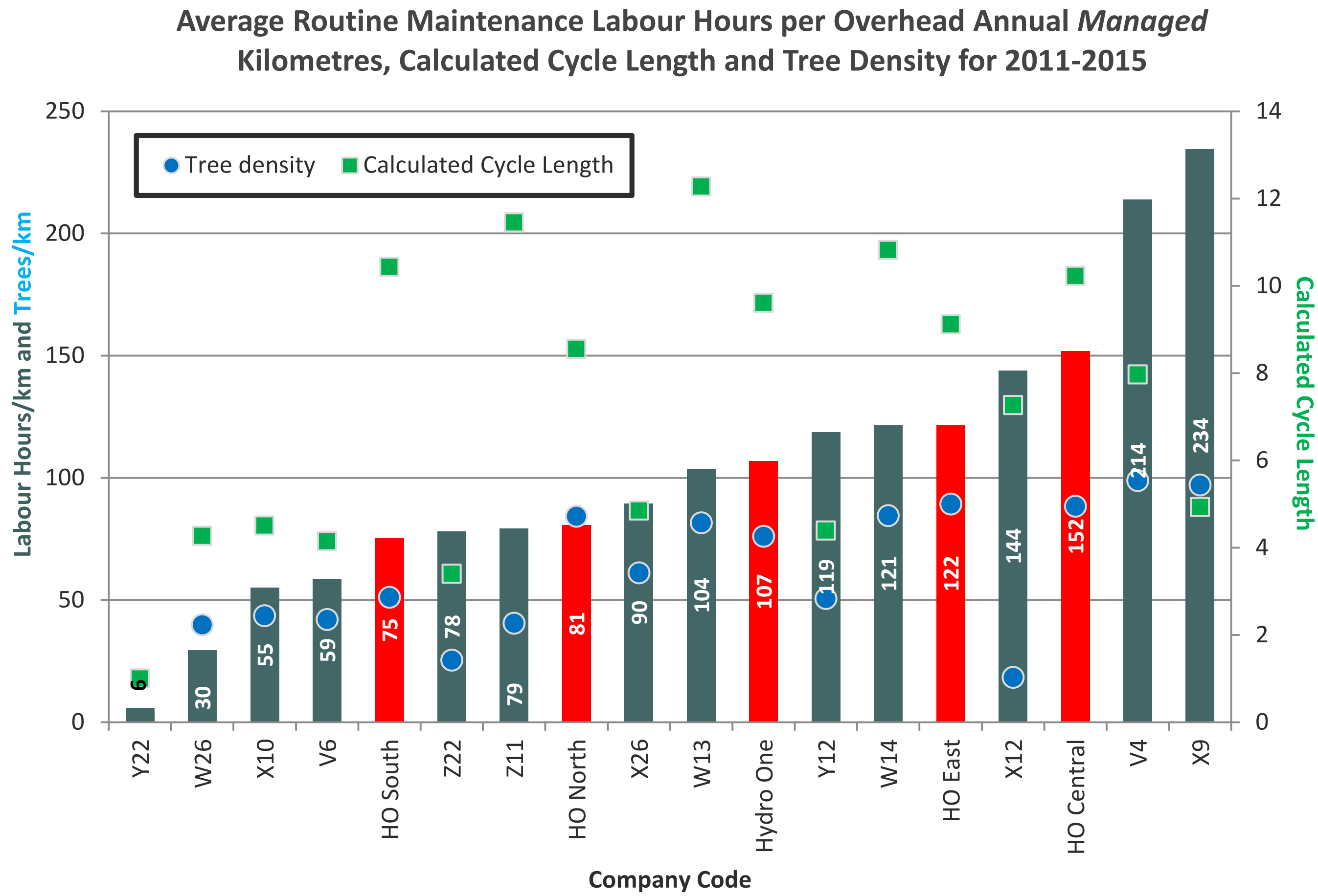


Graph 86: Emergency Response Expenditures as a Percent of Total UVM Spend for 2011-2015*



Graph 87: New Construction Expenditures as a Percent of UVM Total Spend for 2011-2015*

Labour Hours per Kilometre, Tree Density, and Cycle Length



Graph 88: Labour hours per Kilometre, Tree Density and Calculated Cycle Length*

A good correlation (0.7480) exists between tree density and actual cycle length ($p<0.002$). This analysis left-out X12, since this company has high calculated cycle length (143.9) with low tree density (18.3 trees/km). X12 is mitigating a tree mortality epidemic at present, which is affecting management scheduling. Although the reason for this correlation can only be guessed, CNUC believes that the longer cycles are allowing in-growth which produces a larger workload.

A good correlation (0.66656) exists between tree density and labour hours per km ($p<0.005$). This analysis left-out X12, since this company has high labour hour expenditure (143.9) with low tree density (18.3 trees/km). X12 is mitigating a tree mortality epidemic at present, increasing the current workload.

*Cycle length was calculated from information collected for 2011-2015 using the following calculation:

$$Calculated\ Cycle = Average\ \frac{Routine\ Labour\ Hours}{Annual\ Managed\ km} \div Average\ \frac{Routine\ Labour\ hours}{System\ km}$$

PRODUCTIVITY MEASURES

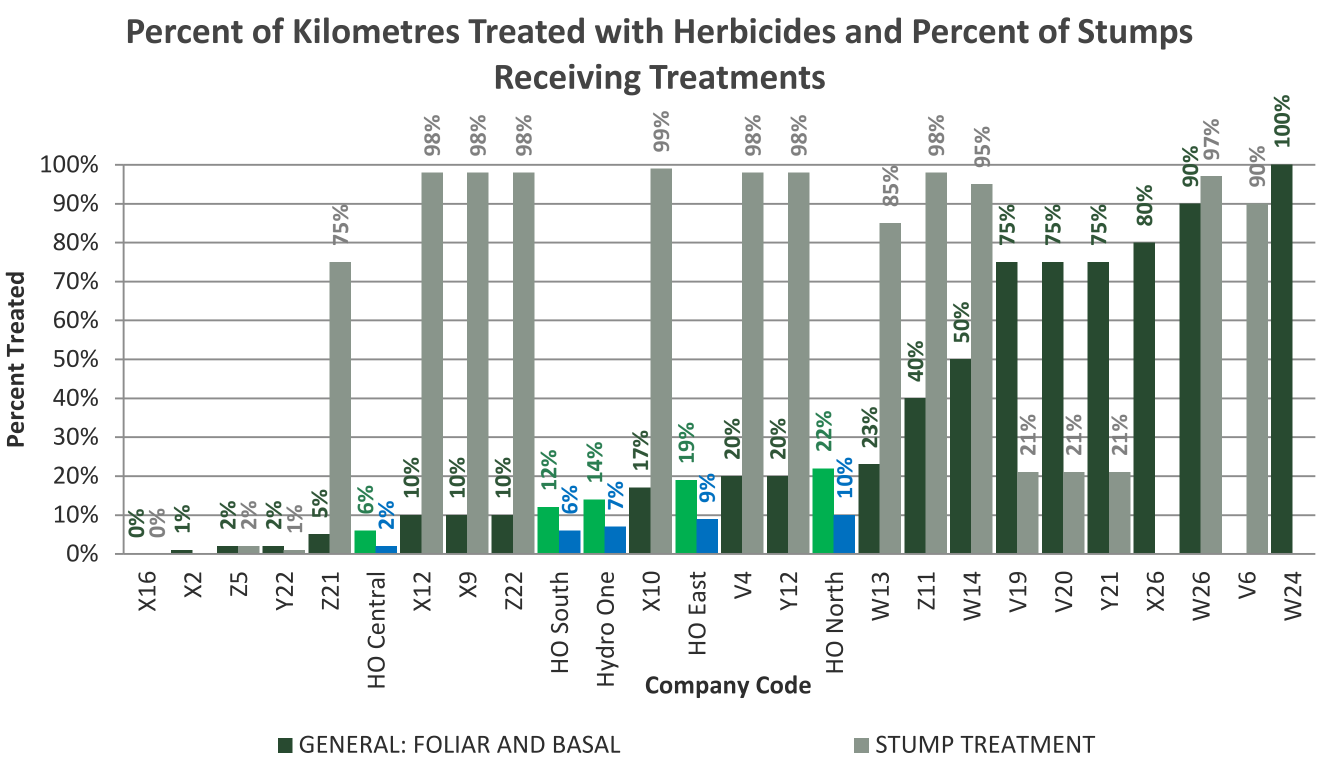
Herbicide Use

Participants were asked, "On average, what percent of the annual managed km (miles) of distribution ROW receive herbicide treatments to eliminate the in-growth incompatible species (excluding stump treatments on established trees)?" for GENERAL application methods (e.g. foliar, basal, etc.). They were also asked, "What percent of stumps from removed trees are treated with an herbicide to prevent re-sprouting?" for STUMP TREATMENTS.

Peer Group Statistics (Sample size: 21):

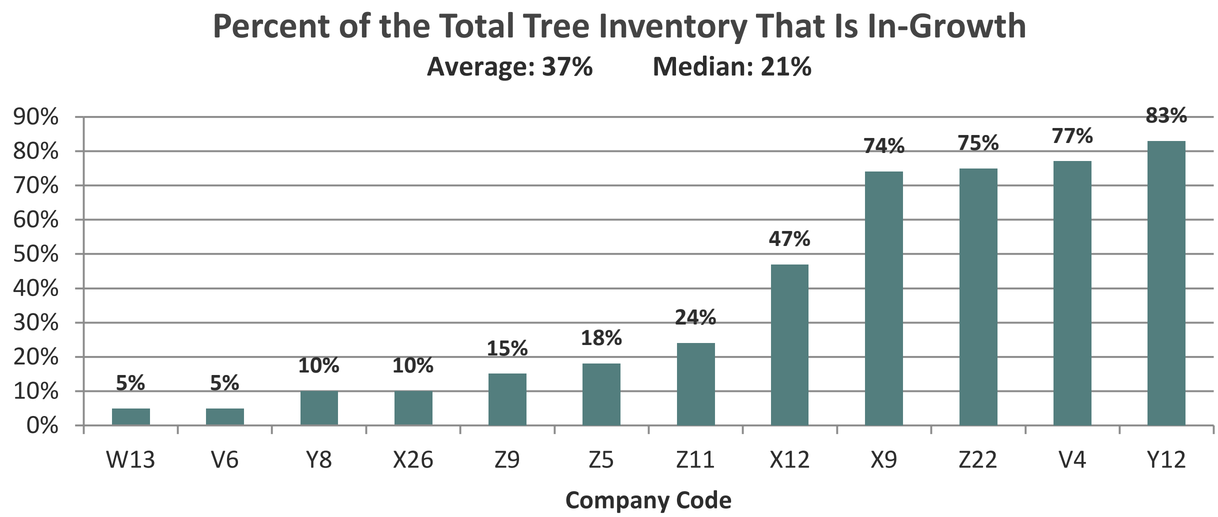
Herbicide Use					
	GENERAL	STUMP		GENERAL	STUMP
Average	35%	66%	**Q3**	75%	98%
Q1	9%	21%	**Max**	100%	99%
Median	20%	93%	**Min**	0%	0%

Statistics Table 6: Herbicide Use - Peer Group Statistics



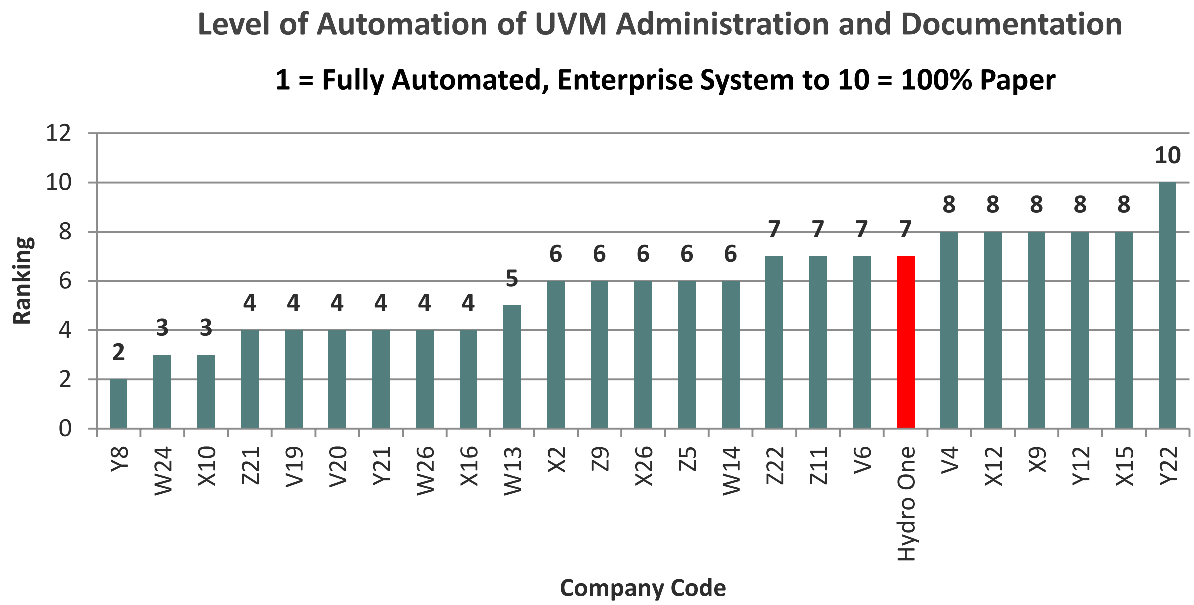
Graph 89: Percent of Kilometres Treated with Herbicides and Percent of Stumps Receiving Treatments

In-Growth Estimates



Graph 90: Percent of the Total Tree Inventory That Is In-Growth

WORK-PLANNING, PRE- INSPECTION AND AUTOMATION



Graph 91: Level of Automation of UVM Administration and Documentation

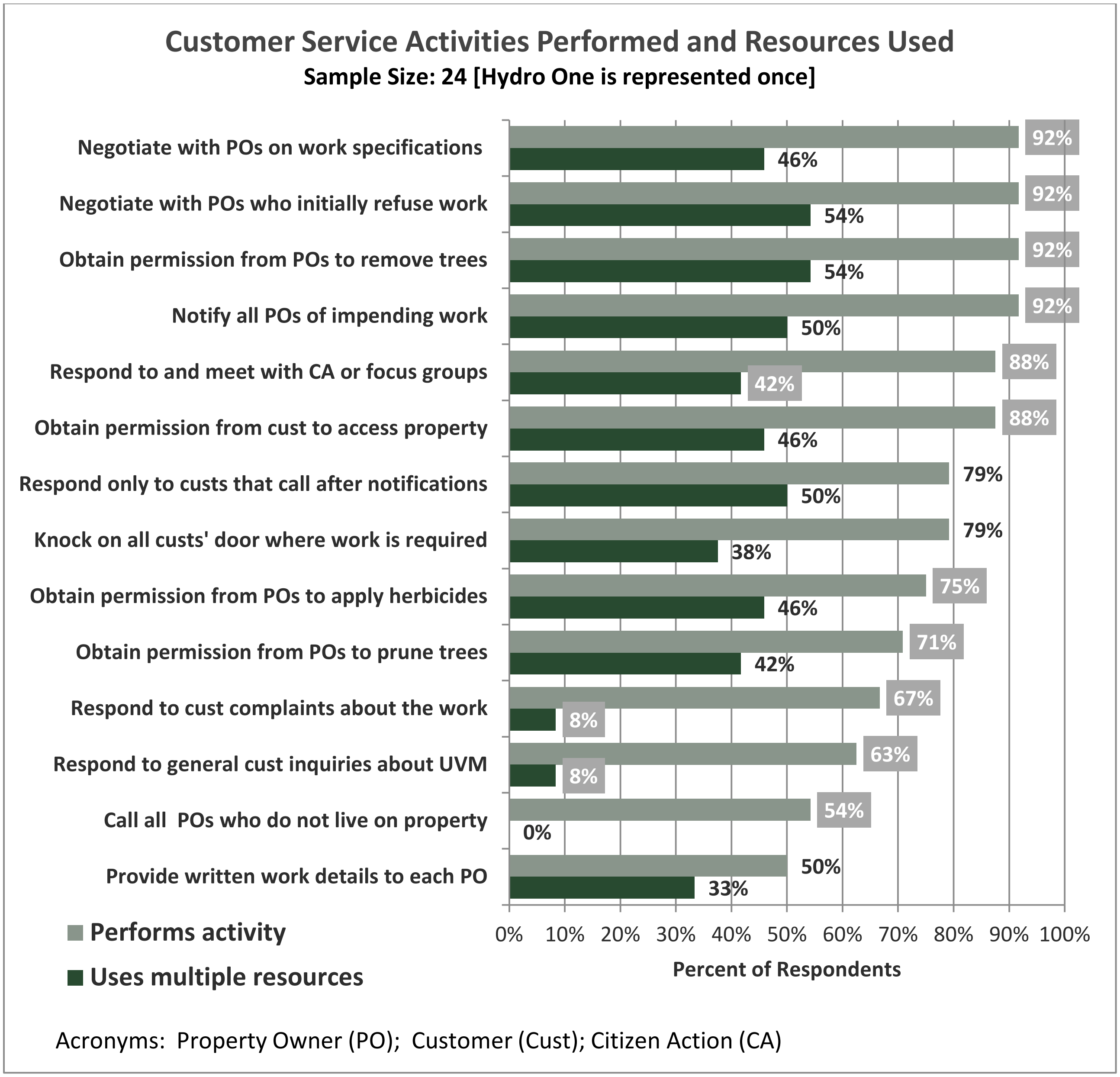
CUSTOMER SERVICE

Customer Service Activities Performed and Number of Resources Used

Survey Participants were asked the following question:

> If you have foresters, preplanners, workplanners, notifiers or auditors included in your distribution UVM program, choose from the following the types of customer communications that these individuals perform as parts of their routine work.

Resource choices were: Notifier, In-House Forester, Consulting Utility Forester (CUF), Line Clearance Planner, Automated Technology or Other. *NOTE: PO = Property Owners*



Graph 92: Customer Service Activities Performed and Resources Used

Customer Relations

Data Collection for Customers that Require UVM on their Property

Peer Utilities and Hydro One networks were asked, "Do you keep records on customers who respond to notification and refuse to allow the planned UVM work?"
Sample Size: 26
Yes 58% [Hydro One responded Yes]
No 42%
One participant said that a database was being developed.

Public Understanding of UVM

Peer Utilities and Hydro One networks were asked, "Do you think there is a "disconnect" (lack of understanding) between industry standards and what your customers/property owners and local agencies require you to do when performing UVM?"
Sample Size: 26
Yes 92% [Hydro One responded Yes]
No 8%

If yes, to what extent and what are the typical issues?
People in [state] love their trees and don't particularly care if we need to remove a tree for reliability or prune a tree to obtain clearance for an entire cycle.
Typically, the opinion of the customer is that we are doing too much work to the tree, or should be leaving the tree / brush alone altogether. Just take a little and come back more often.
General lack of knowledge of state and local guidelines (6 companies)
Only for difficult customers
Most of our customers don't realize there is a service guaranty/contract approved by [PUC] giving us the right to trim/remove trees.
Virtually all utilities operated a dual clearing standard; say 10 feet plus ANSI A-300. It is the ANSI A-300 portion which seems to always lead to misunderstanding.
Don't understand why the tree was trimmed in the manner it was- trimming is performed for clearance from the conductor, not aesthetics.
They do not always understand why we must trim certain trees as we do. Especially the u or v shape cuts made for trees directly under the line. This technique in their eyes is butchering a tree.
Public does not understand the wire-tree conflict issue
It doesn't really affect our operation in terms of getting things done, but the issue continues to be why we trim as much as we do and why we trim using the "natural" method of pruning to direct growth away from the lines.
There is a disconnect regarding the customers don't like the looks of industry standards pruning, but we don't do anything else. They don't "require" us to do something different.
Continued

Customer refusal tab in Tech notification software (Forestry Application Production) where the info about customer refusals is captured. [Hydro One]
It's getting better and better, but in general: Our pruning cycle is often perceived too long, and the result of the activity, too intense. We can also report that our various [customers] grant to trees a very different importance accordingly to their origin, or their culture. As an example: the urbans are more sensitive to the tree than the countryman; the English speaking are more sensitive than French speaking. And urban moved in the countryside wishes a quality of service [as] impeccable as in the city while keeping the forest character of his new environment. Quality of the electric service: the complaints of this nature are among the most numerous but the subject is not carried in the media. Quality of the work done: the aestheticism of the pruning is the object of less numerous complaints but more frequently carried in the media; Also [leaving] debris is the object of complaints.
Typically concerned customers do not want healthy trees pruned to our standards. They do not understand the impact on public safety and reliability when trees are not trimmed to standard. On the other hand when trees are in decline they think it is the Utilities' responsibility to remove the trees at 100% our cost.
Prune to customers often means how they would annually trim their bushes. They don't understand the magnitude of the work. They also don't understand that their small "tree" we call brush. Customers often don't understand how power [electricity] works and that their property's trees can potentially affect thousands of people's power.
Lack of education and public relations by not only the utilities but also by the government agencies themselves.

Table 25: Descriptions of Customer Understanding about UVM

SAFETY AS A PRIORITY

Tracking Safety Metrics

23 peers and Hydro One Networks answered the question, "Do you track safety metrics?

- 92% responded **"Yes"**
- 81% responded **"Yes"** for the industry-wide sample (31 companies)

24 companies (industry-wide sample) *described* how they track safety. The following is a summary of their remarks:

- All utilities monitored *worker* safety by tracking incidents (accidents) and some of the respondents included contractor-caused outages, vehicle incidents, and non-reportable incidents in their statistics.
- Six companies used a web-based program that contractors can access to enter incidents and calculate safety statistics.
- Several have quarterly meetings and have contractors submit logs.
- Two companies ask for near-miss reports.

Only three companies (one of them is Hydro One) had more extensive monitoring. Their comments follow:

- Weekly safety audit are required and tracked through the Supervisor safety and accountability program along with internal Safety specialists and ISN
- We have a safety department within our UVM that tracks incidents and non-compliances of not only our contractors but of our own department as well. Additionally, we conduct monthly safety meetings as an entire department and require annual training of all personnel.
- ***Hydro One- Forestry*** has a number of metrics to track safety of the UVM program. Key focus is reducing High Maximum Reasonable Potential for Harm type incidents and total recordable injuries among other things. The other safety metrics that are constantly monitored are reducing Preventive MVAs, Electrical contact, Musculoskeletal Disorder Injuries, slips, trips, falls, Contact with Sharp Objects, Fall from Heights & Stuck by Falling objects

Other Metrics Applied to Safety

When asked, "**Do you have other measurements that you utilize to measure safety achieved by your UVM program?**" 22 peers and Hydro One Networks responded:

- **43% Yes**
- **57% No**

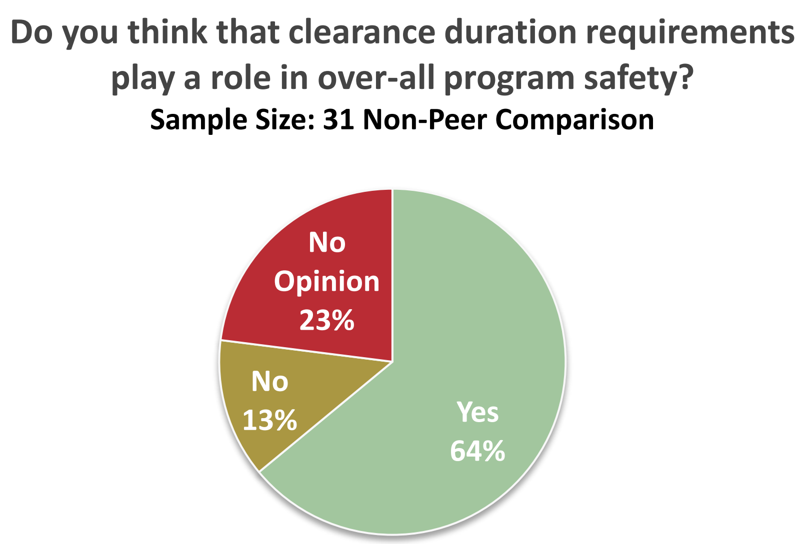
Once again, most of the monitoring was done on incident rate. See comments that follow.

Measuring Safety
We track Total Recordable Injuries per 200,000 hours worked. We also develop on an annual basis Forestry Health, Safety & Environment Initiatives – Prevent Struck by Injuries from lodged tree, Prevent fall from height, eliminate injuries from electrical contacts and off road MVA incidents. We are also meet OHSAS: 18001. [Yes – Hydro One Response]
Any quarter of the year with a lost time recordable injury or a crew caused outage removes that quarter from consideration for Performance Incentives (paid holidays) -Any year with 5 or more injuries or outages (combined) will require a meeting regarding safety process/procedures and an action plan to reduce these incidents [No]
Incident rate, severity rate, DART rate, at fault vehicle accidents [Yes]
We monitor each contractor's RAI [Requests for Additional Information] and have a review with each vendor quarterly to review their safety record and performance records. [Yes]
Track contractor hours, incidents, and TRIRs [Total Recordable Injury Rates] [Yes]

Table 26: Measuring Safety

Safety policies

Clearance Duration Policies and Safety



Graph 93: Clearance Duration Requirements

Comments on the relationship between clearance duration requirements follow.

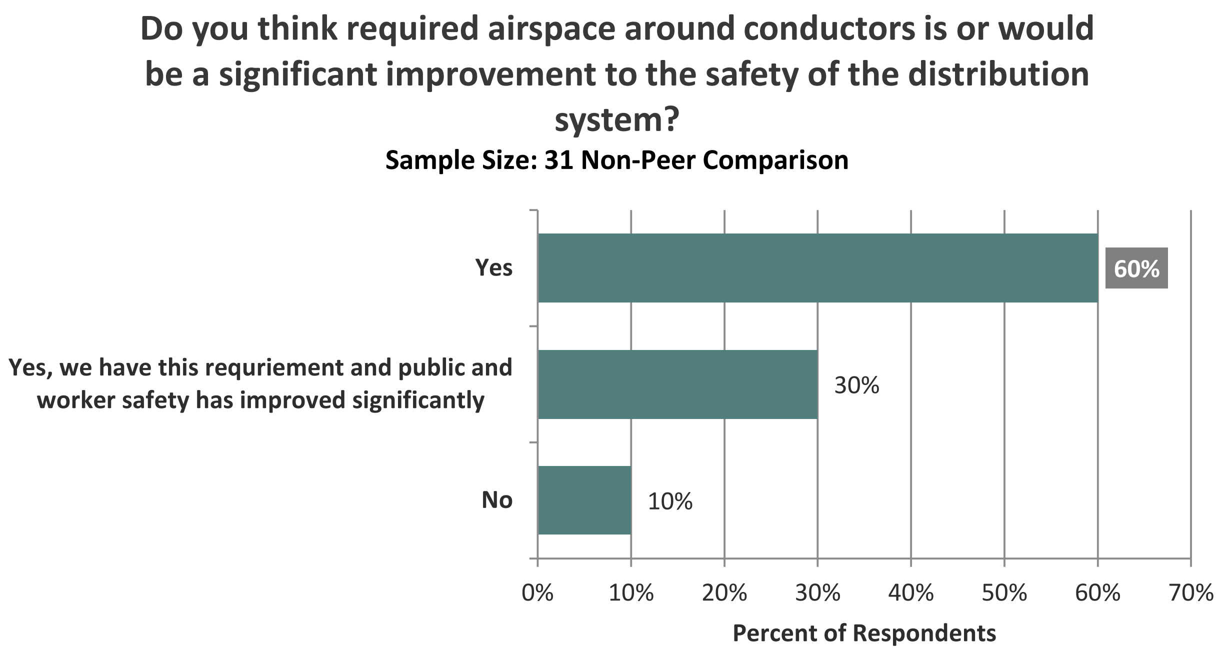
Clearance Duration Requirements and Safety
Longer cycles mean more tree/conductor contact and a higher chance of an incident [Yes]
Increased cycle length means increased exposure. [Yes]
Deferred vegetation maintenance becomes more difficult to deal with. I.E. increased encroachment to energized conductors [Yes]
I do believe that if the ROWs are not kept adequately clear, it can pose safety issues for those who have to work there. [Yes}
Not with our program. Even though we may be behind in cycles, the growth into primary conductors is not significant. The safety concerns (and potential outages) are elevated when it comes to open secondary lines, street light lines, and service drops. [Yes]
If clearance is poor, there is a safety issue with crews working around the wires. The more clearance around the wires at time of pruning, the more visible the wires, and the safer the program is. [Yes]
The farther we can keep our trimmers, vegetation and equipment away from energized lines, the safer all included are. common sense [No]
If safety practices are being thoroughly implemented, there should be no increase in accidents despite clearances. [No]

Table 27: Clearance Durations Requirements and Safety

Required Airspace between Trees and Conductors and Safety

Utilities were asked, **"Do you think required airspace around conductors is or would be a significant improvement to the safety of the distribution system?"**

90% of the industry-wide sample (31) agreed with this statement. See graph below (Each category is exclusive).



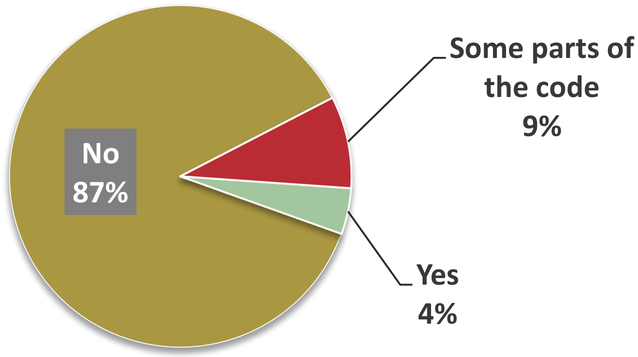
Graph 94: Required Airspace and Safety

Required Airspace and Safety Comments
Mandatory minimum clearances would likely triple our budget but our system would be safer [Yes]
There would be almost no change from what we do now [No]
We have no data to suggest that a required airspace would improve safety. It might increase production if there is less encroachment. There would be a significant increase in costs to achieve a required airspace [No]
I am not in favor of a required amount of clearance. I think clearances should be dependent on species, voltage, site conditions, etc. Maybe there could be a minimum required clearance. [Yes, with modifications]
Certainly couldn't hurt. [Yes]
IHSA requires 3' between conductors and trees to establish safe work areas for climbers. If the tree is within 3' the tree is a hazard. [Yes, Have requirement]
I'm leaning more towards the yes, but before I support it 100% it would be nice to see some research and results on the topic. [Yes]
I think anything coming from the ground, especially wet vegetation which can contact live high voltage conductors, produces a dangerous condition. [Yes]

Table 28: Comments on Required Airspace and Safety Comments

Wildfire-Urban Interface Code

Does your service territory have jurisdictions that have adopted the International Code Council (ICC) Wildland-Urban Interface Code (WUIC) for UVM?
Sample Size: 23 (Hydro One Represented once)



Graph 95: Adoption of the ICC WUIC for UVM

Wildfire Incidents

It should be noted that when peers were asked about fire incidents attributed to fires started by conductor and tree conflicts, several reported none, but they also reported that they had no metrics to track this.

Peers were asked, “Have confirmed tree-wire contact-caused wildfires occurred in your distribution system in the last decade?”
35% Yes
65% No [Hydro One answered **No**]

Fire Incidents in Service Territory Due to Tree-Wire Conflicts
We may have 6-10 small fires per year [Yes]
I know of one small fire contained to the tree and surrounding hedges. [Yes]
No metrics to track wildfires occurring from tree-to-wire contact [No –Hydro One response]
Several small fires (< 2 acres) over the last decade 8 acre fire in 2013 100 (?) acre fire in 2006 No fires the last two years [Yes]
Don't have a firm count, but we know we have caused wildfires in the past. Our climate is not conducive for large wildfires (Our Humidity is high), but during periods of severe drought, this is monitored more closely. [Yes]
We don't have that statistic. Any wild fire resulting from a tree contact is usually a tree fallen (off corridor) tree. We had several of these as a result of the Mountain Pine Beetle epidemic. [Yes]
1. Less than 2 acre grass fire/no structure damage [Yes]

Table 29: Fire Incidents in Service Territory Due to Tree-Wire Conflicts

Safety Training

Safety Training Initiatives Undertaken in Last Three Years
[Contractor] has one of the most intensive safety programs in the country. We allow them to do what they think is needed for safety, we never have to ask them to do more.
100% vendor function
Lodged tree training, heavy equipment training, and Herbicide application training. Foresters receive 30-40 hours of new training annually. [Hydro One response]
Require all contractors to have own safety program, including tailboards and regular safety officer visits. Contract initiation meeting includes review of the program and expected reporting to MH
Contractor KPI impacted by safety numbers, increased safety audits by the utility, training days provided as needed.
Vendors provide basic training, all have different programs.
No information available
We use a 3rd Party company to carry out our Power Safe training. These courses are entry level courses in reviewing the requirements to work for our Utility and we have created some job specific modules that are mandatory for our contractors to take. To take all courses it is about $100 per year per contractor employee and the trainings take about 4-6 hours.
Safety training is handled by the contractors. We do conduct Safety Seminars annually with our contractor's management folks, which cover a variety of safety topics. There is also a steering committee composed of both Ameren and contract employees.
Vendors with a reported caused outage had to undergo company safety mitigation steps to become qualified as a line clearance vendor again, and continue work.

Table 30: Safety Training Initiatives Undertaken in Last Three Years

Public and Non-Utility or Utility-Contracted Tree-Worker Electric Incidents

Survey participants were posed the following question:
OBJECTIVE: To determine the utility's awareness of electrical contacts which occur outside of utility managed line clearance operations. As many as 15-20 on the job electrocutions occur each year in the US that involve non-line clearance tree and landscape workers. It is estimated that there are more that involve the home owners or non-employed tree workers.
QUESTION: Which of the following apply to your company?
Sample: 21 (20 peer utilities and Hydro One Networks)

- The utility provides many public service announcements that discourage pruning or removing trees near powerlines and the utility requires notification to perform or determine approved vegetation management : **71% [Applies to Hydro One]**
- A rate of occurrence is unknown for electrical contacts involving vegetation, powerlines and non-line clearance workers or members of the public: **67% [Applies to Hydro One]**
- The utility company provides electrical hazards awareness training to non-line clearance arborists in the service territory: **19%**

- The utility does not frequently and/or effectively communicate the safety concerns of trees and power lines: **19%**
- The utility is alerted anytime an electrical contact is reported by the media: **0%**
- A study of non-line clearance tree companies has been performed by the utility to determine the percent of tree workers who have had electrical contacts: **0%**

One utility commented: The utility is notified of incidents, but **UVM is not alerted** of all incidents that occur.

State the number of known electrical contacts involving vegetation that have occurred in the utility service territory over the past 5 years:

- One utility stated “**0”**
- I don't know how many electrical contacts we've had in the last 5 years, but we have them occasionally. Probably not more than 1 or 2 per year. They are almost [always] a result of error on the part of the person contacting the system and not a result of poor maintenance or system defects.
- The rest stated that they do not know or the information is not available

Conclusion:
Electrical contact incidents involving non-utility workers or the public is not measured or available to the UVM department.

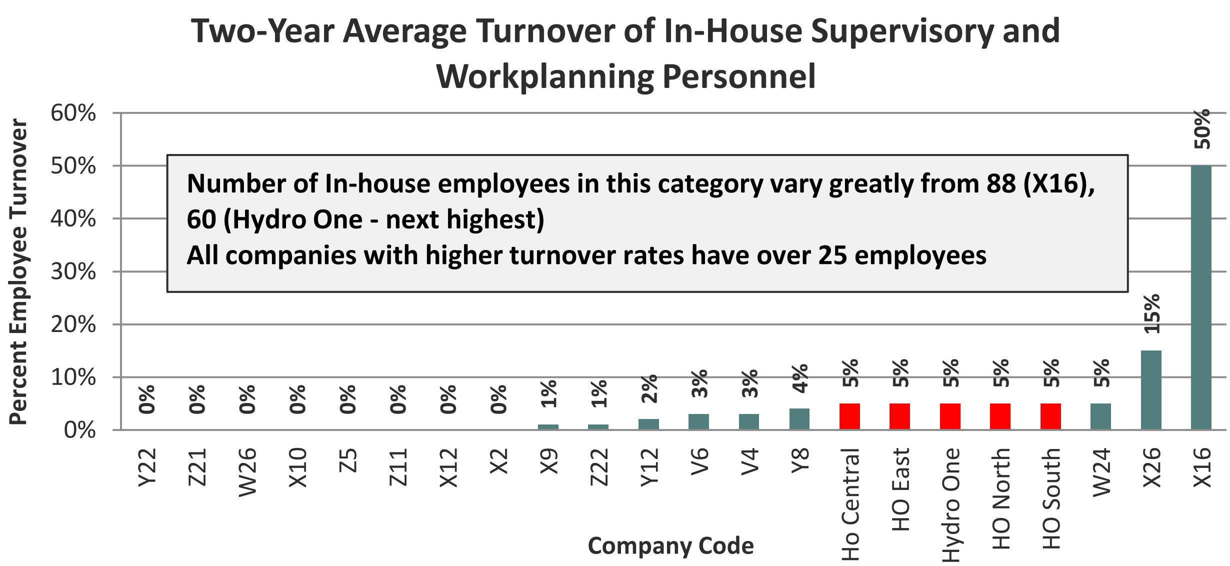
Safety Statistics

Employee Turnover

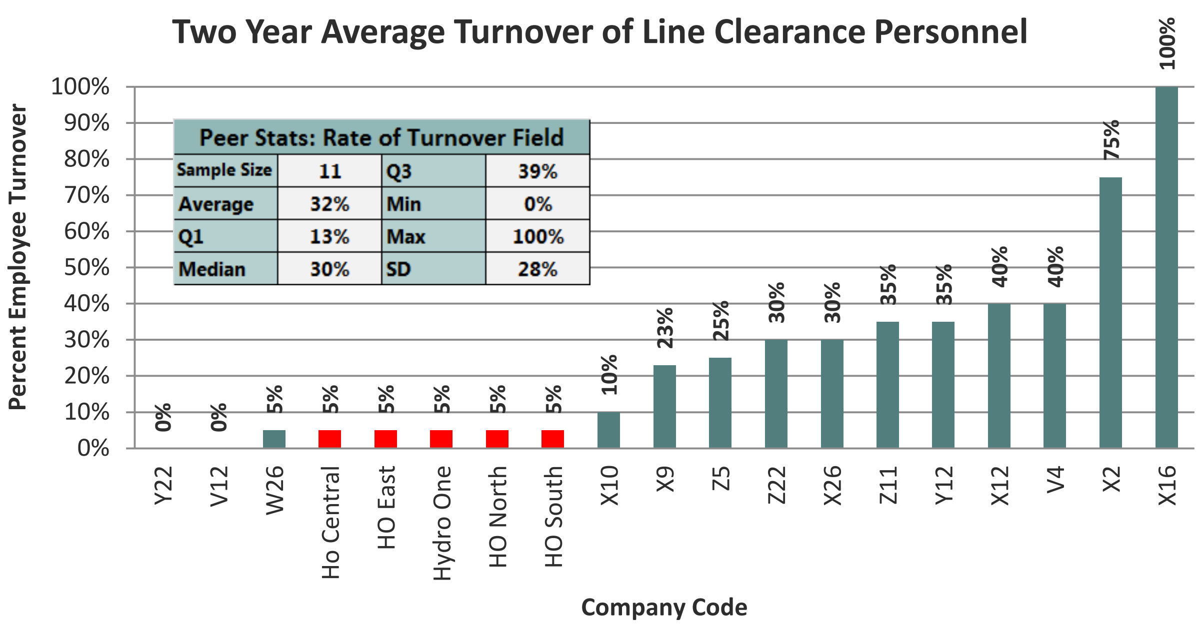
Since there is not a consistent way to measure safety in the UVM industry other than incidents, which are lagging indicators, CNUC looked at employee turnover as an gauge of a safety culture.
The following two quotes identify that employee turnover can be used as a safety measure:

> *While there are certainly more precise and scientific measures of safety culture, I believe that turnover rates provide the best quick, easy, and cheap “snapshot” of an organizations’ culture. — Dave Weber, a former Safety and Environmental Manager and founder of Safety Awakenings*
>
> *When temporary workers have to be continually replaced, their impact on profitability includes: . . .*
>
> - ***Safety** (Bureau of Labor Statistics [shows a correlation between] accidents and safety violations increases proportionately to employee turnover) . . .*
> - ***Training . . .***
> - ***Productivity . . .***
>
> http://www.insourceperforms.com/news/employee-turnovers-impact-on-your-budget

Since Hydro One is the only utility in the survey (and there are very few in the industry as a whole) that performs UVM completely in-house, the turnover rates are divided into in-house (non-clearance activities) and contracted line-clearance personnel. The line-clearance employees are confronted with more safety issues than the non-clearance personnel of the UVM department, so the second graph is of greater significance to the discussion of safety.



Graph 96: Two-Year Average Turnover of In-House Supervisory and Work-planning Personnel



Graph 97: Two-Year Average Turnover of Line Clearance Personnel

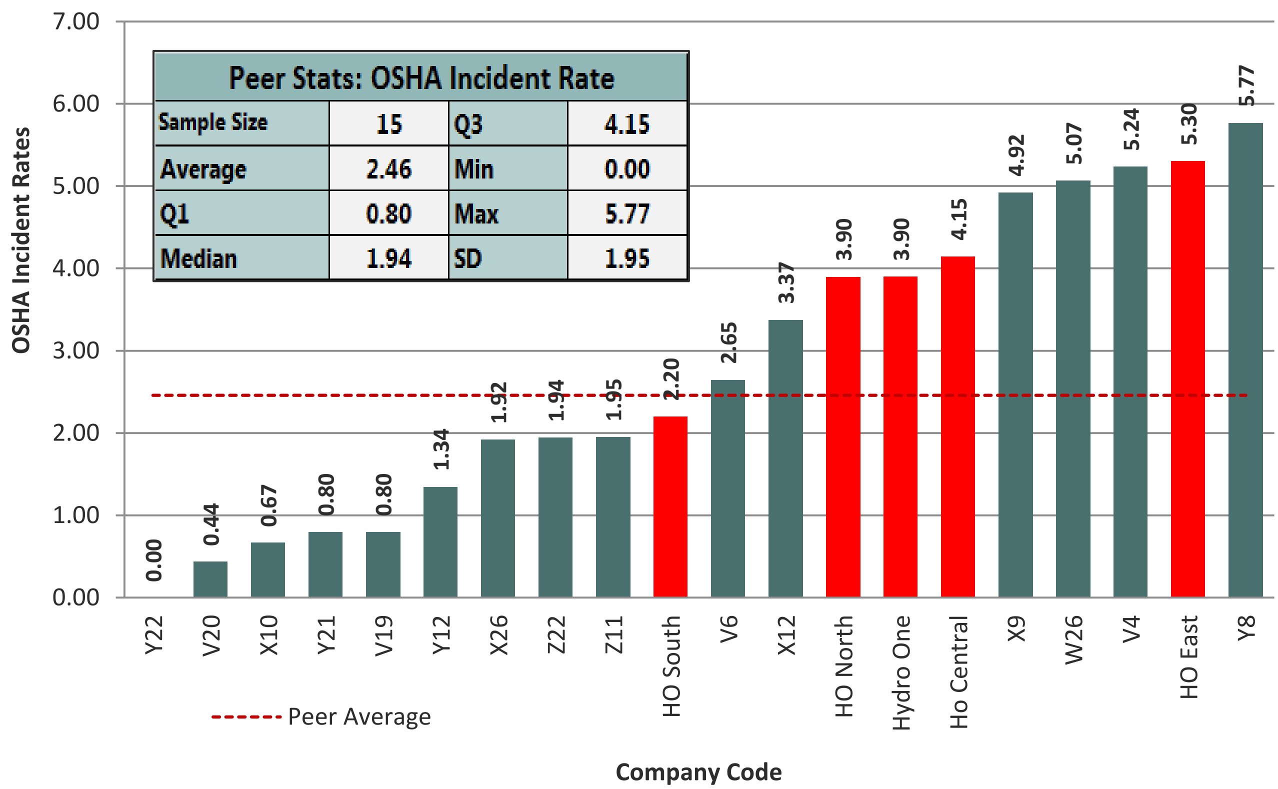
Safety Statistics

Incident rates are shown in the next graph by company. Most of the statistics for this graph have been gathered by the contractors and reported to the utility. Since Hydro One is all in-house employees, the information is gathered by Hydro One.

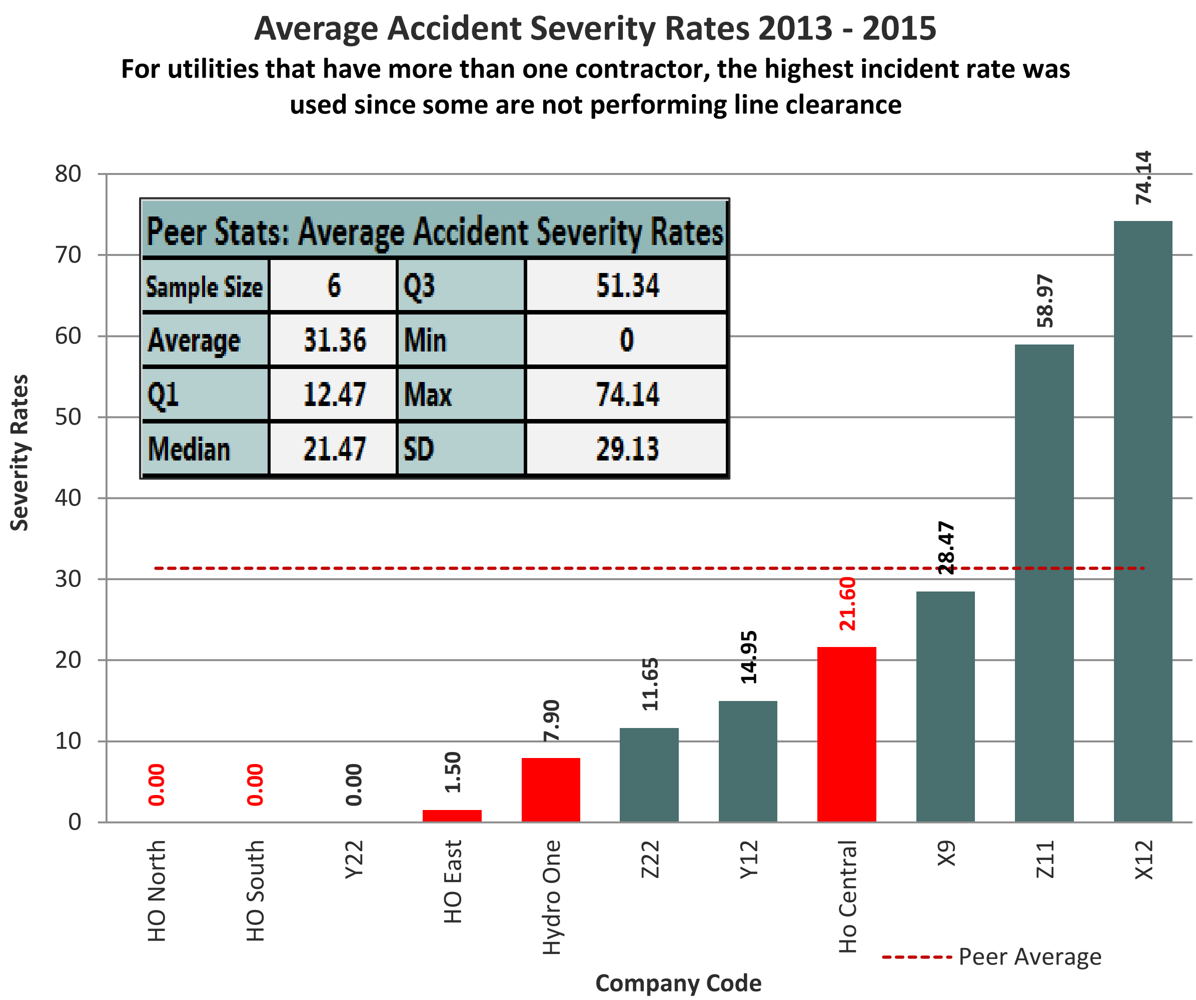
Incident rates vary from severity rates in that an incident may be reported, but very little work time is lost if the incident was not significant to the health of the worker. OSHA incident statistics are the most common form of reporting and only tells part of the story. Unfortunately, the severity rate was not reported by as many utilities, but the sample is adequate to derive some statistics.

Average Standard Health and Safety [OSHA] Incident Rates 2013-2015

For utilities that have more than one contractor, the highest incident rate was used since some contractors are not performing line clearance



Graph 98: Average Standard Health and Safety [OSHA] Incident Rates 2013-2015

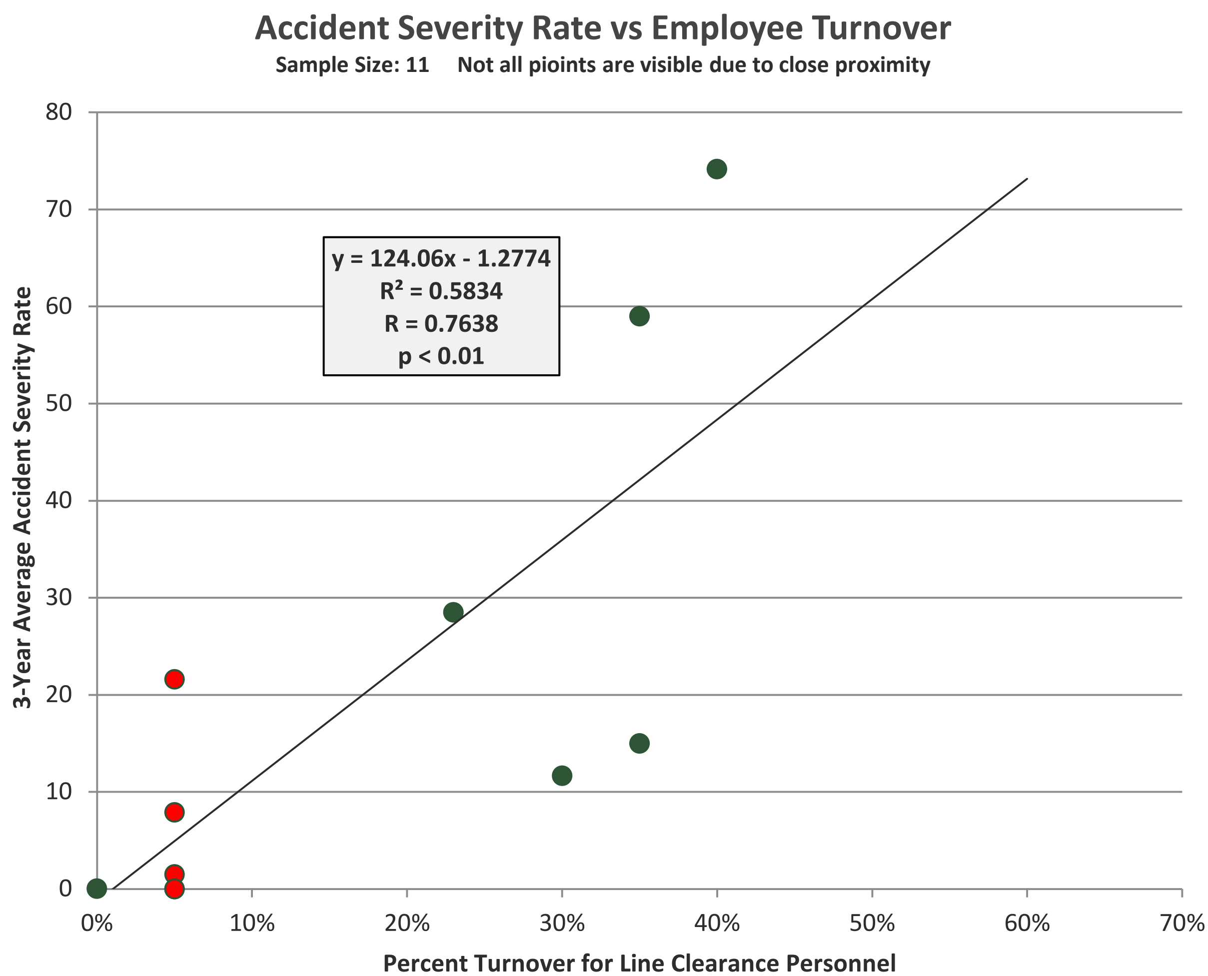


Peer Stats: Average Accident Severity Rates			
Sample Size	6	Q3	51.34
Average	31.36	Min	0
Q1	12.47	Max	74.14
Median	21.47	SD	29.13

Graph 99: Average Accident Severity Rates 2013-2015

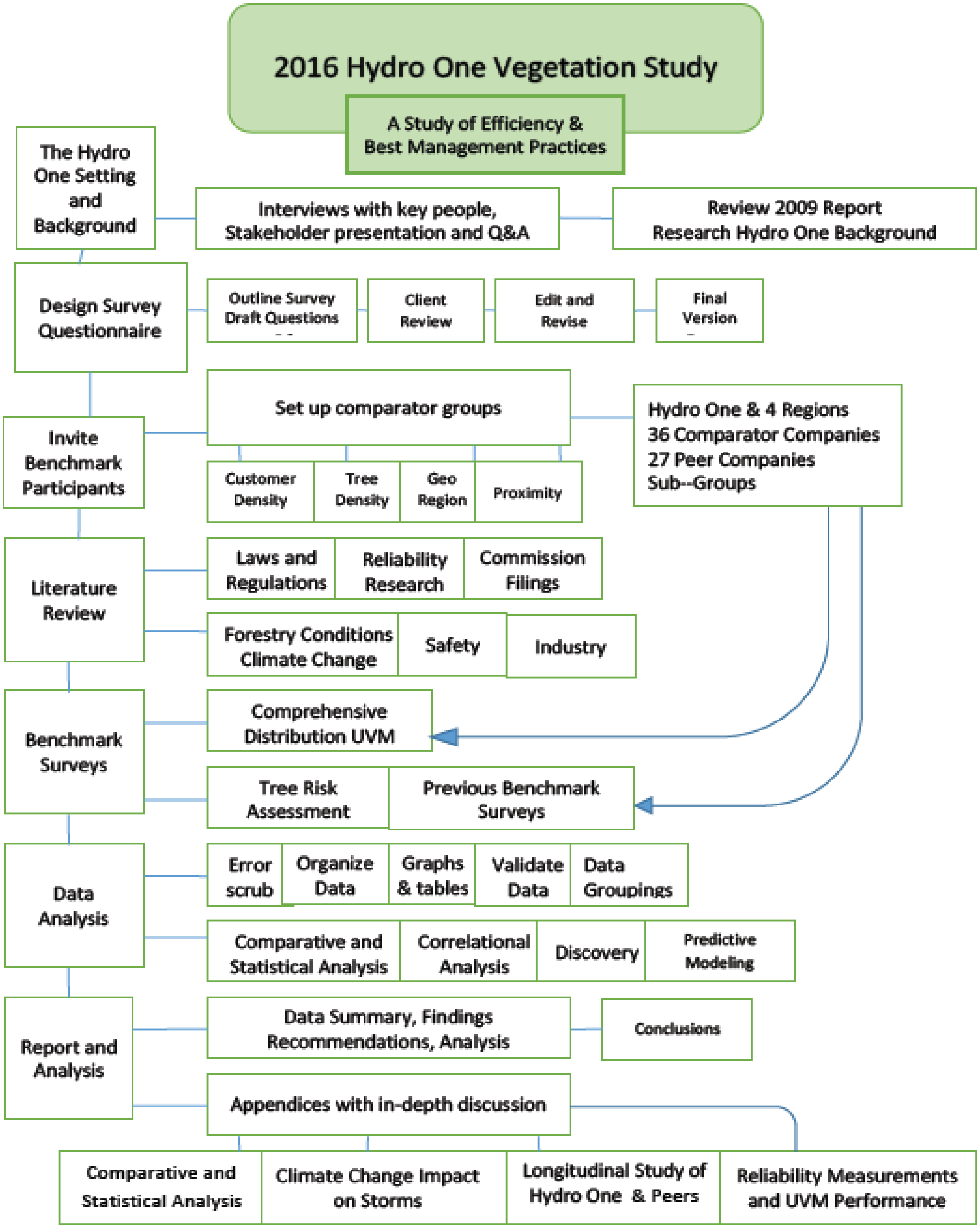
Correlation between Employee Turnover and Safety Severity Rate

A significant correlation can be drawn between employee turnover rates and incident severity rates. Hydro One is identified by red data points. Sample limited to companies that supplied turnover rates and incident severity rates.



Graph 100: Accident Severity Rate vs Employee Turnover

Appendix I: Benchmark Study Process Chart



Appendix J: Longitudinal and Comparative Analysis of Hydro One Regions Data and Peer Data

INTRODUCTION

All the graphical and tabular representations are derived from Hydro One and Peer data collected in the *2015 CNUC Distribution Benchmark Survey*. CNUC has included data from previous CNUC UVM benchmark surveys and from the CNUC *Hydro One 2009 -Vegetation Management Benchmark Study* that was submitted to the Ontario Energy Board in September 2009.

Regional studies of Hydro One's territory include 2009 data, which had separated Hydro One into three regions. The original regions were the South, the North and the East. The current study has four regions with the addition of the Central region. The Central region was created by taking a portion of each of the original three regions. CNUC has taken the percent of the electrical system removed from each of the original three regions to understand trends for the current four divisions. By proportioning regional data from 2009 to the current regional makeup, CNUC was able to compare information dating back to 2008 with a two year gap (2009 and 2010) in these comparisons.

Most of the graphs and tables in this appendix are longitudinal (over time). Some analysis for trends in the data has also been included in this appendix.

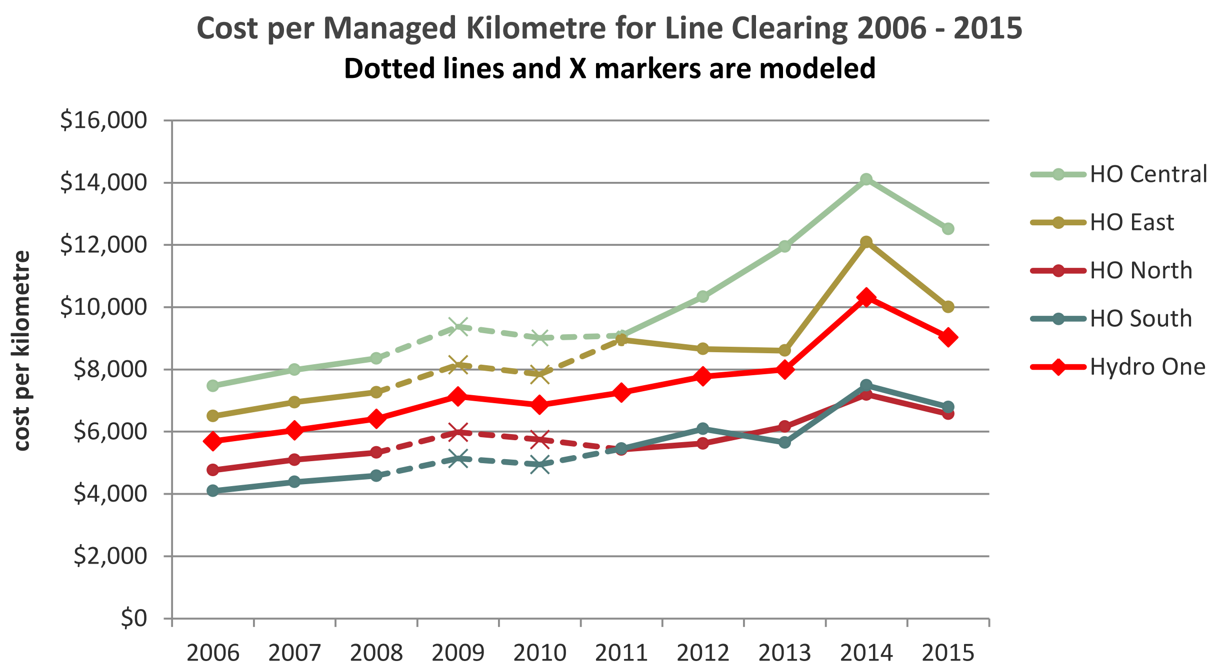
The following concepts are important for interpreting the graphical results:

- "Per System Kilometre"
- "Per Managed Kilometre"

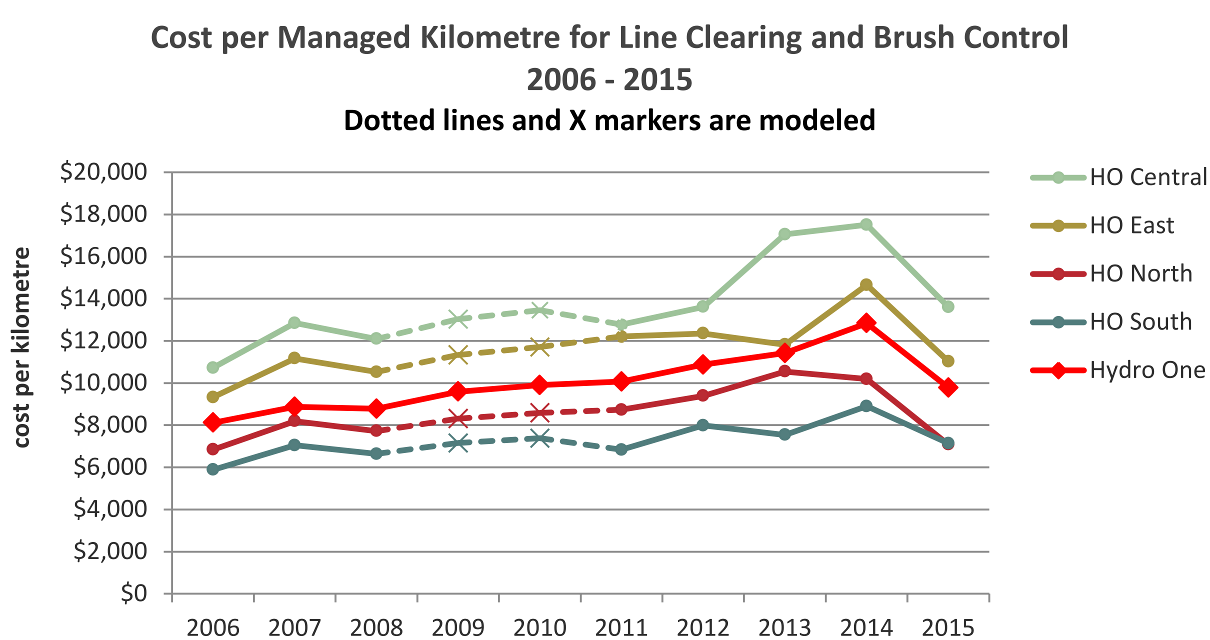
Graph and table numbers in this appendix vary from labels in the main report and other accompanying appendices.

HYDRO ONE REGIONAL FINANCIAL AND LABOR HOUR COMPARISONS

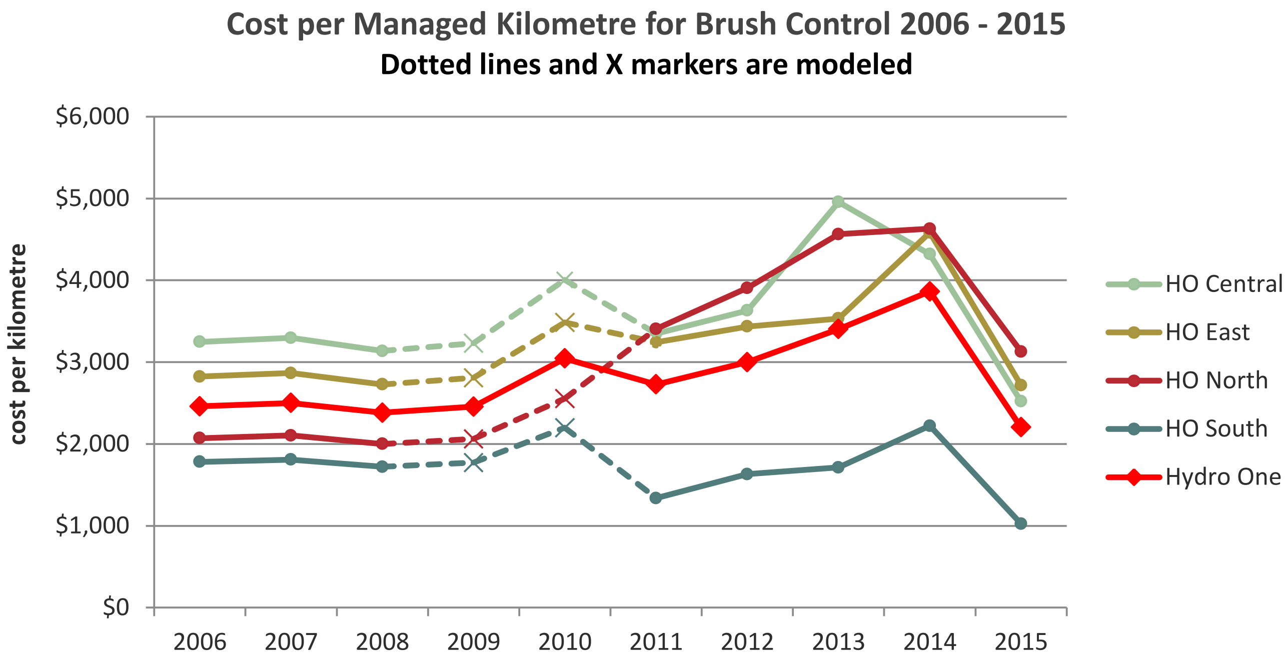
Hydro One UVM Expenditures



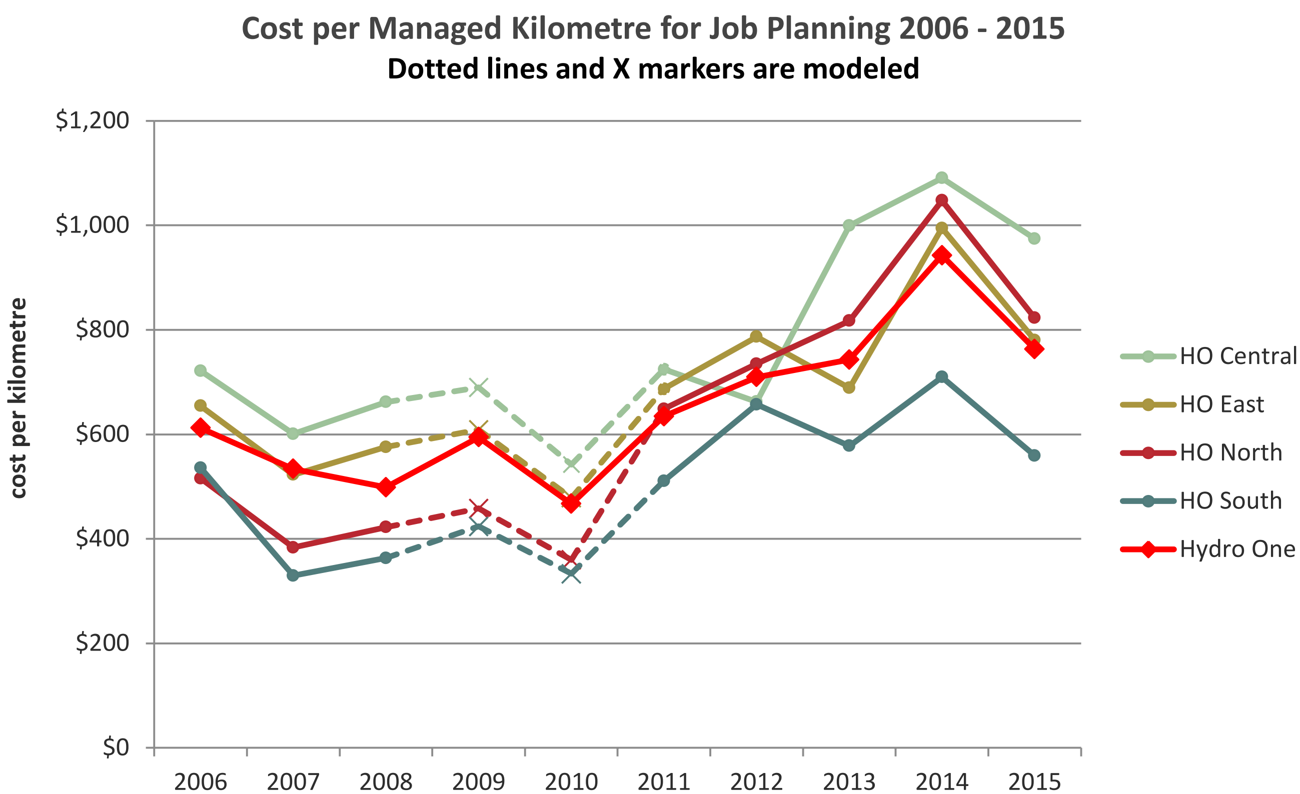
Graph 101: Cost per Managed Kilometre for Line Clearing 2006 – 2015



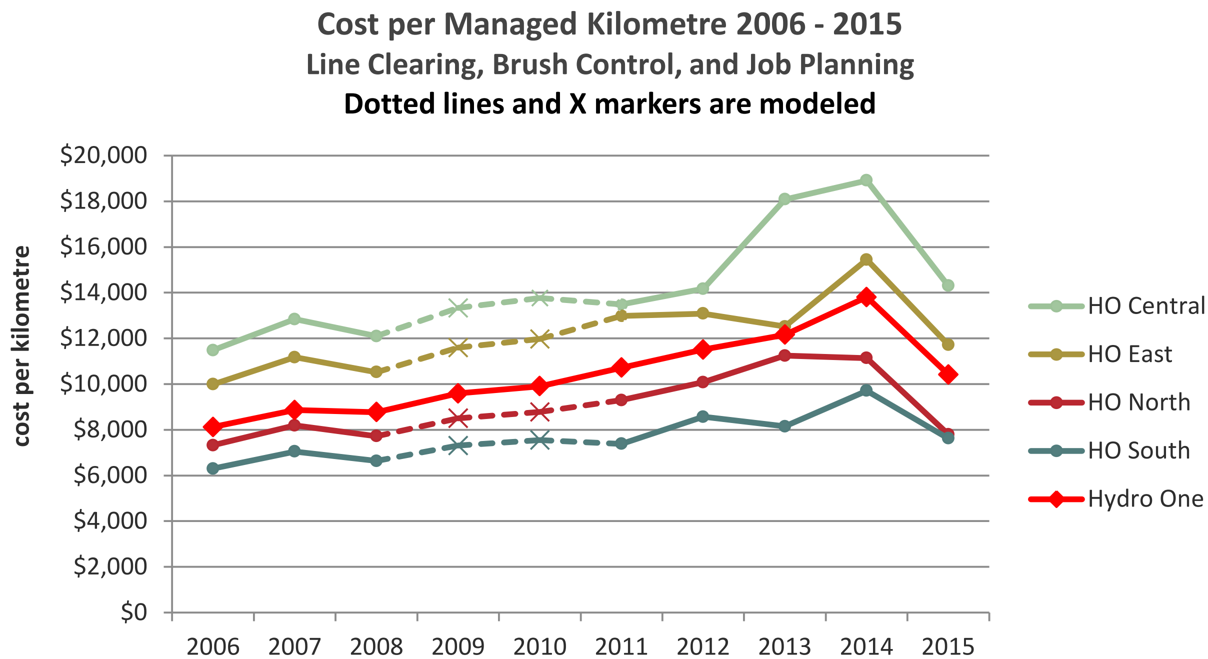
Graph 102: Cost per Managed Kilometre for Line Clearing and Brush Control 2006 - 2015



Graph 103: Cost per Managed Kilometre for Brush Control 2006 - 2015

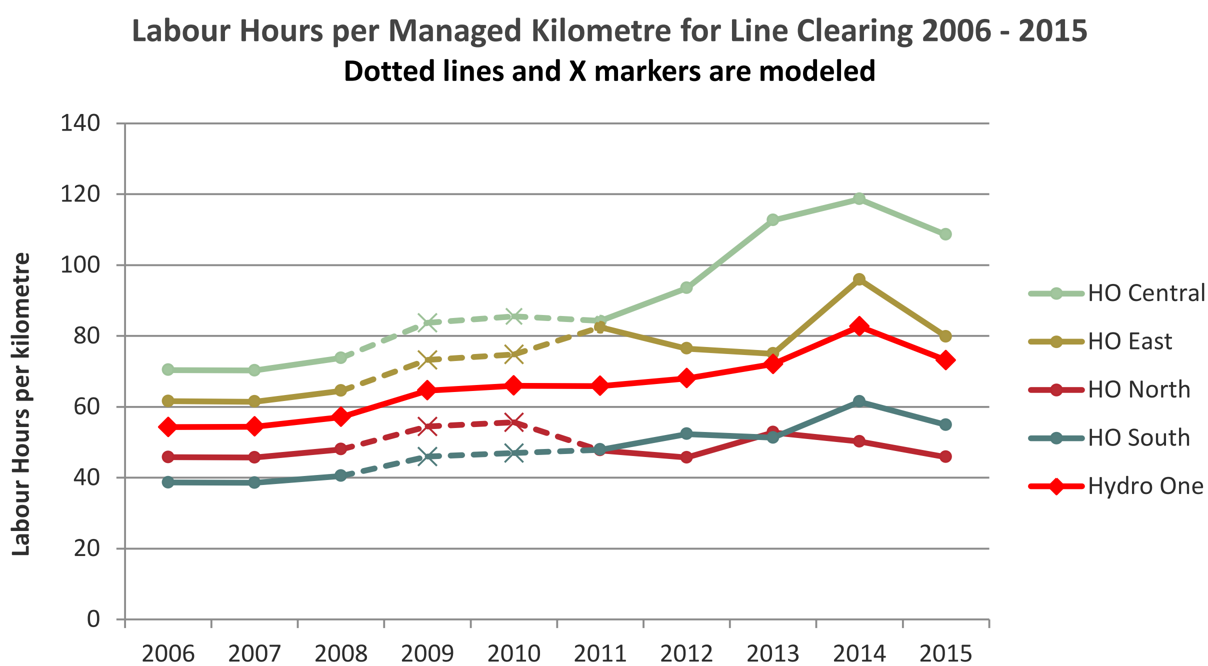


Graph 104: Cost per Managed Kilometre for Job Planning 2006 – 2015

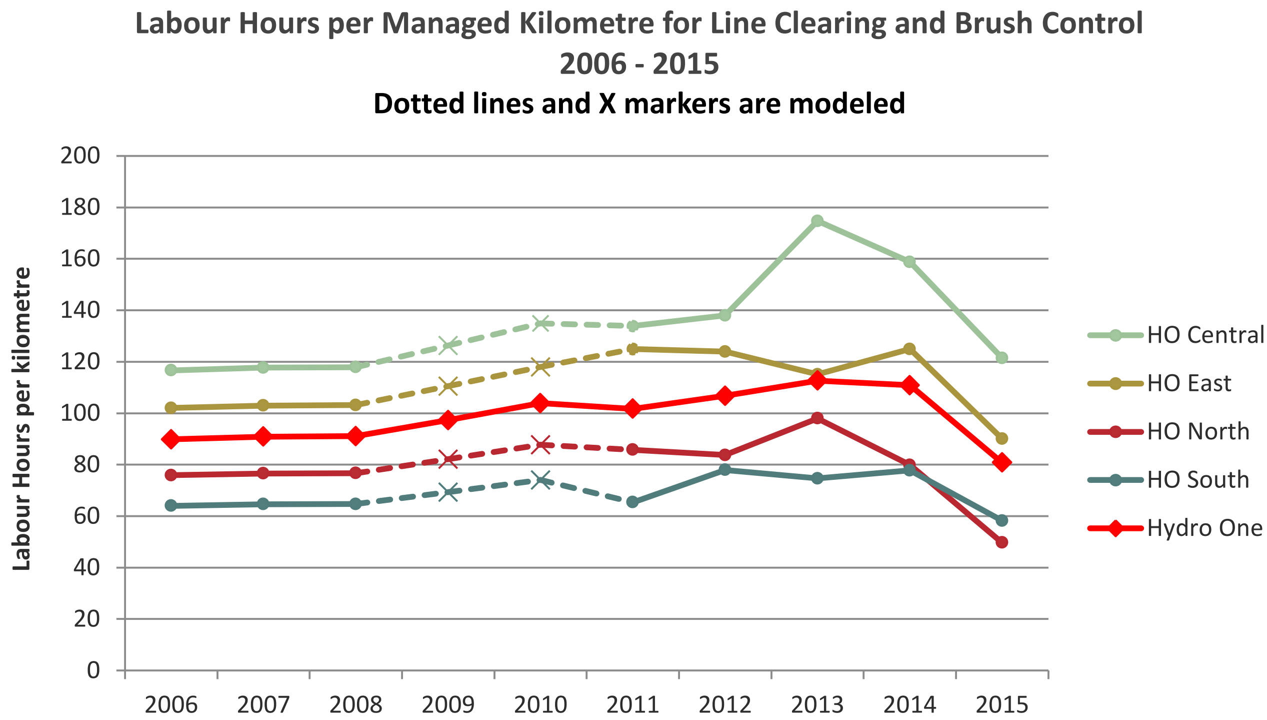


Graph 105: Cost per Managed Kilometre 2006 - 2015

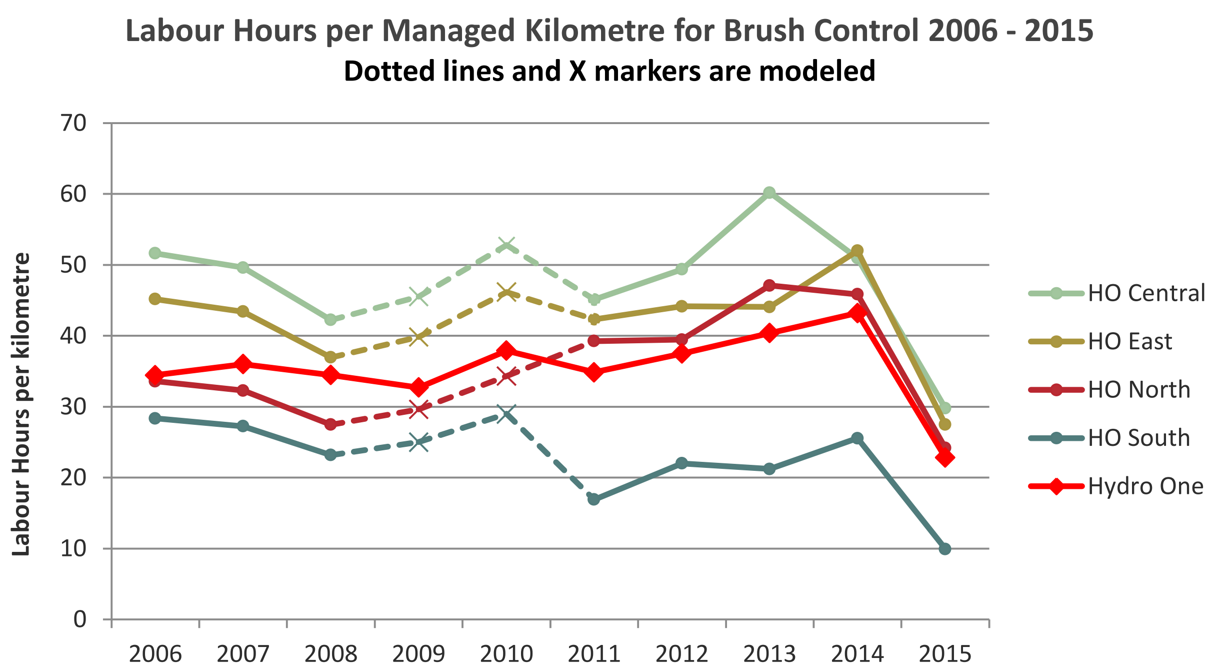
- *Hydro One UVM Labour Hours Expended*



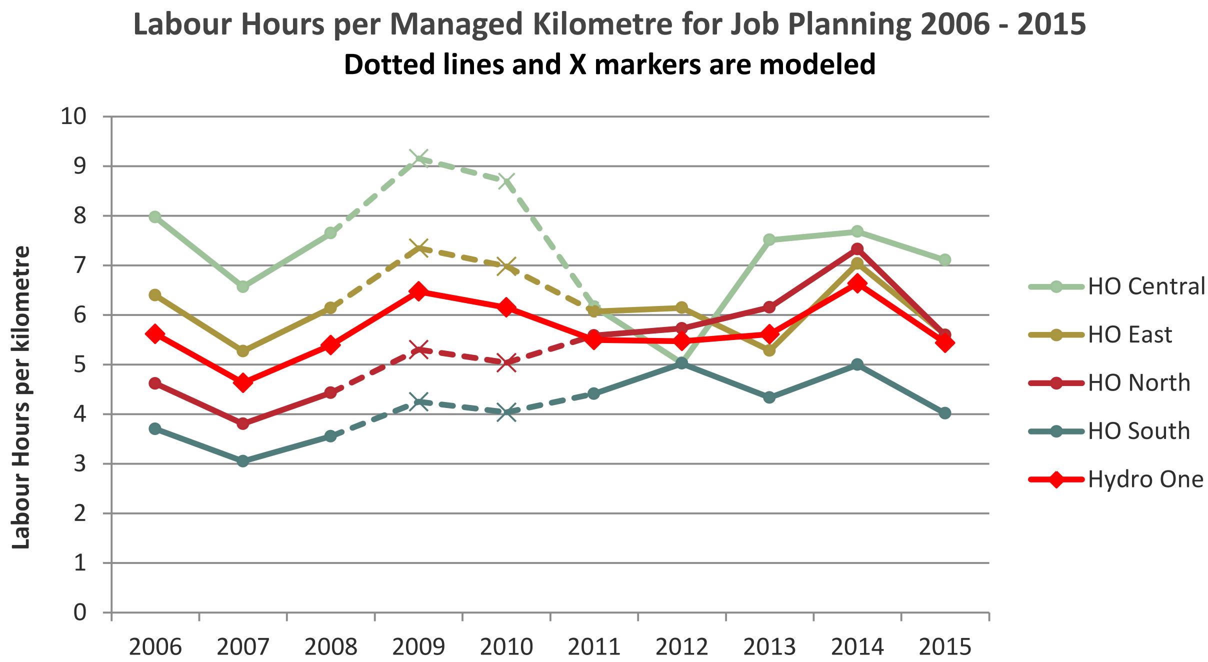
Graph 106: Labour Hours per Managed Kilometre for Line Clearing 2006 - 2015



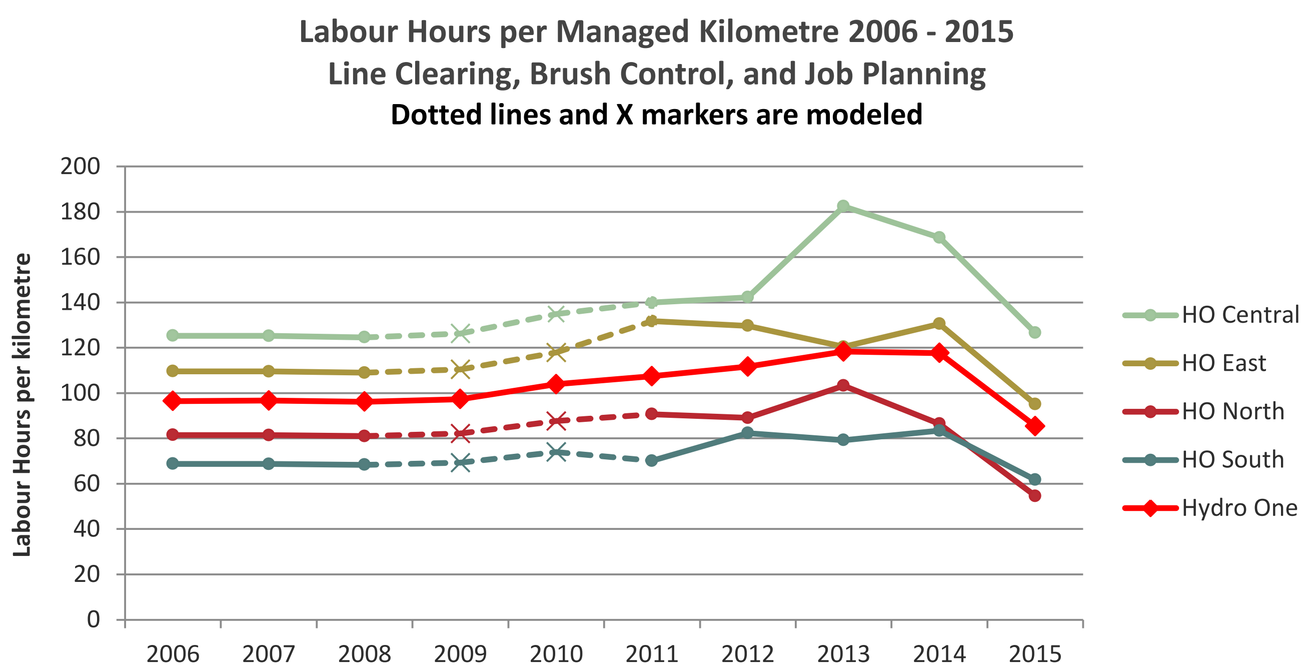
Graph 107: Labour Hours per Managed Kilometre for Line Clearing and Brush Control 2006 - 2015



Graph 108: Labour Hours per Managed Kilometre for Brush Control 2006 - 2015

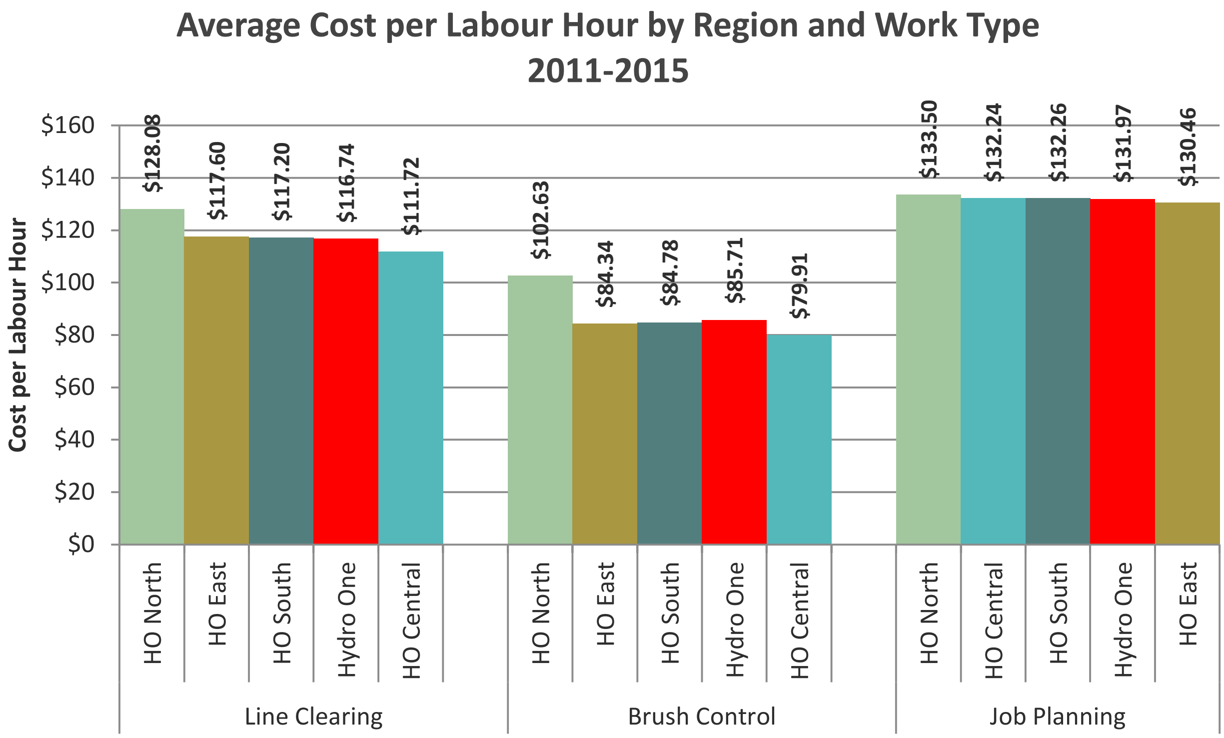


Graph 109: Labour Hours per Managed Kilometre for Job Planning 2006 – 2015

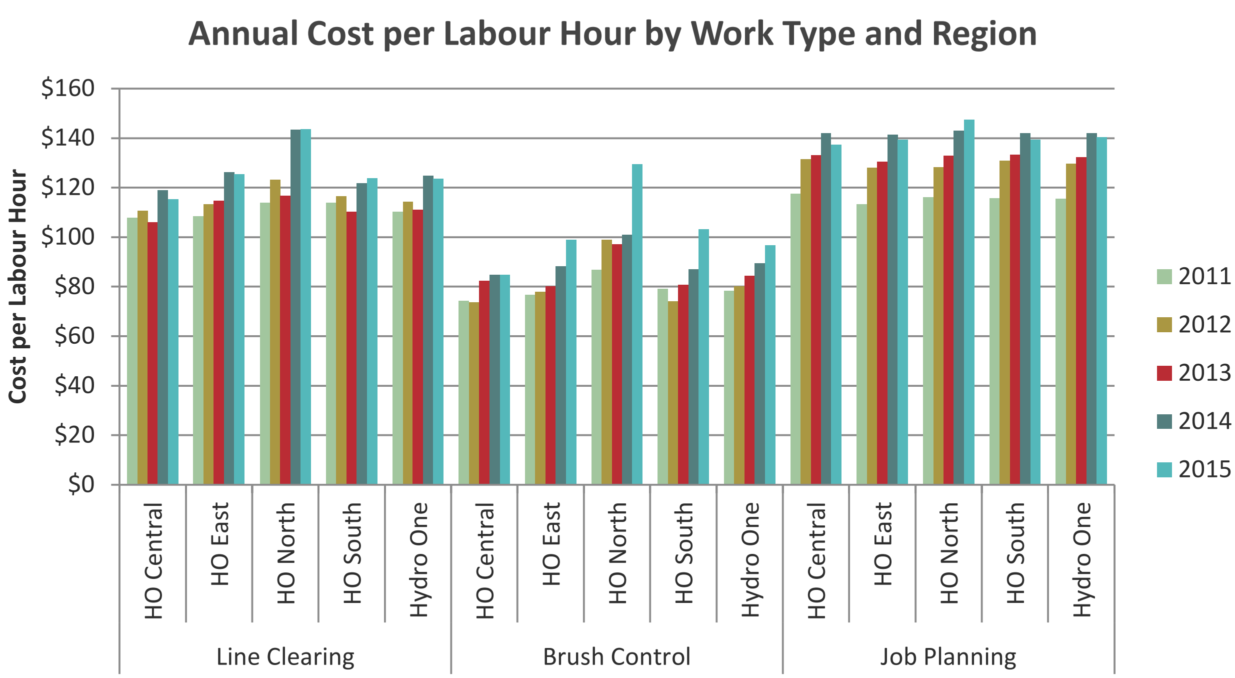


Graph 110: Labour Hours per Managed Kilometre

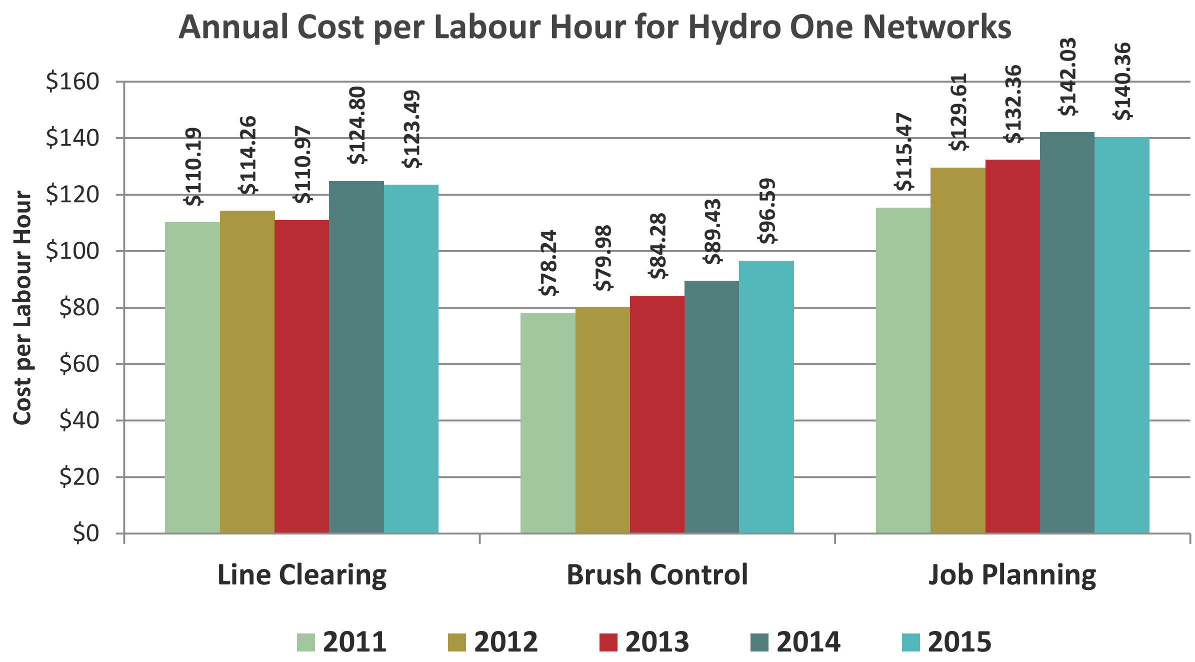
Hydro One Cost per Labour Hour



Graph 111: Average Cost per Labour Hour by Region and Work Type 2011-2015



Graph 112: Annual Cost per Labour Hour by Work Type and Region



Graph 113: Annual Cost per Labour Hour for Hydro One Networks

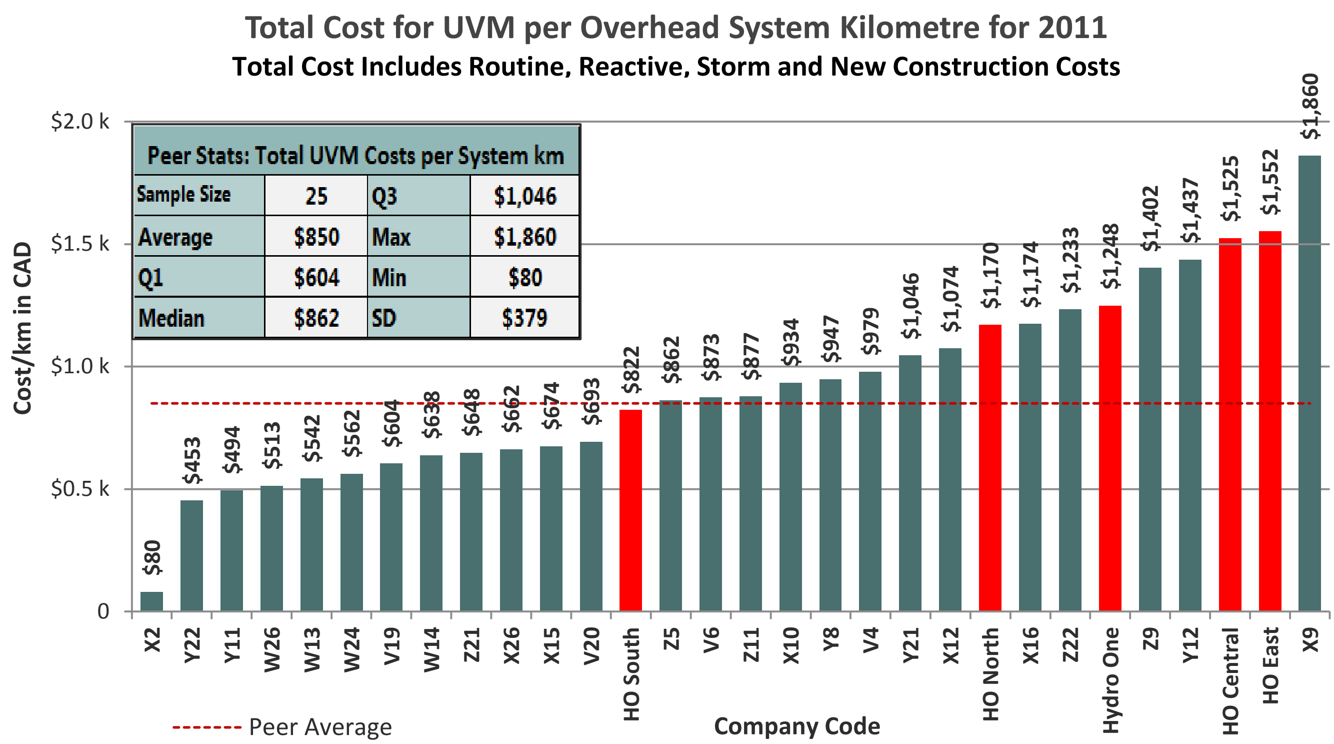
FINANCIAL AND LABOUR HOUR LONGITUDINAL COMPARISONS WITH PEER UTILITIES

UVM Expenditures 2011-2015

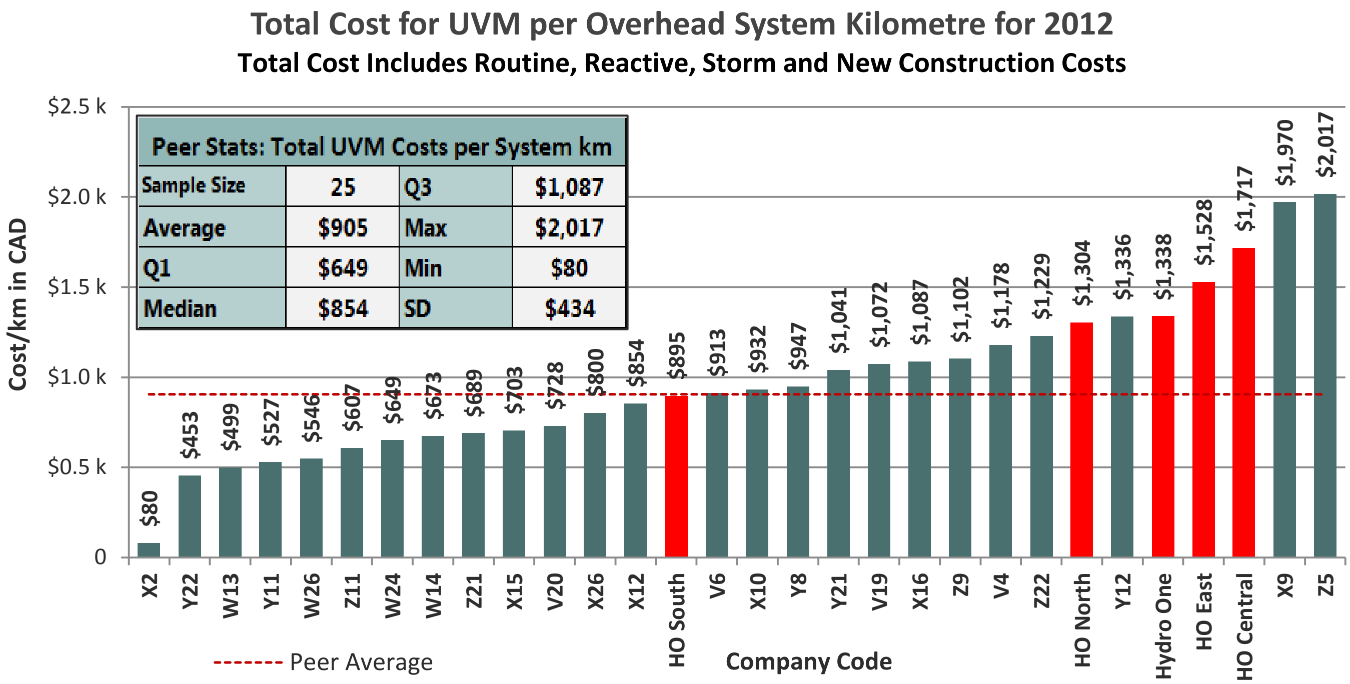
Total UVM Expenditures per Distribution Overhead System Kilometre

Yearly Total UVM Expenditures Comparisons per System Kilometre for Years 2011-2015

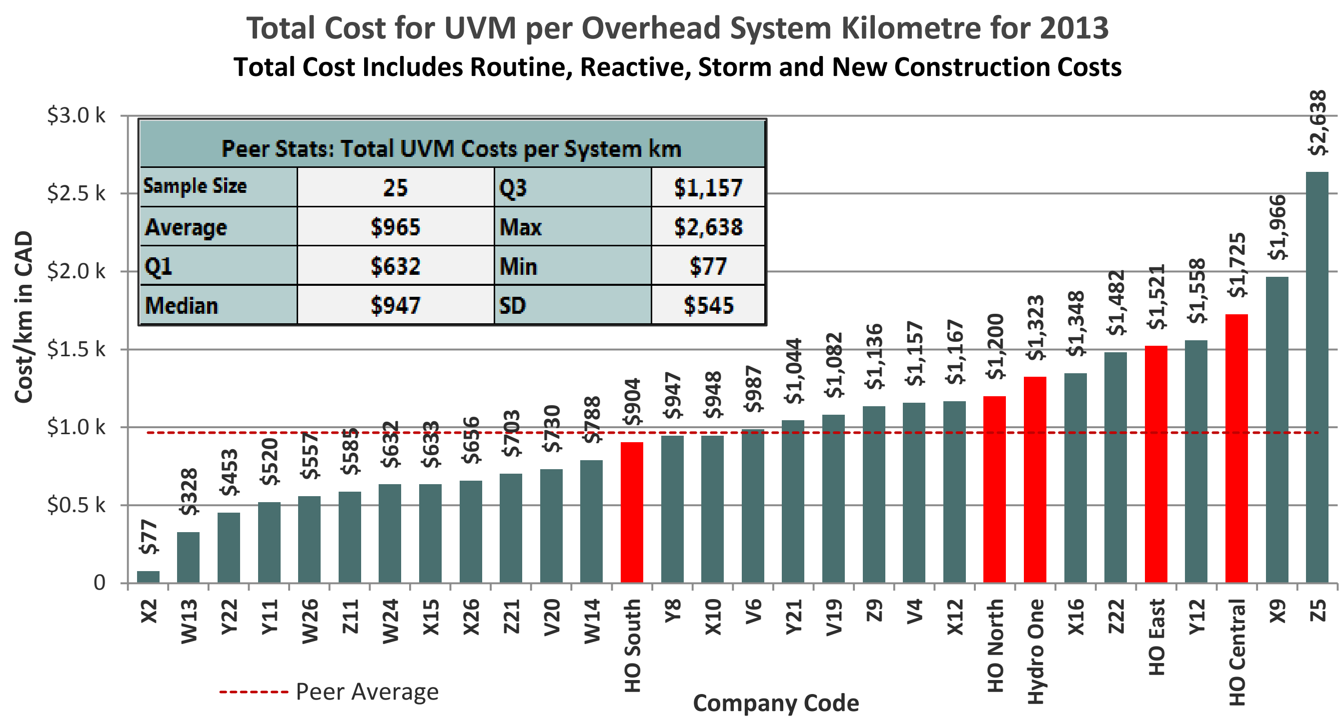
Total Cost Includes Routine, Reactive, Storm and New Construction Costs
It should be noted that not all companies capture their storm or new construction costs in this metric.



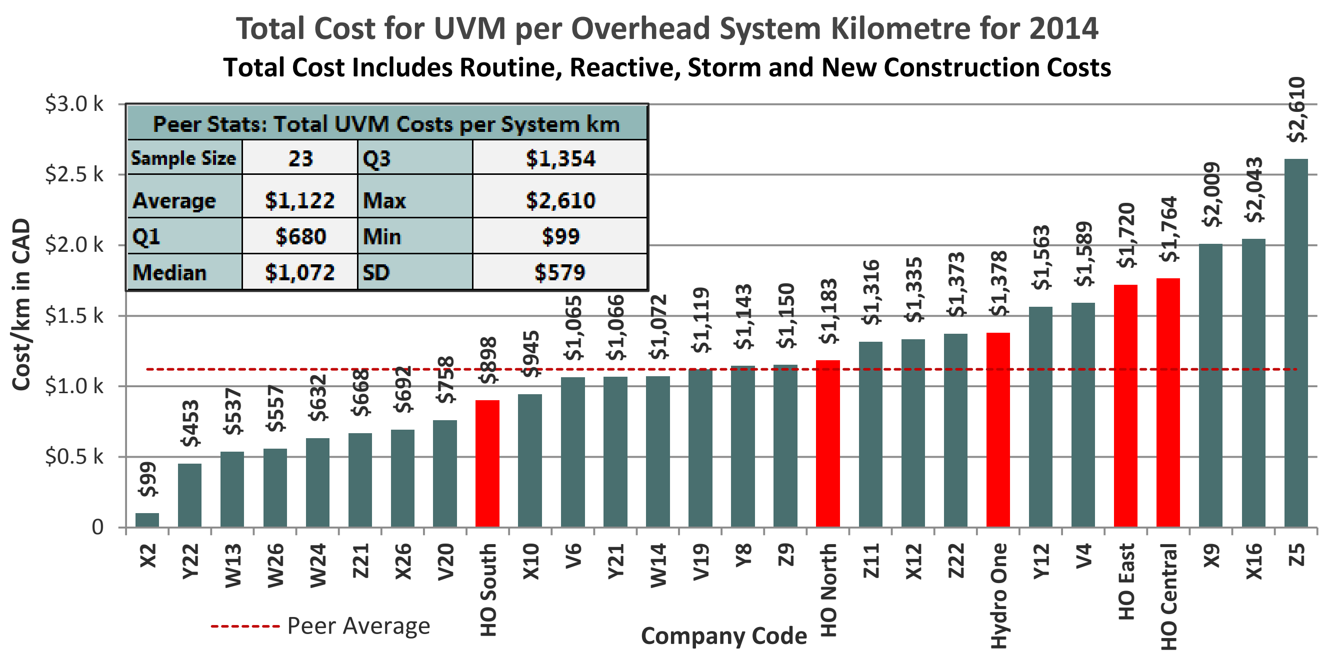
Graph 114: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2011



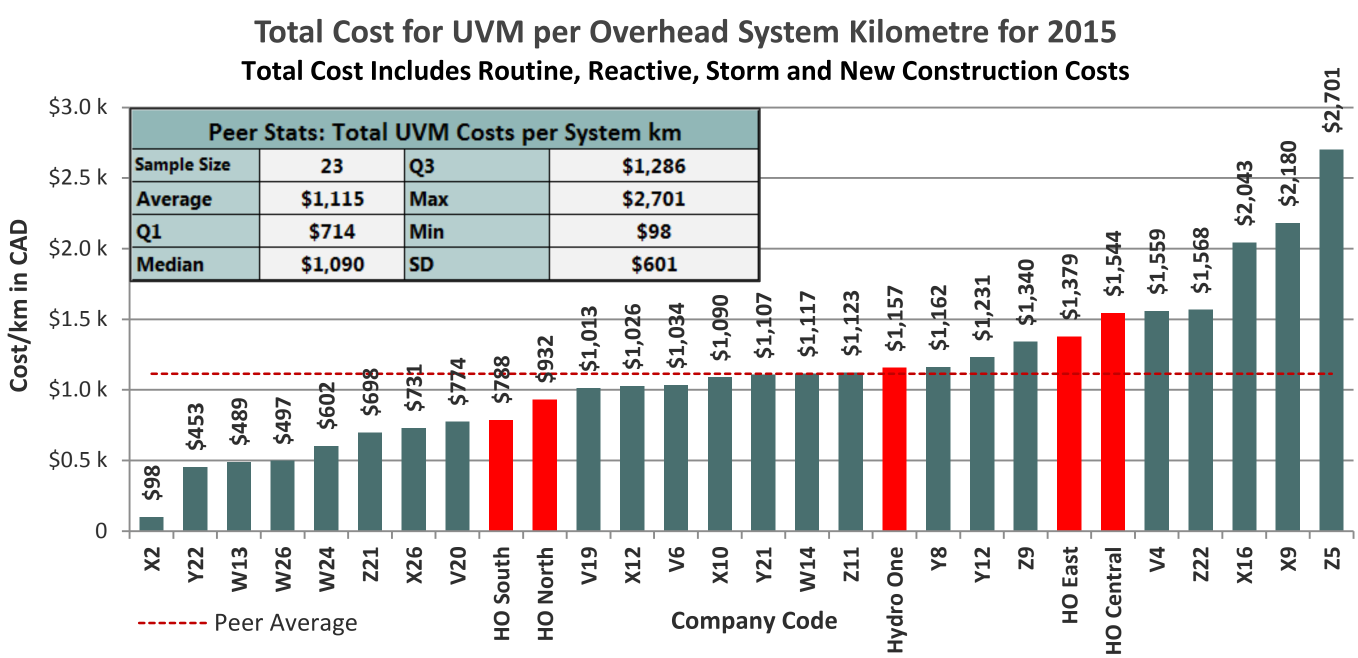
Graph 115: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2012



Graph 116: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2013

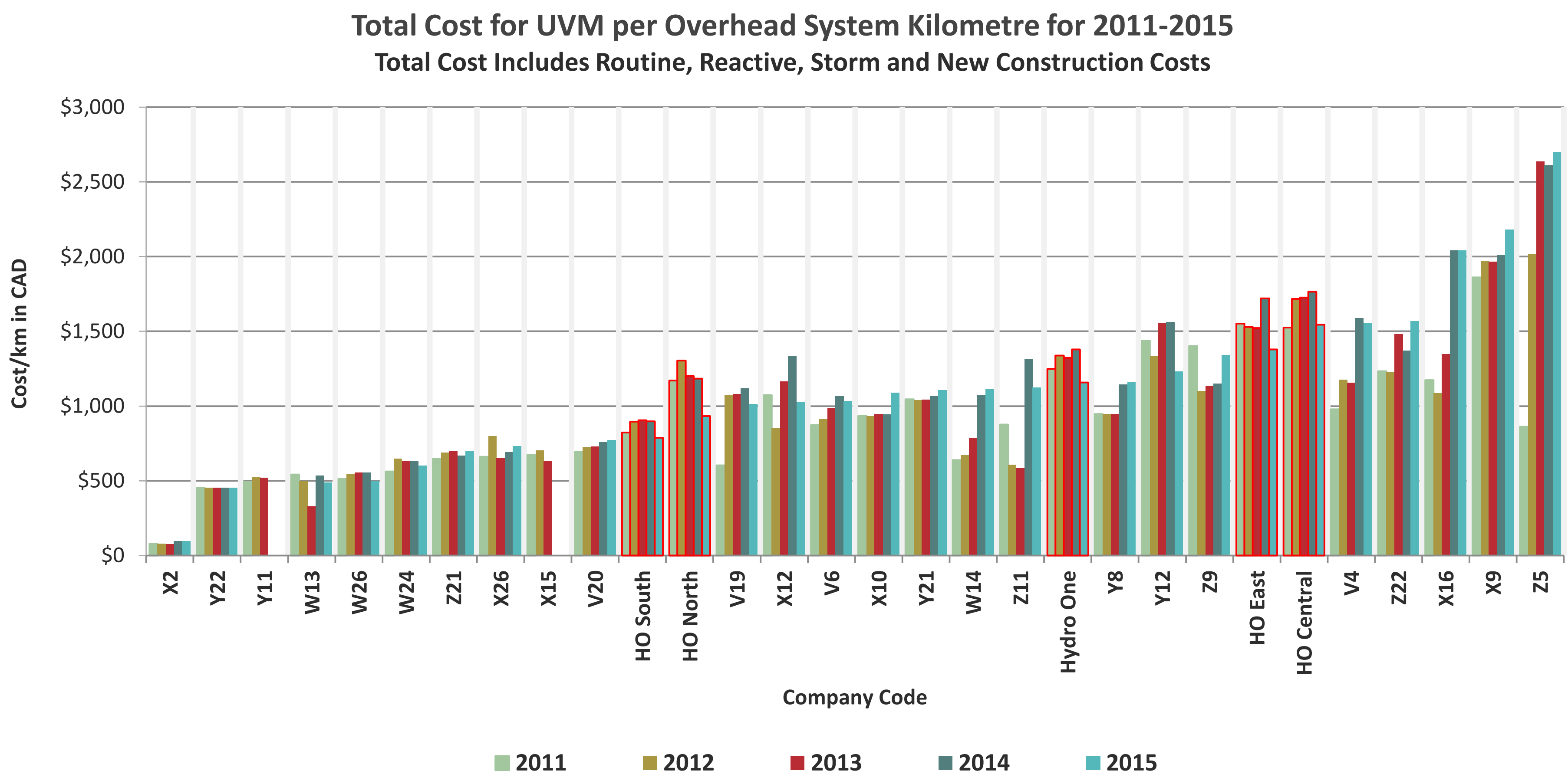


Graph 117: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2014



Graph 118: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2015

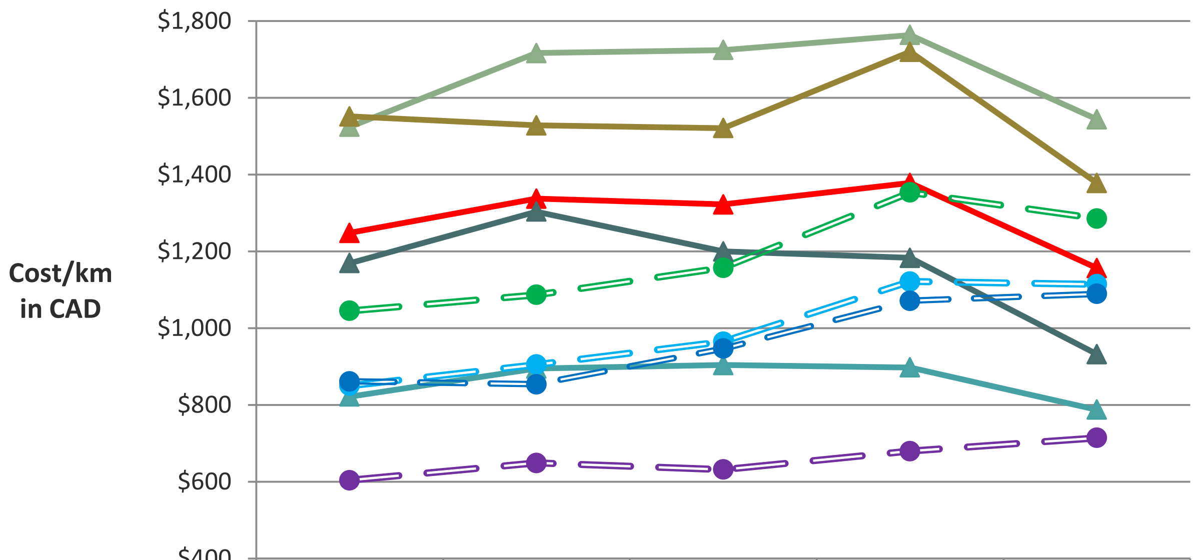
Total UVM Cost per Overhead System Kilometre Comparisons with Peers 2011-2015



Graph 119: Peer Comparisons of Total Cost for UVM per Overhead System Kilometre for 2011-205

Total Cost for UVM per Overhead System Kilometre for 2011-2015

Annual Costs/km for Hydro One and Regions and Peer Statistics

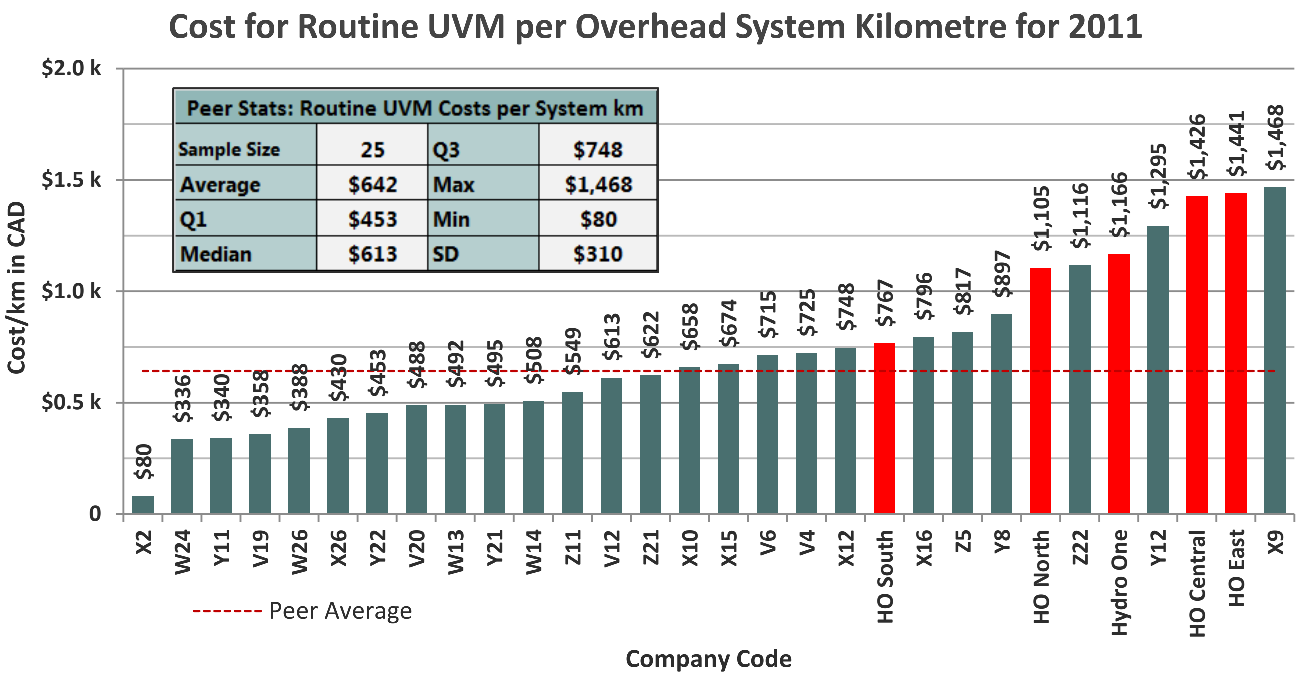


	2011	2012	2013	2014	2015
HO Central	$1,525	$1,717	$1,725	$1,764	$1,544
HO East	$1,552	$1,528	$1,521	$1,720	$1,379
Hydro One	$1,248	$1,338	$1,323	$1,378	$1,157
HO North	$1,170	$1,304	$1,200	$1,183	$932
HO South	$822	$895	$904	$898	$788
Peer Average	$850	$905	$965	$1,122	$1,115
Peer Q1	$604	$649	$632	$680	$714
Peer Median	$862	$854	$947	$1,072	$1,090
Peer Q3	$1,046	$1,087	$1,157	$1,354	$1,286

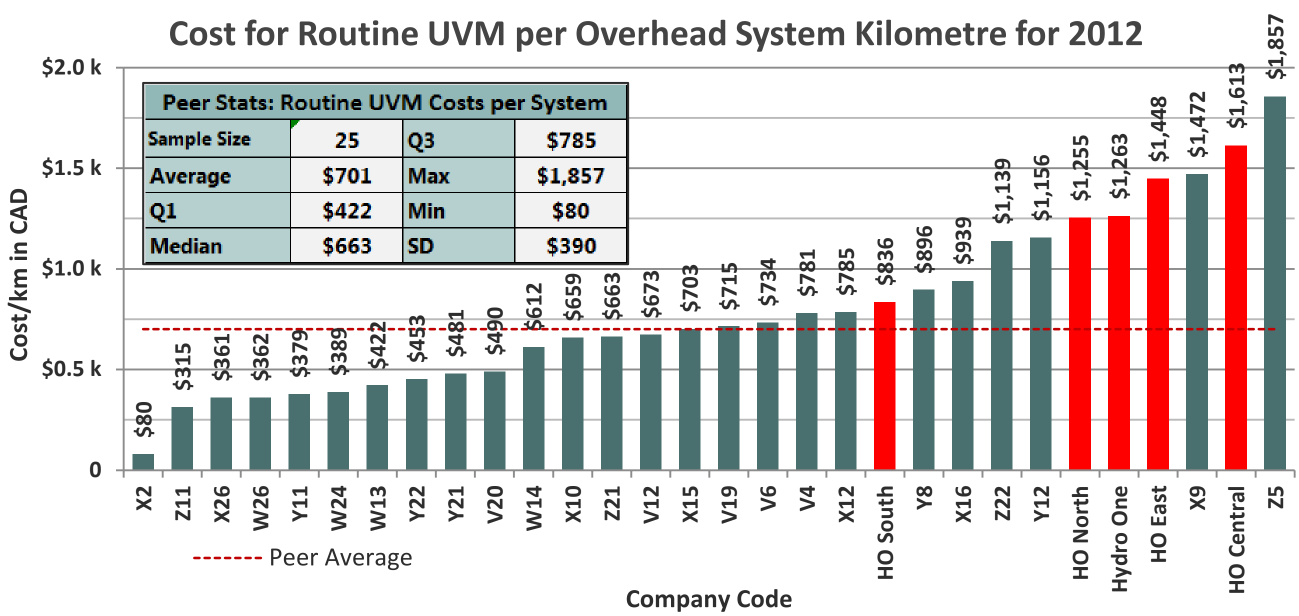
Graph 120: Annual Total UVM Cost per System Kilometre 2011-2015: Hydro One and Regions vs Peer Statistics

Routine Cost UVM Expenditures per System Kilometre

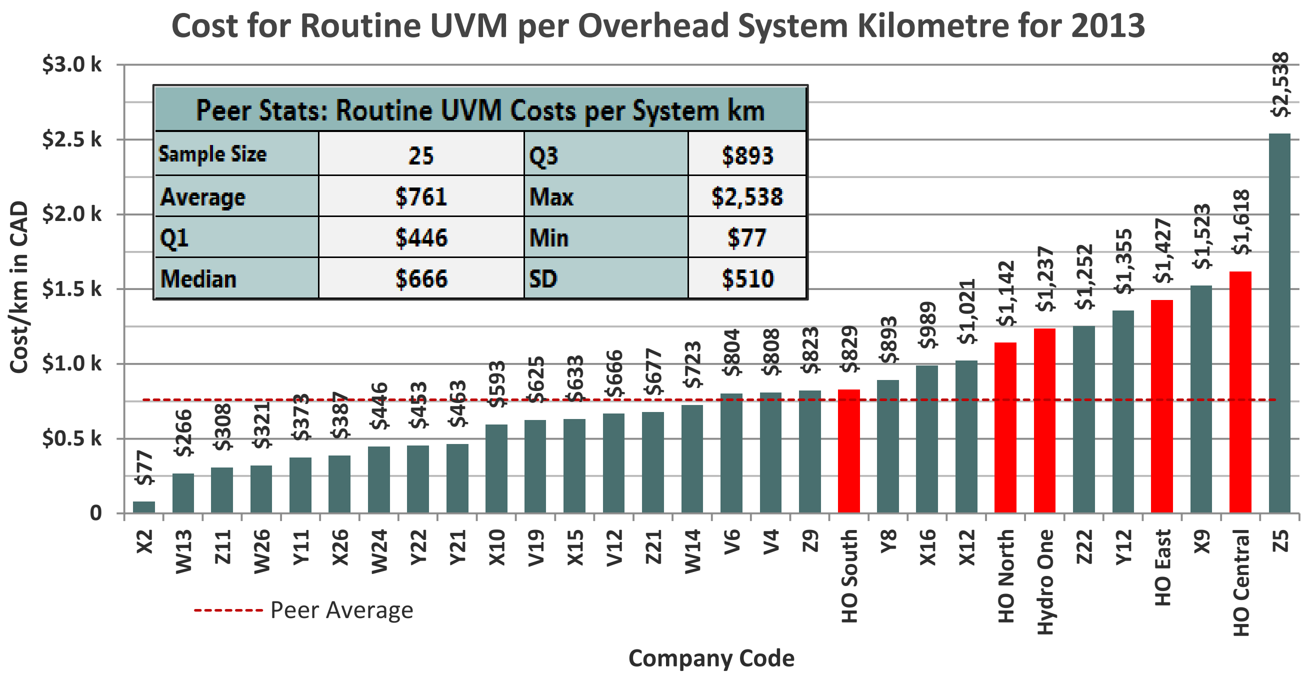
Yearly Routine UVM Expenditures Comparisons for Years 2011-2015



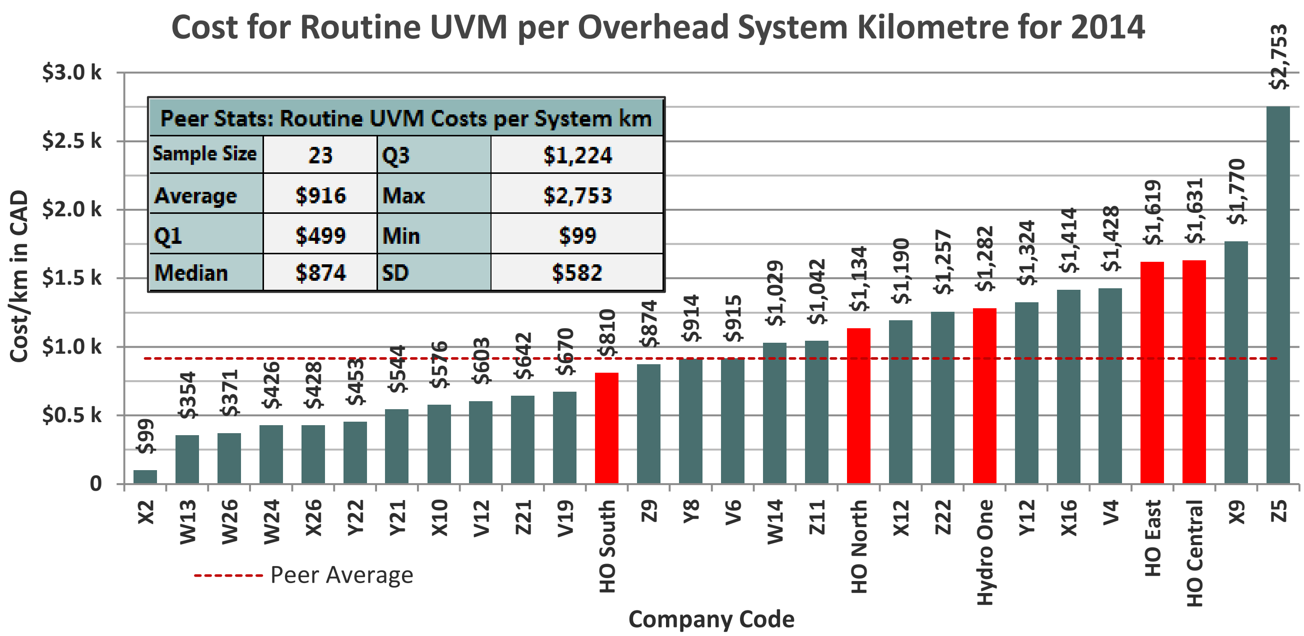
Graph 121: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2011



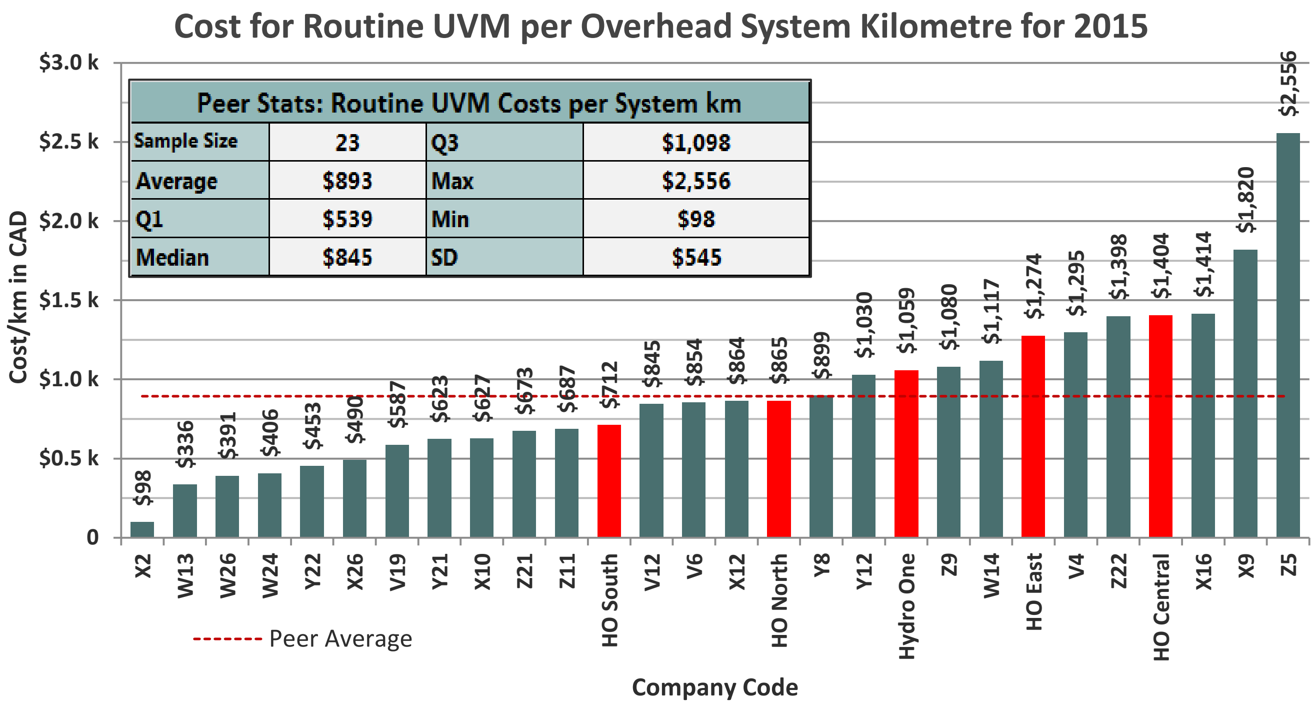
Graph 122: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2012



Graph 123: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2013

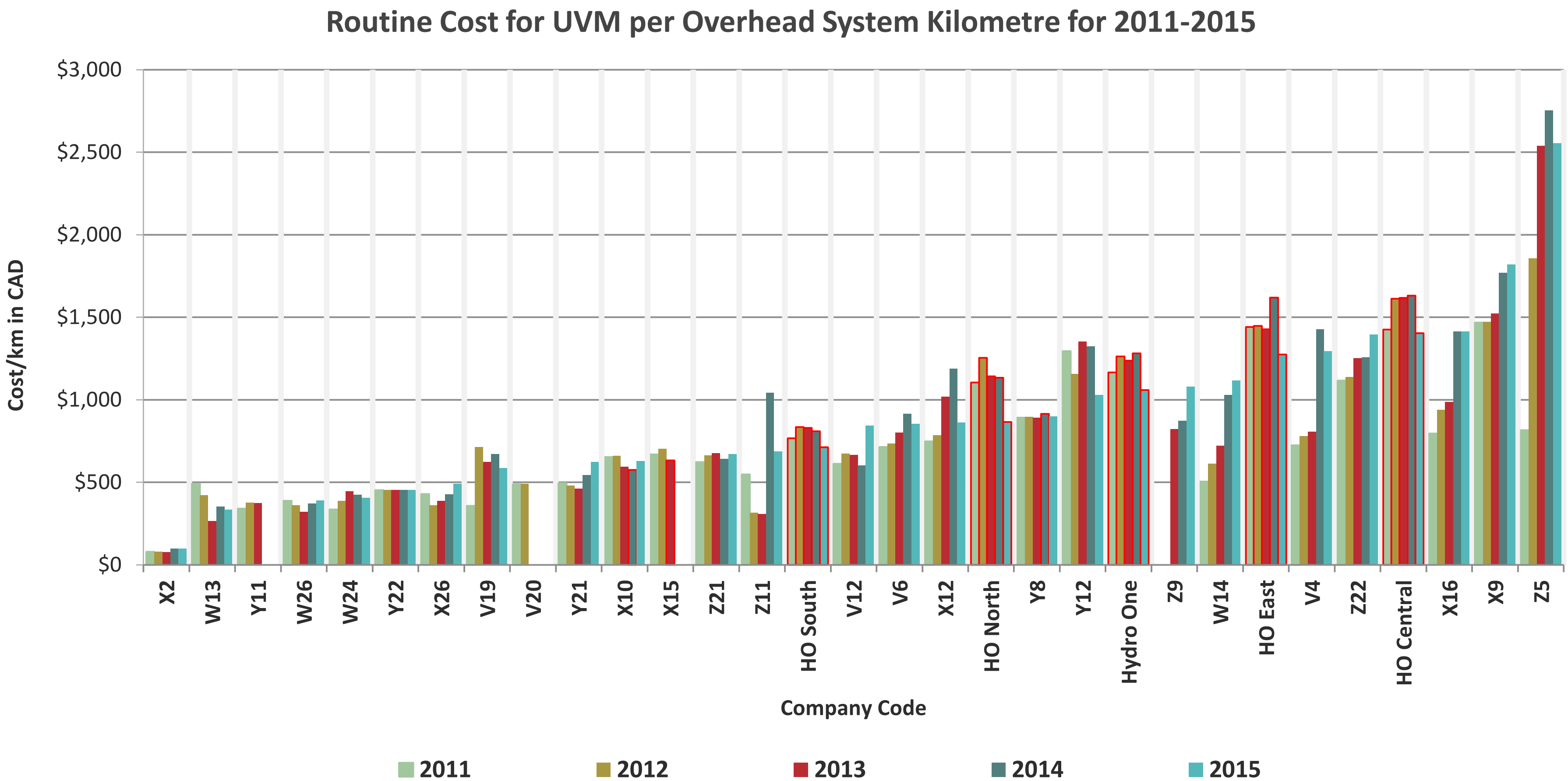


Graph 124: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2014

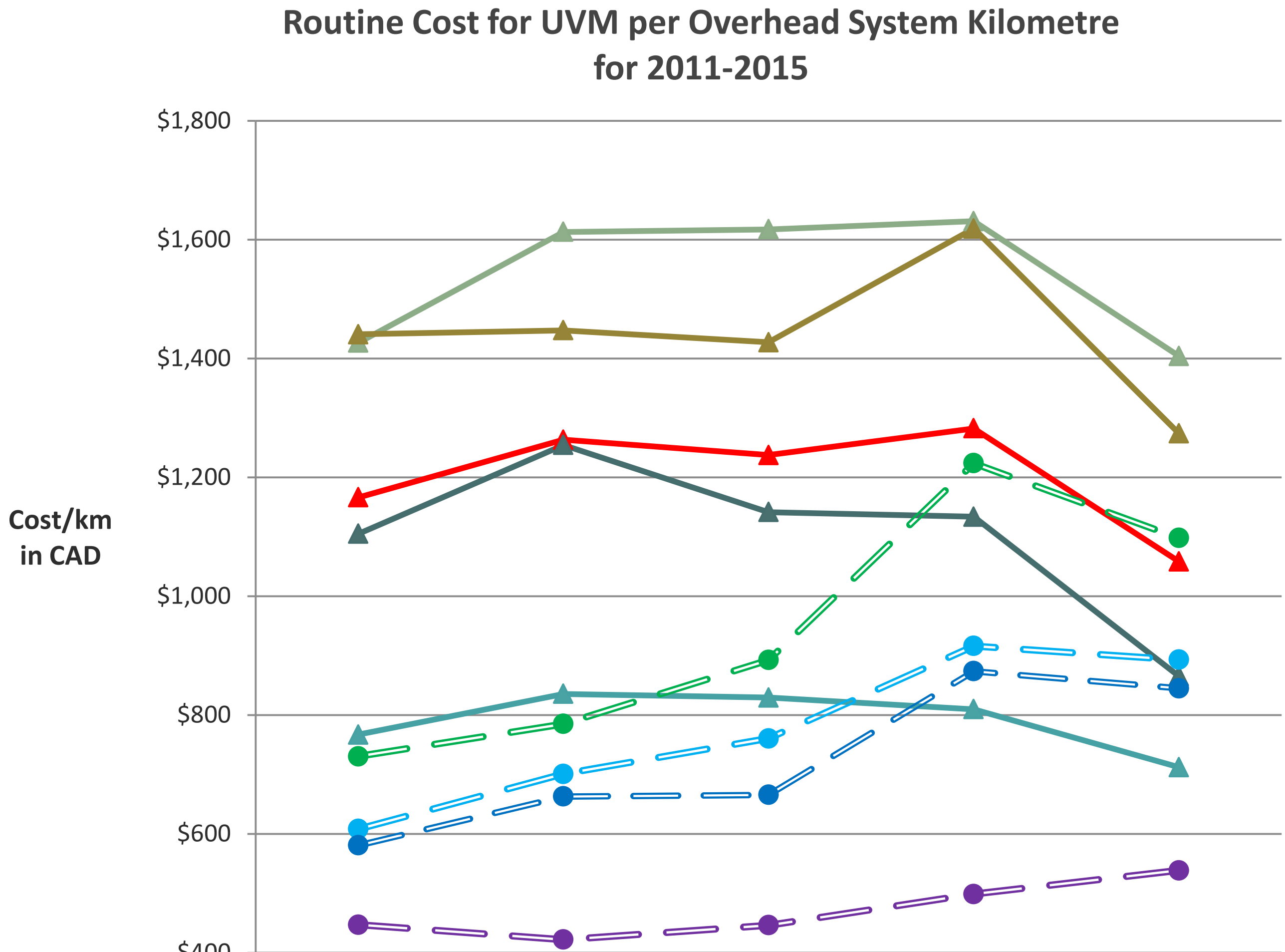


Graph 125: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2015

Routine UVM Cost per System Kilometre Comparisons with Peers 2011-2015



Graph 126: Peer Comparisons of Routine Cost for UVM per Overhead System Kilometre for 2011-2015

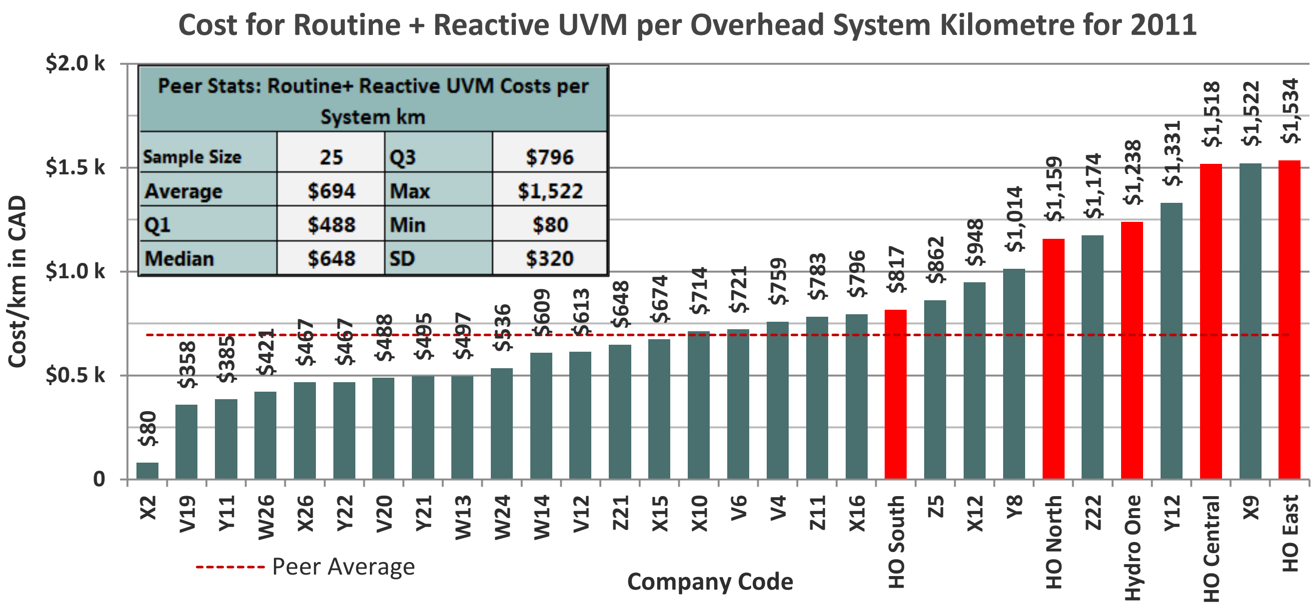


	2011	2012	2013	2014	2015
HO Central	$1,426	$1,613	$1,618	$1,631	$1,404
HO East	$1,441	$1,448	$1,427	$1,619	$1,274
Hydro One	$1,166	$1,263	$1,237	$1,282	$1,059
HO North	$1,105	$1,255	$1,142	$1,134	$865
HO South	$767	$836	$829	$810	$712
Peer Average	$608	$701	$761	$916	$893
Peer Q1	$447	$422	$446	$499	$539
Peer Median	$581	$663	$666	$874	$845
Peer Q3	$731	$785	$893	$1,224	$1,098

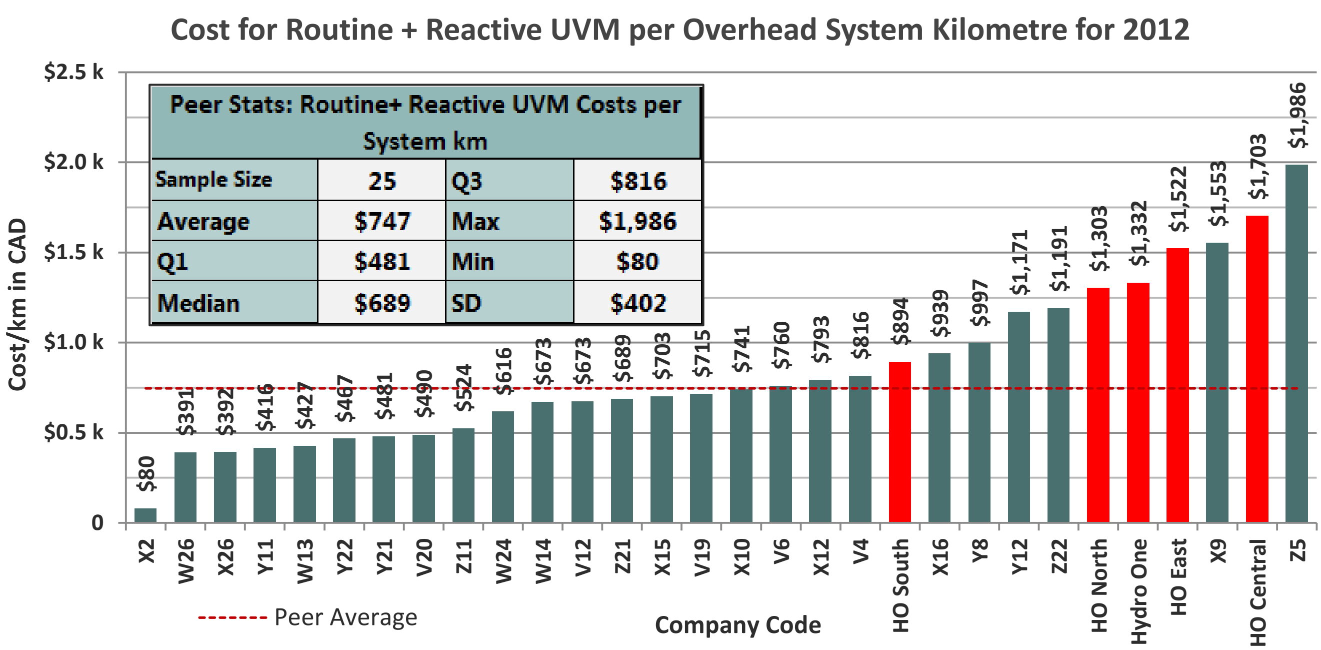
Graph 127: Annual Routine UVM Cost per System Kilometre 2011-2015: Hydro One and Regions vs Peer Statistics

Routine and Reactive UVM Expenditures per System Kilometre

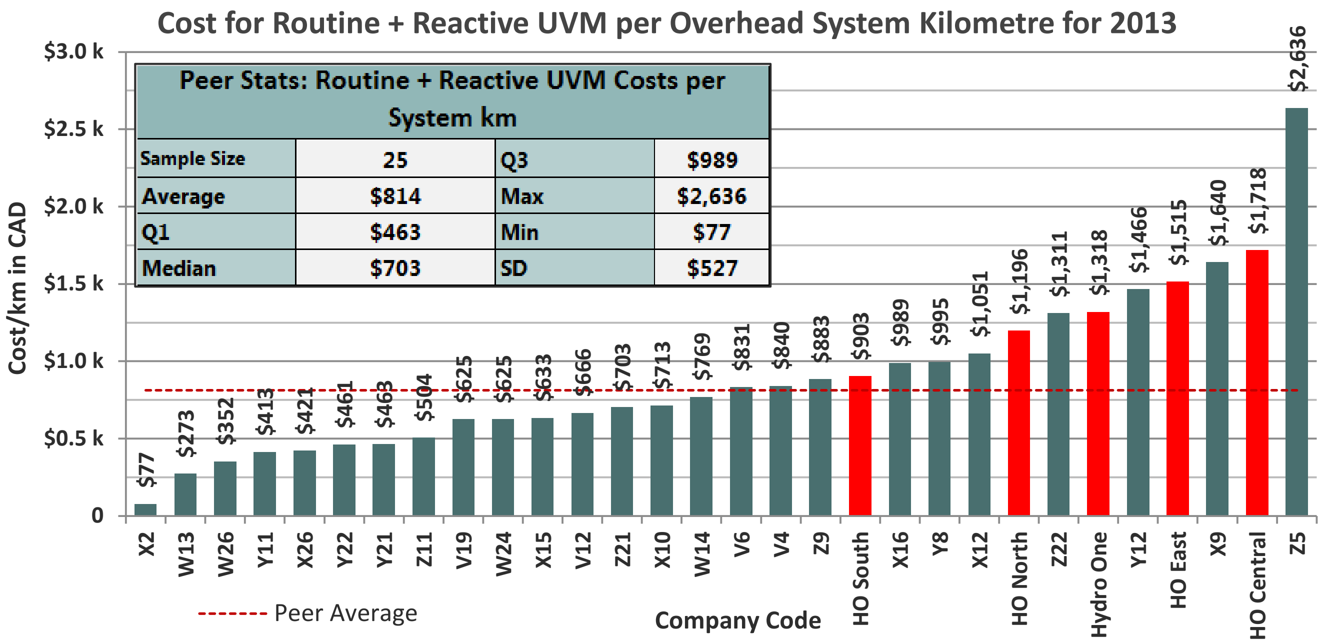
Yearly Routine UVM Expenditures per System Kilometre Comparisons for Years 2011-2015



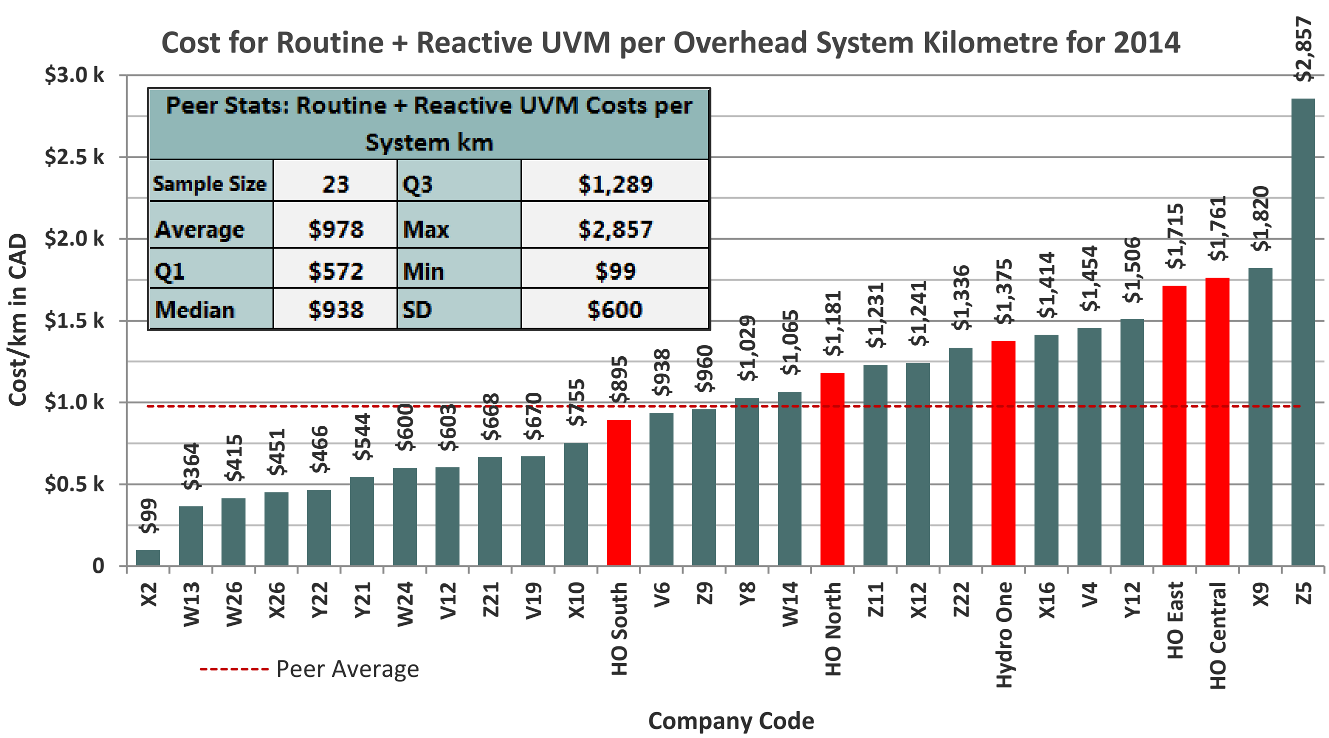
Graph 128: Peer Comparisons of Routine + Reactive Cost for UVM per Overhead System Kilometre for 2011



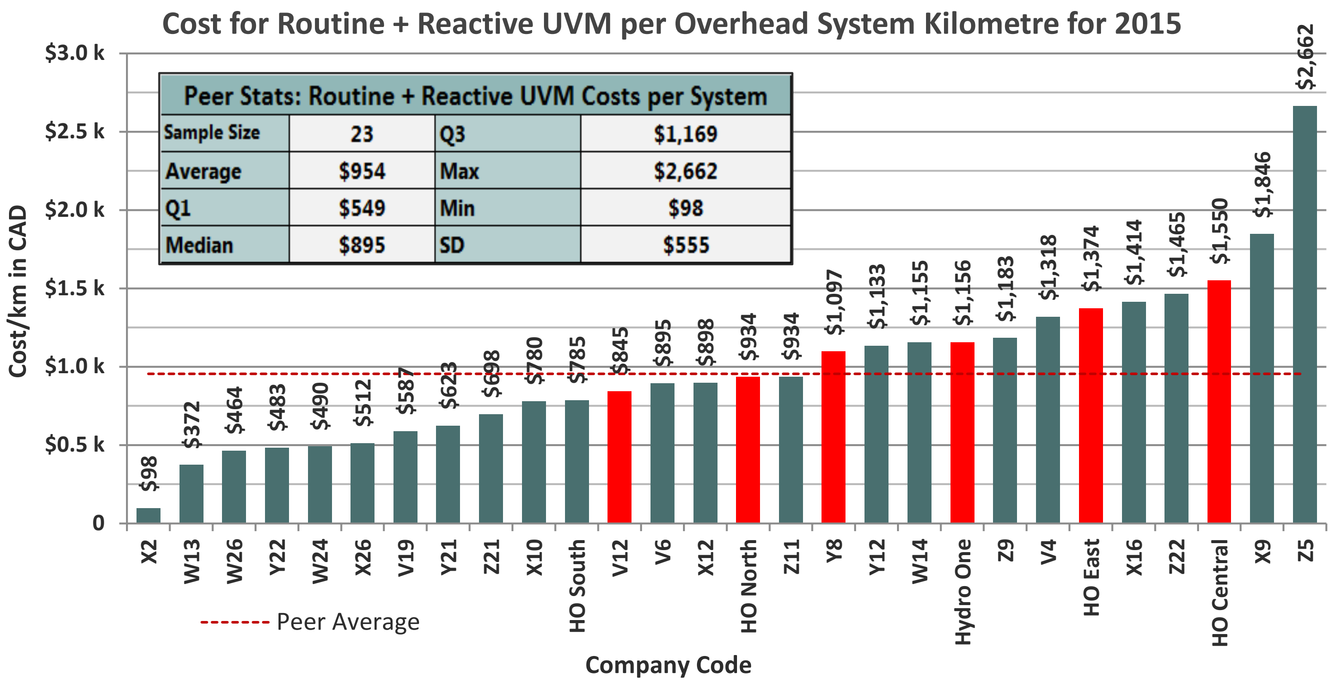
Graph 129: Peer Comparisons of Routine + Reactive Cost for UVM per Overhead System Kilometre for 2012



Graph 130: Peer Comparisons of Routine + Reactive Cost for UVM per Overhead System Kilometre for 2013

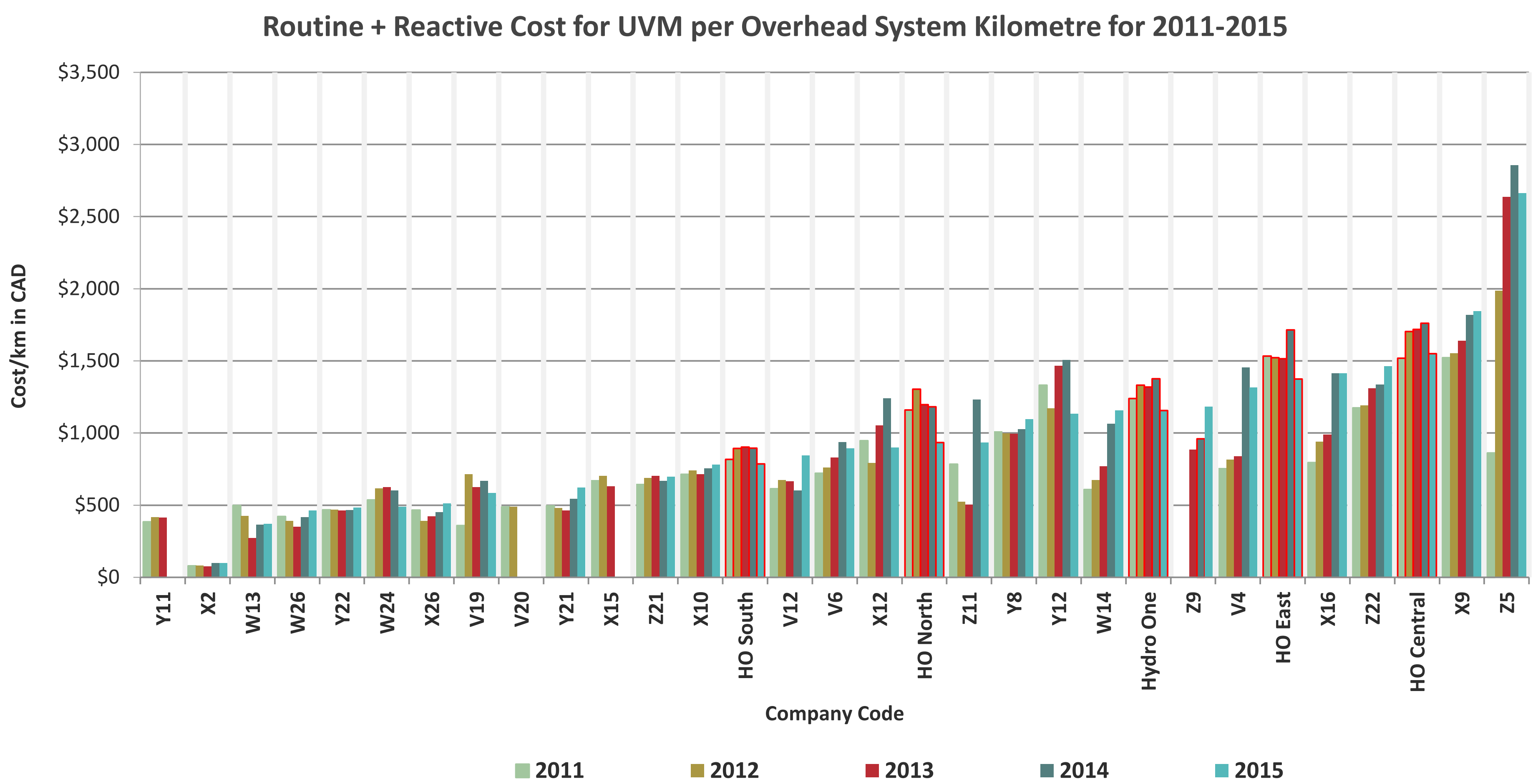


Graph 131: Peer Comparisons of Routine + Reactive Cost for UVM per Overhead System Kilometre for 2014

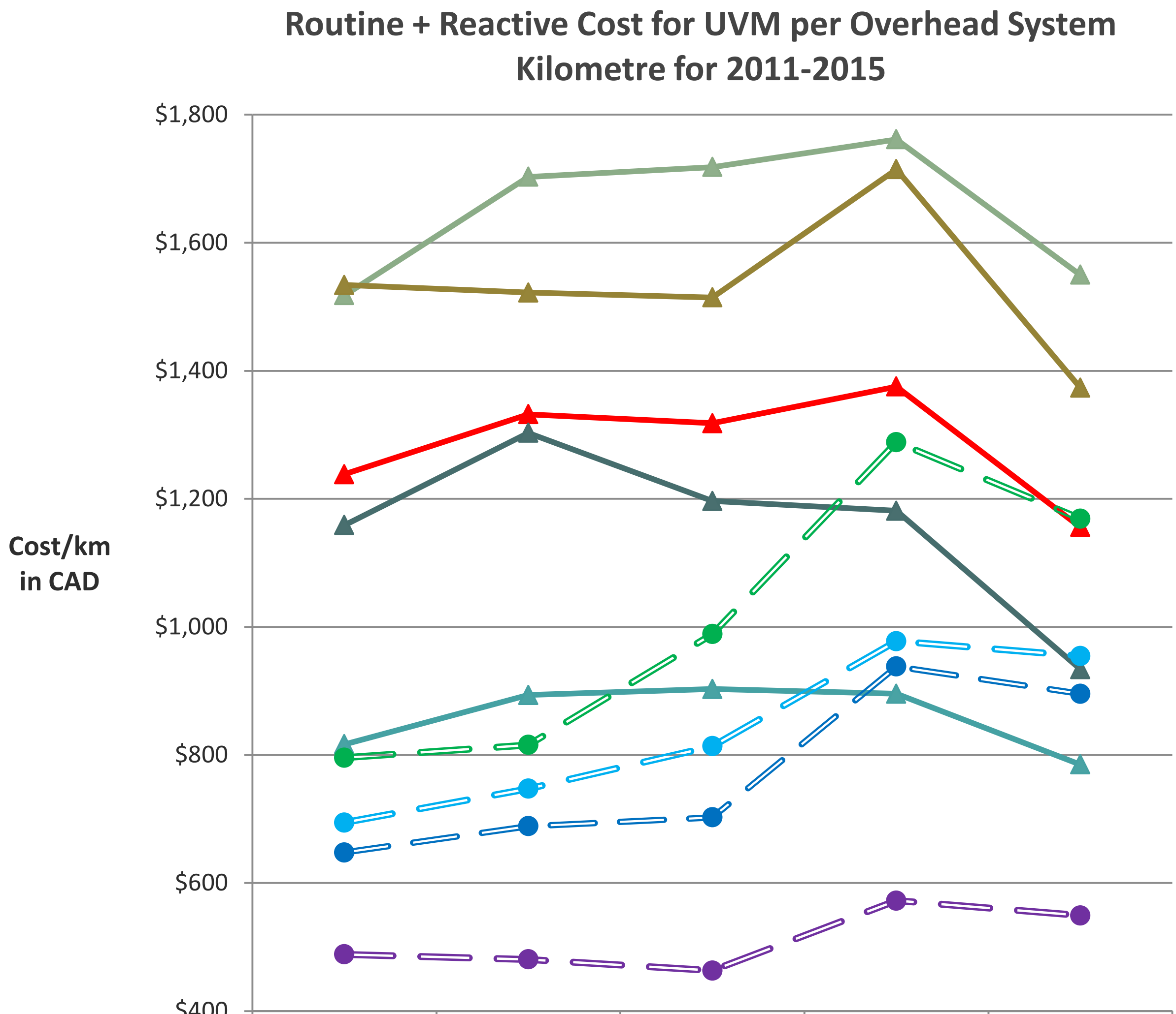


Graph 132: Peer Comparisons of Routine + Reactive Cost for UVM per Overhead System Kilometre for 2015

Routine UVM Cost per System Kilometre Comparisons with Peers 2011-2015



Graph 133: Peer Comparisons of Routine + Reactive Cost for UVM per OH System Kilometre for 2011-2015

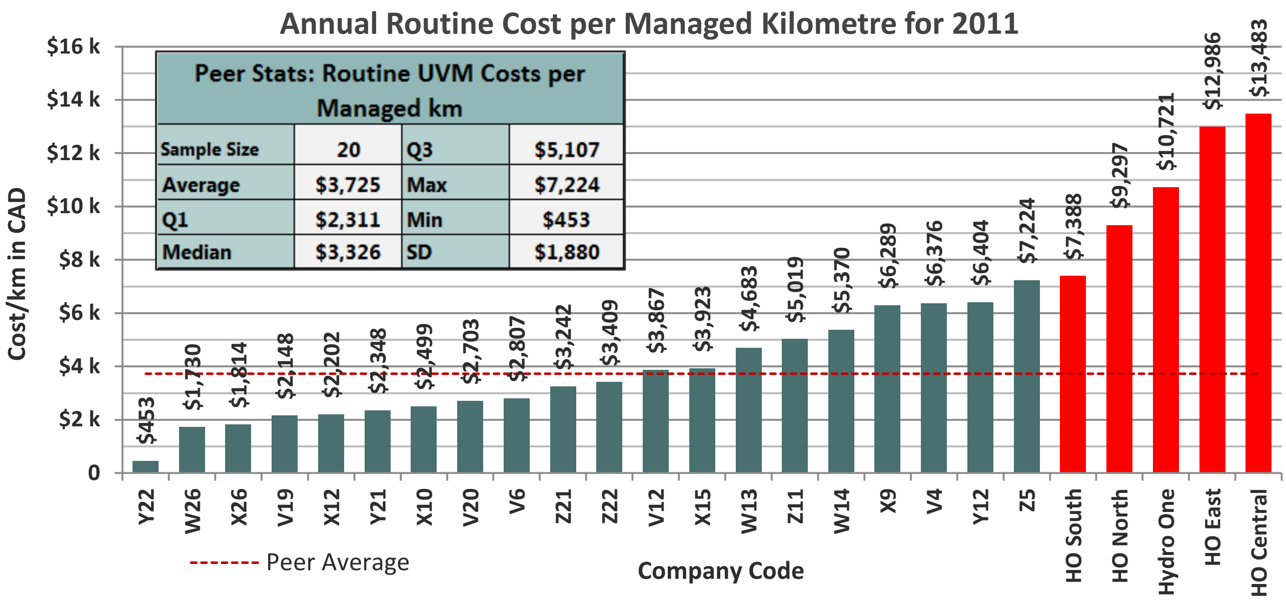


	2011	2012	2013	2014	2015
HO Central	$1,518	$1,703	$1,718	$1,761	$1,550
HO East	$1,534	$1,522	$1,515	$1,715	$1,374
Hydro One	$1,238	$1,332	$1,318	$1,375	$1,156
HO North	$1,159	$1,303	$1,196	$1,181	$934
HO South	$817	$894	$903	$895	$785
Peer Average	$694	$747	$814	$978	$954
Peer Q1	$488	$481	$463	$572	$549
Peer Median	$648	$689	$703	$938	$895
Peer Q3	$796	$816	$989	$1,289	$1,169

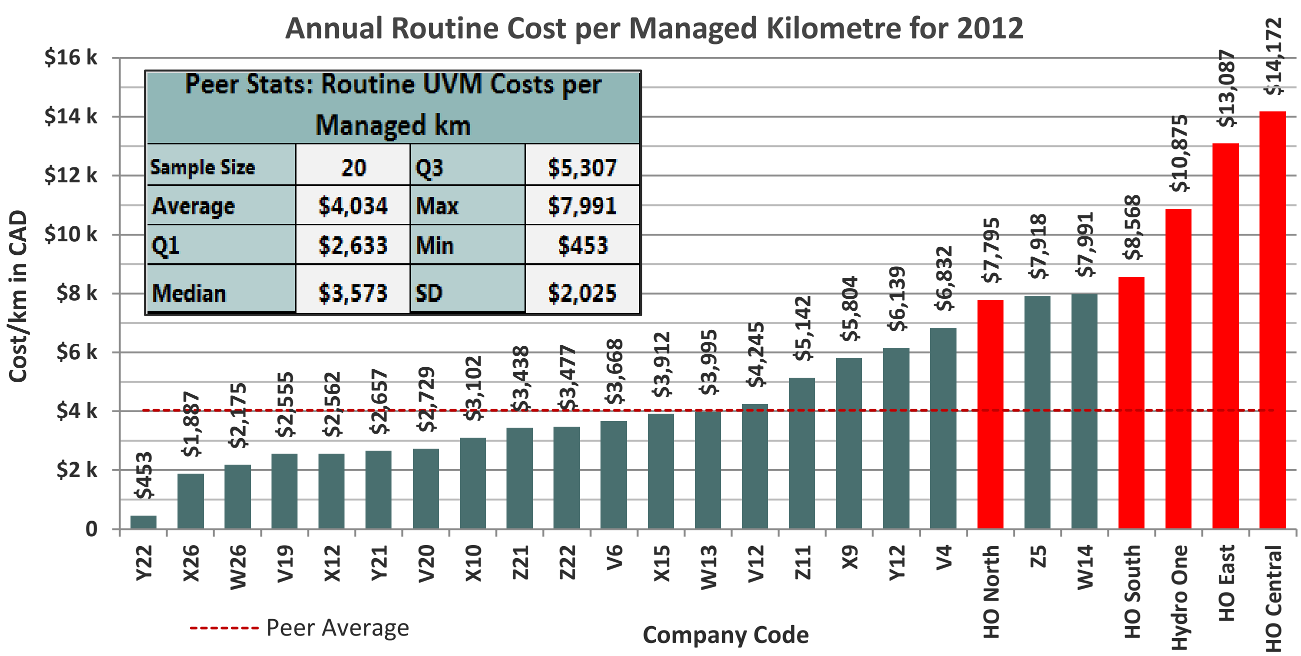
Graph 134: Statistical Comparison of Routine + Reactive UVM Cost per System Kilometre 2011-2015

Annual Routine Cost UVM Expenditures per Managed Kilometre

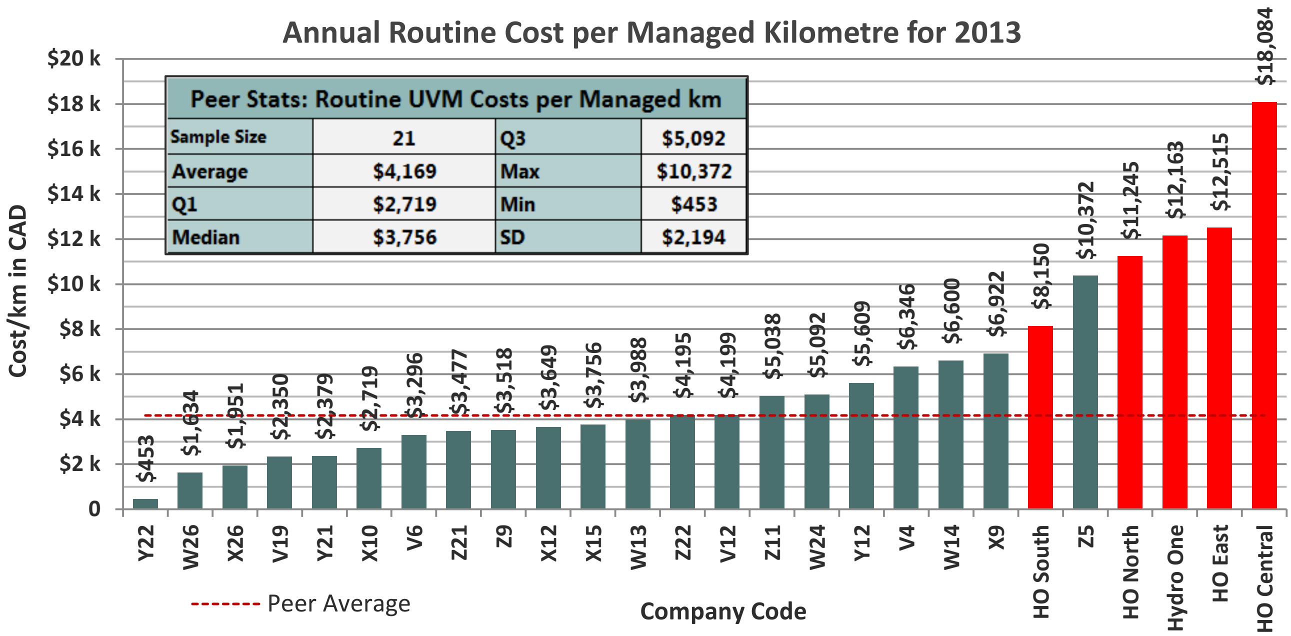
Yearly Routine UVM Expenditures per Managed Kilometre Comparisons for Years 2011-2015



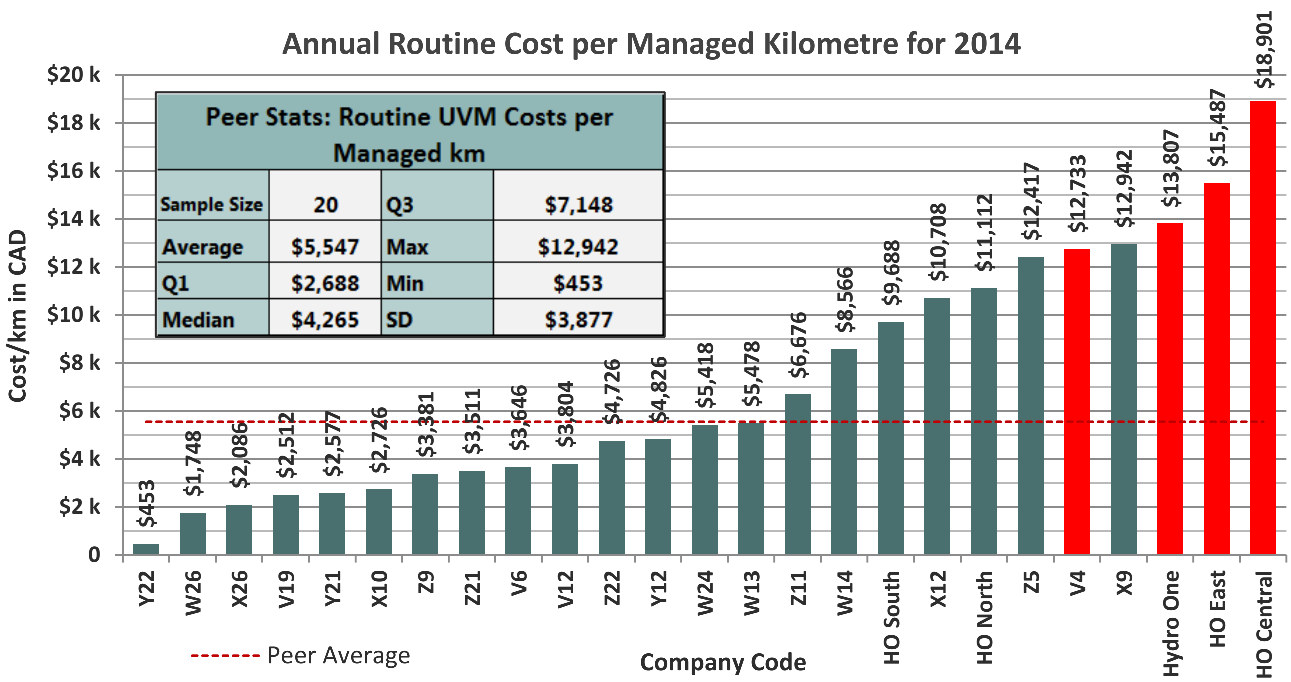
Graph 135: Peer Comparisons of Routine Cost per Managed Kilometre for 2011



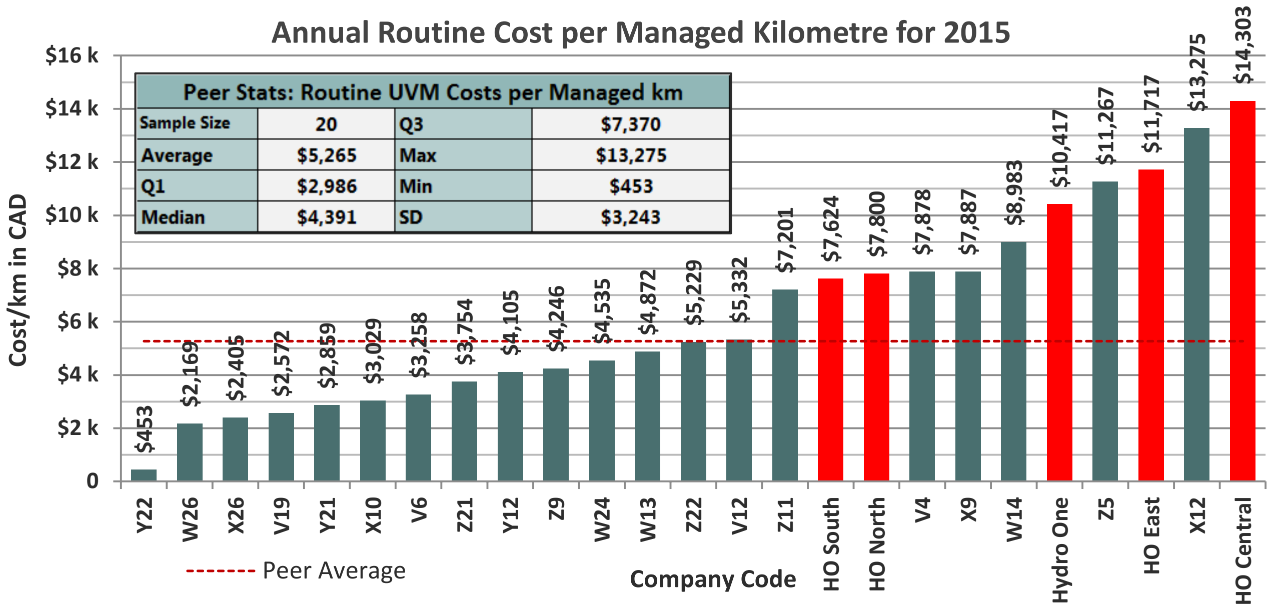
Graph 136: Peer Comparisons of Routine Cost per Managed Kilometre for 2012



Graph 137: Peer Comparisons of Routine Cost per Managed Kilometre for 2013

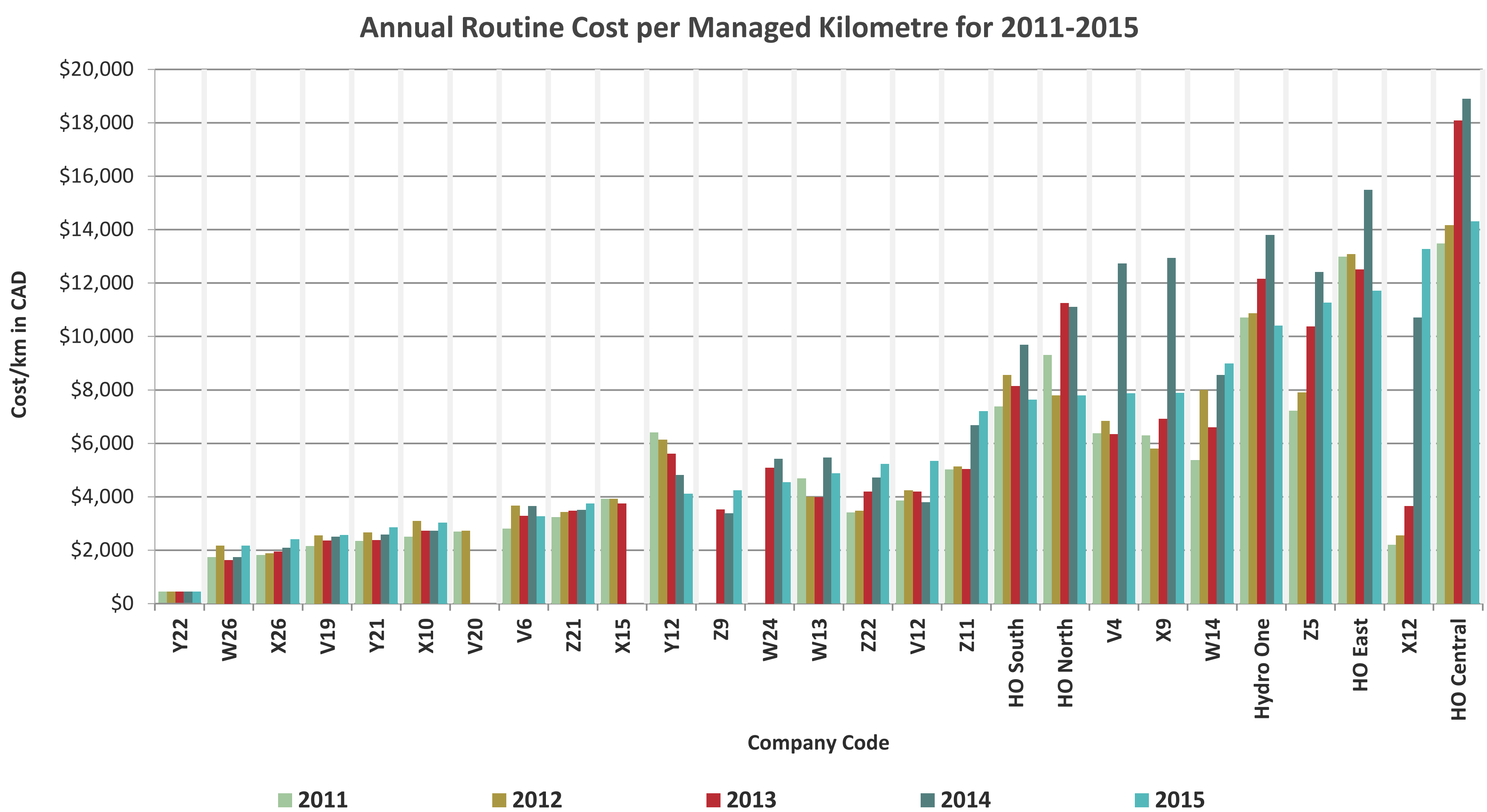


Graph 138: Peer Comparisons of Routine Cost per Managed Kilometre for 2014

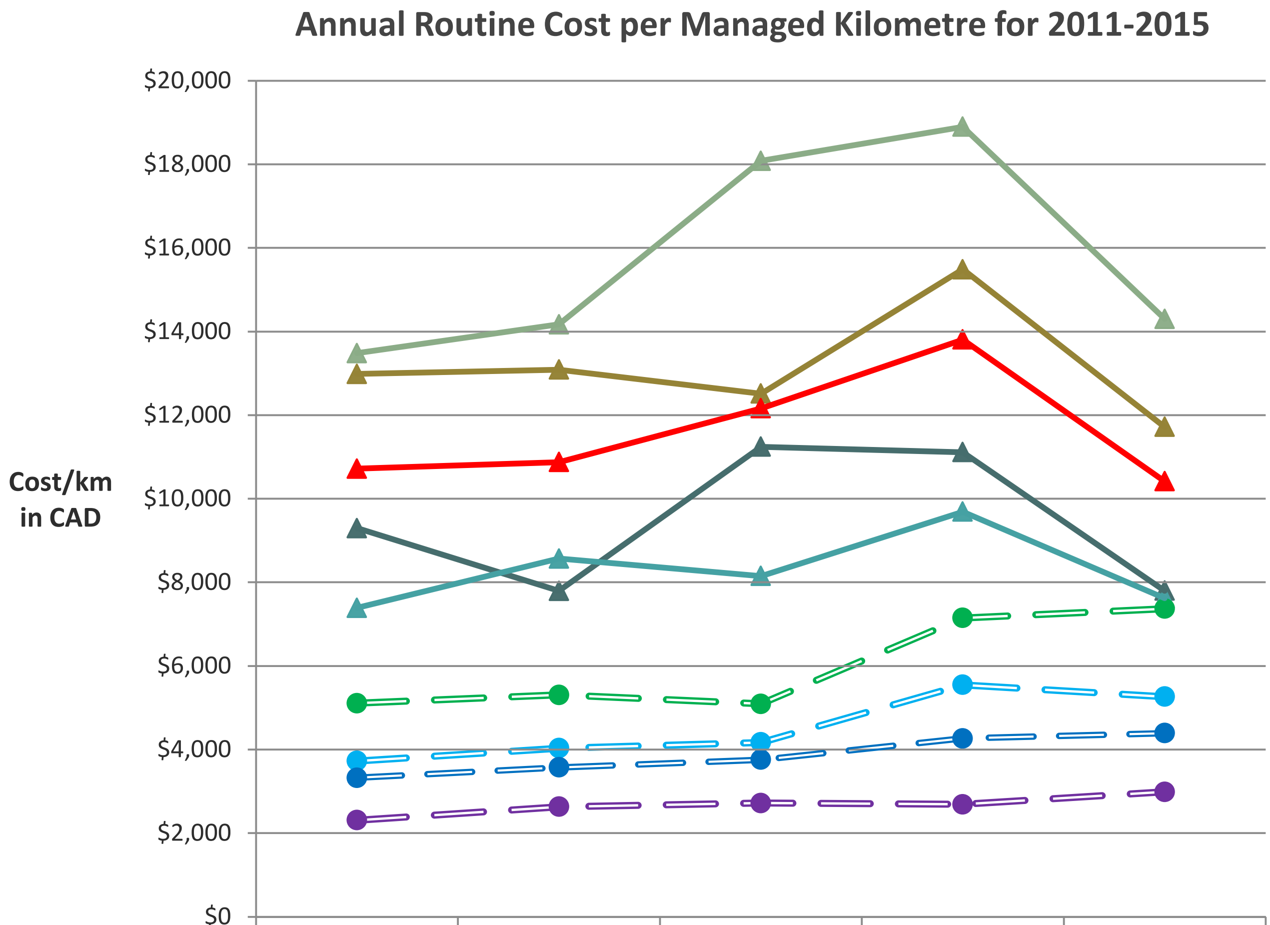


Graph 139: Peer Comparisons of Routine Cost per Managed Kilometre for 2015

Routine UVM Cost per Managed Kilometre Comparisons with Peers 2011-2015



Graph 140: Peer Comparisons of Routine Cost per Managed Kilometre for 2011-2015

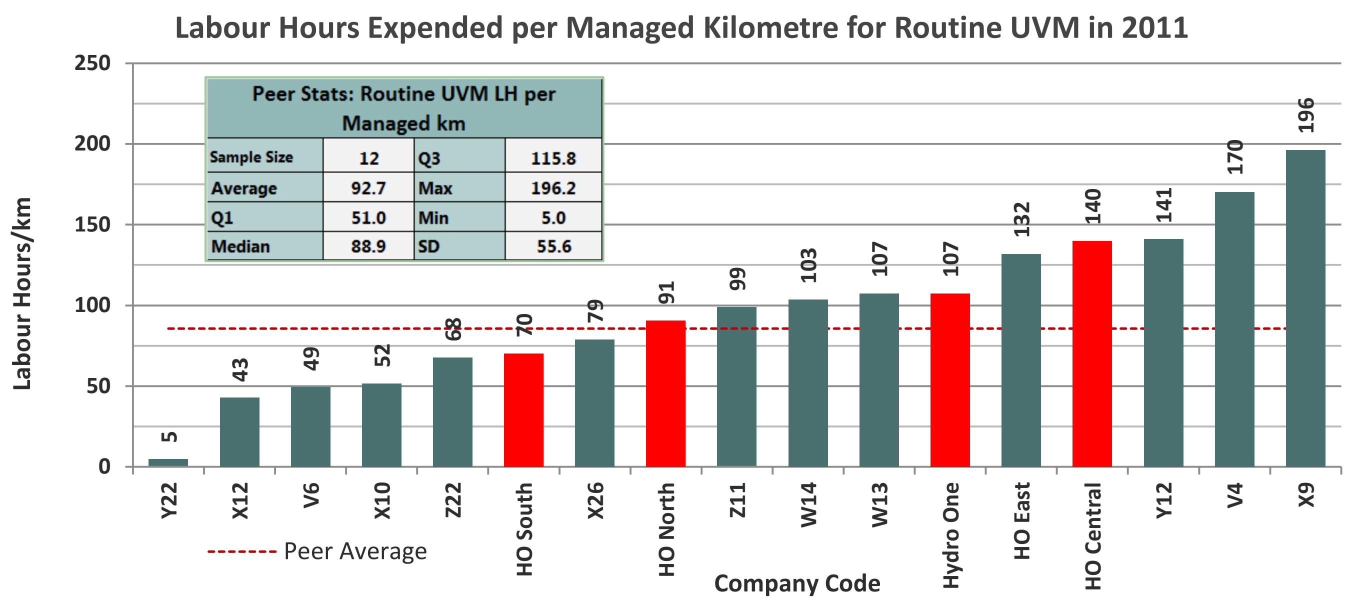


	2011	2012	2013	2014	2015
HO Central	$13,483	$14,172	$18,084	$18,901	$14,303
HO East	$12,986	$13,087	$12,515	$15,487	$11,717
Hydro One	$10,721	$10,875	$12,163	$13,807	$10,417
HO North	$9,297	$7,795	$11,245	$11,112	$7,800
HO South	$7,388	$8,568	$8,150	$9,688	$7,624
Peer Average	$3,725	$4,034	$4,169	$5,547	$5,265
Peer Q1	$2,311	$2,633	$2,719	$2,688	$2,986
Peer Median	$3,326	$3,573	$3,756	$4,265	$4,391
Peer Q3	$5,107	$5,307	$5,092	$7,148	$7,370

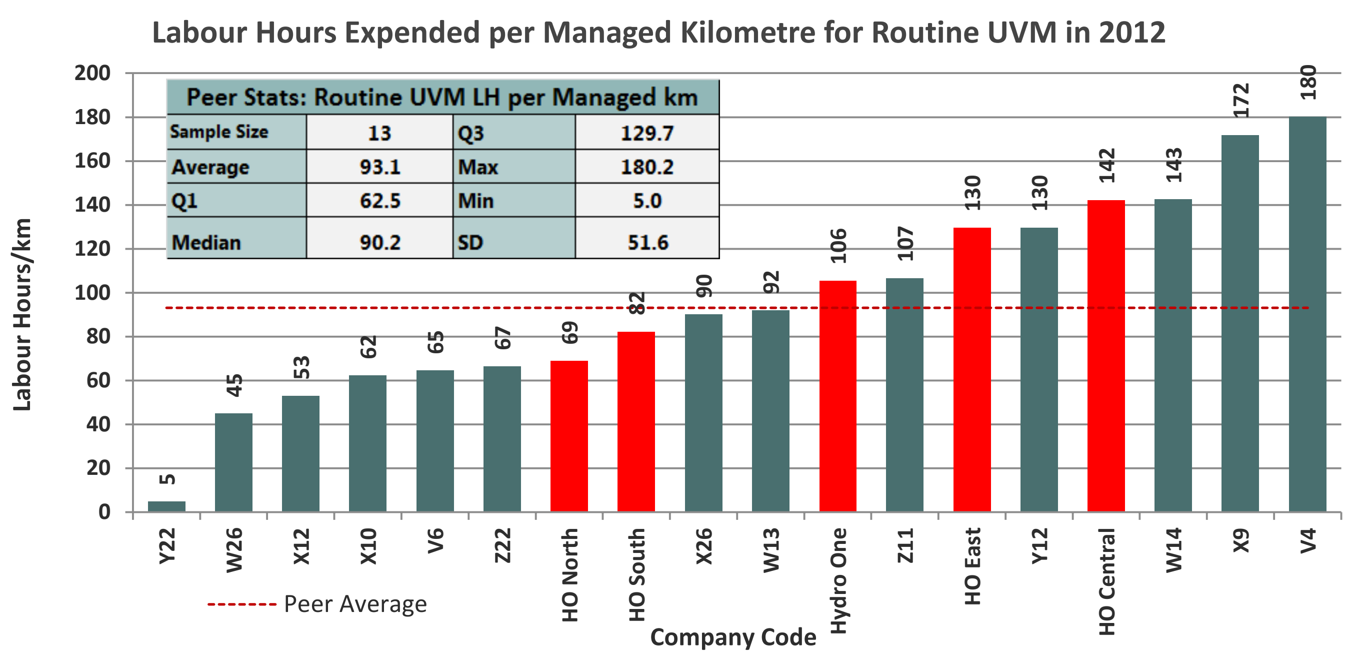
Graph 141: Statistical Comparison of Annual Routine UVM Cost per Managed Kilometre 2011-2015

Annual Routine UVM Labour Hours Expended per Managed Kilometre

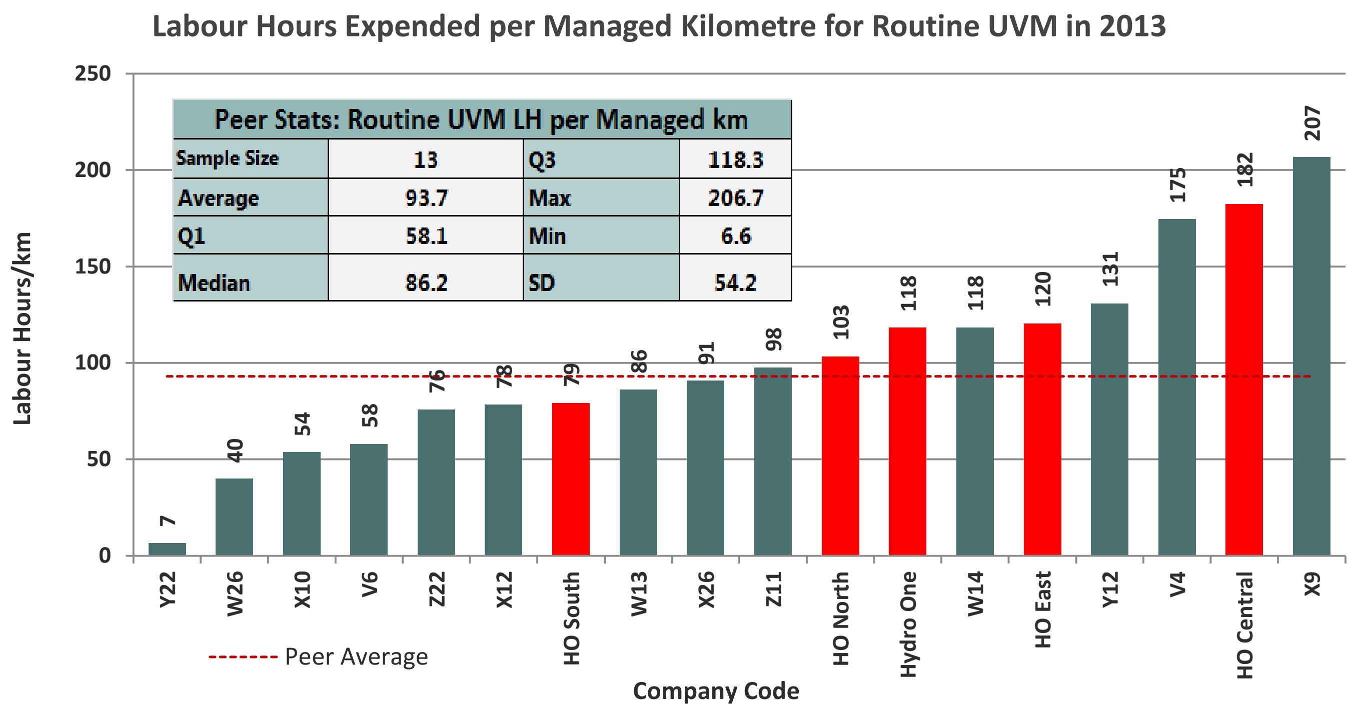
Yearly Routine UVM Labour Hours Expended per Managed Kilometre Comparisons for Years 2011-2015



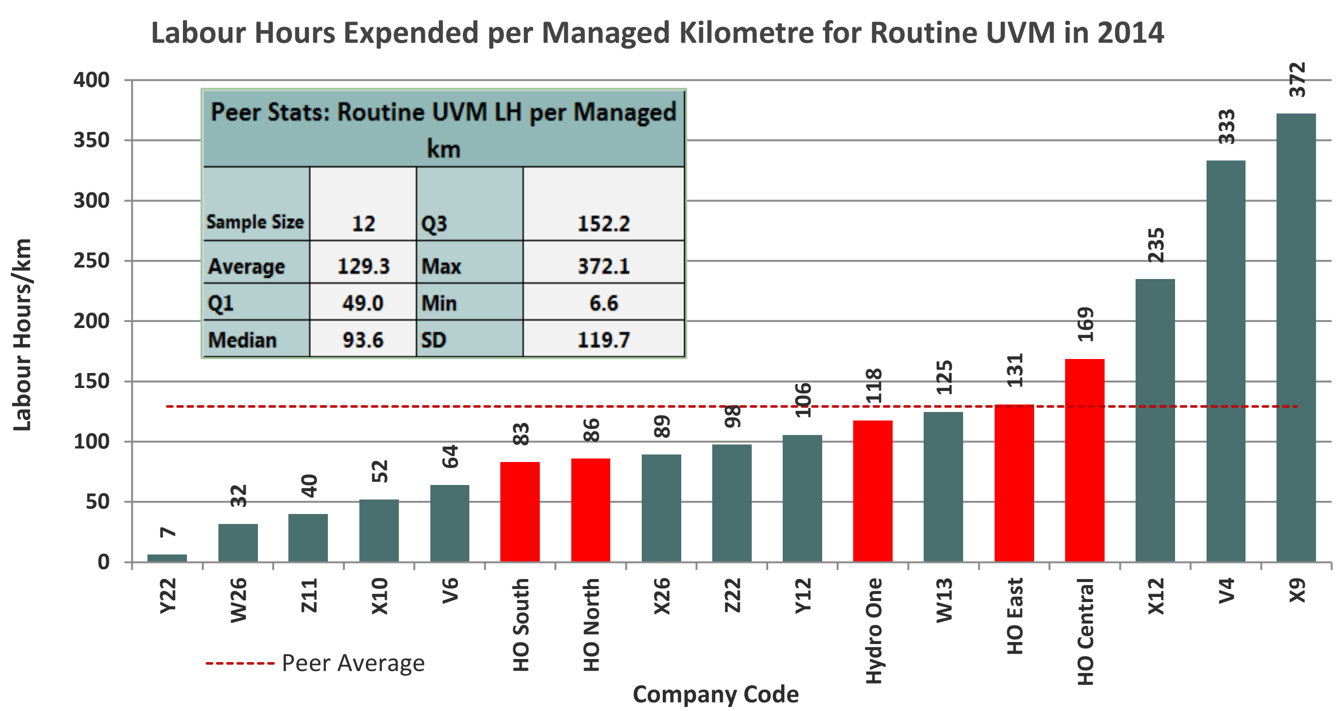
Graph 142: Peer Comparisons of Labour Hours Expended for Routine UVM per Managed Kilometre for 2011



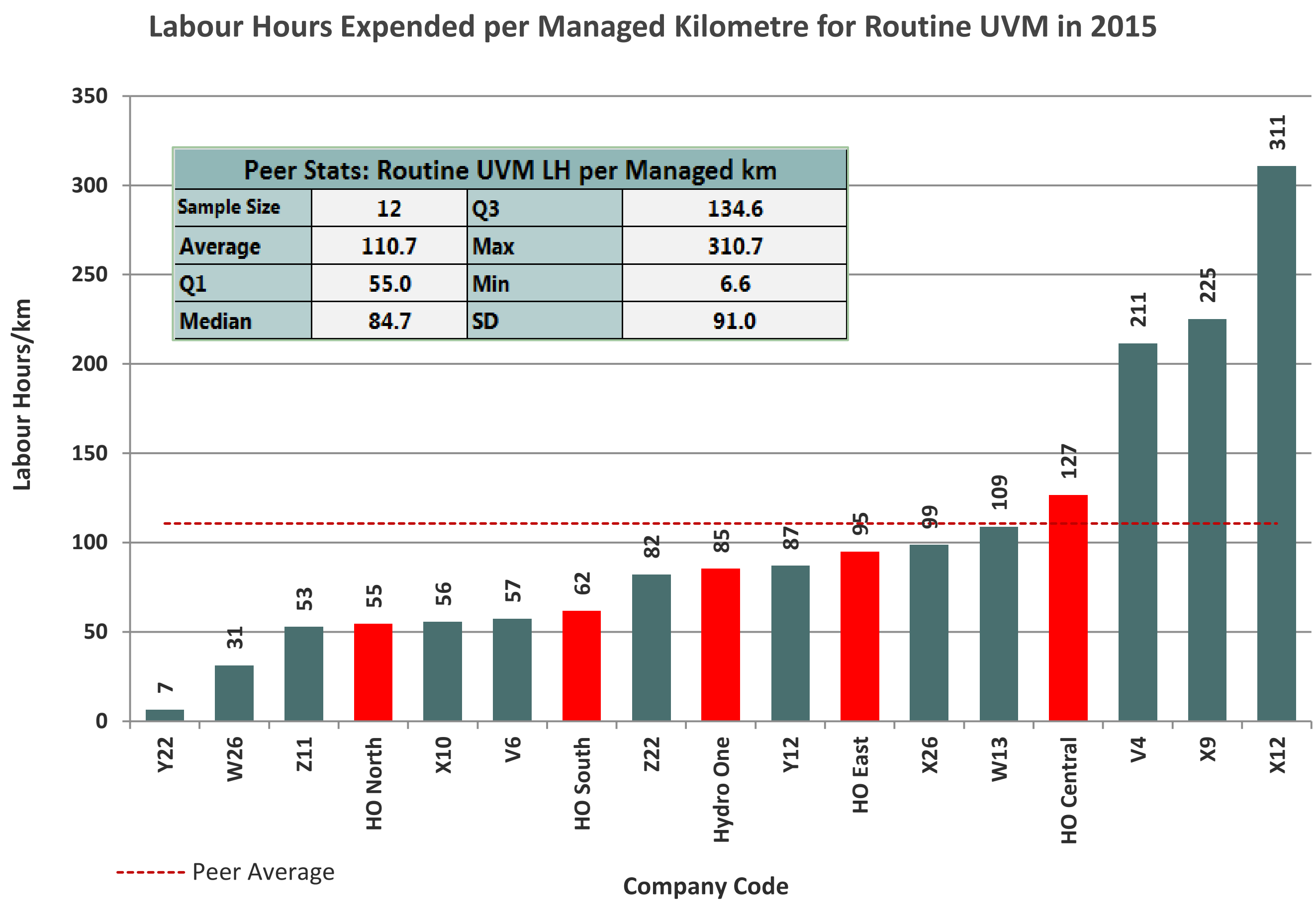
Graph 143: Peer Comparisons of Labour Hours Expended for Routine UVM per Managed Kilometre for 2012



Graph 144: Peer Comparisons of Labour Hours Expended for Routine UVM per Managed Kilometre for 2013



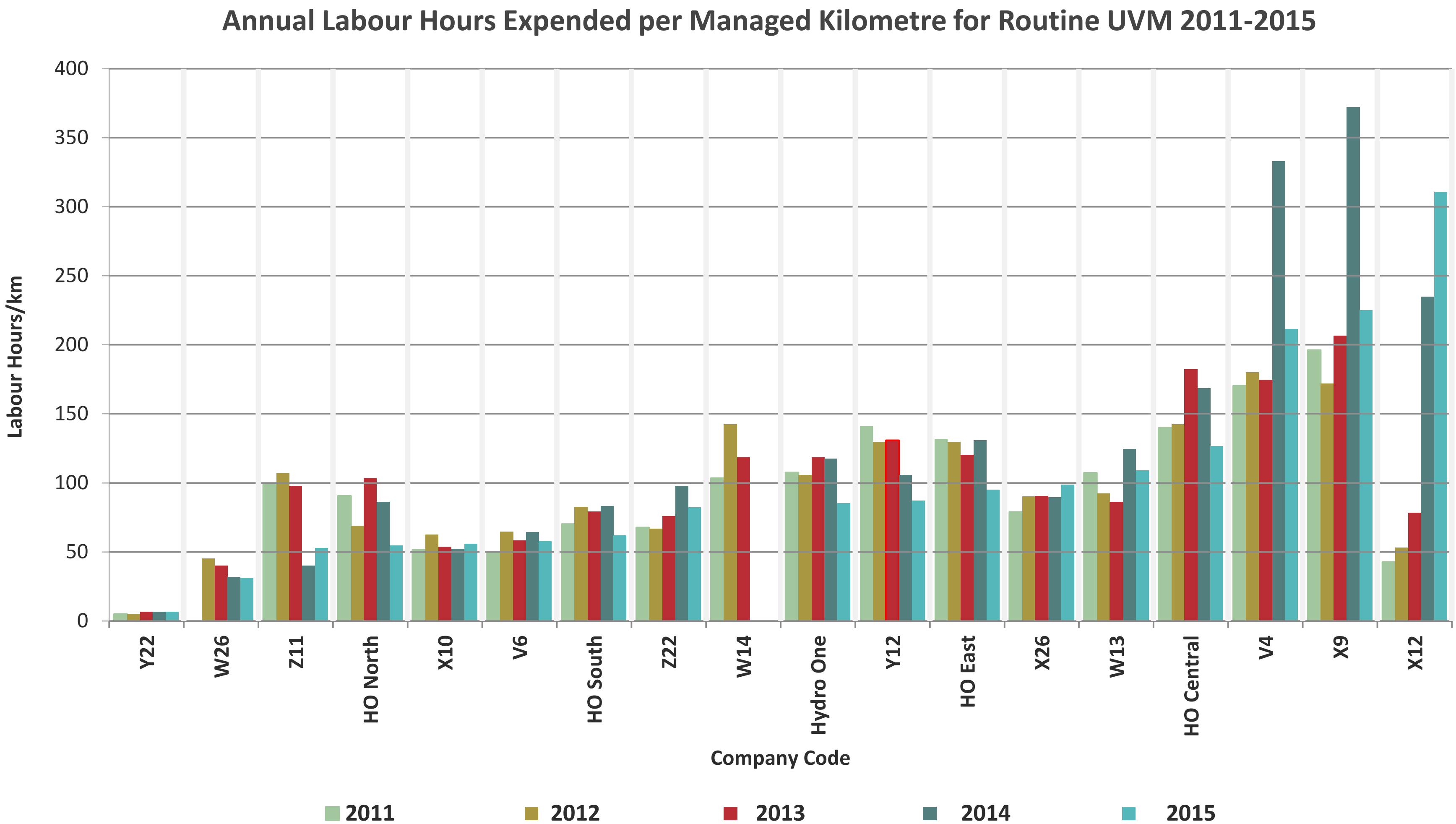
Graph 145: Peer Comparisons of Labour Hours Expended for Routine UVM per Managed Kilometre for 2014



Peer Stats: Routine UVM LH per Managed km			
Sample Size	12	Q3	134.6
Average	110.7	Max	310.7
Q1	55.0	Min	6.6
Median	84.7	SD	91.0

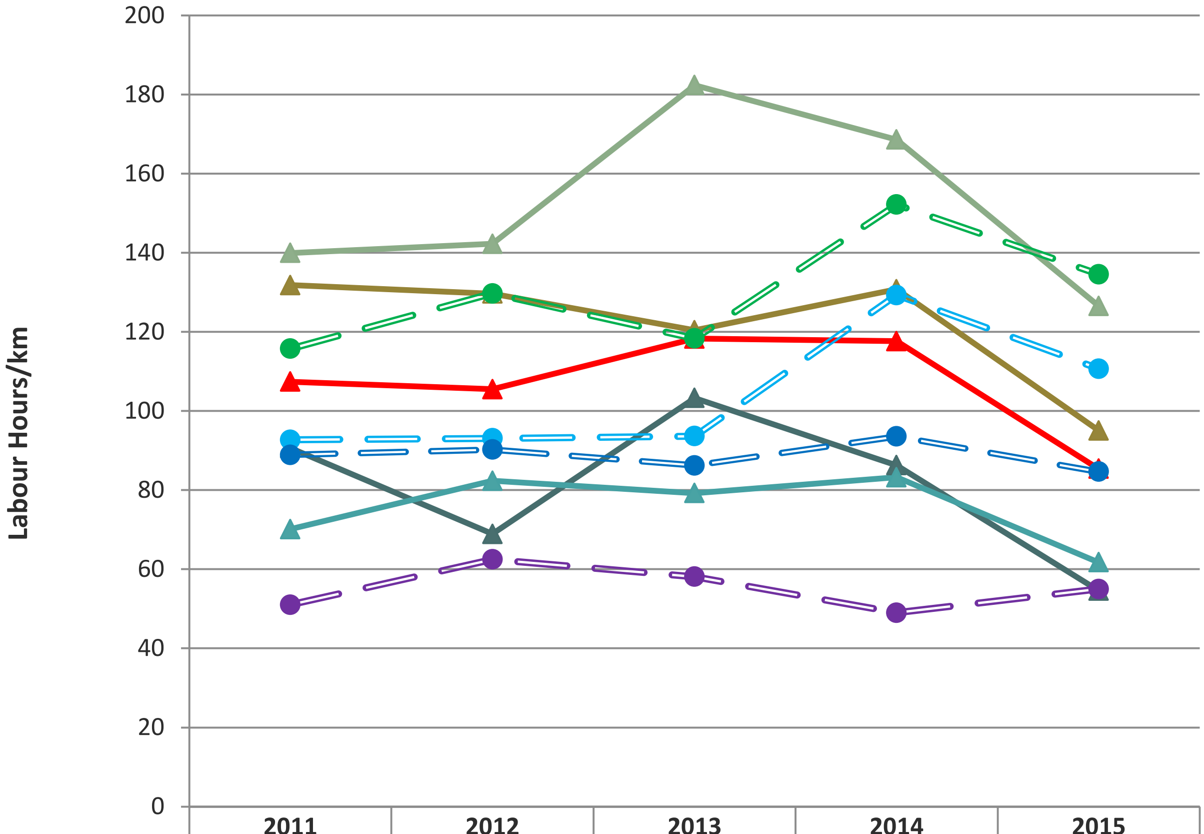
Graph 146: Peer Comparisons of Labour Hours Expended for Routine UVM per Managed Kilometre for 2015

Routine UVM Cost per Managed Kilometre Comparisons with Peers 2011-2015



Graph 147: Peer Comparisons of Routine Labour Hours Expended per Managed Kilometre for 2011-2015

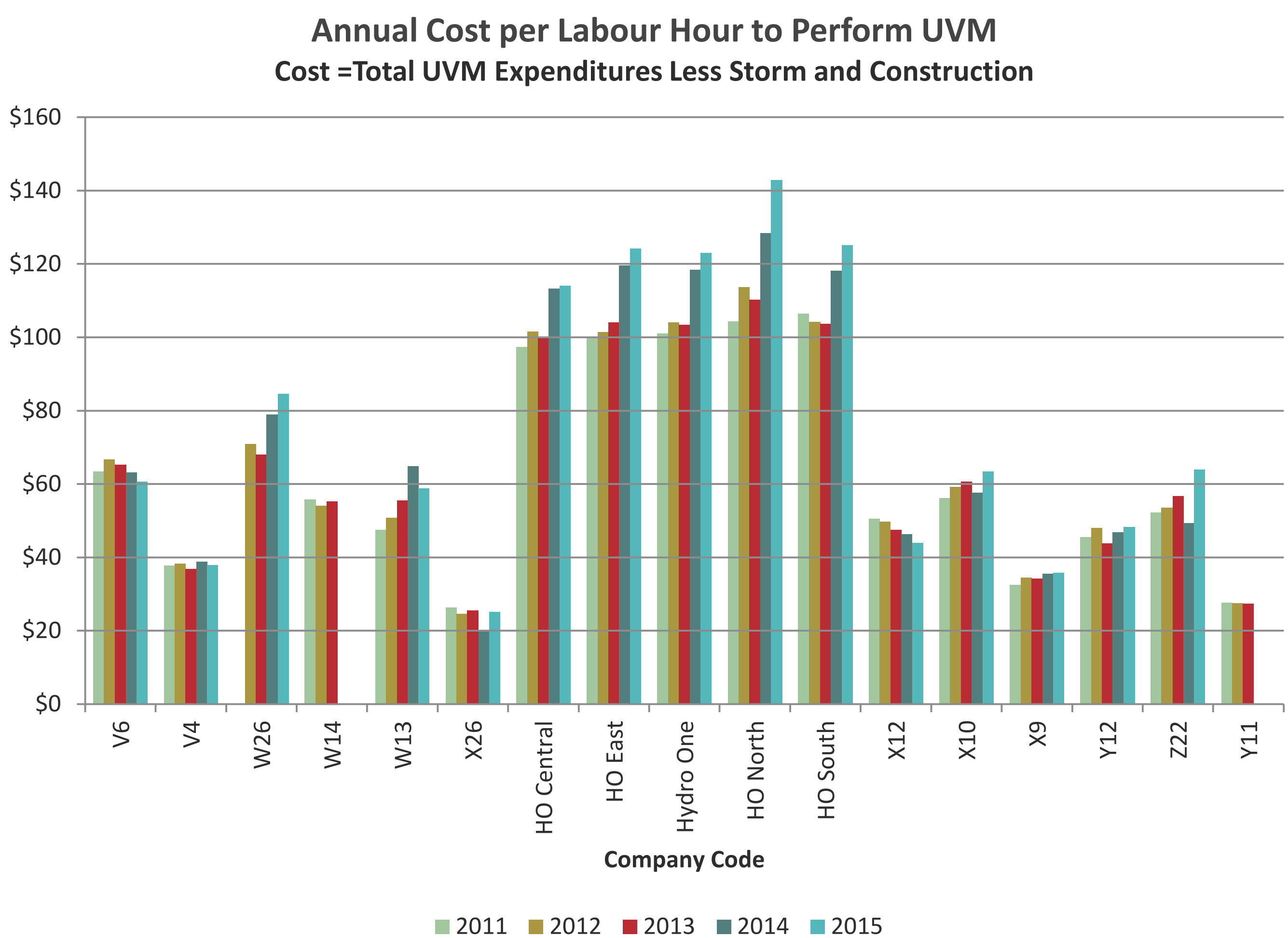
Annual Labour Hours Expended per Managed Kilometre for Routine UVM 2011-2015



	2011	2012	2013	2014	2015
HO Central	139.96	142.26	182.41	168.63	126.56
HO East	131.83	129.68	120.43	130.79	95.09
Hydro One	107.42	105.52	118.30	117.67	85.40
HO North	90.66	68.91	103.29	86.30	54.60
HO South	70.14	82.38	79.23	83.26	61.74
Peer Average	92.7	93.1	93.7	129.3	110.7
Peer Q1	51.0	62.5	58.1	49.0	55.0
Peer Median	88.9	90.2	86.2	93.6	84.7
Peer Q3	115.8	129.7	118.3	152.2	134.6

Graph 148: Statistical Comparison of Annual Routine UVM Cost per Managed Kilometre 2011-2015

Longitudinal Study of Cost per Labour Hour for Peer Group

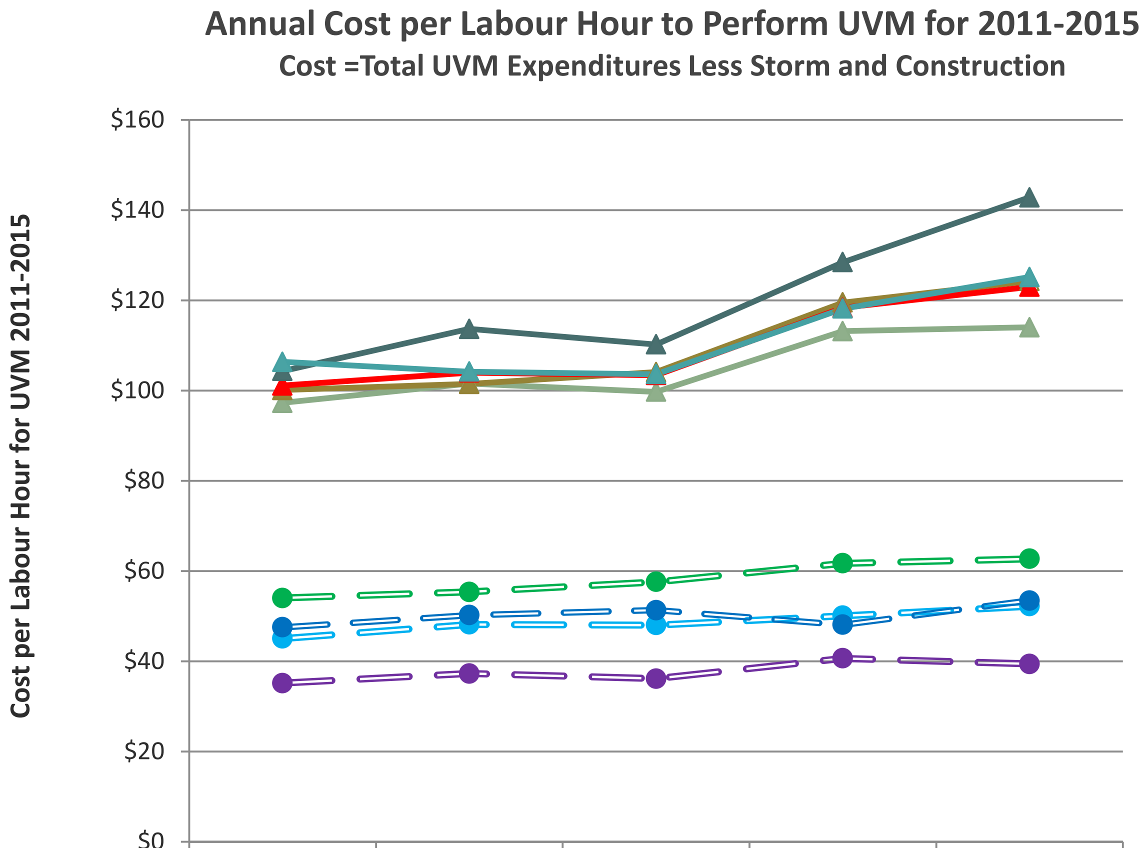


Graph 149: Annual Cost per Labour Hour to Perform UVM

This study was done to visualize the change the change in cost per labour hour over time and identify trends in the change. Companies like V6 are actually decreasing their cost per labour hour, while the majority is increasing.

Storm and New Construction were not included in this study for several reasons:

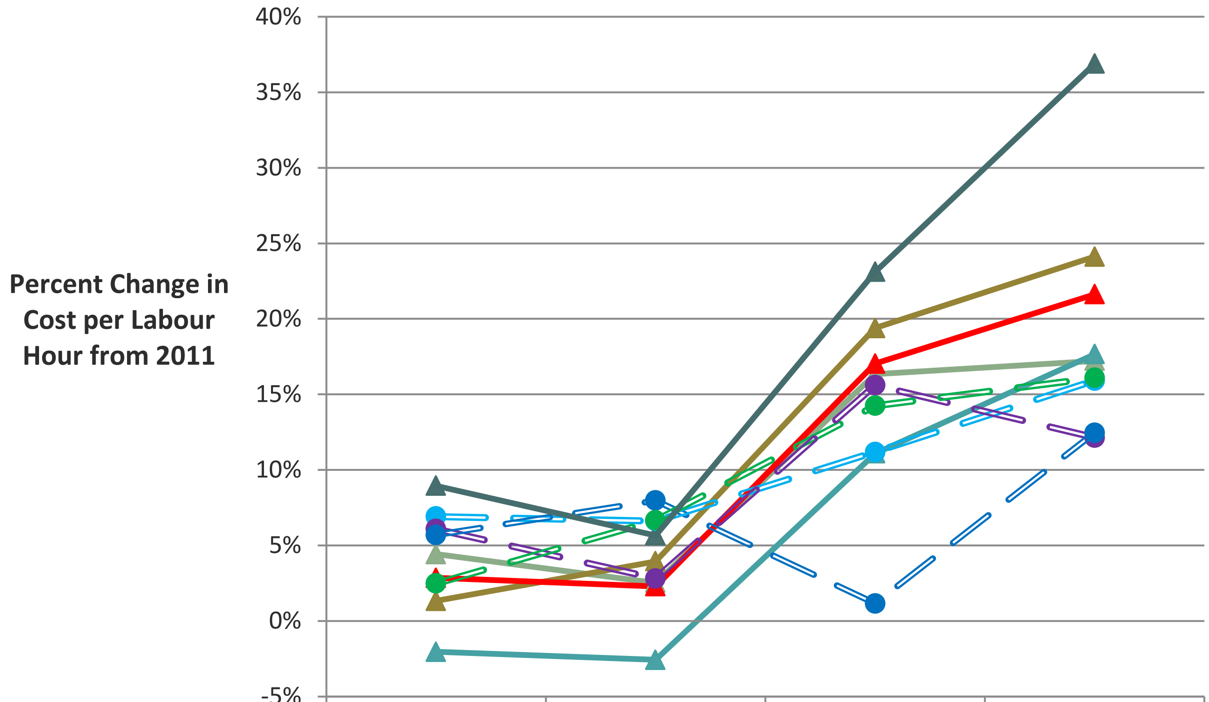
- Some utilities do not capture these costs
- Many companies capitalize these costs or they are paid for by different departments.



	2011	2012	2013	2014	2015
HO Central	$97.30	$101.60	$99.75	$113.20	$114.05
HO East	$100.13	$101.47	$104.09	$119.55	$124.28
Hydro One	$101.12	$104.00	$103.43	$118.34	$122.99
HO North	$104.34	$113.68	$110.25	$128.45	$142.83
HO South	$106.37	$104.19	$103.63	$118.17	$125.16
Peer Average	$45.07	$48.18	$48.05	$50.10	$52.24
Peer Q1	$35.18	$37.32	$36.17	$40.66	$39.45
Peer Median	$47.56	$50.27	$51.35	$48.11	$53.48
Peer Q3	$54.03	$55.37	$57.63	$61.73	$62.73

Graph 150: Annual Cost per Labour Hour Comparison of Hydro One and Regions to Peer Statistics

Change in Annual Cost per Labour Hour to Perform UVM
2012-2015 Cost Minus 2011 Cost
Cost =Total UVM Expenditures Less Storm and Construction



	2012	2013	2014	2015
HO Central	4%	3%	16%	17%
HO East	1%	4%	19%	24%
Hydro One	3%	2%	17%	22%
HO North	9%	6%	23%	37%
HO South	-2%	-3%	11%	18%
Peer Average	7%	7%	11%	16%
Peer Q1	6%	3%	16%	12%
Peer Median	6%	8%	1%	12%
Peer Q3	2%	7%	14%	16%

Graph 151: Change in Annual Cost per Labour Hour Comparison of Hydro One and Regions to Peer Statistics

LONGITUDINAL PRODUCTIVITY COMPARISONS

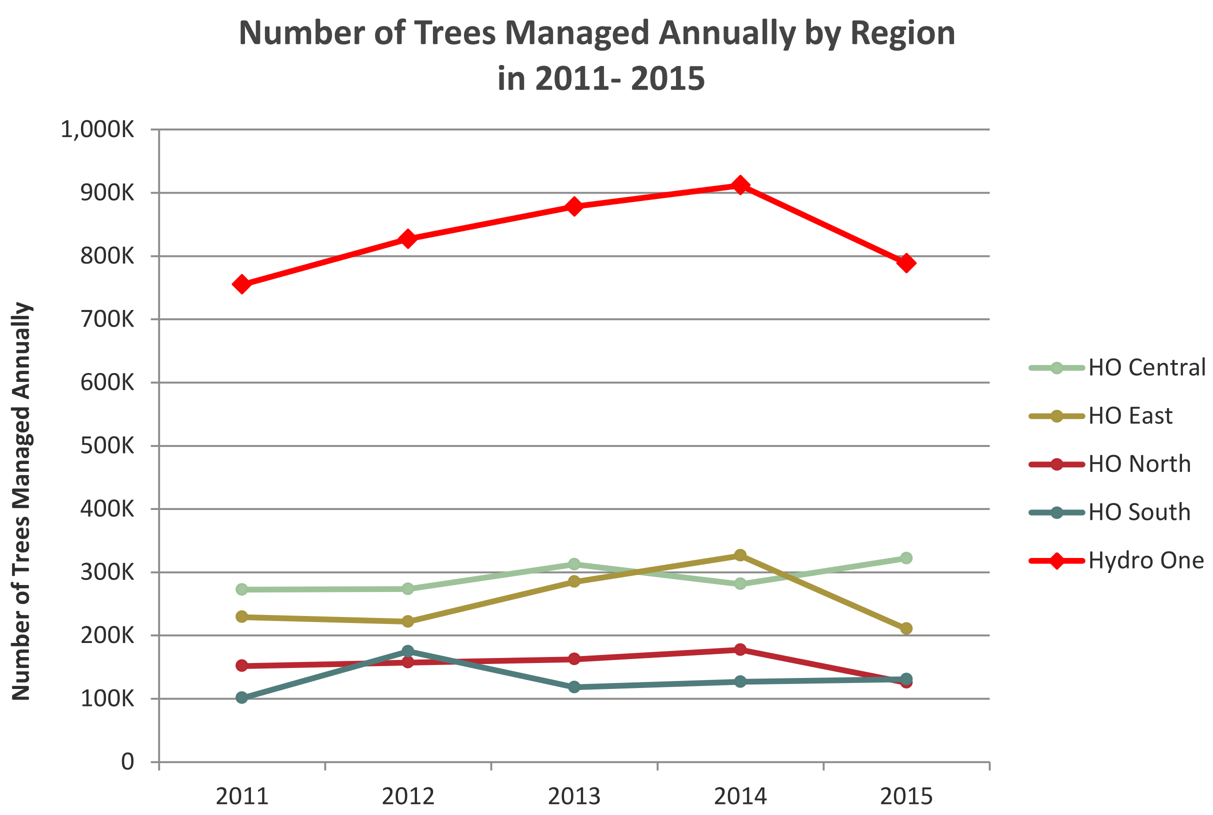
Productivity Comparisons between Hydro One Regions

Hydro One Regional Production Statistics

Five-Year Averages of Tree Production Statistics 2010-2015				
Regions	**Percent Pruned**	**Percent Removed**	**Cost per Tree Treated**	**Labour Hours per Tree Treated**
Hydro One Networks	**53%**	**47%**	**$106.18**	**0.91**
Hydro One Central	**62%**	**38%**	**$98.43**	**0.88**
Hydro One South	**61%**	**39%**	**$153.18**	**1.31**
Hydro One East	**54%**	**46%**	**$110.31**	**0.94**
Hydro One North	**27%**	**73%**	**$81.02**	**0.63**

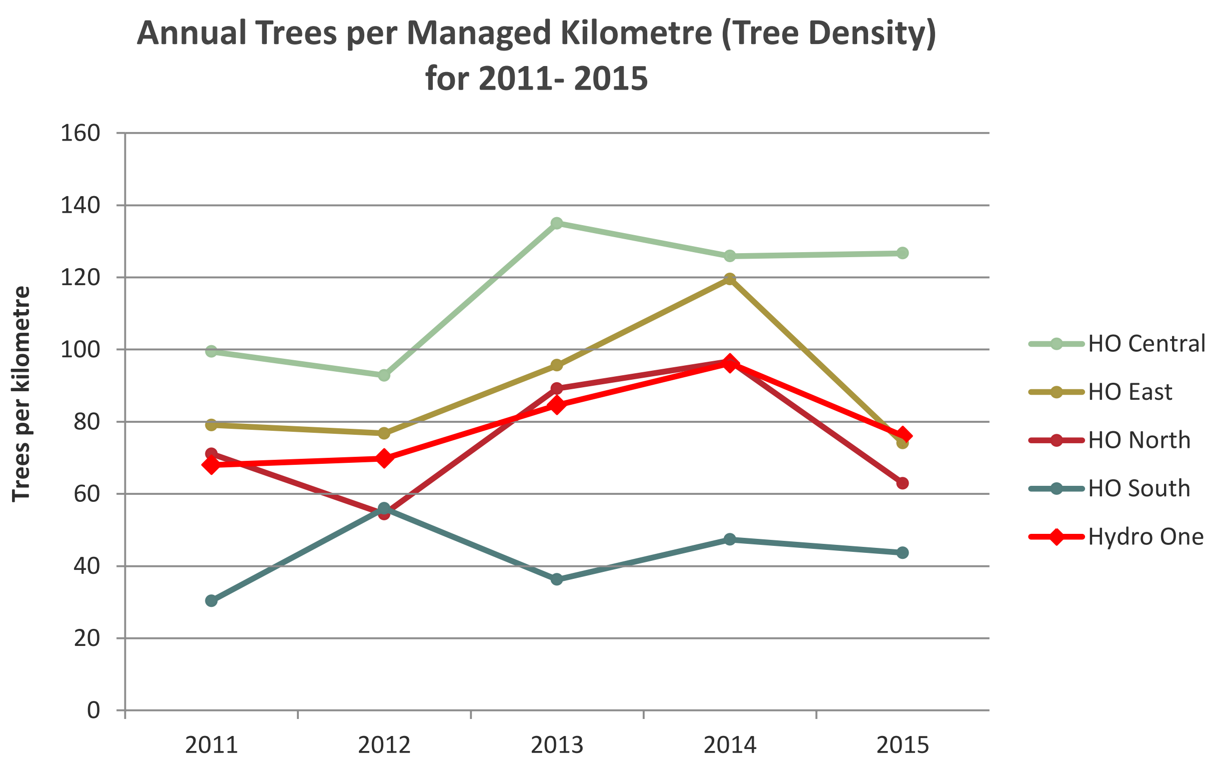
Table 31: Five-Year Averages of Tree Production Statistics 2010-2015

Trees Managed Annually in Hydro One Regions

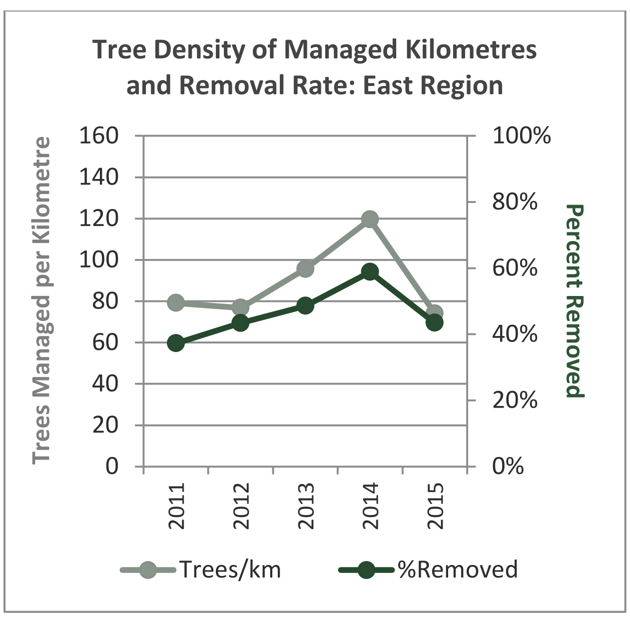


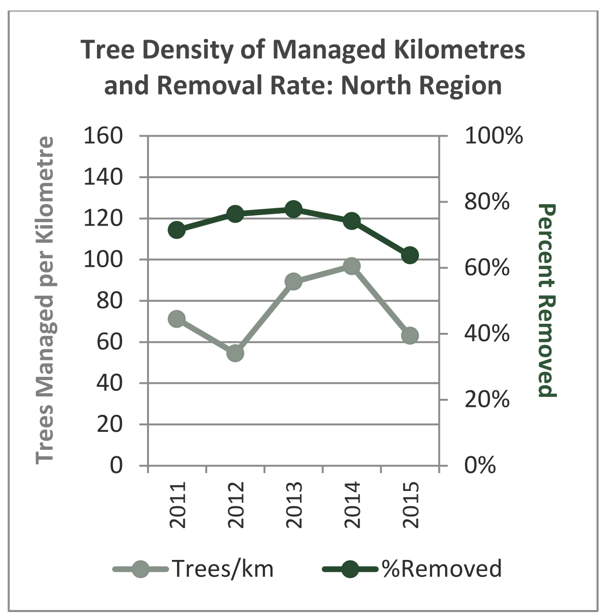
Graph 152: Number of Trees Managed Annually by Region in 2011- 2015

Managed Tree Density for Hydro One by Region

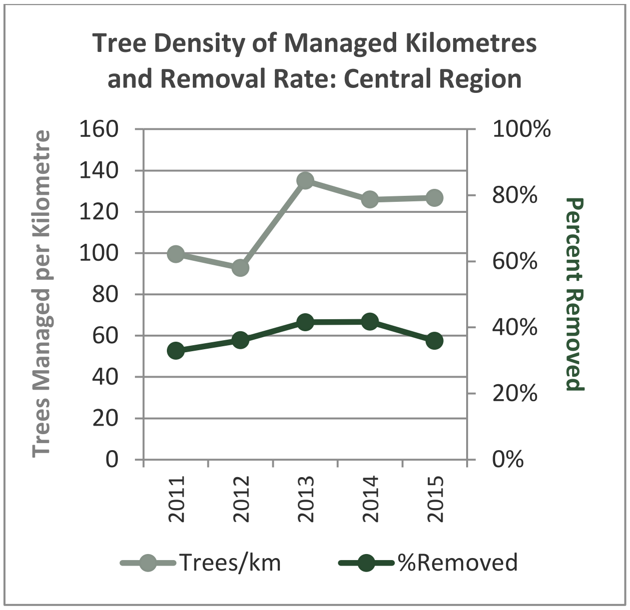


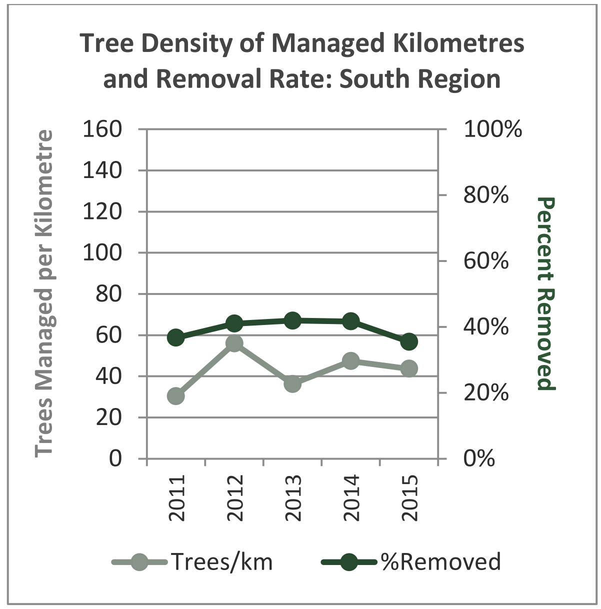
Graph 153: Annual Trees per Managed Kilometre (Tree Density) for 2011- 2015



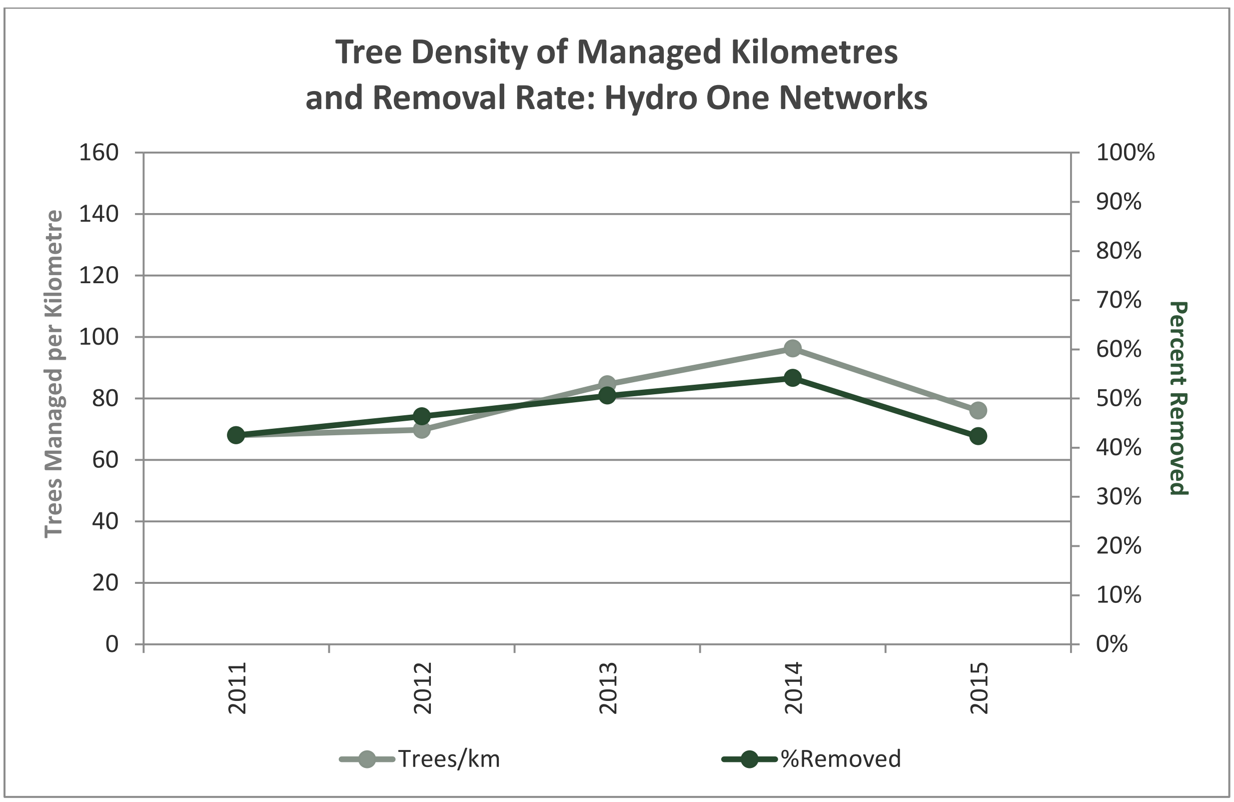


Graph 154: Tree Density of Managed Kilometres and Removal Rate: East Region and North Region





Graph 155: Tree Density of Managed Kilometres and Removal Rate: Central Region and South Region

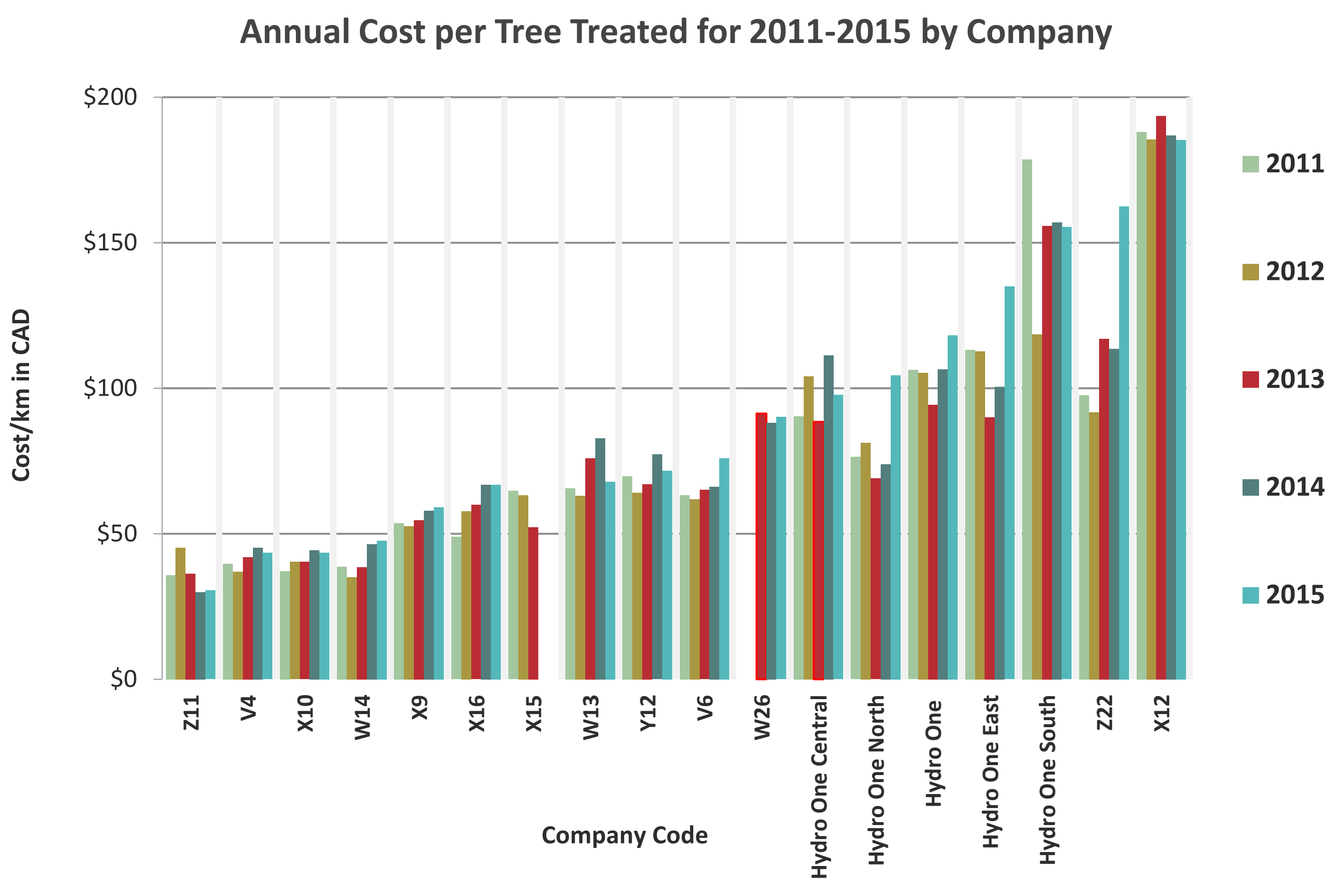


Graph 156: Tree Density of Managed Kilometres and Removal Rate: Hydro One Networks

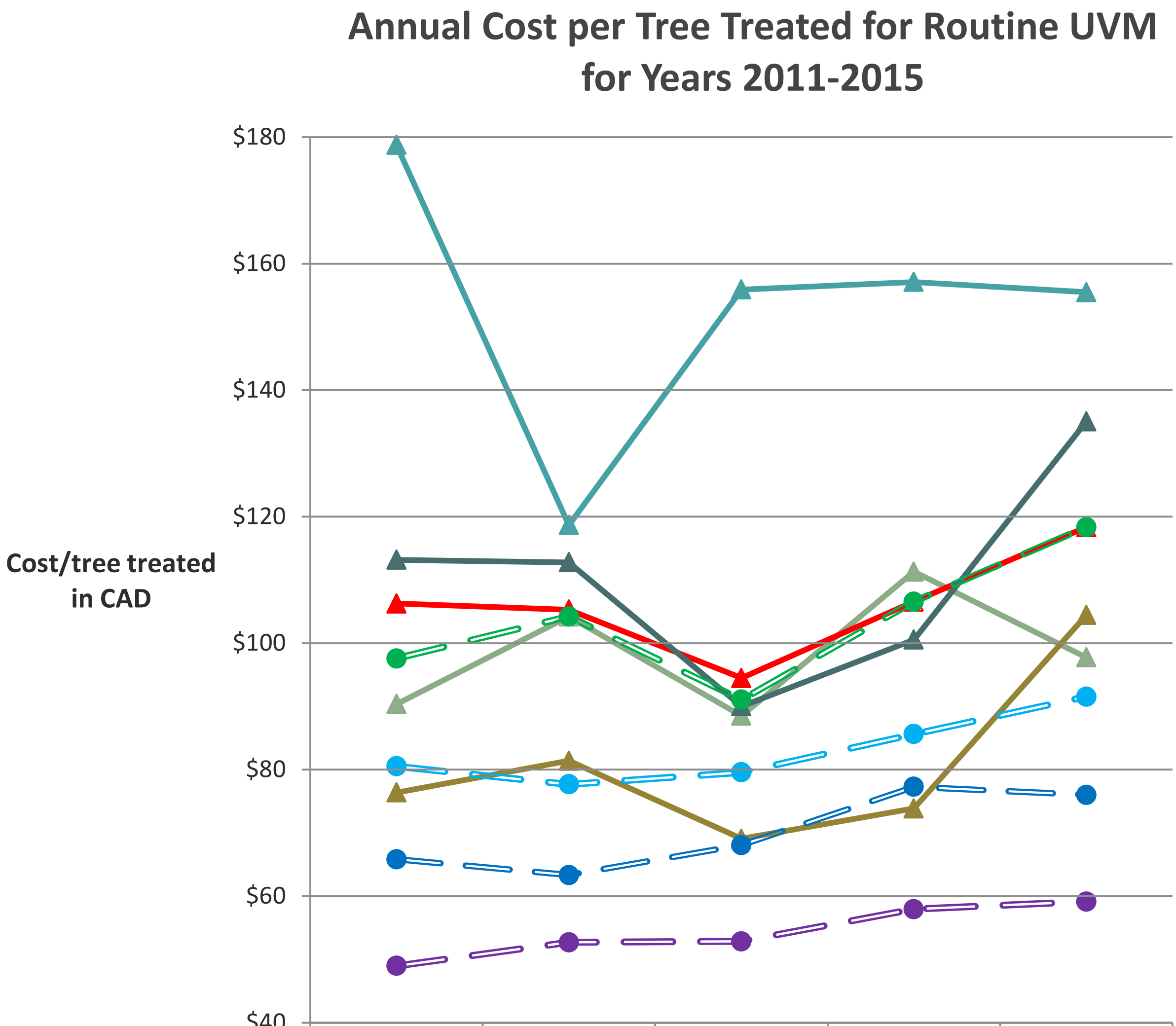
Year by Year Productivity Comparisons between Hydro One and Peers

Tree Treated is defined as trees either pruned or removed. Graphs with clustered bars representing years are sorted by 2015 ratios.

Cost per Tree Treated for Routine Maintenance 2011-2015



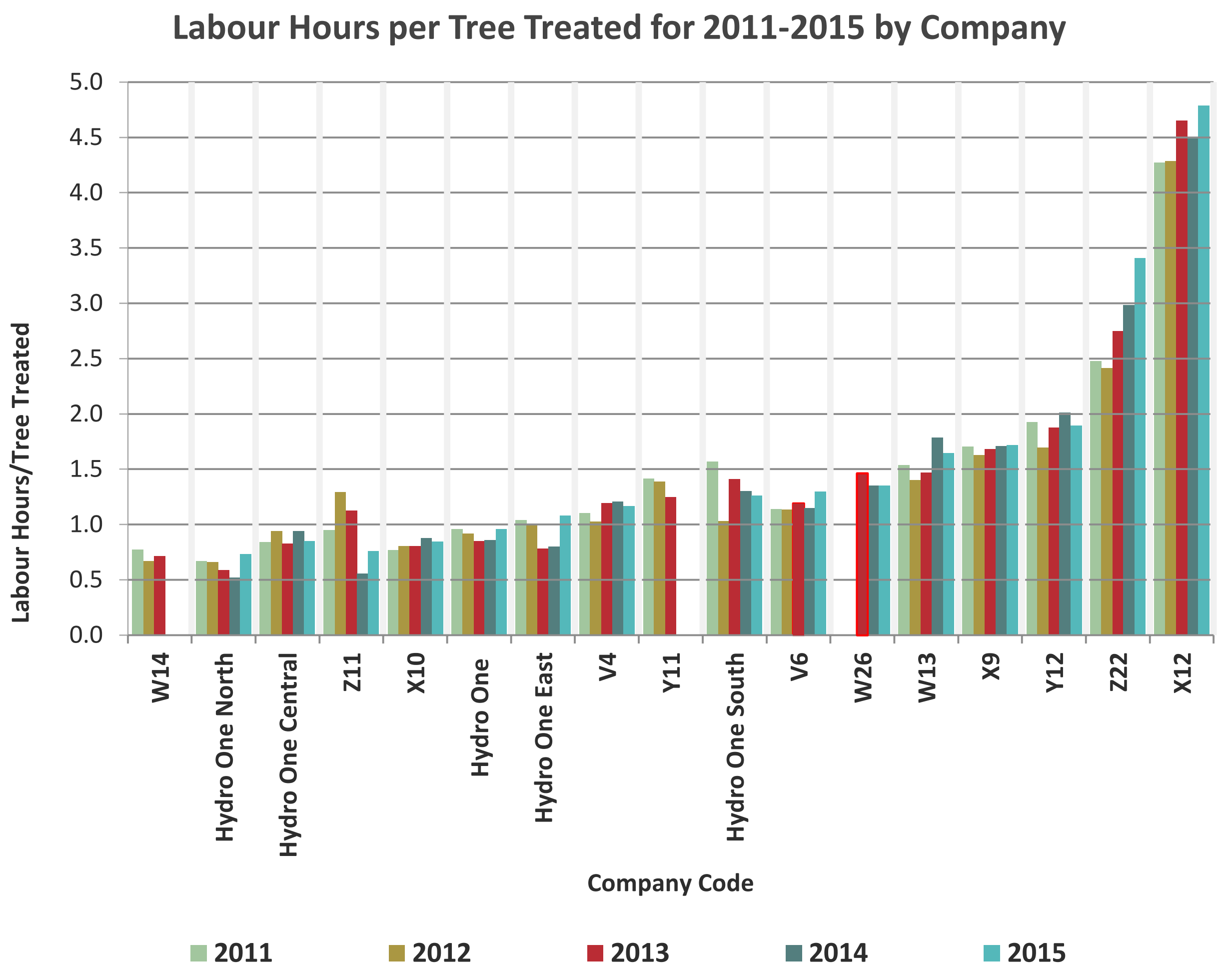
Graph 157: Annual Cost per Tree Treated for Years 2011-2015 by Company



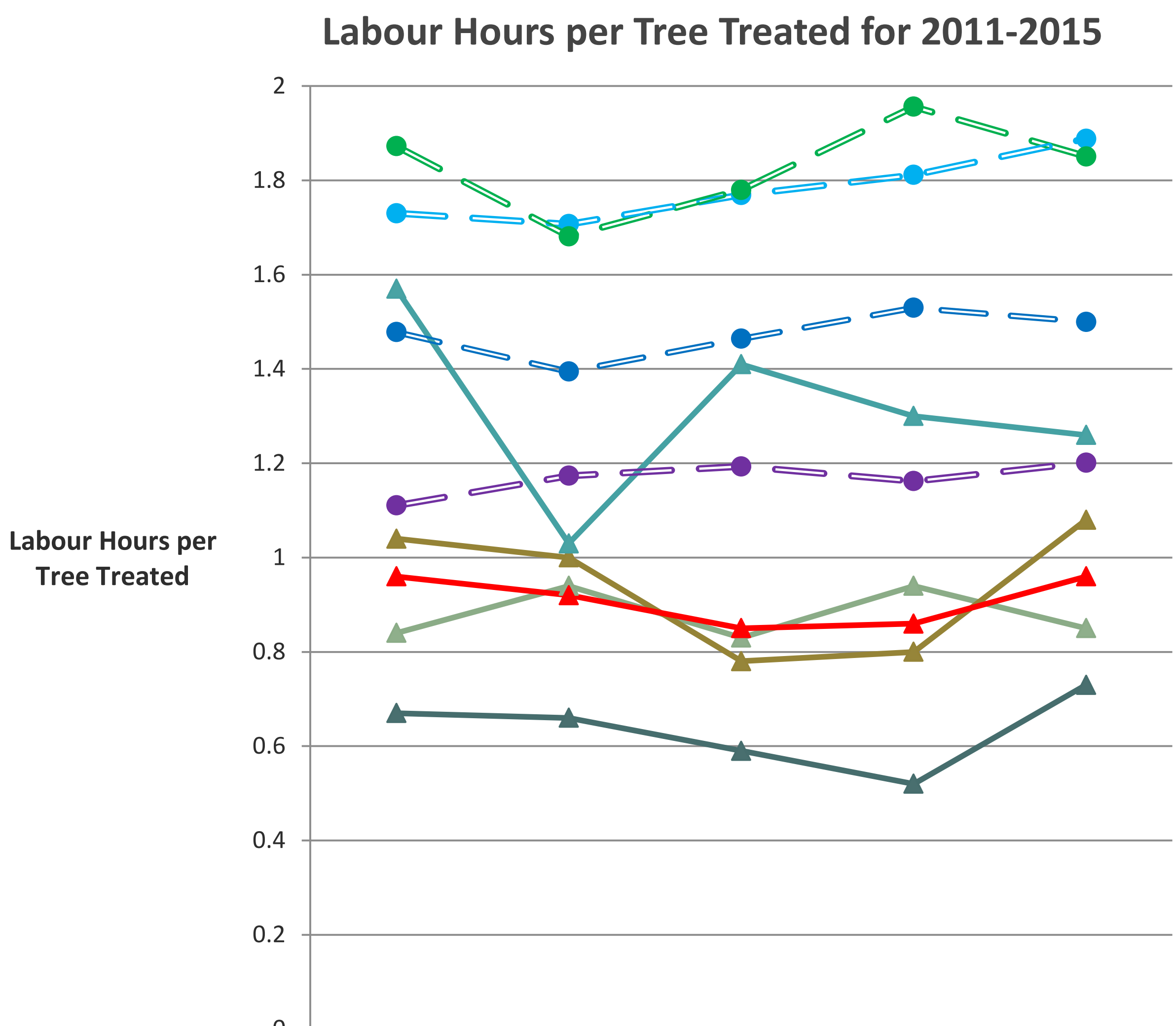
	2011	2012	2013	2014	2015
Hydro One Central	$90.37	$104.22	$88.51	$111.31	$97.74
Hydro One North	$76.37	$81.39	$69.07	$73.85	$104.43
Hydro One	$106.26	$105.28	$94.47	$106.55	$118.33
Hydro One East	$113.18	$112.76	$90.01	$100.55	$135.03
Hydro One South	$178.76	$118.66	$155.89	$157.11	$155.48
Peer Average	$80.51	$77.68	$79.58	$85.62	$91.54
Peer Q1	$48.96	$52.69	$52.84	$57.94	$59.14
Peer Median	$65.82	$63.34	$68.07	$77.29	$76.01
Peer Q3	$97.58	$104.22	$91.07	$106.55	$118.33

Graph 158: Statistical Comparison of Annual Cost per Tree Treated for Routine UVM for Years 2011-2015

Labour Hours per Tree Treated for Routine Maintenance 2011-2015



Graph 159: Annual Cost per Tree Treated for Years 2011-2015 by Company

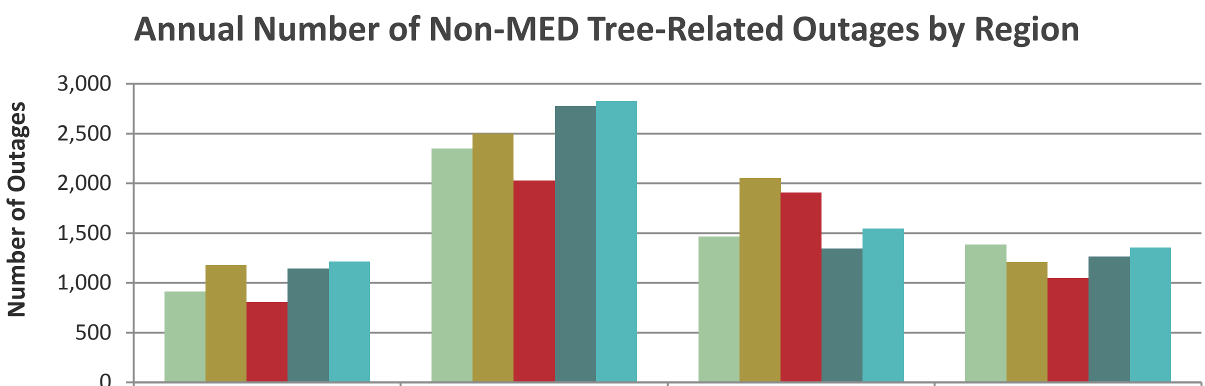


	2011	2012	2013	2014	2015
Hydro One Central	0.84	0.94	0.83	0.94	0.85
Hydro One East	1.04	1	0.78	0.8	1.08
Hydro One	0.96	0.92	0.85	0.86	0.96
Hydro One North	0.67	0.66	0.59	0.52	0.73
Hydro One South	1.57	1.03	1.41	1.3	1.26
Average	1.73	1.71	1.77	1.81	1.89
Q1	1.11	1.17	1.19	1.16	1.20
Median	1.48	1.39	1.46	1.53	1.50
Q3	1.87	1.68	1.78	1.96	1.85

Graph 160: Statistical Comparison of Annual Labour Hours/Tree Treated for Routine UVM for Years 2011-2015

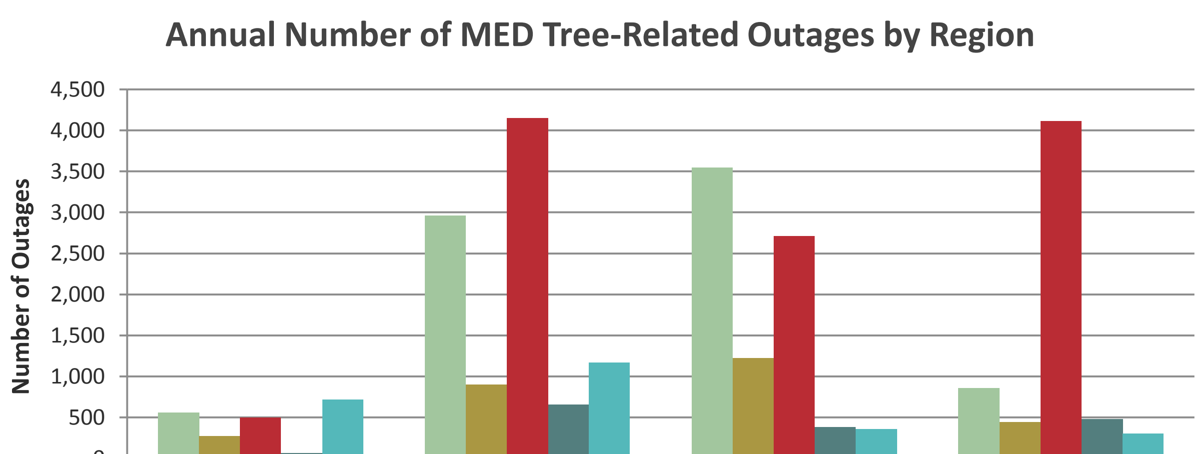
HYDRO ONE RELIABILITY LONGITUDINAL ANALYSIS

Annual Number of Tree-Related Outages



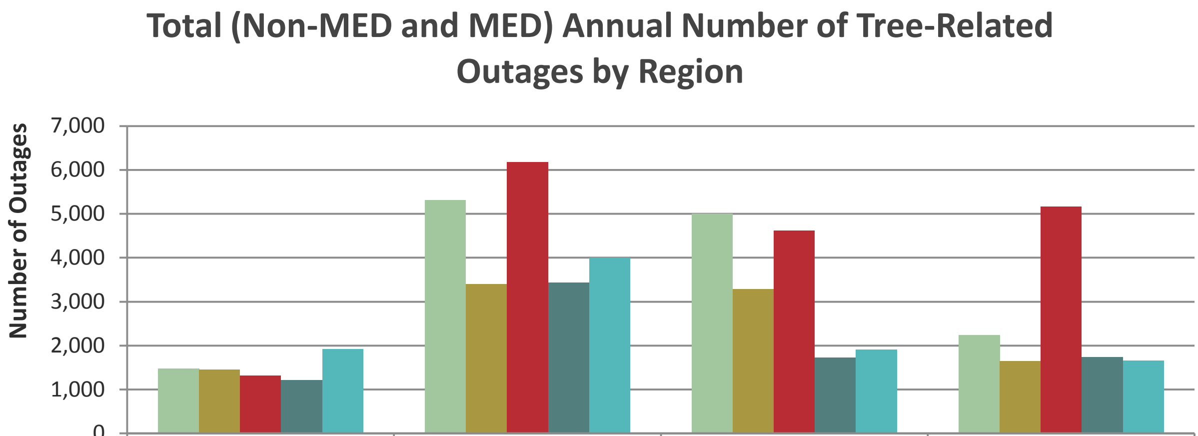
	HO North	HO Central	HO East	HO South
2011	913	2,351	1,462	1,382
2012	1,180	2,501	2,054	1,209
2013	808	2,026	1,907	1,046
2014	1,143	2,777	1,346	1,263
2015	1,212	2,828	1,543	1,354

Graph 161: Annual Number of Non-MED Tree-Related Outages by Region



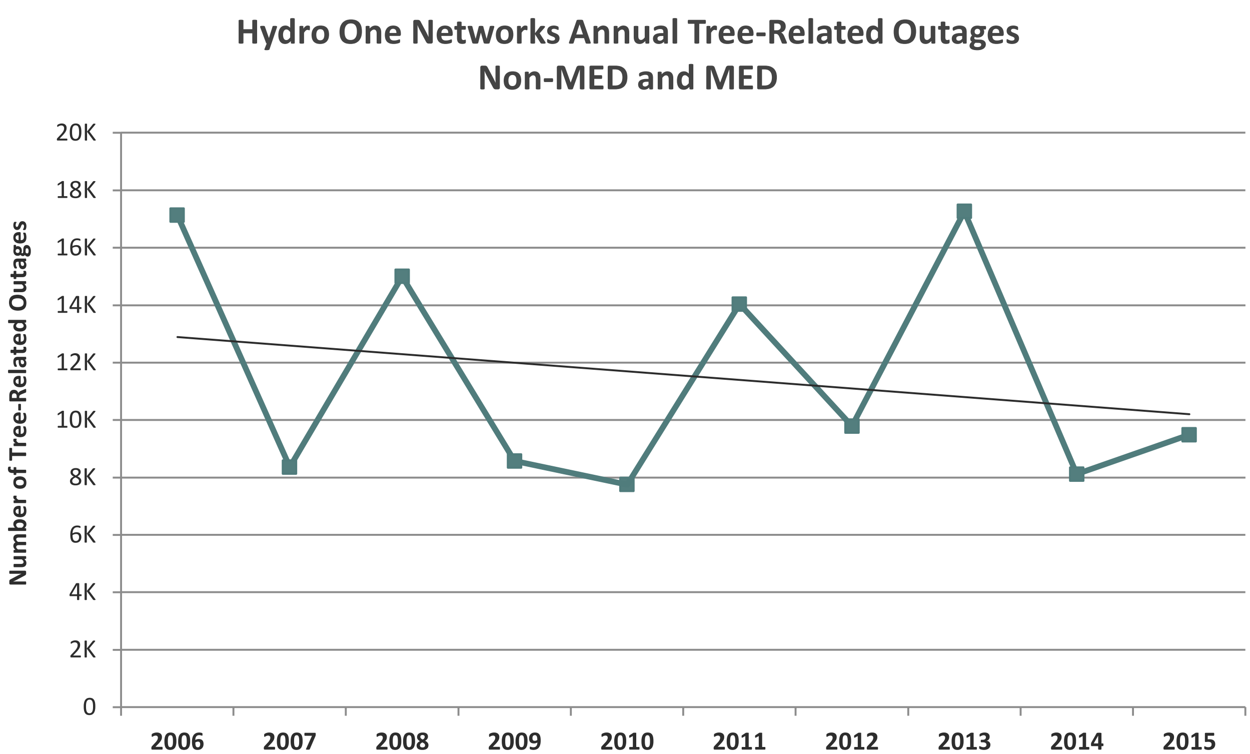
	HO North	HO Central	HO East	HO South
2011	561	2,959	3,546	860
2012	272	901	1,226	443
2013	502	4,152	2,709	4,113
2014	65	658	385	481
2015	715	1,172	358	307

Graph 162: Annual Number of MED Tree-Related Outages by Region



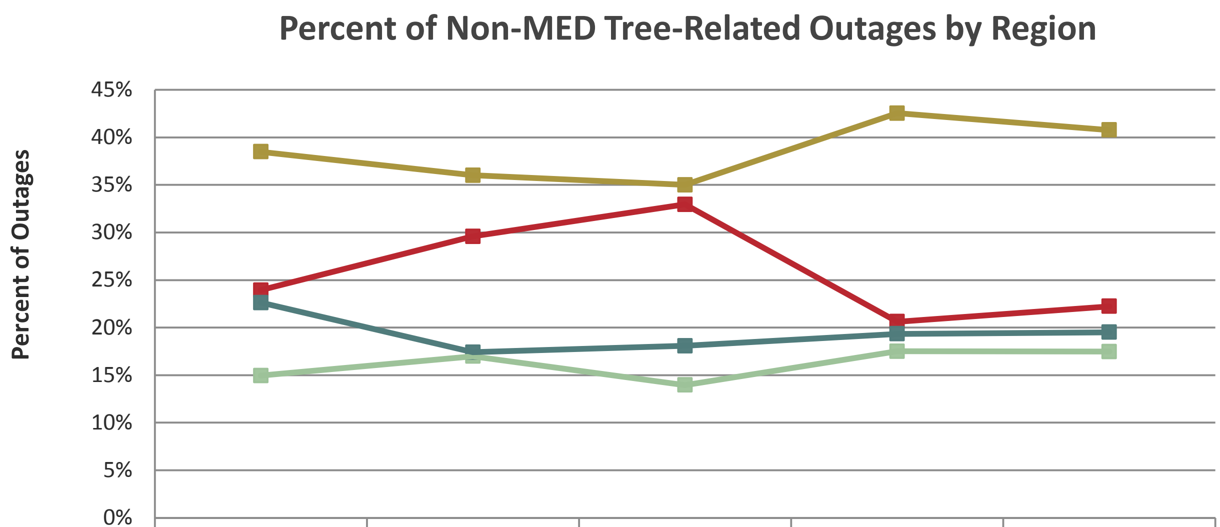
	HO North	HO Central	HO East	HO South
2011	1,474	5,310	5,008	2,242
2012	1,452	3,402	3,280	1,652
2013	1,310	6,178	4,616	5,159
2014	1,208	3,435	1,731	1,744
2015	1,927	4,000	1,901	1,661

Graph 163: Total Annual Number of Tree-Related Outages by Region



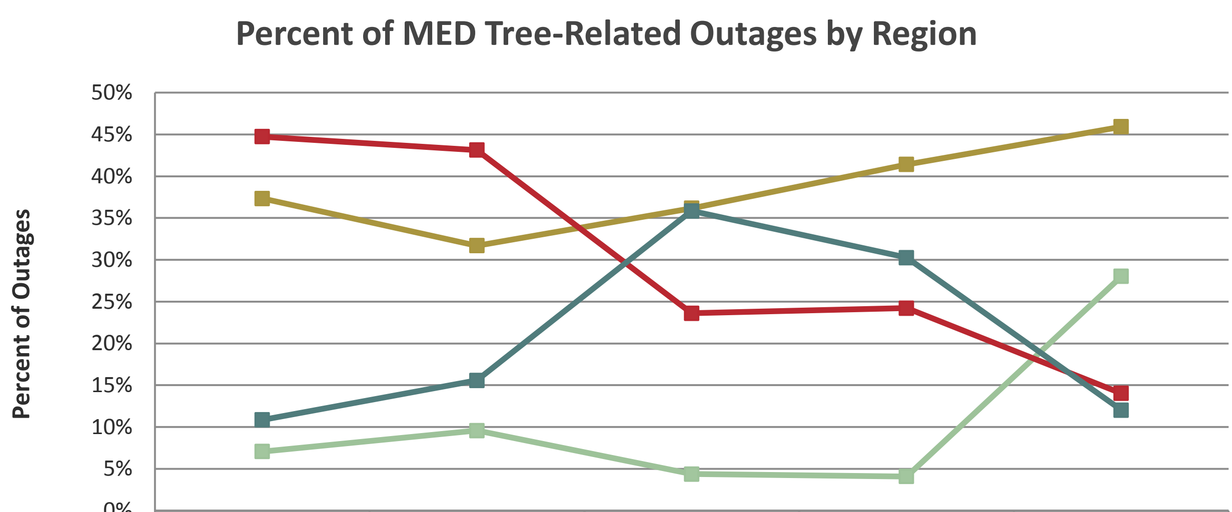
Graph 164: Hydro One Networks Annual Tree-Related Outages

Percent of Company Sustained Outages That Are Tree-Related



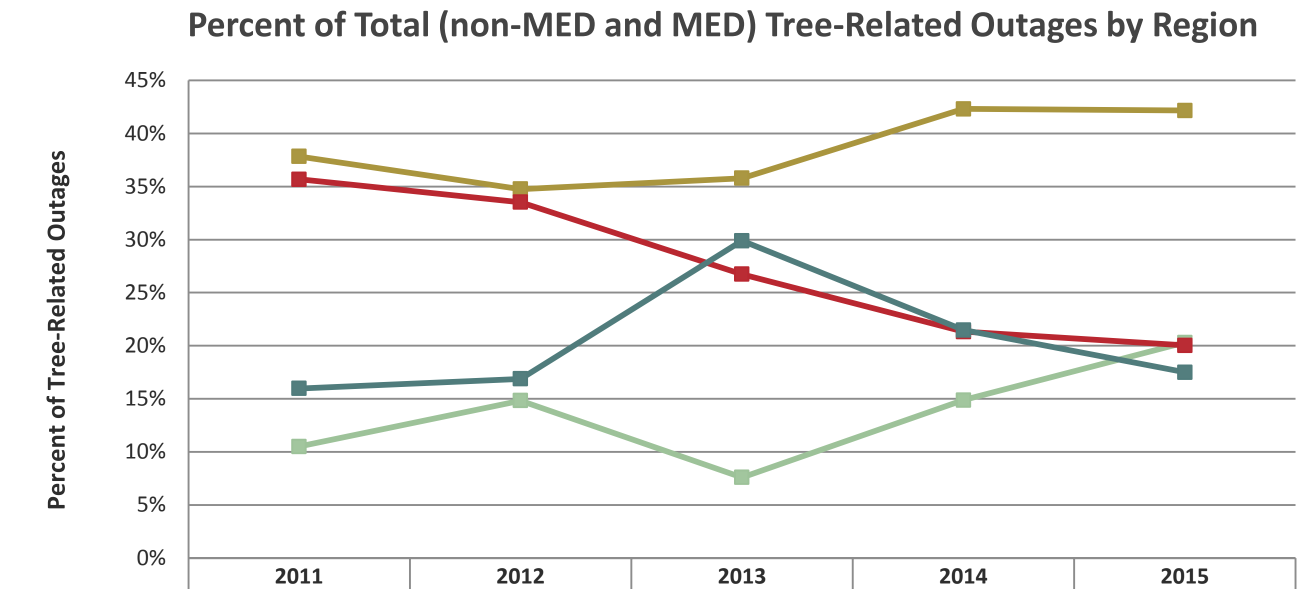
	2011	2012	2013	2014	2015
HO North	15%	17%	14%	18%	17%
HO Central	38%	36%	35%	43%	41%
HO East	24%	30%	33%	21%	22%
HO South	23%	17%	18%	19%	20%

Graph 165: Percent of Non-MED Tree-Related Outages by Region



	2011	2012	2013	2014	2015
HO North	7%	10%	4%	4%	28%
HO Central	37%	32%	36%	41%	46%
HO East	45%	43%	24%	24%	14%
HO South	11%	16%	36%	30%	12%

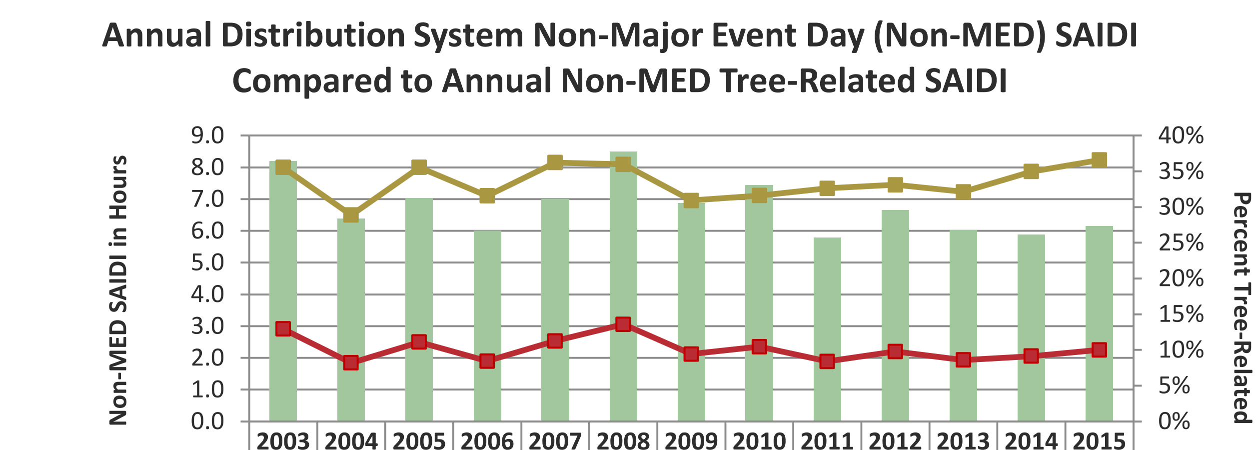
Graph 166: Percent of MED Tree-Related Outages by Region



	2011	2012	2013	2014	2015
HO North	11%	15%	8%	15%	20%
HO Central	38%	35%	36%	42%	42%
HO East	36%	34%	27%	21%	20%
HO South	16%	17%	30%	21%	18%

Graph 167: Percent of Total (non-MED and MED) Tree-Related Outages by Region

Total SAIDI versus Tree-Related SAIDI 2003 - 2015



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	36%	28%	31%	27%	31%	38%	31%	33%	26%	30%	27%	26%	27%
Total Non-MED	8.0	6.5	8.0	7.1	8.2	8.1	7.0	7.1	7.3	7.5	7.2	7.9	8.2
Tree-Related	2.9	1.8	2.5	1.9	2.5	3.1	2.1	2.4	1.9	2.2	1.9	2.1	2.3

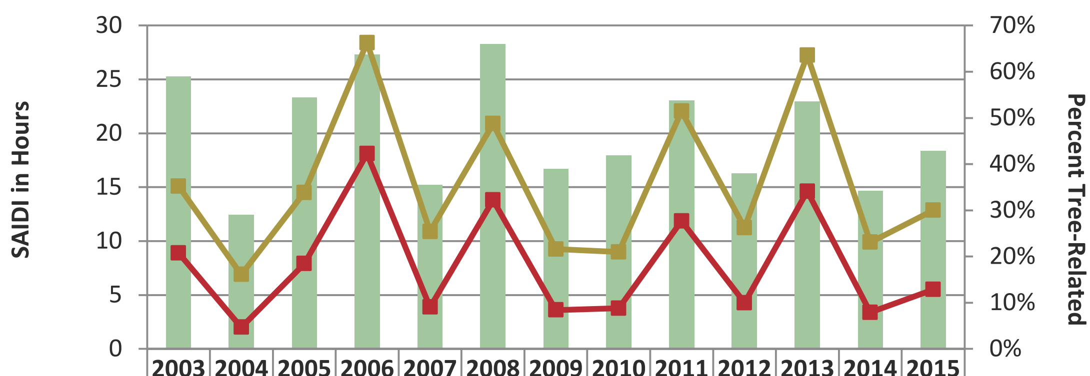
Graph 168: Non-MED SAIDI – Total vs Tree-Related 2003 – 2015

Annual Distribution System Major Event Day (MED) SAIDI Compared to Annual MED Tree-Related SAIDI

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	84%	39%	83%	76%	49%	84%	65%	75%	68%	55%	63%	66%	70%
Total MED	7.1	0.4	6.5	21.3	2.7	12.8	2.3	1.9	14.7	3.8	20.0	2.0	4.6
Tree-Related	6.0	0.2	5.4	16.2	1.3	10.7	1.5	1.4	10.0	2.1	12.7	1.3	3.3

Graph 169: MED SAIDI – Total vs Tree-Related 2003 – 2015

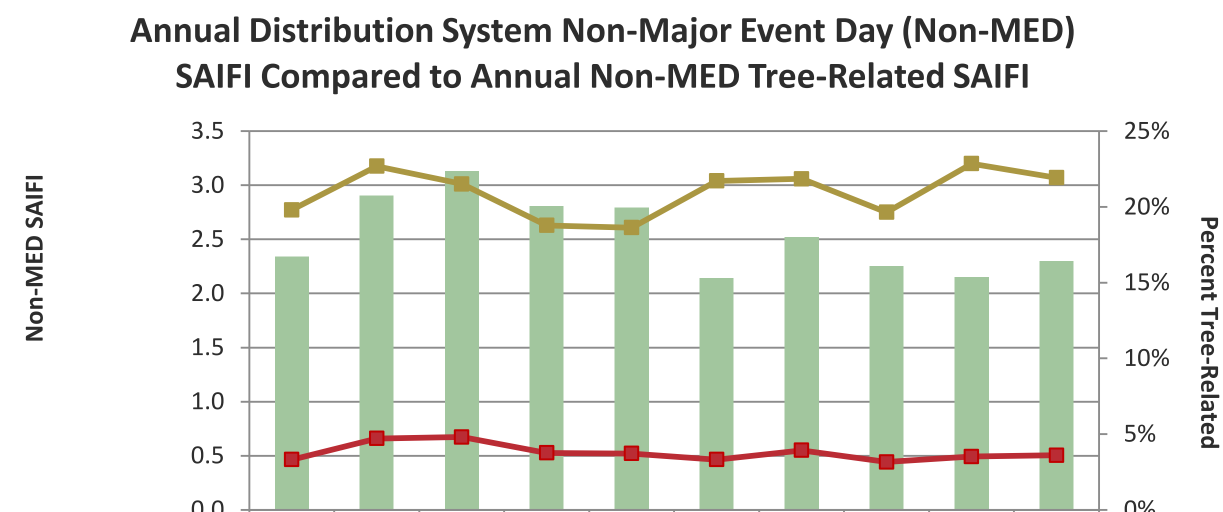
Annual Distribution System SAIDI Compared to Annual Tree-Related SAIDI



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	59%	29%	54%	64%	36%	66%	39%	42%	54%	38%	54%	34%	43%
Total	15.1	6.9	14.5	28.4	10.9	20.9	9.3	9.0	22.1	11.2	27.2	9.9	12.9
Tree-Related	8.9	2	7.9	18.1	3.9	13.8	3.6	3.8	11.9	4.3	14.6	3.4	5.5

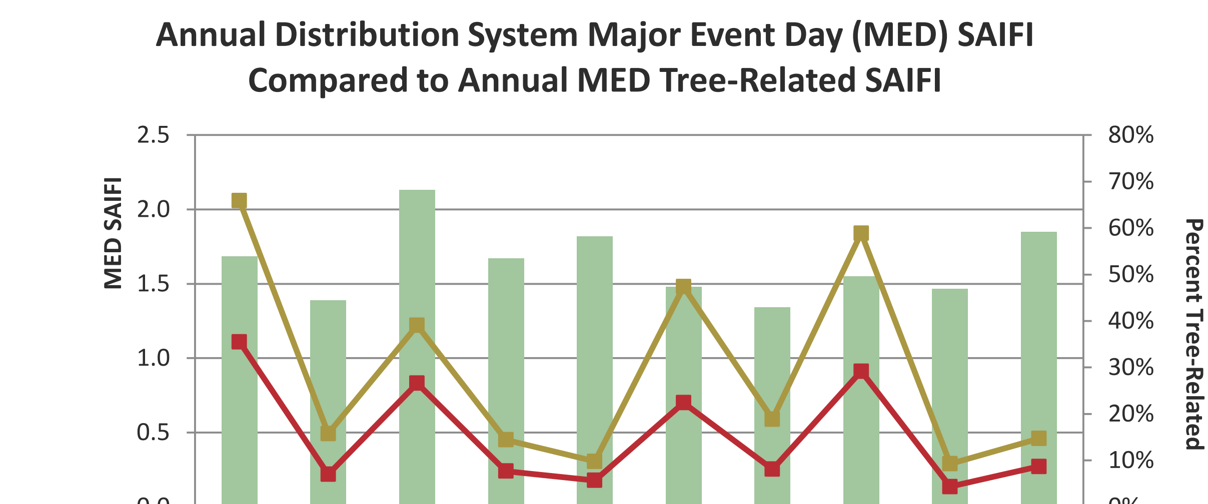
Graph 170: SAIDI – Total vs Tree-Related 2003 – 2015

Hydro One Networks Total SAIFI versus Tree-Related SAIFI 2006 - 2015



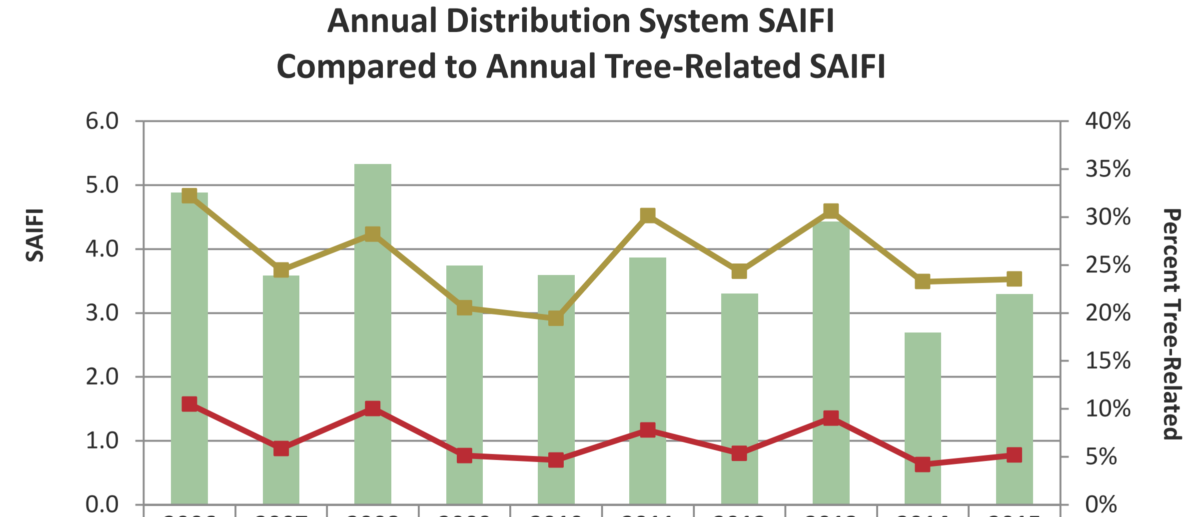
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
% Tree-Related	17%	21%	22%	20%	20%	15%	18%	16%	15%	16%
Total Non-MED	2.8	3.2	3.0	2.6	2.6	3.04	3.06	2.75	3.20	3.07
Tree-Related	0.5	0.7	0.7	0.5	0.5	0.46	0.55	0.44	0.49	0.50

Graph 171: Non-MED SAIFI – Total vs Tree-Related 2006 – 2015



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Tree%	54%	44%	68%	53%	58%	47%	43%	50%	47%	59%
Total MED	2.1	0.5	1.2	0.5	0.3	1.5	0.6	1.8	0.3	0.5
Tree	1.1	0.2	0.8	0.2	0.2	0.7	0.3	0.9	0.1	0.3

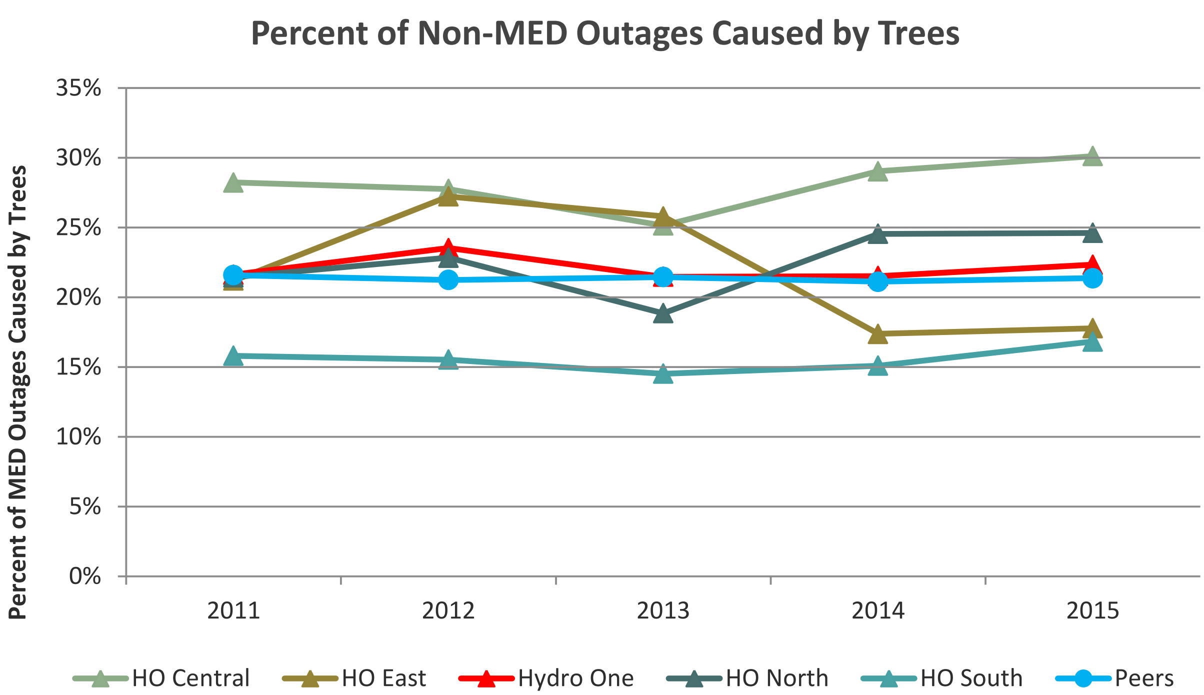
Graph 172: MED SAIFI – Total vs Tree-Related 2006 – 2015



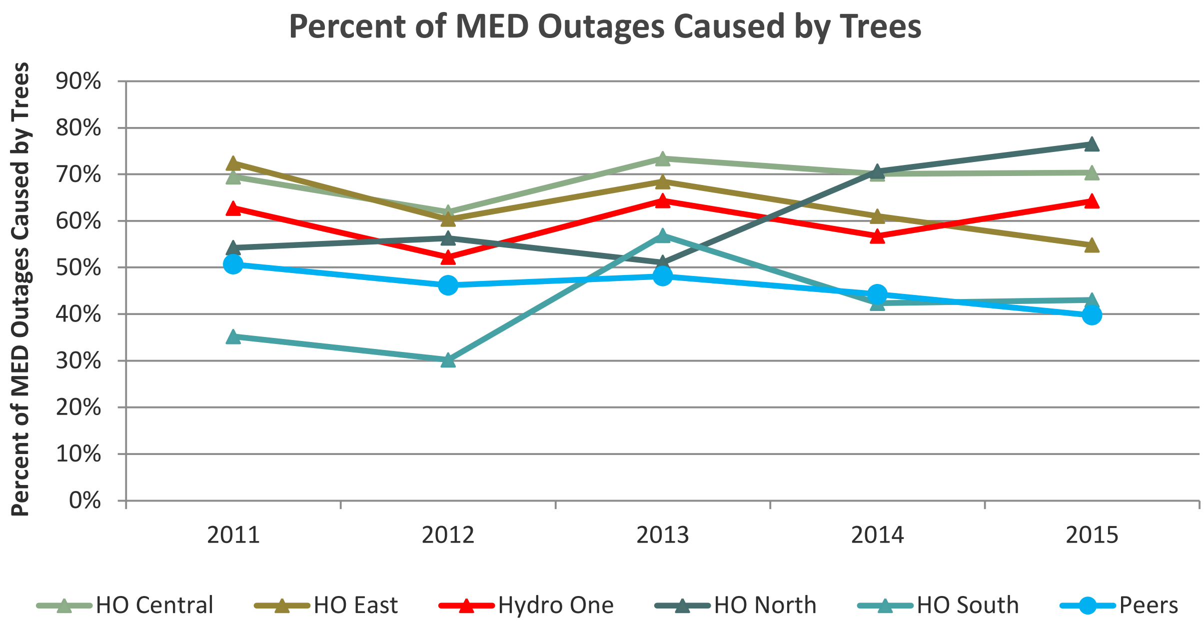
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Tree%	33%	24%	36%	25%	24%	26%	22%	30%	18%	22%
Total	4.8	3.7	4.2	3.1	2.9	4.5	3.7	4.6	3.5	3.5
Tree	1.6	0.9	1.5	0.8	0.7	1.2	0.8	1.4	0.6	0.8

Graph 173: SAIFI – Total vs Tree-Related 2003 – 2015

Outages Caused by Trees in Hydro One Regions



Graph 174: Percent of Non-MED Outages Caused by Trees



Graph 175: Percent of MED Outages Caused by Trees

FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is William Porter (*name*). I live at Chicago (*city*), in the Illinois (*province/state*) of USA .

2. I have been engaged by or on behalf of Hydro One (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 23 February 2017

William Porter

Signature

FORM A

Proceeding:……EB-2017-0049……

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is.......Nina Cohn.......(*name)*. I live at .....Chicago..... (*city)*, in the .....IL..... (*province/state*) of .....USA..... .

2. I have been engaged by or on behalf of.....Hydro One..... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date .....23 February 2017.....

____

Signature

Hydro One

Gartner IT Budget Assessment
Final Report

Prepared for: hydro one

Gartner Contact
Nicholas Lal
Managing Partner
Gartner Consulting
Telephone: +1 1416 228 7663
Nicholas.lal@gartner.com

Gartner Contact
Catherine Taylor
Associate Director
Gartner Consulting
Telephone: +1 1407 257 7303
catherine.taylor@gartner.com

GARTNER CONSULTING

Project Number: 330034892 Version #1

Gartner

Table of Contents

Gartner.

Methodology and Scope

Project Methodology
Gartner Approach
Scope and Peer Group Profile

Gartner.

Project Methodology

Hydro One engaged Gartner to assess its overall IT spending in terms of enterprise-level metrics and the distribution of IT spending. Using industry, revenue, and employee data, Gartner compared Hydro One to a peer group of similar organizations. The following information was collected from Hydro One:

- IT budget spending (capital and operations)
- Revenue and operating expense
- Number of employees
- IT staffing levels

Metrics available from this analysis include:

- IT Spend as a % of Revenue
- IT Spend as a % of Operating Expense
- IT Spending Per Company Employee
- Distribution of IT Spend – by Category (hardware, software, outsourcing and personnel)
- Distribution of IT Spend – by Domain (data center, end user computing, service desk, voice, data, applications development, applications support, corporate IT management, finance and administration)
- Distribution of IT Support – by Domain (data center, end user computing, service desk, voice, data, applications development, applications support, corporate IT management, finance and administration)
- IT Employees as a % of Company Employees
- IT Contractor Usage
- Capital Vs. Operational Spending
- Run, Grow, Transform Spending

Gartner

Gartner Approach

IT Spending Benchmark Project Plan

1 Project Initiation
- Planning
- Kickoff
- Data collection

2 Data Collection
- IT Spending Metrics Data Collection
- Data Collection Assistance
- Status Meetings

3 Data Validation
- Data Validation Review
- Peer Group Review
- Data correction
- Data Freeze

4 Analysis
- Spending Drivers Analysis
- Discussion of opportunities and findings
- Preliminary Report

5 Deliver Results
- Final Reports
- Presentation of Report

- Using Gartner's Cost Model for IT Spending, Gartner collected IT spending and staffing information and performed a cost analysis report using Gartner benchmarking databases
- This analysis focused on enterprise IT cost compared to industry peer group. The outsourcing contract was not evaluated. This analysis did not assess governance mechanisms, strategy or organization design.

Hydro One Scope and Peer Group Profile

Hydro One Business Information:

- 2015 Annual Revenue: $6.5B
- 2015 Annual Business Operating Expense: $5.3B
- Revenue and Operating Expense include fuel and purchased power
- Company Employees: 5,516

Hydro One IT Information:

- Analysis Period: 2015
- Total IT Budget for:
  - IT Capital Investment: $53,800,000
- IT Operational Budget: $141,136,000
  - Total IT Spending, Capital and Operations: $194,936,000
- Total IT FTEs: 102

Peer Group Profile:

- 9 Energy and Utilities Organizations – 6 Canadian, 3 USA.   7 of the 9 are Utilities and the remaining 2 are Canadian Energy (distribution and energy infrastructure).
- Average Peer Group Revenue: $6.6B
- Average Peer Group Operating Expense: $4.8B
- Average Peer Group Company Employees: 6,336

Gartner

Executive Summary

Business Context
IT Drivers
Summary of Metrics
Observations and Recommendations

Business Context establish the priorities and focus for IT investments and the way the IT organization conducts business

Business Context and External Factors	Implications
Geography	▪ Hydro One is Ontario's largest distribution utility spanning 75 percent of the province. ▪ Requires IT to support users and maintain equipment over a large service territory and in remote areas.
Seasonal Workforce and Other Temporary Labour	▪ While Hydro One employs 5,516 full-time employees, there are an additional 2,237 temporary, contract and part-time employees, some of which are seasonal. ▪ The Gartner benchmark includes only the 5,516 in the employee count and this methodology is consistent for the peer comparison group. The Gartner Benchmarking cost model does not include temporary workers in the company employee total. IT contractors are counted in the IT FTE total. ▪ There are IT costs associated with the seasonal staff. ▪ While there is some outsourcing in the peer group, the percentage of outsourcing is lower than Hydro One. ▪ The peer group on average has 820 more total employees than Hydro One.
Labour Agreements	▪ The workforce is unionized and Hydro One estimates that agreements add 20 percent to the employee cost. ▪ Note: The peer comparison group also includes some organized labour.
Regulatory and Compliance	▪ Hydro One is regulated by the Ontario Energy Board.
Business Accounting Policies Governing IT Investment Capitalization	▪ Hydro One has a minimum capital threshold of $2M (IT assets cannot be capitalized if under $2M). This is a higher threshold than typically observed for IT assets for the peer group. For example, software is often in the $200K-$500K range, some are at $1M.

Gartner

IT Drivers influence the decisions and ability for the IT organization to effectively enable the business

IT Drivers	Implications
Cornerstone Project	▪ From 2007 through 2014, Hydro One was engaged in the Cornerstone project. The Cornerstone project replaced legacy CIS applications and transformed business processes. The project lasted longer and was more difficult to implement than originally anticipated. ▪ By 2015, the current benchmark period, Cornerstone is now part of operating expense and remaining depreciation. ▪ The benchmark period therefore represents a time period of minimal transformation spending at Hydro One. ▪ The peer group members report higher allocation to grow and transform. Some peer group members are undergoing CIS implementations.
Strategy, Governance and Organization	▪ Some IT functions have individual strategic plans but it does not appear that there is a comprehensive enterprise IT strategic plan. ▪ There are FTE and contractor resources that appear to be working along with the service provider based on functional assignment in the benchmarking model. It is unknown if there are overlaps in responsibility or duplicated roles. ▪ Hydro One does not show back or charge back IT costs. Business demand impact on consumption is not formally communicated.
Outsourced IT	▪ Hydro One IT is outsourced to Inergi for services. The Gartner benchmark does not convert the Inergi staff into FTE counts. This reduces the FTE count for Hydro One and also impacts the distribution of FTE by function.

Hardware Assets	▪ Multiple drivers influence hardware assets:
	    ▪ Some assets are kept in service for more than five years, such as Network assets and some server equipment.
	    ▪ SAP architecture is based on Unix and is not virtualized.
	    ▪ End User hardware costs are driven by decisions to outfit users with high performance and ruggedized equipment. 74% of the end user devices are mobile. End User assets are also refreshed more frequently.
	    ▪ Hydro One also provides end user computing equipment to Inergi staff.

Summary of Metrics

	Hydro One	Peer Average
IT Spending, Capital and Operations	$194,936,000	$200,135,986
IT Spending Capital and Operating by Cost Category		
Hardware	$18,129,048	$36,246,851
Software	$20,858,152	$47,810,263
Personnel Salaries & Benefits	$27,291,040	$77,830,661
Outsourcing (including telecom carrier costs)	$128,657,760	$38,248,211
IT Spend/% Revenue	3.0%	3.1%
IT Spend/% OPEX	3.6%	4.1%
IT Spend per Employee	$35,340	$32,911
Percentage of IT Spend - Capital	28%	40%
Percentage of IT Spend - Operating	72%	60%
Percentage of IT Spend - Run	79%	65%
IT FTEs, Excluding Outsourcing	102	513
IT FTEs Excluding Outsourcing by Technology Domain		
Enterprise Computing	3	84
End-User Computing	4	35
IT Service Desk	2	24
Voice Network	2	16
Data Network	1	52
Application Development	30	110
Application Support	15	132
Management,Project Management, Finance & Admin	46	60
IT Expense by Technology Domain		
Enterprise Computing	25%	20%
End-User Computing	14%	6%
IT Service Desk	2%	4%
Voice Network	4%	5%
Data Network	6%	10%
Application Development	13%	19%
Application Support	31%	27%
Management,Project Management, Finance & Admin	5%	10%

- Hydro One spends a similar amount on IT compared to the peer group, but there are differences in how the dollars are spent.
- Hydro One uses more outsourcing than the peer group with outsourcing representing $129M of the IT capital and operating budget.
- Hydro One spends half of the peer group level on hardware and software.
- Software includes capital and operating expenses for all software, for example business functionality software such as SAP. Hydro One is lower than the peer group in software but has a higher expense allocation to Applications Support compared to the peer group.
- Capital IT spending is lower. Hydro One does not capitalize below $2M which is higher than most organizations.
- 2015 represents a time period of Run allocation for Hydro One IT with 79% of IT spending as Run, versus 65% for the peer group.
- Hydro One expenses are focused on Enterprise Computing (servers and storage), End User Computing (laptops and desktops) and applications support. Voice and data are both lower than the peer group.
- Hydro One in-house and contractor FTEs are focused primarily in management and applications roles. It is unclear if there are overlaps with the service provider.

Gartner

Observations & Recommendations

Observations	Recommendations
The benchmark results show a similar IT spend to peers but there are differences in how cost and staffing are allocated. Hydro One spending is also directed toward Run now that Cornerstone is complete, while the peer group is directing more IT dollars to Grow and Transform. This study focused on IT spending and did not measure governance mechanisms or value of IT services. It is unclear if Hydro One has a comprehensive enterprise IT strategy that articulates the vision of IT and its role in enabling the business. Currently Hydro One does not charge back or show back for IT services. Without any type of show back or understanding of where IT dollars are going, it is difficult to enable both groups (IT and the business) to be accountable for investment choices.	• Consider an assessment of the IT strategy, capabilities, governance mechanisms and organization design to better understand IT spending and staffing. The goal is to determine if the IT investments are appropriate for the direction of Hydro One. • Review governance mechanisms to understand how decisions are made for projects and services and the carried out with the service provider. • Analyze the IT spending by business service. Grouping IT spending into business services and capabilities will not only help to communicate IT spending in business terms but also determine if funds are directed in the right areas. Promote a focus on business outcomes in addition to IT efficiency to ensure that there is business value (spending on the right things at the right cost). Multiple views of IT spend can also show the impact of external forces out of the organization's control, such as regulatory and compliance and demand for services, which are within the organization's control. This will allow the business to make informed decisions about IT investments and help to manage internally driven complexity. • Review the organization design to understand roles and responsibilities of retained staff to determine if there are overlaps with the service provider, what roles should be retained and how work is managed.

Hydro One has a high capital threshold for IT investments compared to most organizations. IT cannot capitalize below $2M while other organizations are capitalizing at lower amounts (e.g. $250K-$500K range). The current policy does not book any IT spending below $2M as an asset.
While IT leaders should not be the ones to set accounting policy, there should be discussion of impact of policy on IT decisions. For many organizations, capitalization decisions of IT assets are often based on outdated capitalization policies, or "this is how we have always done it."
	• Work with business leadership to review capitalization policies. The capitalization policy has multiple impacts and will require review and analysis jointly among IT leadership, business leadership, legal and accounting professionals.
	
	    • Capitalization of IT assets has an impact on business balance sheet metrics (e.g. net income, cash flow, assets).
	    • Capitalization has an impact on IT budget planning and funding.
	    • Considerations include variability in the IT budget year over year, managing IT investments as company assets, and changing delivery models for services.

Gartner

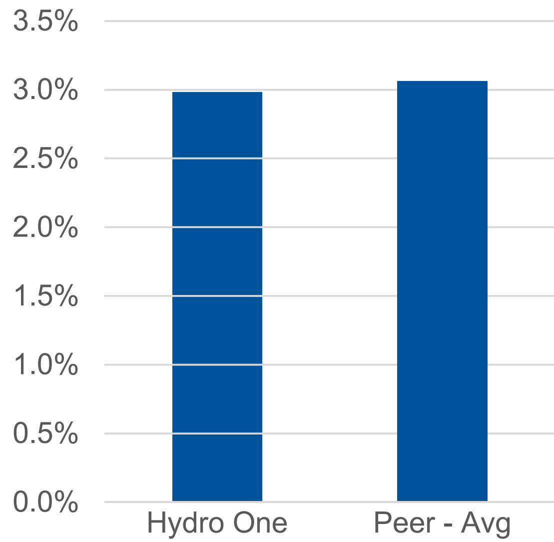
Observations & Recommendations

Observations	Recommendations
Benchmark findings indicate variations to the peer group by spending category and in the functional areas (end user computing, enterprise computing, and applications support are higher, network is lower). End user computing and applications support have a more direct business user impact (equipment and applications) and therefore require more business collaboration to balance cost, value and productivity. Hydro One spends differently than the peer group by category, with outsourcing receiving the highest allocation. Hydro One is outsourced with an additional 102 in-house and contractor FTEs. The in-house and contractor FTEs are allocated throughout the functional areas but with higher concentrations in applications development and support and management.	• Perform a deeper-dive analysis on specific areas to better understand cost drivers. • Ensure that outsourcing contract pricing is competitive in the market and services match both business needs and end user behavior. • As mentioned earlier, review roles and responsibilities of retained in-house and contractor staff and the service provider outsourcer. There are some indications of possible overlaps with retained staff and the service provider. For example, Hydro One reported a total of 45 FTEs in Applications Development and Support. The outsourcer also provides applications services and it is unclear if the 45 FTE and the outsourcer are duplicating effort. There are also a number of corporate IT staff including project management staff. Review role specification, processes and handoffs. • Develop a plan to rationalize enterprise computing costs and review opportunities to increase server virtualization. • Evaluate data management policies and roles at the business level to optimize storage costs. • Consider user segmentation strategies for end user computing, carefully analyzing impact on user productivity. • Review software costs in depth - including the application portfolio and other software usage such as tools against the software spending reported in the assessment. Software costs are low, but applications support spending allocation is high. Is this indicative of applications that have a low software cost but require more maintenance? Is Hydro One investing in tools or applications to improve user productivity? • Analyze data network equipment investment levels for review and possible replacement, especially in remote locations.

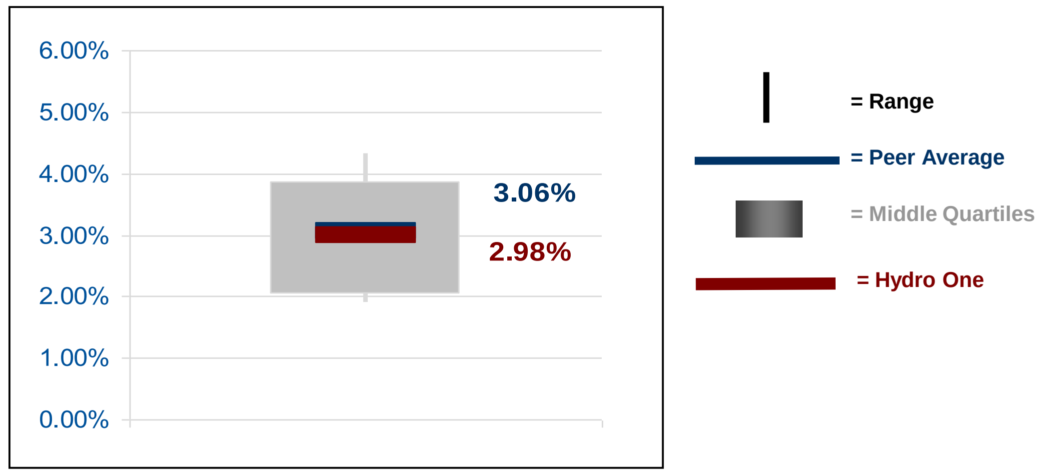
IT Metrics

IT Spending as a Percentage of Revenue

Assessment Area	Observations
IT Spending	▪ IT Spending as a Percentage of Revenue is similar to the peer group. ▪ The analysis period in the benchmark represents a period of minimal transformational initiatives in the IT budget at Hydro One.



	Hydro One	Peer - Avg
IT Spending as a % of Revenue	3.0%	3.1%

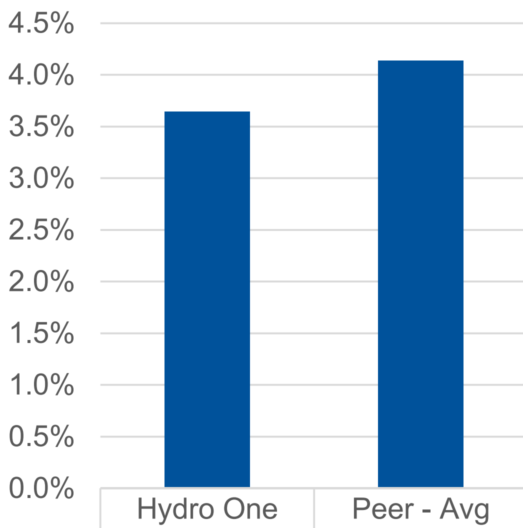


- Definitions:
  - Revenue – includes revenue for business units supported by IT. Includes fuel.
  - IT Spending – includes operations and capital spending (does not include any amortization and depreciation).

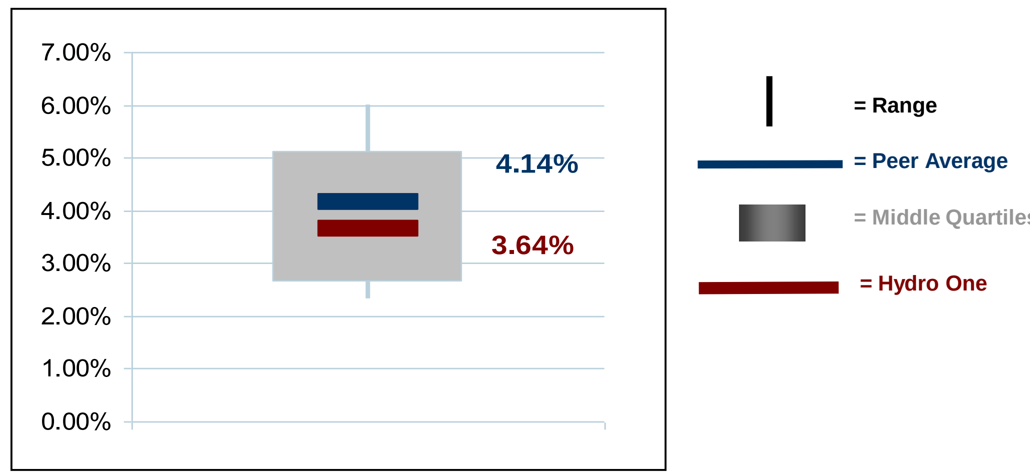
Gartner.

IT Spending as a Percentage of Operating Expense

Assessment Area	Observations
IT Spending	▪ IT Spending as a Percentage of Operating Expense is lower than the peer group. Hydro One has a higher business operating expense compared to the peer group average.



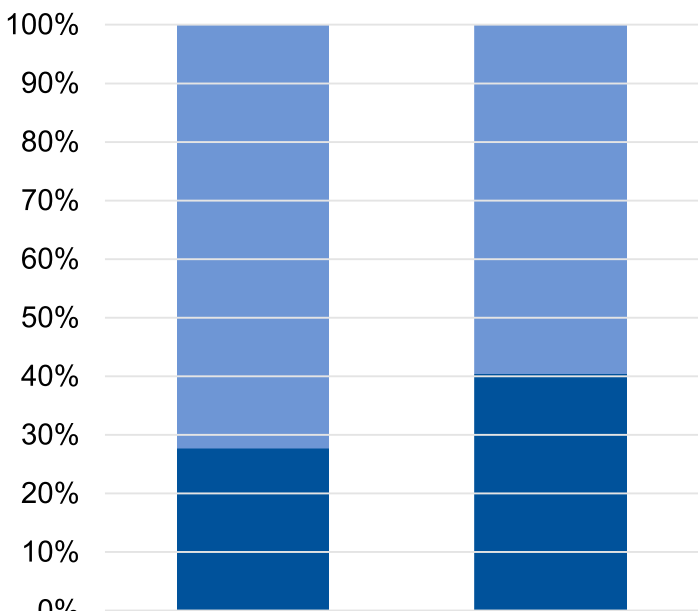
	Hydro One	Peer - Avg
■ IT Spending as a % of Opex	3.6%	4.1%



- Definitions:
  - Operating Expense – includes the total expense associated with the business units supported by the IT organization.
  - Includes items such as selling, general and administrative expenses (SGA), cost of goods sold (or cost of revenue), research and development, depreciation, depletion and amortization expenses etc.
  - IT Spending – includes operations and capital spending (does not include any amortization and depreciation).

IT Spending Distribution – Capital and Operations Spending

Assessment Area	Observations
IT Spending	▪ Hydro One has a lower proportion of capital spending compared to the peer group average. ▪ Hydro One does not capitalize any IT investments below \$2M. This is higher than typically observed in Gartner benchmarks (for example, many organizations are in \$250K-\$500K range).



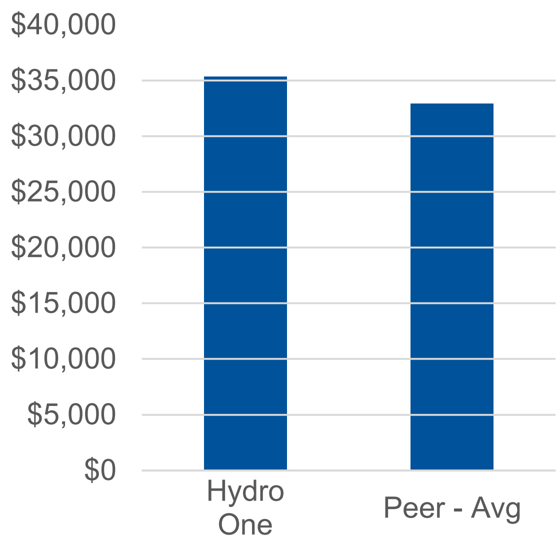
	Hydro One	Peer - Avg
Operations	72%	60%
Capital	28%	40%

IT Spending Distribution – Capital and Operations

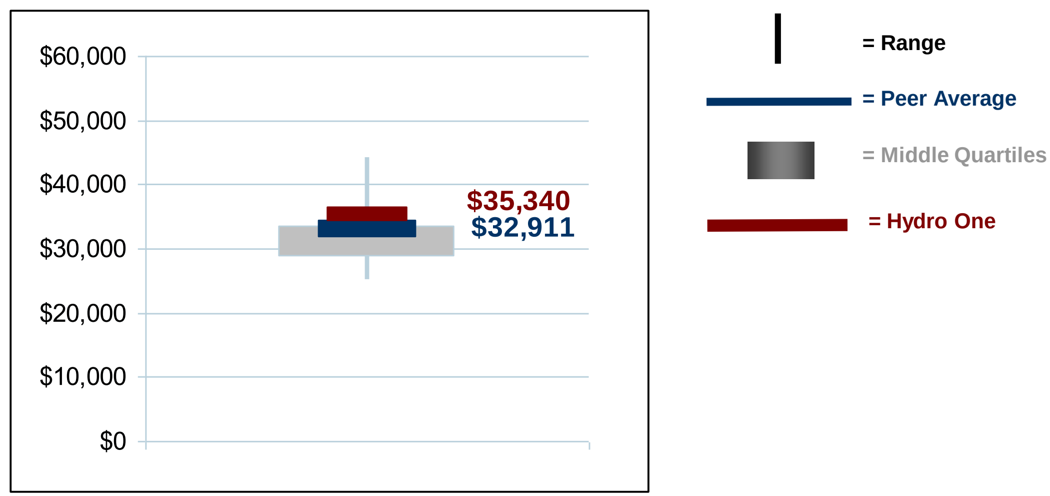
- IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.
- Definitions:
  - Operational IT Spend: IT Operational expenses: Total day to day operations and maintenance expenses for this fiscal year that have not been capitalized. This does not include any amortization and depreciation.
  - Capital IT Spend: Capital Expenses: Total capitalized IT spending for this fiscal year.

IT Spending per Company Employee

Assessment Area	Observations
IT Spending	▪ IT Spending per Employee is higher than the peer group average. Hydro One has fewer employees than the peer group average (5,516 versus 6,336). In addition to the 5,516 full-time employees, there are an additional 2,237 temporary, contract and part-time employees at Hydro One, some of which are seasonal. ▪ IT Spending per Employee is the IT spending for capital and operations for the number of company employees, which excludes contractors and outsourcing. ▪ Hydro One estimates a 20% premium on labour cost due to their heavily outsourced model.



	Hydro One	Peer - Avg
IT Spending per Company Employee	$35,340	$32,911

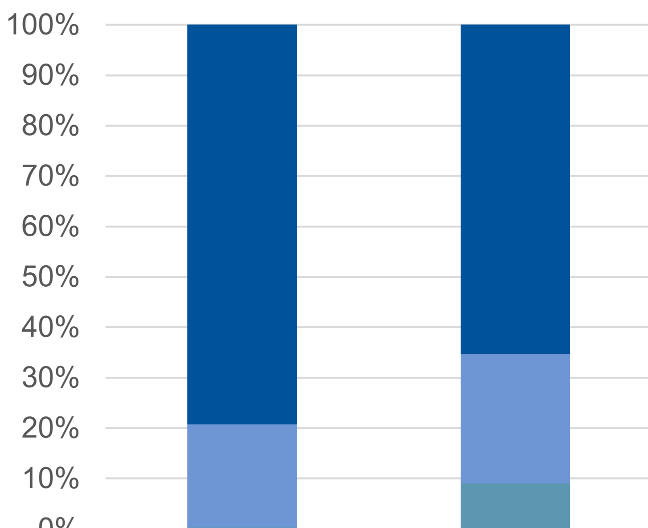


- Definitions:
  - IT Spending – includes operations and capital spending (does not include any amortization and depreciation).
  - Company employees.

Gartner.

Run, Grow and Transform

Assessment Area	Observations
IT Spending	▪ Hydro One is allocating the IT budget to Run and Grow activities and nothing in Transform during the current analysis period. The peer group is spending 35% of their IT budget on Grow and Transform compared to 20% for Hydro One.



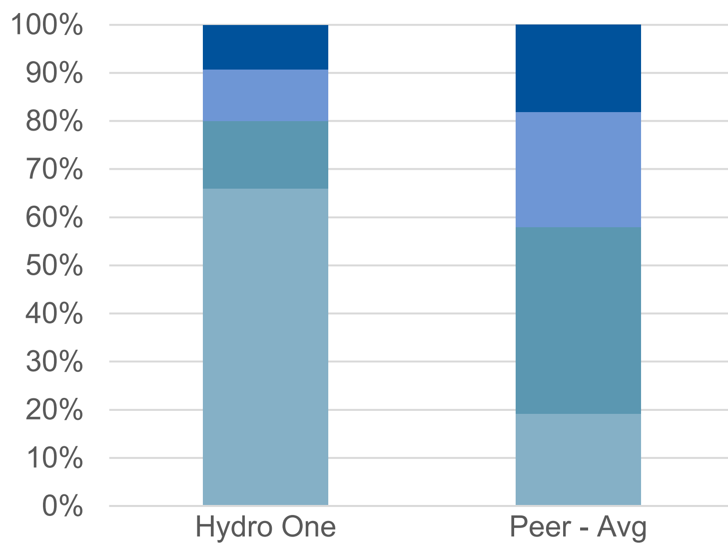
	Hydro One	Peer - Avg
Run	79%	65%
Grow	20%	26%
Transform	0%	9%

IT Spending Distribution by Run, Grow and Transform

- Definition:
  - Allocation of IT Spending ($) capital and operations by run, grow and transform categories.
  - Run: Run-the-business IT initiatives are aimed at essential (and generally non-differentiated) business processes. The objective of a run-the-business initiative is to improve or maintain the desired balance among cost, quality and risk for these essential processes.
  - Grow: Grow-the-business metrics are about improvements in operations and performance, within current business models.
  - Transform: Transform-the-business value metrics are about new horizons — new markets, new products and new business models.

IT Spending Distribution by Cost Category

Assessment Area	Observations
IT Spending	▪ IT support is outsourced with Hydro One owning the assets. There is a 20% premium on labour due to agreements. There are differences in asset age and type by function. For example, network and server assets are kept in service longer, over five years, while end user assets such as laptops are refreshed more frequently. There is a high concentration of mobile devices (74% of devices). Hardware and software spending is lower than the peer group. ▪ The higher percentage of outsourcing also reduces the number of company employees and IT FTEs, since outsourcing staff are not counted.

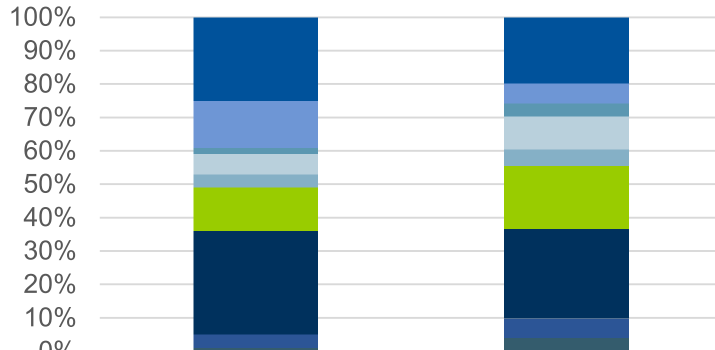


	Hydro One	Peer - Avg
Hardware	9%	18%
Software	11%	24%
Personnel	14%	39%
Outsourcing	66%	19%

- Definitions:
  - Allocates the percentage of capital and operations spending into categories.
  - Outsourcing includes voice and data carrier costs as well as service provider contracts.

IT Expense Spending Distribution by IT Functional Area

Assessment Area	Observations
IT Expense Spending	▪ Hydro One has a higher allocation to Enterprise Computing, End User Computing and Applications Support compared to the peer group.



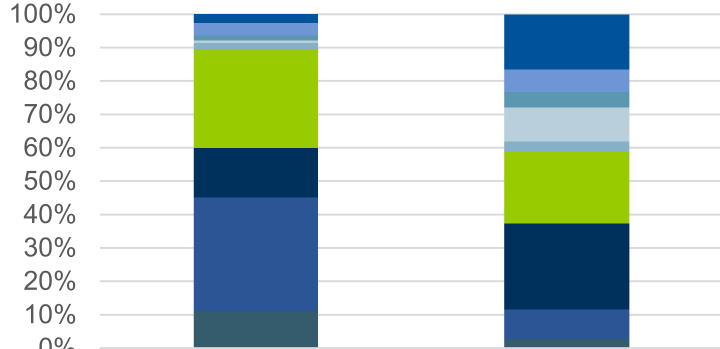
	Hydro One (102)	Peer - Avg (513)
Enterprise Computing and Storage	25%	20%
End-User Computing	14%	6%
IT Service Desk	2%	4%
Data Network	6%	10%
Voice Network	4%	5%
Application Development	13%	19%
Application Support	31%	27%
Corporate IT and Project Management	4%	6%
Finance & Administration	1%	4%

IT Expense Distribution by Functional Area

- The distribution of spending by functional area provides a view of key IT resource consumption. This distribution represents an "expense view" of IT spend which includes current-year operational expense as well as current-year lease, maintenance, depreciation and amortization expense.
- Definitions:
  - Allocates the percentage of expenses into the functional areas.

IT FTEs Distribution by IT Functional Area

Assessment Area	Observations
IT Staffing	▪ This represents In-House and Contractor FTEs and does not include outsourcing. The FTEs are focused on applications and in corporate IT management roles.



	Hydro One (102)	Peer - Avg (513)
Enterprise Computing and Storage	3%	16%
End-User Computing	4%	7%
IT Service Desk	2%	5%
Data Network	1%	10%
Voice Network	2%	3%
Application Development	30%	21%
Application Support	15%	26%
Corporate IT and Project Management	34%	9%
Finance & Administration	11%	3%

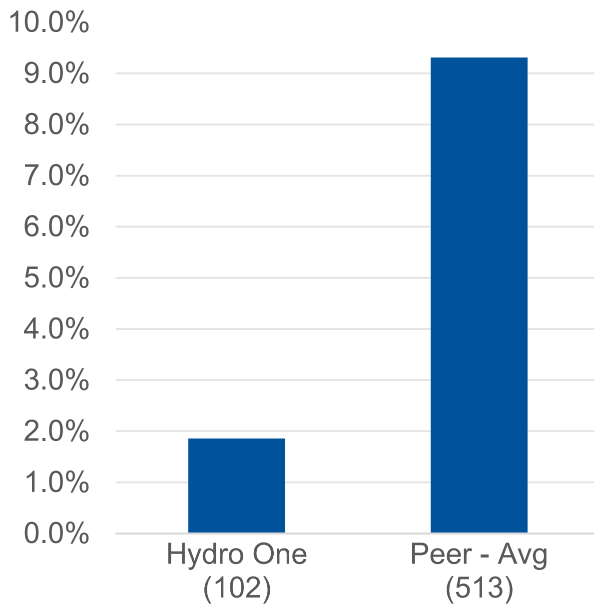
IT FTE Distribution by Functional Area

- The distribution of staffing by technology domain provides a view of key IT resource consumption.
- Definitions:
  - This distribution represents FTE allocation.

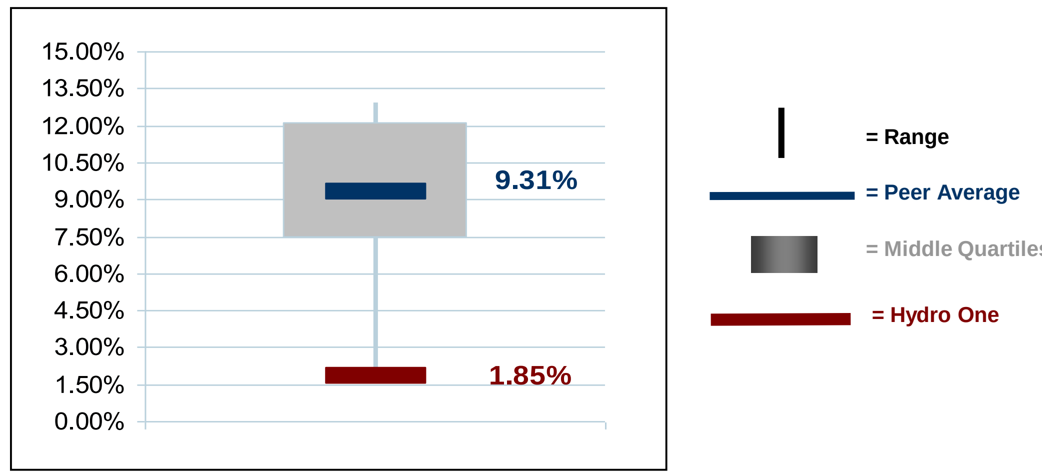
Gartner

IT FTEs as a Percentage of Total Company Employees

Assessment Area	Observations
IT Staffing	▪ Hydro One has a lower ratio of IT FTEs to Hydro One employees due to the level of outsourcing.



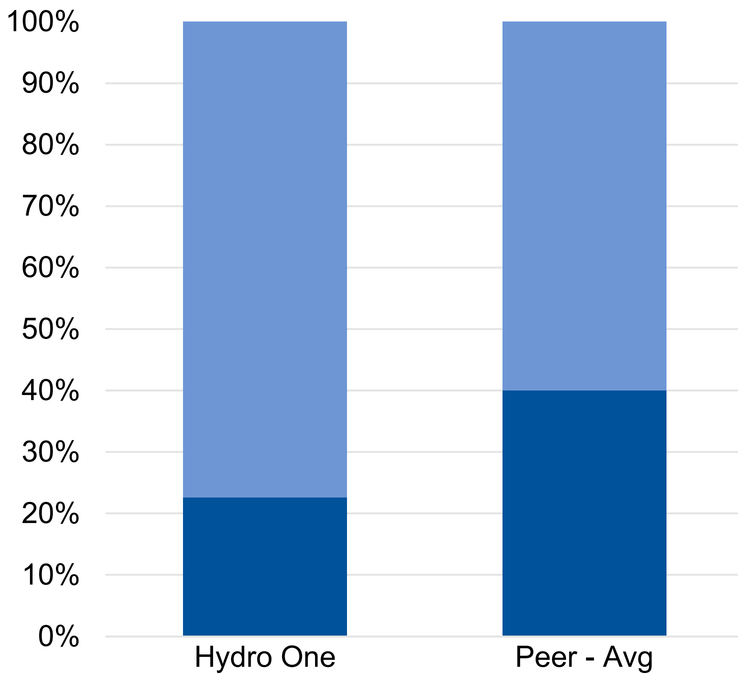
	Hydro One (102)	Peer - Avg (513)
■ IT FTEs as a % of Company Employees	1.8%	9.3%



- Definitions - IT employees includes - In-House IT Full-Time Equivalents (FTEs) and Contractor FTEs:
  - FTEs who are employed by the IT organization and contract FTEs which are supplemental to your staff and "operationally" managed by in-house staff. This includes all full time, part time, and temporary FTEs covered by the IT Spending definitions.
  - Full Time Equivalents (FTEs) Definition: An FTE represents the logical staff to support functions performed by the physical staff, measured in calendar time. This includes all staffing levels within the organization from managers and project leaders to daily operations personnel.

IT Contractor FTE Usage

Assessment Area	Observations
IT Staffing	■ Hydro One uses fewer contractors than the peer group average.



	Hydro One	Peer - Avg
In-House	77%	60%
Contractor	23%	40%

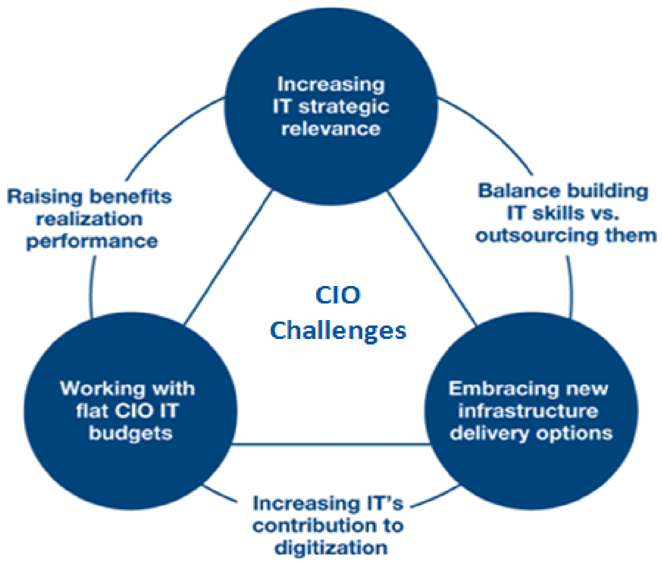
In-House and Contractor Staff Distribution

- Definitions:
  - Contract IT Full-Time Equivalents (FTEs): Total number of contract full-time equivalents, which are supplemental to your staff and "operationally" managed by in-house staff. This includes all full time, part time, and temporary FTEs.

Appendix

IT Strategy
Cost Optimization Model Framework
Data Management
Applications Rationalization

IT organizations run the risk of missing opportunities for longer term business value and strategic impact



IT organizations without a deliberate strategy often describe current capabilities as 'accidental'

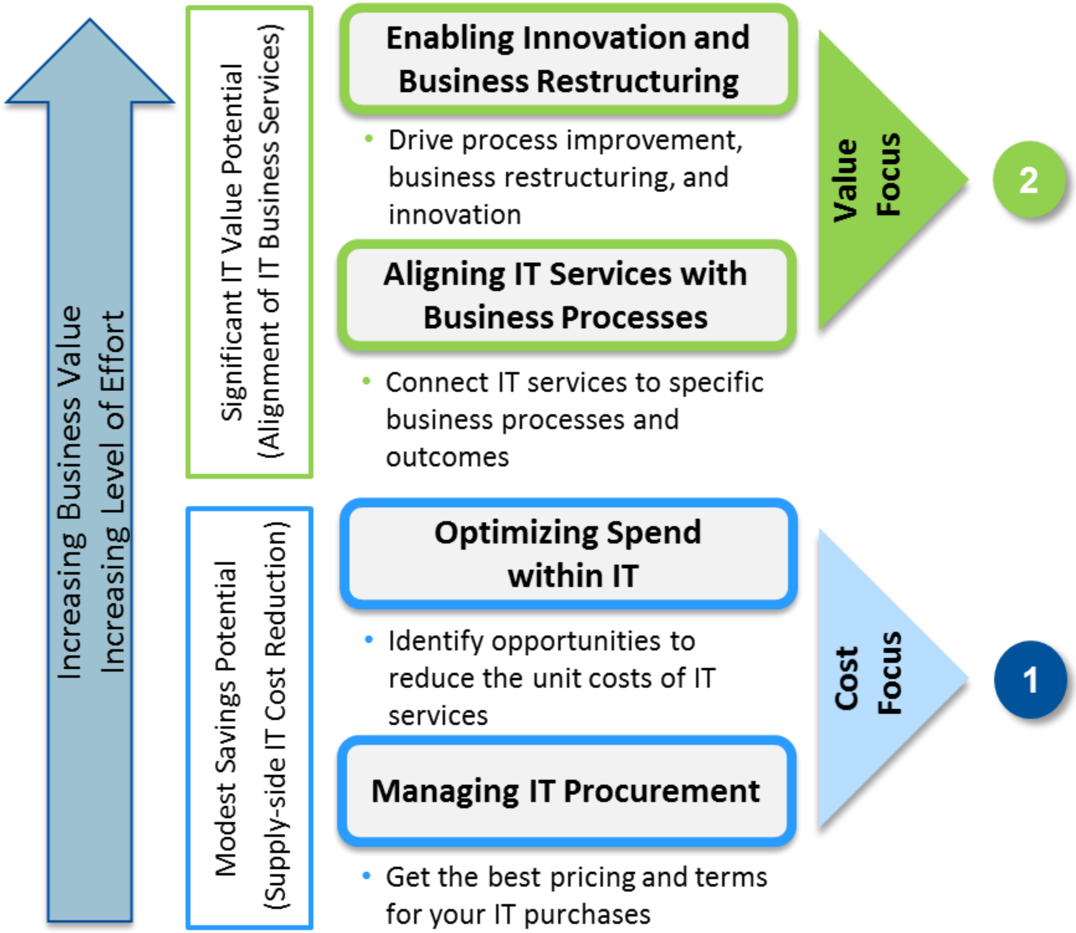
- In the long run, accidental IT strategies are substantially more expensive
- Missed opportunities for growth and differentiation, especially with new emerging technologies
- Carrying costs of low value, high risk projects
- Substantial, real investments to correct, reorganize, modernize, standardize, rationalize, and simplify

- Today more than ever, managing IT performance and delivering IT-intensive projects is necessary but not sufficient to create business, IT and CIO success.
- CIOs must understand that business results and business growth are critical for their success. This means…
  - being more disciplined about benefits realization for new capabilities and investments
  - clarifying business impact of IT contribution to business growth
  - ensuring optimization and reuse of trusted data assets
  - working with the rest of the organization to plan and prioritize IT services and investments based on business priority

Gartner

Gartner Cost Optimization Model

This framework outlines the path to optimization of both value and cost. IT can focus on ensuring that costs under IT control are efficient. Business engagement aligns IT services with business processes in order to ensure investments either contribute to revenue or reduce operating expense through productivity improvements.



- Business involvement is required to maximize the value of IT investments.
- This includes new investments and rationalization of existing applications portfolio.
- IT can manage unit costs but without business involvement cannot change the number of units under IT management or how the business works.

- IT can focus here to harvest any opportunities to improve IT efficiency. This frees up dollars for new investments.
- Measure unit costs to understand price per performance.

Data Management

Review data management and storage volume in light of the higher allocation of expenses to Enterprise Computing. Managing storage growth is a concern for many utilities owing to the large volumes of data. Many organizations have invested more in buying storage, which has a relatively low acquisition cost, than resources, processes and capabilities to manage and use the data. Data management is even more challenging in regulated industries where business requirements govern data retention.

- Barriers to storage optimization often include either a lack of the right resources and/or understanding of the differences between storage management and data management. Storage management and data management are different competencies and the terms are often misinterpreted:
  - Data management is concerned with associating value to data and then creating policies and procedures to determine data retention tiers and safe deletion. This is a business-facing role.
  - IT is a custodian of data and not the data owner, which imposes significant restrictions on IT's ability to discern the business value of data.
- An IT organization can efficiently manage large storage volumes by using products and technologies – which are within IT's direct control. As with applications, IT tools and processes can only be impactful up to a point. Storage optimization requires changing processes, procedures and organizational behavior – determining the value of data – which are out of IT's direct control.
- Review roles and responsibilities for data management and leverage more business self-service to reduce the storage footprint. Ensure that policies and processes around the value of data, such as who owns what data and how it should be retained are developed and followed.

Gartner

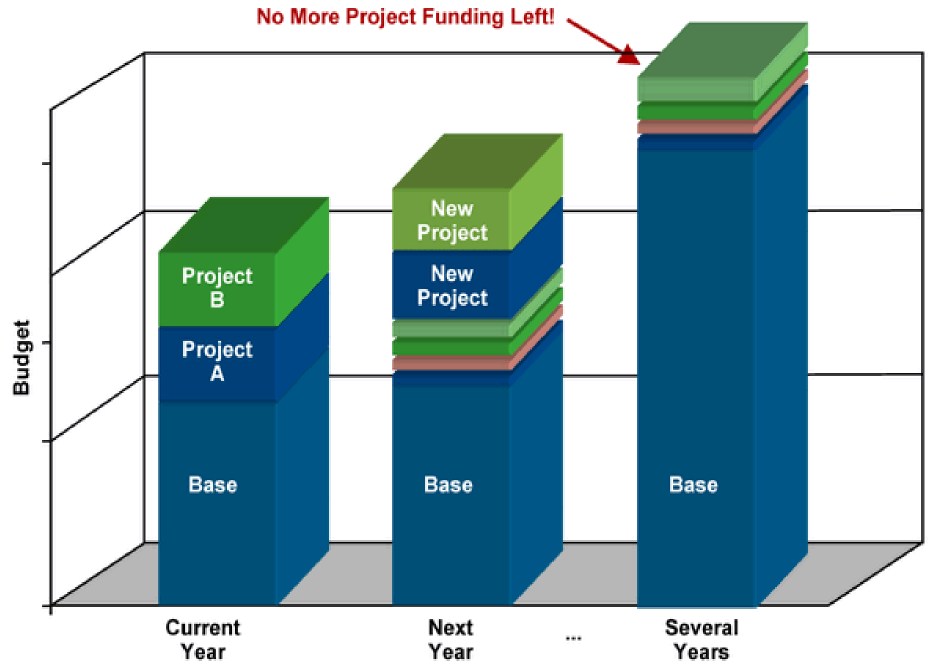
Applications Support

Hydro One allocates more of the budget to Applications Support than the peer group at 31%. Spending is lower on software however, suggesting that there is either overlap in support with the service provider or there are applications that require support but do not have a software cost. There could be an opportunity to rationalize the applications portfolio.

Recommendations

- Review the mix of applications spending to determine if the mix of support and development is appropriate for Hydro One.
- Application Development and Support tends to be more difficult to optimize than assets because of the impact on business processes. The IT organization cannot simply turn off applications. IT acting on its own cannot change how the business works.
- Common optimization initiatives include:
  - Rationalizing the current application portfolio. Taking extra care in managing the application portfolio to ensure that costs for maintaining older applications don't "crowd out" spending on new initiatives. This may require that some application is retired for every new one that is brought in.
  - Being sure to build in ongoing costs through one upgrade cycle when building business plans for new initiatives.
- Business executive sponsorship is required to the success of any application optimization effort.
- Divide application rationalization efforts into two teams – one team to focus on large applications (where there are significant cost savings through reductions in complexity and customization) and one to focus on reducing the number of small applications.

Many companies experience the "Piling On" effect of multiple projects that continuously add to baseline costs year over year. Maintenance costs can crowd out funding. This can create competitive risk in an industry dependent on technology.



Gartner

Contacts

Gartner Contact
Nicholas Lal
Managing Partner
Gartner Consulting
Telephone: +1 1416 228 7663
Nicholas.lal@gartner.com

Gartner Contact
Catherine Taylor
Associate Director
Gartner Consulting
Telephone: +1 1407 257 7303
catherine.taylor@gartner.com

2.0 (5.3) ASSET MANAGEMENT PROCESS

Infrastructure Asset Management is the combination of management, financial, economic, engineering, and other practices applied to physical assets, with the objective of providing a level of service that aligns customer needs and preferences, asset needs and rate impacts. It includes the management of the entire lifecycle of the asset including planning, design, construction, commissioning, operating, maintaining, repairing, modifying, replacing, decommissioning and disposal.

Hydro One's asset management goal is to identify and scope the optimal timing of capital investments and asset maintenance throughout the life cycle of its assets. This is done to manage risks and to support the achievement of Hydro One's Business Objectives, while managing total cost and customer rate impacts.

This section focuses on information pertaining to the asset management processes employed by Hydro One to manage its distribution assets.

Investment Planning Process

For the planning of capital investments, Hydro One utilizes a comprehensive investment planning process for identification, prioritization and optimization of asset and capital investments. An overview of the planning process is included in Section 2.1.

Overview of Assets Managed

An overview of the system that supports the delivery of service to customers including service area and the fundamental assets is included in Section 2.2.

Asset Component Information and Life Cycle Strategies

For the management of assets deployed, strategies are developed based on the characteristics and requirements of the various assets themselves. A summary of the key distribution components outlining the specific maintenance and replacement strategies for each of these various assets is contained in Section 2.3.

2.1 (5.3.1) INVESTMENT PLANNING PROCESS

Hydro One's planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board's filing requirement of a consolidated five-year capital plan. All investments follow this same process. The planning process cycle in 2016, which underpins Hydro One's investments in this Distribution System Plan, pertains to the 2017 to 2022 period.

Hydro One's planning process consists of seven stages, as outlined in Figure 9 below.

1. **Strategic Context**: Incorporation of strategic direction from Hydro One's Senior Executives and the OEB that is used to focus the identification of needs and appropriately prioritize the candidate investments;
2. **Planning Assumptions**: Incorporation of load forecast and economic assumptions to guide the development of investments;
3. **Needs Assessment**: Assessment of needs based on the existing assets, customer preferences, system requirements and other influences;
4. **Investment Development**: Development of alternative solutions and selected candidate investments to address the identified needs;
5. **Investment Optimization**: Prioritization of the proposed investments to yield an optimized investment plan;
6. **Investment Approval and Implementation**: Management of the investments within the optimized investment plan from final approval through to project completion; and
7. **Performance Reporting**: Monitoring of the plan through a set of performance metrics.

The following sections will provide further detail on each stage of the planning process.

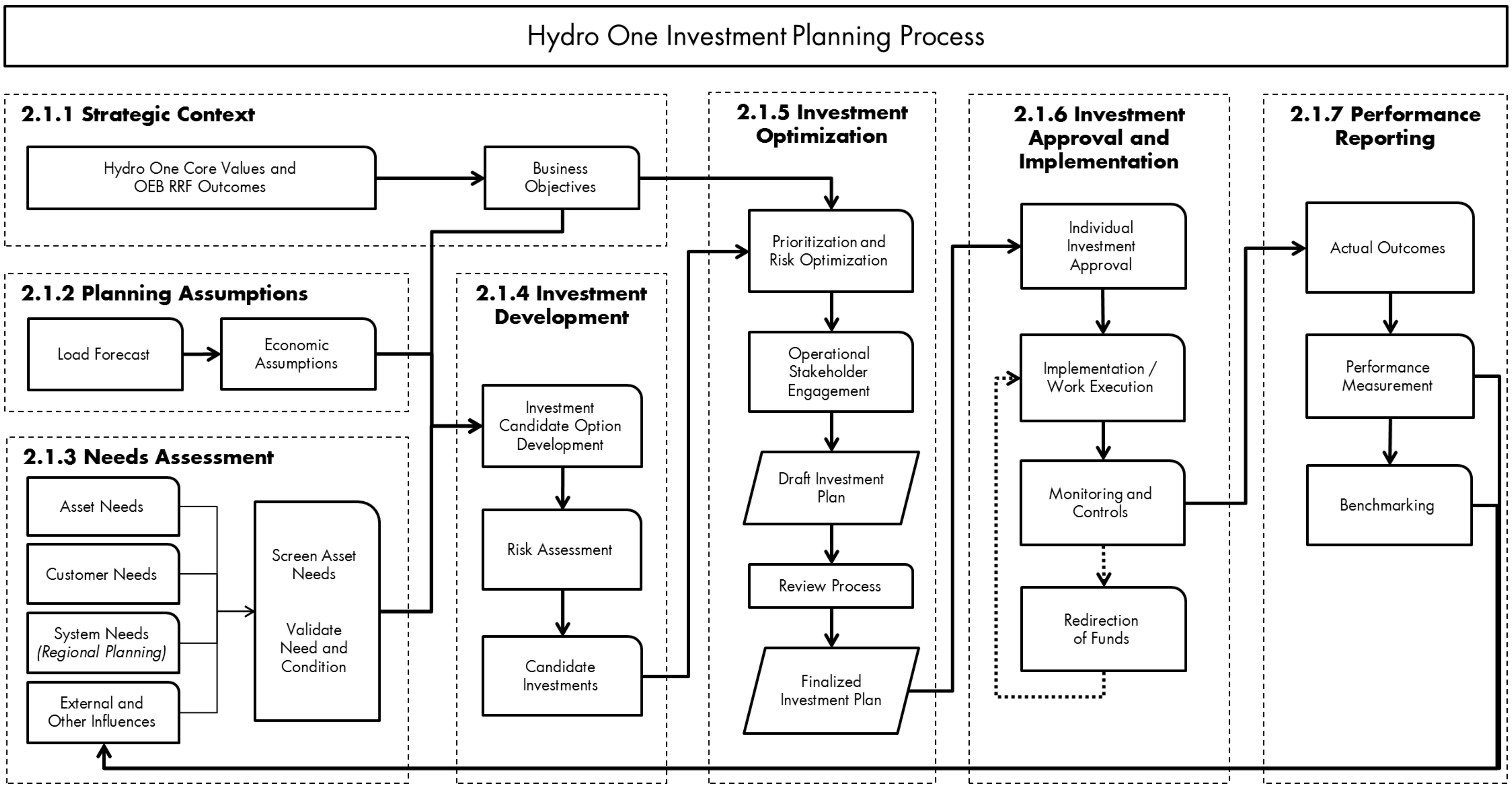
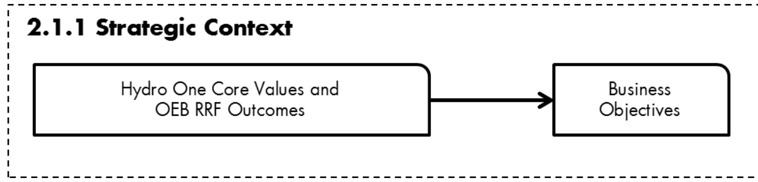


Figure 9 - Hydro One's Investment Planning Process

2.1.1 (5.3.1 A) STRATEGIC CONTEXT



Hydro One aspires to be a best-in-class, customer-centric, commercial utility, while remaining committed to delivering safe, reliable power, and supporting the sustainable development of the Ontario economy. This is reinforced by the company's vision which states, Hydro One will become:

> *"an innovative and trusted company delivering electricity safely, reliably, and efficiently to create value for our customers".*

2.1.1.1 HYDRO ONE CORE VALUES AND OEB RRF OUTCOMES

Hydro One is guided by a set of five Core Values promoting:

- a safe workplace for its employees and the public;
- a customer caring environment;
- one company working to meet customer, commercial and shareholder needs with integrity;
- a people-powered business, committed to engaging, developing and retaining the best people; and
- the pursuit of execution excellence in delivering safe, reliable, affordable transmission and distribution services.

Witness: Darlene Bradley

As a steward of assets that are critically important to customers and the provincial economy, Hydro One is committed to delivering the level of service required by customers, safely, in a manner that complies with regulatory requirements and that manages the company's environmental footprint.

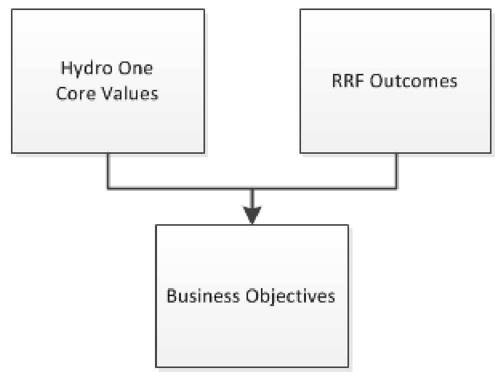
The Renewed Regulatory Framework has a clear set of objectives. To achieve those objectives, the OEB has laid out a series of four RRF Outcomes.

- **Customer Focus** – services are provided in a manner that responds to identified needs and customer preferences;
- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives;
- **Public Policy Responsiveness** – distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance** – Financial viability is maintained; and savings from operational effectiveness are sustainable.

Ultimately, the RRF Outcomes will be used to monitor and measure performance against defined performance outcomes. Hydro One is prepared and ready to meet these outcomes and the expectations of its customers and has integrated the RRF Outcomes into its planning process.

2.1.1.2 BUSINESS OBJECTIVES

Guided by its Core Values and the RRF Outcomes, Hydro One has developed a set of Business Objectives that drive decisions across the Company in the development of an investment plan. Hydro One's Business Objectives are used in the evaluation of asset and other needs in order to inform and guide the development of investment candidates. Moreover, the Business Objectives are further utilized as a basis for the prioritization weightings in the optimization of the investment plan as outlined in Section 2.1.5.

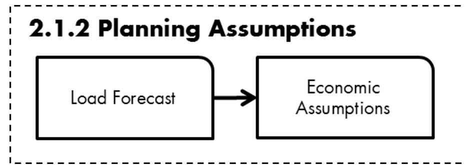


These Business Objectives, outlined in Table 29 below, are aligned with the OEB's RRF Outcomes and provide the layout of how Hydro One intends to measure success to drive continuous improvement as described in Section 1.4.

Table 29 - RRF Outcomes and Hydro One Business Objectives

RRF Outcomes	Business Objectives
Customer Focus	**Customer** • Improve current levels of customer satisfaction • Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Safety** • Drive towards achieving an injury -free workplace for employees and the public
	Reliability • Provide reliability consistent with customer expectations
	Productivity • Actively control and lower costs through OM&A and capital efficiencies
	Employees • Achieve and maintain employee engagement
Public Policy Responsiveness	**Shareholder Value** • Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment • Sustainably manage our environmental footprint
Financial Performance	**Financial Benefit** • Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts

2.1.2 (5.3.1 B) PLANNING ASSUMPTIONS



To facilitate the preparation of Hydro One's investment plan, an economic outlook forecasting key economic statistics and a customer load forecast are developed. The forecasts and assumptions used for Hydro One's investment plan are documented below.

2.1.2.1 LOAD FORECAST

Hydro One uses a number of methods, such as econometric models, end-use models, and customer forecast surveys to produce the load forecast required for its distribution business. This load forecast methodology is the same method that Hydro One has applied in previous Distribution Rate Applications (EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416). Similar methods are used by major utilities throughout North America.

The forecasts presented are weather-normal at the wholesale level unless otherwise specified. Abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. This weather correction methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0317).

A detailed description of Hydro One's forecasting methodology, models and their elements including: consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards are discussed in Exhibit E, Tab 2, Schedule 1.

Using this approved forecasting methodology; the forecast for the test years (2018 to 2022) is presented in the table below.

Table 30 - Forecast Energy Deliveries and Customer Count

Year	Energy Delivery Forecast (GWh)	Change (%)	Distribution Customer Count	Change (%)
2018	36,019	-0.6	1,300,518	0.7
2019	35,680	-0.9	1,309,216	0.7
2020	35,673	0.0	1,317,967	0.7
2021*	36,363	1.9	1,386,522	5.2
2022*	36,373	0.0	1,395,578	0.7

** The figures include the impact of integrating the Acquired Utilities into Hydro One Distribution. Without this, the GWh delivered would have changed by -0.3% in 2021 and 0% in 2022, and the number of customers would have changed by 0.7% in both 2021 and 2022.*

While the Provincial aggregate load growth is expected to decline, the customer count is expected to rise moderately. The decrease in load is mainly due to the impact of Conservation and Demand Management ("CDM") and the current economic conditions. There are also pockets of load and customer growth expected to occur in Hydro One's service territory, primarily in areas that border major urban centres.

Witness: Darlene Bradley

2.1.2.2 ECONOMIC OUTLOOK

Distribution Cost Escalation for Construction, Operations & Maintenance

Hydro One utilized the HIS Global Insight's "Distribution Cost Escalators for Construction, Operations & Maintenance" presented in Table 31 below to forecast expenditure level changes for distribution materials and services. These escalators provide a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour comprised of: operation, supervision and engineering, load dispatching, stations, lines, meters, customer installations, maintenance, structures, overhead lines, underground lines, line transformers, and miscellaneous.

Table 31 - IHS Global Insight's June 2016 Forecast

%	Historical Years					Bridge Year	Test Years				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Distribution Cost Escalation for Construction	2.9	3.5	2.9	2.5	-0.4	1.8	2.5	3.0	3.0	3.0	2.9
Distribution Cost Escalation for Operations & Maintenance	2.3	0.8	0.7	-0.8	-0.7	1.6	2.2	2.4	2.3	2.2	2.0

Consumer Price Index

Hydro One, as an Ontario based distributor, has relied on the Ontario Consumer Price Index ("CPI") presented in Table 32 for its assumptions about inflation and costs. The CPI, published by Statistics Canada, provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in the retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Table 32 - Ontario CPI

%	Historical Years					Bridge Year	Test Years				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CPI-Ontario*	1.4	1.1	2.3	1.2	2.1	1.9	2.0	2.0	2.0	2.0	2.0

** IHS Global Insight's June 2016 forecast.*

Exchange Rates (CDN:USD)

Hydro One utilized historic exchange rates based on the average exchange rates for 2012, 2013, 2014 and 2015 from the Bank of Canada. The exchange rate forecasts for 2016 to 2022 are based on the June 2016 edition of the Global Insight Forecast. These exchange rates, as presented in Table 33, are used to forecast other variables such as Fleet vehicle related costs, forecasts for which are typically obtained in US$. It is an important variable affecting the performance of the Ontario economy.

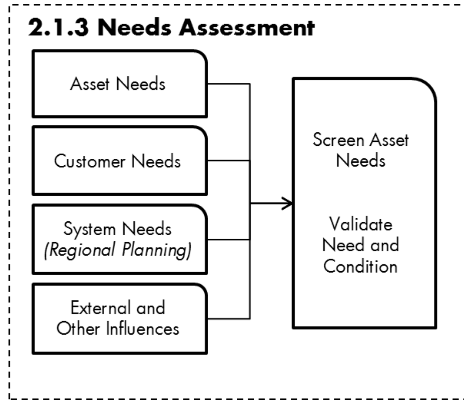
Table 33 - Exchange Rate

USD:CAD	Historical Years					Bridge Year	Test Years				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Exchange Rate	1.000	0.971	0.905	0.783	0.751	0.770	0.790	0.841	0.872	0.885	0.900

Note. Actual exchange rates for 2013 and 2014 were lower than forecasted due to unexpected decline in price of oil
Source: IHS Global Insight's June 2016 forecast.

Witness: Darlene Bradley

2.1.3 (5.3.1 B) NEEDS ASSESSMENT



Hydro One performs a needs assessment in order to identify the needs that will drive the development of candidate investments. The needs assessment considers the asset needs, customer needs and preferences, system needs (including regional planning) and other external influences. The needs assessment also identified potential hazards, vulnerabilities, threats or other risk sources that could present risks to achieving Hydro One's Business Objectives

2.1.3.1 ASSET NEEDS

Individual asset needs are determined, in part, by performing an asset risk assessment ("ARA"), which relies on various information sources such as asset condition data, asset registry for demographics, system configuration, and system performance and utilization data. SAP is Hydro One's asset registry with some supplemental asset information being extracted from GIS, such as conductor length, secondary circuits, etc.

Each of these different information sources are used to assess risk by their corresponding asset risk category, as described below. This assessment is the same process that Hydro One applied in the previous Distribution Rate Application (EB-2013-0416) and is outlined in Figure 10 below.

Witness: Darlene Bradley

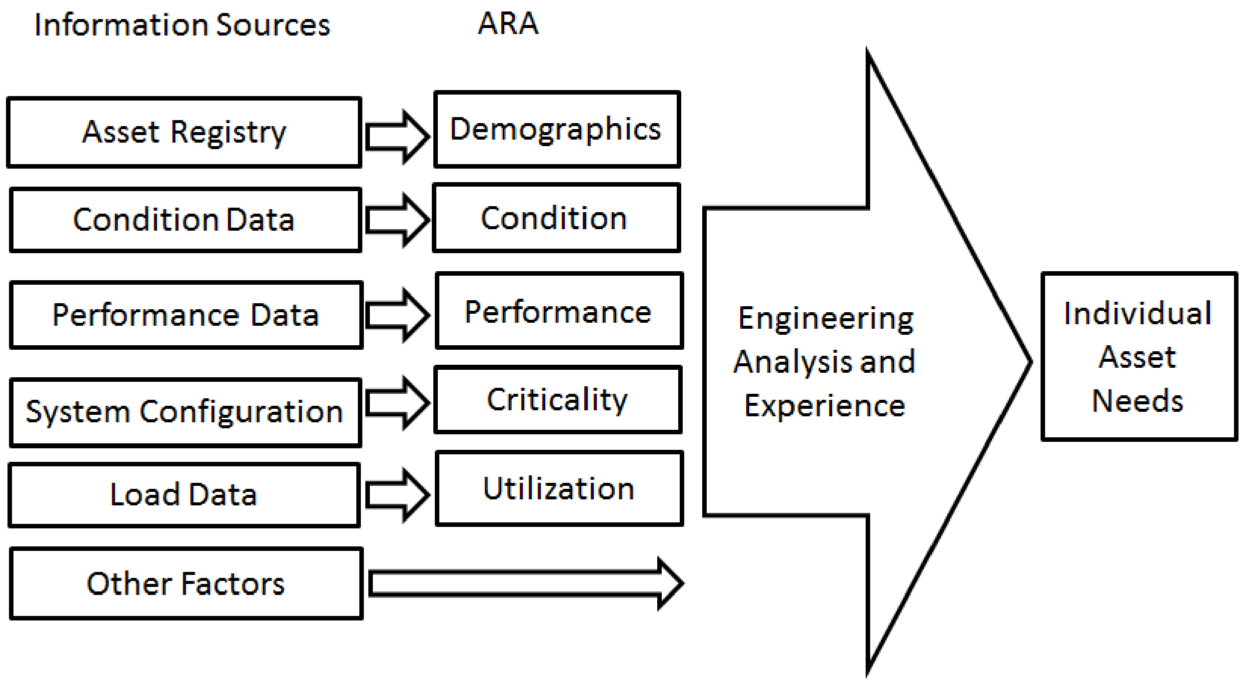


Figure 10 - Asset Need Development Process

Asset Demographic Risk

Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage. Asset demographic data by make and manufacturer is contained within Hydro One's asset registry. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages.

At times, specific asset makes or models are observed to deteriorate at a markedly different rate than other assets of the same type. For example, Hydro One has observed increased deterioration rates in Red Pine wood poles of specific vintages. Poles of this material and of these specific ages therefore carry a higher asset demographic risk than other wood poles of the same age.

Witness: Darlene Bradley

Assets with relatively high demographic risk are candidates for refurbishment or replacement.

Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time. Asset condition is defined using different criteria depending on the asset. For example, the condition of a distribution station transformer is measured by visual inspection and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test and, if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently.

Asset Performance Risk

Asset performance risk reflects the historical performance of an asset. Performance is defined by any power interruptions that have been caused by failure of the asset. Hydro One tracks the failure of an asset and customer power interruption data using its distribution Outage Response Management System. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are occurring more or less frequently over time. Past performance can be a good indicator of expected future performance.

Asset Criticality

Asset criticality represents the impact that the failure of a specific asset has on the distribution system. Primarily, it is defined by the number, type and size of customers impacted by the failure of a given asset. Assets whose failure would result in an interruption to a higher number of customers or in a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller customer impact.

Asset criticality does not directly drive a decision to refurbish or replace an asset. However, it is used to prioritize the refurbishment or replacement of assets whose other risk assessment factors has already resulted in the asset being considered a candidate for refurbishment or replacement.

Asset Utilization Risk

Asset utilization risk represents the increased rate of deterioration (or increased risk of failure) exhibited by an asset that is highly utilized. While not all assets exhibit this increased rate, the deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded beyond their nameplate rating deteriorate more quickly than those that are lightly loaded. Therefore, the asset utilization risk for transformers attempts to consider their relative deterioration based on available loading history.

In assessing asset needs, planners also consider other factors such as environmental risk and requirements, compliance obligations, equipment defects, and health and safety considerations. The results of the ARA, in conjunction with the other factors, are analyzed to develop a list of asset needs by major asset type. The specific information and risks utilized to determine asset needs is dependent on the major asset.

2.1.3.2 CUSTOMER NEEDS

Hydro One customer needs are identified through engagement with its customers. On a regular basis, as part of its everyday operations, Hydro One engages with customers, collecting information on customer needs and preferences via customer surveys. In addition to this regular engagement, Hydro One has undertaken a customer engagement process for the purpose of increasing understanding of customer preferences and aligning those preferences, responsible asset stewardship and rate impacts in its distribution system plan. As described in Section 1.3, this plan is consistent with the OEB's RRF framework.

The key messages from the customer engagement process were integrated into the system plan as follows:

- A top priority for all customers was to minimize rate increases. To address this Hydro One will defer early year capital spending to pace investments in such a way as to minimize rate impacts and implemented a number of productivity initiatives to reduce unit and operational costs.
- Residential and Small Business customers requested that Hydro One maintain its existing level of reliability. Hydro One's overall business plan was optimized to maintain current levels of reliability. To provide cost value and manage system wide reliability performance, Hydro One will focus some investments on feeder performance outliers.
- For Large Customers, improving power quality and reducing the number of sustained outages is their top priority. To address this Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue that they are experiencing. Hydro One has increased the funding of reliability enhancement projects to specifically target Large Distribution Accounts and mid-size industrial customers.

Complete details of how Hydro One has integrated the outcomes of the customer engagement process into the distribution system plan are in Section 1.3.4.

Hydro One seeks to continue to engage customers consistently and proactively, leveraging a better understanding of customer needs into improved overall satisfaction with service. An investment plan that provides customers with outcomes that are value for money is critical to achieving this goal.

2.1.3.3 SYSTEM NEEDS

Hydro One's system needs are identified through the regional planning process and by performing regionally focused reviews of the distribution system's remaining capacity.

Hydro One is actively involved in the regional planning process in conjunction with the IESO, the Transmitter, and other LDCs. The regional planning process identifies primarily transmission-level investments that provide supply to more than one distributor. However, distribution-level investments are also identified when such investments can address a regional need more effectively than other transmission or resource options. A detailed description of the Regional Planning process is included in Section 1.2.

Regionally focused reviews of the distribution system's remaining capacity involve a review of the loading on all major assets supplying the area to determine if there are any assets that are at or near loading limits.

2.1.3.4 EXTERNAL AND OTHER INFLUENCES

Other planning considerations include such factors as: results of the performance reporting metrics benchmarking trends and industry best practices. Benchmarking gives Hydro One the opportunity to compare its performance and internal measures to other utilities within the industry. Hydro One conducted external benchmarking studies on the unit cost of its pole replacement and station refurbishment programs, which highlighted potential productivity and efficiency opportunities that were considered in the development of the investment plan.

2.1.3.5 SCREEN AND VALIDATE NEEDS

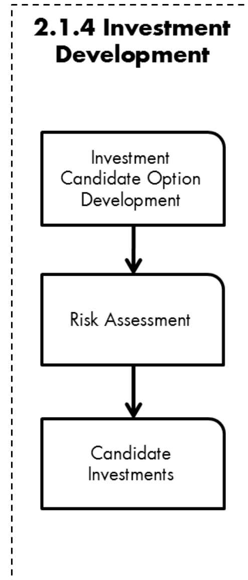
The final step in the Needs Assessment is comprised of three parts.

1. Screening Needs involves prioritizing the needs within the needs categories, e.g., customer expressed a desire for lower rates and improved reliability, but the priority was on rate impacts.

2. Screening Needs also involves grouping the needs identified into logical functional and geographic groups. For instance, a customer need for increased capacity and an asset need to replace a distribution station in deteriorated condition could be grouped together if the same physical assets are involved.

3. Validating Needs entails reconfirming that the need is still present and has not evolved and will not be addressed by other means. For instance, a planned new station may eliminate the need to replace an end of life station and could also provide the additional capacity required by a customer.

2.1.4 (5.3.1 B) INVESTMENT DEVELOPMENT



The process Hydro One undertakes to identify candidate investments entails the development of candidate options and an assessment of risk related to each option.

2.1.4.1 INVESTMENT CANDIDATE OPTION DEVELOPMENT

Hydro One's development of candidate options is driven by three things.

First, Hydro One's Business Objectives act as a filter to determine whether an investment is worth considering. If an investment does not support the achievement of a Business Objective then it is not considered further.

Second, where appropriate, planning assumptions are factored in to ensure that full and unbiased information is available and so that the candidates are ultimately evaluated in a credible fashion.

Finally, investment candidates are chosen by their ability to address the needs identified in the needs assessment. Hydro One classifies investments into one of the four OEB investment categories: System Renewal, System Access, System Service, and General Plant. Each category shares a common investment development process, but the development of investments to address the specific needs is distinct to each category.

System Renewal

System Renewal investments involve replacing and/or refurbishing system assets to extend the expected service life of the assets and thereby minimize life cycle costs and maintain reliability performance.

In general, identifying and selecting System Renewal investments consist of several steps. The first step is to consolidate the risk information identified in the Needs Assessment by major asset type. The next step is to identify options to mitigate risk for assets that are deemed to have a significant increased risk of failure. Hydro One then reviews the needs of assets in close proximity to determine if there are opportunities for an integrated stations or lines centric investment. Hydro One relies upon the factors used to evaluate risk including condition, criticality, performance and demographics as described in Section 2.1.3.1. The aggregate risk is then used to prioritize the assets within an asset type and centric investment types. Following this prioritization, alternative levels of accomplishment and their corresponding levels of risk to which Hydro One will be exposed, are defined. Finally, the preferred option to mitigate the asset risk is selected using the Investment Optimization process described in Section 2.1.5.

System Service

System Service investments are modifications to the distribution system to ensure that it continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

System Service investments are reviewed based on their ability to address the system need in the most cost-effective manner while considering benefits to other Hydro One

Business Objectives. In general, identifying and selecting System Service investments is comprised of the following steps.

First a geographic boundary, based on system needs, is established to determine the extent and scope of the area being considered. Hydro One has a vast service area and thus defining this geographic boundary is necessary to focus the analysis.

Next a series of data reviews for the defined area are undertaken, including:

- A review of the loading on all major assets supplying the area to determine if there are any assets that are at or near their loading limits or if these limits will be exceeded based on expected load growth for the area. The major assets reviewed for remaining capacity include sub-transmission feeders, distribution stations and distribution feeders. Supply capacity from the transmitter is also confirmed. The current peak loading and forecast 10-year peak loading with conservation demand management and without conservation demand management are compared to current loading limits;
- A review of existing and planned Distributed Generators ("DG") in the area for any potential synergies to optimize capital investments as part of the area plan;
- A review of System Renewal and System Access needs in the area to assess opportunities of integrating work into an optimal integrated plan; and
- A review of the system reliability for feeders supplying load in the area. Feeders identified as having a reliability concern will be analyzed to determine if an alternative will improve its reliability.

Based on this information, alternatives are developed to address any issues determined through the analysis described above. These alternatives are compared on economic considerations, efficiency/line losses, reliability and other factors impacted by the alternatives. Finally, a preferred alternative is recommended based on the above analysis.

System Access

System Access investments are non-discretionary in nature and are system modifications that Hydro One is obligated to perform to provide and maintain customer(s) access to electricity services. These investments mainly include:

New Customer Service Requests

Investments are generated in response to customer requests for new connections to Hydro One's distribution system. Hydro One is obligated to connect new customers as per Section 28 of the *Electricity Act* under the conditions specified by the Distribution System Code. To effectively budget for new customer service requests, Hydro One forecasts new customer connections using forecasting methodology described in Exhibit E1, Schedule 2, Tab 1. Specifically, for large customers, new customer service requests are assessed as dictated by the Distribution System Code.

Third-party Infrastructure Development Projects

Investments are generated based on requests from external proponents to relocate Hydro One's assets to accommodate various infrastructure projects, such as a road widening. To effectively identify and budget for third-party infrastructure projects that require plant relocation or modification, Hydro One actively engages in planning and coordination meetings with the Ministry of Transportation, local municipalities and other third party initiated projects that require relocation of Hydro One assets.

Mandated Service Obligations

Investments that Hydro One is mandated to perform by government regulation or policy such as replace/upgrade metering infrastructure, and/or enable distributed generation.

General Plant

General Plant investments are comprised of modification or replacements to distributor's assets that are not part of the distribution system. These include investments related to Hydro One's transport and work equipment fleet, facilities, and information technology. The process to identify and select investments in each of these areas is discussed below.

Transport and Work Equipment Fleet

Transport and work equipment investments are necessary to ensure that crews have the ability and the vehicles required to access and perform the work required. Investments are generally comprised of either new equipment or replacement of existing equipment. The investments are identified and selected based on need which is driven by the following key factors:

- work program requirements;
- industry standards (manufacturer's recommendations) for life cycle expectancy;
- Net Book Value (NBV) to Original Capital Value (OCV) ratios; and
- operating cost drivers.

Based on this information, a preferred alternative is recommended in line with Hydro One's expected Business Plan and Work Programs.

Facilities

Facility investments are necessary to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. The investments are identified and selected based on need which is driven by the following key factors:

Witness: Darlene Bradley

- aging facilities that are at or near their end of life;
- compliance with legal requirements, such as *Accessibility for Ontarians with Disabilities Act*;
- expanding work programs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity.

Based on this information, a comparative evaluation of alternatives, which may entail the lease or purchase of existing or green-field developments against status quo condition, is undertaken. A preferred alternative is recommended based on the objective to pursue the most cost-effective strategy that addresses operational requirements and manages risk.

Information Technology

Information Technology ("IT") investments are identified and selected based on the need to address:

- potential end of life information technology systems and determine the point in time to initiate their upgrade or replacement; and
- mandatory Ontario Energy Board Regulatory Compliance changes to our systems, (e.g. billing, rate increases, policy changes).

2.1.4.2 RISK ASSESSMENT

Once investment candidate options are identified, a risk assessment is undertaken. The risk assessment is based on the value that the candidate creates by mitigating risks identified in the needs assessment or the ability of the candidate to enhance productivity.

The risk assessment includes an evaluation of the effectiveness of existing processes and operations to control risk.

The risk assessment is based on a Risk Evaluation Matrix that defines the level of risk as a product of the likelihood of a risk (i.e. probability) and the severity of a risk (i.e. consequence), as illustrated in Figure 11. The “consequence” of a given risk is measured on a five-point risk tolerance scale from “minor” to “catastrophic”. The “probability” that a given risk will materialize is measured on a six-point likelihood scale, from “unexpected” to “very likely”.

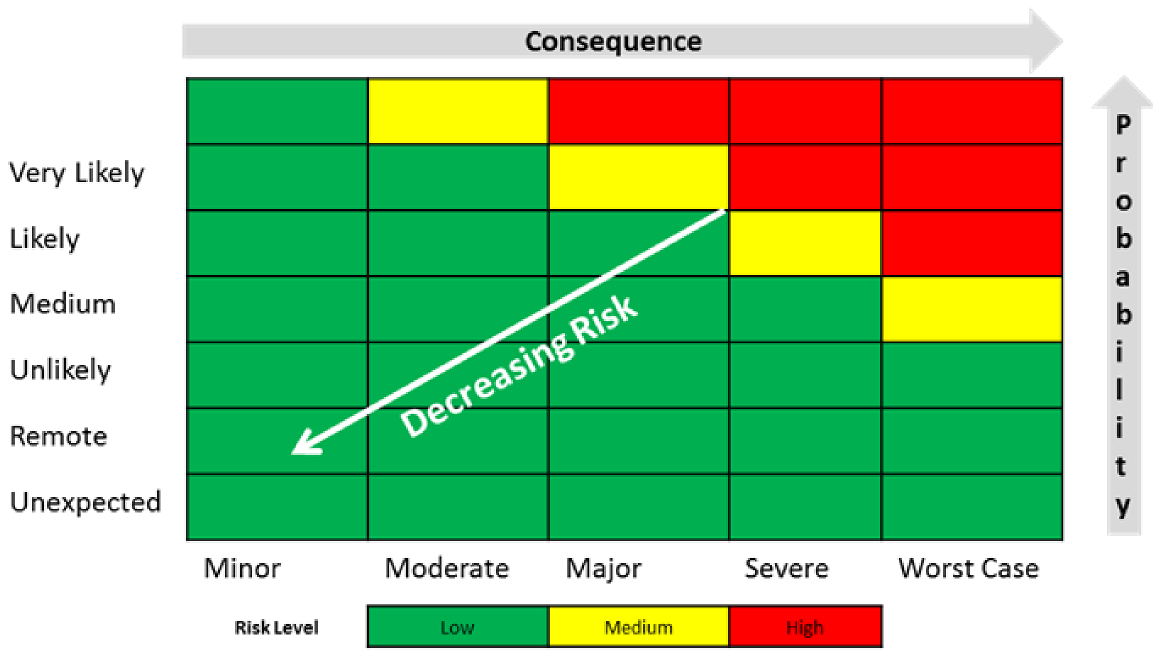


Figure 11 - Risk Evaluation Matrix

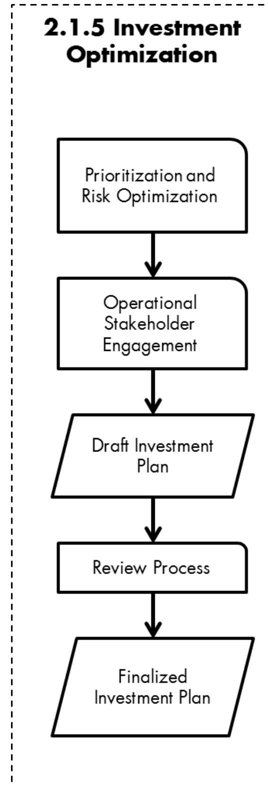
A risk assessment is undertaken for two scenarios: (a) a baseline risk evaluation, representing the risk of not proceeding with the investment; and (b) a residual risk evaluation, representing the remaining risk after the investment is put into service.

These risks assessments form a clear link between the risks and the intended benefit of the candidate investments. The difference between the baseline risk and residual risk is the risk mitigation value created by the investment.

2.1.4.3 CANDIDATE INVESTMENTS

Once the investment candidate options have been through a risk assessment, a structured, multi-level managerial review is conducted. The managerial review is focused on the need justification, the reasonableness of the risk assessment, and the appropriateness of the candidate investment options prior to its inclusion in the investment plan. A decision is made to accept the risk or mitigate the risk. Mitigation is designed to reduce the impact of the risk (consequence) or reduce the likelihood of occurrence (probability). For risks identified for mitigation, a list of recommended candidate investments with associated estimated cost and risk assessment are input into the investment optimization process and used to produce the optimized investment plan.

2.1.5 (5.3.1 B) INVESTMENT OPTIMIZATION



This section details the investment optimization process that takes identified candidate investments and yields a finalized investment plan.

2.1.5.1 PRIORITIZATION AND RISK OPTIMIZATION

All candidate investments are aggregated into a consolidated investment plan for prioritization and optimization. At the core of the process is the multi-variable framework based on the business objectives, which helps decision-makers understand and quantify business risks and uncertainties so that objective decisions can be made respecting investment priorities.

For the purpose of prioritizing investment candidates, the Business Objectives outlined in Section 2.1.1 are translated into a series of prioritization criteria, against which candidate investments are assessed. The prioritization criteria are assigned weights based on their relative importance within the Business Objectives as shown in Table 34.

Table 34 - Hydro One's Prioritization Criteria and Weightings

Prioritization Criteria	Business Objectives	Weighting (Pts)	Weighting (%)
Customer	• Improve current levels of customer satisfaction • Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes	20	17%
Safety	• Drive towards achieving an injury - free workplace	20	17%
Reliability	• Provide reliability consistent with customer requirements	15	13%
Productivity	• Actively control and lower costs through OM&A and capital efficiencies	15	13%
Employees	• Achieve and maintain employee engagement	10	9%
Shareholder Value	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario	10	9%
Environment	• Sustainably manage our environmental footprint	10	9%
Financial Benefit	• Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts	15	13%

The prioritization process attempts to find the combination of investment options that maximize investment benefit without exceeding the defined funding constraints. This iterative process is intended to produce an overall plan of appropriately paced investments that achieves an optimal balance between cost effectiveness, timely responsiveness to customer needs, asset requirements and business needs. This iterative process is a key stage in the process and it is what lead to the determination of Plans A, B and C as described in Section 1.1 and Section 2.4

Witness: Darlene Bradley

2.1.5.2 OPERATIONAL STAKEHOLDER ENGAGEMENT

After prioritization, a company-wide review of the investment plan is conducted by all internal Hydro One stakeholders. These cross-functional review meetings are held to review and discuss the investment plan. This review is meant to facilitate the consideration of additional operational and execution considerations such as resourcing, material availability and outage obtainability. Based on these discussions, adjustments may be made to reflect emerging execution risks and financial considerations. The end product is a draft investment plan that is a prioritized and paced six-year plan that aligns customer preferences, asset needs and rate impacts.

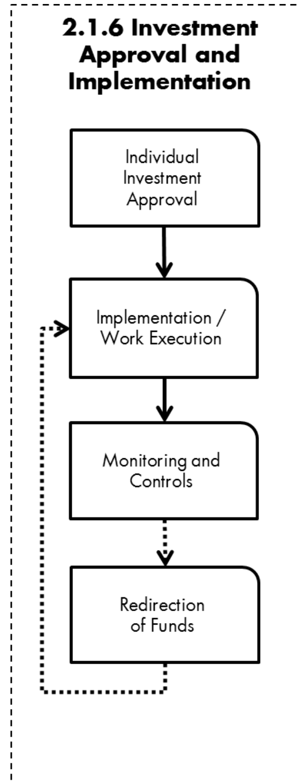
2.1.5.3 REVIEW PROCESS

Following the Operational Stakeholder engagement, the draft investment plan is put forward for review by the Executive Leadership Team ("ELT"). The ELT review is a two-day process that reviews the draft investment plan. The ELT will request additional information on certain investments. Any adjustments to the investment plan, based on input from the ELT review, are completed. A final determination is then made taking into consideration the associated impacts on customer rates, the impact to Hydro One's Business Objectives, and system reliability.

Ultimately, the completed Investment Plan is incorporated into the corporate Business Plan and this is sent to the Board of Directors for approval.

2.1.6 (5.3.1 B) INVESTMENT APPROVAL AND IMPLEMENTATION

Once the overall plan is finalized and approved, individual investments undergo specific individual approvals, are queued for implementation, and monitored during execution.



2.1.6.1 INDIVIDUAL INVESTMENT APPROVAL

Individual projects are reviewed and approved in a series of steps at the senior management and executive levels, consistent with the provisions of the corporate expenditure authority register. This review process entails:

- Verification of the need for the investment and recommended specific investment solution;
- Review of the implications and risks of not executing the investment;
- Review of the anticipated benefits; and
- Review of the estimated costs and execution timing.

Once approval is granted, the individual investments move to the implementation and work execution phase.

2.1.6.2 IMPLEMENTATION/WORK EXECUTION

Hydro One utilizes a fully integrated work execution method that balances and optimizes the use of internal and external resources, costs, system outages, customer needs and material availability in the implementation and execution of its investment plan.

Witness: Darlene Bradley

Hydro One's work execution focus aims to effectively and efficiently execute on its investment plan while focusing on the Company's Business Objectives. Hydro One intends to execute and deliver on its investment plan while maintaining the necessary flexibility to address emergent work and changing priorities.

2.1.6.3 MONITORING & CONTROL

On a monthly basis, year-to-date expenditures and accomplishments as well as projected year-end expenditures are monitored. Variances from plan are identified and presented to senior management for appropriate action.

When it is apparent that an investment will have a material change to scope, schedule or cost from the approved plan, a variance proposal to address the unplanned change is created and presented to the appropriate management level. The approval of the variance proposal is in accordance with the limits set out in the expenditure authority register based on the cost and criticality of the investment. Investments that cannot be re-justified are reprioritized, cancelled or otherwise adjusted to conform to the new condition.

2.1.6.4 RE-DIRECTION OF FUNDS

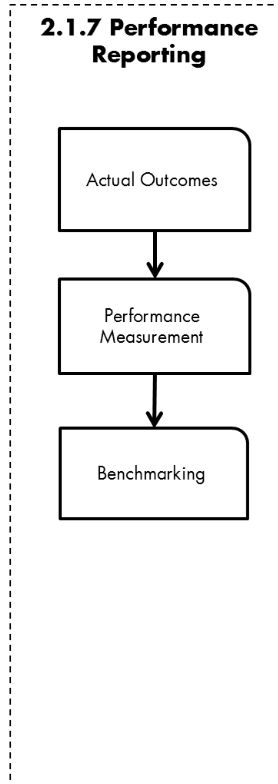
While the investment plan is the product of extensive planning and analysis, implementation of the investment plan must be done in a manner that is dynamic and flexible. Following on the monitoring outlined above, Hydro One may be required to re-direct funds or even authorize additional spending. Depending on the situation, new risks or opportunities could emerge, including:

- Changing customer needs and requirements (e.g., new regional plans, unexpected load growth, etc.);
- Changing asset priorities based on new information;

- Changing external requirements (e.g., new or changing regulatory and/or technical standards, new policy initiatives, etc.); and
- Significant unforeseen events (e.g., extensive storms and equipment failures).

The re-direction or allocation of new funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. For example, the emergency restoration work needed to repair equipment failures or storm damage to distribution lines can be significant and may necessitate the re-direction of funds from other projects.

2.1.7 (5.3.1 B) PERFORMANCE REPORTING



The final stage of the planning process is to monitor performance of the approved investment plan. The performance is monitored through tracking actual outcomes, measuring performance and benchmarking. The results of performance monitoring are utilized to facilitate continuous improvement of the plan in future years.

2.1.7.1 ACTUAL OUTCOMES

Hydro One performs a comparison between the actual investment costs and accomplishments and the proposed investment plan throughout the year and at the end of the investment plan year.

If the plan is projected to miss the planned outcomes within the year, the variance proposal may call for resources to be redeployed to bring the plan back in line with expectations. At year end, the actual investment plan accomplishments and costs are used to adjust future years' expected plan results to allow next year's expected plan to be more accurate.

2.1.7.2 PERFORMANCE MEASUREMENT

In addition to actual outcome monitoring, Hydro One is proposing a set of key performance measures to be incorporated into Hydro One's scorecard to track the company's performance. For more information on how this Performance Measurement is tracked, please refer to Section 1.4.

These performance measures will be evaluated and used to inform future investment plans as part of the feedback to the External and Other Influences portion of the Needs Assessment process.

2.1.7.3 BENCHMARKING

The measurement of selected accomplishments and costs for each investment is used to benchmark Hydro One's performance against other utilities. Complete details for the results of Hydro One's benchmarking activities that informed this DSP can be found in Section 1.6.

Benchmarking for major investment accomplishments serves to identify potential productivity and efficiency gains. Internal review and analysis of Hydro One's work practices and cost structure can lead to new work practices, along with modified productivity and cost efficiency targets. Any future identified productivity gains are used to adjust the plan accomplishments and costs accordingly.

2.1.8 INVESTMENT PLANNING PROCESS SUMMARY

Hydro One's investment planning process begins with its five core values and its vision of becoming a best-in-class, customer-focused utility. Planners navigate through seven important steps, including understanding needs, assessing candidate investments and measuring risk. The ultimate goal is to develop a comprehensive investment plan that embraces the overall Business Objectives, responds to the OEB's Renewed Regulatory Framework and aligns customer needs and preferences, system reliability (asset needs) and rate impact.

2.2 (5.3.2) OVERVIEW OF ASSETS MANAGED

The Hydro One distribution system, one of the largest in North America, has evolved over more than 100 years. Hydro One manages over $7 billion in distribution assets supplying electricity to customers across the province of Ontario. The distribution system delivers electricity at voltages below 50 kV from Ontario's transmission and generation systems to approximately 60 Local Distribution Companies, 90 Large Distribution Accounts, 8,000 Commercial & Industrial customers and 1.3 million Residential and Small Business customers.

A large number of Hydro One's assets have deteriorated in condition and significant investment is required to maintain supply reliability and to mitigate the associated risks to Hydro One's Business Objectives.

Hydro One has a number of proactive investment programs that aim to pre-emptively address critical assets where a failure would impact a large number of customers.

Hydro One has maintenance programs to address less critical assets that individually serve fewer customers, in order to quickly respond to events such as asset failures on a reactive basis.

Finally, Hydro One has demand-driven programs that react to unforeseen incidents that affect the entire system, such as storms or other external factors.

2.2.1 (5.3.2 A) DESCRIPTION OF THE DISTRIBUTION SERVICE AREA

The Hydro One distribution service area is over 99% rural with less than 1% considered to be in urban areas. Hydro One's distribution system includes approximately 1.6 million poles to serve 1.3 million customers. To service these rural areas the distribution system is radial in design, with very little transfer capability in supply to customers. A small part of the distribution system is monitored. M Class Sub Transmission feeders are monitored for volt, current, and status at the station. Smart grid devices have been deployed at the Owen Sound operating centre, including monitoring of line reclosers, capacitors and distribution stations in the operating centre's area. Otherwise, Hydro One has limited monitoring and control of breakers and switches on the system. Furthermore, the majority of the Hydro One distribution system is located overhead, with only about 8% of the system being underground. This design is consistent with other rural systems.

The map below is a representation of Hydro One's distribution service territory.

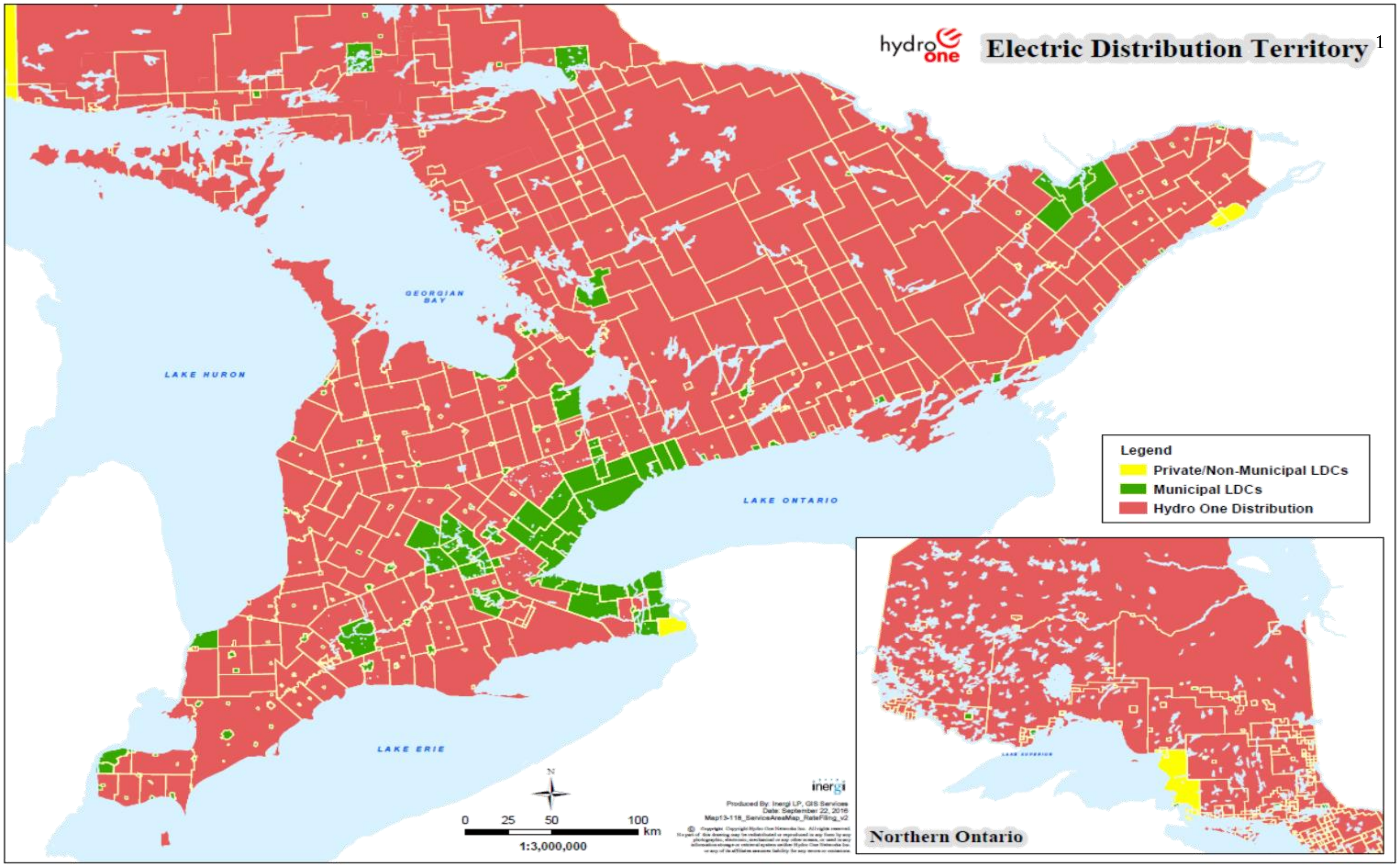


Figure 12 - Hydro One's Distribution Territory

Witness: Lyla Garzouzi

Hydro One's service to its customer is susceptible to a variety of weather conditions. Storms in Ontario include such extremes as blizzards, hail, ice storms, lightning and thunderstorms including tornadoes. Due to the radial configuration in most of the service territory, storm damage almost always results in an outage to customers and requires immediate repair to restore service.

To effectively manage the response to trouble calls from customers, the initial problem assessment and dispatching of a response is handled through a single facility, the Ontario Grid Control Centre ("OGCC"). Hydro One has Service Centres located throughout the province to cost-effectively provide operating, maintenance and restoration services. These Service Centres provide base locations for field crews and related materials, tools and equipment. In storm conditions, additional crews can be brought in from unaffected Service Centres to assist with power restoration.

Hydro One deems a force majeure to have occurred when 10% or more of Hydro One customers have been interrupted by an event. Over the past 3 years, there has been an average of 8 force majeure days per year. These types of events may include severe ice storms in the winter, or major wind and rain events in the summer months.

Another characteristic of Hydro One's service area is Ontario's forests. Southern Ontario is mostly agricultural land, but has some scattered deciduous forests. The eastern and central regions of the Hydro One service area are about fifty percent densely forested with large conifer, deciduous, and mixed forests. The northern zone, is about 74 percent covered with forests. Given that the majority of the Hydro One distribution system is located overhead, with only about 8% of the system being underground, the system is susceptible to vegetation caused outages.

System load growth over the next five years is expected to be in line with historic growth patterns. Overall, load on the Hydro One distribution system is forecast to grow at 0.1 % per year net of CDM initiatives over the next five years. During the same period, the overall increase in the number of customers is anticipated to be about 100,000, or 8.0% of the existing customer base. These figures include the impact of integrating the newly acquired LDCs into Hydro One's distribution system in the year 2021.

The majority of growth and new customer connections are expected to occur in Hydro One's urban service territories which border major urban centres including the City of Ottawa, City of Kingston, northern York and Peel Regions, Durham Region, and the City of Hamilton. For the remainder of Hydro One's service territory, which is mostly rural in nature, load growth and new customer connection activity is expected to be in line with historic growth rates - about 0.7% for new customers.

2.2.2 (5.3.2 B, C, D) DESCRIPTION OF SYSTEM CONFIGURATION AND CAPACITY

The Hydro One distribution system receives wholesale electricity from the transmission system and/or distributed generation facilities and delivers it to consumers at lower voltages. The system consists primarily of the following asset categories:

1. Distribution Stations
2. Distribution Lines
3. Other Assets

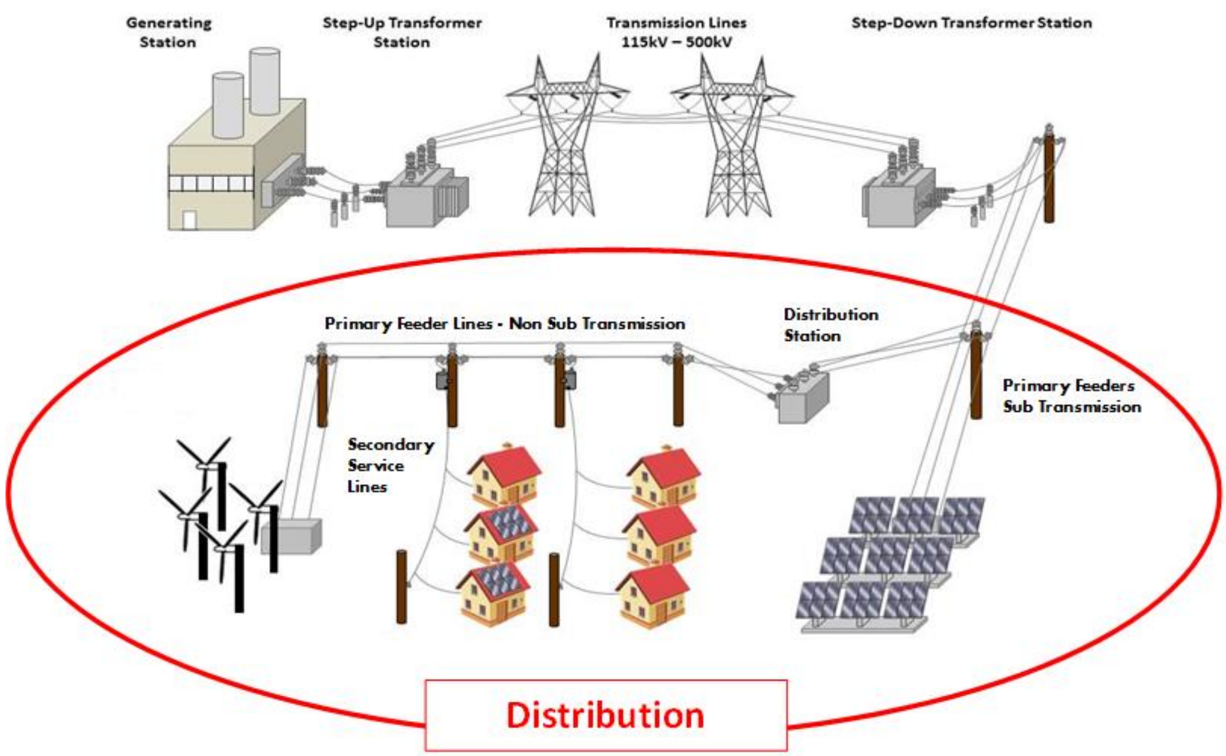


Figure 13 - Hydro One Networks' Distribution System

A description of each of these categories is provided in the following sections.

2.2.2.1 DISTRIBUTION STATIONS

Distribution Stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm, year-round residential and seasonal residential customers. Regulating Stations are a special type of station that maintains voltage within the prescribed limits in response to load variations that can cause voltage increases or decreases.

Hydro One owns and operates approximately 1,005 Distribution and Regulating Stations. They typically consist of one or two transformers, depending on the load that needs to be supplied. A loss of any one element (such as a transformer or a breaker) at a distribution station will normally result in the interruption of service to all customers served from that element until the failed component is repaired or replaced, or until an alternate service is enabled.

The capacity of a distribution station is mainly a function of the station's transformers. These can vary from less than 2 MVA to over 15 MVA with the largest percentage of transformers having a nameplate capacity of 5 MVA. Total capacity of Hydro One's Distribution Stations is over 6,500 MVA.

System asset utilization is assessed by Hydro One through planned area studies and system impact assessments. These studies are typically done on a cyclical basis (or on a demand basis if an urgent need arises). When any system assets are identified to approach or exceed Hydro One's established planning limits, corrective scopes of work are issued to address the concern. The source of utilization information for station loading is an annual data collection program through the use of electronic recording ammeters. Meters are installed on each phase of the station feeders and left for a week to record data. This data is then collected and loaded into a system simulation tool called

CYME where the system is then studied in detail. Advancements with Grid Modernization will eventually eliminate this method of data collection and allow asset loading to be sourced from the Distribution Management System ("DMS") using SCADA and DMS state estimation. Modernizing the grid will be key to delivering reliable and cost effective services to our customers going forward. Remote monitoring and control of power system equipment will be undertaken largely in conjunction with asset renewals. Distribution station refurbishment projects (ISD SR-06) will provide such functionality that delivers better determination of fault location and restoration timelines. Further deployment of equipment monitored through the DMS will be implemented through the equipment replaced through the Worst Performing Feeders (ISD SS-06), Distribution Station Reclosers Upgrade (ISD SR-05) and Distribution Lines Planned Component Replacement (ISD SR-10). All of the remotely monitored and controlled devices will be enabled by communication infrastructure implemented in the Advanced Distribution System Project (IS SS-07). As well, another component of this project is the Advanced Metering Infrastructure Analytics ("AMIA") that will leverage the smart metering data to provide transformer, feeder and distribution station information on an asset-by-asset basis and will also allow aggregation at a station level according to the network connectivity model.

Figure 14 represents the percentage of Distribution stations in each capacity category.

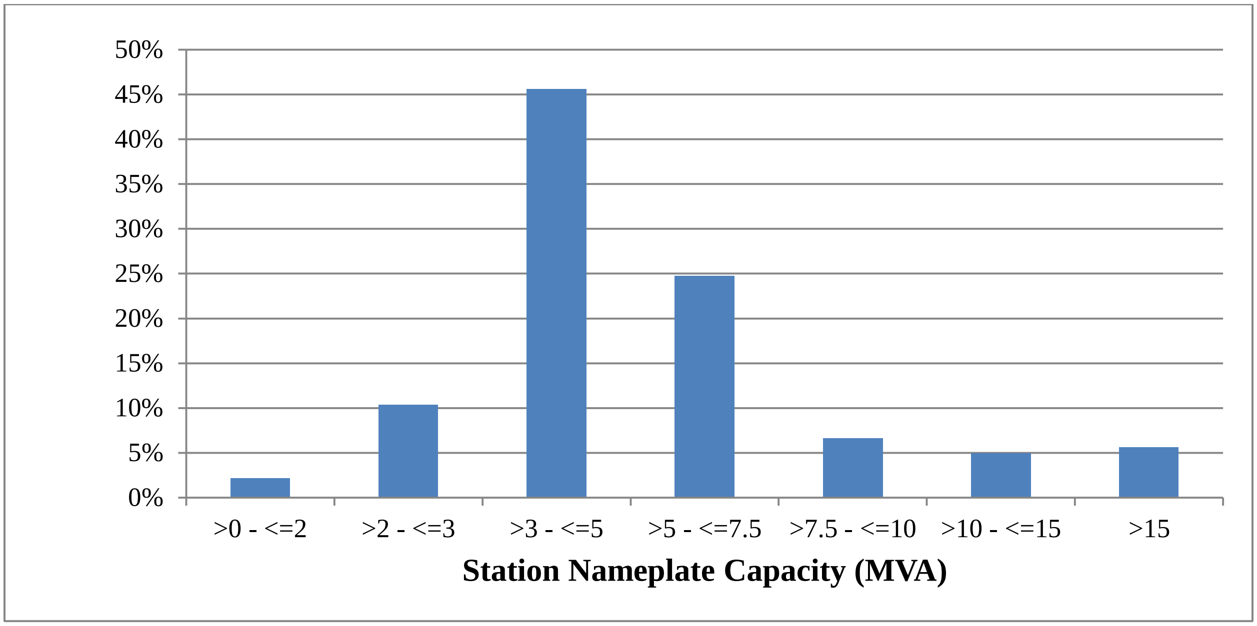


Figure 14 - Station Population by Size

2.2.2.2 DISTRIBUTION LINES

Feeder Lines include the distribution assets necessary to carry power from a station to the customer.

Distribution Feeders are classified into one of the following:

- Primary Feeder – Sub Transmission;
- Primary Feeder – Non Sub Transmission; and
- Secondary Service Lines.

Primary feeders are the lines whose main purpose is to carry electricity from a distribution station to another distribution station or to a line transformer in preparation of final transformation to a voltage that can be utilized by customers. Hydro One owns and operates more than 122,000 circuit kilometres of Primary Distribution feeders across Ontario.

Table 35 - Primary Feeder Length (km) and Count by Voltage Level

Voltage Level (kV)	Overhead (km)	Underground (km)	Submarine (km)	Total Length (km)	Feeder Count
44	9,766	48	16	9,830	343
27.6*	10,849	2,035	95	12,979	377
25*	5,433	99	369	5,901	80
22.8	48	0	0	48	3
Sub-Total Sub-Transmission				**28,758**	**803**
13.8	227	100	0	327	35
12.5	34,731	839	2,907	38,477	619
8.32	50,905	2,023	316	53,244	1,369
4.16	1,359	294	17	1,669	415
Sub-Total Non-Sub Transmission				**93,717**	**2,438**
Total	**113,318**	**5,438**	**3,720**	**122,475**	**3,241**

** Some 27.6 and 25 kV lines function as Non-Sub Transmission feeders but they are grouped together here for simplicity*

Primary Feeders – Sub Transmission

Hydro One has approximately 29,000 circuit kilometers of primary feeders that are considered to be sub-transmission. These feeders originate at transmission transformer stations or high-voltage distribution stations.

Witness: Lyla Garzouzi

Sub-transmission feeders, often referred to as M-Class feeders, typically supply power at 25 kV, 27.6 kV or 44 kV from a high voltage station to other distribution stations. These stations may be owned by Hydro One, other LDCs or large customers. Further voltage transformation takes place at these downstream stations that take power from the M-Class feeders.

In some cases, Regulating Stations are used to maintain voltages on sub-transmission feeders within the prescribed limits. This is needed because the increases or decreases in line voltage depend on load variations at the distribution stations supplied by the sub-transmission feeders.

Primary Feeders – Non Sub Transmission

Hydro One has approximately 94,000 circuit kilometers of primary feeders that operate below sub transmission voltages between 4.16 kV and 13.8 kV.

These feeders, also referred to as F-Class feeders, are circuits that deliver power from distribution stations to line transformers generally in preparation for final transformation to customer voltages. These feeders also connect increasing numbers of distributed generators.

Hydro One’s primary feeder lines are predominately radial in design. As with Stations, a loss of any one element will normally result in the interruption of service to all customers served from that feeder until the failed component is repaired or replaced, or until an alternate service is enabled.

Secondary Service Lines

Hydro One secondary system includes approximately 50,000 kilometers of secondary service lines. This system generally provides a connection from a pole top or pad mounted transformer to an individual customer's demarcation point, which is generally the meter for most residential customers. The Secondary system operates at lower voltage levels that are useable by customers.

The secondary service lines could be either underground or overhead when originating from a pole top transformer. These lines are always underground when originating from a pad mounted transformer.

Secondary service lines generally serve a single customer. Therefore, an outage on a secondary line usually has minimal impact to customers on the system. As such, Hydro One does not perform preventative maintenance on secondary lines. They are repaired as needed on a run to fail basis.

2.2.2.3 OTHER ASSETS

Other Assets are items vital to the continued, effective operation and maintenance of the system but are not necessarily grid-related assets. The significant items in this category include:

- IT Hardware and Applications;
- Real Estate and Facilities;
- Transport and Work Equipment (Fleet); and
- Customer Care Assets.

Each of these assets are significant in size and essential in function. Each undergoes unique asset management strategies designed to optimize the life cycle of the asset. The key component and their relevant strategies are outlined in Section 2.3.3 below.

2.3 (5.3.3) ASSET COMPONENT INFORMATION AND LIFE CYCLE STRATEGIES

During the Customer Engagement sessions, Hydro One's customers said that they want the Company to sustain current levels of reliability. Therefore, maintenance and renewal plans have been designed to manage asset condition across the fleet over the planning period to sustain overall reliability performance. Within each asset category, there are numerous individual components, all of which have different characteristics, requirements and risk factors that are considered from an asset management point of view.

In addition to properly maintaining the assets, these maintenance programs inform the renewal projects and programs for the assets with condition information. Hydro One's asset strategy is the methodology by which Hydro One seeks to maintain its fleet of assets to meet its Business Objectives and customer preferences. Each individual component has a unique asset strategy based on its individual characteristics. Hydro One's asset strategy for each component is summarized in the table below:

Table 36 - Asset Strategy Summary

Section	Component	Asset Strategy
2.3.1.1	Station Transformers and Regulators	Mitigate the risk of failures through predictive testing and, where needed, proactive replacement.
2.3.1.2	Breakers	Perform maintenance every 6 years, and replace those which are obsolete, non-arc resistant, or beyond their service life, with electronic reclosers under station refurbishment investments.

Section	Component	Asset Strategy
2.3.1.2	Reclosers	Maintain based on manufacturer recommended number of operations, and to upgrade to newer technology reclosers when their fault ratings are close to being exceeded, when they demonstrate reliability issues, or when there are opportunities to bundle their replacement under station refurbishment projects
2.3.1.3	Station Switches and Fuses	Inspect during routine station inspections, and bundle preventive maintenance with transformer maintenance to minimize the number of planned outages. When fuses are defective, they are replaced. When switches are defective, they are replaced if they cannot be repaired.
2.3.1.4	Mobile Unit Substations	Address the ageing demographics and deteriorating condition of the MUS fleet by purchasing new MUSs.
2.3.1.5	Other Station Assets	Visually inspect for defects, and address the defects when they are identified. If components are broken and cannot be repaired, then they are replaced.
2.3.2.1	Poles	Asset strategy centres on condition information collected through the line patrol program. Once a pole has been assessed to be in poor condition it is planned for replacement.
2.3.2.2	Rights of Way	Continue with cycle program to address routine vegetation management and augment with a tactical program to focus on poor performing assets for leveraged improvement in reliability.
2.3.2.3	Line Transformers	Replace units upon failure. The exception is PCB contaminated transformers, which are being replaced over the period of 2017-2023.
2.3.2.4	Submarine Cables	Mitigate the risk of failures through visual inspection at the shoreline using the distribution line patrol. Repair/replacement is performed if there is any damage to the cable armour.

Section	Component	Asset Strategy
2.3.2.5	Other Distribution Line Components	Visually inspect all lines assets as part of the distribution line patrol program. Individual assets are assessed and replaced on a "run to failure" basis or on condition-based assessment.
2.3.3.1	IT Hardware and Applications	Hardware: Adhere to the IT industry standard practice of managing assets through a life cycle program ensuring vendor support is available and decreasing the likelihood of failure. Applications: Replace or upgrade where required to ensure continued vendor support and compatibility with the current IT environment.
2.3.3.2	Real Estate and Facilities	Conduct planned maintenance of key facility systems and infrastructure. Undertake inspections at an appropriate frequency to identify and enable corrective maintenance. Undertake annual operational assessments with the various lines of business to confirm facility requirements.
2.3.3.3	Transport and Work Equipment (Fleet)	Provide safe and reliable equipment while balancing the decision to replace or repair equipment based on age, mechanical condition, kilometers traveled and cost per kilometer as well as the current Net Book Value ("NBV").
2.3.3.4	Customer Care Assets	Coordinate the activities of IT and the service provider to maintain customer-facing systems to ensure regulatory compliance while balancing cost and customer satisfaction.

2.3.1 (5.3.3 A, B) KEY COMPONENT SUMMARIES – DISTRIBUTION STATIONS

Hydro One's station maintenance program includes the assets in the Distribution Station. The program inspects and maintains 1,005 distributing and regulating stations. The station asset hierarchy is maintained in SAP. Inspection and maintenance work orders are auto-generated by maintenance plans with asset specific-maintenance frequencies, tasks and unit costs.

Stations and associated asset inspection frequencies are selected to satisfy the DSC – Minimum Inspection Requirements. Rural stations are visually inspected every 6 months, and urban stations are visually inspected monthly. Station transformer and regulator main tanks and oil-filled tap-changer compartments receive an annual oil sample, which is sent to a third party lab for analysis to obtain industry-standard diagnostic test results. In addition, all distribution stations receive an annual infrared thermography inspection of the power equipment in order to identify thermal defects.

The frequencies at which station asset types are removed from service for maintenance is based upon a variety of factors including asset condition data (obtained through inspections and diagnostic testing), equipment performance, maintenance records, manufacturer recommendations, replacement plans, bundling opportunities, and funding constraints.

The main components managed under the Station Maintenance program include:

- Station Transformers and Regulators;
- Reclosers and Breakers;
- Switches and Fuses;
- Mobile Unit Substations; and
- Other Station Assets.

2.3.1.1 STATION TRANSFORMERS AND REGULATORS

Transformers comprise the single largest component of Hydro One's distribution station asset base.

Station transformers convert a high level voltage (typically 115kV, 44kV, or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 and 4.16 kV). Regulating transformers are also included in this asset group.

Figure 15 – Picture of Station Transformer

Hydro One owns and operates over 1,200 distribution station transformers. The number of distribution transformers maintained by Hydro One grouped by primary voltage is outlined in Table 37.

Table 37 - Transformer by Voltage Level

Primary Voltage Level	Number of Transformers
230 kV	1
115 kV	141
44 kV	777
27.6 kV	244
< 27.6 kV	59

Witness: Lyla Garzouzi/Lincoln Frost-Hunt/Rob Berardi

Hydro One's distribution asset strategy for transformers is to mitigate the risk of failures through predictive testing and maintenance. Where condition warrants, proactive replacement of these transformers is conducted before they fail to avoid lengthy customer interruptions. Opportunities to integrate transformer replacements with other work required at a distribution station are analyzed in order to improve work efficiency and minimize customer outages.

Preventative Inspection and Maintenance Program

Hydro One utilizes maintenance plans to facilitate distribution station transformer maintenance that is issued and tracked in the SAP system.

The transformer maintenance plans are broken down into the following 7 distinct maintenance activities. Each of the following maintenance activities has an associated frequency, list of tasks, and unit price.

- *Station Visual Inspection* – Station transformers and regulators are visually inspected on a six month cycle for rural stations and monthly for urban stations.

- *Thermovision Inspection* – Annually, each station receives a thermography inspection of all power equipment, at which time the transformer is inspected to identify hot spots in any components.

- *General Oil Test* – Annually, an oil sample is taken from the transformer main tank and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including Dissolved Gas Analysis, Moisture Content and Furan Analysis.

- *Transformer Diagnostic Test* – Following an unsatisfactory oil sample result, the main tank of the transformer may receive diagnostic testing and an internal inspection. This maintenance activity includes the following: Inspection of current carrying parts, bushing oil level check, verification of PCB content in oil, insulation resistance tests, turns ratio and phase angle tests, core loss test, dissipation factor and capacitance test, winding resistance test, inspection of oil conservator breather, repair of minor or moderate oil leaks, function test of pressure vacuum device, check and top-up oil levels, function test of gauges and indicators, and application of touch-up painting to mitigate rust.

- *Under-Load Tap-Changer Oil Analysis* – Annually, an oil sample is taken from tap-changer oil filled compartments and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including Dissolved Gas Analysis, Moisture Content and Furan Analysis.

- *Tap-Changer Selective Intrusive Inspection* – Internal inspection and maintenance of under-load tap-changers with mechanical moving parts is performed every 12 years. If there are unsatisfactory tap changer oil analysis results, inspection and maintenance may be performed earlier in the cycle. This maintenance activity includes the following: filtration of insulating oil, flush and clean oil compartments, visual check for oil leaks and contact wear, inspection of current carrying parts, checks of insulation condition, collector ring, drive chains, pushrod, reversing switch, oil compartment door gaskets, exercise isolation and grounding switch, function test of operating limit switches, gauges and indicators.

- *Power Factor Test* – 115 kV distribution station transformers will receive a power factor test to verify the integrity of the transformer insulation material, and to ensure they are functioning correctly. This is performed when the transformers are removed from service for diagnostic testing or SI maintenance.

The annual budgets are based on the known asset population of transformers and upcoming maintenance schedule based on the maintenance plans.

Optimization, Prioritization and Scheduling

Transformer maintenance is prioritized as follows and within the following four categories:

1. Transformer Condition Based Maintenance (CBM) following high risk oil sample results for transformer main tanks or tap-changers;
2. Maintenance on transformers with unsatisfactory polychlorinated biphenyl ("PCB") content[1], to reduce the content in oil filled compartments down to Environment Canada acceptable levels;
3. Maintenance on leaking transformers to mitigate the leaks; and
4. Tap-changer time-based maintenance for regulators and step-down transformers equipped with under-load tap-changers.

In instances where the visual inspection or diagnostic testing of the transformer identify deficiencies for which the transformer repair cost is relatively high, planners utilize a "repair versus replace" economic model to aid in repair/replace decision-making based on a Net Present Value ("NPV") analysis. In instances where it is more economical to replace the transformer as opposed to repairing it, the transformer is planned for replacement.

In addition to the condition data obtained from the transformer maintenance program and NPV analysis, Hydro One considers other factors such as condition, demographics, performance, utilization, criticality and other influencing factors. Distribution transformers are then ranked based on a composite score which is a combination of the factors.

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

Condition

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

Hydro One assesses a distribution transformer's condition primarily on transformer oil test results by applying industry standard diagnostic testing. Annual oil sample test results are obtained for all transformer main tanks and under-load tap-changer compartments. In addition to annual oil sampling, other aspects of transformer condition identified through preventive inspection and maintenance activities include oil leaks, under-load tap-changer operation, PCB content, and bushing condition.

One of the best ways to determine the health of a transformer is by taking a sample amount of oil and testing its physical properties. Transformers with poor dissolved gas analysis test results, poor moisture content test results, and poor furan test results are given a higher priority for replacement. These poor test results identify transformers that are experiencing internal conditions that will eventually result in permanent electrical failure. Proactive replacement of these transformers before they fail avoids lengthy customer interruptions. Leaking transformers are also given a higher priority for replacement because they pose environmental risk and often are uneconomical to repair.

Based on results gathered, approximately 23% of distribution station transformer condition assessments fall into the high risk category. Figure 16 illustrates which component of the transformer is the main contributing factor to the condition of the 280 high risk distribution station transformers.

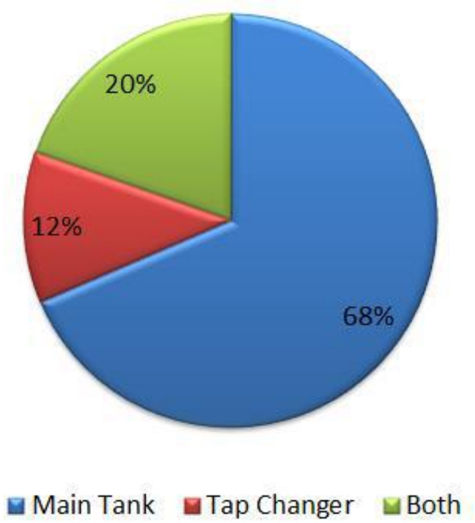


Figure 16 - Reason for Classification of Transformers as High Risk

These units are at a higher risk of failure compared to the transformer population and should be considered for replacement, refurbishment or other remedial action in order to correct significant deterioration or deficiencies. This is required to prevent failures and reduce impacts to Hydro One's distribution customers.

Demographics

The age of the transformer compared to its expected service life is used in 'repair versus replace' decision making. In general, older transformers have a higher probability of failure compared to newer transformers, and therefore older transformers are commonly given a higher priority for replacement. Transformers are not planned for replacement based on age alone. Hydro One monitors the condition of aged distribution transformers through inspections and oil sampling, and plans replacements as needed.

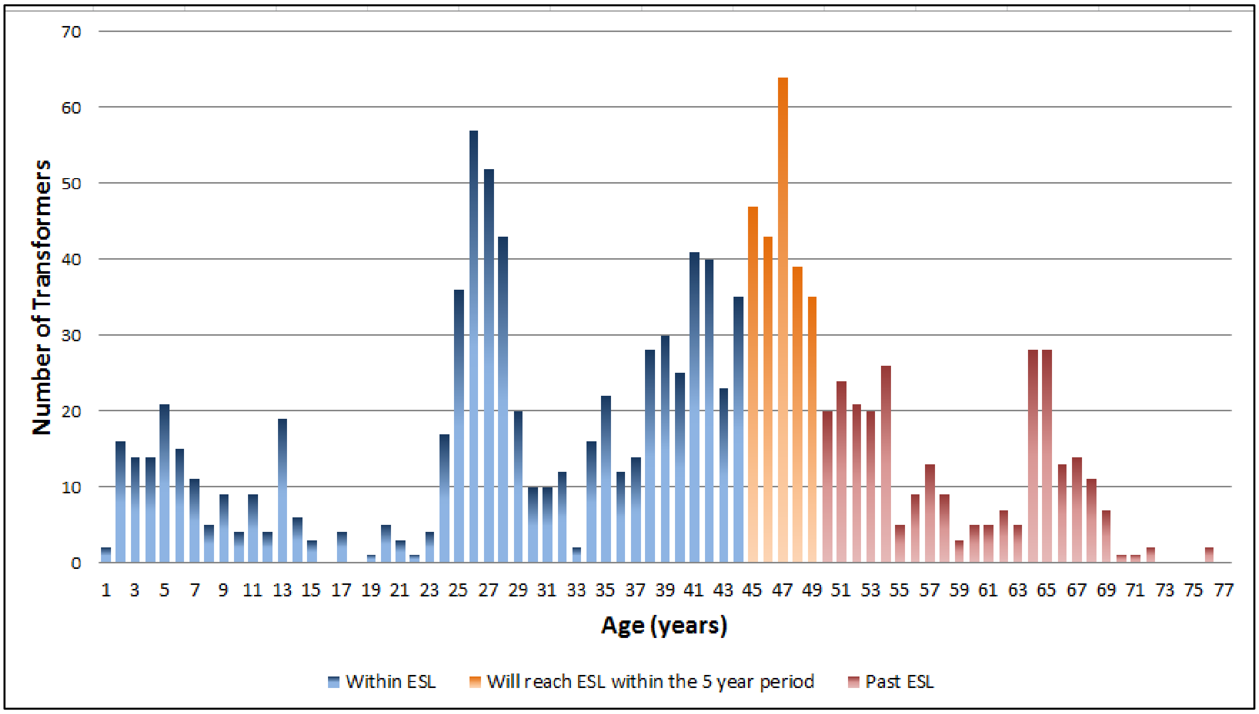


Figure 17 - Demographics of the Distribution Station Transformers

Hydro One utilizes an expected service life of 50 years for its distribution station transformers. The current average age of the transformer fleet is 38 years. Currently 23% of the transformer population is beyond its expected service life, with an additional 19% to reach its expected service life in the next five years. While not all of these transformers require immediate replacement, the long-term management of the high number of transformers reaching expected service life requires increased capital investment. A sustained program targeting a high number of transformer replacements is required to maintain the historical number of transformer failures at a manageable level for customers.

Performance

Distribution station transformer failures are highly impactful. Hydro One's distribution stations typically do not have on-site spare transformers that can be switched into service in the event of a failure, and load cannot be transferred amongst rural stations, which are most often fed from a radial system. In these instances, when a station transformer fails, service restoration requires the installation of a mobile unit substation.

The total number of failures varies from year to year. However, the number of major transformer failures (Class 1) and number of potential major failures avoided by proactively removing transformers from service (Class 2) are shown in Figure 18. Total failures have gone down on the system since 2013.

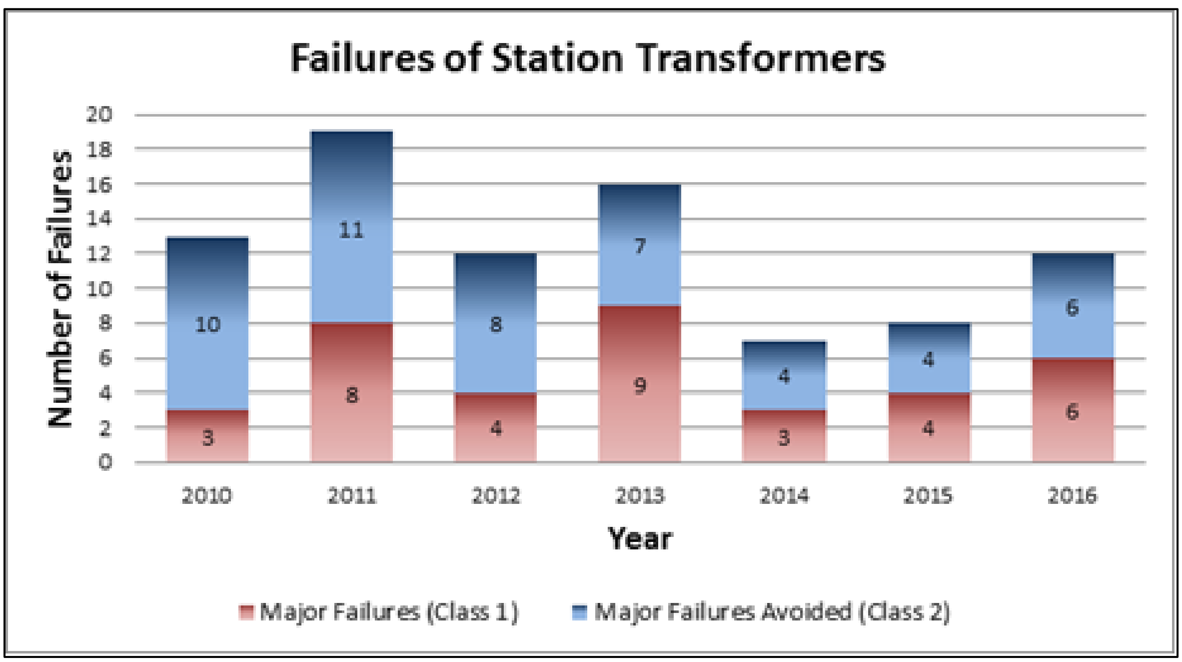


Figure 18 - Failures of Station Transformers

The reason for the decrease in failures in years 2014 and 2015 is the result of an increase in planned replacements of transformers in poor condition. Figure 19 shows a graph of the number of planned and unplanned station transformer replacements from 2010 to 2016. It can be observed that there has been a steady increase in total transformer replacements from 2011 to 2015. Similarly over this period, there has been an overall decrease in transformer failures.

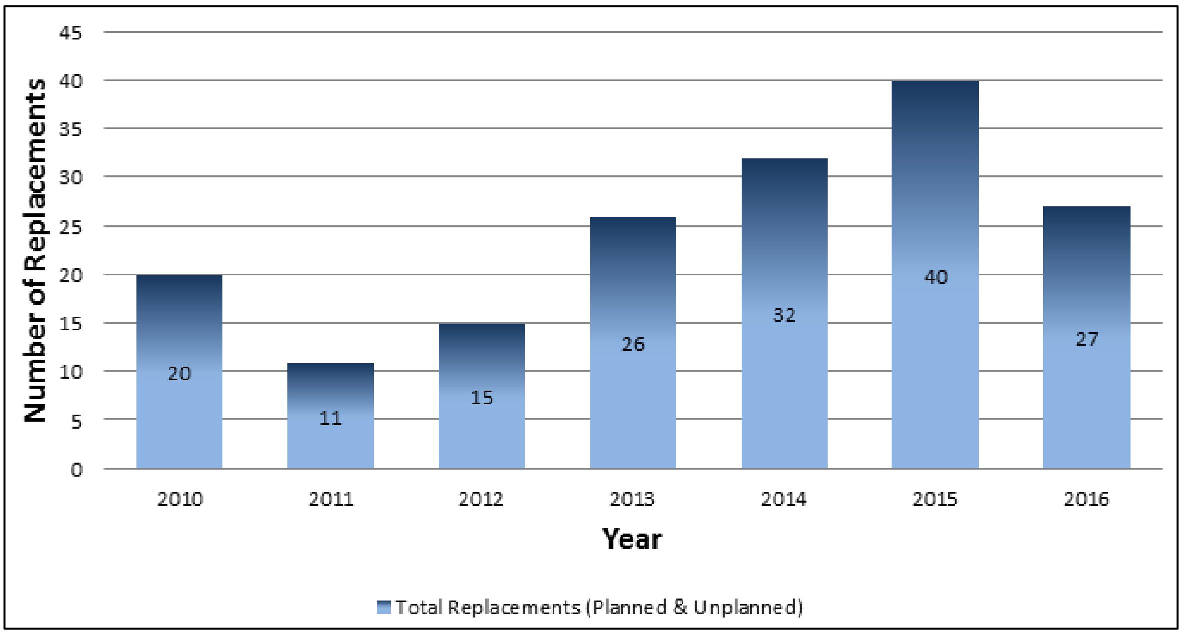


Figure 19 - Number of Transformer Replacements

Utilization

Station transformers that are overloaded, or are more heavily loaded, experience higher winding temperatures which shorten the life of the paper insulation within the transformer. These transformers are given a higher priority for replacement compared to those that are lightly loaded.

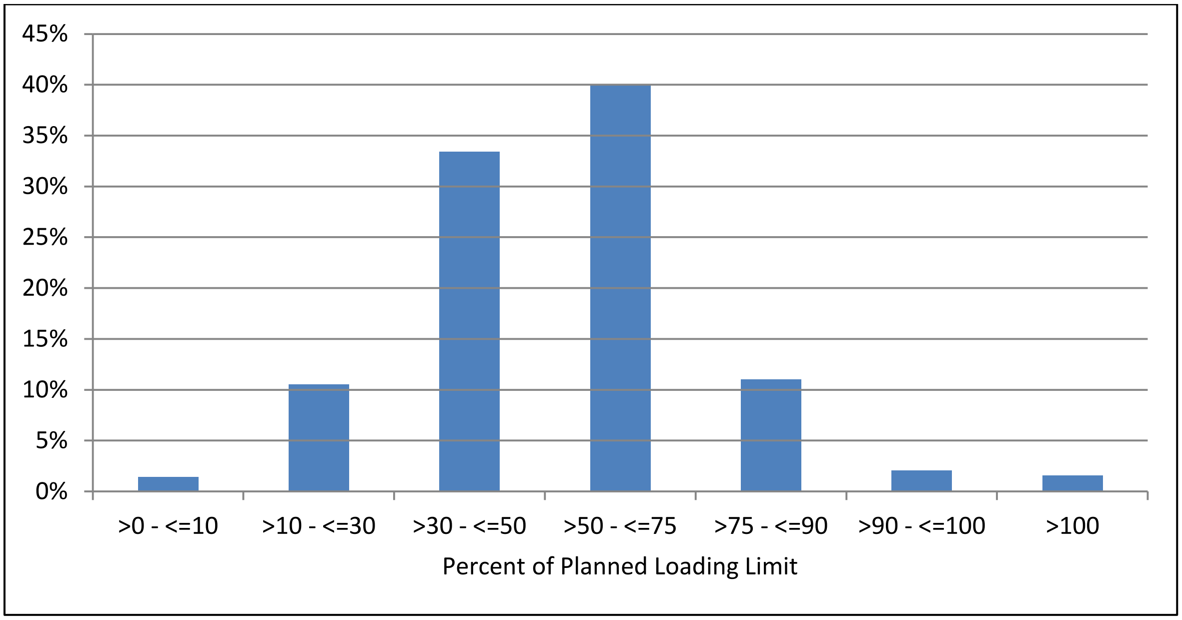


Figure 20 - Station Loading as a Percentage of Total Fleet

Criticality

Transformer replacements are prioritized based on impact on downstream customers and magnitude of downstream load supplied. Higher priority is given to transformers that would impact a higher number of customers and a higher magnitude of load in the event of a failure.

2.3.1.2 STATION RECLOSERS & BREAKERS

Hydro One currently manages approximately 2,263 three-phase equivalent distribution station reclosers and approximately 155 distribution station circuit breakers. Reclosers and breakers are used to remove assets from service under fault conditions. Reclosers are also used to attempt to restore service to customers when faults are temporary or transient in nature.

Hydro One has three main types of reclosers / breakers on its distribution system. The number of devices for each type is shown in Table 38.

To keep pace with manufacturers' change in technology, Hydro One is currently installing new vacuum technology reclosers at its distribution stations.

Figure 21 – Picture of Station Reclosers

Table 38 - Breaker and Recloser by Type

Type	Number of Reclosers	Number of Breakers
Oil	1,758	13
Vacuum	505	4
Metalclad	0	137

The asset strategy for station reclosers is to maintain them based on manufacturer recommended number of operations, and to upgrade them to newer technology reclosers when fault ratings are close to being exceeded, when they demonstrate reliability issues, or when there are opportunities to bundle their replacement under station refurbishment projects. Additional reclosers are planned for upgrade to move towards an advanced distribution system.

Witness: Lyla Garzouzi/Lincoln Frost-Hunt/Rob Berardi

The asset strategy is to perform maintenance on station breakers every 6 years, and replace those that are obsolete, non-arc resistant, or beyond service life, with electronic reclosers under station refurbishment investments.

Preventative Inspection and Maintenance Program

The recloser and breaker maintenance program is primarily triggered based on the number of open and close operations that the device experienced. The annual maintenance budget for reclosers and breakers is based on the known asset population and upcoming maintenance program schedule.

Hydraulically controlled reclosers receive maintenance based on the number of open and close operations that they experience. During station inspections, the number of counter operations is checked and compared with the manufacturer recommended number of operations before required maintenance. Hydraulic reclosers that have exceeded the recommended number of operations are removed from service and replaced with another set of reclosers from inventory. The removed set are then sent to a Hydro One recloser shop for maintenance before being placed into inventory. Hydraulic reclosers are also replaced with units from inventory for other reasons, including observation of cracked or chipped bushing porcelain, corrosion of components, or oil leaks.

Electronically-controlled reclosers equipped with oil interrupters may also be planned for maintenance based on the manufacturer recommended number of operations as well as identification of oil leaks, or identification of hot spots through thermovision inspections. When in need of maintenance work, they are removed from service and receive maintenance at their station location.

Electronically-controlled vacuum interrupter reclosers are the newest technology available. These reclosers have higher fault interrupting ratings compared to hydraulic reclosers and can undergo 10,000 mechanical operations before requiring maintenance or replacement, compared to hydraulic reclosers that are limited to between 58 and 248 operations. Electronically-controlled reclosers equipped with vacuum interrupters are visually inspected and receive thermovision inspections. Hot spots identified through thermovision inspections are addressed by corrective repair. Back-up controller batteries are replaced every five or six years as per OEM instruction.

Most Hydro One distribution station breakers are metalclad air magnetic type breakers. When these breakers are removed from service for maintenance, they undergo the following activities:

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

Optimization, Prioritization and Scheduling

The upgrade of unserviceable oil reclosers to the newest electronic vacuum recloser technology under capital investments are prioritized as follows:

1. Under station rebuild projects;
2. When the calculated fault levels for the associated feeder are approaching or beyond the fault interrupting rating of the installed recloser;
3. Replacement of electronic reclosers with performance or reliability issues; and
4. Upgrade of hydraulic reclosers with electronically-controlled reclosers to move towards an advanced distribution system.

Most of the metalclad air magnetic breakers on the Hydro One distribution system are approaching or beyond their expected service life. They are technically obsolete (no longer supported by manufacturers for spare parts) and are not arc resistant, which is a safety concern for electrical maintenance staff. As a result, most of these breakers on the distribution system are either planned for replacement with vacuum interrupter, electronically-controlled reclosers under station rebuild projects, or are planned for removal through voltage conversion projects.

Condition

The condition of station recloser and breaker assets is monitored through information gathered during the preventative inspection and maintenance activities. A visual inspection of the reclosers and breakers is completed twice a year to note any defects and to record the number of operations the devices have sustained. The number of recloser and breaker defects Hydro One has noted during inspections is shown in Table 39. Defective reclosers and breakers are addressed either through repair or replacement.

Table 39 - Breaker and Recloser Defects

Year	Number of Recloser Defects	Number of Breaker Defects
2010	431	3
2011	304	9
2012	336	2
2013	323	4
2014	356	9
2015	324	2

Demographics

Hydro One maintains an asset registry of all reclosers and breakers on the Hydro One distribution system.

Reclosers make up the majority of the recloser/breaker asset fleet. The age profile of the 505 station vacuum reclosers in the system range from the early 2000's to present. Station oil filled reclosers in general were purchased prior to the year 2000. Historically, reclosers were removed from service and replaced with overhauled units every six years. Hydro One has adopted a more targeted approach to trigger when reclosers need to be replaced with overhauled units. The number of operations (i.e., fault interruptions) that a recloser performs triggers a recloser replacement with an overhauled unit. The number of operations that trigger a recloser replacement is dependent on the make, model and type of the unit, as explained above. As a result of the utilization based approach, recloser age-based demographic information is no longer relevant in recloser OM&A sustainment planning process.

Breakers comprise a small percentage of the overall breaker/recloser population. These breakers were mainly added to the fleet through Hydro One's acquisition of Local Distribution Companies. Distribution breakers have an expected service life of 50 years. Breakers are replaced if they are obsolete, non-arc resistant, or beyond their expected service life.

Other Influencing Factors

Most metal clad breakers on the Hydro One distribution system are obsolete and replacement parts are not available. These breakers are no longer supported by the manufacturer. As such, when one breaker in a bank of metalclad breakers fails and is not repairable, the entire bank of metalclad breakers must be replaced.

Some of the metalclad breakers were designed in small buildings, which do not meet Hydro One clearance requirements. Hydro One mitigates this risk with safe work practices, removing the breaker from service before the execution of work. Since service interruptions are impactful to customers, this too is considered in the prioritization of upgrades.

2.3.1.3 STATION SWITCHES & FUSES

Hydro One currently manages approximately 2,525 three-phase switches and 1,850 three-phase fuses installed at distribution stations.

Station switches provide a means of isolating pieces of equipment such as transformers, breakers or reclosers so that maintenance work can be performed on them, or for the purpose of isolation for other reasons.

Figure 22 – Picture of Station Switch and Fuse Combination

Station fuses provide a means to protect transformers in stations when a fault occurs. Station fuses also provide a means to by-pass station reclosers; although not all distribution station reclosers are equipped with by-pass fuses. Distribution stations which do not have feeder breakers or feeder reclosers are equipped with fuses to provide a means of protection for the feeder.

The asset strategy is to visually inspect station switches and fuses during routine station inspections and to bundle their preventive maintenance with transformer and regulator maintenance to minimize the number of planned outages. As discussed in Section 2.3.1.1, station transformers and regulators receive maintenance based on unsatisfactory main tank or tap-changer oil sample results, and under-load tap changers have a default 12 year maintenance cycle. Defective fuses are replaced. Defective switches are replaced if not repairable.

Table 40 - Switches and Fuses by Voltage

Primary Voltage Level	Number of Switches	Number of Fuses
230 kV	2	1
115 kV	150	103
44 kV	870	759
27.6 kV	503	225
< 27.6 kV	999	760

Preventative Inspection and Maintenance Program

Switch and fuse inspection costs are embedded in the Station Visual Inspection (“SVI”) unit price, which is reviewed and adjusted annually as required. Switch and fuse maintenance is triggered based on SAP maintenance plans, which have associated frequencies, tasks and unit price. The unit prices are reviewed annually and adjusted as required based on historical expenditure. The annual switch and fuse inspection and maintenance budgets are based on the known asset population of switches and fuses, and upcoming maintenance schedule based on SAP maintenance plans.

The switch and fuse maintenance program is bundled with transformer maintenance in order to reduce the number of planned outages, and to keep switch and fuse maintenance unit costs to a minimum. When stations are removed from service for transformer maintenance, the switches and fuses are tested, current carrying parts are inspected, and hinges are cleaned and lubricated.

Optimization, Prioritization and Scheduling

Station fuses which fail testing are replaced. Transformer or recloser replacements may also trigger the need to replace fuses with those of different continuous current rating and interrupting speed in order to allow for proper protection coordination. Fuses at stations, which act as feeder protection in the absence of reclosers or breakers, are planned for replacement with vacuum electronic reclosers for improved reliability by allowing transient faults to clear and not cause a sustained outage, which likely would be the case with a fuse.

Station switches that fail to operate and are not repairable are replaced. Under station rebuild projects, switches will be planned for replacement based on their condition.

Condition

The condition of the switch and fuse assets are determined during regular station maintenance program activities. A visual inspection of switch and fuse assets are completed twice a year to note any defects. Switches and fuses that fail testing or are found to be in substandard condition are replaced.

Table 41 - Switch and Fuse Defects

Year	Number of Switch Defects	Number of Fuse Defects
2012	118	139
2013	81	135
2014	98	94
2015	110	185

Some of the main failure modes of switches include: seized bearings or load interrupters, and failure of porcelain insulators. Fuses located on the switch/fuse assembly are prone to falling due to hairline cracks in porcelain support insulators. The number of switch and fuse defects Hydro One has noted during inspections are shown in Table 41.

2.3.1.4 MOBILE UNIT SUBSTATIONS

Hydro One currently has a fleet of 30 mobile unit substations ("MUSs"). The MUSs have similar components to a distribution station, however the components are mounted on a trailer. The MUS fleet is utilized for:

- Emergency power restoration in the event of a transformer or other station component failure;
- Carrying the station load during maintenance and capital activities; and
- Load relief for distribution stations, as required.

Figure 23 – Picture of Mobile Unit Substation

Hydro One's asset strategy is to address the aging demographics and deteriorating condition of its MUS fleet by purchasing new MUSs to replace those in need of replacement. The MUS asset strategy also involves expanding the MUS fleet to address a shortfall in MUSs required to support the distribution system and proposed work programs. The appropriate size of MUS fleet is determined based on having MUSs which can be deployed to stations to support failures and restore customers within eight to twelve hours, and to have sufficient MUSs to allow for the completion of planned and unplanned capital and maintenance work. Six MUSs are planned for replacement and three new MUSs will be procured to expand the fleet over the five year period.

The ISD containing details on the investment in new MUS units is SR-02.

Preventative Inspection and Maintenance Program

Because the MUSs are such a critical component of the distribution system (relied upon for emergency restoration, capital projects and maintenance work) each MUS receives an annual inspection and full maintenance of all electrical components each year. The maintenance activities for the MUS transformers, switches, fuses, reclosers and other electrical components are the same as for those installed in stations, other than the higher (annual) frequency. MUS annual maintenance for each unit takes two weeks to complete. When MUSs are deployed for maintenance or capital work, commissioning checks are performed on the MUS trailer and electrical equipment to ensure safe operation and supply voltage with CSA standards.

When MUSs are deployed for emergency restoration, they are typically deployed to stations, installed, and connected within eight to twelve hours, restoring the interrupted load. Depending on the magnitude of work required to repair or replace the failed equipment, the MUS installation time can range from a few days to a year. The replacements of failed insulators, surge arresters or fuses are examples of emergent work where an MUS would be installed for a few days. MUS deployments for failed transformer replacements can take up to a year if the replacements require adjacent land to be procured.

MUS trailers receive a mandated annual inspection. They require an Ontario Ministry of Transportation ("MTO") annual inspection certificate.

Demographics

The MUSs are assessed by focusing on two key components, the transformer and the trailer. The age distribution for these two components of the MUSs is shown in Figures 24 and 25.

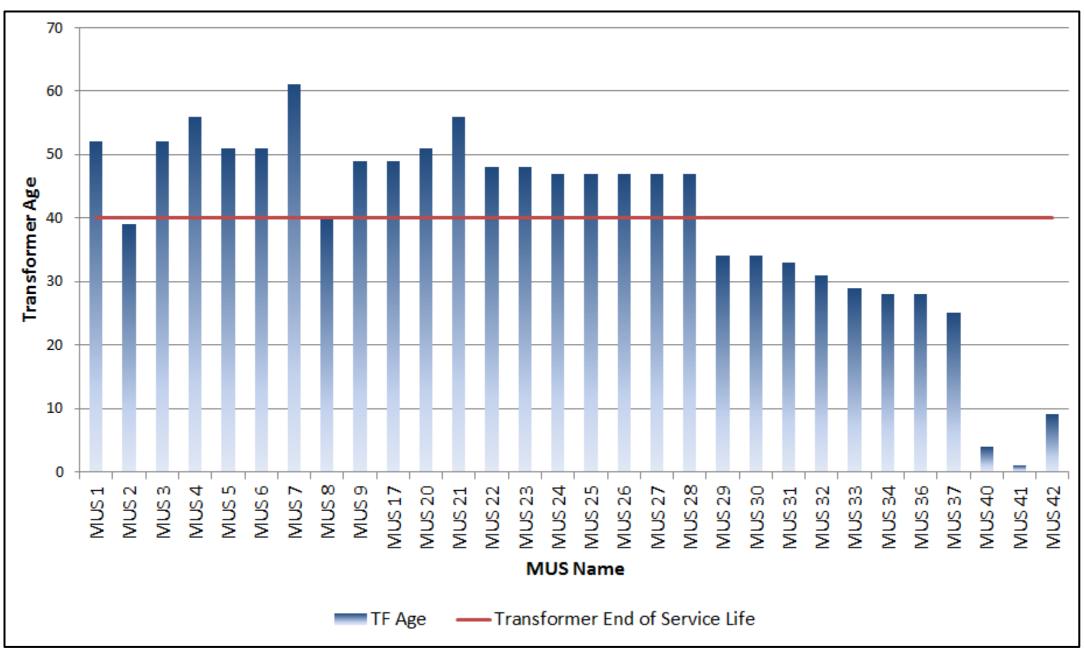


Figure 24 - Demographics of the Mobile Unit Substation Transformers

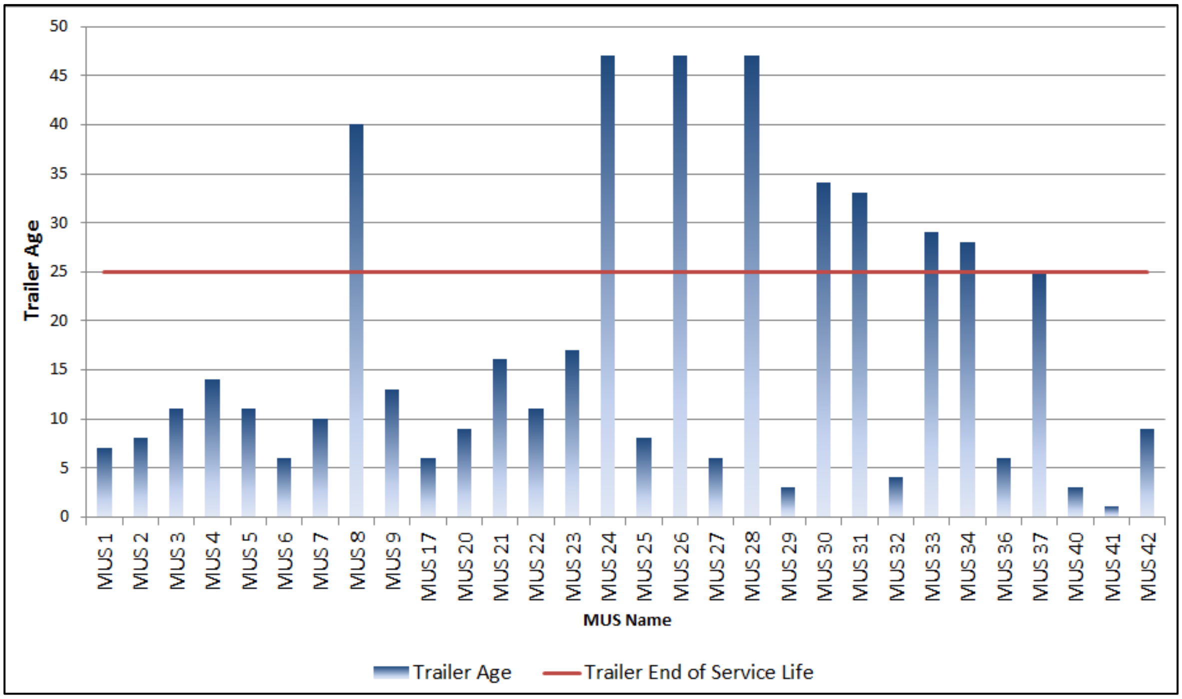


Figure 25 - Demographics of the Mobile Unit Substation Trailers

Hydro One utilizes an expected service life of 40 years for its MUS transformers and 25 years for the MUS trailers. The average age of the MUS transformers is 40 years. Currently, 60% of the MUSs transformers are beyond their expected service life. The average age of the MUS trailers is 17 years. Currently 30% of the MUS trailers are at or beyond their expected service life.

Condition

The condition of the trailer is inspected as required by the Ministry of Transportation and the electrical equipment is inspected in detail on an annual basis. Inspection and maintenance of the MUS electrical equipment (such as, the transformer, reclosers and switches) are identical to that of a distribution station but more frequent as these assets are relied upon during emergency situations. Any significant defects are logged and immediate plans are made to correct them.

Table 42 - MUS Defects

Year	Transformer Defects	Trailer Defects	Switchgear Defects	Cable Defects	Total MUS Defects
2012	8	5	11	5	**29**
2013	7	3	12	7	**29**
2014	18	9	16	10	**53**
2015	17	5	13	8	**43**
2016	14	9	12	16	**51**

Failure modes and condition defects of MUSs include the typical defects that station transformers, switches, fuses and reclosers experience. Additional defects that MUSs can experience compared to that of a station can include trailer rust, and damage to MUS feeder connection cables. The number of MUS defects that Hydro One has noted is shown in Table 42.

Currently, 40% of the MUS transformers and 30% of the MUS trailers fall into the high risk category. Overall, 43% of the MUS fleet is categorized as high risk.

2.3.1.5 OTHER STATION ASSETS

In addition to the assets previously mentioned, Hydro One distribution stations also typically have station structures, fences and gates, grounding systems, station service transformers, insulators and bus. Stations equipped with breakers or vacuum electronic reclosers also have protection relays or intelligent electronic devices (IEDs). Stations identified as having high environmental risk are equipped with spill containment systems.

Station Structures are used in stations for mounting electrical components such as switches, fuses, reclosers, station service transformers, bus, and IEDs. Some station structures are wooden, though most are made of steel. The earliest station structures in Hydro One stations were built in the 1920's.

Fences are used to separate live station equipment from the public to maintain public safety, while *gates* are used as an entry point for Hydro One maintenance vehicles, construction vehicles and staff. Most station fences are chain link, though some are wooden.

Grounding Systems are used in stations to safely dissipate fault currents into the ground in the event of equipment failure, to protect Hydro One employees and the public.

Station Service Transformers are used to transform distribution system voltages to 120 V to supply station equipment such as IEDs and receptacles.

Insulators provide electrical insulation between live equipment and grounded station structures. They are also used to mount the power equipment to the station structures.

Bus work in stations is used to electrically connect the power equipment within the station.

Protection Relays in stations are used to trip feeder breakers in the event of a system fault.

IEDs are used to control electronic vacuum reclosers, directing the reclosers when to open and close during system faults.

Spill Containment Systems are present in stations that have a high spill risk. These spill containment systems contain transformer oil in the event of a transformer tank rupture.

Table 43 - Other Distribution Station Components

Station Component	Units
Station Structures	2,172
Fences[1]	1,005
Station Grounding Systems[1]	1,005
Station Service Transformers	820
Insulators	NA
Bus Work	1,316
Protection Relays[2]	154
IEDs	236
Spill containment systems	88
MUS Structures	788

1. Assumed to match the number of stations
2. Assumed to match the number of breakers

Preventative Inspection and Maintenance Program

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

Optimization, Prioritization and Scheduling

The strategy for these station components is to visually inspect them for defects, and address the defects when they are identified. If they are broken and cannot be repaired, then they are replaced.

2.3.2 (5.3.3 A, B) KEY COMPONENT SUMMARIES – DISTRIBUTION LINES

The Distribution Lines Maintenance program encompasses all the pole, wire and transformer assets for both M-class and F-class feeders. The purpose of this program is to ensure that the distribution lines are safe and will continue to deliver reliable power to the load and generation customers.

Distribution lines are inspected on a six-year cycle for rural areas and a three-year cycle for urban areas as required by the DSC, Appendix C – Minimum Inspection Requirements. Approximately 350,000 locations are planned for inspection per year. SAP is used to plan these inspections and schedule the feeders and release the work on the applicable cycle. During these inspections, information about the condition and demographics of specific assets is collected.[2] This information informs our maintenance programs and capital renewal projects and programs.

Often, lines are located off-road. Off-road sections of feeders are difficult to access during power interruptions resulting in increased risk of prolonged outages and public safety concerns. When inspections identify significant concerns with the condition of an off-road line, including wood poles, crossarms, and insulators, this poses an elevated risk to reliability and public safety. The most cost-effective option to address these risks is often to rebuild entire feeders or feeder sections to current standards on a nearby road allowance, funded by the Distribution Lines Sustainment Initiatives, ISD SR-12.

[2] Secondary Service Lines are not actively maintained and the assets included in this category are addressed on a Break/Fix basis. Detailed demographic and condition data on Secondary Service Lines is not available.

The main components maintained in the Distribution Lines Management program include:

- Poles;
- Rights of Way;
- Line Transformers;
- Submarine Cables; and
- Other Distribution Line Components.

2.3.2.1 POLES

Poles comprise the single largest component of Hydro One's lines asset base. Poles keep conductor and line equipment at a safe distance from the ground and other objects. Hydro One utilizes poles made from wood, concrete, steel and composite material based on specific situations. However, as shown in Table 44, wood poles make up the vast majority of the pole fleet.

Table 44 – Number and Age by Pole Material

Material	Number of Poles	Average Age
Wood	1,597,000	39.7
Steel	6,000	19.6
Concrete	2,000	29.2
Composite	2,000	6.9

Hydro One's asset strategy for the management of distribution poles centres on condition information collected through the line patrol program. Once a pole has been assessed to be in poor condition it is planned for replacement.

Witness: Lyla Garzouzi/Lincoln Frost-Hunt/Rob Berardi

Preventative Inspection and Maintenance Program

Typical pole inspections begin with a visual assessment of the pole's current condition. Items the inspector would identify are the severity of woodpecker damage, mechanical damage, and insect damage. The inspector would also determine if the pole is severely leaning and report on the amount of surface decay.

The inspector will also perform a hammer test on every pole inspected to ensure the soundness of the pole. In some situations the pole may be bored to measure the remaining shell thickness. All of this condition data is used for prioritizing pole replacements.

During the inspections other defects associated with the line are collected at the pole level such as a broken guy wire. These issues are corrected as part of the defect correction program unless there are capital replacement plans for the pole.

All data collected during these inspections is recorded in SAP and is used for planning replacements and defect corrections. During the data collection, the inspector will confirm all characteristic data about the pole is correct and up to date.

Optimization, Prioritization and Scheduling

Hydro One's asset strategy for the management of distribution poles centres on their condition and the forecast condition using demographics of the population. The condition information is used in the selection and prioritization of specific poles to be replaced annually, whereas the demographic profile enables the projection of long term pole replacement rates. Hydro One endeavours to replace poles before they fail, pose a safety hazard, or cause a service interruption. Where possible, these replacements are made in conjunction with other planned work on the distribution system to increase efficiency and minimize the number of planned outages.

Condition

The condition of the poles, as determined by distribution line patrols, impacts pole replacement, line refurbishment and defect correction investment plans. The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, or other factors that reduce the structural integrity of the pole. The number and type of pole related defects on the distribution system are illustrated in Figure 26. Depending on the severity of the damage the pole may be prioritized for replacement.

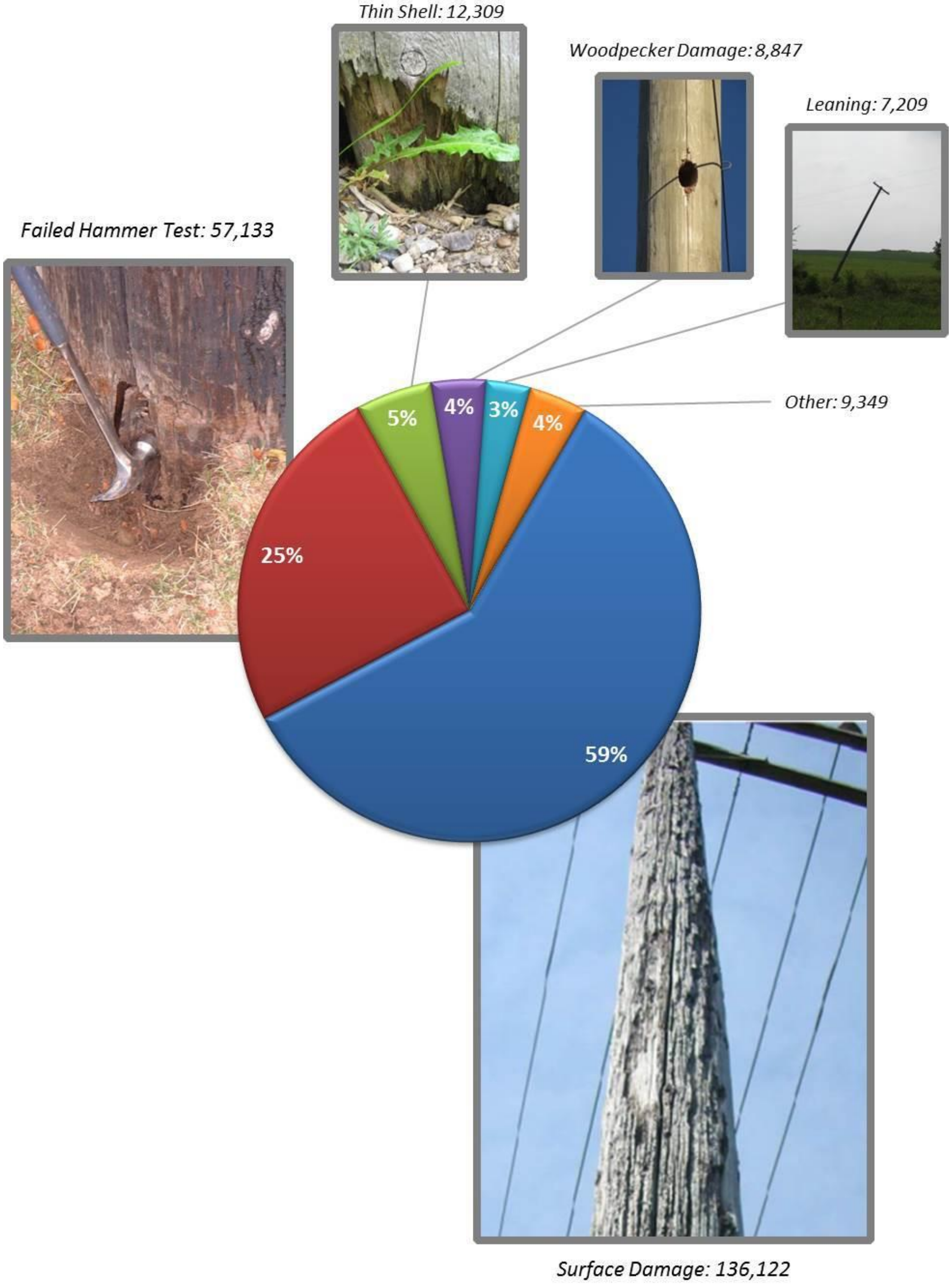


Figure 26 - Pole Defects

Note: Poles in poor condition may have multiple defects and some defects are not severe enough to cause a pole to be classified as poor condition.

Witness: Lyla Garzouzi/Lincoln Frost-Hunt/Rob Berardi

Where other needs are identified, they can be included in large sustainment or development projects and addressed in conjunction with other planned work.

Figure 27 summarizes the current condition of Hydro One's poles based on the results gathered. Poles in poor condition currently require replacement in the next five years. Poles in fair condition have some defects but do not require replacement. Poles in good condition passed their last inspection with no defects recorded.

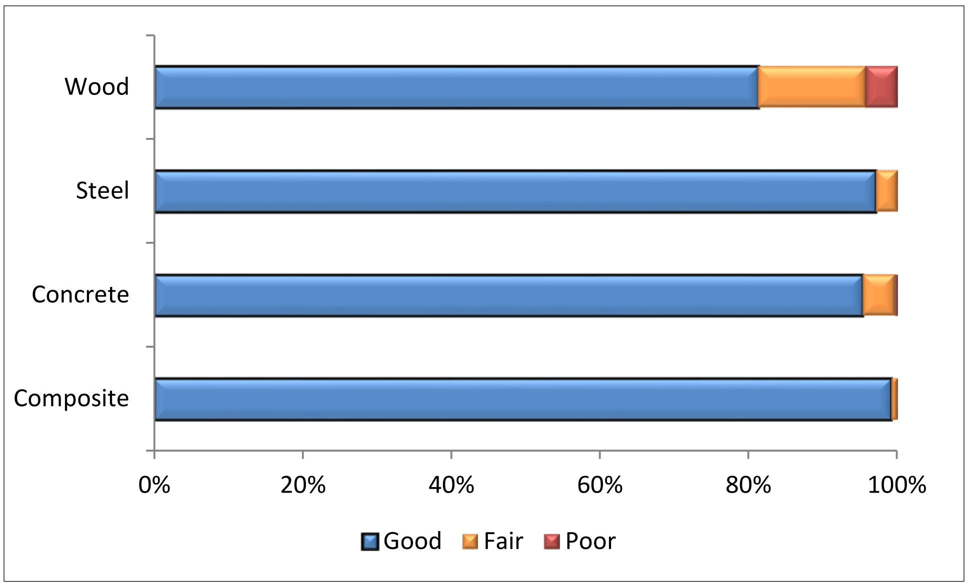


Figure 27 - Pole Condition by Material

Figure 28 details the total poles that are categorized as being in poor and fair condition. The total volume of Red Pine wood poles requiring replacement due to premature degradation is also included.

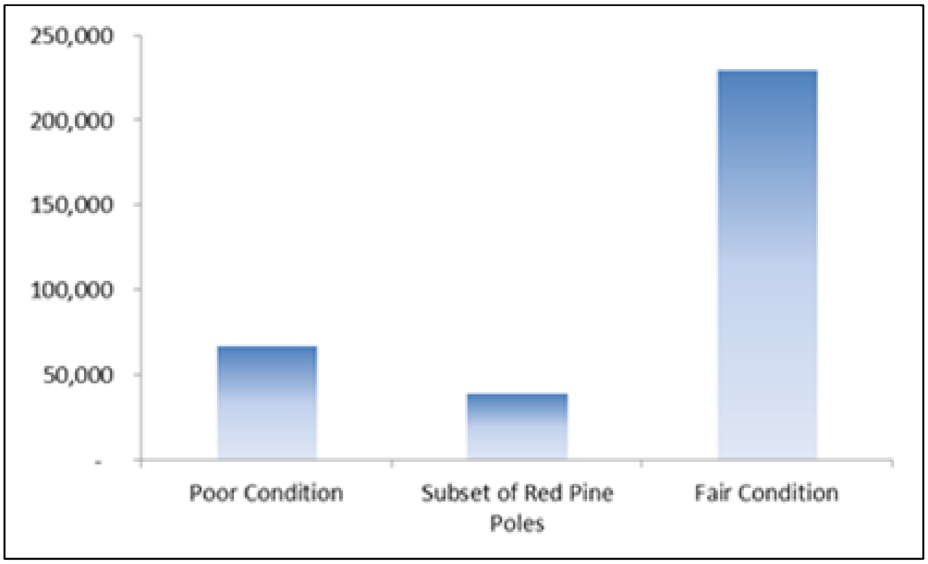


Figure 28 - Poles in Poor or Fair Condition

Demographics

Analysis of wood pole failures has indicated that the expected life of a wood pole is approximately 62 years. Based on the current demographics of the Hydro One wood pole population, 280,000 poles are at least 62 years old, with an additional 120,000 poles reaching 62 over the next five years. To ensure a long-term sustainable pole replacement program, the number of poles being replaced is proposed to increase over historical levels. The age distribution of wood poles owned by Hydro One is shown in Figure 29.

There are currently 37,000 poles with no age information available. This data will be updated over time as the distribution line patrol program inspects poles on a six or three-year cycle. Some of the data will remain unknown because the manufacturer information becomes illegible as a pole ages.

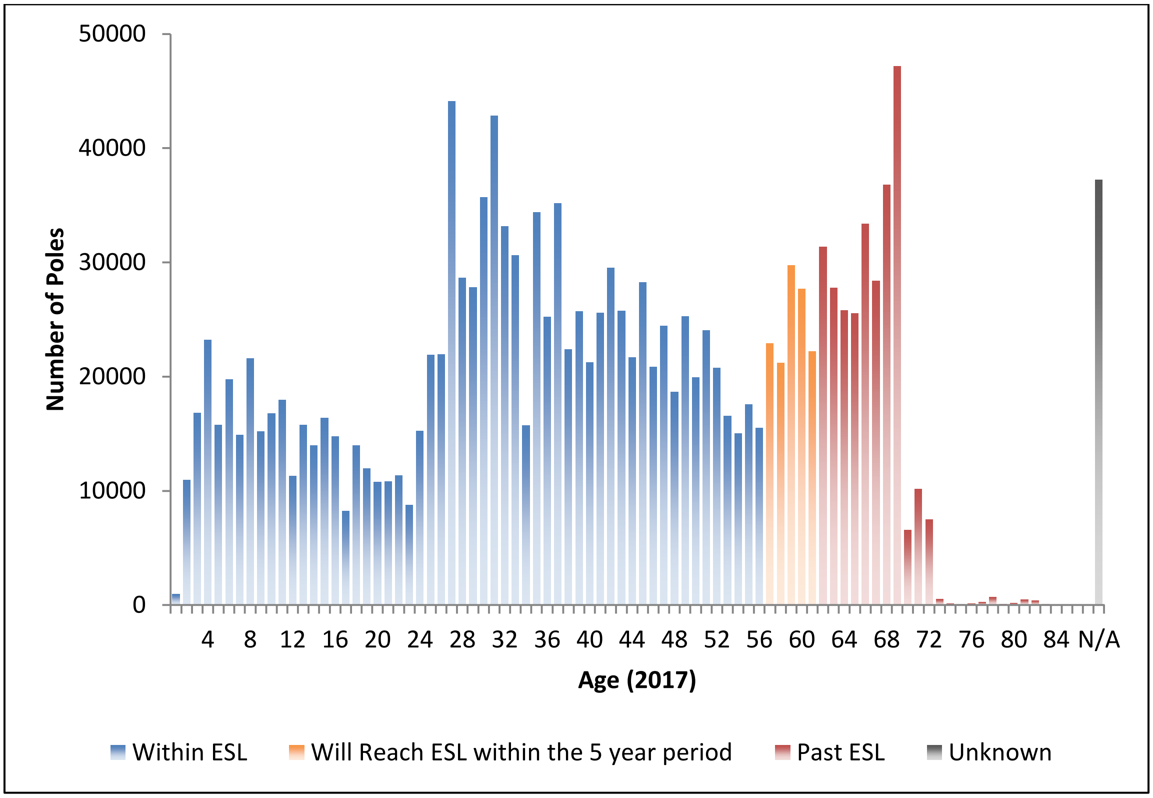


Figure 29 - Wood Pole Demographics

Performance

Another driver of wood pole replacement work is the impact pole failures have on reliability. When poles fail, they are highly impactful and typically require an emergency pole replacement to restore service. These unplanned repairs are more difficult, take longer and are more costly than a planned pole replacement. The average duration of an unplanned outage involving a pole replacement is about nine hours. The average duration of a planned outage involving a pole replacement is about 2 hours. The improvement in outage duration for planned replacements, combined with the benefits of scheduling and notifying customers of work before it is done, drives Hydro One to replace end-of-life poles on a planned basis.

Criticality

Poles are prioritized based on their impact on downstream customers and their potential safety risks. Factors such as number of downstream customers, downstream load, and joint use attachments are considered when determining criticality. These factors are used to give higher priority to poles that have a potentially higher impact on reliability and safety.

Other Influencing Factors

Hydro One continues to address a subset of Red Pine wood poles that are experiencing premature degradation. These poles have a considerably shorter expected service life, and require replacement on a priority basis. Further details on the Red Pine pole issue can be found in proceedings EB-2012-0136 and EB-2009-0096.

2.3.2.2 RIGHTS OF WAY

Hydro One's distribution system is comprised of approximately 112,000 km of right-of-way. Hydro One's rights-of-way are adjacent to approximately 7 million trees, which are the most prevalent cause of distribution power outages. The vegetation management program is the largest budget within operations and maintenance. The program is designed and executed to facilitate the safe and reliable distribution of power to Hydro One customers.

The asset strategy for the management of rights-of-way is to regain control of backlogged maintenance and shorten the average maintenance cycle in order to improve asset condition, asset performance and program costs. This will be accomplished by classifying the right-of-way assets into two groups based on their impact on customers. The first group will be managed in the cycle clearing program, which manages high impact rights-of-way on their optimum cycle length. The second group will be managed in the tactical maintenance program which is focused on the lower impact rights-of-way managed using a risk based approach that considers reliability, asset condition, asset age and feedback from our customers and within the organization. More detailed information on the vegetation management programs can be found in Exhibit C1, Section 1 Tab 2.

Preventative Inspection and Maintenance Program

Right-of-way assets are acquired through capital expansion of the distribution network. Once in service, rights-of-way are managed through the sustaining OM&A budget. Asset maintenance is accomplished through planned and demand investments.

Condition

Right-of-way condition data is collected during the distribution line patrol and is used to prioritize planned and demand vegetation management programs. The condition of a right-of-way deteriorates over time as vegetation grows and the health of over-mature trees adjacent to the right-of-way gradually declines. The number and type of vegetation related defects on the distribution system are illustrated in Figure 30.

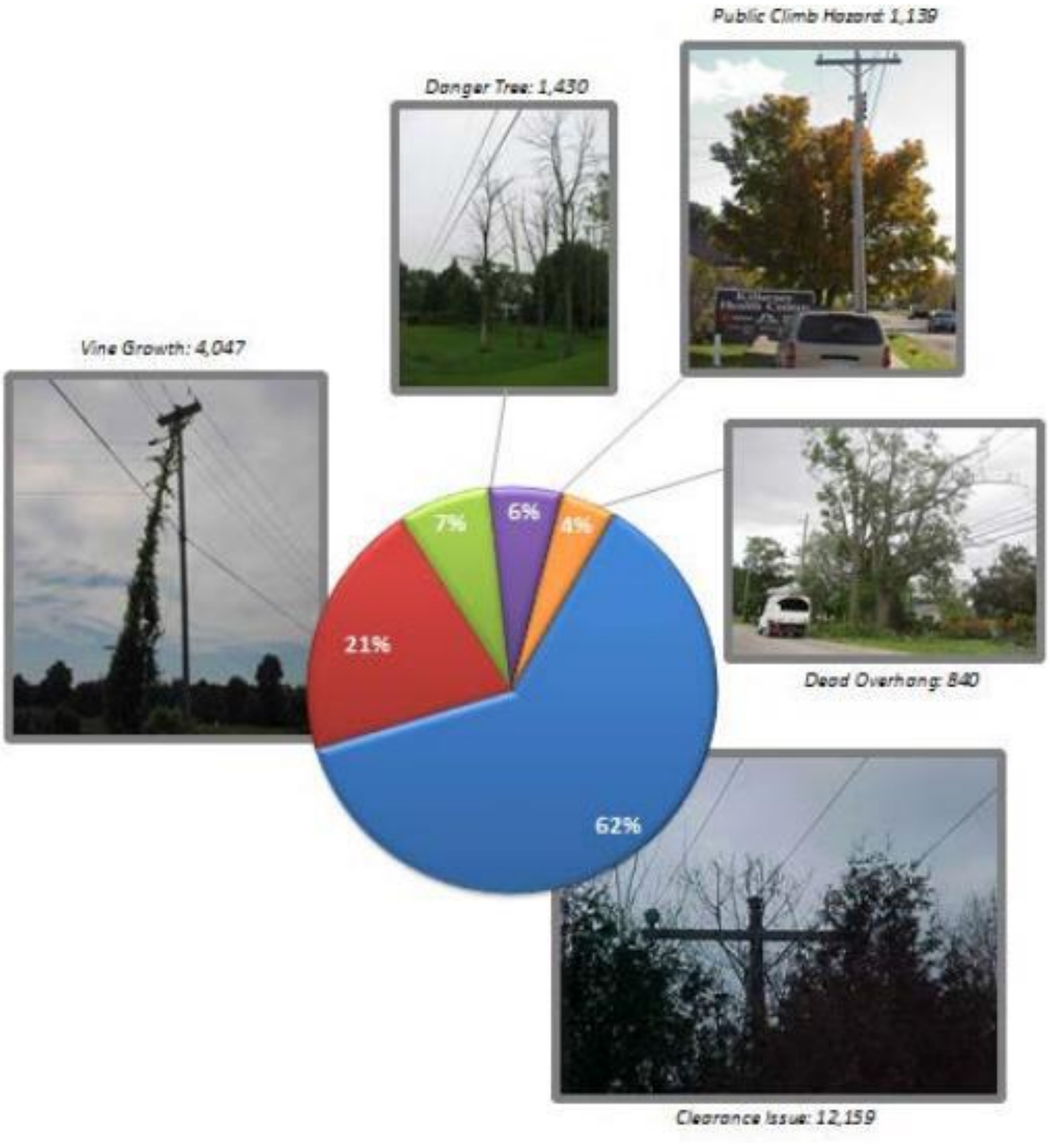


Figure 30 - Vegetation Defects

Demographics

"Asset age" for rights-of-way is a reflection of the number of years since the last planned vegetation management treatment. Asset age and maintenance cycles are important concepts in vegetation management because asset performance tends to deteriorate as vegetation grows. For example, if a tree ages and becomes unstable to the point of falling or if a vine grows and overruns a pole, these are issues where the asset requires protection from the growing vegetation surrounding it. An effective vegetation management program is able to invest in maintenance at the most cost effective time and mitigate sharp increases in vegetation-caused issues on the power system.

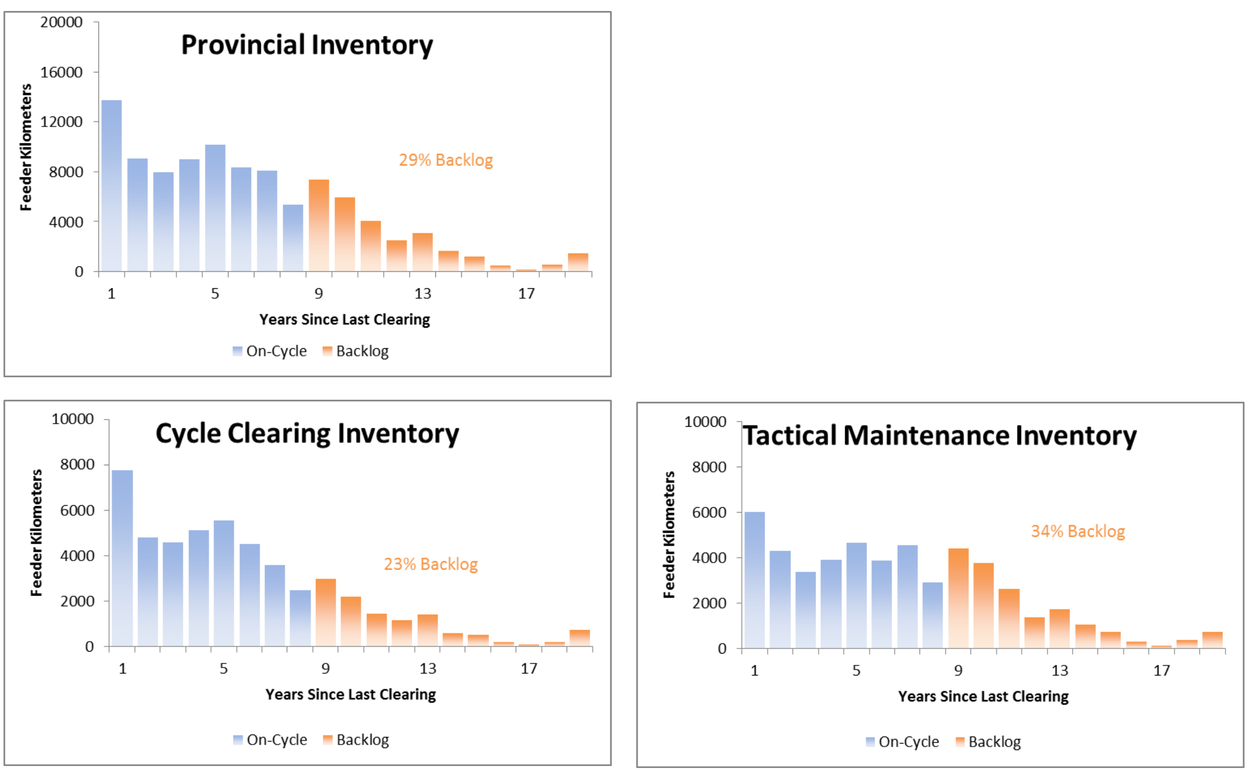


Figure 31 - ROW Vegetation Demographics

Within Hydro One's right-of-way inventory, optimal maintenance cycles vary between four and eight years depending on the feeder specific vegetation conditions and management considerations. The majority of the Province is managed on a six-year cycle which is consistent with the peer average reported in the vegetation benchmarking study summarized in Section 1.6. In Northern Ontario, where the growing season is shorter, cycles are eight years. In select areas of Southern and Eastern Ontario, vegetation growing conditions require a shorter cycle and those areas have been assigned a four-year cycle. Provincially, 29% of Hydro One's right-of-way assets have not been cleared in over eight years (backlog) and the Provincial average right-of-way age is 6.2 years.

Hydro One's strategy for reducing the Provincial backlog is to classify the right-of-way inventory based on impact to customers and to phase in appropriate cycles on the most impactful assets first. The cycle clearing program manages the assets that have the largest impacts on Hydro One's customers and eliminating backlog in this inventory is a primary objective for the 2018 – 2022 planning period. Presently, the assets managed within the cycle clearing program have a backlog of 23% and an average age of 5.7 years.

The tactical vegetation maintenance program manages the lower impact assets in the distribution network (single and two phase lines). Instead of being managed on a cycle, the tactical program is managed using a risk-based approach that considers reliability, asset condition, asset age and feedback from customers and within the organization. Presently the assets managed in the tactical maintenance program have a backlog of 34% and an average age of 6.7 years. Improvements in age demographics (years since last cleared) within the tactical maintenance program will be sought once the assets in the Cycle Clearing inventory have been optimized.

Performance

One driver for continuing to pursue a stable clearing cycle is improving system reliability for Hydro One customers. Annually, vegetation-caused outages account for approximately 16% of non-force majeure distribution outages and those outages contribute to an average of 27% of the annual corporate SAIDI score. The most common root cause of tree caused power outages (see Figure 32) are whole tree failures originating from outside the cleared right-of-way. These are considered hazard trees by the nature of their condition and proximity to lines. Preventing tree fall outages is accomplished through tree removals in the planned and unplanned programs. The newly initiated tree outage investigation process, which is a result of the peer benchmarking exercise, will result in additional insight into hazard tree failures that will be used to improve Hydro One's vegetation maintenance practices.

Table 45 - Total SAIDI and Vegetation Contribution

	All Interruptions (hours)			Force Majeure Events (hours)		
Year	**Total**	**Tree Contribution**	**Tree %**	**Total**	**Tree Contribution**	**Tree %**
2013	27.3	14.6	53%	20.0	12.7	64%
2014	9.9	3.4	34%	2.0	1.3	65%
2015	12.9	5.5	43%	4.6	3.3	72%
Total	**50.1**	**23.5**	**47%**	**26.6**	**17.3**	**65%**

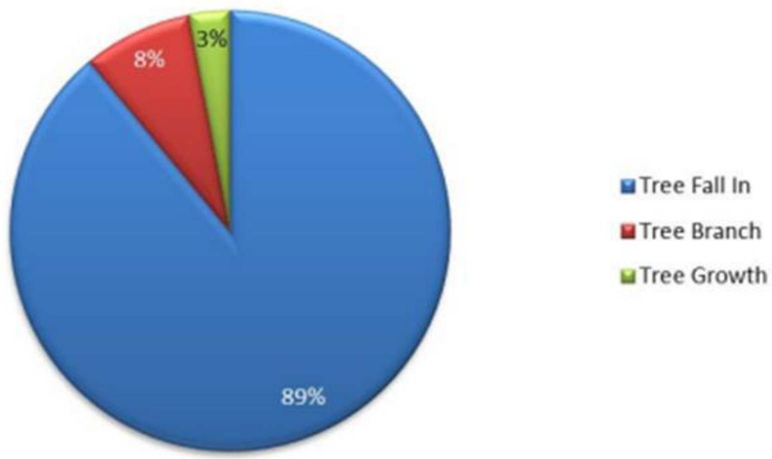


Figure 32 - Root Cause of Vegetation Outages

Criticality

Criticality for rights-of-way is a reflection of the assets housed within the right-of-way and the consequences of tree failure on those assets. Asset criticality has been addressed in the vegetation management program through identifying and managing high impact assets within the cycle clearing program.

2.3.2.3 LINE TRANSFORMERS

Distribution Line Transformers are used to convert electricity from primary distribution voltage levels (e.g., 44kV, 27.6 kV, 14.4 kV, or 8 kV) to secondary voltage levels (e.g., 600 V or 220/110V) so the power can be utilized by residential and small business customers.

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

Figure 33 – Picture of Pole-Top Line Transformer

Hydro One maintains a total fleet of approximately 500,000 transformers in overhead (pole mounted) or underground (pad mount or submersible) configurations.

Table 46 - Line Transformer Type

Transformer Type	Quantity
Pole-mounted Transformer	445,500
Pad-Mount Transformers	53,250
Submersible Transformers	121
Transclosures and Pole-Trans Transformer	800

Hydro One's asset strategy for distribution line transformers is to replace units upon failure. The exception is PCB contaminated transformers which are being replaced as part of the PCB removal program over the period of 2017-2023.

Preventative Inspection and Maintenance Program

Historically, the asset data collected for line transformers did not include the manufactured date and, as a result, Hydro One does not possess age data for most of its fleet of line transformers. With this component being a "run to failure" asset, there was no requirement for cataloguing the age information. However, with the introduction of the 2009 Environment Canada legislation, requiring the removal of equipment with a PCB concentration of greater than 50 ppm, the policy of "run to failure" is being modified to address the retirement of PCB contaminated assets in an organized manner. Hydro One has an ongoing initiative to correct and update the lack of data in SAP over time. The immediate need and driver for the collection of this information is the PCB legislation requirements. The methodology for addressing this need is outlined below.

Based on oil sampling results, PCBs in concentrations greater than 50 ppm have been found in distribution line transformers manufactured as late as 1984. Because manufacturer's dates were not readily available to determine the line transformer population demographics, transformer ages were recorded starting with the 2011 Line Patrol data collection program. As outlined in Figure 34, based on the sample population compiled, approximately 53% of line transformers were manufactured before 1985 or have a date of manufacture that is unknown.

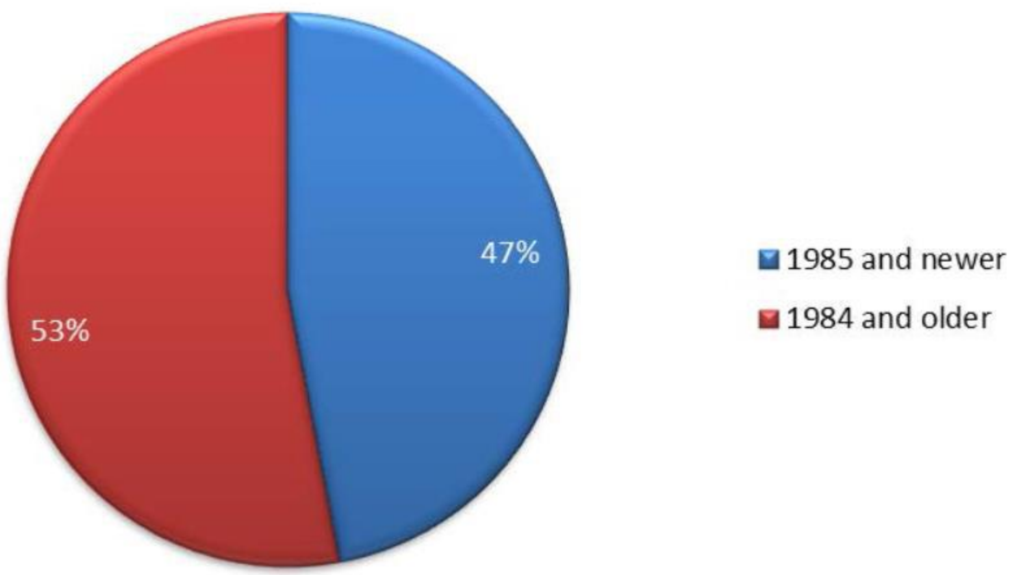


Figure 34 - Line Transformer Age Distribution

Each of the transformers in 1984 or older category will require oil sampling and PCB analysis. During the years 1997 to 2003, Hydro One conducted a Due-Diligence PCB inspection program, involving approximately 87,000 transformers. At that time, the Environment Canada legislation was foreseen, but not yet finalized. Based on past experience with PCB testing, transformers up to 1984 were found to contain PCBs greater than 50ppm. It is this threshold that is being used in the current PCB Inspection and Testing Program. Hydro One predicts that approximately 8% of tested transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination.

The OM&A Transformer Inspection and Testing Program commenced in 2009 with the completion of the underground assets – the pad mounted transformer population of 53,250. In 2014, the Overhead Pole Mounted Equipment Inspection and Testing Program started with a pilot program of 5,000 locations. In 2015, inspection and testing expanded to 13,000 locations. In 2016, the full program was rolled out at 30,000 locations per year going forward to completion. The inspection and testing program visits each overhead transformer location, verifies the transformer age and collects an oil sample for any transformer manufactured prior to 1985. Oil samples are analyzed by a third party laboratory and any transformer with PCB content greater than 50 ppm is scheduled for planned replacement.

Optimization, Prioritization and Scheduling

The OM&A Distribution Line Patrol program breaks the province down into six sectors, with one sector being patrolled each year to comply with the DSC requirements. The line patrol program collects distribution system data, including, where possible, the overhead transformer nameplate information. Beginning In 2017, in an attempt to optimize the data collection initiatives, the Overhead Equipment Inspection and Testing program will follow the same sectors by a year lag. For example, overhead equipment inspection and testing in Sector 1 will take place a year after distribution line patrols for Sector 1. This plan will allow for a more efficient targeted approach to the inspection and testing program. The schedule calls for the completion of the inspection and testing program by 2023, to allow a buffer to complete all transformer replacements with greater than 50 ppm to meet Environment Canada's deadline of December 31, 2025.

Asset Condition

The failure of a distribution line transformer is difficult to predict. While a transformer does deteriorate due to exposure to the elements, its life is mainly impacted by the electrical stresses on which it is placed. These stresses include the loading of the transformer and electrical faults or lightning strikes on the feeder supplying the transformer. Transformers are also replaced as a result of distribution feeder rebuilds, traffic accidents or when they pose an environmental hazard due to oil leakage or failure.

Trends and Impacts

In 2014, Hydro One commenced the PCB inspection and testing of pole mounted line transformers. In order to comply with PCB regulations by 2025, Hydro One will perform approximately 35,000 to 40,000 inspections and approximately 20,000 to 25,000 tests annually. As described above, pole mounted transformers with PCB content 50ppm or greater will be replaced.

2.3.2.4 SUBMARINE CABLES

In order to service certain remote customers, Hydro One builds and maintains a number of submarine cable installations. A submarine cable is a distribution conductor, installed under water, to service customers for which overhead crossings are not technically or economically feasible. Submarine cable installations are primarily in Ontario's "cottage country" supplying island residences. Approximately 11,500 such installations are currently in service, with a total circuit length of about 3,750 kilometers.

Figure 35 – Picture of Submarine Cable Entering Entering Water

Table 47 provides a synopsis of the submarine cable based on a 2014 survey.

Table 47 - Number of Cables and Length

Number of Phases	Cable Run Length (km)	Total Cable (km)	Number of Cables
Single-Phase	3,434	3,434	10,913
Two-Phase	13	26	66
Three-Phase	108	324	684
Total	**3,555**	**3,784**	**11,663**

Hydro One’s asset strategy for submarine distribution cables is to mitigate the risk of failures through visual inspection at the shoreline using the distribution line patrol. Repair/replacement is performed if there is any damage to the cable armour.

Preventative Inspection and Maintenance Program

Submarine cables are installed in environmental conditions that are among the harshest experienced by any distribution assets. They are permanently submerged in water and cross shorelines that are subjected to both severe wave action and winter cycles of freezing and thawing, along with ice build-up. Aside from the harsh conditions to which submarine cables may be exposed, their locations make them exceptionally difficult to access. For these reasons, it is challenging to perform effective maintenance on submarine cables. Submarine cables are managed in conjunction with the Distribution Line Patrol Program; all submarine cables are reviewed on a six-year cycle.

Submarine cable assessments are condition based, prioritized by the missing concentric neutral wires and also by the condition/existence of shoreline protection where the cable egresses the water. The Submarine cable program is focused on replacing cables where potential public hazards are found

Demographics

As evidenced by the information in Table 48, the amount of demographic information available for submarine cables regarding installation date and service life is minimal. In the past, similar to Secondary Service Lines, these assets have been installed to connect individual customers and repairs take place based on customer request. Service life plays no part in the decision regarding the replacement of a submarine cable and there has been no program in place regarding preventative maintenance activities with these assets. Therefore, there was no requirement for detailed information and the life of the asset was generally not maintained.

Table 48 - Submarine Cables by Known Decade of Construction

	1960s	**1970s**	**1980s**	**1990s**	**2000s**	**2010s**	**Unknown**	**Total**
Single-Phase	10	36	408	184	120	40	10,115	10,913
Two-Phase				1			227	228
Three-Phase							33	33
Total	**10**	**36**	**408**	**185**	**120**	**40**	**10,375**	**11,174**

Hydro One is changing the practice around maintenance of submarine cable. Primarily to ensure public safety, Hydro One is initiating an assessment program built around a six year cycle. Out of this program, data will be logged and the robustness of the data is expected to improve over time.

Condition

Submarine cables exposed at shorelines are subject to the action of waves and to repeated cycles of freezing and thawing. Many older cables do not have any form of shoreline protection installed. Especially on rocky shorelines, natural processes can lead to significant cable damage.

Distribution patrols show that approximately 25% of cables are exposed at the shoreline with no mechanical protection. Due to natural forces, the protective armour of these exposed cables is more susceptible to deterioration. In many cases it is completely deteriorated or missing, thus leaving the concentric neutral wires exposed and prone to failure. Protective armour damage and the subsequent neutral failure is the predominant failure mode for submarine cables. While not necessarily causing service interruptions, this type of damage can cause power quality issues or potentially dangerous public safety hazards. Cables are repaired or replaced when the armour is found to be compromised.

Trends and Impacts

In order to mitigate the risk associated with cables that are subject to natural processes at the shoreline, Hydro One has revised standards for these installations including a revised cable design and has developed improved mechanical shoreline protection techniques and products – specifying a more rigid PVC protective covering, which will help mitigate the armour damage

Hydro One also developed and tested numerous mechanical protection systems that will lessen the damaging effects as the submarine cable transitions from the water to the pad mount transformer or the overhead connection.

As patrols identify submarine cables at beginning stages of deterioration they will be repaired or replaced under the Submarine Cable Replacement program. Hydro One is proposing to spend $8M per year for the next five years to replace 220 to 250 submarine cables per year to address the number of deteriorating cable installations. Details of this investment can be found in ISD SR-11

2.3.2.5 OTHER DISTRIBUTION LINE COMPONENTS

In addition to the major line components referenced in the previous sections – poles, line transformers and submarine cables – there are a number of other components that contribute to the total Distribution System. The following table provides a list of these components and numbers in service.

Table 49 - Other Distribution Line Components

1 of 2			Voltage Level (kV)									Totals
			44	**16/ 27.6**	**14.4/ 25**	**22.8**	**8/ 13.8**	**7.2/ 12.5**	**4.8/ 8.32**	**2.4/ 4.16**	**Other**	
Conductor	**Overhead (Km)**	3 Phase	9,780	6,785	2,247	48	146	8,761	15,560	856		**44,183**
		2 Phase		25	21			677	1,177	25		**1,925**
		1 Phase		3,282	3,240		81	25,295	33,237	471		**65,606**
	Underground (km)	3 Phase	47	466	21.0		26.9	125.0	416	100		**1,202**
		2 Phase		165	2.6		11.6	27.8	150	19.3		**376**
		1 Phase		1,245	79.5		63.6	676.0	1,433	154		**3,651**
AMI	**Retail Meters**										1,335,000	**1,335,000**
	Collectors										10,400	**10,400**
	Repeaters										38,000	**38,000**

2 of 2

			Voltage Level (kV)									Totals
			44	16/ 27.6	14.4/ 25	22.8	8/ 13.8	7.2/ 12.5	4.8/ 8.32	2.4/ 4.16	Other	
Switches	**Air Break and Load Break**	3 Phase	1,648	1,004	49	7	23	140	103	79	9	**3,062**
Reclosers	**Hydraulic**		40	305	262		32	3,093	8,214	61	28	**12,035**
	Electronic		42	87	4	1		54	37	2	9	**236**
Regulators			1	98	79		3	744	1,346	15		**2,286**
Capacitor Banks			86	263	36		5	230	661	38	2	**1,321**

Hydro One's asset strategy for maintenance of distribution lines assets is to visually inspect all lines assets as part of the distribution line patrol program. Individual assets are assessed and replaced on a "run to failure" basis or on a condition-based assessment.

Distribution lines are inspected on a six-year cycle for rural area and a three-year cycle for urban areas. During these inspections information about the condition and demographics of specific assets is collected. During the line patrols, defects found on any component are recorded and, depending on the nature and seriousness of the defect, repairs are scheduled for correction.

For the components above, all are managed on a "run to failure" basis, with heavy emphasis on the Line Patrol program to identify defects/issues before the components reach the failed state. Several have Capital Component Replacement programs, which replace, like for like, components that are defective or have reached end of life.

The Advanced Meter Infrastructure (AMI) is composed of retail revenue meters, repeaters, collectors and other electronic components. The AMI is used to implement Time of Use electricity pricing and to remotely collect customer billing data. AMI components are currently replaced when they fail. To facilitate timely replacement of AMI components, an inventory of AMI components is maintained to better serve customers.

The vast majority of retail revenue meters are Smart Meters. Smart Meters have a manufacturer-stated service life of 15 years. It is expected that the Smart Meters will exhibit unacceptable performance beyond their expected service life. As a result, Smart meters are planned to be proactively replaced starting in 2021. The replacement schedule will match the historic installation schedule which began in 2006.

Distribution Line Switches – Three Phase Load Break and Air Break – are a vital component during line construction for safety and isolation and during outage restoration. These switches are maintained under an OM&A program for Switch Maintenance. Any switches found under this maintenance program to be un-repairable, are replaced under the Capital Component Replacement program.

Distribution Line Reclosers and Regulators are divided across the province into six sectors and are replaced at a rate of 1,250 per year under the Component Replacement program. The regulators and hydraulic reclosers are replaced with units that have been refurbished at several maintenance shops across the province.

Distribution Line Capacitor Banks are utilized to ensure that the distribution lines voltage performance complies with power quality industry standards. The capacitor banks are part of distribution line patrol inspection program with replacement on a “run to failure” basis.

2.3.3 (5.3.3 A, B) KEY COMPONENT SUMMARIES – OTHER ASSETS

The assets that Hydro One employs to operate the system and its business include some assets not directly related to the provision of electricity, but that are nonetheless critical to ensuring the success of continuing operations.

IT Hardware and Applications are the systems that support all of the grid and administrative operations. Real Estate and Facilities include the numerous physical and locational assets housing assets and crews. Transport and Work Equipment are comprised of the different types of vehicles that transport staff and materials. Customer Care includes the specific assets needed to effectively serve customers.

These assets are as vital to the successful achievement of Business Objectives as are the electrical components described above. Details on these various groups of assets are included below.

2.3.3.1 INFORMATION TECHNOLOGY – HARDWARE AND APPLICATIONS

Background

Information Technology ("IT") refers to computer systems (hardware, software and applications), enterprise data storage and processing systems, and voice communication systems that support business processes and allow employees to perform their work to serve customers effectively. Hydro One currently manages approximately $150 million of IT assets and uses approximately 800 business software applications. IT hardware includes desktop/notebook computing equipment, field tablet computers, storage devices, servers, and telecommunication infrastructure including switches, and computer-telephony interfaces.

IT Minor Fixed Assets ("MFA") programs ensure the continued operation of the IT hardware infrastructure. These programs address equipment needs generated by the growth in demand for IT services, capacity limitations, and the replacement of end-of-life equipment. The replacement of aging hardware is based on the age and the nature of the applications running on the hardware. Equipment may be upgraded, or improvements may be made to extend hardware lifecycle. IT MFA is broken down into the categories shown in Table 50 below and the number of devices currently employed for each type is provided.

Table 50 - IT Minor Fixed Assets

Description	**Quantity**
Number of Enterprise Servers	1,539
Number of Desktops & Laptop computers	7,503
Number of Tablets, Printers and Plotters	2,172
Volume of Enterprise Data Storage(TB)	946.5

Telecommunication infrastructure includes equipment such as Local Area Network ("LAN") switches, Wide Area Network ("WAN") routers, firewalls, Virtual Private Networks ("VPN"), telephony services (dial tone and voice mail), infrastructure cabling and Uninterrupted Power Supplies ("UPS").

The Asset Strategy for Hardware is to adhere to the IT industry standard practice of managing assets through a life cycle program ensuring vendor support is available and decreasing the likelihood of failure. Investment decisions are made based on software life cycles, vendor schedules, reliability requirements, customer requirements, and experience with similar equipment.

Witness: Lyla Garzouzi/Lincoln Frost-Hunt/Rob Berardi

The Asset Strategy for Applications is to replace or upgrade where required to ensure continued vendor support and compatibility with the current IT environment in order to minimize business interruption. Investment decisions are based on return on investments calculations which reflect savings and constraints of software life cycles, vendor schedules and, reliability requirements.

Hardware Maintenance

Investments in servers and storage are required to respond to and manage growth in demand for processing and storage capacity and to address end-of-life issues. In determining when equipment requires replacement, functionality and operating and maintenance costs are assessed. Spending varies depending upon hardware life cycles and business requirements for increased processing capacity. Lifecycles vary due primarily to demand for additional functionality from the applications being hosted or the expected failure rate provided by the vendor; generally expressed as Mean Time Between Failures ("MBTF").

Desktop and laptop computers are used by most Hydro One staff. Rugged tablet computers are used by field staff. Tablets are used with geospatial information systems ("GIS") applications for system design work and asset condition assessments. Plotters are used by engineering and operations staff for design work and to plot system maps.

Hydro One's practice is to replace desktop and laptop computers every three to five years, and printers and plotters, every four to five years. The renewal timeline is consistent with industry practices as outlined by leading technology analytics organizations including Gartner, IDC, Forrester and others. Hydro One strongly values and takes industry insight into consideration for its own IT strategies and practices.

Another factor governing the replacement timelines is that hardware maintenance costs typically increase after the four to five-year expected life cycle period, making it a more appropriate time to refresh. MBTF for physical components is another consideration for refresh. In general terms, as physical components continue to be powered on and active, their reliability and performance (for example, Solid-State Disks and Flash RAM), degrades. This drives more frequent component failures after the four to five-year period. At times, the refresh cycle has been adjusted to accommodate business requirements. Moreover, application upgrade projects performed on broadly used applications, such as Microsoft Windows, may have effects on hardware replacement. For example, the newer versions of Windows tend to have increased hardware requirements. Therefore, an update to Windows may accelerate the refresh cycle on a large number of computers. Hydro One has implemented the refresh cycles it currently has in place in order to minimize the overall life cycle costs of the assets.

The telecom assets of Hydro One are varied with different installation dates and life cycles. The business telecom network transmits data required to run business applications. Voice or data network improvements or replacements improve network efficiency and ensure equipment is current and supported by third party vendors. Projects regularly undertaken include rewiring local area networks, replacing end-of-life data network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source systems, and upgrading security solutions for external network interfaces. For voice and data network equipment, the equipment refresh generally occurs about every five years. Funding for voice and data networks may vary depending upon hardware lifecycles, technology changes, and business needs for increased bandwidth.

Key enterprise systems and their supporting hardware must always be available to customers and to the employees involved with the delivery of customer service programs and work management programs linked to Hydro One's Business Objectives.

Application Maintenance

Hydro One's Enterprise Applications provide the backbone of business operations. Customer Information systems enable effective delivery of call centre, meter reading, billing, collections and settlement services to Hydro One customers. Enterprise Resource Planning ("ERP") systems provide the tools to seamlessly manage administration across multiple lines of business including finance, human resources, supply chain, as well as, asset and work management for field staff upgrading and maintaining the power system. Work Management Systems enable timely connection of customers through demand related activities and effective operations through scheduled plant maintenance or storm restoration activities. The reliability of Enterprise systems is critical to keeping Hydro One running effectively.

The following general architectural principles apply to all Hydro One IT applications:

- Applications will be commercial-off-the-shelf ("COTS") and maintained in a vendor-supported version lifecycle to ensure continued functionality and maximum longevity;
- Custom applications are migrated to COTS solutions where possible to minimize development, integration and maintenance costs;
- Where possible, application rationalization is applied to reduce the number of applications supported and lower support costs; and
- Middleware will be used to facilitate application interconnectivity. Hydro One has invested in implementing middleware or Service Oriented Architecture ("SOA") to enable data integration within and between applications and ensure continued interoperability.

The ongoing maintenance and sustainment of Hydro One IT applications and the supporting infrastructure is outsourced to Inergi LP. Based on support levels established by Hydro One IT operations and the respective business operations, applications are managed through the "IT infrastructure library", a framework focused on incident, problem, and change management.

When an application is placed into service, it is assigned a Support Level ("SL") designation. The SL contains a set of characteristics and expectations which determine the standards to which each application will subsequently be maintained. The uptime expectations are included in Table 51 below.

Table 51 - Uptime Expectations by IT Support Level

Support Level	Expected	Minimum	Hours of Operation*
SL-1	99.91%	99.53%	7x24x365
SL-2	97.30%	95.25%	7x24x365
SL-3	99.55%*	97.15%*	Mon. - Fri. x Business Hours x 6:00 – 18:00

** Higher than SL-2 as Hours of Operation are Business Hours only. No single outage of a SL 1 or SL2 Application shall exceed thirty (30) cumulative minutes during any measurement window.*

There are a number of important and coincident factors that must be considered when determining whether an application should be upgraded. These include:

- age (lifecycle) of the existing application;
- dependencies on other up/downstream applications;
- complexity of the upgrade process;
- cost and duration of application upgrade;
- potential impact to the business (ex. tolerance for downtime);
- risk and potential impacts to other up/downstream applications;
- maintaining vendor supportability;
- providing enhanced business functionality/capability required by Hydro One; and
- integration with other applications, including "cloud-aware" applications that use modern development architectures and authentication/authorization/federation protocols (for example, OpenID, SAML, and OAuth).

IT Development

IT Development projects enable the replacement and/or upgrade of end-of-life applications and may also include investments in new applications to meet changing business and customer requirements. Applications are replaced when they have become inadequate for current functional needs; where the platform is no longer supported by the vendor; to address legislative changes or market driven initiatives; or to significantly modify the application to better support an evolving business capability. New applications are only added when necessary to address business needs and to support existing or new business processes.

The strategic decisions to conduct system upgrades are largely based on industry standard Systems Development Life Cycle ("SDLC") methodologies. An SDLC is composed of a number of clearly defined and distinct work phases which are used to plan for, design, build, test, and deliver information systems. An SDLC aims to produce high-quality systems that meet or exceed customer expectations, based on customer requirements, by delivering systems which move through each phase, according to scheduled time frames and cost estimates.

Business planning is performed on an annual basis with business stakeholders to assess whether investments in business processes and IT technology are required. When a requirement is identified, the details are sent to the Corporate Projects department of IT. This group makes provisions by assessing the need against potential benefits and costs to calculate a return on investment. IT capital projects are required to submit a business case to justify the cost against future savings.

Projects are generally 1 of 3 types:

Investments in new functionality to meet business objectives

These investments include new or upgraded applications designed to improve functionality, customer support and efficiency. The projects may support other Business Objectives. Examples of these projects include:

- Work Management & Mobility (ISD-GP-10);
- S/4 HANA for Finance and Enterprise Asset Management (ISD-GP-17);
- HR and Pay Related Technology Investments (ISD-GP-13);
- Collections Enhancements (ISD-GP-31);
- Customer Data and Analytics (ISD-GP-32); and
- Customer service Complaint Management Tool (ISD-GP-33).

Investments to replace or upgrade end-of-life applications

These investments address hardware deficiencies to support efficiency and performance. Examples of these projects include:

- Enterprise Geographical Information System (ISD-GP-11);
- Call Centre Technology (ISD-GP-28); and
- Smart Meter Network Investments (ISD-GP-34).

Investments to address regulatory (legislative) requirements

In certain cases, a technology solution is required to address a regulatory requirement. An example of this type of project is:

- Customer Service Regulatory (ISD-GP-30).

Other Influencing Factors

Aside from maintaining an up to date and effective IT environment to support employees and customers, the proposed investments also includes items to:

- improve customer service satisfaction based on priority items from the customer engagement sessions described in Section 1.3;
- monitor and implement, where feasible, new and disruptive technologies that can be leveraged to improve business functionality and enhance customer service;
- support the lines of business to improve the cyber security posture of the company assets based on the North American Electric Reliability Corporation (NERC) version 5 and 6 mandatory standards;
- improve safe work practices for Hydro One employees with mobile and GIS investments; and
- create work management efficiencies to improve customer satisfaction and reduce cost per unit measures.

2.3.3.2 REAL ESTATE AND FACILITIES

Background

Hydro One Real Estate Facilities assets include Administrative Centres, Operations Centres, Maintenance/Work Centres, Warehouses, Maintenance Garages, Helicopter Hangars, Material Yards and numerous others. These facilities are vital assets to the company in support of the business operations to fully deliver the prescribed work programs.

Capital investment is periodically required in order to continue to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business.

Hydro One currently manages a total of approximately 136 facilities that exclusively serve the Distribution program or in common with the Transmission program. The key elements of these facilities are 486 buildings of various natures serving the business requirements. These facilities and their related buildings are broadly distributed across the Province as depicted by Figures 36 and 37 below.

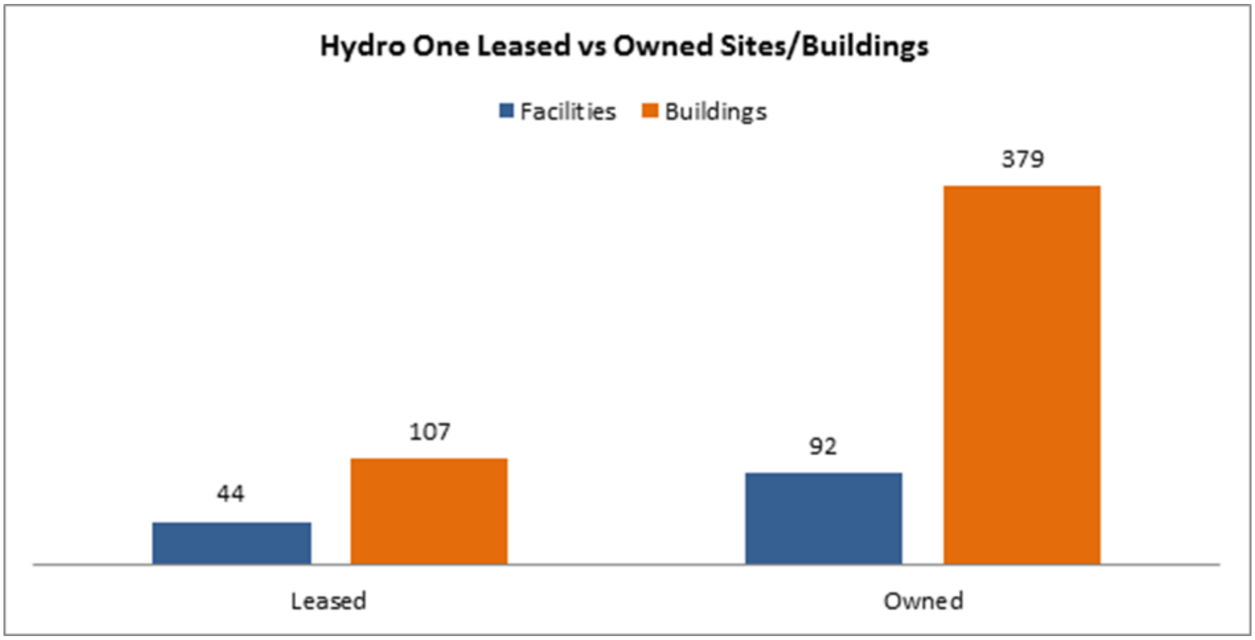


Figure 36 - Leased vs Owned Facilities & Buildings

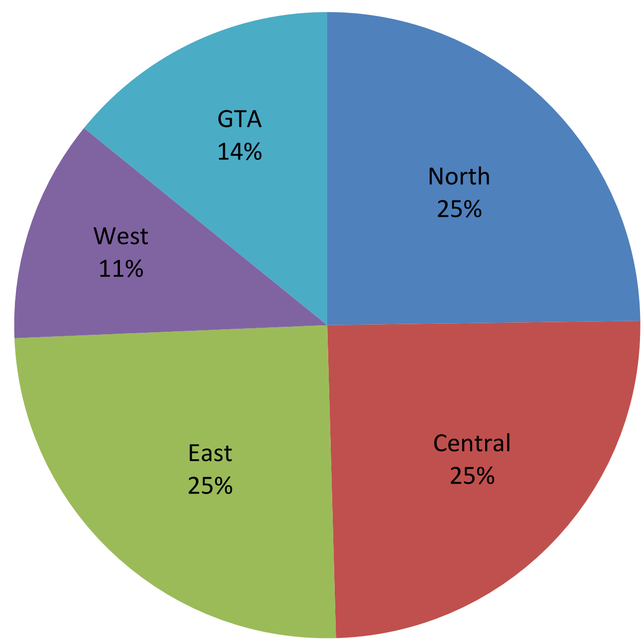


Figure 37 - Distribution of Facilities in Ontario

Hydro One facilities are distributed to align with the configuration and demands of the network and customers as well as the diverse operational requirements of the various lines of business. In addition, the siting of facilities is established against a number of factors, which are balanced and optimized. These factors can be categorized as internal and external.

Internal factors include network demands, which dictate/influence business operations and requisite facility requirements. The aim is to maximize operational effectiveness of the various lines of business operating within their respective regions, which may be incremental or complementary. Furthermore, financial performance will dictate an examination of various alternatives, (e.g. lease versus owned).

External factors also affect the siting and development of facilities. Some of these external factors include regulatory framework, public policy and municipal and economic development. Furthermore, provincial geography and topography influence or dictate the siting of facilities. Finally, market conditions also dictate the availability and feasibility of solutions which can impact a facility's siting.

The asset strategy for Facilities and Real Estate is to maintain facilities that serve operational requirements in accordance to a life cycle approach by conducting planned maintenance of key facility systems and infrastructure and undertake inspections at an appropriate frequency to identify and undertake corrective maintenance. Undertake annual operational assessments with the various lines of business to confirm facility requirements and as necessary complete renovations, additions or replacements for new requirements and/or end of life condition.

Condition

More than 40% of administration and service facilities are greater than 40 years old. These facilities are commonly undersized, ill-configured and, in context of operational requirements, are underperforming. The result is an increase to operating costs for maintenance and repair and inefficiency to business operations. In addition, the facilities program is tasked with addressing corporate growth objectives, such as LDC acquisitions. With past and ongoing resource constraints, the objective is to make timely and prudent investments that address priority requirements that serve operational and condition gaps and align with future plans to upgrade or replace these facilities.

Building condition assessments of all facilities have been initiated to identify condition gaps and required future investments needed for ongoing requirements. To date, assessments have been completed for approximately 60% of the facilities within the current portfolio. These assessments have identified approximately 20% of buildings to be in fair to very poor condition. These assessments are to be completed within two years. In conjunction with operational assessments, corrective plans will be established to address conditions on a priority basis.

Maintenance and Inspection

Hydro One's facilities maintenance program is supported by visual inspections and building condition assessments at planned frequencies. Execution of facility maintenance and inspections is outsourced to Brookfield Global Integrated Solutions in accordance to internal and external guidelines. Hydro One has documented the maintenance and inspection guidelines within its controlled document system. In addition, the service provider through its experience has and continues to provide insight and recommendations for appropriate level of maintenance and repair. These recommendations are typically identified through inspection reporting and building condition assessments.

These guidelines are defined and enforced through contractual obligations with the service provider and service level agreements for the facilities. Guidelines are developed to serve operational and corporate defined requirements, regulatory requirements and general commercial guidelines employed by the facilities industry.

Visual inspections are conducted at all facilities with frequencies ranging from monthly to annual as defined below to optimize performance. Each facility is visually inspected on a monthly basis, which consists of preventative maintenance plans scheduled for various components. The monthly visual inspections are done on various major building systems such as, HVAC, lighting and fences. Bi-monthly, visual inspections of the building envelope and site are completed. Annual inspections address fire systems, building auxiliary, sewage system, and foundation and floor pads. However, Hydro One may carry out additional inspections after storms, earthquakes, fire, vandalism, and public reports, as deemed necessary.

Building condition assessments are performed every five years to provide Hydro One with comprehensive insight of the facility's asset condition. It provides short, medium and long term assessment of the facility and associated levels of required investment with respect to ongoing use. This assessment serves to establish or confirm a facility asset strategy in conjunction with operational requirements.

In line with the facility asset strategy, the results from the visual inspections and building condition assessments either trigger corrective maintenance, capital expenditure for renewal, or replacement, or are documented and re-evaluated in future planning. The results of inspections and assessments are completed and considered on an individual facility basis. Global reporting is currently under development, which will refine the assessment and reporting. The objective will be to update guidelines for planned maintenance and corrective plans.

The level of corrective maintenance at each site, which may vary, is determined by whether the site is owned or leased, the life-cycle standing (i.e., the remaining estimated life of the asset), and the future operational requirement. The exception is Hydro One's leased facilities where the burden of capital repairs and/or replacements resides with the Landlord other than repairs that are specific to Hydro One's operations (i.e., tenant improvements). Building and site elements in fair or good condition resulting from the building condition assessments would be re-evaluated every five years and implemented in context of the facility capital asset strategy.

Identification and Assessment of Operational Requirements

An effective facilities management program is contingent upon identifying and prioritizing business and operational requirements. These requirements can range from minor capital repair or upgrade of existing facilities to establishment of a new work centre to address operational, business or regulatory requirements.

The process entails conducting ongoing operational assessments with each line of business to ensure facilities are fully aligned with operational requirements and to identify and reaffirm planned investments. An annual planning meeting is conducted with each line of business to review their specific portfolio to identify facility requirements to current, planned or operational trends/strategies. As part of this review, opportunities and risks are considered to assist in the prioritization of facility requirements within and amongst the various lines of business. In addition to the annual meeting, broader stakeholder meetings are conducted on a semi-annual basis with all lines of business. This provides each group with operational status of the various facility projects and initiatives in progress to confirm alignment with operational requirements. These stakeholder meetings may lead to identification of operational synergies, such as co-location opportunities, so that different lines of business can leverage common infrastructure and facility elements. Periodic meetings are also conducted as needed to review newly identified corporate initiatives, which may impact the operational and facility requirements of the lines of business.

Corporate and individual lines of business requirements often create competing requirements with respect to timing and resources. Therefore, these requirements are assessed within and amongst each other to establish priorities and timing. The process of prioritization considers a variety of factors, including but not limited to:

- Impact to business (regulatory and operational risks);

- Corporate initiatives (e.g. customer service strategies and LDC acquisitions);
- Life-cycle standing of assets (condition);
- Facility constraints (physical, regulatory and operational)
- Market opportunities (existing and greenfield developments); and
- Financial (corporate, shareholder and ratepayer).

Prioritization often results in gaps to addressing defined operational requirements. This necessitates strategies that recognize these gaps with interim facility solutions that lead or contribute to the preferred strategy. This can be accomplished through maintenance of current facilities with incremental additions, short-term facilities and phased developments.

Identification and Assessment of Facility Alternatives

Based on the established priorities and resulting facility strategy, Hydro One considers a range of potential alternatives available to meet the requirements on a project basis. Alternatives considered include:

- Current location;
- Relocation to another existing Hydro One facility;
- Acquisition (purchase or lease) of existing available facilities in the marketplace; and
- Greenfield developments.

The identification of alternatives in the marketplace entails leveraging municipal economic development departments, local real estate brokerage community, and like resources.

Alternatives undergo a rigorous analysis, which considers risks measured against the continuation of the status quo. Alternatives are assessed on their ability to meet line of business operational requirements, satisfy regulatory requirements, and address financial considerations, such as facility costs (initial capital and ongoing operations) and potential savings to the lines of business. All alternatives are assessed on a comparative basis, supported by input from architects, engineers, cost consultants and real estate consultants/brokers, as well as prior experience. Recommended alternatives are reviewed and approved as part of the investment planning process. Hydro One considers potential risks to ongoing business requirements and a corresponding facility exit strategy for all alternatives.

Other Factors - Divestment of Assets

Periodically, Hydro One determines various facility assets to be surplus to requirements and seeks to divest these properties. However, most facilities are located in smaller markets where low value and demand result in delayed sales, usually below book value.

Hydro One divests itself of its surplus properties through an open and competitive process, generally through a Real Estate Broker listing, with the intention of maximizing exposure and optimizing return on the asset. In cases where a sale of the asset is not possible, Hydro One will attempt to lease the property to a third party or mothball/demolish to offset ongoing cost and liability. To ensure that Hydro One realizes fair market value and as a check in the sale process, surplus properties are independently appraised by qualified real estate professionals.

The decision to declare properties as surplus considers the life cycle standing of the asset and future operational requirements, the latter entailing the input from the lines of business through the operational assessment process.

2.3.3.3 TRANSPORT AND WORK EQUIPMENT (FLEET)

Background

Hydro One Fleet Management Services provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Transport and Work Equipment ("TWE") consists of a variety of different equipment types including:

1. Light duty (cars, vans, pickups);
2. Heavy duty (service trucks, highway tractors, bucket trucks, Figure 39, and radial boom derricks (RDB), Figure 40);
3. Off-Roads (rubber tire and tracked);
4. Miscellaneous equipment such as trailers, boats, chippers, puller tensioners, manlifts and forklifts; and
5. Helicopters.

Figure 38 summarizes the number of vehicles by equipment type.

Fleet vehicles support the various lines of business, including Provincial Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These regulations include, but are not limited to CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. The objective is low environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

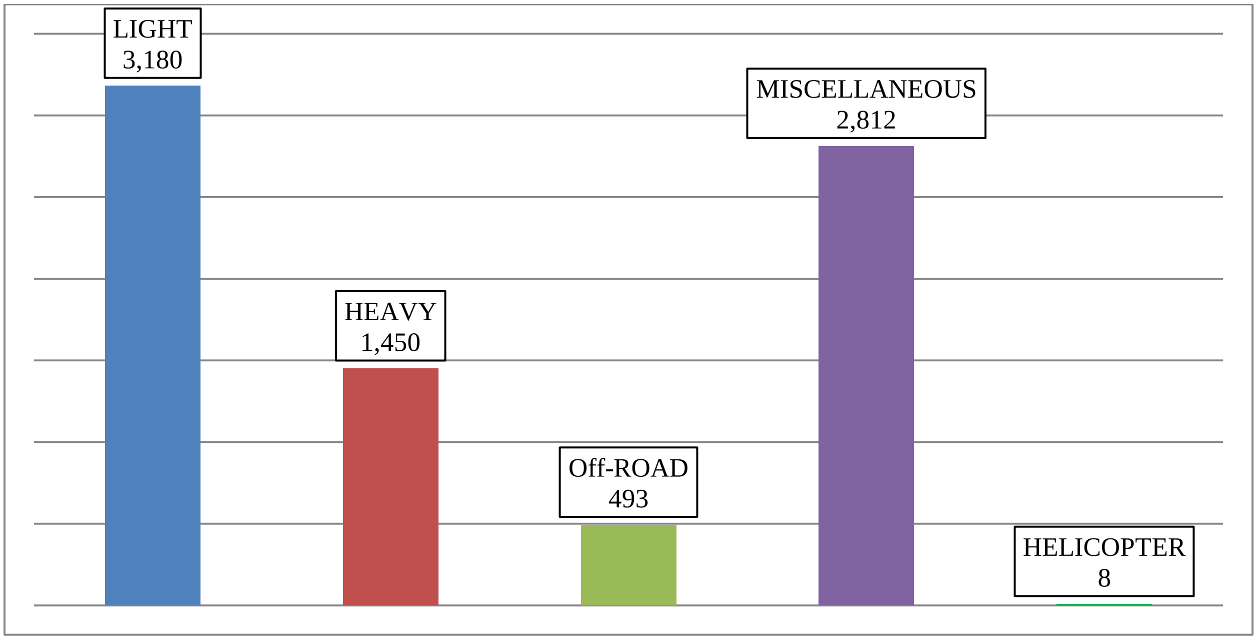


Figure 38 - Fleet Equipment by Type

The asset strategy for TWE assets is to provide safe and reliable equipment for employees to deliver safe, reliable and economical service while balancing the decision to replace or repair equipment. The decision to replace or repair equipment is based on age, mechanical condition, kilometers traveled and cost per kilometer, as well as the current Net Book Value (“NBV”).

Figure 39 – Picture of Heavy Bucket Truck

Figure 40 - Picture of Radial Boom Derrick

Inspection and Maintenance Program

Fleet Management Services has developed a balanced maintenance model for mobile service. Staff can arrange to have local mechanics provide service at the location of the breakdown or they can have it towed to a centralized facility. This model provides for 41 provincial locations and balances geographical customer requirements, travel time, third party vendor support and response time. The locations of the 41 garages are based on the density of equipment and Line of Business ("LOB") work centres. Mobile/satellite repair units provide timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance. Services provided to the LOBs meet the requirements of Fleet Management Services' agreements and are structured as a mobile model to meet customer requirements.

Fleet Management Services employs specialized heavy duty mechanics that deal with most heavy, off-road and miscellaneous equipment. If there is an issue with the equipment, the driver will drop the equipment off at their fleet maintenance garage to get the vehicle repaired. If the driver is unable to deliver the equipment, they will call into their fleet maintenance garage where the supervisor will make an assessment of whether the equipment will be towed in or a mechanic will drive out to the equipment and repair it on site. The Fleet Management Services mechanics will also complete inspections of the equipment based on regulation and manufacturers' timelines.

For all light vehicles Hydro One has agreements in place to allow external mechanics to complete all inspections, services and repairs. If there is a service or repair that needs to be completed on a light vehicle, the driver can take it to any non-Hydro One garage for the issue to be addressed. All light vehicle repairs get approved by Fleet Management Services prior to any work being completed.

For all helicopters, Fleet Management Services has a group of experienced Pilots and Air Maintenance Engineers based in five strategic locations across the province to support the LOBs. All Pilots and Air Maintenance Engineers hold Transport Canada licenses and receive annual training and testing to maintain a high level of proficiency.

Demographics, Condition and Performance

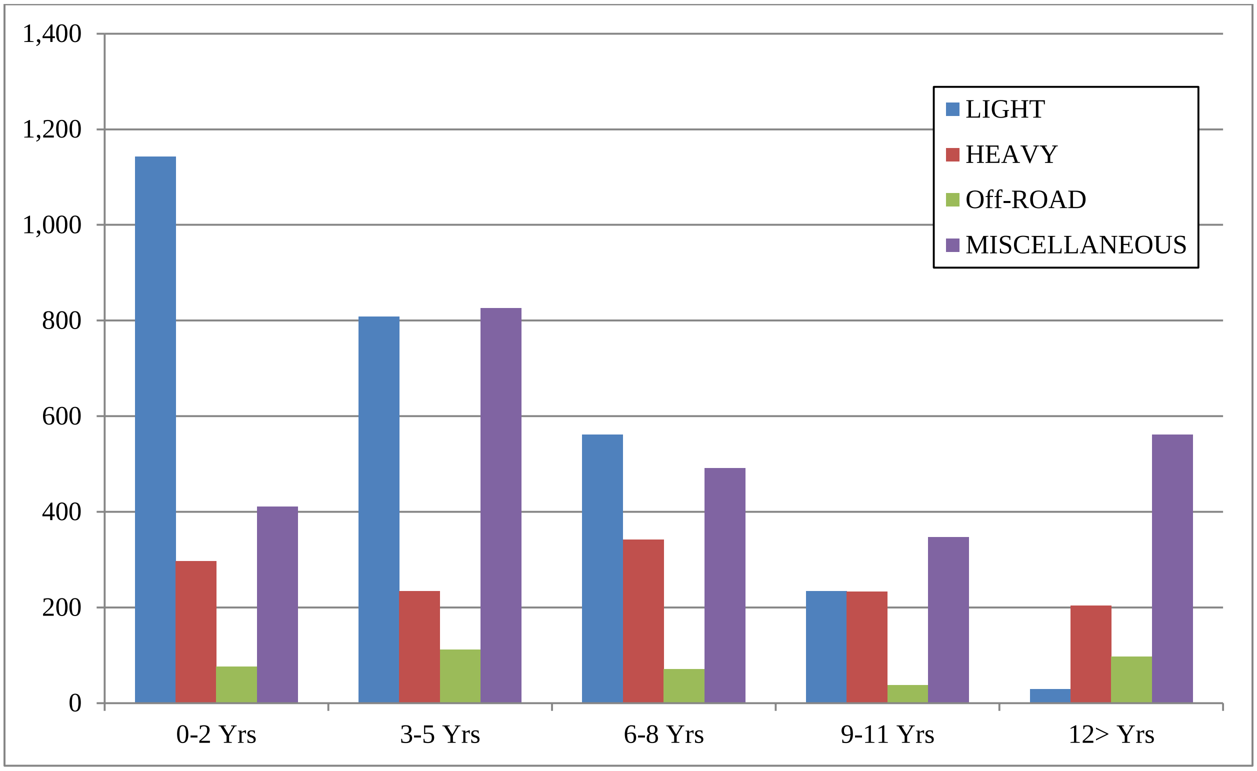
Each year, Fleet Management Services and the LOB complete a review of all the equipment that has met the replacement guidelines, stated below. The NBV, age and condition of the vehicles are reviewed against the future work programs and staff needs. Where possible, replacement equipment is pulled from the current inventory based on utilization and transferred to other locations or LOBs. If there is no equivalent equipment available in the current inventory, a requisition will be completed to order a new replacement vehicle. The vehicles that will be replaced are sent back to Fleet Management Services to be sent to auction or disposed of locally.

Fleet Management Services replacement program reviews:

- equipment capital forecast;
- equipment productivity, functionality, and future requirements;
- equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- safety/risk;
- work programs, evaluating staff and equipment complement;
- tendered procurement process;
- fleet's original capital value and net book value;
- historical and future utilization; and
- strategic procurement.

Replacement guidelines per type of equipment are:

- Light vehicles (personnel carriers) are considered for replacement after 6 years or 180,000 km;
- Heavy vehicles:
  - Service Trucks are considered for replacement after 6 years or 300,000 km;
  - Work equipment-single axle (RBDs, buckets, etc.) are considered for replacement after 8 – 10 years or 400,000km; and
  - Work equipment-tandem axle (RBDs, buckets, etc.) are considered for replacement 12-14 years or 400,000km.
- Off-Road and Miscellaneous equipment are specialized and due to a lower utilization can be kept for a longer period of time. Replacement is dependent on availability of parts, the condition of the equipment at the annual inspections, future work program requirement and changes in technology as well as the length of the replacement timeframe and availability of rentals; and
- Helicopters are considered for replacement on a case by case basis depending on utilization, condition of the aircraft and the cost of refurbishment as well as work program requirements.

1 

2 **Figure 41 - Transport and Work Equipment Demographics**

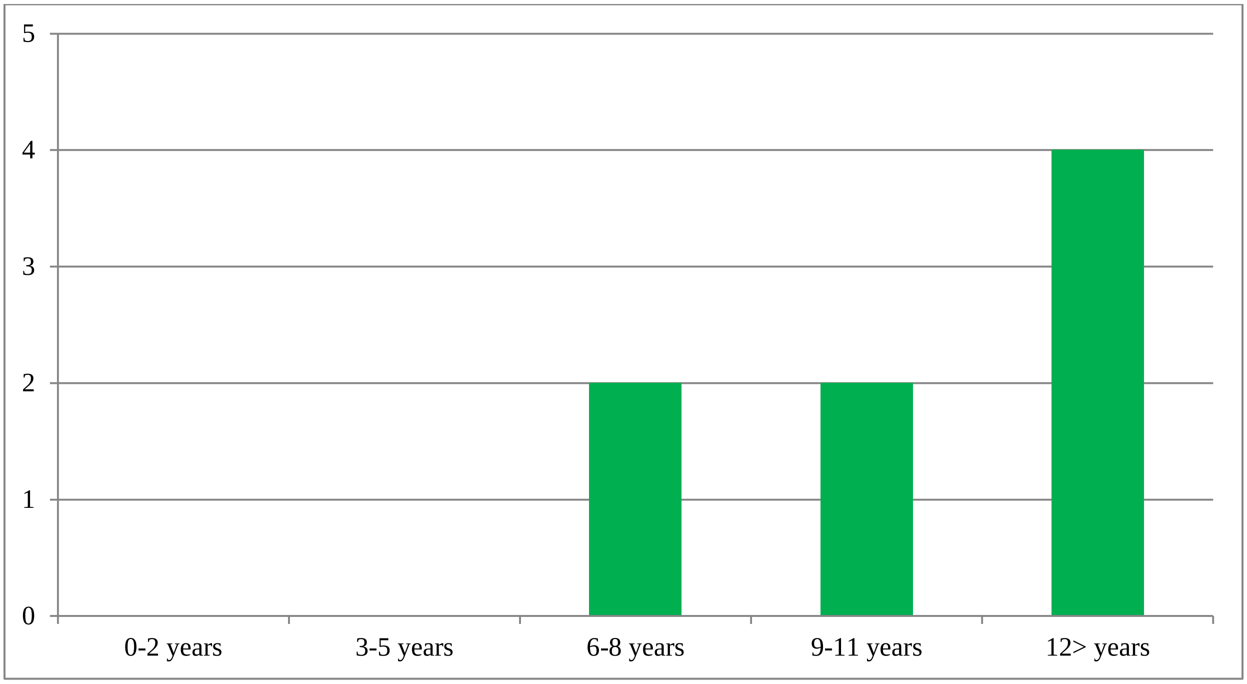


Figure 42 - Helicopter Demographics

Other Influencing Factors

Fleet Management Services has implemented a fleet telematics system for 4,700 fleet vehicles. Integrating telecommunications, global positioning systems (GPS), and informatics systems, Telematics provide location of vehicles and live vehicle operation and performance data. This project was completed at the end of 2016.

The Telematics system provides the following benefits:

- Improves operator safety through awareness of driving habits using Speeding and Harsh Events (hard breaking) reports;
- Provides better visibility to Fleet Management Services regarding vehicles that are not being utilized by a LOB and those vehicles can be redeployed to other work

groups leading to better utilization or possibly a reduction of overall fleet using the Utilization report;

- Allows implementation of fuel efficiency and greenhouse gas reductions by changing driver habits with the Speeding and Idling reports;
- Improve Fleet Management Services response time with live vehicle locations;
- Improved fuel tax credit savings with the Power Take Off (PTO) reports;
- Visibility to the Engine Control Module of the vehicles allow for tracking of vehicle condition, optimization of routine maintenance; and
- Decrease thefts and increase security of the fleet vehicles through the advertisement of on-board GSP telematics systems.

In 2017, Fleet Management Services will leverage the telematics data to institute a framework to define the baseline metrics with respect to equipment utilization and productivity. Savings are forecast to begin in 2017 with $0.3M in OM&A but will ramp up to $3.1 million Capital and $2.2 million in OM&A by 2022. Further details on the productivity savings expected from the Telematics system are included in Section 1.5.1.5.

2.3.3.4 CUSTOMER CARE

Background

Hydro One's Customer Service division services approximately 1.3 million residential, small business, commercial, and industrial customers. The Customer Service department is responsible for responding to customer inquiries when they contact the call centre, obtaining meter readings, and issuing timely and accurate bills. In 2016, the call centre handled over 2.7 million calls from customers and delivered over 14 million bills. As Hydro One pursues its vision of becoming a best-in-class, customer-centric company, managing this large customer base requires a number of large assets and advanced technology.

The Hydro One Customer Contact Centre relies on the following technologies to operate effectively:

- Customer Information System ("CIS") – A billing software that manages customer information, meter data, electricity consumption, billing calculations, service orders, and collection activities. The system also provides customer service representatives a single solution for tracking all interactions with customers and enables interactions with customers, generators and other partners, such as retailers and social services agencies.
- Interactive Voice Response ("IVR") System – An automated telephone system that interacts with callers, gathers information through voice prompts, and routes calls to the appropriate recipient.
- Computer Telephony Integration ("CTI") – Gathers information through voice prompts, routes calls to the appropriate recipient, and coordinates interactions with CIS.

The Customer Service department also relies on Smart Meter technology. Hydro One was one of the first LDCs to introduce smart meters in 2006 and this project delivered the Advanced Meter Infrastructure ("AMI") to 1.2 million customer premises by the 2010 OEB target date. The corresponding smart meter communication network was completed in 2013.

Smart meters measure the total amount of electricity used over a billing period, record how much and when electricity is used (typically hourly), and transmit this information automatically to

Hydro One's CIS. The smart meter will record total electricity consumption and send that information to Hydro One through a wireless communications network. Customers will then receive bills based on automated meter readings. Smart Meters, when teamed with Time-of-Use prices, are energy management tools that help customers manage their electricity use and costs, reduce the need for additional power generation during peak periods, and create real supply and environmental benefits.

The Asset Strategy for customer service capital is to coordinate the activities of IT and the service provider to maintain customer-facing systems to ensure regulatory compliance while balancing cost and customer satisfaction – the latter of which is determined via direct and varied engagement with customers. As outlined in Section 1.3, surveys, focus groups, and customer engagement sessions are used to gauge the current satisfaction levels of customers and identify needs, preferences and issues.

Condition and Performance

Customer Information System

Hydro One's most recent CIS went live May, 2013. The CIS replacement project was designed to address current needs, improve customer value, and enable a customer service delivery vision. Although the system is operating effectively from a billing perspective, the following enhancements are required in order to improve internal operations and customer satisfaction.

Billing – Hydro One's latest survey results indicated that only 62% of customers find their bill easy to understand. In order to help customers better understand their bill, Hydro One plans to redesign the bill. Continued interaction with the technology to help modernize our bills is required. There is also a need to improve billing for non-energy services (whereby Hydro One provides specialized work for non-energy services to external parties). Hydro One's existing tool is inefficient and is not integrated in CIS. As a result, there are inconsistent customer service policies between energy related billing and non-energy related billing.

Data and Analytics – Customers are also concerned about the high cost of electricity, based on feedback received from customers via the Distribution Customer Engagement and detailed in Section 1.3. The feedback indicated that reducing cost is the top priority for Residential and Small Business customers. Many customers believe that total electricity costs are approaching an unaffordable level. CIS is capable of providing analytics to customers to help them manage their consumption. Currently, CIS has minimal interaction opportunities with customers to provide this type of information effectively. Hydro One is planning on implementing a new suite of technology to address the shortcomings of the current CIS in this respect.

Complaint Management – Hydro One receives approximately 3,000 complaints from customers on an annual basis. Complaints are currently managed within an access database. This database is not integrated with CIS and therefore complete and robust customer information is often not available to Hydro One employees addressing the customer's complaint. Plans are in place to implement a tool on top of CIS that will not only track customer complaints from initiation to resolution, but also provide account information, contain workflows to improve productivity, and assist with root cause analyses.

Collections – Hydro One's collections tool within CIS offers customers a variety of payment options and sends reminders to overdue customers. However, the existing collections functionality within CIS requires enhancements in order to reduce overdue receivables and Net Bad Debt for Hydro One. Based on feedback received from customers via the Distribution Customer Engagement (as detailed in Section 1.3), customers have a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. As such, Hydro One will implement technology and process changes to encourage customers to promptly pay their bills, thereby increasing the likelihood of payment and reducing uncollectable accounts receivables moving forward.

Contact Centre Technology

Hydro One's IVR and CTI systems were last replaced in 2004 and are now past their recommended useful life. As a result, the current IVR is at risk of not being supported by vendors from a break fix perspective. Extended maintenance contracts only address existing defects but will not develop or release new code for legacy versions of software. This introduces a high risk around recovery time when system outages are experienced, thus in turn impacting customer satisfaction. Customers who have billing related inquiries, and more importantly, customers calling to report emergencies on a 7/24 basis, won't be able to reach the call centre. In addition, newer systems offer enhanced call routing, enhanced call monitoring capabilities, and more effective monitoring of agents and call centre performance.

Smart Meter Technology

Hydro One designed a number of custom applications in order to integrate the Smart Meter network, the IESO Meter Data Management and Repository ("MDM/R"), and CIS in order to meet regulatory requirements set by the Ontario Energy Board. However, these systems are no longer supported by the vendor. As such, Hydro One plans to replace the custom applications with commercial-off-the-shelf ("COTS") applications wherever possible, thereby reducing the risk of system failure currently present and gaining vendor support to avoid failure in the future. If the systems were to fail, billing operations would be disrupted, thereby impacting customers.

Other Influencing Factors

Regulatory and government policy play a key role in shaping the decisions made with respect to Hydro One's customer assets.

Capital funding is required to implement system changes to support the Distribution System Code Demand to Interval amendments that came into force August, 2014. Section 5.1.3 requires a distributor to install an interval meter on any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW and pay the hourly Ontario energy price from the IESO-administered real-time energy market based on their actual usage by August, 2020.

The Ontario Energy Board also issued its Regulated Price Plan Roadmap: Guideline for Pilot Projects on RPP Pricing in July, 2016. Dynamic Energy Pricing encourages customers to reduce electricity usage and shift usage away from peak hours. Capital funding is required to extend the pilot beyond April, 2017. This investment will provide customers with new pricing options, thereby encouraging energy conservation, making electricity more affordable, and improving customer satisfaction through the new pricing model.

2.4 (5.3.3 B) HOW THE PLAN REFLECTS INVESTMENT PLANNING AND ASSET MANAGEMENT

Starting early in 2016, and informed by work completed on efficiency studies and business objectives described earlier in the DSP, the Investment Management team finalized an asset investment plan that forecast improvement of approximately 6% in SAIDI and 4% in SAIFI related to Hydro One's most significant areas of reliability performance over the five-year period. This "Plan A" was supported by detailed analysis, and the outcomes followed significant iteration and assessment of investment candidates and asset sustainment plans, as described in Section 2.1.

In an effort to explore solutions that align customer preferences, asset investment and rate impacts, Investment Management, as part of its process (see Section 2.1.5.1), also put forward a plan with lower levels of investment known as "Plan B". This plan proposed to deliver a reliability improvement of approximately 3% SAIDI, and 2% SAIFI.

Investment Management also assessed what would be required to achieve the lowest 2018 rate increase without material disruption to Hydro One operations. This "Plan C" scenario forecast a degradation of approximately 2% in both SAIDI and SAIFI.

The final subset of options considered was a scenario labelled "Plan B Modified." This scenario proposed a pacing of investments designed to minimize rate impacts while holding reliability performance constant and in line with customer expectations. Asset replacement rates are reduced for a short but manageable period.

Reliability Performance Impact Estimation

Reliability impacts for the proposed scenarios were modelled using the effect of relative investment impacts for:

- Vegetation Management;
- Pole Replacement; and
- Distribution Stations.

Reliability performance is affected by other factors. Other Line Components are also included in the forecast. However, the three asset areas listed above contribute the majority of reliability impacts, and represent the most significant, predictable drivers of reliability for which Hydro One has meaningful statistical data. The data allowed Hydro One to understand each option before deciding on a solution that aligned customer preferences, asset needs and rate impacts.

Below is a summary of the forecast of the primary sources and impact on reliability of the Distribution system. The SAIDI and SAIFI impacts were calculated on a high level estimate basis, using simplified assumptions and are approximate. The methodology to determine the link between percent changes in SAIDI and SAIFI for poles, distribution station, other line components and vegetation under investment plans A, B, C, and B-Modified is briefly summarized below.

Pole Replacement

Hydro One has extensive condition data on its pole population. Assets in poor condition have a higher probability of failure than assets in good condition. Hydro One's change in asset condition profile for its fleet of wood poles at the end of the planning period was projected under the various proposed investment plans. Current SAIDI and SAIFI reliability contributions due to pole failure were assumed to be indicative of the current asset condition profile for the wood pole fleet. Projected changes in the profile for the wood pole fleet condition were assumed to be directly proportional to improvements in SAIDI and SAIFI arising from changes in pole failure. If the condition of the wood pole fleet improved by a certain percentage then SAIDI and SAIFI would improve by a proportional percentage. This methodology was used to estimate the expected change to SAIFI and SAIDI under the various proposed investment plans.

Hydro One manages a population of 1.6 million poles, of which 106,000 require replacement. Inspections show that 67,000 are in poor condition and 39,000 are in the Red Pine pole set that need to be addressed due to premature failure. Outages due to pole failures average 345 annually, and each outage impacts an average of 185 customers for 10 hours. In total, pole failures contribute approximately 3% to SAIDI and 2% to SAIFI. In addition, as pole failures generally occur in the public domain (i.e., not in a Hydro One enclosed area); they also represent a public health and safety risk.

- Plan A proposed a reduction in the number of poles needing replacement from 106,000 to 93,000 by the end of the planning period (2022). The plan would reduce forced outages to 303 instances per year. Both SAIDI and SAIFI impacts from wood poles would improve by 12%.
- Plan B proposed a reduction in the number of poles needing replacement to 96,000 by the end of the planning period. It would reduce forced outages to 312 instances per year, improving reliability impacts from wood poles by 10%.
- Plan C forecast an increase in the number of poles needing replacement to 126,000 by the end of the period. Plan C would increase forced outages to 409 instances per year, decreasing reliability due to wood poles by 18%.
- Plan B-Modified proposed a reduction in the number of poles needing replacement to 99,000 by the end of the period. Plan B-Modified is forecast to decrease forced outages down to 321 instances per year, forecasting an overall improvement in reliability due to wood poles of 7%.

Distribution Stations

Defective equipment is the leading contributor to distribution station outage frequency and second highest contributor to outage duration. Defective equipment can be directly influenced by proactive asset replacements. The number of distribution stations in poor condition at the end of the planning period was projected under investment plans A, B, C and B-modified. Based on the projected distribution station profile under the various investment plans, Hydro One modelled the effects on reliability to estimate the corresponding impact on SAIDI and SAIFI.

Hydro One operates 1,005 stations, of which 70 are in poor condition. Currently, 16 stations per year, on average (23% of those in poor condition) require a station outage. Each outage affects an average of 1,200 customers for 24 hours and contributes 4% to SAIDI and 3% to SAIFI. Because of the distributed nature of these stations, a failure has consequential impacts. For example, failures often require redirecting a mobile station from a planned replacement underway and increasing cost. Also, a station failure will affect an entire community and that has major impacts if it occurs in cold conditions in Northern Ontario.

- Plan A proposed to replace all stations deemed to be in poor condition (70) by the end of the planning period (2022). SAIDI and SAIFI were forecast to improve by 14%.
- Plan B proposed to reduce the number of stations in poor condition to 40 by the end of the period. SAIDI and SAIFI were forecast to improve by 5% as a result.
- Plan C proposed a scenario that would lead to an increase in the number of stations in poor condition to 90 by the end of the period. SAIDI and SAIFI were forecast to degrade by 4% as a result.
- Plan B-Modified proposed a scenario that would maintain the number of stations in poor condition at 70 by the end of the period. SAIDI and SAIFI were forecast to change by 0% as a result of this factor.

<u>Vegetation Management</u>

Rights-of-way ("ROW") in need of vegetation management are assumed to contribute to a proportion of vegetation caused outages. Hydro One's change in km of ROW in poor condition and in need of vegetation management was projected under the various proposed investment plans. Changes to SAIDI and SAIFI reliability were estimated for the various investment plans based on the proportional change in km of ROW in poor condition.

Hydro One currently maintains 112,000 km rights-of-way that generate approximately 15,530 outages per annum due to tree contact. These outages contribute 27% to SAIDI and 16% to SAIFI. All scenarios include consistent spending on high priority rights-of-way, with targets to eliminate the backlog of off-cycle rights-of-way by 2022 (9% decrease of SAIDI, 9% of SAIFI).

- Plans A and B proposed a scenario wherein the work on medium or low-priority rights-of-way maintenance is reduced by 1,000 km/yr. This is forecast to cause an increase in the backlog of approximately 8%, and a degradation to both SAIDI and SAIFI of 1%. However, this decrease in maintenance is significantly offset by the 9% improvements in high priority rights of way for a total reliability improvement of 8%.
- Plan C would reduce maintenance by an additional 1,000km/yr. The increased backlog causes a forecast decrease in reliability of 2%. After factoring positive impact of rights of way, the net improvement in SAIDI and SAIFI falls to 4% from 8% envisioned in the other plans.
- Plan B-Modified includes the same levels of spending as Plans A and B.

Table 52 - SAIDI Projection for Investment Plan Scenarios

SAIDI[1]:	**Avg. 2013-15: 7.3 hours/year**	**Average Number of Hours that a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIDI by 2022[2]**			
	Failure Rate/Impact	**Contribution to SAIDI**	**SAIDI Contribution** (based on 2013-15)	**Plan A**	**Plan B**	**Plan C**	**Plan B-M[3]**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	12%	10%	(18)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%	8%
Estimated Impact to SAIDI				**5%**	**2%**	**(2)%**	**0-1%**
Forecasted SAIDI (hours)				**7.0**	**7.1**	**7.4**	**7.3**

1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIDI by then end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3 – Impacts for "Plan B-M" refer to Plan "B-Modified" described earlier in this Section.

Table 53 - SAIFI Projection for Investment Plan Scenarios

SAIFI [1]:	**Avg. 2013-15: 2.6 outages/year**	**Average Number of Times a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIFI by 2022[2]**			
	Failure Rate/Impact	**Contribution to SAIFI**	**SAIFI Contribution** (based on 2013-15)	**Plan A**	**Plan B**	**Plan C**	**Plan B-M[3]**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	12%	10%	(18)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0-1%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.7**	**2.6**

1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIFI by then end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3 – Impacts for “Plan B-M” refer to Plan “B-Modified” described earlier in this Section.

Summary

As described in Section 1.1, Hydro One considered all the options in the context of customer preferences and reliability. The ultimate decision coming out of the planning process was to proceed with a hybrid plan referred to as Plan B-Modified, the plan described in this DSP. The plan's financial details are included in Section 3 below. Hydro One determined that this plan best aligned customer needs and preferences, responsible asset management and rate impacts. This plan adopts lower 2018 spending to minimize near term rate impacts. Reliability performance through the 2018-2022 period is forecast to be stable under this plan and consistent with recent system performance.

3.0 (5.4) CAPITAL EXPENDITURE PLAN

The requested capital expenditures result from the rigorous business planning and work prioritization processes described in detail in Sections 1.1 and 2.1. These processes reflect a risk-based decision-making approach to ensure appropriate and cost-effective investments that meet Hydro One’s Business Objectives and the RRF Outcomes.

Hydro One has right-sized its 2018 capital plan by increasing its efficiency and reducing its OM&A costs before asking customers to pay higher rates. The DSP reflects Hydro One’s plan to appropriately prioritize and pace its capital investments over the 2018 to 2022 period which will align: (a) customer needs to keep rates as low as possible and a preference to maintain current service levels; (b) asset needs driven by condition and compliance requirements; and (c) rate impacts.

The capital expenditures in this Application represent investments that will ultimately become in-service capital assets supporting the Hydro One distribution system. Specifically, these expenditures include:

a) planning, purchase, construction and commissioning of specific assets providing future economic benefits;
b) additions to or replacement of specific assets; and
c) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

Section 3.7 includes a list of all Investment Summary Documents (“ISD”) for material projects forecast over the five-year planning period. The materiality limit for ISDs for Hydro One, as listed in the OEB filing requirements, is $1 million in any single year.

<u>Category Descriptions</u>

Investment projects and activities have been grouped into one of the four OEB-defined investment categories:

System Access

System Access investments are modifications (including asset relocations) to the distribution system. Hydro One is obligated to perform to provide a customer (including a generator customer) or a group of customers with access to electricity services via its distribution system.

System Renewal

System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Hydro One's distribution system to provide customers with electricity service.

System Service

System Service investments are modifications to Hydro One's distribution system to ensure that the system continues to meet operational objectives while addressing anticipated future customer electricity service requirements.

General Plant

General Plant investments are modifications, replacements or additions to Hydro One's distribution assets that are not part of the electricity distribution system; including land

and buildings, tools and equipment, rolling stock, electronic devices, and software to support day-to-day business and operations activities.

The Investment Summary Documents for all categories are included in Section 3.8.

3.1 (5.4.1) CAPITAL EXPENDITURE SUMMARY

Hydro One’s distribution capital expenditures for the historical, bridge and test years by OEB investment categories are summarized in Tables 54 – 57 in Section 3.2. In Hydro One’s last distribution rates application (EB-2013-0416), capital expenditures were summarized using the following categories: Sustainment, Development, Operating and Common Capital. To provide continuity between filings, the capital expenditures in this Application are also summarized by EB-2013-0416 categories. For clarity, a definition of Sustainment, Development, Operating, and Common Capital are provided below.

Distribution sustaining capital represents expenditures required to replace or refurbish existing components of the distribution system to ensure they will continue to function as originally designed. Opportunities to install distribution automation devices are considered and installed, where appropriate. The sustaining capital programs are subdivided into expenditures in three asset categories, Stations, Lines, and Meters

Development capital represents investments required to connect new load and generation customers, and to enhance or construct distribution facilities. These investments ensure the system’s capability to provide a secure and reliable supply of electricity in response to new large load customer connections, cumulative system-wide load growth and system demands associated with new generators.

Operations capital investments are required to implement, enhance, and modify the physical tools, systems and infrastructure used to operate the Hydro One distribution system. These investments provide performance improvements in the form of reduced outage duration, improved customer satisfaction, and accurate information for regulatory reporting as required by the Distribution System Code (DSC).

Corporate Common Costs expenditures support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. consisting of assets shared by Transmission and Distribution businesses. Corporate Common Costs include information technology, buildings, office equipment, transportation and work equipment, tools, and service equipment.

3.2 (5.4.1 B) CAPITAL EXPENDITURE FORECAST

Table 54 - Historical and Bridge Year Capital Expenditure Summary

Category	Historical and Bridge (previous plan and actual)										
	2013*	2014*	2015			2016			2017 Bridge		
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var
	$M	$M	$M	$M	%	$M	$M	%	$M	$M	%
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)
System OM&A**	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)

** 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.*

*** System OM&A values include all Operations, Maintenance and Administration expenses.*

1 **Table 55 - Historical and Bridge Year Capital Expenditure Breakdown by SDOC**

Category	SDOC	SDOC Breakdown	Historical and Bridge (previous plan and actual $M)							
			2013	2014	2015		2016		2017	
			Actual	Actual	Plan	Actual	Plan	Actual	Plan	Forecast
System Access	Sustaining Capital	Lines	26.2	26.3	26.7	25.5	27.3	23.3	27.8	21.5
		Meters	11.2	35.8	14.6	34.7	20.5	42.3	23.8	29.8
	Development Capital	Connections, Upgrades	92.7	111.3	108.9	113.9	112.1	108.2	115.8	108.3
		Generation Connections	25.5	25.4	33.1	13.9	22.7	8.8	8.7	8.7
		Wholesale Revenue Meters	3.9	0.4	0.0	0.1	0.0	0.1	0.0	0.1
System Access Total			**159.5**	**199.4**	**183.3**	**188.1**	**182.6**	**182.7**	**176.1**	**168.3**
System Renewal	Sustaining Capital	Lines	201.2	190.7	189.0	216.0	202.1	212.5	221.3	196.5
		Meters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
		Stations	56.5	69.4	61.7	87.1	63.3	66.9	63.7	42.5
	Development Capital	System Capability Reinforcement	8.0	2.6	0.0	5.3	0.0	8.8	0.0	12.8

Category	SDOC	SDOC Breakdown	Historical and Bridge (previous plan and actual $M)							
			2013	2014	2015		2016		2017	
			Actual	Actual	Plan	Actual	Plan	Actual	Plan	Forecast
System Renewal Total			**265.7**	**262.7**	**250.7**	**308.4**	**265.4**	**288.3**	**285.0**	**252.2**
System Service	Sustaining Capital	Lines	7.0	4.6	11.9	9.2	17.4	15.2	18.3	6.9
		Meters	21.1	16.0	2.0	1.8	0.0	0.0	0.0	4.2
		Stations	0.0	0.0	2.2	0.0	4.5	0.0	4.8	0.0
	Development Capital	System Capability Reinforcement	62.0	56.4	81.4	54.7	71.5	45.0	83.2	39.5
	Operations Capital	Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Smart Grid Pilot	6.4	8.5	22.5	6.0	9.9	17.2	3.9	16.0
System Service Total			**96.5**	**85.5**	**120.1**	**71.6**	**103.3**	**77.4**	**110.1**	**66.6**
General Plant	Development Capital	System Capability Reinforcement	0.0	0.0	0.0	0.3	0.0	3.0	0.0	8.3
	Operations Capital	Operations	3.6	4.1	9.4	7.0	18.8	10.3	7.0	12.6
	Capital	Cornerstone	47.6	7.3	0.0	1.2	0.0	0.3	0.0	0.0

Witness: Darlene Bradley

Category	SDOC	SDOC Breakdown	Historical and Bridge (previous plan and actual $M)							
			2013	2014	2015		2016		2017	
			Actual	Actual	Plan	Actual	Plan	Actual	Plan	Forecast
	Common Corporate Costs and Other Costs	Facilities & Real Estate	10.1	20.3	19.0	18.5	15.3	25.1	15.4	19.9
		Information Technology	13.4	17.7	22.6	30.9	20.1	58.8	22.9	56.2
		Other	-2.9	1.5	0.0	0.1	0.0	0.8	0.0	4.3
		Transport and Work, and Service Equipment	43.5	49.1	43.8	52.1	49.1	47.6	44.8	45.0
General Plant Total			**115.3**	**99.9**	**94.8**	**110.1**	**103.3**	**145.9**	**90.1**	**146.3**
Grand Total			**637.0**	**647.5**	**648.9**	**678.3**	**654.7**	**694.2**	**661.4**	**633.5**

1 **Table 56 - Forecast Test Years Capital Expenditure Summary**

Category	Forecast (Planned $M)				
	2018	2019	2020	2021	2022
System Access	154.6	157.6	160.9	165.9	170.0
System Renewal	248.6	318.7	336.7	362.5	451.1
System Service	81.8	93.4	85.6	78.8	69.5
General Plant	149.0	187.1	135.8	133.4	136.6
Total	633.9	756.8	719.0	740.7	827.2
System OM&A*	584.8	593.3	601.9	621.4	630.4

2 ** System OM&A values include all Operations, Maintenance and Administration expenses.*

1 **Table 57 - Forecast Test Years Capital Expenditure Breakdown by SDOC**

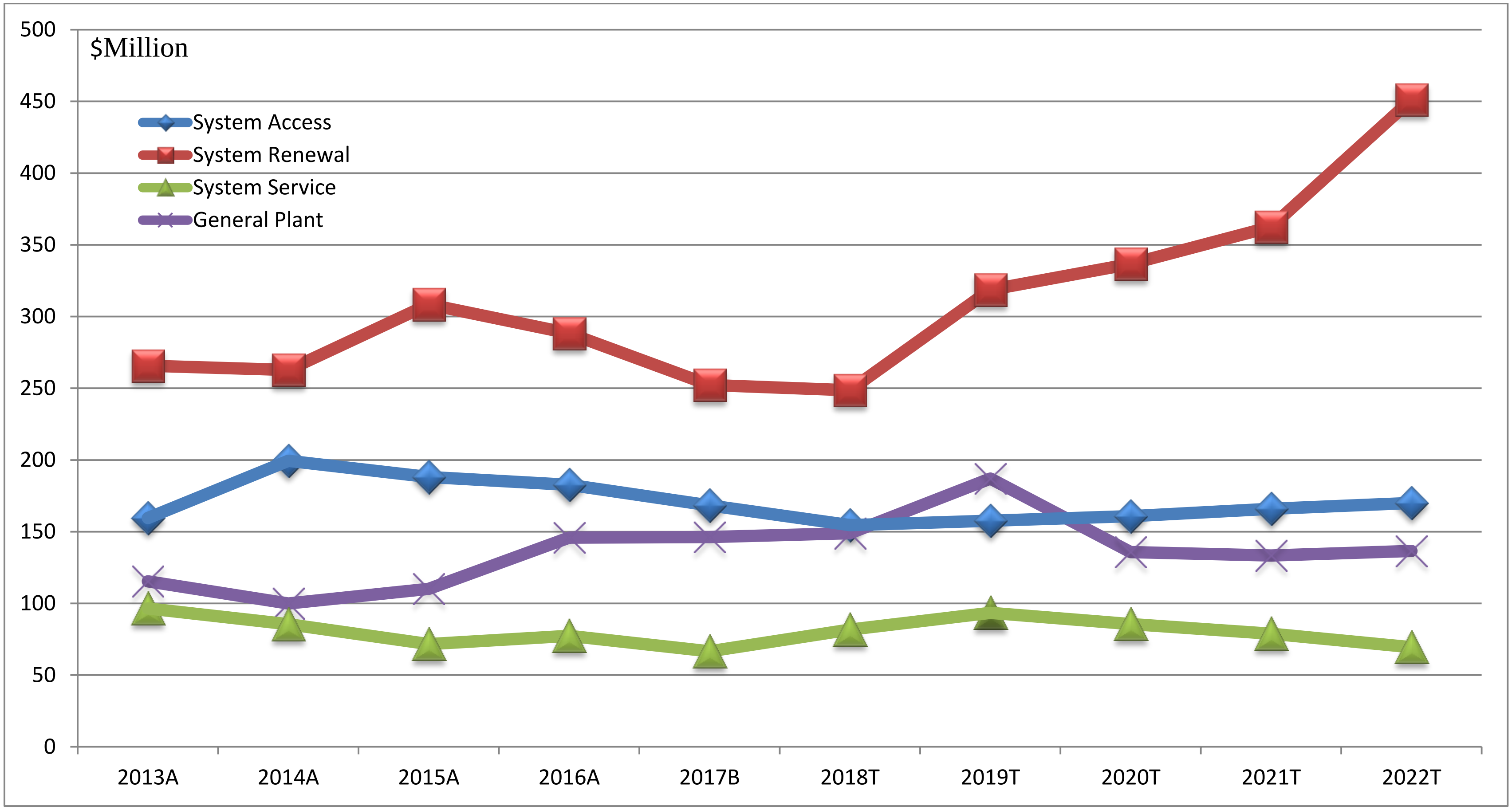
Category	SDOC	SDOC Breakdown	Test Years (Forecast $M)				
			2018	**2019**	**2020**	**2021**	**2022**
System Access	Sustaining Capital	Lines	21.7	22.0	22.2	22.6	22.8
		Meters	18.9	19.4	19.7	20.5	21.1
	Development Capital	Connections, Upgrades	109.9	112.9	115.7	120.0	123.2
		Generation Connections	4.1	3.4	3.3	2.9	3.0
		Wholesale Revenue Meters	0.0	0.0	0.0	0.0	0.0
System Access Total			**154.6**	**157.6**	**160.9**	**165.9**	**170.0**
System Renewal	Sustaining Capital	Lines	199.8	245.7	263.1	279.2	283.7
		Meters	0.0	0.0	0.0	1.4	78.5
		Stations	28.3	45.9	51.1	52.9	54.0
	Development Capital	System Capability Reinforcement	20.5	27.1	22.4	29.0	34.9
System Renewal Total			**248.6**	**318.7**	**336.7**	**362.5**	**451.1**
System	Sustaining	Lines	7.1	7.3	7.4	7.7	7.8

Category	SDOC	SDOC Breakdown	Test Years (Forecast $M)				
			2018	2019	2020	2021	2022
Service	Capital	Meters	6.0	6.0	5.9	5.8	5.8
		Stations	0.0	0.0	0.0	0.0	0.0
	Development Capital	System Capability Reinforcement	63.6	80.1	72.3	64.6	55.9
	Operations Capital	Operations	0.0	0.0	0.0	0.7	0.0
		Smart Grid Pilot	5.0	0.0	0.0	0.0	0.0
System Service Total			**81.8**	**93.4**	**85.6**	**78.8**	**69.5**
General Plant	Development Capital	System Capability Reinforcement	8.2	1.3	0.0	0.0	0.0
	Operations Capital	Operations	16.8	46.4	6.1	6.4	9.1
	Capital Common Corporate Costs and Other Costs	Cornerstone	0.0	0.0	0.0	0.0	0.0
		Facilities & Real Estate	36.5	44.0	38.0	38.0	35.1
		Information Technology	43.2	46.3	42.0	37.9	39.3
		Other	6.6	6.5	6.1	5.8	5.9

Witness: Darlene Bradley

Category	SDOC	SDOC Breakdown	Test Years (Forecast $M)				
			2018	2019	2020	2021	2022
		Transport and Work, and Service Equipment	37.8	42.5	43.6	45.2	47.3
General Plant Total			**149.0**	**187.1**	**135.8**	**133.4**	**136.6**
Grand Total			**633.9**	**756.8**	**719.0**	**740.7**	**827.2**

1 **Figure 43 - Actual/Forecast Capital Spending 2013- 2022**



2

Witness: Darlene Bradley

3.3 IMPACTS AFFECTING CAPITAL EXPENDITURES

Impacts affecting the capital expenditures that form the DSP are summarized in the list below.

1. The Regional Planning process identifies capital expenditure investments that should be undertaken by Hydro One to meet regional needs.
2. Hydro One's customer consultations identified customer needs and preferences. This customer and stakeholder input informed Hydro One in developing its investment plan, refine and shape the elements of its distribution rate application and helped to ensure that customer and stakeholder concerns were understood and addressed. This included right-sizing the capital expenditure budget for 2018 to specifically address the rate sensitivities of customers pursuant to Hydro One's distribution customer engagement process.
3. Hydro One conducted two benchmarking studies for significant capital investments: pole replacement and station refurbishment investments. These studies have resulted in changes to implementation of these investments, as described in the subsection below and in Section 1.6.
4. Hydro One's investment planning process prioritizes and selects, from a list of candidate investments posed by planners, those investments that best meet identified Business Objectives including those important to customers. The result of this process is the investment plan.
5. Hydro One will implement capital investments that will result in reduced OM&A annual costs. These capital expenditures include replacing old distribution stations with new stations, replacing oil reclosers with vacuum reclosers and moving off-road lines to on-road locations.

Further details on each item are included in the subsections below.

3.3.1 (5.4.1 A) CAPABILITY TO CONNECT NEW LOAD OR GENERATION CUSTOMERS

Hydro One is obligated to provide a connection service to new industrial, commercial, residential, seasonal and generation customers when requested under section 28 of the Electricity Act, 1998.

The division of costs between Hydro One and the customer is determined based on the Company's connection policies, which are in accordance with the DSC requirements. A basic load customer connection consisting of a service layout, overhead transformation, 30 metres of overhead conductor, and standard retail metering is provided free of charge to new customers that lie along the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine the net customer capital contribution. The capital contribution is based on any shortfall between estimated future revenues resulting from the connection and the cost of the connection and network expansion.

Most of Hydro One's distribution system is radial in design, with limited transfer capability to supply customers. Connections to Hydro One's distribution system are generally constrained by a variety of engineering factors, including but not limited to:

- equipment ratings;
- reverse power flow constraints in the case of generators;
- supply feeder current ratings;
- power quality; and
- remaining short circuit capacity at transmission stations.

Hydro One Distribution assesses system capacity capability to accommodate additional load through participation in the Regional Planning Process (described in Section 1.2.1) and through the following five main local distribution planning activities:

1. load vs. capability screening at the station and feeder levels;
2. planned feeder studies (six-year cycle studies);
3. system impact assessments for large new or increased service size requests for load connections;
4. assessment of field and customer identified issues related to power quality or other operating concerns; and
5. system impact assessments for large new or increased service size for generator connections.

Activities 1 to 4 are expanded in ISD SS-02 System Upgrades Driven by Load Growth and activity 5 is expanded on in ISD SA-05 Generation Connections.

There are two main determinants in the determination of capacity - Station Capacity and Feeder Capacity.

Station Capacity

When investigating the ability to connect additional customers, Hydro One determines the available capacity at a Station asset by considering the thermal capacity of the transformers at the distribution station, as well as protection device ratings and settings. Station upgrade is required if the additional load causes the transformer thermal capacity or protection device ratings to be exceeded. For generation connection investigation, the reverse flow capacity of the transformer and protective device, and short circuit capacity at the distribution station are also considered.

Feeder Capacity

Capacity determinations at a feeder level are made by considering the thermal rating of equipment on the feeder, voltage drop along the feeder as well as the phases on which the loads are connected. Feeder upgrade is required if the additional load causes equipment rating to be exceeded or causes the voltage along the feeder to be outside of the acceptable range of 0.94 to 1.06 p.u. For generation connection, short circuit level, distance from station to the generation, loading vs. generating balance, and interrupt rating of protection devices are also considered.

Outlook

Hydro One's forecasts for load and customer growth (See Section 2.1.2) are relatively flat. Average annual change in load over the planning period is -0.3%. The average change in customers over the planning period is +0.7%[1]. This means that growth is relatively flat on an overall system basis. However, in many areas, especially on the outskirts of urban areas, Hydro One experiences significant growth. These local regions comprise most of the customer increase. Certain assets will require testing to ensure capacity can be met.

Through the Regional Planning Process and local distribution planning activities Hydro One anticipates the need for the following projects to address local capacity limitations.

Regional Planning Projects:

- Dundas TS #2 Feeders, ISD SS 02 Project LG-28
- Enfield TS - capital contribution, ISD GP-27
- Enfield TS Feeder Development, ISD SS-02 Project LG-11
- Leamington TS Capital Contribution, ISD GP-25
- Leamington TS Feeder Development, ISD SS 02 Project LG-14
- Kingston Gardiner TS M26 Feeder Development, ISD SS-02
- Hanmer TS Capital Contribution, ISD GP-26
- Hanmer TS Feeder Development, ISD SR-13 Project LC-10

Identified Through Distribution Planning Activities:

- Cumberland DS F4 Development, ISD SS-02 Project LG-1
- Devlin DS F1 3 Phase Upgrade, ISD SS-02 Project LG-2

[1] Load and customer forecasts provided here exclude Acquired Utilities.

- Kleinburg TS M6 Mayfield Rd Line Extension, ISD SS-02 Project LG-3
- Orangeville TS M3 - Mayfield West Line Extension, ISD SS-02 Project LG-4
- New Bradford North DS, ISD SS-02 Project LG-5
- Caledonia TS M3 Extension, ISD SS-02 Project LG-6
- Alfred DS F2 Feeder Upgrades, ISD SS-02 Project LG-7
- Cameron DS Feeder Improvements, ISD SS-02 Project LG-8
- Armitage TS M22 Extension, ISD SS-02 Project LG-9
- City of Owen Sound Tie-Line Reinforcement, ISD SS-02 Project LG-10
- Grand Bend DS F3 Voltage Conversion, ISD SS-02 Project LG-12
- Kirkland Lake Voltage Conversion – Part 1, ISD SS-02 Project LG-13
- Manotick DS Feeder Development, ISD SS-02 Project LG-15
- Stouffville 10th Line DS New T3 & Feeder, ISD SS-02 Project LG-16
- Town of Shelburne Voltage Conversion, ISD SS-02 Project LG-17
- Twelve Mile Bay DS - New Station & Feeders, ISD SS-02 Project LG-18
- Beckwith DS F3 Feeder Development, ISD SS-02 Project LG-19
- Crilly DS Replacement and Transformer Upgrade, ISD SS-02 Project LG-20
- Kirkland Lake Voltage Conversion-Part 2, ISD SS-02 Project LG-21
- Manotick DS F3 New Feeder, ISD SS-02 Project LG-22
- Margach DS F3 Voltage Conversion - SW676, ISD SS-02 Project LG-23
- Muskoka TS M5 x M1 Feeder Tie, ISD SS-02 Project LG-24
- Rockland DS T2 Transformer, ISD SS-02 Project LG-25
- Barrie TS - Construct New Feeders, ISD SS-02 Project LG-26
- Caledonia TS New Feeders, ISD SS-02 Project LG-27
- King City DS - New Station & Feeders, ISD SS-02 Project LG-29
- New Old School DS, ISD SS-02 Project LG-30
- Town of Dundalk Voltage Conversion, ISD SS-02 Project LG-31
- Greely DS F1 Feeder Development, ISD SS-02 Project LG-32
- Kirkland Lake Voltage Conversion-Part 3, ISD SS-02 Project LG-33
- Midhurst Wilson DS F2 Extend to Doran Rd, ISD SS-02 Project LG-34
- Midhurst Wilson DS F1 Extend to Dobson Rd, ISD SS-02 Project LG-35
- Perth Area Upgrades, ISD SS-02 Project LG-36
- Macville DS - New 27.6kV Station, ISD SS-02 Project LG-37
- Wikwemikong DS & Line Work, ISD SS-02 Project LG-38
- Dunchurch DS F2 - Extend to Magnetawan, ISD SS-02 Project LG-39
- Fairbanks Lake Line Upgrade, ISD SS-02 Project LG-40
- Kleinburg TS M26 extension to Mayfield West, ISD SS-02 Project LG-41

- Lively DS F2 SW142 Upgrade Black Lake Road, ISD SS-02 Project LG-42
- Mar DS – New Station, ISD SS-02 Project LG-43
- Ancaster West DS Transformer Upgrade, ISD SS-02 Project LG-44
- Brockville 44kV System Upgrades, ISD SS-02 Project LG-45
- Manitoulin TS - Add Third 44 kV Feeder, ISD SS-02 Project LG-46
- Point Au Baril DS F2 Extension, ISD SS-02 Project LG-47
- Aspdin DS F1 Feeder Upgrade, ISD SS-02 Project LG-48

Generator Connection Requests:

- Kirkland Lake TS – DX Feeders, ISD SA 05
- Wendover HVDS – DX Feeders, ISD SA 05
- Muskoka TS – DX Feeders, ISD SA 05

Hydro One expects full capability to meet customer needs for connections over the planning period. ISD SA-04 includes the specific capital spending planned on New Load Connections and ISD SA-05 includes the details regarding Generation Connections.

3.3.2 (5.4.1 C) IMPACTS OF INVESTMENT PLANNING PROCESS

Hydro One completes a detailed investment planning process annually to identify and implement a plan that aligns customer needs and preferences, the needs of the system and its assets, and rate impacts. The RRF Outcomes and Hydro One's Core Values lead to a set of Business Objectives that are fundamental to that process. Each objective is assigned a weighting to guide the prioritization of the potential candidate investments. Details regarding the derivation of the Business Objectives and their alignment with the RRF Outcomes are included in Section 2.1.1. Specific details regarding the investment prioritization stage of the process are included in Section 2.1.5.

How these objectives impact investments in each category is discussed below. The impact of customer consultation on the business plan will be expanded upon separately as Hydro One has undertaken extensive customer consultation and has used the results to drive changes to the investment plan so that it more closely aligns with customer expectations and preferences.

System Access

Hydro One will invest more than $100 million per year in new distribution load customer connections and service upgrades for existing distribution customers (ISD SA-04). The investment meets customer needs and fulfills a regulatory requirement to connect new customers. System Access investments do not materially impact reliability.

Line relocation due to municipal, joint use tenant and land owner requests requires more than $20 million annually (ISD SA-01). These requests must be fulfilled to comply with joint use agreements and property owner expectations. The main outcome achieved is public policy responsiveness by complying with requests from land owners and other utilities.

System Renewal

The pole replacement program is the largest investment in the System Renewal category with a plan to invest an average of $115 million annually (ISD SR-09). Hydro One has approximately 1.6 million poles, of which 67,000 poles are currently in poor condition. Furthermore, each year, approximately 9,000 more poles are identified as being in poor condition. Investing in poles that are in poor condition seeks to minimize risks to public safety and improve reliability which improves customer experience. The current level of investment is expected to contribute to maintaining current levels of reliability.

Investments are also made to move poor condition poles that are located in off-road corridors onto road allowances with less vegetation interference thus improving reliability performance and shortening outage times for customers (ISD SR-12). Proactively moving poles onto road allowance also results in productivity benefits that improve operation efficiency as locating and repairing damaged poles in off-road corridors is time consuming.

Another significant program is distribution station refurbishments (ISD SR-06). These investments are prioritized based on asset condition and reliability performance. A new strategy of installing low profile stations with significantly fewer structures is expected to reduce the unit cost of the station refurbishment. The new design is expected to improve reliability as there are fewer components that can fail. The reduced cost and maintenance requirements will improve financial performance in this program.

System Service

Hydro One plans to invest $28 million between 2018 and 2022 to implement remote meter functionality (ISD SS-01). This investment will drive significant productivity gains and improve Hydro One’s operational efficiency as it will reduce the need for staff to physically travel to the meter to perform certain functions. The current level of investment is expected to contribute to maintaining current levels of reliability.

Approximately $50 million has been allocated to improve the reliability of the feeder performance outliers on the Hydro One distribution system (ISD SS-06). One strategy to improve reliability will be to strategically deploy electronic reclosers to reduce outage duration. Electronic reclosers reduce outage duration by sending information about the fault location to the OGCC which reduces the time for repair crews to locate the fault. Other strategies will be deployed such as addressing vegetation encroachment and assets in degraded condition that are contributing to poor reliability.

Hydro One will invest approximately $19 million per year on average to solve power quality and reliability issues that are raised by customers or identified by Hydro One asset inspections or system studies (ISD SS-03, SS-04, SS-05). These investments allow Hydro One to continue to operate the distribution system in compliance with the DSC and provide targeted reliability improvements in areas where customers have expressed concerns about reliability performance.

General Plant

Between 2018 and 2020, $56 million will be allocated to Hydro One Distribution to build an Integrated System Operation Centre ("ISOC") to ensure the continued safe and reliable operation of the Hydro One distribution system (ISD GP-18). The ISOC will provide a backup operation and telecommunication management centre as well as a security operation centre. The existing facilities no longer meet North American Electricity Reliability Corporation ("NERC") standards due to increasing failures of critical infrastructure. The investment will maintain Hydro One's compliance with regulatory standards which contributes to public policy responsiveness. General Plant investments do not materially impact reliability.

Hydro One will invest $200 million between 2018 and 2022 to keep the 7,800 fleet units operating safely (ISD GP-01). Vehicles are maintained at an optimal level to ensure public and employee safety and meet regulations such as the *Highway Traffic Act* which ensures Hydro One is in alignment with public policy. Hydro One has shown a positive trend in fleet utilization over the past 15 years, which reflects productivity and operational efficiency improvements.

3.3.3 (5.4.1 E) IMPACTS OF REGIONAL PLANS

Hydro One actively participates in the Regional Planning process to address supply and reliability issues on a regional level. Distribution-level investments are undertaken when they can address a regional need more effectively than transmission or resource options. A description of how Hydro One engages in the Regional Planning Process is contained in Section 1.2. The major investments that the Regional Planning Process identified are captured below:

Enfield TS Capital Contribution and New Feeders

Significant load growth in the Durham region will cause the existing Wilson TS to be overloaded. Hydro One Distribution will contribute $3 million between 2018 and 2019 towards building Enfield TS to offload Wilson TS (ISD GP-27). Hydro One Distribution will also invest about $7 million in the same time period to build feeders out of the new Enfield TS to pick up the load from Wilson TS (ISD SS-02, LG11).

Leamington TS Capital Contribution and New Feeders

Significant load growth in the municipalities of Leamington and Kingsville will cause the existing Kingsville TS to be overloaded. Hydro One Distribution will contribute $2.2 million in 2018 towards building Leamington TS to offload Kingsville TS (ISD GP-25). Hydro One Distribution will also invest $3.7 million in the same time period to build feeders out of the new Leamington TS to pick up some load from Kingsville TS as well as accommodate new load connections (ISD SS-02, LG-14).

Hanmer TS Capital Contribution and New Feeders

Coniston TS supplies the East Sudbury area and is in poor condition. The Regional Infrastructure Plan for Sudbury/Algoma proposed a new station called Hanmer TS to replace Coniston TS and supply future load growth in the area. Hydro One Distribution will make a $4 million capital contribution between 2018 and 2019 (ISD GP-26).

3.3.4 (5.4.1 F) IMPACTS OF CUSTOMER ENGAGEMENT FEEDBACK

Hydro One recognizes the need to have customer needs and preferences inform the business plan. External consultant Ipsos was retained to develop and lead a customer engagement process. This process included a number of opportunities to interact with Hydro One distribution customers including surveys, focus groups, one-on-one meetings and call centre interactions. The details of this process and full results are detailed in Section 1.3.1.

The results of the Ipsos work and Hydro One's on-going engagement with its customers indicate that they are very sensitive to costs; especially in the residential and small-business segments. Moreover, reliability was also a key concern, along with power quality for large customers.

Hydro One is listening to its customers and, in order to address their concerns, has incorporated a number of initiatives into its investment plan which are described below.

- Hydro One is deliberately deferring early year capital investments to pace investments so as to minimize rate impacts and offset the effects of a reduced load forecast. This includes managing rate of replacement and, where appropriate, accepting decreased levels of reliability performance to minimize rate impacts;
- Hydro One is implementing numerous productivity enhancements, which will ultimately lead to lower costs for customers. These initiatives are detailed in Section 1.5;
- Hydro One is implementing a program to install power quality meters when needed to assist in power quality investigations and improve on-going power quality for large customers with sensitive equipment;
- Hydro One is increasing spending on feeders where sensitive large and mid-size industrial customers are connected in order to improve reliability and reduce costly outages (ISD SS-03); and

- Hydro One is targeting reliability investments on feeder performance outliers (ISD SS-06) in the Hydro One portfolio to improve reliability for customers affected by poor reliability.

3.3.5 (5.4.1 F) IMPACTS OF BENCHMARKING

After Hydro One's last distribution rate application, the OEB directed Hydro One to undertake several benchmarking studies and submit the results. Two of these studies were directly related to capital investment programs: the pole replacement and station refurbishment programs. The complete benchmarking findings are in Section 1.6. The findings relevant to capital investments are summarized below.

Pole Replacement Program

The pole replacement benchmarking study found that Hydro One had a short inspection cycle but completed less comprehensive inspections than industry average. Hydro One plans to seek regulatory approval to lengthen the DSC-mandated inspection cycle and complete more comprehensive inspections.

Station Refurbishment Program

The station refurbishment benchmarking study recommended that Hydro One incorporate test results and maintenance history for switching and protection equipment into the decision-making process for station refurbishment. The study also recommended that Hydro One enhance cost and work completion reporting as well as implement a set of Key Performance Indicators ("KPIs") to track project cost and asset health. These recommendations have been implemented into the station refurbishment program (ISD SR-06)

3.3.6 (5.4.1 G) SYSTEM DEVELOPMENT FORECAST OVER THE PLANNING PERIOD

Hydro One's work programs and upgrades consider future distributed generation plans and load trends. Since the start of the FIT program in 2009, Hydro One has seen a substantial increase in distributed generation connections with over 14,250 connected to date. Various IESO incentive programs drive future growth of distributed generation connections. From 2017 to 2022, Hydro One is forecasting the connection of over 3,400 new distributed generators. More details are available in Section 3.5.2.

Hydro One is continuing its efforts to make the distribution system more efficient and reliable. By investing in its smart grid project, Hydro One is piloting, testing, and validating smart grid capabilities on a larger scale to enable distributed generation integration, improve reliability and operations, and enhance outage restoration and network planning. Work on establishing the foundation for the smart grid project is expected to be completed by 2018.

Hydro One has also started its multi-year program to deploy distribution automation and fault location to its feeders. This program will install devices on the distribution feeders and distribution substations that will be able to be controlled and monitored centrally. These investments are expected to help maintain reliability in the face of aging assets.

New control systems have been established at the Ontario Grid Control Centre that will leverage the new distribution automation and fault location devices on the distribution network. With this foundational technology, Hydro One will be better able to locate faults and reconfigure the distribution network from the control centre. This investment will enable more work to be done in the control centre creating some operational efficiency as well as reduce sustainment effort. This will translate to total annual savings of $4 million of OM&A.

Hydro One is leveraging its investments in smart meters to improve operational decision making. New systems have been established that enable Hydro One to utilize smart meters to identify and isolate outages as well as confirm power restoration. This investment is expected to achieve a fifty percent reduction in unnecessary truck rolls. This will translate to total annual savings of $2 million of OM&A.

With additional intelligent devices on Hydro One's distribution network, new data streams can be leveraged to improve distribution planning and operations. By leveraging data from the existing smart meters and the newly installed distribution automation devices, Hydro One will be able to produce new analytics that enable deeper insights into the distribution system. This includes more granular identification of distribution network loading.

3.3.7 (5.4.1 H) LIST OF PROJECTS PLANNED TO ADDRESS CUSTOMER, TECHNOLOGY, AND INNOVATION

The following is the list of the projects planned in response to Customer Preferences.

Table 58 - Projects in Response to Customer Preferences

ISD #	Name	Total Cost ($M)
SS-06	Worst Performing Feeders	49.9
GP-16	Customer Self Service Technology	12.9
GP-29	Customer Service Billing Investments	10.4
GP-30	Customer Service Regulatory Changes and Pricing Options	14.0
GP-32	Customer Data and Analytics	9.9
GP-33	Customer Service Complaint Management Tool	3.3

The following is the list of the projects planned to take advantage of technology opportunities.

Table 59 - Projects to Take Advantage of Technology Opportunities

ISD #	Name	Total Cost ($M)
SS-01	Remote Disconnection / Reconnection Program	28.5
SA-03	AMI Network Expansion	14.3
GP-12	Business Process Consolidation	2.7
GP-13	HR and Pay Related Technology Investments	5.0
GP-14	Warehouse Scanning Device Replacement	1.8
GP-31	Collection Enhancements	6.1

The following is the list of the projects planned to study or demonstrate innovative processes, services, business models or technologies.

Table 60 - Projects Driving Innovation

ISD #	Name	Total Cost ($M)
SS-07	Advanced Distribution System	5.0
GP-07	Corporate Performance Reporting	3.5
GP-08	PCMIS Modernization and Optimization	1.6
GP-17	S4 HANA for Finance and Enterprise Asset Management	6.5
GP-35	Asset Analytics Risk Factor	2.0

3.4 (5.4.2) CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW

The capital expenditure planning process is part of Hydro One's Asset Management process. Hydro One's asset management goal is to identify and scope the optimal timing of capital investments and asset maintenance throughout the life cycle of its assets. This is done to manage risks and to support the achievement of Hydro One's Business Objectives, while managing total cost and customer rate impacts.

Investment Planning Process

For the planning of capital investments, Hydro One utilizes a comprehensive investment planning process for identification, prioritization and optimization of asset and capital investments. Details of the planning process are included in Section 2.1.

3.5 (5.4.3) DISTRIBUTED GENERATION CONNECTIONS

Distributed Generation ("DG") refers to small-scale generators that connect to the distribution system and produce electricity to serve local areas. DG Connections include the assets to support over 14,000 DG projects supplying approximately 2,500 MW of generation capacity. These projects are primarily solar and wind installations that range in size anywhere from a few kW to several MW.

Hydro One's asset strategy for distributed generation connections is to meet its distribution license requirements to connect generators that meet the principles set out in the Distribution System Code ("DSC"), and to perform Renewable Enabling Improvements (as defined in the DSC) to allow for the connection of DGs. In addition, all work is done in a timely fashion in order to meet customer schedules and maximize customer satisfaction.

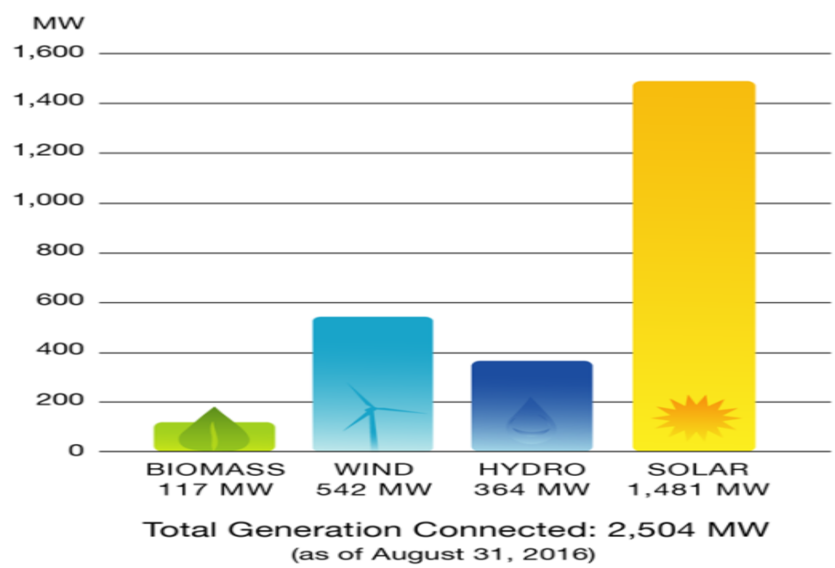


Figure 44 - Renewable Generation Connections

** Approximately 145MW of generation come from various sources other than those listed here for a total of 2,649.*

Witness: Lyla Garzouzi

3.5.1 (5.4.3 A) RENEWABLE APPLICATIONS

The Renewable Energy Standard Offer Program ("RESOP") launched by the Ontario Power Authority ("OPA") in 2006 attracted a tremendous amount of interest in connecting renewable energy generation to distribution systems in Ontario. Hydro One received the majority of the applications under this program in its large, rural service territory. The cost for connecting the RESOP projects to Hydro One's distribution system was 100% recoverable from the generation customer.

In 2009, the OPA launched the Feed-in Tariff ("FIT") program and the OEB amended the Distribution System Code ("DSC") to facilitate the FIT program. The FIT prices paid to developers for the renewable energy produced were higher than RESOP. In addition, there was a change in cost allocation of distribution investment costs to be borne by the generation customers and the distributor. The revised DSC required Hydro One to fund a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement ("REI") investments for renewable energy generation projects. The generation customer paid for connection assets, the expansion cost exceeding $90,000 per MW, and upstream station upgrades, if required.

3.5.2 (5.4.3 B) CONNECTION FORECAST - DISTRIBUTED GENERATION

The vast majority of DG and renewable connections are for small, microFit projects. These units possess a generation capacity of 10kW or less per unit and comprise less than 10% of the capacity of the DG connections on the system. At time of writing, Hydro One has received over 13,885 applications and has connected 13,429 with a total capacity of 121.8 MW of generation.

Among the larger generators, since 2010 Hydro One has received over 1,140 applications for connections greater than 10kW. So far 989 generators have been connected with a total capacity of approximately 2,025 MW.

Based on the definitions in the DSC, Hydro One classifies DGs into four categories for planning purposes.

1. Capacity Allocation Required ("CAR"), this includes large DGs, mid-sized DGs and Small embedded DGs that are not capacity allocation exempt;
2. Capacity Allocation Exempt ("CAE");
3. Capacity Allocation Exempt generators that are Net-Metered ("CAE-NM"); and
4. Micro embedded (10kW or less) – including MicroFIT.

Table 61 details the additions to the system in terms of quantity and capacity of generation projects from each of the four segments.

1 **Table 61 - DG Connections Committed and Connected – 2010-2017**[1]

2

		Connected								Committed	
Year		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**	**2016**	**2017**
CAR	**Projects**	40	24	25	49	60	62	19	**279**	30	19
	Capacity (MW)	315.5	159.5	220.9	342.4	468.1	326.2	65.5	**1,898.1**	127.8	66.4
CAE	**Projects**	1	75	141	102	142	182	53	**696**	60	38
	Capacity (MW)	0.5	11.6	22.8	18.6	24.4	34.4	13.7	**126.0**	14.5	14.8
CAE Net Metered	**Projects**	1	0	2	1	1	6	3	**14**	4	0
	Capacity (MW)	0.1	0.0	0.2	0.2	0.03	0.3	0.2	**1.1**	0.3	0.0
Micro Embedded	**Projects**	2,462	5,389	2,353	1,489	617	584	535	**13,429**	446	10
	Capacity (MW)	21.5	49.6	21.9	13.2	5.4	5.3	4.9	**121.8**	4.0	0.1
Total	**Projects**	2,504	5,488	2,521	1,641	820	834	610	**14,418**	540	67
	Capacity (MW)	337.6	220.7	265.9	374.5	497.9	366.2	84.3	**2,147.0**	146.7	81.3

[1] Approximately 502 MW of DG was connected prior to 2010.

The following Government initiatives have recently been put in place through the IESO (formerly OPA) to procure renewable energy for the province of Ontario.

- The FIT 4.0 procurement has concluded as the Independent Electricity System Operator (IESO) prepares to offer 936 new Feed-in Tariff (FIT) renewable energy contracts as per IESO website link given below. These FIT 4.0 contracts represent 241 MW of power.[2] Out of 936 new CAR and CAE contracts assigned by the IESO under FIT 4.0 program, 379 are in Hydro One territory.
- The FIT 5.0 Program was created to procure an additional 150MW of capacity of all capacity allocation types (CAR and CAE). Fit 5.0 will also classify microFIT projects as CAE due to the cancellation of the microFIT program at the end of 2017.[3] The process of assigning contracts under the FIT 5.0 program is complete and its application period opened on October 31, 2016.
- The Hydroelectric Standard Offer Program (HESOP) was developed to procure new hydroelectric capacity in Ontario in two streams. The municipal stream procured a total of 10MW of CAR projects between 500kW and 5MW and 50MW of CAR projects 5MW or larger. In addition the expansion stream had a procurement total of an additional 40MW.[4]
- The Combined Heat and Power Standard Offer Program (CHPSOP) 2.0 was developed to support the efficient use of gas-fired electricity generating facilities that use combined heat and power (CHP) technology. It procured 92MW of CAR projects each up to maximum of 20MW in size.[5]

---

[2] http://fit.powerauthority.on.ca/newsroom/newsroom-2016/June-29-2016-Contracts-Offered-for-FIT-4
[3] http://fit.powerauthority.on.ca/newsroom/newsroom-2016/August-26-2016-Final-FIT-5-0-Materials-Posted
[4] http://www.powerauthority.on.ca/hesop
[5] http://www.powerauthority.on.ca/combined-heat-power-procurement

- The Energy Storage Procurement Program was developed to explore the use of energy storage on Ontario's grid and has resulted in total of 50.3MW of CAR projects being connected in two phases.[6]
- The Large Renewable Procurement (LRP) I process concluded in April 2016, with the execution of 454.885 megawatts of new wind, solar, and waterpower contracts as per IESO directive.[7] There are nine LRP1 contracts for total of 57.4 MW under Hydro One distribution territory.

Based on the Government directive and procurement targets and DG connection investment carryovers of the previous Renewable Energy Standard Offer Program ("RESOP") and FIT program, the number of projects forecast for 2017 to 2022 is shown in the Table 62. The corresponding data source is listed for each group. Notable in this forecast is the change in volumes for small generation from the microFIT program to a net metering program.

[6] http://www.ieso.ca/Pages/Participate/Energy-Storage-Procurement/default.aspx
[7] http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx

Table 62 - Forecast DG Connections – 2017-2022

		Forecasted					
Year		2017	2018	2019	2020	2021	2022
CAR	Projects	8	6	5	5	5	5
CAE	Projects	200	200	170	160	110	110
CAE Net Metered	Projects	17	295	280	305	335	370
Micro Embedded	Projects	500	200	200	20 0	200	200

3.5.3 (5.4.3 C, D, E) CAPACITY AND CONSTRAINTS – DISTRIBUTED GENERATION

The capacity required to connect the forecasted level of DG connections is available on different distribution stations all across the Hydro One distribution system. Hydro One provides information on station capacity in order to provide potential generation customers with assistance in determining a suitable location for their generation projects.

The Hydro One distribution system is radial in design, with limited transfer capability in the supply to customers. The system was designed with a forward power flow direction with the supply coming from the transmission system flowing downstream to the customers.

When distributed generation is connected to Hydro One's distribution system it may lead to operational issues that must be assessed and addressed before connections can be made. First, under certain conditions, power may flow in the reverse direction leading to required protection system upgrades to ensure effective operation of the protection system in all situations. Second, the reverse power flow may also lead to an unacceptable voltage rise above the Distribution System Code limits, requiring Hydro One to upgrade system equipment. Finally, added generation sources lead to increased fault current levels and may require that protective devices be replaced and upgraded to meet the new fault levels.

Operational issues stem from the DG fault current contribution and potential reverse power flow as a result of the DG connection. Reverse power flow may lead to unacceptable voltage increases in the distribution system, which would necessitate upgrades to the voltage regulating devices or conductor size to mitigate this effect. Reverse power flow through metering devices will require replacement with bi-directional devices. DG fault contribution leads to increased fault levels and may require protective devices to be replaced with higher interrupting ratings. The DG fault contribution may also cause mis-operation of existing protection equipment, requiring bi-directional protective devices be installed.

The amount of generation capacity connected to Hydro One's distribution system is constrained by a variety of engineering factors, including but not limited to:

- Equipment ratings;
- Reverse power flow constraints;
- Supply feeder current ratings;
- Power Quality; and
- Remaining short circuit capacity at TS stations.

The impacts of connecting potential generators are studied on each application. Upgrades to both lines and stations equipment may be required to mitigate the above factors and ensure that unsafe flows do not occur.

A local distributor embedded within Hydro One's distribution system that is seeking to connect a new generator to its system would need to account for the same factors as a generator connecting directly to Hydro One's distribution system. Equipment ratings, power flow constraints, and short circuit impacts on the embedded distributor and Hydro One systems would need to be studied for each connection application. Upgrades may be necessary at both distribution and/or transmission stations to mitigate these factors.

3.6 (5.4.4) CAPITAL EXPENDITURE SUMMARY

Table 63 - (Table 2) Capital Expenditure Summary

CATEGORY	Historical (previous plan and actual)											Forecast (planned)				
	2013 [1]	2014 [1]	2015			2016			2017 Bridge [2]			2018	2019	2020	2021	2022
	Plan	Plan	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Test	Test	Test	Test	Test
	$M	$M	$M		%	$M		%	$M		%	$M	$M	$M	$M	$M
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3	149.0	187.1	135.8	133.4	136.6
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)	633.9	756.8	719.0	740.7	827.2
System OM&A [3]	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)	584.8	593.3	601.9	621.4	630.4

1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.

2) Bridge year 2017 is a forecast as of end of 2016

3) System OM&A values include all Operations, Maintenance and Administration expenses.

For explanatory notes on Shifts in Forecast vs. Historical Budgets by Category, please see Section 3.6.1.

For explanatory notes on Plan vs. Actual Variance Trends by Category, please see Section 3.6.2.

3.6.1 (5.4.4 – TABLE 2) SHIFTS IN FORECAST VS. HISTORICAL BUDGETS BY CATEGORY

System Access

System Access investments are expected to modestly decrease from historical levels in 2018 continuing the trend from 2014. The decrease is primarily due to the completion of the advanced meter infrastructure investment for the planned phase out of CDMA technology in meters and collectors in 2017 and a decrease in spending for generation connections (ISD SA-05). From 2018 to 2020 system access investments are expected to increase marginally until 2021 and 2022 where there is an increase due to the incorporation of the Acquired Utilities (Norfolk, Haldimand, and Woodstock) which are incorporated into the investment plan in 2021.

System Renewal

System Renewal spending will gradually increase above historical levels starting in 2019. The additional spending is required to replace end-of-life wood poles (ISD SR-09), relocate off-road feeders that are currently on poles in poor condition (ISD SR-12), and refurbish distribution stations (ISD SR-06). The increased spending is needed to address an aging infrastructure, characterized by a large number of assets in poor condition. The objective over the planning period is to maintain reliability performance and this level of spending is designed to accomplish this objective. In 2022, there is a significant increase forecast in System Renewal spending due to the planned replacement of Hydro One's metering infrastructure that is reaching end of life (ISD SR-14).

System Service

System Service spending will remain within historical spending levels from 2018 to 2022. This represents a decrease as compared to previous budget amounts. This reflects a more realistic stance on the ability to complete the necessary work.

General Plant

General Plant spending increased in 2016 above historical levels and is projected to continue to increase through 2019 before decreasing. The increases from 2017 to 2019 are attributed to: (a) capital contributions to three major transmission projects (ISD GP-25, GP-26, GP-27); (b) an increase in real estate spending to replace end of life operation centres or accommodate an increase in operational activity (ISD GP-02); (c) a major investment in the Integrated System Operating Centre which is required to maintain compliance with several regulatory requirements (ISD GP-18); and (d) IT investments to implement mandated billing changes (ISD GP-30), improve customer service (ISD GP-28, GP-32, GP-33) and improve work efficiency and planning (ISD GP-10, GP-11).

3.6.2 (5.4.4 – TABLE 2) PLAN VS. ACTUAL VARIANCE TRENDS BY CATEGORY

System Access

From 2013 to 2014 there was an increase in System Access spending of about $40 million. This increase was due to unplanned defective meter replacement, the initiation of the phase out of CDMA technology in meters and collectors and an increase in demand driven customer connection requests. Overall spending across System Access investments for 2015 and 2016 was generally in line with plan levels. However, $42 million above planned spending was caused by an accelerated meter replacement investment. Hydro One planned to phase out CDMA technology in meters and collectors over a five-year period, but this was compressed to two years because a vendor declined to support the technology beyond the two-year window. This increase was offset mostly by a reduction in generation connections. Hydro One had forecast $55 million of connection work, but due to the withdrawal of several connection applications, the actual work completed totalled $23 million.

System Renewal

In 2015, System Renewal projects were $58 million above planned spending. Most of that variance is attributable to the following 4 items. A total of $29 million was due to increased spending on distribution station refurbishment projects to address the high number of stations in poor condition. Increased work on line relocation projects, for the purpose of improving access and reliability, contributed $13 million to the overage. Projects from previous years were under construction and had significant portions carry over into 2015. Increased storm damage and trouble call activity contributed another $14 million to the spending above planned levels.

System Renewal investments for 2016 were $23 million above plan. Spending on storm, trouble call and post-trouble response was the largest source of variance at $22 million above planned levels. Distribution station refurbishments and line sustainment projects, for the purpose of improving access and reliability, accounted for $15 million and $4 million of the overage, respectively. Pole replacement program spending was $5 million less than planned. Additionally, station spare transformer purchases and PCB equipment replacement spending were $12 million and $3 million less than planned, respectively.

The current 2017 forecast for System Renewal investments is $33 million below the previous approved plan due to deferral of the PCB Equipment Replacement Program to future years, a decrease in the Pole Replacement Program, a decrease in Distribution Line Sustainment Initiatives and a decrease in Distribution Station Refurbishments as a result of reprioritized spending into General Plant investments, which are elaborated on below.

System Service

System Service investments were $49 million below planned investment levels in 2015 and $26 million below planned spending in 2016. The 2015 variance is due primarily to a $17 million variance attributable to a delay in the start of the Advanced Distribution System project. Several initiatives of this project were delayed to start in 2016 to align with other related investments. Also, $27 million in 2015 and $25 million in 2016 below planned spending levels were due to a reduction in spending on investments related to distribution system expansion. These investments were reprioritized to accommodate unforeseen increases in other areas of capital spending.

The current 2017 forecast for System Service investments is $43 million below the previous approved plan primarily due to a reduction in investments for System Upgrades driven by load growth as a result of reprioritized spending into General Plant investments, which are elaborated on below.

General Plant

The General Plant over spending in 2015 ($15 million) and 2016 ($43 million) was primarily a result of the following investments:

- $8 million of the overage in 2015 is due to the implementation of efficiencies in the Customer Service Organization's (CSO) operations needed to receive reduced pricing specified on the CSO's single source agreement with Inergi LP;
- $8 million above planned spending in 2015 was due to the Telematics Project undertaken by Hydro One Fleet Services. This project was not planned at the time of the rate filing however it was undertaken to realize productivity efficiencies in the fleet operations from 2017 onward. The Telematics Project will allow Hydro One to lower costs related to fleet operation by reducing non-productive idling and speeding as well as increase the overall fleet utilization;
- $9 million above planned spending in 2016 was to implement customer alert and analytics functionalities. Customers will be alerted if their consumption is trending higher than a pre-defined threshold and receive personalized insights and program promotions. Customers will be able analyze their energy usage through an enhanced web portal. As a result of these investments, Hydro One anticipates improved customer experience and satisfaction, increased customer engagement, and ultimately a reduction in calls to the call centre;
- $6 million above planned spending occurred in 2016 to redesign the Hydro One website to make it more user-friendly to address customer concerns about performance, navigability and mobile responsiveness. The customer “My Account” portal will be upgraded to improve customer experience. The intended result is improved customer satisfaction with the portal, increased customer engagement, and a reduction in calls to the call centre;
- $10 million above planned spending occurred in 2016 to make improvements to SAP, Hydro One’s integrated financial planning, work management and billing environment. Several improvements were implemented and are listed below:

- A new testing environment was implemented to simplify bi-annual rate changes and will reduce costs associated with future system updates;
- The financial reporting module was approaching end of support and was updated to the latest version. The new version of the software automates several financial reporting processes and will reduce the time and manual effort to produce reports while increasing reporting accuracy; and
- The billing module was updated to improve the accuracy of monthly bills and to track unbilled revenue. The module was also updated to improve the collections process by enabling security deposit functionality and fraud checking.

- $10 million of the overage in 2016 was due to the construction of a new Bolton operation centre, which provides a permanent location for field crews. This will reduce costs via lower commute times to work sites and increase service response to a high growth area of Hydro One's service territory; and
- $7 million of the overage in 2016 was due to the "Move-to-Mobile" project. This goal of this project is to increase operational efficiency by improving the use of technology by field staff. Field staff and schedulers will have real-time information updates which will reduce manual administrative effort and drive productivity by improving scheduling, dispatching and reporting workflows. In the last distribution rate filing (EB-2013-0416), the project was targeted to take five years to complete. However, during the discovery phase of the project, it was identified that overall project costs could be reduced by shortening the execution timeline to three years with a majority of the spending happening in 2016. The reduction in overall project costs will be achieved through reduced project management and change management costs.

The current 2017 forecast for General Plant investments is $56 million above the previous approved plan primarily due to the following investments:

- $23 million increase in investments for customer centric Information Technology investments such as, Web Redesign, eBilling Customer Usage Analytics, Bill Redesign, Contact Centre – Customer Insight and Data, and CTI Replacement;
- $10 million is due to unplanned Transmission Capital Contributions for Enfield TS (ISD GP-27) Leamington TS (ISD GP-25) and Hanmer TS DESN (ISD GP-26); and
- $12 million is due to an increase in common Information Technology investments that serve both the transmission and distribution business.

3.6.3 (5.4.4) IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING

Hydro One has a number of capital investments that reduce Hydro One Operations, Maintenance & Administration ("OM&A") spending. Several examples of capital initiatives that reduce OM&A costs are listed below.

Hydro One is investing in mobile technology to improve the productivity of the Provincial Lines organization. The investment will reduce inefficiencies, time delays and data inaccuracies in the scheduling, dispatching and execution of work completed by Provincial Lines. The investment will leverage existing technology like SAP and Hydro One's geographical information system. The investment is expected to achieve a five percent productivity gain across the organization which will translate to total annual savings of $13 million, $3 million of this being directly related to OM&A (ISD GP-10).

Hydro One serves approximately 1.3 million customers. To effectively manage customer accounts, there are between 10,000 and 21,000 trips each year to disconnect and reconnect customers. An investment in meters with remote connect and disconnect functionality is planned to eliminate approximately 6,000 of these trips each year. This will result in estimated annual OM&A savings of $4.5 million (ISD SS-01).

Further detailed discussion on OM&A is included in the application throughout Exhibit C1.

Witness: Darlene Bradley

3.7 (5.4.5.1) LIST OF MATERIAL CAPITAL INVESTMENTS PROPOSED

Below is a list of the Investment Summary Documents ("ISD").

Each ISD includes a priority.

- "**Demand**" Priority refers to those projects that are part of Demand Work and are effectively non-discretionary in nature. Not completing these projects is likely to cause or extend failures on the system. Completion of these activities may be necessary to satisfy legislative or regulatory directives.
- **"High"** Priority projects ranked highest in the risk matrix. Failure to complete is expected to have significant impacts on the risk profile of the system in the short term.
- **"Medium"** Priority projects represent the largest group of projects. If reductions are required and sufficient savings are not available from the Low priority group, the Medium items would be reviewed as well for possible decreases in spending.
- **"Low"** Priority is for those projects ranking among the lowest group in the risk prioritization methodology. These projects are important to Hydro One but should a reduction in spending be necessary, Hydro One would look at these projects first for cost savings. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

Ref #	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
System Access						
SA-01	Joint Use and Line Relocations Program	21.7	22.0	22.2	22.6	22.8
SA-02	Meter Infrastructure Sustainment	14.3	14.8	15.1	15.6	16.1
SA-03	AMI Network Expansion	3.0	2.9	2.9	2.7	2.8
SA-04	New Load Connections, Service Upgrades, Cancellations and Metering	109.9	112.9	115.7	120.0	123.2

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
SA-05	Generation Connections	4.1	3.4	3.3	2.9	3.0
Projects Under $1M		1.6	1.6	1.7	2.1	2.1
Subtotal – System Access		**154.6**	**157.6**	**160.9**	**165.9**	**170.0**
System Renewal						
SR-01	Distribution Station Demand Program	2.3	2.3	2.4	2.6	2.7
SR-02	Mobile Unit Substations Program	3.5	5.7	5.8	5.9	6.0
SR-03	Station Spare Transformer Purchases	2.6	3.4	4.1	4.2	4.3
SR-04	Distribution Station Component Planned Replacement Program	1.9	2.0	2.0	2.5	2.6
SR-05	Distribution Station Reclosers Upgrade	2.3	2.3	2.4	2.5	2.5
SR-06	Distribution Station Refurbishments	15.0	29.6	33.8	34.5	35.2
SR-07*	Distribution Lines Trouble Call and Storm Damage Response Program	75.6	77.1	78.5	80.5	82.0
SR-08	Distribution Lines PCB Equipment Replacement Program	11.6	11.8	12.1	18.5	18.9
SR-09	Pole Replacement Program	73.8	112.1	127.9	131.3	133.9
SR-10	Distribution Lines Planned Component Replacement	9.1	6.0	6.1	7.1	7.0
SR-11	Component Replacement Submarine Cable	7.5	7.7	7.8	8.0	8.2

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
SR-12	Distribution Lines Sustainment Initiatives	22.3	31.1	30.9	33.8	33.7
SR-13	Life Cycle Optimization and Operational Efficiency Projects	20.5	27.1	22.4	29.0	34.9
SR-14	AMI Hardware Refresh	0.0	0.0	0.0	1.4	78.5
Projects Under $1M		0.6	0.5	0.5	0.7	0.7
Subtotal – System Renewal		**248.6**	**318.7**	**336.7**	**362.5**	**451.1**
** A portion of SR-07 funding is reported in System Service.*						
System Service						
SS-01	Remote Disconnection Reconnection Program	5.8	5.8	5.7	5.6	5.6
SS-02	System Upgrades Driven by Load Growth	40.4	51.4	42.9	32.7	22.6
SS-03	Reliability Improvements	4.6	7.0	6.3	7.2	8.1
SS-04	Demand Investments	3.6	3.7	3.8	4.3	4.4
SS-05	Distribution System Modifications	7.3	7.2	8.0	8.8	8.8
SS-06	Worst Performing Feeders Program	7.1	10.1	10.5	10.9	11.3
SS-07	Advanced Distribution System	5.0	0.0	0.0	0.0	0.0
SR-07*	Distribution Lines Trouble Call and Storm Damage Response Program	7.1	7.3	7.4	7.7	7.8
Projects Under $1M		0.9	0.9	1.0	1.6	0.9

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
Subtotal – System Service		**81.8**	**93.4**	**85.6**	**78.8**	**69.5**
** A portion of SR-07 funding is reported in System Renewal.*						
General Plant						
GP-01	Transport and Work Equipment	35.0	39.5	40.4	42.0	44.1
GP-02	Real Estate Facilities Capital	35.4	42.9	36.9	36.9	33.9
GP-03	MFA Servers and Storage	3.2	3.2	3.2	3.2	3.2
GP-04	MFA PC and Printer Hardware	2.1	1.9	1.9	1.9	1.9
GP-05	Hardware/Software Refresh and Maintenance	3.9	4.1	4.1	4.1	4.1
GP-06	MFA Telecom Infrastructure	1.3	1.4	1.4	1.4	1.4
GP-07	Corporate Performance Reporting	1.5	2.0	0.0	0.0	0.0
GP-08	PCMIS Modernization and Optimization	0.0	1.6	0.0	0.0	0.0
GP-09	ECM - Phase C	0.0	0.0	0.2	0.9	1.0
GP-10	Work Management & Mobility	4.0	4.6	0.0	1.4	0.6
GP-11	Enterprise Geographical Information System	2.0	1.9	0.9	0.9	0.9
GP-12	Business Process Consolidation	0.0	0.0	1.5	1.2	0.0
GP-13	HR and Pay Related Technology Investments	0.5	2.9	1.6	0.0	0.0

Ref #	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
GP-14	Warehouse Scanning Device Replacement	0.7	1.1	0.0	0.0	0.0
GP-15	SAP Treasury	0.0	1.5	1.2	0.0	0.0
GP-16	Customer Self Service Technology	0.0	2.3	1.4	2.3	6.9
GP-17	S4 HANA for Finance and Enterprise Asset Management	0.0	0.0	1.2	1.7	3.6
GP-18	Integrated System Operating Centre - New Facility Development	10.5	42.6	3.3	0.0	0.0
GP-19	Operating Common Information Technology Infrastructure	2.7	1.4	0.8	2.1	4.1
GP-20	Network Outage Management System (NOMS) Refresh	1.1	0.0	0.0	0.0	0.0
GP-21	Ontario Grid Control Centre Data Centre Remediation	2.4	1.6	0.6	0.0	0.0
GP-22	Ontario Grid Control Centre Office Remediation	0.0	0.0	0.0	0.5	1.1
GP-23	Integrated Voice Communications and Telephony System Refresh	0.0	0.0	0.0	3.0	3.5
GP-24	Station Security Upgrades	1.1	1.1	1.1	1.2	1.2
GP-25	Leamington TS Capital Contribution	2.2	0.0	0.0	0.0	0.0
GP-26	Hanmer TS Capital Contribution	3.4	0.3	0.0	0.0	0.0

Ref #	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
GP-27	Enfield TS - Capital Contribution	2.0	1.0	0.0	0.0	0.0
GP-28	Call Centre Technology	7.5	0.0	7.2	2.9	0.0
GP-29	Customer Service Billing Investments	0.0	0.0	0.0	4.5	5.9
GP-30	Customer Service Regulatory Changes and Pricing Options	3.4	5.6	3.9	1.0	0.0
GP-31	Collection Enhancements	0.0	0.0	0.0	0.0	6.1
GP-32	Customer Data and Analytics	1.8	0.0	2.6	5.5	0.0
GP-33	Customer Service Complaint Management Tool	3.0	0.3	0.0	0.0	0.0
GP-34	Smart Meter Network Investments	2.5	6.9	4.0	1.4	0.0
GP-35	Asset Analytics Risk Factor	0.0	0.0	2.0	0.0	0.0
Projects Under $1M and Other Capital		15.8	15.4	14.4	13.4	13.1
Subtotal – General Plant		**149.0**	**187.1**	**135.8**	**133.4**	**136.6**

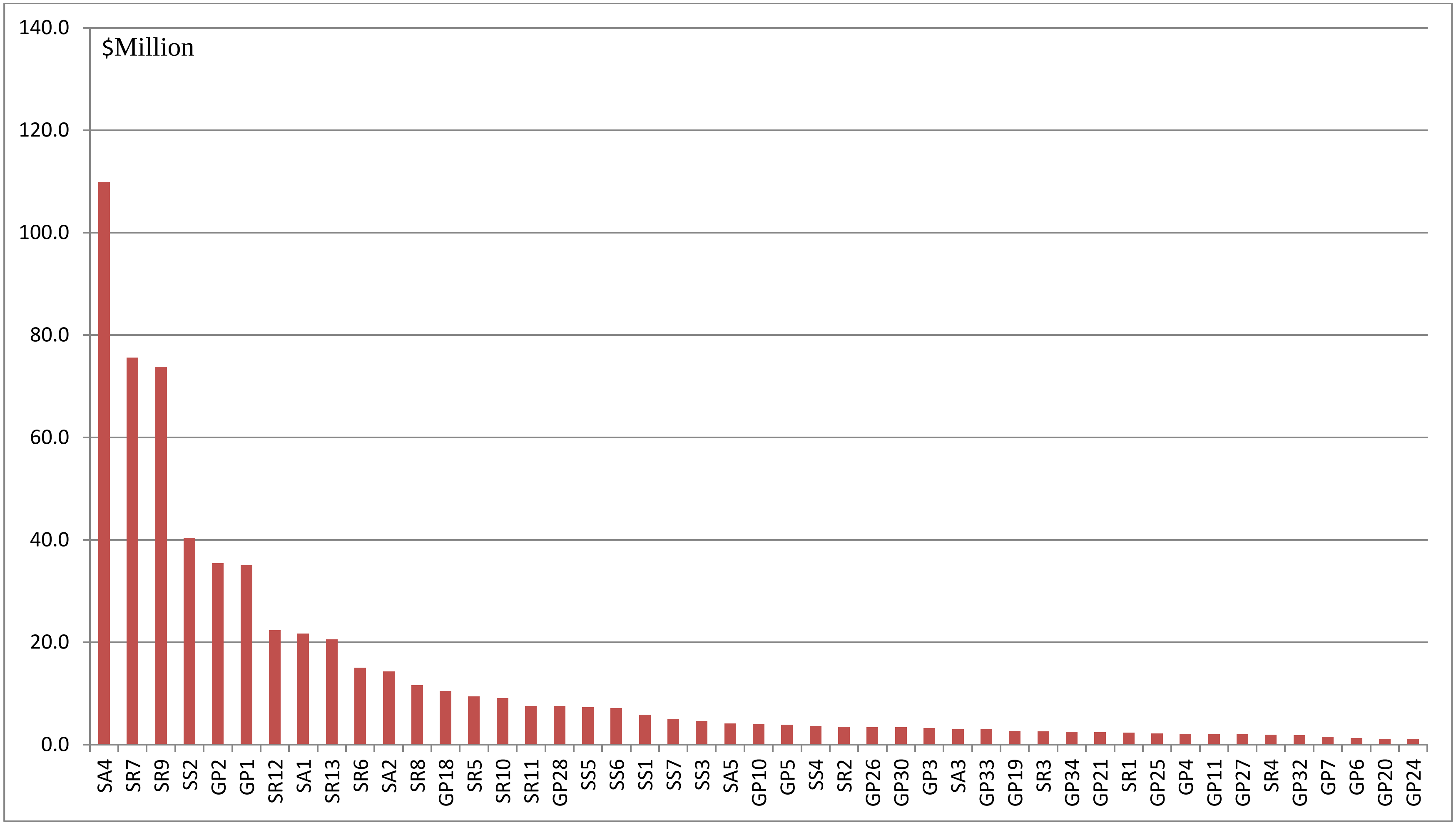


Figure 45 - Investments greater than $1 Million – 2018

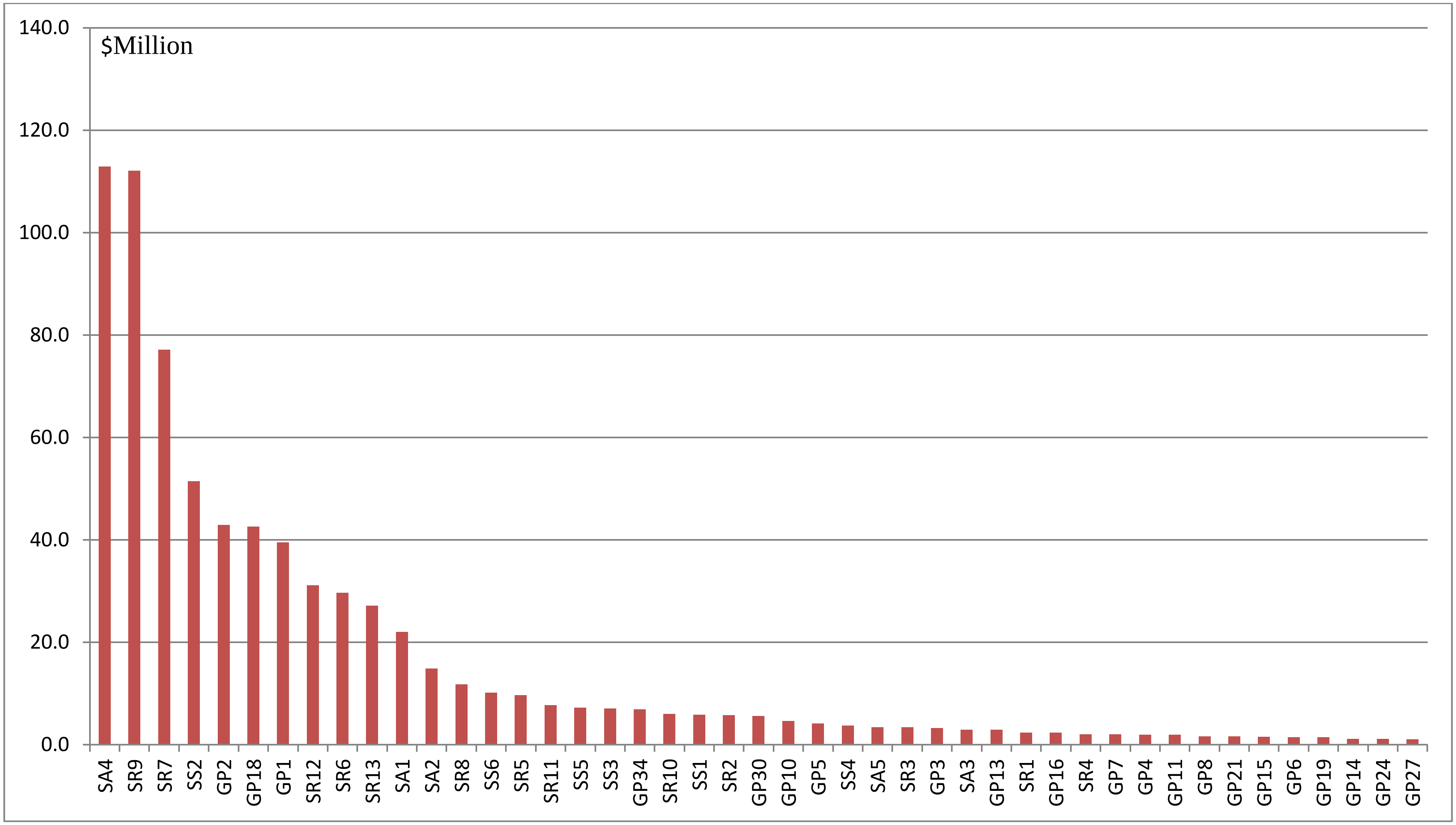


Figure 46 – Investments greater than $1 Million – 2019

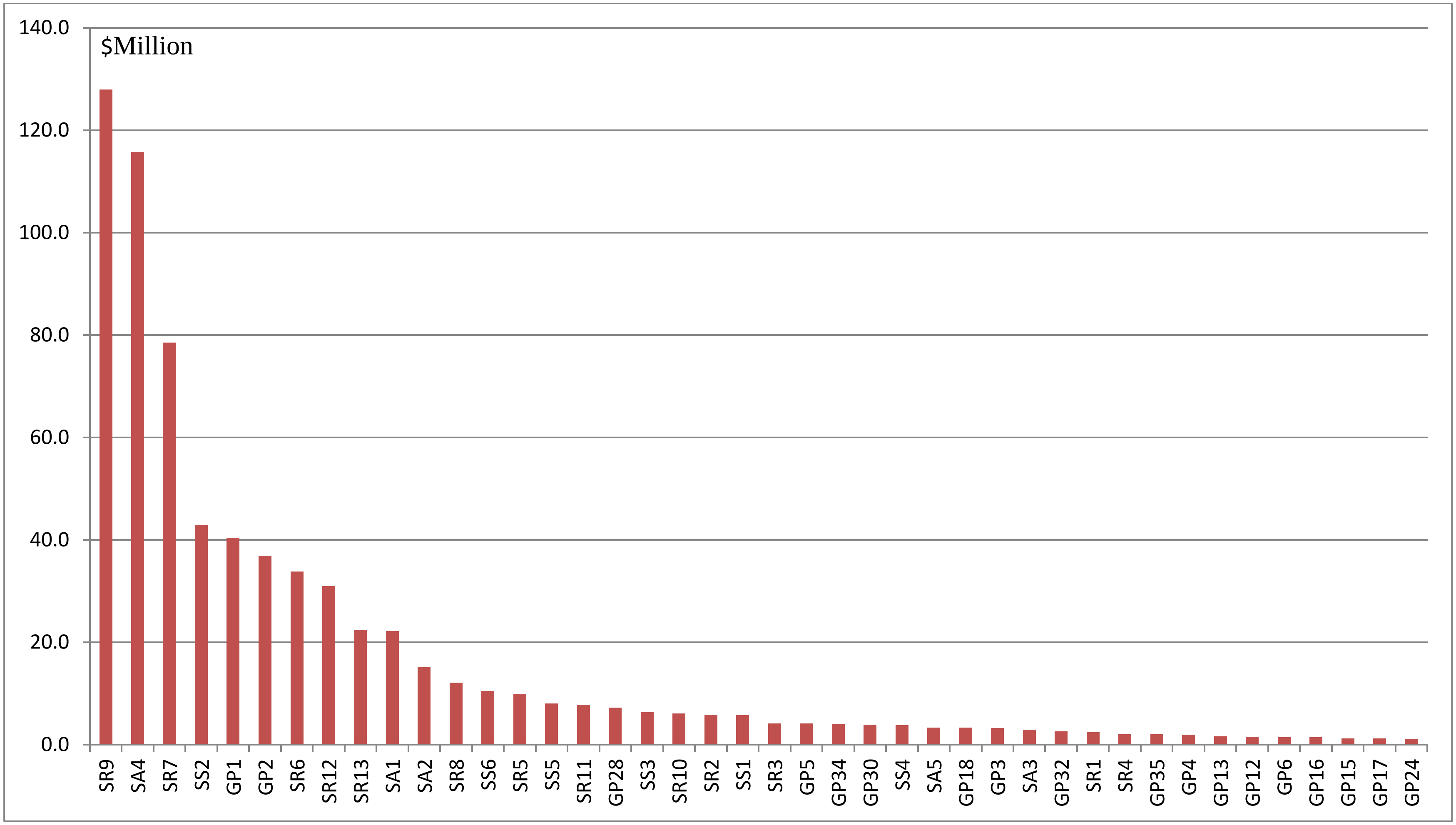


Figure 47 – Investments greater than $1 Million – 2020

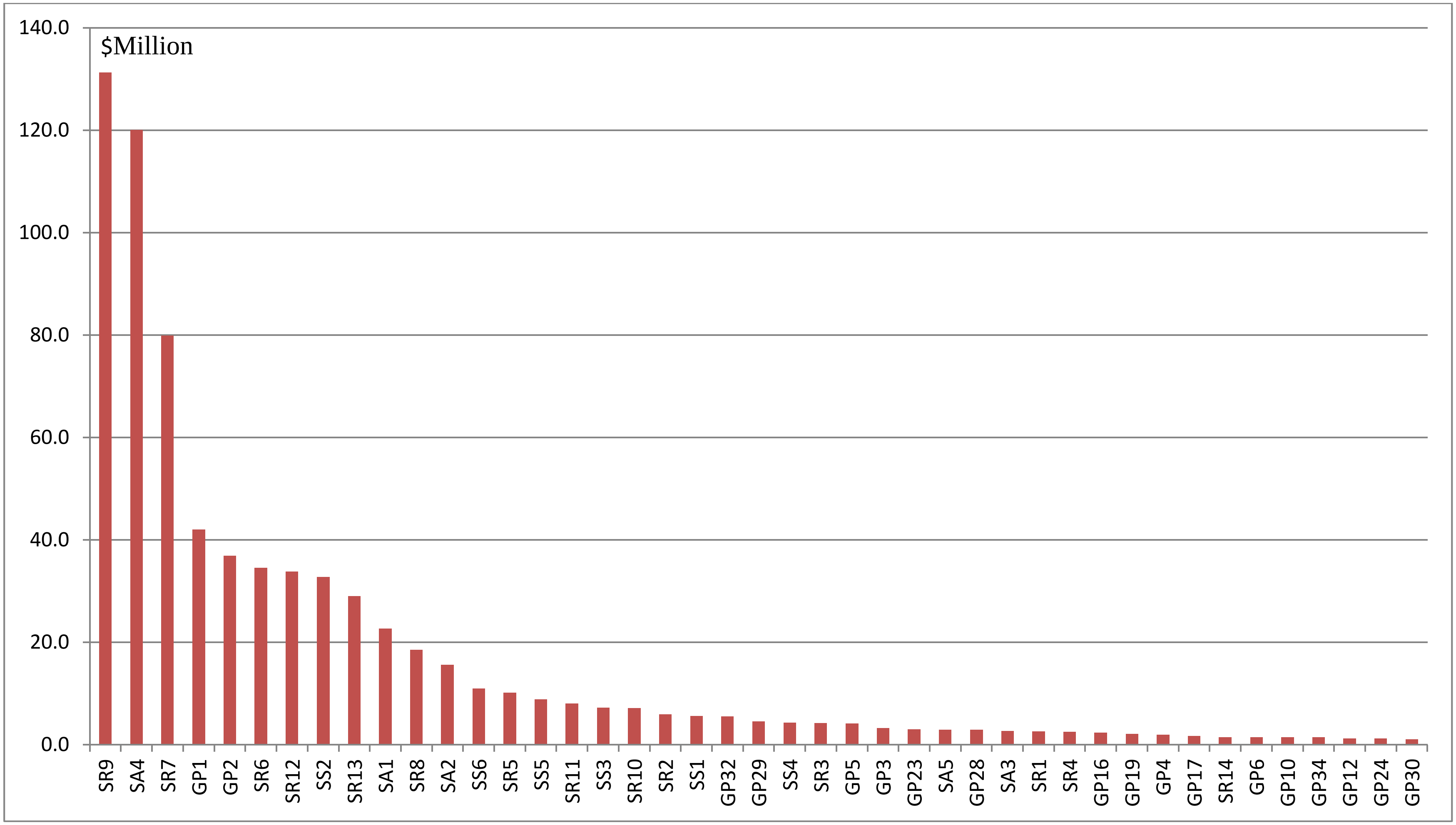


Figure 48 – Investments greater than $1 Million – 2021

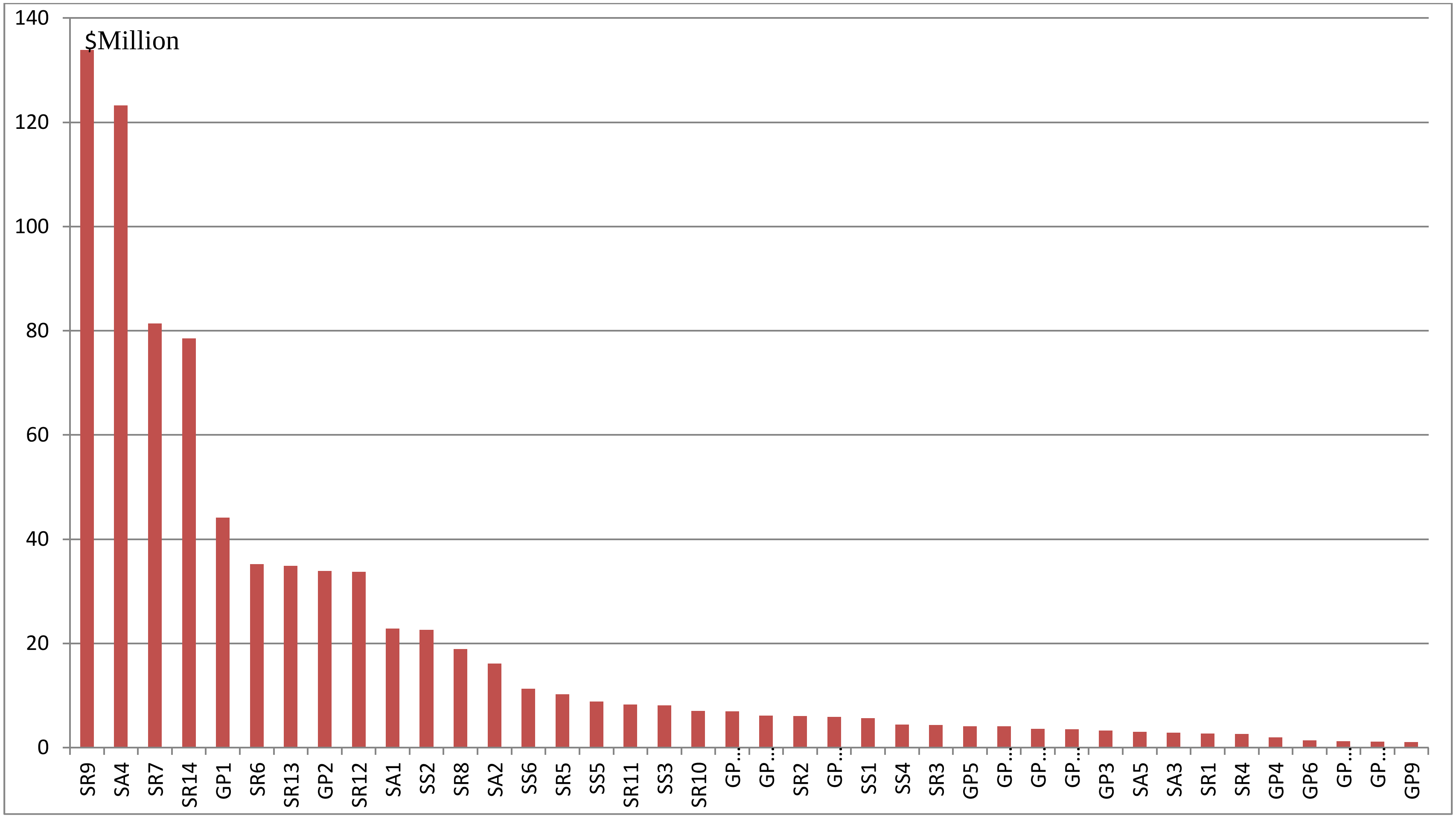


Figure 49 – Investments greater than $1 Million – 2022

3.8. (5.4.5.2) ATTACHMENTS: MATERIAL INVESTMENTS

SA-01 Joint Use and Line Relocations Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	111.3
Primary Trigger:	Infrastructure Development Requirement		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One must meet contractual obligations to joint use partners as per existing Joint Use Agreements. In addition, a growing number of distributed generators have become third parties on poles owned by Hydro One, causing an increase in the number of upgrades required to Hydro One's distribution assets required by other parties.

Hydro One is also obligated to perform line relocation work at the request of Municipal and Provincial road authorities as per the requirements of the *Public Service Work on Highways Act* and associated Ministry of Transportation guidelines, as well as line relocation work requested by customers in accordance with Hydro One's Conditions of Service.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to perform the requested work would place Hydro One in violation of contractual obligations with the third party joint use partners; as well as could jeopardize Hydro One's occupation rights on the public road allowance.

Investment Description:

This investment addresses the externally driven requirements for joint use work and line relocations, as noted below. Due to the demand nature of this work, the total number of joint use and line relocation projects can vary year to year from 250 to 400 projects annually; with the cost of each project being less than $1 million.

<u>Joint Use</u>

Joint Use investments alter or upgrade Hydro One distribution line equipment in order to accommodate the use of this equipment by joint use partners. These partners may include telephone or cable companies (communication circuits), municipalities (street lighting), local distribution companies, or generators connected to the distribution system.

The type of upgrade or change required may involve increasing pole class to accommodate changes in pole loading, and/or increasing pole height to obtain appropriate ground clearances for public safety. These activities may also carry the cost associated with premature retirement of in-service assets.

Cost sharing provisions in joint use agreements allow Hydro One to recover costs resulting from requests to accommodate new attachments to its poles.

Line Relocations

Line relocation investments alter the location of Hydro One distribution line equipment in response to road modifications initiated by road authorities or in response to property development initiated by individual customer requests.

Hydro One occupies road allowances at no cost. However in return, Hydro One is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate specific road authority or property development requirements. Most commonly, this involves relocating lines to accommodate changes to roads, highways, and bridges.

The cost of the plant relocation is either fully or partially recoverable, depending on the specific circumstances of each project.

Risk Mitigation:

The risk to completion of this investment as planned is the fluctuation and volume of projects which must be completed on annual basis. This program, driven by third party requirements, can be subject to changing requests and additions. These risks are mitigated by maintaining open communication channels with the third party agencies – reviewing priorities and timelines for project completion.

Result:

The joint use and line relocation program will result in:

- Satisfying Hydro One’s contractual and legal obligations with third party joint use partners, road authorities, and customers; and
- Maintaining property rights for distribution lines located on road allowances.

Outcome Summary:

Customer Focus	• Improve customer satisfaction with joint-use customers by providing joint use capabilities. • Deliver on customer requests in a timely manner.
Operational Effectiveness	• Realize reliability improvements, where possible, on upgrades or renewal of the distribution system in response to customer requests.
Public Policy Responsiveness	• Comply with contractual and legal obligations under the *Public Service Work on Highways Act* and Hydro One’s Conditions of Service.
Financial Performance	• Realize cost savings by cost sharing, where possible, on upgrades or renewal of the distribution system in response to customer requests.

Costs:

The average gross investment cost for this program over the five year period is in line with the average historic gross spend over the last 5 years. The factors which affect the costs in this investment are the volume of requests and scope of such requests. The costs for the joint use and line relocation program are based on projections from joint use partners including new generator customers, road authorities and property development customer requests. Provincial government infrastructure initiatives can cause an increased in project volumes. Any significant changes to these projects would affect the overall investment cost.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacement and coordinating joint use and relocation projects with other sustainment programs where feasible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	45.5	46.0	46.6	47.2	47.8	233.1
Less Removals	5.1	5.2	5.3	5.3	5.4	26.3
Gross Investment Cost	**40.4**	**40.8**	**41.3**	**41.9**	**42.4**	**206.8**
Less Capital Contributions	18.7	18.9	19.1	19.3	19.5	95.5
Net Investment Cost	**21.7**	**22.0**	**22.2**	**22.6**	**22.8**	**111.3**

**Includes Overhead at current rates.*

SA-02 Metering Infrastructure Sustainment Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	75.9
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. With an asset base of this magnitude, it is reasonable to expect that there will be a number of meters and network devices that will fail to operate as intended and must be replaced in a timely fashion.

With the introduction of smart meters in 2006, customer meters have the capability to provide billing settlement data electronically. However, any disruptions in the electronic communication due to the failure of a meter or network device (i.e., collector or repeater), results in an estimated bill being generated to which customers have routinely indicated their displeasure.

Furthermore, replacement of failed components is critical to maintain a reliable meter infrastructure network and resultant source of billing settlement data to satisfy the OEB Distribution System Code Section 7.11 “Billing Accuracy” requirement to have 98% billing accuracy.

Alternatives:

This investment is non-discretionary. No alternatives were considered, since failure to perform the work to repair and/or replace the meters and associate network would be in violation of the OEB Distribution System Code Section 5.1 "Provision of Meters and Metering Services" and has the potential to negatively impact the reliable source of billing settlement data.

Investment Description:

This investment addresses the like for like replacement of failed metering devices and the maintenance of an adequate level of inventory of metering devices to ensure timely replacement.

The meter inventory consists of meters, repeaters, collectors and other electronic components used in the meter infrastructure network. The required inventory levels are determined based on the population size of particular meter or equipment model, and historical failure rates. The annual inventory purchases are dependent on which categories of equipment were deployed to replace failed equipment each year.

Based on recent operational experience, Hydro One estimates the approximate number of devices, consisting of meters and various network devices, that are required to be removed and replaced each year are as outlined below. The forecasted number of meter devices procured are lower than the number replaced since a portion of failed metering devices may be repairable.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Metering Devices Procured	27,000	25,000	25,000	25,000	27,000
Number of Metering Devices Replaced	29,880	27,000	27,000	27,000	29,000

Risk Mitigation:

The risk to completion of this investment as planned is the potential unavailability of resources in certain locations. This risk is mitigated by managing program resources and hiring temporary staff as required.

Result:

The meter infrastructure sustainment program will result in:

- Ensuring timely availability of meters and network devices;
- Complying with regulatory requirements; and
- Ensuring a reliable source of billing settlement data that increases customer confidence and satisfaction that bills are accurate.

Outcome Summary:

Customer Focus	• Reduce unwanted estimated customer bills. • Reduce customer interruption time by maintaining an adequate level of components to ensure timely replacement of failures.
Operational Effectiveness	• Increase efficiency by reducing number of manual reads. • Maintain meter network reliability to ensure a reliable source of billing settlement data.
Public Policy Responsiveness	• Comply with OEB Distribution System Code requirements to provide accurate and timely billing. • Comply with the *Electricity and Gas Inspection Act* to ensure meter accuracy.
Financial Performance	

Costs:

The costs for this program are projected based on these historic labour costs, material unit costs, and future anticipated needs. The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts;
- The volume and types of meters and network devices requiring replacement; and
- The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.

Controllable costs have been optimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	14.9	15.4	15.7	16.3	16.7	79.0
Less Removals	0.6	0.6	0.6	0.6	0.6	3.1
Gross Investment Cost	**14.3**	**14.8**	**15.1**	**15.6**	**16.1**	**75.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**14.3**	**14.8**	**15.1**	**15.6**	**16.1**	**75.9**

**Includes Overhead at current rates.*

Witness: Lyla Garzouzi

SA-03 Meter Infrastructure Expansion Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	14.3
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	System Efficiency		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. With the introduction of smart meters in 2006, customer meters have the capability to provide billing settlement data electronically. Hydro One uses a metering infrastructure network to communicate with these smart meters; which has been constructed to take advantage of Canada and Rogers Communications ("the Carriers") cellular networks. However some of these meters cannot communicate reliably with Hydro One's meter infrastructure network, resulting in manually reading of these meters at specific intervals and estimated billing for the customer.

The OEB's Distribution System Code requires 98% billing accuracy, thereby limiting the use of estimated billing for customers. In the fall of 2015, Hydro One received an exemption from this OEB requirement to allow the use of estimated billing for approximately 170,000 customers with poorly communicating smart meters. This exemption was granted to the end of 2019.

Since that time, Hydro One has been working to establish reliable communication with these customers where economically viable in order to comply with the OEB direction for Hydro One to transition to time of use pricing. This improvement in communication levels is largely due to the success of the Carriers widening the capability of the cellular network. Another factoring contributing to the success was Hydro One's implementation of a flexible bill window, allowing billing data to be based on a meter read within a certain time frame rather than necessarily at a particular moment in time thereby creating a broader time window within which it can obtain a successful read.

Nonetheless, there remains approximately 123,000 meters that the meter infrastructure network still cannot communicate reliably with. By continuing to leveraging onging Carrier upgrades, there exists opportunties to allow more customers to communicate reliably.

Alternative 1: Maintain existing meter infrastructure network

Continue to operate the existing meter infrastructure network as is, and not leverage ongoing Carrier upgrades. This alternative is rejected as it will not improve the communication reliably nor does it align with OEB direction to move customers to time of use pricing and achieve 98% billing accuracy.

Alternative 2: Expand the meter infrastructure network *(Recommended)*

Expand the meter infrastructure network by leveraging the Carriers upgrades by installing collectors, repeaters and executing configuration changes to improve communicate reliably with meters. This alternative is recommended as it will reduce the resource requirements of manual meter reads and improve Hydro One's billing accuracy by reducing the number of meters with unreliable communication to 96,564 from 123,000 by the end of the five year period.

Investment Description:

This investment addresses the expansion of Hydro One's meter infrastructure network by leveraging the Carriers upgrades where economically viable. As the Carriers expand their network, Hydro One will expand their network by executing configuration changes and installing repeaters and/or collectors to enable reliable, remote, meter reading. This will result in a reduction of manual meter reading and the transfer of customers from two-tier billing to time-of-use rate schedules consistent with OEB direction for Hydro One to transition meters to time of use.

Hydro One has estimated that the proposed level of investment in the expansion of the communication network will result in approximately 26,436 customers transitioning from two-tier pricing to time of use over the five year period as outlined in the table below. In addition to meeting OEB guidelines, this will reduce the number of meters requiring manual meter reads.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Customers Transitioned to Time of Use	5,843	5,551	5,273	5,010	4,759

At the end of this period, approximately 96,564 meters (representing 78% of the existing 123,000 meters with unreliable communication) will still not have reliable communication and will remain on two-tier pricing, requiring exemption from the OEB requirement.

Risk Mitigation:

The risks to completion of this investment as planned are that the Carriers may not expand their networks at the forecasted rate or that their network expansion does not match the geographic areas where Hydro One is experiencing unreliable communication. These risks are considered low as there is a very competitive market demand for cellular service availability and performance that continues to drive the Carriers to expand their network.

Result:

The meter infrastructure network expansion program will result in:

- Providing reliable communication for remote reading of an additional 26, 436 meters; and
- Enabling the transition of 26,436 customers from two-tier to time of use pricing in accordance with OEB guidelines to do so where economically viable.

Outcome Summary:

Customer Focus	• Provide reliable remote meter reading enabling time of use pricing in order for customers to manage their electricity usage to reduce costs. • Increase customer confidence and satisfaction by providing a reliable communication network and reducing the number of bills issued on estimated data.
Operational Effectiveness	• Reduce resource requirements of manual meter reads.
Public Policy Responsiveness	• Comply with OEB direction to transition customers to time of use pricing, where economically viable. • Comply with OEB Distribution System Code Section 7.11 “Billing Accuracy” requirements to provide accurate and timely billing.

Financial Performance	• Avoid the cost of manual meter reading by reducing the number of meters with unreliable communication.

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The number of meters that can communicate reliably with a newly installed collector or repeater.

Controllable costs have been minimized through issuance of vendor contract to secure unit pricing for procurement of materials and the establishment of a standard on the minimum number of meters required to communicate reliably to justify installing a network device such as a repeater or collector.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.0	3.0	3.0	2.8	2.8	14.6
Less Removals	0.1	0.1	0.1	0.1	0.1	0.3
Gross Investment Cost	**3.0**	**2.9**	**2.9**	**2.7**	**2.8**	**14.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.0**	**2.9**	**2.9**	**2.7**	**2.8**	**14.3**

**Includes Overhead at current rates.*

SA-04 New Load Connections, Upgrades, Cancellations and Metering

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	581.6
Primary Trigger:	Customer Service Requests		
Secondary Trigger:	Mandated Service Obligations		

Investment Need:

Hydro One is obligated to connect new customers to the distribution network, upgrade services for existing customers, and install meters for new services under Hydro One's Distribution License. These system investments include the following activities:

<u>New Connections</u>**:** As part of its obligations under Hydro One's electricity distribution license and the distributor's responsibilities in the Distribution System Code ("DSC"), Hydro One is required to make an offer to connect all distribution customers on a non-discriminatory basis, upon written request for connection.

<u>Service Upgrades</u>: A service upgrade occurs when a customer requires a larger service entrance. A service upgrade normally requires the preparation of a service layout and replacement of secondary service lines. Transformers may also have to be upgraded, meters replaced and possibly additional transformation installed.

<u>Metering</u>: Installations may be required for new connections and service upgrades. Revenue meters, are funded under this program for new connections and service upgrades.

<u>Cancellations</u>: For cancellations of existing service, Hydro One is required to remove idle assets (such as transformers, poles, wires and meters) for safety and security reasons.

Alternatives:

Not proceeding with these investments would result in non-compliance with Distribution license requirements and with obligations under the DSC. This work is a regulatory requirement.

Investment Description:

Individual investments within these programs are managed on a project basis. Projects include design (service layouts), labour, material and other costs associated with actual physical connection or removal.

New Connections:

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to provide a connection service to new industrial, commercial, residential, and seasonal customers when requested. The division of costs between Hydro One and the customer is determined based on the company's connection policies, which are in accordance with the DSC requirements. A basic connection consisting of a service layout, overhead transformation, 30 metres of overhead conductor, and standard retail metering is provided free of charge to new customers that lie along the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and network expansion. Customer contributions for system expansions and other recoverable costs beyond the basic connection are forecasted to be between $32.9 million and $36.7 million between 2018 and 2022. Projected costs for these programs are primarily based on historic demand and forecast load growth.

Service Upgrades:

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to respond to existing customers who require a larger service to accommodate additional load and/or modify their electrical service entrance. These costs are classified as upgrade costs. A service upgrade normally requires the replacement of secondary service wires and the preparation of a service design. Also, it may be necessary to upgrade transformer(s), replace meters or install additional transformers. For standard service upgrades, Hydro One will provide a service layout, pole-mounted transformer, and the meter installation, if required. Costs for service modifications that exceed the cost of a standard installation would be recovered from the customer on a user-pay basis. Hydro One's customer capital contribution policies adhere to DSC requirements.

Service Cancellations:

Service cancellations are included in this program's "Removals" costs in the cost table in this document. These involve customers who request disconnection from the distribution system. Hydro One removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. As this work involves the removal of Hydro One owned equipment, these costs are accounted for under depreciation and are not capitalized.

The currently projected volume (number of units) of new connections, service upgrades and service cancellations from 2018 to 2022 is summarized in the table below.

Description	**2018**	**2019**	**2020**	**2021**	**2022**
New Connections	14,724	14,862	15,005	15,148	15,291
Service Upgrades	4,473	4,515	4,558	4,601	4,645
Service Cancellations	5,562	5,614	5,668	5,722	5,776

Risk Mitigation:

Hydro One connects several thousand customers to its distribution system every year. The main risk to this program is volume and timing of the customer requests. Every effort is made to prioritize these projects in order to meet the required service obligations. This prioritization and timing is completed at a service centre level through scheduling of work. Communication is maintained with the customer to ensure expectations are being met.

Result:

- Connect new customers and satisfy the requirements of the DSC and Hydro One’s distribution license;
- Upgrade the services of existing customers;
- Remove assets when services are cancelled and mitigate safety risks; and
- Satisfy the requirements of the DSC and Hydro One’s distribution license.

Outcome Summary:

Customer Focus	• Fulfill customer requests for connections and upgrades within established time frames to improve customer satisfaction.
Operational Effectiveness	• Ensure all new connections or upgrades meet latest standards. • Remove assets when services are cancelled to mitigate safety risks.
Public Policy Responsiveness	• Comply with requirements in the DSC and distribution licence to provide new connections or service upgrades when requested by customers.
Financial Performance	• Leverage financial benefits on company-wide productivity initiatives.

Costs:

Planned costs for the program are based on historic actual costs and a forecast of future load growth, factoring in future savings initiatives. The actual program costs will be comprised of the individual projects (connections, upgrades, cancellations) completed on an annual basis. Controllable costs are minimized by ensuring that all projects are completed using standard processes and within standard unit costs. Any unforeseen issues at a work location, outside the established unit cost, will result in increased costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	153.3	157.5	161.6	167.5	172.1	812.0
Less Removals	10.5	10.8	11.2	11.6	11.9	56.0
Gross Investment Cost	**142.8**	**146.7**	**150.5**	**155.9**	**160.2**	**756.0**
Less Capital Contributions	32.9	33.8	34.7	35.9	37.0	174.3
Net Investment Cost	**109.9**	**112.9**	**115.7**	**120.0**	**123.2**	**581.6**

**Includes Overhead at current rates.*

SA-05 Distributed Generation Connections

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	16.6
Primary Trigger:	Customer Service Requests		
Secondary Trigger:	Mandated Service Obligation		

Investment Need:

The Distribution System Code ("DSC") and Hydro One's distribution license obligate it to connect generation facilities that meet the requirements of the DSC. Hydro One's generation connection investments fund additions and modifications required to connect generating facilities to the distribution system. Generators make capital contributions to this work in accordance with Hydro One's connection policy and the DSC. Similar to load customers, Hydro One gives credit to the customer based on the forecasted load for station services of the distributed generator.

Alternatives:

This is a demand-based program for connecting new distributed generation. There are no viable alternatives as not proceeding with these investments would result in non-compliance with the requirements of Hydro One's distribution license and the DSC. This work meets a regulatory requirement.

Investment Description:

Individual investments within these programs are managed on a project basis. Projects involve estimating, design, labour, material and costs associated with actual physical connection of new generators.

Hydro One's investment plans are based on Ministry of Energy ("MOE") directives on distributed generation facilities and the IESO's Feed-in Tariff ("FIT") programs for distributed generators of different sizes, as well as other procurement initiatives from the IESO. The cost allocation requirements are as set out in the DSC. These determine the investments that are presented in this section.

The DSC divides DGs into five size categories: micro, capacity allocation exempt small, small, mid-sized and large. In Section 1.2 – Definitions, each of the five size categories is defined:

- Micro-embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 kW or less;
- Capacity allocation exempt small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line;
- Small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1 MW or less in the case of a facility connected to a 15 kV or greater line;
- Mid-sized embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 MW or less and a) more than 500 kW in the case of a facility connected to a less than 15 kV line; and b) more than 1 MW in the case of a facility connected to a 15 kV or greater line; and
- Large embedded generation facility – an embedded generation facility with a name-plate rated capacity of more than 10 MW.

Based on the definitions in the DSC, Hydro One places DGs into four categories for planning purposes:

1. Capacity Allocation Required (“CAR”) DGs which includes large DGs, mid-size DGs and small embedded DGs that are not capacity allocation exempt;
2. Capacity Allocation Exempt (“CAE”) DGs;
3. Capacity Allocation Exempt generators that are Net-Metered (“CAE-NM”); and
4. Micro-embedded DGs (including MicroFIT and Micro-embedded Net-Metered).

Hydro One makes lines and stations equipment upgrades to mitigate the above factors. The numbers of estimated projects are summarized below:

DG Category	Forecasted				
	2018	2019	2020	2021	2022
CAR	6	5	5	5	5
CAE	200	170	160	110	110
CAE -NM	295	280	305	335	370
Micro Embedded	200	200	200	200	200

At the time of writing, the identified material projects for 2018 are set out below.

Project	Name Plate Capacity (kW)	DG Category	Target In-Service
Kirkland Lake TS – DX Feeders	3,000	CAR – FIT project*	2018
Wendover HVDS – DX Feeders	12,000	CAR – Large renewable procurement project*	2018
Muskoka TS – DX Feeders	11,760	CAR – Large renewable procurement project*	2018

**Descriptions of FIT and large renewable procurement projects are provided in Section 3.5 of the Distribution System Plan.*

The connection requirements for each project vary depending on its size. For the CAR and CAE projects, the investments are broken down into three components: (1) Renewable Enabling Improvements ("REI") which are upgrades to existing lines; (2) "Expansions" which are actual line extensions; and (3) Connection Assets. The cost allocation for each component is based on Hydro One's connection policy and is in accordance with the DSC. All project connection costs are recoverable from the customer if the source of energy is non-renewable. If the source of energy is renewable, then a portion of the expansion cost (up to $90,000/MW) and 100% costs under REI is funded by Hydro One pursuant to the DSC. Costs of Expansions exceeding $90,000 per MW and the cost for any upstream station upgrades, if required, are recoverable in full from the customer.

Hydro One's distribution system is radial in design, with limited transfer capability to supply customers. The system was designed to move power from the transmission system downstream towards customers. As a result, the amount of generation capacity connected to Hydro One's distribution system is generally constrained by a variety of engineering factors, including but not limited to:

- equipment ratings;
- reverse power flow constraints;
- supply feeder current ratings;
- power quality; and
- remaining short circuit capacity at transmission stations.

These constraints are addressed on a project-by-project basis with engineering involvement when required. This may entail new line expansions, protection system upgrades, control system upgrades, new voltage regulators, voltage regulator control upgrades, line and station recloser upgrades. Associated costs include procurement, engineering, and project management costs associated with each project. Costs have been minimized through standardized design and procurement processes.

Consistent with the requirements of O. Regulation 330/09 under the *Ontario Energy Board Act*, *1998*, a portion of the costs associated with the connection of renewable generators is allocated to Hydro One ratepayers and a portion of the costs are allocated to all provincial ratepayers. The allocation of costs is explained in Exhibit G1. The allocation of costs to Hydro One ratepayers and provincial ratepayers is different for Expansion assets and for REI assets. Connection assets are paid for by the generator customer.

Risk Mitigation:

Hydro One connects many DGs to its distribution system every year on demand. The main risk to this planned execution of this program is volume and timing of the customer requests.

DG projects are prioritized in order to meet the required service obligations. This prioritization and timing is completed through scheduling of work. Hydro One maintains communications with the customer to ensure that all requirements are met so the parties can complete their connection by the agreed upon in-service date.

Result:

- Connect new generators and satisfy the customers' timelines;
- Upgraded distribution lines as required; and
- Compliance with the requirements of the DSC and Hydro One's distribution license.

Outcome Summary:

Customer Focus	• Improved customer satisfaction by connecting new generators within contractually established time frames.
Operational Effectiveness	• Ensure all upgrades reflect latest standards and future load and generator forecasts.
Public Policy Responsiveness	• Compliance with requirements in the DSC and Hydro One's distribution licence to connect qualifying generators.
Financial Performance	• Lower engineering costs using standardized design and work practices.

Costs:

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	16.1	14.6	14.4	13.4	13.7	72.3
Operations, Maintenance & Administration and Removals	-	-	-	-	-	-
Gross Investment Cost	**16.1**	**14.6**	**14.4**	**13.4**	**13.7**	**72.3**
Less Capital Contributions	12.0	11.2	11.1	10.5	10.7	55.7
Net Investment Cost	**4.1**	**3.4**	**3.3**	**2.9**	**3.0**	**16.6**

**Includes Overhead at current rates.*

SR-01 Distribution Stations Demand Capital Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	12.3
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Safety		

Investment Need:

Service interruptions or unplanned system deficiencies associated with various distribution station assets occur and require an immediate response by Hydro One personnel. Asset failure or extreme weather may result in service interruptions that require restoration of power to maintain reliability. Over the past five years, there has been an average of 59 interruptions per year related to station equipment.

Hydro One also performs station inspections; rural stations every six months and urban stations monthly. These regular inspections may also identify damaged or failed distribution station assets that pose a safety hazard or customers may report power quality issues. Hydro One is obligated to replace these assets in accordance with good utility practice and the requirements of the Distribution System Code.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to quickly respond to service interruptions or other situations where assets have failed would violate the Distribution System Code and result in unacceptable reliability and safety risks.

Investment Description:

This investment addresses the replacement of failing or failed distribution station equipment in a timely manner in order to maintain distribution system reliability, safety, and/or power quality in situations where the assets cannot be repaired, and replacement is the only viable option in compliance with the Distribution System Code. Stations are key critical assets in that a large number of customers are impacted by station related failures. Examples of the most common work that is undertaken under this distribution station demand program include:

- Replacement of power transformers that have failed or are failing, must be replaced immediately to maintain the integrity of the system, also transformers that generate customer complaints with noise levels that exceed the guidelines must be replaced to comply with the requirements set out by the MOECC;
- Replacement of assets that have become significantly overloaded due to unexpected customer loading variations;
- Replacement of failed reclosers, or reclosers whose fault interruption levels have become exceeded or are close to being exceeded; and
- Replacement of failed or failing insulators, switches or poles within the station.

These failures are difficult to predict, but must be addressed quickly because they generally result in customer interruptions or present significant safety risks. Planned expenditures in this investment are projected based on historical trends and adjusted to reflect recent experiences.

Risk Mitigation:

The work in this investment is unplanned in nature. However, there are risks to executing such unplanned work including the availability of the mobile unit substations ("MUSs") and engineering resources. These risks are mitigated by ensuring that there is always at least one MUS available for emergent work in each voltage/capacity category and by having a process to enable reprioritization of engineering resources to support the immediate and emergent work as required.

Result:

From this investment, customers will benefit from sustained reliability resulting from the replacement of failed, failing and overloaded station equipment in a timely manner. The replacement of failing and overloaded station equipment before the failures occur results in fewer customer interruptions. The replacement of failing equipment also mitigates safety issues.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by minimizing the customer interruption duration by carrying out unplanned outages in a timely manner.
Operational Effectiveness	• Maintain distribution system reliability, safety, and/or power quality. Reduce safety risks associated with failed equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	

Costs:

The costs for this demand program are projected based on these historic costs and future anticipated needs. The average investment cost for this program over the five year period is in line with the average five year historic spending. The factors which affect the costs in this investment are the following:

- The scope of the replacement required to address the failure;
- The type and number of failed assets requiring replacement (i.e. transformers, switches, reclosers, etc.); and
- The ratings of the equipment requiring replacement.

Controllable costs have been minimized through the standardization of station designs and equipment ratings, establishment of unit price contracts with vendors, and maintaining a spare inventory for replacement of failed equipment to minimize outage time.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.5	2.5	2.6	2.8	2.9	13.2
Less Removals	0.2	0.2	0.2	0.2	0.2	0.9
Gross Investment Cost	**2.3**	**2.3**	**2.4**	**2.6**	**2.7**	**12.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.3**	**2.3**	**2.4**	**2.6**	**2.7**	**12.3**

**Includes Overhead at current rates.*

SR-02 Mobile Unit Substation Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	26.9
Primary Trigger:	Failure Risk		
Secondary Trigger:	Operational Functionality		

Investment Need:

Hydro One owns, maintains and operates a fleet of 30 mobile unit substations ("MUS") located across Ontario to support Hydro One's distribution stations that are designed primarily with only one transformer and with very little transfer capability. These MUS's perform an integral role in the operation of Hydro One's distribution system and are utilized for the following purposes:

- To offload distribution stations during maintenance and capital activities;
- For emergency power restoration in the event of a transformer or other distribution station component failure; and
- For load relief for distribution stations.

The management of Hydro One's MUS fleet is required to ensure that an adequate, safe and reliable fleet is available to satisfy these outage requirements noted above. The MUS fleet must adhere to the requirements of the Highway Traffic Act. Under the Highway Traffic Act, each MUS must receive an annual vehicle safety and structural inspection from an approved facility to certify that they meet minimum safety requirements. If an MUS does not pass the annual inspection, it cannot be transported. As a result, it is imperative that high risk MUS trailers are addressed to ensure usability.

As documented in DSP Exhibit 2.3, thirteen of the MUS fleet is in the high risk category resulting from deteriorated trailers, transformers, and other components in failing condition. The prolonged use of high risk MUS's could increase risk to Hydro One employees and the general public. There is also a need for higher MVA capacity MUS's to support heavier loaded stations, and MUS's with under load tap-changers to provide for voltage regulation.

There continues to be strain placed on the MUS fleet resulting from Hydro One's proposed work programs to address ageing infrastructure on the distribution system. Each year, approximately 30% of planned station work is deferred due to an insufficient number of available MUSs. In 2016, there were 121 scheduled MUS deployments to stations to support planned maintenance and capital work. Of the 121 scheduled outages, 31 were cancelled due to MUS unavailability. To ensure there is an adequate number and type of MUSs to accomplish all planned and unplanned station work and to minimize customer outages, additions to the MUS fleet are required. An inadequate MUS fleet has an adverse impact on emergency failure response that would jeopardize customer reliability and would negatively impact the ability of Hydro One to proceed with maintenance and capital work programs.

Alternative 1: Reactive Component Replacements

Wait for MUS transformer and trailer components that are at high risk to fail, and replace the failed MUS transformers and trailer components on a reactive basis. This alternative is rejected for several reasons. When MUS components such as MUS transformers or trailer components fail, the MUSs are unavailable until the failed components are replaced. The lack of availability of appropriate level of MUS fleet would have a negative impact on customer service, emergency power restoration and system reliability. Furthermore, the lead time to replace a failed major MUS component such as the transformer or trailer is expected to be 1.5 years; which would limit the capability of the MUS fleet to support emergency power restoration and/or capital and maintenance activities.

Alternative 2: Planned Component Replacements

Replace individual major MUS assets identified as high risk on a component basis. While this alternative is viable where only one of the major components is at high risk; it is not ideal when multiple MUS assets (i.e., trailers and transformers) are at high risk and in need of replacement. This alternative is rejected as the assessment of the MUS fleet, as documented in DSP Exhibit 2.3, has identified multiple assets in deteriorated condition. The replacement of MUS components on an individual basis will also not allow for higher MVA MUS transformers with voltage regulation capability to be installed on existing MUS trailers due to space and weight limitations. Furthermore, this alternative also does not address the shortfall in the MUS fleet.

Alternative 3: Planned Full MUS Replacements

Replace six MUS's at end-of-life. This alternative addresses the condition of the existing fleet by replacing half of the MUS's identified as high risk, with the remaining seven high risk MUSs to be replaced beyond the planning period. However, like Alternatives 1 and 2, this alternative does not address the shortfall in the MUS fleet. This alternative is rejected as the existing MUS fleet level is insufficient to address demands of the proposed work program and address emergency power restoration.

Alternative 4: Planned Full MUS Replacements and Fleet Expansion *(Recommended)*

Replace six MUS's at end-of-life to address the condition of the existing fleet identified as high risk, and expand the fleet with the procurement of three additional MUS's to address the shortfall in the MUS fleet. This alternative is recommended as it attempts to address the immediate needs identified for the MUS fleet to ensure system reliability is maintained and begins to alleviate backlog by making strategic expansion to the fleet.

Investment Description:

This investment addresses the replacement of MUSs that are at end-of-life, and addresses a shortfall in MUSs required to support the distribution system and proposed work programs.

The MUS fleet identified for replacement is based on MUS trailers and transformers in high risk, and are prioritized based on their level of risk and number of years beyond their expected service life. As outlined in DSP Exhibit 2.3, twelve of the MUS transformer condition assessments fall into the high risk category, while nine of the MUS trailers are in high risk. Also some of the MUS transformers have limited capacity or lack voltage regulation capability, which limits the utilization of the MUS. The appropriate level of MUS fleet is determined based on having MUSs which can be deployed to stations to support failures and restore customers within eight to twelve hours, and to have sufficient MUSs to allow for the completion of planned and unplanned capital and maintenance work.

Based on this assessment, six MUSs are planned for replacement and three new MUSs will be procured to expand the fleet over the five year period as outlined in the table below.

	2018	**2019**	**2020**	**2021**	**2022**
Number of MUS Replaced	2	1	2	1	0
Number of MUS Procured	0	0	0	1	2
Total	2	1	2	2	2

The MUSs will be replaced with units that have higher MVA capacity and will include voltage regulation. The new MUSs will also be equipped with electronic reclosers capable of remote operation and interruption of higher fault conditions. The specification for the replacements is as follows:

- Four MUS's with capacity of 10MVA, and voltage rating of 44kV – 12.5/8.32kV;
- One MUS with capacity of 7.5MVA, and voltage rating of 27.6kV – 8.32kV; and
- One MUS with capacity of 15MVA, and voltage rating of 115kV–27.6/25/12.5/8.32kV.

Of the three planned MUS purchases, two will be 10 MVA capacity with voltage rating of 44kV – 12.5/8.32kV, and one will be 7.5 MVA capacity with voltage rating of 27.6 kV – 8.32kV.

Risk Mitigation:

The risks to completion of this investment as planned are the time required to execute the procurement process, and the availability of vendor to manufacture and deliver the MUSs. Depending on when in the year the manufacturer receives the request for procurement, they may be fully booked and not able to immediately accommodate the request. These risks are mitigated by early evaluation of vendors, and by providing MUS procurement forecasts to vendors in advance to ensure that they will be able to accommodate the requests and issuance of the purchase orders in a timely matter.

Result:

The mobile unit substation program will result in:

- Ensuring a safe and reliable MUS fleet to respond to station failures in a timely manner;
- Obtaining an adequate MUS fleet to support failures with emergency power restoration and offload distribution stations to execute the proposed work program without unacceptable outage impacts to customers; and
- Maintaining the condition of the MUS fleet to mitigate risks to Hydro One staff and the general public.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by ensuring an adequate level of MUSs to provide emergency power restoration to failure events.
Operational Effectiveness	• Maintain the reliability of the distribution system by obtaining an adequate level of MUSs to carry the distribution station load while performing capital and maintenance work to mitigate power disruption to customers.
Public Policy Responsiveness	• Comply with Ministry of Transportation licensing requirements by ensuring the units are roadworthy and electrically functional.
Financial Performance	• Utilization of MUSs provides a cost effective alternative to constructing redundant transformation at distribution stations across the province.

Costs:

The factors which can affect the unit price of each MUS include the following:

- The specification of the MUS requirement replacement (i.e. MVA capacity of the transformer, Primary voltage(s), Secondary voltage(s), etc); and
- The cost of material and term of procurement contracts.

Controllable costs have been minimized through standardization of the MUS purchasing specifications with standardized MVA capacity for given voltage levels (i.e. 10 MVA for the 44 kV – 12.5/8.32 kV MUS's, and 7.5 MVA for the 27.6 kV – 8.32 kV MUS's). A general outline agreement with vendors for MUS unit prices will be established to further control costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.5	5.7	5.8	5.9	6.0	26.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.5**	**5.7**	**5.8**	**5.9**	**6.0**	**26.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.5**	**5.7**	**5.8**	**5.9**	**6.0**	**26.9**

**Includes Overhead at current rates.*

SR-03 Station Spare Transformer Purchases Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	18.6
Primary Trigger:	Failure		
Secondary Trigger:	Reliability		

Investment Need:

Transformers comprise the single largest component of Hydro One's distribution station asset base. Hydro One owns, maintains and operates 1,222 distribution station transformers. As outlined in DSP Exhibit 2.3, 23% of the distribution station transformer condition assessments fall into the high risk category.

Hydro One's distribution stations are designed primarily with only one transformer without on-site spare transformers that can be switched into service in the event of a failure, and typically have very little transfer capability based on the radial design of the distribution system. Each distribution station transformer supplies approximately 1,200 customers; hence a distribution station transformer failure is highly impactful to customers.

Over the past five years, there has been an average of nine spare transformer deployments per year to support failed transformers, as well as transformers on the verge of failure based on oil samples, demonstrating major oil leaks or violating noise guidelines set by the Ministry of Environment and Climate Change ("MOECC"). In these instances, when a station transformer fails, service is initially restored with the installation of a mobile unit substation ("MUS") until a spare transformer can be transported and installed at the station.

In order to ensure timely response in the event of a failure and maintain system reliability, a sufficient number of spare transformers are required as the lead time to procure transformers can range from 6 to 12 months. If the spare transformer inventory is not maintained, MUSs will be deployed to support failures for prolonged periods of time. Planned project and maintenance work would be deferred, resulting in an increase in failures.

Alternative 1: Reactive Procurement of Replacement Transformer

Deploy spare transformers currently in inventory to support failures, without replenishing the spare transformers which were deployed. Once all the existing spare transformers are depleted, Hydro One would no longer continue to maintain an inventory of spare transformers. Rather, transformer replacements would only be procured after the failure event has occurred. This alternative is rejected as the current fleet of MUSs cannot support this level of utilization. MUSs would be required to remain in service for extended periods of time until a replacement transformer could be purchased (typically 6 to 12 months). This would minimize the MUS's availability to support the proposed maintenance and capital work program, and provide emergency power restoration for other system failures which may occur, resulting in a negative impact on system reliability. Deferral of planned capital and maintenance work will result in an increase in failures. Once the failures exceed the number of available MUSs, system reliability will decrease and customers will be without power for extended periods of time.

Alternative 2: Maintain Sufficient Stock of Spare Transformers *(Recommended)*

Continue to maintain a sufficient inventory of spare transformers to address transformer failures by replenishing the spare transformer inventory when spare transformers are deployed to support failures. This alternative is recommended as it addresses transformer failures in a timely manner; and minimizes the utilization of MUSs for extended periods of time, enabling MUS availability to support the proposed maintenance and capital work program and maintain system reliability.

Investment Description:

This investment addresses the procurement of spare transformers for distribution stations as needed to support the in-service population. These spare transformers are used as replacements for failed units, replacements for transformers with escalated internal heating which must be forced out-of-service, replacements for noisy transformers identified through customer complaints which violate MOECC guidelines, and replacement for transformers with a major unexpected defect identified during routine inspection (i.e. failed tap-changer or significant oil leaks) which are not economical to repair.

The optimal number of spares Hydro One maintains is based on a probabilistic risk analysis model of each transformer category. Transformers are categorized by MVA capacity, primary voltage, secondary voltage, step-down transformers versus voltage regulators, auto voltage regulation capability, 3-phase versus 1-phase and bushing style.

The model determines the optimum number of spares required for each group of transformers by taking into consideration several factors including demographics, failure rates, delivery lead time and repair/replacement time. As outlined in DSP Exhibit 2.3 the failure rate of station transformers is on average 11 transformers per year. To address the failures, there has been an average spare deployment of 9 units per year.

Based on a recent assessment of the spare transformer fleet, and in consideration of previous spare transformer deployments, the proposed level of transformer replacements under the station refurbishment investment, and the optimum level of transformer spares projection of 149 units by 2022, thus the expectation is that 27 spare transformers will be required to be procured over the five year period in order to support failing and failed units as outlined in the table below.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Transformers Procured	4	5	6	6	6
Expected Number of Spares Deployed	9	9	9	9	9
Transformers in Inventory	164	159	155	152	149

The transformers purchased under this investment will vary in size and type, dependent on the spare that is deployed to support a failure event, in order to replenish the spare inventory to support the sizes and types of the in-service transformer fleet. Careful consideration is given to the available number of spares in each group. These spare transformers will be purchased only for instances where spare transformers deployments result in the spare category being below the required stock level.

With an average of 9 spare deployments per year, overall, this investment level will reduce the spare transformer inventory over the planning period from 164 spares to 149 spares, however, system reliability is expected to be maintained as long as planned replacements continue.

Risk Mitigation:

The risk to completion of this investment as planned is the availability of transformer vendors to manufacture and deliver the spare transformers in a timely manner. Manufacturer lead times are typically 6 to 12 months; and depending on when in the year the manufacturer receives the request for procurement, they may be fully booked and not able to immediately accommodate the request. This risk is mitigated by providing transformer purchase forecasts to vendors in advance to ensure that they will be able to accommodate the requests, and issuance of the purchase orders in a timely matter.

Result:

The station spare transformer program will result in:

- Sustaining reliability of the distribution system by replacing failed and failing transformers with new units from the spare inventory in a timely manner; and
- Reducing the number of customer interruptions by replacing transformers identified on the verge of failing.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by replacing failed or failing transformers in a timely manner to maintain system reliability.
Operational Effectiveness	• Maintain safe and reliability operation of the distribution system by maintaining an adequate level of spares. • Minimize the utilization of MUSs for extended periods of time to support failures; thereby ensuring the MUS availability to support maintenance and capital work program.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	• Realize cost savings through planned replacements of transformers identified as failing prior to failure as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the following:

- The actual number of transformer failures and demand transformer replacements which occur in year that require spare deployment; and
- The type of transformer requiring spare deployment, as the costs of the spare transformers can vary based on transformer specifications such as: voltage, capacity and tap-changer requirements.

Controllable costs have been minimized through standardization of transformer purchasing specifications with standardized MVA capacities for given voltage levels, and development of unit pricing with the transformer vendor.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.6	3.4	4.1	4.2	4.3	18.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**2.6**	**3.4**	**4.1**	**4.2**	**4.3**	**18.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.6**	**3.4**	**4.1**	**4.2**	**4.3**	**18.6**

**Includes Overhead at current rates.*

SR-04 Distribution Station Planned Component Replacement Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	11.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One owns, operates, and maintains 1,005 distribution stations across the province. As outlined in DSP Section 2.3, Hydro One performs inspections and preventative maintenance to assess the condition of the assets (i.e., switches, insulators, support structures, station service, fences and grounding) at distribution stations. These assessments identify a number of distribution station components that are in deteriorated condition, as outlined in DSP Section 2.2. Other influencing factors that affect the operation of the distribution station include components that have safety issues, substandard design or manufacturer defects (i.e., certain models of switches which are prone to failure due to seized bearings, seizing load interrupters and failure of porcelain insulators). The management of these components is required to mitigate these safety and environmental risks and maintain the reliability of the distribution system.

Alternative 1: Reactive Replacements

Wait for distribution station components to fail while in service and replace them on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Reactive management of the distribution station components will lead to increased failures resulting in increased safety risks given the emergency nature of the work and degraded reliability for Hydro One's customers.

Alternative 2: Planned Component Replacements (*Recommended*)

Planned replacement of distribution station components identified in deteriorated condition or that have deficiencies, safety issues, substandard design, manufacturer defects. This alternative is recommended as it maintains the safe and reliable operation of the distribution stations.

Investment Description:

This program addresses the individual replacement of distribution station components. The components are identified annually for replacement based on the condition of the asset. These replacements are coordinated with maintenance activities, where possible, to minimize the number of outages. Replacements under this program include but are not limited to the following:

<u>Switches</u>
Switches that are prone to failure due to seized bearings, load interrupters, and/or damaged porcelain insulators require replacement to ensure the reliability and operability of the system.

<u>Structures</u>
Mobile unit substation poles and "dead-end" poles identified in deteriorated condition require replacement to maintain the reliability of the system.

<u>Station Service</u>
Batteries and chargers identified in deteriorated condition require replacement to ensure the operation of protection and control devices, breakers, and circuit switchers in the event of a loss of station service power supply. These devices support reliability and protect other assets on the system.

<u>Fences and Grounding</u>
Station fences identified in deteriorated condition or of substandard height as well as damaged or stolen grounding components require replacement to maintain public safety and security.

The proposed plan is to replace an average of 35 distribution station components annually over the five year period, as noted in the table below. The capital investment for each component replacement is below $1 million. This is expected to maintain the overall condition of the station assets.

Component	**2018**	**2019**	**2020**	**2021**	**2022**
Switches	10	10	11	14	15
Structures	15	15	16	21	22
Other	5	5	5	6	5
Total Component Replacements	**30**	**30**	**32**	**41**	**42**

These planned component replacements are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in ISD SR-06.

Risk Mitigation:

The risks to completion of this investment as planned are outage scheduling and mobile unit substation availability. These risks are mitigated by identifying and planning the work in advance and in a timely manner to ensure that work can be coordinated with existing maintenance work.

Result:

The distribution station component replacements program will result in:

- Mitigating the risk of safety concerns with failed or defective assets;
- Maintaining the reliability of the distribution system; and
- Mitigating the risk of lengthy equipment outages from component failures that affect customers.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by minimizing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by reducing asset failure incidents.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a station inspection.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the number and the type of assets identified for replacement during the routine station inspections and preventative maintenance.

Controllable costs have been minimized by coordinating replacements with regular maintenance schedule, where possible. In situations where a station refurbishment is planned in the near-term, component replacement is bundled with the refurbishment to reduce costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.1	2.1	2.2	2.7	2.8	11.8
Less Removals	0.1	0.1	0.2	0.2	0.2	0.8
Gross Investment Cost	**1.9**	**2.0**	**2.0**	**2.5**	**2.6**	**11.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.9**	**2.0**	**2.0**	**2.5**	**2.6**	**11.0**

**Includes Overhead at current rates.*

SR-05 Distribution Station Feeder Protection Upgrade

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	12.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Grid Modernization		

Investment Need:

Hydro One's distribution system has about 2,438 non-sub transmission primary feeders. The majority of these feeders (93%) are protected by various types of station reclosers, while the remaining 7% are protected by circuit breakers and station fuses with no reclose capability.

The 7% of distribution feeders that are protected by circuit breakers and fuses with no reclose capabilities have reduced reliability performance for customers. In the event that a fuse experiences a momentary fault resulting in a disconnection, the feeder would be subject to a sustained outage until it is manually re-energized. This situation is avoided when the feeder protection is upgraded to utilize a recloser (with reclose capability) to protect the distribution feeder.

There is also a subset of reclosers that have become technically obsolete and are no longer supported by the manufacturer. Not only are there no spare parts available should repairs be required, but these reclosers are also more prone to failure. Feeders with obsolete recloser types are only 2% of all feeders, however they account for 5% of all defects identified in 2016.

Furthermore, there are concerns that some of the existing reclosers have reached 95% to 100% of the reclosers' ratings and are approaching a point that the reclosers will no longer have sufficient short circuit and/or interrupt capability to meet the distribution station short circuit levels. Short circuit levels at these stations have increased due to several factors, such as: system reconfiguration, addition of generation on feeders, and/or installation of higher rated station transformers. These reclosers need to be replaced prior to short circuit levels reaching beyond 100% of the recloser's rating.

Alternative 1: Reactive Replacements

Wait for the feeder protection to fail while in service and replace them on a reactive basis. This alternative is rejected for several reasons. Reactive management of the feeder protections will lead to increased unplanned outages due to failures of the reclosers and fuses at unexpected times. This may result in safety risks, reduced feeder protection and reduced reliability for Hydro One's customers. Also the existing feeder protection fleet would require a large stock of spares to be maintained as there are various types and voltage levels of reclosers and fuses on the distribution system. In circumstances, where the existing reclosers are obsolete, modification of the existing structure and station design may be required to install a new recloser design which can take up to 12 months.

Alternative 2: Planned Replacements *(Recommended)*

Proactively install new electronic vacuum type reclosers with communication capability, where the existing protective device has become insufficient and at risk of failure due to condition, short circuit capability, or the lack of reclosing capability. This alternative is recommended as it upgrades the feeder protection before a failure occurs and improves reliability on feeders that are being upgraded from fuse protection to recloser protection due to the reclose capability of a recloser. Also the new electronic controlled vacuum type reclosers have a higher operation limit before maintenance is required compared to the traditional oil filled hydraulic type reclosers, and are also equipped with communication capability for remote controllability.

Investment Description:

This investment addresses concerns with the existing feeder protection through the installation of new vacuum type reclosers with electronic control and communication capability.

These new reclosers are designed for up to 10,000 reclose operations with minimal maintenance. This will reduce the maintenance required compared to oil filled hydraulic type reclosers which are only designed with a threshold of 58 to 272 reclose operations before a maintenance cycle is required. These new electronic reclosers also contain multiple protection settings that can be changed without the need for intrusive upgrades to the recloser, making them more flexible and adaptable to system changes than fuses and hydraulic reclosers. Furthermore, these new reclosers also provide remote control and monitoring capability features to allow automation of the distribution system. This capability modernizes the distribution system, which allows for monitoring and remote control of the recloser. This added benefit can reduce the restoration time when an outage occurs.

Feeder protections are identified and prioritized for replacement based on risk assessment of distribution feeders, in consideration of the following:

- Feeders where station short circuit current level and/or fault current is approaching short circuit rating/interrupt rating of the existing feeder protection;
- Feeders currently protected by fuses that provide reduced reliability to customers as this type of feeder protection has no reclose capability; and
- Feeders where the existing feeder protection is technically obsolete and/or historically prone to failure.

Each feeder protection upgrade will vary in scope and duration depending on the type of existing feeder protection and the design of the station. The forecast of the number of feeder protection requiring replacement annually over the five year period is provided in the table below. The capital investment of each feeder protection replacement is below $1 million.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Replacements	13	13	13	12	12

By the end of 2022, approximately 8% of all distribution feeders would have been upgraded to new electronically controlled vacuum type recloser with remote communication capability. These planned feeder protection upgrades are limited to cases where no other assets at the station require replacement. If other assets at the station have deteriorated and require replacement, then the work is bundled into an integrated Station Refurbishment project as outlined in ISD SR-06.

Risk Mitigation:

The risk to completion of this investment as planned is the time required to execute an upgrade if the distribution station has a substandard design or insufficient clearances, to ensure the newly installed recloser meets current standards. This risk is being mitigated by identifying requirements early in the engineering phase such that proper resources can be allocated to complete the feeder protection upgrade.

Result:

The feeder protection upgrade investment will result in:

- Modernizing the distribution system with feeder reclosers that have a higher operation limit and can be monitored and controlled remotely;
- Improving safety to those stations where fault current levels are on the rise, with the installation of new electronic vacuum type recloser that have a higher interrupt capability and rated for higher fault current levels; and
- Improving customer experience by reducing number and duration of potential sustained customer interruptions.

Outcome Summary:

Customer Focus	• Reduce the number of potential sustained interruptions to customers by adding reclose capability.
Operational Effectiveness	• Improve operational efficiency by adding monitoring and remote controllability to feeder protection. • Address rising station short circuit levels by increasing interrupt capability of the feeder protection.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Enable the potential for more renewable generation to be connected by increasing short circuit rating of the feeder protection.
Financial Performance	

Costs:

The factors that impact the cost of a feeder protection upgrade include the station design and the existing type of feeder protection that is being upgraded. These factors determine the complexity of the installation and the amount of alteration required for each station to install new reclosers.

Controllable costs have been minimized through the procurement of new reclosers that have a higher operation limit before maintenance is required when compared to the traditional oil filled hydraulic type reclosers and allow for monitoring and remote control capability that have the added benefit of reducing the restoration time when an outage occurs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.4	2.5	2.5	2.6	2.7	12.7
Less Removals	0.1	0.1	0.1	0.1	0.1	0.6
Gross Investment Cost	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**	**12.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**	**12.1**

**Includes Overhead at current rates.*

SR-06 Distribution Station Refurbishment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	148.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Capacity Upgrade		

Investment Need:

Hydro One owns, maintains, and operates 1,005 distribution stations in Ontario. Each distribution station serves an average of 1,200 customers. A vast majority of these stations are a single transformer design with limited transfer capability.

In the event of a failure of the transformer, the supply to the transformer, or the bus work at a distribution station; all customers supplied by that distribution station would experience an interruption of service until power restoration was achieved through either a repair of failed equipment or connection of a mobile unit substation ("MUS"). These power restoration efforts can take 12 to 24 hours depending on the severity of the failure and location of the station. Over the last five years there has been an average of five transformer failures per year which caused interruption of service.

As outlined in DSP Exhibit 2.3, the main power equipment at these distribution stations are transformers and 23% of these transformers are classified as high risk based on condition assessment. There are also concerns with the condition of some of the structural components of distribution stations, including rotting high and low voltage wood structures, failing tube and clamp structures, fence and grounding systems.

Some other factors contributing to the need for the refurbishment of a distribution station are: loading requirements, lack of MUS facilities, obsolete equipment, environmental spill risk mitigation, and safety issues or a combination of all of these factors. Details relating to these factors can be found in DSP Exhibit 2.3.

Alternative 1: Reactive Component Replacements

Wait for distribution station equipment to fail and replace the failed components on a reactive basis. This alternative is rejected for several reasons. Reactive management of stations would lead to degraded reliability for Hydro One's customers as a result of station failure increases and the duration of outages being longer in length (12 to 24 hours). The reactive replacements would be limited to only addressing the failed component and would not address other components in deteriorated condition that are also at risk of failure. The volume of failures would increase and the MUS and spare transformer fleet would need to be expanded in order to address the additional failures in a timely manner to maintain the customer reliability. Where a station requires additional capacity, the increase in capacity cannot be addressed with a reactive component replacements strategy.

Alternative 2: Planned Component Replacements

Replace individual components identified in high risk condition on a planned component basis. This alternative is viable where only one component at a distribution station is in deteriorated condition (as documented in Investment Summary Document SR-04). Planned replacements have the advantage of avoiding customer outages by arranging for an alternative supply (MUS or load transfer) unlike reactive replacements. However, this alternative is not ideal when multiple components are in deteriorated condition, as individual replacements work is not integrated resulting in increased costs due to multiple mobilizations to replace the different assets.

Alternative 3: Planned Station Refurbishments *(Recommended)*

Refurbish entire stations that have multiple assets in high risk condition, before failures occur. This alternative is recommended as it addresses the needs identified at the distribution station to maintain reliability for Hydro One's customers supplied from that station in the most cost effective manner, consistent with the findings of the customer engagement process. Furthermore for distribution stations in high risk condition where a capacity upgrade is required, station refurbishment is the only feasible alternative as an increase in capacity requires several components of the station need to be replaced or modified (i.e. larger transformer, additional reclosers, increase structure size and station footprint, change conductor and cable size).

Investment Description:

This investment addresses the refurbishment of distribution stations to address station equipment in high risk condition where the likelihood of a failure is high. The level of investment has been determined based on this assessment of condition and in consideration of: customer preferences, safety concerns, compliance requirements, and the benchmarking recommendation to incorporate test result data into the condition assessment.

The proposed plan is to refurbish an average of 15 distribution stations per year over the 5 year period, as noted in the table below. This is expected to maintain the current level of transformers in poor condition at 23% (even though the overall age of the fleet will increase) with the goal of maintaining the current level of station reliability in line with customers' preference to balance reliability and rate impacts.

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2018	Blenheim DS	1	27.6	8.32	3.6	5
	Duff DS	1	27.6	8.32	5	7.5
	Gorrie DS	1	44	8.32	5	7.5
	Haliburton DS	1	44	12.5	6	7.5
	Joyceville DS	1	44	12.5	6	7.5
	Meaford Vincent DS	1	44	4.16	5	5
	Sowerby DS	1	115	27.6	2.2	7.5
	Wainfleet DS	1	27.6	8.32	3	7.5
2019	Birch Island DS	1	44	12.5	6	6
	Brigden DS	1	27.6	8.32	3.6	5
	Chatham Raleigh DS	1	27.6	8.32	3.6	7.5
	Dack DS	1	44	12.5	3	5
	Grand Valley DS #2	1	44	12.5	3	7.5
	Hawley DS	1	44	8.32	4	7.5
	Ostrander DS	1	27.6	8.32	5	7.5
	Owen Sound DS #2	1	44	8.32	2	5
	Shedden DS	1	27.6	8.32	3.6	5
	Stratford DS	1	27.6	8.32	3	5
	Stratford East Hope DS	1	27.6	8.32	3	5
	Troy DS	1	27.6	8.32	5	5
	Ufford DS	1	44	12.5	3	5
	Waupoos DS	1	44	8.32	5	7.5
	Whitedog DS	1	13.8	12.5	2	5

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2020	Aspdin DS	1	44	12.5	6	7.5
	Carleton Place Edmund DS	1	44	4.16	5	5
	Cobalt DS	1	44	12.5	3	5
	Colpoys Bay DS	1	44	12.5	6	7.5
	Island Grove DS	1	44	8.32	5	5
	Kenora DS	1	115	12.5	3.6	5
	Millington DS	1	44	8.32	5	5
	Oil Springs DS	1	27.6	8.32	4.7	5
	Nottawaga DS	1	44	8.32	5	5
	Reid Corners DS	1	44	8.32	3	5
	Tara DS #2	1	44	8.32	3	5
	Washago DS	1	44	8.32	5	5
	Williamstown RS	1	44	44	25	25
	Woodland Beach DS	1	44	8.32	5	5
	Wroxeter DS	1	44	8.32	3	5
2021	Aberdeen DS	1	44	8.32	5	5
	Bothwell Corners DS	1	44	8.32	5	5
	Cedar Mills DS	2	44	27.6	20	20
	Constance DS	2	115	27.6	30	30
	Crown Hill DS	1	44	8.32	5	5
	Dwight DS	1	44	12.5	6	7.5
	Emsdale DS	1	44	12.5	6	7.5
	Elmvale DS	1	44	8.32	3	5
	Emo DS	1	44	12.5	3	5
	Ferndale DS	1	44	12.5	6	7.5
	Harriston DS #2	1	44	8.32	5	5
	Keswick DS	1	44	8.32	10	10
	Lake Vernon DS	1	44	12.5	6	5
	Milverton DS #2	1	44	8.32	5	5
	Oxmead DS	1	44	8.32	7.5	7.5
	Willow Beach DS	1	44	8.32	5	5
	Wolsey Lake DS	1	44	12.5	6	5

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2022	Belleville DS #2	1	44	8.32	5	7.5
	Blackstock DS	1	44	8.32	5	5
	Brunelle DS	1	44	8.32	5	5
	Chemung DS	1	44	8.32	5	5
	Coboconk DS	1	44	12.5	10	7.5
	East Luther DS	1	44	12.5	6	5
	Horning Mills DS	1	44	8.32	5	5
	Listowel Davidson DS	1	44	4.16	5	5
	Madoc DS #2	1	44	12.5	6	5
	Pinestone DS	1	44	12.5	10	7.5
	Pleasant Point DS	1	44	12.5	6	5
	Precious Corners DS	1	44	8.32	5	5
	Rutherglen DS	1	44	12.5	2.3	5
	Schreiber Winnipeg DS	1	115	13.8	6	7.5
	Sherburne Andrew DS	1	44	4.16	5	5
	Tory Hill DS	1	44	12.5	6	5
	West Lorne DS	1	27.6	8.32	5	5
	Woodville DS	1	44	8.32	5	7.5

Each station refurbishment will vary in size and scope. The refurbishment will address: aged transformers and structures, defective equipment, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues. The stations will be refurbished to comply with present standards.

Risk Mitigation:

The risks that can impact the completion of a distribution station refurbishment project are: procurement of real estate to accommodate the station configuration, and environmental remediation of the site. These risks are mitigated by determining the requirements of the new station early in the project planning process and requesting a land survey and environmental site survey before detailed design work has started.

Result:

The station refurbishment program will result in:

- Ensuring sufficient capacity to meet customer loading requirements for the foreseeable future;
- Addressing assets in poor condition to reduce customer interruption time; and
- Resolving operational and safety issues and mitigating environmental spill risk where the risk exists.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by minimizing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by addressing degrading equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system.
Financial Performance	• Realize cost savings by addressing multiple degrading components within the station as part of the same project.

Costs:

The factors which affect the cost of this investment are the following:

- The station design and required station capacity;
- The level of environmental remediation required at the distribution stations; and
- The condition of the structure and level of refurbishment required.

Controllable costs have been optimized through consideration of the station load forecast to avoid additional investments due to overloading in the foreseeable future, and the use of a risk based approach when deciding the level of environmental remediation required.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	16.2	31.8	36.4	37.1	37.8	159.3
Less Removals	1.1	2.2	2.5	2.6	2.6	11.1
Gross Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**

**Includes Overhead at current rates.*

SR-07 Distribution Lines Trouble Call and Storm Damage Response Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	431.0
Primary Trigger:	Failure		
Secondary Trigger:	Safety		

Investment Need:

Service interruptions associated with distribution lines invariably occur that require immediate response by Hydro One personnel. Extreme weather or asset failures may result in a service interruption that requires restoration of power to customers. Regular patrols and inspections may also identify damaged or failed distribution line assets that pose a safety hazard or customers may report power quality issues. Hydro One personnel must be dispatched to assess and resolve any urgent deficiency in accordance with good utility practice and the requirements of the Distribution System Code.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to respond to service interruptions or other system deficiencies would violate the OEB Distribution System Code and result in unacceptable reliability for customers and safety risks.

Investment Description:

This investment encompasses the capital costs of asset replacements associated with responding to trouble calls, storm damage, power interruptions and other situations that pose reliability or safety risks and require immediate attention in compliance with the Distribution System Code.

The distribution lines trouble call and storm damage response program includes the following activities:

- Emergency pole and line equipment replacements,
- Emergency submarine and underground cable replacements,
- Storm damage response and resolving service interruptions caused by adverse weather conditions,

- Post trouble-call response and providing permanent solutions to any temporary repairs that were required during an emergency or a service interruption,
- Power quality response requiring modifications to the system to resolve unacceptable voltage or frequency levels, and
- Damage claims, including payment for third party damage that Hydro One cannot recover.

All other trouble call and storm damage response costs which cannot be capitalized are allocated to the OM&A work program as documented in Exhibit C, Tab 1, Schedule 2.

Risk Mitigation:

The work in this investment is unplanned in nature. However, there are risks to executing such unplanned work including the number of asset failures and storm events and the availability of qualified resources. This risk is mitigated by diverting qualified resources from other projects to complete restoration activities.

Result:

The distribution lines trouble call and storm damage response program will result in:

- Maintaining reliability of the distribution system by ensuring timely response to trouble calls, service interruptions, and power quality complaints,
- Mitigating safety risks of defective or failed assets, and
- Satisfying customer and regulatory requirements.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by minimizing the customer interruption duration by carrying out unplanned outages in a timely manner. • Mitigate customer complaints related to power quality and reduce public safety hazards.
Operational Effectiveness	• Maintain the safe and reliable operation of the distribution system.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	

Costs:

Planned expenditures for this demand program are projected based on historical costs, factoring in anticipated needs and inflation over the period. The factors which affect the costs in this investment are the following:

- The volume of the asset failures and storm events which occur on an annual basis.
- The scope of the work required to address asset failures and storm events.

Any significant changes to these would affect the costs.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacements.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	97.2	99.1	100.9	103.5	105.5	506.1
Less Removals	11.7	11.9	12.1	12.4	12.6	60.7
Gross Investment Cost	**85.5**	**87.2**	**88.8**	**91.1**	**92.8**	**445.4**
Less Capital Contributions	2.8	2.8	2.9	2.9	3.0	14.4
Net Investment Cost	**82.7**	**84.4**	**85.9**	**88.1**	**89.8**	**431.0**
Net Costs in System Renewal	75.6	77.1	78.5	80.5	82.0	393.5
Net Costs in System Service	7.1	7.3	7.4	7.7	7.8	37.4

**Includes Overhead at current rates.*

***Note:** Costs for forestry and premium time incurred as part of storm damage restoration are captured as part of OM&A Trouble Calls.*

SR-08 Distribution Lines PCB Equipment Replacement Program

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	72.8
Primary Trigger:	Mandated Obligation		
Secondary Trigger:	Substandard Performance		

Investment Need:

Hydro One owns, operates, and maintains 450,000 pole top transformers, 54,000 pad mount/submersible transformers and 3,000 pole mounted capacitor units; all of which are oil filled equipment. Prior to year 1985, a chemical compound known as a polychlorinated biphenyl (“PCB”) was widely deployed in dielectric and coolant fluids in the manufacturing of oil filled electrical apparatus. However, this manufacturing practice was discontinued in the late 1970’s when it became evident that PCBs build up in the environment and exposure to high levels can cause harmful health effects. In 2008, Environment Canada enacted legislation mandating that all oil-filled equipment whose insulating oil contains greater than 50 ppm of PCBs be removed by December 31, 2025. Therefore Hydro One must remove all such oil-filled equipment. Hydro One’s distribution assets which are oil-filled consist solely of pole top transformers, pad mount mount/submersible transformers and pole mounted capacitor unit.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to remove PCB contaminated distribution line equipment would place Hydro One in violation of Environment Canada regulations and result in increased public health and safety risks.

Investment Description:

This program addresses the removal and replacement of distribution line oil-filled equipment (i.e., pad mount transformers, pole top transformers and pole mounted capacitor banks) whose insulating oil contains PCB contamination levels are greater than 50 ppm. All of Hydro One’s pad mount transformers have already been tested as part of the PCB inspection and testing program, and all units with greater than 50 ppm of PCBs have been replaced.

All of Hydro One's pole-top transformers manufactured prior to 1985 will require inspection and oil sampling testing. To date, approximately 10 to 15% of the transformers have be inspected and tested. Hydro One proposes to inspect and test the remaining transformers at a consistent rate over the period from 2018 to 2024.

From past experience with PCB testing, approximately 8% of these transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination. The replacement of the pole-top transformers is slated to lag the PCB inspection and testing program by one year, allowing time for the identification of contaminated transformers and optimization of a plan to replace the transformers that minimizes the impact to customers. Based on historic sampling results this would result in approximately 2,400 to 2,600 replacements per year to ensure that the program will be completed by the 2025 deadline set out by Environment Canada.

Capacitor units cannot be tested for PCBs without causing them significant damage. Therefore, all of Hydro One's capacitors manufactured before 1985, will require replacement. Hydro One proposes to replace the units at a consistent rate over the period from 2018 to 2024.

Risk Mitigation:

The risk to completion of this investment as planned is based on the uncertainty of the volume and exact location of the PCB contaminated equipment exceeding the allowable threshold of 50 ppm. This risk is mitigated by the establishment of an inspection and testing program to identify all oil filled equipment that must be replaced under legislative requirement and an associated process to replacement the identified contaminated equipment.

Result:

The distribution lines PCB equipment replacement program will result in:

- Mitigating health and safety risks associated with PCB contamination by removing the affected line equipment; and
- Ensuring compliance with environmental legislation.

Outcome Summary:

Customer Focus	• Mitigate potential health and safety hazards to customers and the public by removing the contaminated lines equipment.
Operational Effectiveness	• Realize improvement of distribution lines by replacing the old PCB contaminated equipment with new equipment.
Public Policy Responsiveness	• Comply with Environment Canada legislation to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.
Financial Performance	• Avoid non-compliance penalties arising from a failure to complete the mandated PCB elimination by 2025.

Costs:

The costs for this program are projected based on historic sampling results and future anticipated replacement needs which lag the PCB inspection and testing program by one year. The factors which affect the costs in this investment are any unforeseen issues at each work location, for example all new installations must meet Electrical Safety Authority requirements, so where a transformer is to be replaced, minimum pole height standards are mandated which could result in multiple pole and other equipment replacements.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement, and coordinating with other sustainment programs where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	13.3	13.6	13.8	21.2	21.6	83.5	113.0
Less Removals	1.7	1.7	1.8	2.7	2.8	10.7	14.4
Gross Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018 and forecasted costs beyond 2022.*

SR-09 Pole Replacement Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	579.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	Safety		

Investment Need:

The structural integrity of a distribution line is largely dependent on the poles that support the line. Hydro One owns, maintains and operates approximately 1.6 million poles, of which 99% are wood poles.

The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, or other factors that reduce the structural integrity of the pole. Once a pole's condition has deteriorated to the point that it has a significant risk of failure under adverse weather condition, it is deemed to be at end-of-life. During storm conditions, poles that fail can sometimes trigger "cascading failures", which result in the failure of a larger number of distribution system assets.

As outlined in DSP Exhibit 2.3, there are currently approximately 67,000 poles in poor condition that are at high risk of failure. By the end of 2022, it is forecasted that an additional 77,000 poles will be added to this high risk category due to deteriorating condition.

In addition to concerns with condition, there are still a subset of 39,000 red pine poles that are demonstrating premature degradation, as documented in previous proceedings (EB-2013-0416, EB-2012-0136 and EB-2009-0096), that require replacement.

Furthermore, one of the finding of the benchmarking study discussed in DSP Section 1.6 found that Hydro One's poles replacement rate of approximately 10 700 pole per year over the past five years is slower than the comparison utilities. The study also found that the average pole on the Hydro One system is on average eight years older than the comparison utilities.

Alternative 1: Reactive Replacements

Wait for the poles that are at end of life to fail and replace the failed poles on a reactive basis. This alternative is rejected for several reasons. The cost of reactive replacements is more expensive as documented in DSP Exhibit 2.3. Reactive management of the poles will lead to increased failures resulting in a risk to public safety and degraded reliability for Hydro One's customers. Also the volume of poles requiring replacement will quickly increase to the point where the volume of trouble calls will become unmanageable.

Alternative 2: Planned Pole Replacements at Historic Rate

Planned replacement of end of life poles at the historic rate of replacement. This alternative is rejected as it would not address all of end of life poles within the five year period resulting in a backlog of poles which will lead to more frequent and/or longer duration outages for Hydro One customers.

Alternative 3: Planned Pole Replacement at an Increased Rate (Recommended)

Planned replacement of end of life poles at an increased rate (as noted in the following table) that balances asset needs, resource availability, and cost impact to customers. The number of poles at high risk of failure requiring replacement will be slightly reduced over the plan. This alternative is recommended as it will maintain reliability of the distribution system.

Investment Description:

This investment addresses the replacement of poles that are at end-of-life, and addresses the subset of red pine poles demonstrating premature degradation. Poles are inspected on a regular basis, and are identified and prioritized for replacement based on an asset risk assessment that considers factors such as: condition, performance, demographics and criticality.

Hydro One has been gradually ramping up the number of poles replaced each year to a sustainable level of replacement that balances the needs of the asset, resource availability, and the rate impact to customers.

Hydro One is sensitive to customer needs and will manage the population of poles in poor condition that are at high risk of failure over the five year plan so as to reduce cost impacts to customers. There are currently a large number of poles in poor condition that are at high risk of failure and it is forecasted that this number will be slightly reduced to 99,000 poles (including the red pine pole subset) over the plan. Poles are prioritized for replacement based on their impact on reliability and potential safety risks. The table below outlines the planned volume of poles to be replaced throughout the five year period.

	2018	2019	2020	2021	2022
Number of Poles Replaced	9,600	14,300	16,000	16,123	16,128

Pole replacement costs and accomplishments are tracked and reported monthly. Depending on the types of poles requiring replacement (i.e. pole height, pole class, number of circuits, etc.) and the accessibility conditions of the area, the cost of replacement can vary. Where possible, the efficiency of this investment is maximized by bundling work and replacing poles in close proximity to each other. Larger line rebuilds are funded by the "Distribution Lines Sustainment Initiative" program as outlined in ISD SR-12.

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, the number of storms in recent years this has not been an issue.

Result:

The pole replacement program will result in:

- Reducing the risk of pole failure by replacing poles in poor condition;
- Reducing safety and reliability risks on the distribution system; and
- Ensuring compliance with Canadian Standards Association standards.

Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing wood poles prior to failure. • Focus on balancing the rate impact to customers while addressing the replacement need and risks associated with end of life poles.
Operational Effectiveness	• Maintain safe and reliability operation of the distribution system by proactively replacing end of life poles.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with Canadian Standards Association standard by replacing wood poles that have deteriorated to 60% of their design strength.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

Pole replacement costs and accomplishments are tracked and reported monthly. The factors which affect the costs in this investment are the following:

- The types of poles requiring replacement (i.e. pole height, pole class, number of circuits, etc.);
- The location accessibility conditions of the area in which the poles are being replaced. Accessing off road locations can be more costly due to the use of specialize equipment; and
- The cost of material and term of procurement contracts.

Controllable costs have been minimized through balancing the pole types and locations selected for pole replacements in a given year and by standardization the procurement of materials and procedures for equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	83.8	127.4	145.3	149.2	152.1	657.8
Less Removals	10.1	15.3	17.4	17.8	18.2	78.8
Gross Investment Cost	**73.8**	**112.1**	**127.9**	**131.3**	**133.9**	**579.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**73.8**	**112.1**	**127.9**	**131.3**	**133.9**	**579.0**

**Includes Overhead at current rates.*

SR-10 Distribution Lines Planned Component Replacement Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	35.3
Primary Trigger:	Failure Risk		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeders lines across the province. As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of line equipment (i.e. cross arms, nest platforms, overhead conductor, regulators, reclosers, sentinel lights, transformers, and switches) on those feeders. These condition assessments have identified a number of distribution line components that due to their condition, are near the end of their expected service life. Additionally, there are a number of components on the system that are substandard or that pose environmental risks. The management of these components is required to mitigate these safety and environmental risks and maintain reliability of the system.

Alternative 1: Reactive Replacements

Wait for the distribution line equipment to fail while in service and replace it on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Reactive management of distribution line equipment will lead to increased failures resulting in risks to employee and public safety and degraded reliability for Hydro One's customers.

Alternative 2: Planned Component Replacements (*Recommended*)

Planned replacement of distribution line equipment identified in deteriorated or substandard condition. This alternative is recommended as it mitigates the risk of failure of critical customer service assets and ensures a safe and reliable distribution system.

Investment Description:

This investment addresses the individual replacement or refurbishment of distribution line components when it is not economical to integrate the work into one of the large sustainment initiative projects, as described in ISD SR-12. The program comprises the replacement of the following asset types:

Overhead Conductor

Some types of overhead conductor (i.e., #2 ACSR and #4 ACSR) have been found to pose increased safety risks requiring modified work practices. The presence of this conductor limits Hydro One's ability to work on poles and equipment, and can pose work issues for Joint Use Partners. Replacement is based on the location and joint use status of poles which support these conductor types.

Cross arms

Cross arms are fastened to poles to support insulators and conductors. As these components deteriorate with age, their risk of failure increases, posing increased safety risks to the public and Hydro One personnel. System reliability is also potentially impacted.

Nest Platforms

Bird nests on distribution poles can potentially cause pole fires and damage equipment, impacting safety, asset condition, and system reliability. Nest platforms are constructed to allow bird nests to be relocated from distribution poles, while complying with environmental regulations protecting species at risk. The relocated nest platforms can be installed on existing poles, on taller poles, or on separate adjacent poles.

Lines Regulators and Reclosers

Regulators and reclosers are integral components in the operation of the distribution system. Devices requiring replacement are those which are inoperable and where maintenance is not deemed feasible. Failed or inoperable regulators and reclosers can lead to disproportionately widespread and/or extended outage impacts.

Lines Transformers

Some types of transformers (i.e. pole transformer units and trans closure units) have been found to be substandard as these transformers are housed in enclosures, resulting in sub-standard working clearances. These transformers are in poor condition and provide inadequate operational clearances. As a result, any work on the transformers can only be completed if they are taken out of service, which results in long outages. As these types of transformers are not currently part of Hydro One's standards, limited supplies of spare parts can also result in extended outages if they fail. These substandard transformers are replaced with pad mount transformers to current Hydro One standards.

<u>Lines Switches</u>

Switches are integral components in the operation of the distribution system. Overhead Air Break and Load Break switches requiring replacement are those which have failed or have operational issues that cannot be feasibly repaired. Failed or inoperable switches can lead to reduced operational flexibility as well as disproportionately widespread and/or extended outage impacts.

<u>Sentinel Lights</u>

Sentinel Lights are legacy equipment which provides dusk to dawn lighting for Hydro One's customers. Hydro One is contractually obligated to maintain existing installations, which may include replacing failed fixtures or poles. No new customer contracts for installation of these sentinel lights are being issued. This program also funds the removal of lights that are no longer required.

Planned replacement of these aged, deteriorated or defective assets can greatly reduce these risks of failure thereby ensuring reliability is maintained for Hydro One's customers. Depending on the types of distribution line equipment requiring replacement and the location conditions of the area, the cost of the replacement can vary. The table below outlines the proposed volume of the components to be replaced throughout the five year period. The overhead conductor replacements are project based and can vary year over year based on length and complexity of replacement.

	2018	**2019**	**2020**	**2021**	**2022**
Cross arms	1,780	1,780	1,780	1,780	1,780
Nest Platforms	15	15	15	15	15
Regulators and Reclosers	1,244	1,244	1,244	1,244	1,244
Transformers	100	100	100	100	100
Switches	60	60	60	60	60
Sentinels Lights	1,400	1,400	1,400	1,400	1,400

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, the number of storms in recent years this has not been an issue.

Result:

The line component replacement program will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets;
- Maintaining reliability of the distribution system; and
- Satisfying customer and regulatory requirements.

Outcome Summary:

Customer Focus	• Maintain reliability for customers by minimizing the number of interruptions to customers due to equipment failures. • Reduce public safety hazards of deteriorated line components.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the following:

- The location in which the equipment is being replaced;
- Unforeseen property/easement issues; and
- Availability of required resources.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement, and coordinating with other sustainment programs where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	11.3	7.8	8.0	9.1	9.0	45.2
Less Removals	2.2	1.8	1.9	2.0	2.0	9.9
Gross Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**

**Includes Overhead at current rates.*

SR-11 Submarine Cable Replacement Program

Start Date:	Q1 2018	Priority:	Medium
In-Service Date:	Program	Plan Period Cost ($M):	39.1
Primary Trigger:	Safety		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One's distribution system contains approximately 11,663 submarine cables totaling about 3,300 circuit kilometers in length. These cables are used to traverse water when overhead crossings are technically or economically unfeasible.

Distribution system patrols have found that many cables are deteriorating, particularly at the shoreline. Cables that are exposed at or near the shore can be damaged by the movement of water or ice and by human activity. This damage usually takes the form of abrasion or corrosion of the protective cable armour, which can lead to neutral failure or water ingress.

Cables that are damaged or exposed at the shoreline can pose significant public safety hazards, as well as increased reliability risks.

Alternative 1: Reactive Replacement

Wait for submarine cables to fail while in service and replace them on a reactive basis. This alternative is rejected as it results in an unacceptable safety risk to the general public and employees. Contact with a damaged cable can lead to serious injury or a fatality. Emergency repairs are also more expensive as materials and resources tend to be at a premium cost.

Alternative 2: Planned Replacement (*Recommended*)

Planned replacement or refurbishment of submarine cables approaching end-of-life or demonstrating deteriorating condition. This alternative is recommended as it will mitigate the risk of failure and ensure a safe and reliable distribution system.

Investment Description:

This investment addresses the replacement or refurbishment of submarine cables that are damaged or that are exposed at the shoreline. Cables that meet these criteria are identified during distribution system line patrols. If a cable is found to pose an immediate hazard, it is immediately replaced under the "Trouble Call" program. If immediate replacement is not possible, these cables are temporarily repaired and scheduled for replacement or refurbishment. Depending on the location and extent of damage to a cable, the submarine cable may require either a sectional repair or a full cable replacement. In the case of a sectional repair, damaged locations are identified and a new section is spliced into place. However, if the cable is severely damaged, is obsolete, has exhibited poor performance, or has required repeated repairs, it is completely replaced.

This program will replace or refurbish approximately 220 to 250 submarine cable sections per year. This program also addresses the re-establishment of mechanical shoreline protection (cable covering which protects the submarine cable from deterioration caused by ice and wave damage) and the installation of warning signage for these cables.

Risk Mitigation:

Due to the significant public safety hazards associated with these defective submarine cables, these replacements are treated as a high priority and therefore no risks are foreseen with completing this replacement program as planned.

Result:

The submarine cable replacement program will result in:

- Mitigating the public safety risks of defective submarine cable; and
- Maintaining reliability of the distribution system.

Outcome Summary:

Customer Focus	• Mitigate public safety hazards from defective submarine cable. • Maintain reliability by reducing interruptions to customers from defective submarine cable.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factor which affects the costs in this investment is the shoreline condition where the cable exits the water; as shoreline protection may be required for the cable.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	8.5	8.7	8.9	9.1	9.3	44.5
Less Removals	1.0	1.0	1.1	1.1	1.1	5.3
Gross Investment Cost	7.5	7.7	7.8	8.0	8.2	39.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**7.5**	**7.7**	**7.8**	**8.0**	**8.2**	**39.1**

**Includes Overhead at current rates*

SR-12 Distribution Lines Sustainment Initiatives

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	151.7
Primary Trigger:	Failure		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeder lines across the province with approximately 17% of these feeders lines being located off-road. These off-road sections of feeders are difficult to access during power interruptions and can result in increased risk of prolonged outages.

As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of its distribution feeder lines. These assessments have identified a number of concerns with the condition of the components on the primary feeders.

In addition to the condition of the distribution feeder line, there are a number of component installations that are of sub-standard design/construction based on changes over time in industry standards and do not meet current Hydro One standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks.

Alternative 1: Reactive Replacements

Wait for the distribution line equipment to fail while in service and replace it on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Moreover, reactive management of the distribution line equipment will lead to increased failures resulting in risks to employee and public safety and degraded reliability for Hydro One's customers.

Alternative 2: Planned Components Replacements

Planned replacement of distribution line equipment identified in deteriorated or substandard condition, on a "like for like" component basis. This alternative is viable where an individual component of standard design on a distribution line is in deteriorated condition. However it is not ideal when multiple components are in deteriorated condition or the components are of substandard design, as individual replacement work does not allow for cost efficiencies associated with integration of replacements of assets in close proximity to each other; as well as it would require custom-engineered designs to address substandard equipment. Furthermore, this alternative would not address any accessibility concerns and would result in higher ongoing maintenance costs.

Alternative 3: Planned Lines Sustainment Initiatives (Recommended)

Planned refurbish or rebuild of entire feeders or feeder sections, when multiple components of the distribution line have been identified in deteriorated condition, in order to improve the performance of that distribution line. This alternative is recommended as it addresses the needs identified on the distribution lines in order to maintain the reliability of the distribution system in the most cost effective manner and minimize any safety risks to the public and Hydro One personnel.

Investment Description:

This investment address the refurbishment of entire feeders or feeder sections in an integrated manner to address line equipment with likelihood of failure is high. Distribution line assets deteriorate over time, taking into account the overall condition of poles, conductors and associated components; feeder sections are identified and prioritized for refurbishment or rebuild. Refurbishing or rebuilding an entire feeder section is preferred when the cost of maintaining or replacing individual components on that section becomes excessive.

There are a number projects identified under this program annually; which vary significantly in size and scope. The projects with capital investment exceeding $1 million are provided in the following table.

Year	Project Name	Net Total ($Million)
2018	City of Owen Sound Refurbishment - Part 3 of 4, *Owen Sound*	1.2
	Dundas TS M1 Rebuild Carlisle, *Dundas*	2.0
	Duart TS M6 Relocation, *Strathroy*	4.0
	Dymond TS M3 Rebuild - Part 1 of 2, *New Liskeard*	3.6
	Manitouwadge TS M2 Rebuild - Part 5 of 5, *Thunder Bay*	3.5
	Minden TS M2 - Part 2 of 2, *Minden*	2.5
	Otonabee TS M28 - Part 3 of 3, *Peterborough*	1.5
	Projects Less Than $1M	4.0
2019	Brant TS M21 Relocation, *Simcoe*	1.8
	Brockville TS 24M2-Part 5 of 5, *Brockville*	1.0
	City of Owen Sound Refurbishment-Part 4 of 4, *Owen Sound*	2.2
	Dobbin TS 20M4/6/8 Reconstruction, *Peterborough*	1.3
	Duart TS M5 Relocation, *Kent*	3.9
	Dymond TS M3 Rebuild-Part 2 of 2, *New Liskeard*	3.0
	Errington Street Rebuild—Chelmsford, *Sudbury*	1.6
	Manitoulin TS M25 Relocate, *Manitoulin*	1.1
	Martindale TS M5 Rebuild-Part 6 of 6, *Sudbury*	1.6
	Muskoka TS 30M1 Relocation-Part 1 of 5, *Huntsville*	1.0
	Owen Sound TS M24 Rebuild-Part 2 of 3, *Owen Sound*	2.8
	Tillsonburg TS 20M10/Norfolk TS M3, *Simcoe*	4.3
	Wanstead TS M2 Petrolia Tap Relocation, *Lambton*	3.0
	Projects Less Than $1M	2.4
2020	Angus 44 kV Backlot Relocate, *Barrie*	1.2
	Augasabon DS F1 & F2 Rebuild (Part 1 of 2), *Thunder Bay*	2.5
	Brant TS M22 Relocation, *Beachville*	2.0
	G3K Towerline Refurbishment, *Kirkland Lake*	1.0
	Ingersoll TS M46 Rebuild, *Beachville*	2.5
	Kent TS M16 Relocation, *Kent*	1.2
	Kleinburg TS M8, *Bolton*	2.0
	Muskoka TS M1 Relocation - Part 2 of 5, *Huntsville*	4.0
	Napanee TS M2 Relocation - Part 1 of 2, *Picton*	3.0
	Owen Sound TS M24 Rebuild - Part 3 of 3, *Owen Sound*	2.8
	Palmerston TS M1 Relocation - Part 1 of 2, *Listowel*	3.0
	Sidney TS M7 Reconductor, *Frankford*	1.3
	Weston Lake DS F1 Relocation, *Timmins*	1.0
	Projects Less Than $1M	3.4

Witness: Lyla Garzouzi

Year	Project Name	Net Total ($Million)
2021	Augasabon DS F1 & F2 Rebuild (Part 2 of 2), *Thunder Bay*	2.5
	Clarke TS M2 Relocation, *Strathroy*	2.5
	Colgan DS Inaccessible Switch 2314 Relocation, *Alliston*	1.0
	Havelock TS M2 Rebuild-Part 1 of 2, *Tweed*	2.5
	Lauzon TS M25 Rebuild, *Essex*	2.0
	Longueuil TS 26M23 Relocate, *Vankleek Hill*	3.5
	Meaford TS M1 Lower Valley Rd Rebuild, *Owen Sound*	1.5
	Muskoka TS 30M1 Relocation-Part 3 of 5, *Huntsville*	1.7
	Muskoka TS M2 Relocate, *Huntsville*	1.4
	Napanee TS M2 Relocation-Part 2 of 2, *Picton*	3.0
	Old E1R Ear Falls DS F3, *Dryden*	2.5
	Palmerston TS M1 Relocation-Part 2 of 2, *Listowel*	1.0
	Tillsonburg M1 Refurbishment, *Beachville*	2.7
	Projects Less Than $1M	6.0
2022	Forest Jura DS F1 Relocation, *Lambton*	2.0
	Geraldton Rebuild-Part 1 of 3, *Thunder Bay*	1.0
	Havelock TS M2 Rebuild-Part 2 of 2, *Tweed*	2.5
	Kirkland Lake TS G3K Relocate-Part 1 of 2, *Kirkland Lake*	4.0
	Mair Mills DS F1 Grey Rd 21 Rebuild, *Stayner*	1.0
	Muskoka TS 30M1 Relocation-Part 4 of 5, *Huntsville*	2.5
	Muskoka TS M3 Relocation, *Bracebridge*	2.0
	Palmerston TS M3 Relocation-Part 1 of 2, *Listowel*	2.5
	Picton TS M5 Rebuild (Part 1 of 2), *Picton*	3.0
	Sidney TS M7 Rebuild-Part 1 of 2, *Frankford*	3.0
	Stayner TS M2 Rebuild, *Stayner*	3.4
	Wanstead TS M1 Rebuild Alvinston, *Lambton*	2.0
	Projects Less Than $1M	4.8

Each of these projects involves equipment that is identified as a concern during the condition assessment. The refurbishment or rebuilding of entire feeders or feeder sections entails replacing all components to the present Hydro One' standard and is done in compliance with Electrical Safety Authority (ESA Reg. 22/04) requirements for new construction.

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, due to the lower number of major storms in recent years this has not been an issue. This investment assumes the level of major storms to be in line with historical trends.

Result:

The lines sustainment initiatives will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets;
- Maintaining the reliability of the distribution system; and
- Obtaining operational efficiencies by executing work in an integrated manner and reducing customer interruption time.

Outcome Summary:

Customer Focus	• Maintain reliability for customers by reducing the number of planned outages on distribution lines. • Improve response time by relocating off-road line segments to more accessible locations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively addressing lines equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings by addressing multiple degrading components along a section of line as part of the same project.

Costs:

The factors which affect the costs in this investment are the following:

- The location in which the equipment is being replaced;
- Unforeseen property/easement issues; and
- Availability of required resources.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	25.3	35.3	35.1	38.2	38.2	172.1
Less Removals	3.0	4.2	4.2	4.4	4.4	20.4
Gross Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**

**Includes Overhead at current rates*

SR-13 Life Cycle Optimization & Operational Efficiency Projects

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	134.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	System Efficiency		

Investment Need:

Assets at the end of their expected service life are typically addressed by system renewal projects and programs that focus on like-for-like replacements. However, in some situations it is more efficient from a cost and operations perspective to address end-of-life assets by other means such as constructing supply facilities at a different location, upgrading nearby assets, or modifying the network configuration in order to eliminate the need for certain assets.

As assets reach end-of-life, the risk of failure under adverse conditions increases, which can lead to lengthy interruptions to customers and can increase the likelihood of exposing the employees and the public to safety hazards. In situations where other issues are also present, such as poor voltage, limited load transfer capability, or multiple/incompatible system voltages, it is often beneficial to address all issues through one project that upgrades or modifies the existing network configuration. As an example, converting feeders fed from an end-of-life station to a higher operating voltage results in higher load meeting capability, better power quality, and reduced line losses.

These investments provide an opportunity to achieve overall cost savings by bundling asset renewal work on stations and feeders and integrating other system capacity and operational needs under a common solution. Eliminating or combining assets reduces future operating and maintenance costs and improves operational efficiency. Other factors which may lead to addressing end-of-life assets by other than like-for-like means may include environmental factors, property issues, and incompatibility of existing assets with surrounding land uses. Project-specific information is provided in Attachment 1.

Not proceeding with this investment would result in higher expenditures, reduced productivity and inefficient operations. The issues addressed under this investment are a mix of urgent needs and good planning practices that improve overall system operations. By executing projects that simultaneously address these items over individual refurbishment or upgrade projects, overall costs are reduced and fewer resources are required.

Alternative 1: Address End of Life Assets only Through Like-for-Like Replacement

Address all end-of-life asset issues only through like-for-like replacements through other system renewal projects or programs.

This alternative is not recommended since it presents a lost opportunity to achieve overall operational efficiencies and customer benefits which can be achieved by identifying more optimal asset replacement approaches.

Alternative 2: Modify The Distribution System to Eliminate Operationally Inefficient Assets that are Nearing End-of-Life *(Recommended)*

Address specific end-of-life asset needs by means other than like-for-like where there are opportunities to reduce costs and achieve increased operational efficiencies. When stations or lines are approaching their end-of-life based on the condition of their individual components, there may be opportunities to implement system changes other than like-for-like replacement of these assets in order to achieve cost savings and long-term operational efficiencies. It may be possible to eliminate stations or consolidate line assets through voltage conversion projects, or transfers to other stations. Reduced upfront capital costs as well as future maintenance savings can be realized using this approach.

Investment Description:

A number of distribution stations are approaching their end of life. For stations where other alternatives may exist to address renewal needs, an integrated planning approach is taken. This involves assessing other potential system renewal needs in the surrounding network, capacity needs, as well as reliability and operational needs. Alternative solutions are evaluated and an optimal plan is developed which addresses all identified needs in the most cost-effective manner. In cases where stations can be completely eliminated, all existing equipment, structures and materials are removed from the property. Any necessary land remediation needed to remove contaminated soil and site restoration is also included.

To improve operational efficiency and optimize asset life cycle costs, there are several types of projects that are commonly executed.

Station Decommissioning through Voltage Conversions: One approach to remove a station from service is to convert the voltage of its feeders to match its upstream voltage. For example, to decommission a 27.6kV - 8.32kV station, the 8.32kV feeders could be converted to 27.6kV, which removes the need for the station. This approach is advantageous because it addresses stations that are near end-of-life, and improves the voltage quality and capacity of the downstream feeders.

Station Decommissioning by Constructing New Station/Feeders: Another approach used to decommission stations is to construct new stations in their place. In some cases, a new station may suffice to replace multiple stations that are near end-of-life. These projects also include the construction of new feeders to take over the loads from stations planned for decommissioning.

The most common type of project addressed under this investment is the elimination of a distribution station that has reached end-of-life by converting the station's low-voltage feeders to a higher distribution voltage. This may involve feeding the station load directly from the upstream TS supply feeder where it is feasible to do so, or by transferring it to another nearby station operating at a higher voltage. Performing a voltage conversion project may involve replacing feeder assets such as poles, transformers, primary and secondary conductors and secondary service connections, which may also be approaching end-of-life.

A listing of all proposed projects under this investment category with costs in excess of $1 million over 2018 to 2022 time frame is provided in Attachment 1. These projects are reprioritized each year based on updated condition assessment and performance data to ensure they are addressed in order of criticality. Additional funding is included in this investment for projects less than $1 million and to cover emergent needs or to coordinate system renewal needs with work initiated by other third parties such as the transmitter, land developers, municipalities, and road authorities. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as risks around property rights for poles, anchors and tree trimming required for feeder construction. For projects that require the construction of new stations, there are additional risks associated with the acquisition of new property such as the lack of a willing seller, delays due to negotiations with property owners, municipalities, and in some cases First Nation concerns. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

- Eliminated end-of-life assets to mitigate reliability, customer dissatisfaction, and safety risks;
- Improved power quality and load meeting capability of the system;
- Provide enhanced operating flexibility to mitigate customer impacts during planned outages or emergency situations;
- Improvement in overall cost effectiveness by implementing integrated solutions that address end-of-life assets, capacity, and operational needs simultaneously; and
- Reduced line losses.

Outcome Summary:

Customer Focus	• Avoided material deterioration in reliability and customer satisfaction. • Reduced outage duration by eliminating obsolete network equipment with non-standard designs/equipment. • Improved load meeting capability of the network. • Large customer needs for enhanced voltage support and other quality of power criteria addressed.
Operational Effectiveness	• Streamlined operations by eliminating multiple operating voltages and the requisite additional inventory, work methods and training needs. • Minimized cost by taking an integrated planning approach based on area supply needs. • Improved long-term operating and maintenance efficiency due to consolidating and reducing the number of system assets.
Public Policy Responsiveness	• Compliance with DSC requirements to maintain and plan the system in accordance with good utility practice. • Reduced overall environmental impact by eliminating stations where feasible.
Financial Performance	

Costs:

Construction costs for voltage conversion work can vary depending on conditions such as ground conditions, customer density, urban vs. rural, and condition of existing feeder assets. Newer lines built to present day standards can be converted to higher operating voltages at minimal cost, while older lines tend to require complete replacement and upgrading to current standards.

Costs are controlled by avoiding costly or complex design solutions where possible, by sub-contracting specialized civil work to external service providers, and by using intermediate step-down transformers where feasible to reduce the amount of line reconstruction work.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	22.7	31.8	25.3	30.6	35.9	146.2
Less Removals	2.2	4.6	2.9	1.6	0.9	12.2
Gross Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**
Less Capital Contributions						
Net Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**

**Includes Overhead at current rates.*

1 **Attachment 1 – Life Cycle Optimization & Operational Efficiency Projects List of**
2 **Projects >$1M**

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-1	Barrys Bay Voltage Conversion	Convert existing 4.16 kV lines to 12.5 kV and re-supply from adjacent 12.5kV system.	Eliminate end-of-life 4.16kV distribution station and refurbish old 4.16 kV lines.	1.8	2018
LC-2	Burford DS Removal	Convert two 8.32 kV feeders to 27.6kV and remove existing Burford DS.	Eliminate end-of-life station assets.	1.5	2018
LC-3	Margach DS F3 – SD3676 Voltage Conversion	Convert 7.2 kV single-phase line section to 14.4 kV.	Eliminate end-of-life step-down transformer and line equipment.	1.4	2018
LC-4	Beaver Valley RS	Construct New 44 kV Regulating Station & Remove Existing Eugenia RS.	Eliminate End of Life Assets and potential high impact spill risk at Eugenia RS.	1.5	2018
LC-5	Carlton Place DS's Reconstruction	Construct new dual-transformer 27.6 kV station and single-transformer 8.32 kV station with MUS facilities at the site of Carleton Place Bridge DS and Edmund DS. Construct a new 27.6 kV feeder to relieve the existing Carlton Place DS #2 F2 and install step-down transformers to eliminate 4.16 kV station.	Replace end-of-life station assets at Carlton Place DS #2, Carlton Place Bridge DS, and Carlton Place Edmund DS. Improve loop feed capabilities and supply capability in the Town of Carlton Place.	5.9	2018-2019
LC-6	Dresden DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Dresden DS.	Elimination of end-of-life station assets at Dresden DS.	2.6	2018-2019
LC-7	Dundas Sydenham DS Voltage Conversion	Convert 8.32kV line section to 27.6kV. Remove existing Dundas Sydenham DS.	Eliminate end-of-life station.	2.9	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-8	Coniston Voltage Conversion	Convert 22 kV 3-wire feeder and 22 kV connected substations to 44 kV operation.	Eliminate obsolete 22 kV system voltage and allow de-commissioning of Coniston TS T1/T2 transformers which are at end of life.	3.9	2018-2019
LC-9	Town of Forest Voltage Conversion	Convert 5-4.16kV feeders to 27.6kV to match incoming supply voltage. Remove Forest Jefferson DS and Forest McNab DS.	Eliminate end-of-life station assets at Forest Jefferson DS and Forest McNab DS.	3.2	2018-2019
LC-10	Hanmer TS Feeder Development	Construct 3 new 44 kV feeders from new Hanmer TS DESN.	Elimination of existing 44 kV off-road line sections fed from Martindale TS which are at end of life.	4.9	2018-2019
LC-11	Lucan Market DS Voltage Conversion	Convert two 4.16 kV feeders to 27.6 kV operation, install 2 x 2.5MVA 27.6-8kV step down transformers to replace existing 5MVA transformers at Lucan Market DS.	Eliminate end-of-life station assets at Lucan Market DS.	3.3	2018-2019
LC-12	Warkworth DS Removal	Offload station by reconfiguring and extending existing feeders from other adjacent stations, and remove Warkworth DS.	Eliminate end-of-life station assets at Warkworth DS.	2.9	2018-2019
LC-13	Grand Bend Downtown Voltage Conversion	Convert loads in downtown Grand Bend currently fed at 8.32 kV to 27.6 kV supply.	Eliminate end-of-life 8.32 kV line assets and reduce line congestion in main business section of Grand Bend.	1.3	2019
LC-14	Brookside DS Removal	Off load Brookside DS by building and reinforcing feeder ties to adjacent stations. Remove Brookside DS.	Eliminate end-of-life station assets at Brookside DS.	1.9	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-15	Drumbo DS Voltage Conversion	Convert two 8.32 kV feeders to 27.6kV to match incoming supply voltage and remove existing Drumbo DS.	Eliminate end-of-life station assets at Drumbo DS.	2.0	2019-2020
LC-16	Lily Lake DS Removal	Off load Lily Lake DS by building and reinforcing feeder ties to adjacent stations including some limited voltage conversion. Remove Lily Lake DS.	Eliminate end-of-life station assets at Lily Lake DS.	3.3	2019-2020
LC-17	Rondeau DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Rondeau DS.	Eliminate end-of-life station assets at Rondeau DS.	1.7	2019-2020
LC-18	Thorold Turner DS Voltage Conversion	Replace Thorold Turner DS with padmount transformers.	Eliminate end-of-life station.	1.0	2019-2020
LC-19	Wallaceburg DS Voltage Conversion	Convert 3-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Wallaceburg DS.	Eliminate end-of-life station assets at Wallaceburg DS.	1.7	2019-2020
LC-20	Devlin DS Rebuild and Voltage Conversion	Refurbish Emo DS and Devlin DS and replace existing 44-12.5 kV transformers with 44-25 kV units. Convert 12.5 kV line sections to 25 kV operation.	Replace end of life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.0	2020
LC-21	Blind River Voltage Conversion	Convert 12.5 kV feeder to 25 kV to match incoming supply voltage & remove Blind River DS.	Eliminate end of life station assets including obsolete single phase transformers.	1.0	2020
LC-22	Kemptville Area System Upgrades	Upgrade Kemptville West DS from 5 MVA to 7.5 MVA and add new feeder position.	Meet forecast load growth in the Town of Kemptville.	4.2	2020-2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-23	Maxville Area System Upgrades	Off load Maxville Prince DS by converting feeders from 4.16 kV to 8.32 kV and transferring to Maxville George DS.	Eliminate end-of-life station assets at Maxville Prince DS and eliminate 4.16 kV system in Town of Maxville.	4.2	2020-2021
LC-24	Prescott Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2020-2021
LC-25	Wardsville DS Voltage Conversion	Convert 8.32 kV feeder to 27.6kV to match incoming supply voltage and remove existing Wardsville DS.	Eliminate end-of-life station assets at Wardsville DS.	1.1	2020-2021
LC-26	Alexandria Area System Upgrades	Upgrade Alexandria Industrial DS from 5 MVA to 7.5MVA. Remove Alexandria – Margaret DS, East Boundary DS, Kenyon West DS and transfer loads to adjacent DSs. Convert the town 4.16kV feeders to 8.43kV.	Eliminate end-of-life station assets as Kenyon West DS, provide loop feeds for single contingency backup of DS's in the town of Alexandria.	3.8	2021
LC-27	Anderdon DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Anderdon DS.	Eliminate end-of-life station assets at Anderdon DS.	1.5	2021
LC-28	Town of Elliot Lake Station Upgrades	Replace Mississauga DS T2 transformer with larger unit and add second transformer at Porridge Lake DS.	Facilitate the elimination of Elliot Lake DS which is at end-of-life and improve load transfer capability in Town of Elliot Lake.	3.5	2021
LC-29	Vanastra DS Voltage Conversion	Convert 8.32 kV lines to 27.6 kV to match incoming supply voltage and install step-down transformers.	Eliminate Vanastra DS which is at end of life.	2.2	2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-30	Berwick-Finch Area Upgrades	Offload Crysler DS F2 onto Casselman DS F1 by reinforcing feeder ties.	Crysler DS F2 feeder load is approaching planning guideline.	4.2	2021-2022
LC-31	Brockville Distribution System Upgrades	Upgrade various distribution feeder sections within the Town of Brockville.	Replace end-of-life distribution line assets, including direct buried cable, and eliminate back lot construction.	4.2	2021-2022
LC-32	Chesterville Area Upgrades	Add a second 5 MVA 44-8.32 kV transformer at Frood DS and one with additional feeder. Convert 5 existing 4.16 kV feeders to 8.32kV and remove Chesterville DS#2 & Brennen DS.	Eliminate end-of-life station assets at Chesterville DS #2 and Brennen DS and standardize on a single voltage 8.32 kV in the Town of Chesterville.	4.2	2021-2022
LC-33	Ivy Lea Area System Upgrades	Upgrade Ivy Lea DS station capacity.	Provide load relief to transformer loaded above planned load limit.	4.2	2021-2022
LC-34	Russell Area System Upgrades	Offload Russell DS to the neighbouring stations and Remove Russell DS.	Eliminate end-of-life station assets at Russell DS.	4.2	2021-2022
LC-35	Smiths Falls System Upgrades	System upgrades to allow removal of Smith Falls James DS.	Address end-of-life station assets and reliability risks due to lack of MUS facilities.	4.2	2021-2022
LC-36	Actons Corners Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2022
LC-37	Sleeman DS Rebuild and Voltage Conversion	Rebuild Sleeman DS at a new location and convert 12.5 kV line sections to 25 kV.	Replace end-of-life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.4	2022

SR-14 Advanced Meter Infrastructure Hardware Refresh

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	79.9
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. There are several factors that can trigger the need to upgrade these meters; some of the key factors are listed below:

- Hydro One Distribution is accountable, based on the market rules, to upgrade wholesale meter installations to a retail revenue meter when customers decide to become a retail customer of Hydro One Distribution at seal expiry;
- Hydro One Distribution has acquired non-standard meter installations due to a boundary change or the outright acquisition of an LDC;
- Hydro One Distribution has a population of 600V self-contained meters that are being replaced with inherently safer 120V transformer rated meters;
- Hydro One Distribution is required by the Distribution System Code, to upgrade existing customer's demand meters to interval meters when the average annual monthly peak demand is equal to or greater than 50 kW. There is also a requirement to install interval meters for customers who exceed 150,000 kWh of energy consumption per year; and
- Hydro One Distribution will require to replace smart meters once these meters reach the end of expected service life.

Alternatives:

No alternatives are considered, since this program represents the minimum level of work to satisfy Hydro One Distribution's operational requirements. Replacement of meters is critical to maintaining a reliable source of billing settlement data.

Investment Description:

This investment provides planned upgrades to address meters that no longer meet current standards, are obsolete, have reached end of service life; and to address regulatory requirements imposed by the Distribution System Code. The work includes, but is not limited to the following:

- Upgrade wholesale meter installations or acquired non-standard retail meter installations to Hydro One Distribution's current retail revenue meter standard;
- Upgrade 600V self-contained meters, with expired seals, with new 120V meters. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, allows Hydro One Distribution to meet expired seal obligations, eliminates a reliance on a single source supply as like-for-like replacements are not readily available on the market, and assists in standardizing inventory;
- Upgrade existing customer's meters to interval meters or demand meters when the energy consumption exceeds the thresholds set out in the Distribution System Code; and
- Replace smart meters which have reached the end of their expected service life. Smart meters have a manufacturer service life of 15 years, therefore, meter replacements will commence in 2021 with 3,621 replacements and another 206,119 replacements in 2022. A similar level of replacements will be required beyond the planning period.

The forecast of the number of meters requiring replacement and upgrade annually over the five year period is provided in the table below. The capital investment of each meter upgrade is below $1 million.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Meter Upgrades/Replaced	341	341	341	4,134	206,632

Risk Mitigation:

The risks to completion of this investment as planned are the availability of the vendor to manufacture and deliver the meters in a timely manner, and the availability of qualified resources to perform the volume of replacements required. These risks are mitigated by providing procurement forecasts upfront to the vendor, maintaining ongoing discussions with vendor regarding future product supply, and managing resources with option to hire temporary staff as required.

Result:

This meter upgrade program will result in:

- Ensuring timely replacement of meters,
- Complying with regulatory requirements, and
- Ensuring a continue reliable source of billing settlement date for customers.

Outcome Summary:

Customer Focus	• Maintain billing accuracy and customer confidence by ensuring reliable meter performance.
Operational Effectiveness	• Maintain reliable operation of the meter and meter infrastructure network by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the OEB Distribution System Code Section 2.10 “Estimated Billing” requirement for no more than 2 estimated meter reads per year and Section 7.11 “Billing Accuracy” requirements.
Financial Performance	• Avoid the cost of manual meter reading through timely replacement of meter and network equipment.

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The accessibility conditions of the area in which the meters are being replaced. Accessing off road locations or replacing a meter on a lake cottage can be more costly due to the use of specialized equipment.

Controllable costs have been minimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.0	0.0	0.0	1.4	78.5	79.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**0.0**	**1.4**	**78.5**	**79.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**0.0**	**1.4**	**78.5**	**79.9**

**Includes Overhead at current rates.*

SS-01 Remote Disconnection / Reconnection Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	28.5
Primary Trigger:	System Efficiency		
Secondary Trigger:	Customer Service Requests		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. From time to time, there is a need to have power to these meters disconnected and/or reconnected as a result of customer non-payment and vacant premises.

Hydro One makes every effort to work proactively with customers to address billing issues and adheres closely to all steps mandated in the OEB Distribution System Code. Disconnection is only considered as a last resort; as customers rely on their power and understandably become upset if a decision is made to disconnect power. Hydro One makes every effort to take swift action in the reconnection of power for customers in order to reestablish important electrical services to their home or business.

Hydro One currently implements a manual disconnection and reconnection process, requiring at least two trips to the customer premises. These disconnection and reconnection activities cause between 10,000 and 21,000 on-site visits per year. The costs and associated risks of this manual process can be avoided with the utilization of meters that have the functionality to execute remote disconnection and reconnection.

Alternative 1: Continue Manual Disconnections/Reconnections

Continue to manually disconnect and reconnect customer meters when required in accordance with Section 4.2 of the OEB Distribution System Code. This alternative is rejected as it will not result in improving the customer experience or achieving operational efficiencies.

Alternative 2: Remote Disconnections/Reconnections *(Recommended)*

Install new meters with remote disconnection and reconnection functionality at customer sites where non-payment and/or vacant premises situations exist. This alternative is recommended as it will reduce the number of visits to customer premises resulting in operational efficiencies, and improve customer experience by providing a faster response time for disconnection and reconnection requests. Active and timely actions to address customers in arrears also assists customers in staying current with their invoices and reducing bad debt expenditure.

Investment Description:

This investment addresses the replacement of existing meters at customer premises with new meters capable of remote disconnection and reconnection functionality. Meter replacements will be identified for replacement when disconnection required based on assessment of customer accounts in arrears due to non-payment and/or customer premises with noted vacancy. These replacements are to be rolled out in stages as work orders are authorized and appropriately approved for action of disconnection. The table below is an annual forecast of meter replacements.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Meter Replacements	11,875	11,500	11,125	10,750	10,375

Once the new meters are installed, the actual execution of the reconnection (or disconnection) is accomplished within a few minutes after the customer request has been authorized and appropriately approved for action thereby reducing lost revenue for unbilled power, and providing improved customer service through faster response time.

Risk Mitigation:

The risks to completion of this investment as planned are the availability of the vendor to manufacture and deliver the meters in a timely manner, and the accessibility of the meters required to be replaced. These risks are mitigated by providing procurement forecasts upfront to the vendor, maintaining ongoing discussions with vendor regarding future product supply, and managing coordination with resources required to gain access.

Result:

This remote disconnection/reconnection program will result in:

- Reducing the number of required visits customer premises thereby delivering operational efficiency, and potentially avoiding approximately $4.5 million in costs annually arising from on-site reconnections and disconnections and the safety risks related to driving hours; and
- Improving the customer's experience by providing a faster disconnection or reconnection response time.

Outcome Summary:

Customer Focus	• Improve customer experience by providing a faster response time for disconnection and reconnection requests.
Operational Effectiveness	• Increase operational effectiveness by executing the disconnection/reconnection process in a more efficient manner. • Reduce employee safety risks related to driving hazards by avoiding travel to customer premises.
Public Policy Responsiveness	• Comply with the OEB Distribution System Code Section 4.2 regarding disconnection and reconnection process.
Financial Performance	• Avoid the cost arising from on-site reconnection/disconnection at customer premises by installing new meters with remote reconnection/disconnection functionality.

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.

Controllable costs have been minimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	5.9	5.9	5.8	5.8	5.7	29.1
Less Removals	0.1	0.1	0.1	0.1	0.1	0.6
Gross Investment Cost	**5.8**	**5.8**	**5.7**	**5.6**	**5.6**	**28.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**5.8**	**5.8**	**5.7**	**5.6**	**5.6**	**28.5**

**Includes Overhead at current rates.*

SS-02 System Upgrades Driven by Load Growth

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	190.0
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

Over time, new customers connect to the system, and load growth occurs as a result. This also occurs due to increased loading at some existing customers who may increase their service sizes. This places additional stress on the elements of the distribution system. Increases in distribution station and feeder loading can lead to system elements operating at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load.

In accordance with Section 3.3 of the Distribution System Code ("DSC"), Hydro One Distribution plans and executes enhancement projects on its distribution system to improve system operating characteristics and relieve system capacity constraints. This investment covers major system upgrades that are needed in response to load growth.

Investments with a gross cost less than $300,000 are normally included in either the Distribution System Modifications (ISD SS-05) or Demand Investments (ISD SS-04) capital programs.

The capability of the Hydro One distribution system to accommodate forecast loading needs is determined through the following four main activities:

1. load versus capability screening at the station and feeder levels;
2. planned feeder studies (six-year cycle studies);
3. system impact assessments for large new load connections; and
4. assessment of field and customer identified issues related to power quality or other operating concerns.

Load versus system capability and planned feeder studies (six-year cycle studies) are the main pro-active planning activities carried out to assess the capability of Hydro One's system to accommodate existing and forecast needs. These activities take into account the capability of the network to meet load needs based on normal anticipated load growth. Load growth rates vary for different segments of the system. For example, the growth rates can differ significantly between urban and rural segments. Normal load growth is determined locally within the system based on historical trends, known or planned development in an area, and information from local municipalities including official plan documents and long-term population projections. In some cases, local power quality or reliability issues may be identified by field staff or customers due to specific local loading issues or changes that develop over time and may need to be addressed through system upgrades. If these issues cannot be accommodated under the Demand Investments capital program (ISD SS-04) then a major capital project may be required.

For all new load connections or customer upgrades above 500 KVA, and for new subdivisions with more than fifteen lots, a distribution system impact assessment is conducted in order to determine the impact of the proposed load with respect to equipment ratings, voltage and protection criteria, and planning guidelines. Where planning criteria will be violated, system upgrades may be required. Where an upgrade is required in order to meet the specific loading needs of one individual customer, a customer contribution may be required based on a discounted cash flow evaluation of future revenues and costs.

For distribution feeders, planning guidelines for load-ability have been established based on feeder voltage level. Planning guidelines are used to conduct high-level screening of system capability to maintain loading within equipment ratings, meet system voltage and protection needs, and ensure a reasonable degree of operating flexibility and efficiency. Planning guidelines are based on typical feeder topology and lengths. In some parts of Hydro One's distribution system where feeder distances are significantly long or load centers are far from the supply station, technical considerations such as voltage and system protection needs restrict maximum feeder loading to values, which are less than the planning guidelines.

Where major new capacity upgrades are deemed necessary through load screening or other means, Hydro One uses an integrated planning approach to identify and develop the optimal system development plans for a specific area. This involves assessing other potential system needs in the surrounding network from the perspective of capability, performance, operability, sustainment, and efficiency/effectiveness. Once the full long-term needs for the system are determined, integrated solutions are identified to ensure the long term viability of the network in the most cost-effective manner.

Alternative 1: Allow System Assets to Become Overloaded

Wait until overloaded assets reach critical values such that customers are experiencing significant power quality issues, or a material decrease in reliability is observed.

This alternative was rejected since it does not satisfy the DSC requirement for a distributor to enhance its system in response to normal load growth. Also, due to the long lead times needed to implement effective solutions, there would be significant customer dissatisfaction due to on-going power quality issues and reduced reliability.

Alternative 2: Upgrade System to Meet Normal Load Growth (Recommended)

Pro-actively monitor system loading, conduct system studies for forecast new load connections and develop appropriate investment plans to address system needs based on forecast load.

The recommended plan satisfies section 3.3 of the DSC, which requires distributors to plan and expand their systems in response to normal load growth. Identifying and implementing major projects to maintain loading on assets within design ratings ensures acceptable delivery voltage is provided to customers, that reliability is maintained at acceptable levels, and that system assets are not exposed to undue stress.

Investment Description:

System load growth over the next five years is expected to be in line with recent historic growth patterns. Approximately 90,000 new customer connections and 27,000 service upgrades are forecast for the 2018-2022 time period. Cancellation of about 34,000 existing services is also anticipated for an overall increase in customers of 56,000 or 4.4% of the existing customer base over the next five years.

The majority of growth and new customer connections are expected to occur in Hydro One's urban service territories which border major urban centers including the City of Ottawa, City of Kingston, northern York and Peel Regions, Durham Region, and the City of Hamilton. For the remainder of Hydro One's service territory which is mostly rural in nature, load growth and new customer connection activity is expected to be in line with historic rates which are generally lower.

Proposed investments to address load growth include station upgrades, feeder upgrades and modifications, new feeders, construction of new distribution stations and new voltage regulating stations, and conversion of feeders to higher voltages. Also included are feeder development projects in accordance with recommendations of Regional Infrastructure Plans. A list of all planned system upgrades in excess of $1 million along with their proposed timing is provided in Attachment 1. Additional funding is included to cover projects less than $1 million as well to cover emergent needs due to unforeseen customer connections or upgrades.

There are a variety of ways to relieve overloaded equipment. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Feeder Reinforcement: One common solution is to redistribute load through reinforcement projects. In urban areas, this can entail upgrading or creating new radial loops. These projects focus on optimizing load distribution by reconfiguring existing feeders to enable load transfers between phases, and between different feeders. By extending feeders, installing new phases and tie points, and updating feeder protections, lightly loaded feeders can offload heavily loaded sections.

Station Upgrade: Station upgrade projects are executed in areas where the existing configuration cannot be utilized to offload equipment that has reached its planned loading limit. Instead, additional capacity must be added to the system. Station upgrades involve an increase in capacity to existing stations by upgrading transformer sizes; installing additional transformers; increasing the station's secondary voltage (voltage conversion at the station); or installing fan monitoring to cool station transformers. These projects also include adding new feeder positions at the station to increase the number of available feeders.

Construct New Station: In some situations, constructing a new station is more effective from a cost and operating perspective than upgrading an existing station. In these cases, a new distribution station is installed and incorporated into the distribution system. New feeders are also used to provide additional capacity to areas that are overloaded. These feeders may be built to compliment the construction of a new distribution station.

Voltage Conversion: To increase equipment ratings and capacity, feeders may also be converted to higher voltage levels. These upgrades may coincide with a station voltage conversion or may involve a reconfiguration with nearby feeders that operate at higher voltage levels.

Risk Mitigation:

The main risks concerning project execution are real estate/property rights, shortage of qualified labour, customer delays, and delays in finalizing development plans.

Construction of new stations requires acquisition of new property and is subject to delays due the lack of a willing seller, negotiations with property owners, municipalities, and in some cases First Nation concerns. Construction or upgrading of feeders requires occupancy rights on road allowances or private property, as well as cutting rights and anchoring easements on private property. Delays, or the inability in obtaining these rights, can lead to the need for re-design, or route alterations. In some cases, road authorities may have coinciding plans for road widening or other construction, which need to be coordinated with new pole locations resulting in delays to line construction work. These risks are mitigated by providing appropriate lead times during the design and estimating stages to allow sufficient time for obtaining necessary property rights. For new station or station upgrade work, Hydro One has recently implemented a new project planning approach where any new property needed will be determined and acquired prior to commencing engineering/design work.

Execution of the proposed station and feeder construction projects identified in this investment driver requires the coordinated efforts of multiple technical and engineering disciplines some of which are highly specialized. Lack of available resources in these specialties can lead to project delays. These risks are mitigated by establishing appropriate project time lines in conjunction with internal and external service providers to reflect available resources for design and construction.

Projects that are being driven by specific customer requests or by specific development needs are also subject to delays due to changes in the customers’ or developers’ timing.

Projects are reprioritized each year as new loading information and updated forecasts become available to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement due to unforeseen load growth or specific customer requests. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Result:

System Upgrades Driven by Load Growth will result in:

- Ensuring there is adequate capacity within the distribution system to meet existing and forecast customer load needs;
- Maintaining acceptable Power Quality throughout the distribution system;
- Ensuring the safe and reliable operation of the distribution system;
- Reducing the risk of lengthy customer outages caused by failure or malfunction of overloaded assets;
- Balancing loads to allow for additional customer connections and to improve voltage and power quality;
- Reducing line losses; and
- Providing additional supply options to relieve overloaded feeders and enable future load growth and customer connections.

Outcome Summary:

Customer Focus	• Meet load needs of existing and new customers. • Ensure acceptable delivery voltage and other quality of power criteria are provided to customers. • Improve customer reliability.
Operational Effectiveness	• Maintain safe and effective operation of the distribution system. • Minimize overall costs by taking an integrated planning approach based on an overall assessment of area supply needs.
Public Policy Responsiveness	• Meet requirements of the Distribution System Code to plan the system to accommodate reasonable forecast load growth. • Comply with equipment standards which include Renewable Energy enabling technologies.
Financial Performance	

Costs:

Costs are primarily affected by design requirements and conditions of construction. Hydro One uses three main styles for new station construction based on rural vs. urban as well as operating requirements. The optimal design solution is based on a number of factors including property availability, capacity requirements, operational needs, compatibility with surrounding land uses, as well as environmental mitigation needs.

Feeder construction costs can vary widely depending on conditions such as ground type (soil vs. rock), tree density where right-of-way clearing or expansion is required, underground vs. overhead, and whether it is green field construction versus upgrading or overbuilding of existing lines. Costs are controlled by avoiding costly or complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions) -	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	47.6	55.9	46.6	34.5	24.6	209.2
Less Removals	4.4	4.5	3.6	1.8	2.0	16.3
Gross Investment Cost	**43.2**	**51.4**	**42.9**	**32.7**	**22.6**	**192.9**
Less Capital Contributions	2.8					2.8
Net Investment Cost	**40.4**	**51.4**	**42.9**	**32.7**	**22.6**	**190.0**

**Includes Overhead at current rates.*

1 **Attachment 1 – System Upgrades Driven by Load Growth**

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-1	Cumberland DS F4 Development	Extend the lightly loaded F4 feeder from Cumberland DS to meet with the more heavily loaded F2.	Provide a loop feed for the Cumberland urban load area and meet future load needs.	1.2	2018
LG-2	Devlin DS F1 3 Phase Upgrade	Upgrade 3 km of two-phase and 1.5 km of single-phase line to three-phase along Highway 613.	Address single phase line loading above Planning Guidelines.	1.0	2018
LG-3	Kleinburg TS M6 Mayfield Rd Line Extension	Extend 27.6 kV along Mayfield Road, for approximately 4 km, from Airport Rd to Dixie Road.	Improve supply efficiency and reliability and provide capability to supply future loads along Mayfield Road in the Town of Bolton.	1.0	2018
LG-4	Orangeville TS M3 - Mayfield West Line Extension	Extend 44 kV feeder from Chinguacousy Rd, east along Old School Road, for approximately 6 km.	Introduction of 44kV to the Mayfield West area, to facilitate connection of anticipated industrial loads, and to construct a future Old School Road DS.	1.8	2018
LG-5	New Bradford North DS	Construct new 44-27.6 kV DS, as well as associated feeders.	To meet forecast residential and commercial load growth in the Town of Bradford West Gwillimbury.	5.0	2018-2019
LG-6	Caledonia TS M3 Extension	Convert 7.5 km of 4.16 kV line to 27.6kV and transfer load from Jarvis TS M3 to Caledonia TS M3.	Relieve overloaded step-downs and improve reliability to Six Nations.	1.1	2018-2019
LG-7	Alfred DS F2 Feeder Upgrades	Upgrade 6 km of single-phase line to three-phase, balance loads between phases, and between F1 and F2 feeders.	Single phase line section loaded above planning guideline.	2.4	2018-2019
LG-8	Cameron DS Feeder Improvements	Construct new F2 feeder out of Cameron DS and upgrade existing single phase line to three phase along Monarch Road and Hwy 35.	To meet forecast residential load growth in west part of the Town of Lindsay.	1.4	2018-2019
LG-9	Armitage TS M22 Extension	Extend M22 feeder by double circuit with existing M12 feeder, for approximately 6 km. Transfer Wesley DS from M12 to M22.	Provide load relief to Armitage TS feeder M12 which is loaded beyond planning guidelines.	2.0	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-10	City of Owen Sound Tie-Line Reinforcement	Construct new 4.16 kV tie-lines between 24th St West DS and 2nd Ave West DS, and between 6th Street East DS, and 2nd Ave East DS.	To provide loop feeds for single-contingency back up of DS transformers which do not have MUS facilities.	1.3	2018-2019
LG-11	Enfield TS Feeder Development	Construct two new 44 kV feeders out of Enfield TS consisting of 18 km of new feeder line.	To meet forecast load growth in Durham Region.	7.6	2018-2019
LG-12	Grand Bend DS F3 Voltage Conversion	Convert existing 8.32 kV feeder to 27.6 kV and connect to Grand Bend East DS F2 feeder.	To address substandard voltage being experienced by customers along the Lake Huron shoreline south of Grand Bend.	2.4	2018-2019
LG-13	Kirkland Lake Voltage Conversion – Part 1	Rebuild Goodfish DS and replace 44-4.16 kV transformer with a 44-12.5 kV unit. Convert Goodfish DS F8, F9, F10 feeders from 4.16 kV to 12.5 kV.	Meet future load needs in the Town of Kirkland Lake and eliminate obsolete metalclad switchgear at Goodfish DS.	4.8	2018-2019
LG-14	Leamington TS Feeder Development	Build 8 new 27.6 kV feeders from Leamington TS, transfer load and DG from Kingsville to Leamington TS, and partial 8.32 kV DS conversion to 27.6 kV.	Meet future load needs in the towns of Kingsville and Leamington consistent with Supply to Essex County Transmission Reinforcement (SECTR) work.	3.7	2018-2019
LG-15	Manotick DS Feeder Development	Extend new F3 feeder to off-load existing F1 feeder and to connect to new residential subdivisions.	To connect new residential subdivisions in Manotick to new F3 feeder.	2.6	2018-2019
LG-16	Stouffville 10th Line DS New T3 & Feeder	Construct new DS with 2 x 44 - 27.6 kV and 1 x 44 - 8.32 kV transformer.	Replace existing end-of-life 8.32 kV T1 station assets and add more capacity to meet the load growth in the Town of Stouffville.	6.6	2018-2019
LG-17	Town of Shelburne Voltage Conversion	Convert 4.16 kV feeders to 8.32 kV and rebuild Shelburne DS as a single-transformer station, 44-8.32kV. Remove existing T1 and T2 transformers.	Increase transformer and feeder capacity at Shelburne DS to meet forecast load growth.	8.4	2018-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-18	Twelve Mile Bay DS - New Station & Feeders	Construct a new 44-12.5 kV station including 1 km of new 44 kV line with 12.5 kV underbuild, and install 11 km of new three-phase submarine cable in Georgian Bay to connect the new station to the Honey Harbour DS F1 feeder.	Provide load relief to Foots Bay DS which is loaded above its PLL, and to the Honey Harbour DS F1 feeder which does not meet system protection requirements.	4.0	2018-2019
LG-19	Beckwith DS F3 Feeder Development	Extend new Beckwith DS F3 feeder to off-load F1 and T1 transformer.	Relieve T1 overloading and create a three-phase loop feed for urban customers.	1.8	2019
LG-20	Crilly DS Replacement and Transformer Upgrade	Construct new Crilly DS 2 km from existing DS site. New Crilly DS will be supplied from Hydro One 115 kV circuit.	Address overloaded transformer and eliminate non-standard supply from privately owned generating station bus.	6.7	2019
LG-21	Kirkland Lake Voltage Conversion-Part 2	Replace 44-4.16 kV transformer at Woods DS with a 44-12.5 kV unit. Convert Woods DS F5, F6, F7 feeders from 4.16 kV to 12.5 kV.	To meet future load needs in the Town of Kirkland Lake.	2.0	2019
LG-22	Manotick DS F3 New Feeder	Add new feeder position and underground egress to connect new F3 Feeder	To meet forecast residential load growth in the Village of Manotick	1.9	2019
LG-23	Margach DS F3 Voltage Conversion - SW676	Extend Keewatin DS feeder F2 for 3.5 km to off-load part of the Margach DS F1 load onto Keewatin DS F2.	Provide load relief to overloaded step-down transformer.	1.4	2019
LG-24	Muskoka TS M5 x M1 Feeder Tie	Extend the Muskoka TS M5 feeder for 14 km from Ullswater DS to the village of Rosseau by overbuilding existing 12.5 kV feeders with 44 kV.	To facilitate off-loading Parry Sound TS through a load transfer to the Muskoka TS M1 feeder and to create a 44 kV loop feed around Lake Rosseau.	5.3	2019
LG-25	Rockland DS T2 Transformer	Install a second transformer at Rockland DS.	Provide load relief to existing T1 transformer and meet forecast load growth.	2.3	2019
LG-26	Barrie TS - Construct New Feeders	Construct 8 km of New 2-circuit 44 kV Line from Barrie TS to Salem Road.	To meet forecast load needs of InnPower embedded LDC.	2.6	2019-2020
LG-27	Caledonia TS New Feeders	Construct 6 km of new 27.6 kV feeders from Caledonia TS.	Relieve Existing Feeders which are loaded above planning guideline.	4.3	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-28	Dundas TS #2 New Feeders	Construct 2.5 km of new feeders from Dundas TS#2. Construction will be done across the Niagara Escarpment and through a subdivision.	To provide load relieve to Dundas TS T1/T2 DESN.	6.7	2019-2020
LG-29	King City DS - New Station & Feeders	Construct a new 44-13.8kV DS. Build feeder ties with existing 13.8kV feeders from Eversley DS, and balance load between feeders / stations.	Provide a second 13.8 kV source of supply for King City to enable loop feeds and meet future load growth.	4.6	2019-2020
LG-30	New Old School DS	Construct a new 44-27.6kV DS. Construct 27.6kV feeders and tie to Snelgrove DS and Kleinburg TS M6.	Relieve capacity issues at Snelgrove DS, and provide a second 27.6kV source to improve loop feed supply.	7.0	2019-2020
LG-31	Town of Dundalk Voltage Conversion	Construct a new 44-8.32kV DS. Convert existing 4.16kV loads within the town of Dundalk to 8.32 kV, and remove existing 44-4.16kV transformer.	Provide increase station and feeder capacity to meet forecast load growth in Town of Dundalk.	9.5	2019-2021
LG-32	Greely DS F1 Feeder Development	Extend F1 feeder from Greely DS to offload existing feeders.	To meet forecast load growth in south Ottawa.	1.5	2020
LG-33	Kirkland Lake Voltage Conversion-Part 3	Convert Kirkland Lake DS #1 F1, F2, F3 feeders from 4.16 kV to 12.5 kV and re-supply from Goodfish DS and Woods DS. Remove Kirkland Lake DS #1.	Meet future load needs in the Town of Kirkland Lake and eliminate Kirkland Lake DS #1 which has obsolete switchgear and is located inside the Kirkland Lake TS yard.	2.8	2020
LG-34	Midhurst Wilson DS F2 Extend to Doran Rd	Overbuild 6.5km of existing 8.32 kV line with new 27.6 kV feeder from Wilson Road to Doran Road.	To meet future residential subdivision growth in the north-east Midhurst Area (Midhurst Secondary Plan – Neighbourhood 2).	2.2	2020
LG-35	Midhurst Wilson DS F1 Extend to Dobson Rd	Extend Midhurst Wilson DS 27.6 kV feeder for 3.5 km to Dobson Rd by converting existing Grenfel DS F2 feeder from 8.32 kV to 27.6 kV.	Address forecast overloading of Grenfel DS F2 feeder due to residential subdivision load growth.	2.2	2020
LG-36	Perth Area Upgrades	Reconstruct station egress’s with higher capacity underground cable.	Provide back feed capability for single contingency station transformer outage.	2.0	2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-37	Macville DS - New 27.6kV Station	Extend Kleinburg TS M26 44 kV feeder for 2km and construct a new 44-27.6kV DS.	Provide Additional DS capacity to meet forecast load growth in the Town of Caledon.	3.7	2020-2021
LG-38	Wikwemikong DS & Line Work	Build a 15 kV 44 kV feeder extension by overbuilding existing a 12.5 kV line and construct a new 44-12.5 kV station. Upgrade an additional 3 km of existing 12.5 kV line to double-circuit.	To meet forecast load growth at Wikwemikong First Nation on Manitoulin Island.	6.5	2020-2021
LG-39	Dunchurch DS F2 - Extend to Magnetewan	Upgrade 10 km of existing single-phase line to three-phase and build 1 km new line to extend Dunchurch DS F2 feeder to Town of Magnetewan.	Provide load relief to Burks Falls DS F2 feeder which is loaded above planning guidelines and does not meet system protection criteria.	2.8	2021
LG-40	Fairbanks Lake Line Upgrade	Upgrade 2.6 km existing single-phase line to three-phase and build 8.7 km of new three-phase line.	To Address Substandard Feeder Protection on existing Whitefish DS F1.	2.5	2021
LG-41	Kleinburg TS M26 extension to Mayfield West	Extend Kleinburg TS M26 to Mayfield West (approximately 12 km).	Provide load relief to Pleasant TS M21 feeder based on forecast loading.	3.2	2021
LG-42	Lively DS F2 SW142 Upgrade Black Lake Road	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.4	2021
LG-43	Mar DS – New Station	Construct a new 44-12.5 kV station and 2 km of new 12.5 kV feeders.	Provide load relief to Colpoys Bay DS which is loaded above the transformer Planned Load Limit (PLL).	3.0	2021
LG-44	Ancaster West DS Transformer Upgrade	Upgrade Ancaster West DS transformer from 5 MVA to 7.5 MVA.	Provide DS Capacity to meet forecast load growth.	2.0	2021-2022
LG-45	Brockville 44kV System Upgrades	Extend Brockville M7 and Morrisburg M24 feeders to off load B1R and M5 feeders.	Provide load relief to Brockville TS B1R & M5 feeders which are currently loaded above planning guidelines.	10.5	2021-2022

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-46	Manitoulin TS - Add Third 44 kV Feeder	Add new 44 kV breaker at Manitoulin TS, new feeder tie switches, and construct 1.5 km new 44 kV line to Little Current DS.	To maintain 44 kV feeder loading within protection limits during transformer or breaker outages.	4.6	2021-2022
LG-47	Point Au Baril DS F2 Extension	Extend the Point Au Baril DS F2 feeder for 8.5 km by double-circuit the existing F1 feeder north of Point Au Baril.	To provide load relief to the Point Au Baril DS F1 feeder which has substandard system protection and voltage.	3.6	2021-2022
LG-48	Aspdin DS F1 Feeder Upgrade	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.3	2022

SS-03 Reliability Improvements

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	33.1
Primary Trigger:	System Efficiency		
Secondary Trigger:	Reliability		

Investment Need:

The Hydro One distribution system is normally planned based on a radial supply configuration. Due to system growth and development over time, there may be alternate feeds available to certain load centres or specific customer locations. However, alternate feeds may not be capable of supplying the entire load. Also, in many cases, only a single radial supply exists so there are no opportunities to transfer load during outages. Extended outages can be particularly disruptive to commercial and industrial customers due to lost business or lost productivity and in some cases lost/damaged product due to processing interruptions. Some industrial customers may also be sensitive to momentary supply interruptions due to lightning or even to voltage fluctuations which may occur when lightning strikes other parts of the system that do not directly supply them.

To improve reliability and increase customer satisfaction in certain areas, investments focused on improving backup capability, adding new tie-lines, and lightning mitigation may be needed.

Alternative 1: Status Quo

Address customer concerns about poor reliability in sensitive areas on a reactive basis only.

This alternative is rejected since it would lead to decreased customer satisfaction and continued poor reliability in areas where concerns have already been expressed. Not proceeding with this investment would leave customers susceptible to longer and more frequent outages that are characteristic of radially configured lines. The risk of serving customers at unacceptable power quality levels will also increase. If left unaddressed, poor power quality can lead to equipment damage and sustained outages for customers.

Alternative 2: Targeted Reliability Improvements (Recommended)

Implement targeted projects to improve reliability in areas where customer concerns have been raised and where practical system development opportunities exist to meaningfully improve system capability and performance.

Investment Description:

There are a variety of ways to improve system reliability. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Examples of projects to improve reliability include building tie lines to provide alternative supply capabilities, installing express feeders to critical load centers, improving sectionalizing capabilities on multi-branch feeders, adding voltage regulators or upgrading conductor to improve capability of existing ties, and installation of lightning arrestors on feeders. These reliability investments typically occur in areas with a high customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

<u>Constructing Alternative Supply Options & Improving Sectionalizing Capabilities</u>: To minimize the duration of an outage experienced, customers can be temporarily supplied by alternative sources as the faulted section of line is addressed. This is typically achieved by connecting two or more feeder sections through tie-lines and ensuring that appropriate equipment is in place to enable switching over to the alternative supply. Improved sectionalizing capabilities help reduce the number of customers impacted by sustained power interruptions.

<u>Reducing Line Exposure</u>: By decreasing the circuit length of a feeder, the total amount of conductor exposed to the elements is lessened. This reduces the likelihood of that circuit experiencing a fault due to natural elements, such as trees.

<u>Improving Power Quality through Line Upgrades</u>: Power quality can be improved by increasing conductor sizes or installing voltage regulating equipment.

<u>Installing Lightning Arrestors</u>: Lightning arrestors are used to prevent power interruptions due to lightning strikes. These are installed on feeders that experience a high frequency of lightning storms.

The proposed overall expenditure includes placeholder funding of approximately $3 million annually for planned reliability improvements to large distribution account customers based on customer engagement sessions.

A list of planned and scoped projects in excess of $1 million over the 2018-2022 period is provided below.

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
RI-1	Nebo TS Feeder Extension to Binbrook	Construct a new 6 km 27.6 kV feeder and tie to Nebo TS M5.	Provide a loop feed for Binbrook area.	2.8	2019-2020
RI-2	Tilbury DS New Feeder	Add a new 27.6 kV feeder position at Tilbury West DS, construct 0.6 km 27.6kV feeder and transfer Tilbury West DS F2 load to the new feeder position	Provide a loop feed for Town of Tilbury and lighthouse cove area.	1.9	2019
RI-3	Puslinch DS 4th Feeder	Construct a new 27.6kV feeder for 2 km out of Puslinch DS.	Provide a dedicated supply to industrial customers for improved reliability.	2.9	2021
RI-4	Orangeville TS M3-M6 Tie Line	Construct approximately 10km of new 44kV line between Caledon DS and Sleswick DS (along Charleston Road).	Provide a loop feed for to enable backfeed during outages.	2.6	2022
RI-5	Tilsonburg-Norfolk Tie Line	Construct 4 km 27.6kV feeder tie between Tilsonburg TS M1 and Norfolk TS M1.	Provide backup supply for Town of Delhi loads.	1.1	2022

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as the usual risks around property rights for poles, anchors and tree trimming. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

Reliability Improvement projects will:

- Improve customer satisfaction levels, particularly where customer concerns have been raised;
- Reduce outage durations for specific load centers or customers; and
- May improve operational efficiency and safety through increased system flexibility on projects involving tie-line upgrades.

Outcome Summary:

Customer Focus	• Reduce outage durations/frequency for sensitive customer loads. • Reduce lengthy outages to certain areas by providing an alternate feed capability. • Mitigate voltage fluctuations due to lightning activity for industrial customers.
Operational Effectiveness	• Allow increased operational flexibility to supply some loads by an alternate means in order to perform planned and unplanned maintenance.
Public Policy Responsiveness	
Financial Performance	• Cost saving opportunities such as making provisions for future circuits or tie-lines during routine work such as road relocation, end-of-life pole replacements are pursued when possible. • Maximum benefit/cost outcome is a primary factor taken into consideration when selecting appropriate investments under this category.

Costs:

Cost estimates are based on historical actual costs. Costs are mainly affected by design requirements and conditions of construction. Costs are controlled by avoiding costly and complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	5.2	7.9	7.2	8.2	9.2	37.6
Less Removals	0.6	1.0	0.9	1.0	1.1	4.5
Gross Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**
Less Capital Contributions						
Net Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**

**Includes Overhead at current rates plus Allowance for Funds During Construction*

SS-04 Demand Investments

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	19.9
Primary Trigger:	Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

Minor distribution system modifications are required to address system needs identified by customer power quality complaints, feeder studies and system impact assessments. These system needs are identified by the Distribution System Code ("DSC") as "enhancements" (section 3.3) and are completed for the purposes of improving system operating characteristics or for relieving system capacity constraints. Responding to these needs ensures an adequate supply of electricity to customers.

Resolution of issues within the individual projects of this investment could include upgrading conductor size, voltage conversion, supplying three phase circuit where a single phase supply would not be adequate, or protection upgrades.

Alternatives:

This investment addresses issues that arise on a demand basis and typically relate to power quality, and feeder protection. As these issues arise on the distribution system, it is imperative for Hydro One to address them in an expedient and efficient manner. Completion is required to comply with the DSC.

Not proceeding with this investment would be a failure to comply with the DSC and result in critical issues remaining on the system, leading to deteriorated service reliability and power quality, decreased customer satisfaction and substandard supply. Damage to distribution system assets could also occur.

Investment Description:

The triggers of the projects within this investment are driven by customer requests to increase loading on the system or to resolve power quality issues. When a request is received, a system impact assessment is performed to investigate possible resolution. Technical criteria are used in assessing system and customer needs.

System enhancements addressed by this plan include items such as protection coordination, and installing new equipment or equipment upgrades.

This investment resolves lower cost, high priority issues identified by customers, feeder studies, or system impact assessments with a short lead-time. These investments generally cost between a few thousand dollars for low cost projects such as fuse upgrades upwards to a few hundred thousand dollars for costly upgrades such as voltage conversion or single to three phase line conversion.

Risk Mitigation:

To ensure customer satisfaction it is important that work is prioritized to avoid catastrophic failure of critical assets supporting large numbers of customers. Projects are prioritized among the work in the queue for a given work centre. Higher priority projects may need to be completed on a faster turnaround causing the lower priority projects to be delayed.

Result:

This investment will address the following:

- Maintain reliability and quality of service within supply standards; and
- Address customer issues in an expedient and efficient manner.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by resolving high priority issues.
Operational Effectiveness	• Improve power quality by ensuring that protection settings are effective and within acceptable levels for customers.
Public Policy Responsiveness	• Adhere to DSC by maintaining reliability and power quality standards. • Address issues identified in feeder studies and/or system impact assessments.
Financial Performance	• Avoided costs by proactively replacing equipment that is causing issues on the system.

Costs:

As the types of issues that need to be resolved in this program are unforeseen, this work is considered non-discretionary and annual costs are based on historic spending.

The costs of the project are affected by the complexity of the work involved to resolve the reported issues. Costs are controlled by avoiding costly/complex design solutions where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	4.1	4.3	4.4	5.0	5.0	22.6
Less Removals	0.5	0.5	0.5	0.7	0.7	2.7
Gross Investment Cost	**3.6**	**3.7**	**3.8**	**4.3**	**4.3**	**19.9**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**3.6**	**3.7**	**3.8**	**4.3**	**4.4**	**19.9**

**Includes Overhead at Current Rates.*

SS-05 Distribution System Modifications

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	40.1
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

These investments provide adequate supply to accommodate system load growth on the distribution system with new or modified distribution facilities.

These investments focus on correcting feeder load balance, voltage quality and protection coordination, which are issues that arise over time due to variability in feeder load resulting from changes like natural load growth and economic changes. As these changes occur, the distribution of load along feeders can vary significantly. This can affect the voltage quality and conductor loading, cause improper protection operations, and potentially cause equipment ratings to be exceeded.

To identify issues that have arisen, the distribution system is reviewed for load balance and protection coordination on a cyclical basis. To correct issues that arise such as feeder load balance, voltage quality and protection coordination issues, the scope of work involved can include rebalancing and re-phasing feeders, changes to feeder configuration, new or modified protection equipment and voltage regulators, feeder expansions, and construction of new feeders and voltage conversion.

Alternative 1: Do Nothing

Not proceeding with this investment increases reliability and safety risks associated with low feeder end voltages, overloaded equipment, and improper protection operation. It also increases the risk of not adhering to industry standards for voltage regulation and current levels.

Alternative 2: Make Frequent Investments

This alternative would correct feeder load balance and protection coordination issues on a frequent basis driven by any system changes.

Annual investments on each feeder are not recommended because year over year the changes to load distribution are relatively minimal and this alternative does not lead to the most efficient use of resources.

Alternative 3: Infrequent Investments

This alternative would correct feeder load balance and protection coordination based on a cycle greater than six years.

A review cycle longer than six years is not recommended because the investment needs resulting from natural load growth and economic changes would not be addressed in a timely manner. This could cause issues in terms of coordination of the cycle study reviews with the current line patrol frequency. This would significantly increase the risk of operating the distribution system with overloaded equipment, voltage issues and improper protection.

Alternative 4: Planned Six-year Cycle (Recommended)

This alternative would correct feeder load balance and protection coordination based on a six-year review cycle, consistent with the outcomes of the studies described in Section 2.3 of the DSP. The recommended six-year review cycle length aligns with Hydro One's six-year inspection cycle mandated by the Distribution System Code, Appendix C. Acting on information about a feeder that has just been inspected reduces risks arising from data errors or discrepancies.

This represents a balance between addressing natural load growth in a timely manner and effectively applying resources to maintain all distribution feeders at appropriate voltage and protection levels.

Investment Description:

The work performed under this investment is coordinated with feeder studies that will be conducted on a six-year cycle through Development OM&A activities. The investments address the needs identified through the studies and are executed through this program on a priority basis.

Separate scopes of work are developed for each distribution station and their downstream feeders based on the results of feeder studies. Work is prioritized based on the severity and criticality of the issues being addressed.

The investment is expected to complete approximately seventy-five projects annually over the five-year business plan.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction. These risks will be mitigated by ensuring that appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Implementation timing is dependent on resources available in the work centres where the projects are occurring.

Result:

This investment provides the following results:

- Reliability and safety risks associated with improper protection coordination, overloaded equipment, and non-standard voltage levels are reduced;
- Power quality issues are reduced;
- System voltage and current levels will be maintained within industry standards; and
- Improve operational efficiency with effective protection schemes.

Outcome Summary:

Customer Focus	• Minimize power interruptions to customers by improving voltage levels and power quality with adjusted protection settings.
Operational Effectiveness	• Improve operational efficiency by addressing overloading on parts of the system, proper phase balancing and ensuring effective protection schemes to deal with changes on the system.
Public Policy Responsiveness	• Maintain system voltage and current levels within industry standards.
Financial Performance	

Costs:

As the types of issues that need to be resolved in this program are unforeseen, this work is considered non-discretionary and annual costs are based on historic spending. Final costs of the program are affected by the scope and complexity of the modifications required for each project. Projects that could incur significant costs get released for design and estimate before execution. This gives system planners an opportunity to consider alternatives to the proposed work and include longer term plans where possible. Other projects which are low in cost or have no alternatives available go straight to release for construction.

Controllable costs are minimized by selecting the most cost effective alternative that addresses the issues.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	8.3	8.2	9.1	10.0	10.0	45.5
Less Removals	1.0	1.0	1.1	1.2	1.2	5.5
Gross Investment Cost	**7.3**	**7.2**	**8.0**	**8.8**	**8.8**	**40.1**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**7.3**	**7.2**	**8.0**	**8.8**	**8.8**	**40.1**

**Includes Overhead at current rates.*

SS-06 Worst Performing Feeders

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	49.9
Primary Trigger:	Reliability		
Secondary Trigger:	Customer Service		

Investment Need:

Hydro One has various programs that deal with asset based sustainment. Most sustainment programs rely on various condition-based and/or time-based data and use various characteristics such as asset condition, demographics, criticality, utilization and others to determine which feeders are most likely to lead to a failure incident over the planning period. Provisions are made to service those assets with immediate maintenance requirements.

Recently, Hydro One has been able to leverage the available reliability data and has come up with a list of the "worst performing feeders" on the system. Rather than using pure asset-based requirements, the identification of these feeders is primarily based on their reliability metrics as a contributor to System Average Interruption Duration Index ("SAIDI") and/or System Average Interruption Frequency Index ("SAIFI"). These metrics are referred to in combination as Customer Average Interruption Delivery Index ("CAIDI"). [$SAIDI \div SAIFI = CAIDI$]. The trending of performance also factors into the determination of the list.

The worst performing feeders program will include those feeders whose contribution to SAIFI/CAIDI is three times the average feeder's contribution. Based on preliminary analysis, this represents approximately 230 feeders whose contribution to SAIFI is three times the average and approximately seventy feeders whose contribution to CAIDI is three times the average. Improving performance of this small number of feeders should improve reliability of the overall system for customers.

Generally, the primary reason for a feeder being on the worst performing list is related to vegetation management. However, solving the issue is not necessarily about more aggressive forestry practices. Modernization can be a significant contributor to improvement as can placement of the line away from pending forestry contacts. Moreover, improved communication would help to address outages more quickly and reduce their duration to the benefit of customers on these lines.

Witness: Lyla Garzouzi

Alternative 1: Status Quo:

This alternative continues to use the current practice of analyzing and addressing feeder components based solely on their individual characteristics. This alternative misses the opportunity of providing targeted reliability improvements to customers.

Alternative 2: Initiate Program to Modernize Worst Performing Feeders (Recommended)

This alternative specifically targets those feeders whose contribution to SAIFI/CAIDI is three times the average feeder's contribution.

The program will invest in communication to open point switches, installed sectionalizers, and feeder breakers. These investments will allow the grid control room to more quickly identify the origin of a fault and perform operational actions in order to improve reliability. Also, this program will address those feeders where an asset-based approach or vegetation management programs cannot eliminate high numbers of momentary outages.

Initial estimates suggest that this program itself could, over time, increase the reliability of the distribution network by approximately one percent.

Investment Description:

This program focuses on overall feeder performance using reliability data. This approach allows Hydro One to upgrade entire feeder sections rather than just underlying components on an individual basis. Recently improved components on these feeders would not be replaced.

This investment program will use feeders' contribution levels to metrics to identify those feeders where proactive action will result in tangible benefits. Analysis of historical SAIFI contribution values will identify those feeders that are experiencing a significant number of interruptions. Analysis of historical CAIDI contribution values will identify feeders where outage duration is the longest.

This investment program will focus on reducing of two key elements of reliability:

1. Reducing the number of system interruptions (SAIFI) – Key causes of interruptions that can be proactively addressed are vegetation encroachment and equipment failure. Off-road to on-road feeder relocations and remote conditions monitoring are all options for reducing momentary outages.
2. Reducing the duration of customer interruptions when they occur (CAIDI) – Use of fault detectors, automation and remote control of switching equipment and "self-healing-grid" solutions are all options for reducing outage duration.

The program will take proactive action to increase the reliability of the distribution network using a number of solutions:

- Equipment monitoring and alerts;
- Adding monitoring and remote control to existing equipment capable of supporting SCADA, which will be done for problematic feeders to support rapid response to outages when they occur;
- Deployment of modern switching equipment that can act autonomously and can also be remotely controlled to provide isolation and sectionalizing (which is particularly important around existing manually operated open points) with integration to the Distribution Management System ("DMS") through high speed wireless communication systems;
- Construction of additional ties between feeders capable of supporting load transfers; and
- Relocating sections of feeders from off-road to on-road.

Risk Mitigation:

Risk associated with completion of the program is minimal and in line with other upgrade programs. Availability of resources and length of outages are the biggest factors to manage.

The level of approved program investment would impact on modernization effort and hence improved reliability.

Result:

This investment will have an impact on the following:

- Reducing the customer hours of outage by an automated system of back-to-back supply for the faulty feeder and improving reliability through SAIFI and CAIDI metrics resulting in increased customer satisfaction;
- Reducing Hydro One outage times by 50% on faults involving main feeder trunks through identifying the location of faults through DMS monitoring and control telemetry system instead of dispatching a crews to drive along feeders to perform the same task; and
- Performance improvement by allowing the grid control room to quickly identify the origin of a fault and perform operational actions to allow back-to-back supply for the faulty feeder.

Outcome Summary:

Customer Focus	• Improved customer reliability through back to back supply from alternative adjacent feeders. • Improved response times to dispatch.
Operational Effectiveness	• Improved efficiency through enablement of back-to-back switching and remote automation through DMS. • Reduced public safety risk by quickly and accurately identifying dangerous faults. • Improved reliability where current programs are not as effective in removing momentary outages.
Public Policy Responsiveness	• Improved compliance with DSC requirements in responding to trouble situations.
Financial Performance	• Reduced unit costs through more accurate and timely location of faults as well as potentially fewer and more targeted truck rolls. • Reduced level of field effort and, therefore cost, dealing with trouble events.

Costs:

Cost estimates are planners' estimates. Individual feeders may have different issues and hence different solutions. Individual estimates will be obtained in order to fully define the volume of work required.

The factors which affect the estimates for this investment are determined by the annual purchase of the smart equipment units. Controllable costs for this program were based on modernization of open points.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	7.1	10.1	10.5	10.9	11.3	49.9
Operations, Maintenance & Administration and Removals	-	-	-	-	-	-
Gross Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**

**Includes Overhead at current rates.*

SS-07 Advanced Distribution System ("ADS")

Start Date:	Q1 2013	**Priority:**	High
In-Service Date:	Q2 2018	**Plan Period Cost ($M):**	5.0
Primary Trigger:	System Operational Objectives		

Investment Need:

The ADS investments were part of the smart grid investments outlined in Exhibit D1, Tab 3, Schedule 5 (Customer Services Capital) of EB-2013-0416. They were originally planned for completion within the last approved rate period. Investments were delayed due to a later than anticipated release of a version of software that incorporated more functions into one platform.

The current Distribution Management System ("DMS") went in service in 2012. A lifecycle system refresh is planned to replace hardware and software system components. Specifically, two key sub-projects were delayed: (1) the "DMS Upgrade" project; and (2) the Demand Response for Operations project. The DMS Upgrade project will provide the functionality of the following projects identified on pages 5 to 7 of Exhibit D1, Tab 3, Schedule 5 in Hydro One's last distribution application (EB-2013-0416): DMS Enhancements, Selective Load Shedding, Infrastructure Support, Mobility Solutions and Online Operating Diagrams projects.

The DMS is a control system that monitors and controls the distribution system. It provides a platform for distribution supervisory, control and data acquisition (SCADA). It also provides a set of advanced applications that enable proactive management of the distribution system (such as fault location). The new DMS will include new functionality that will improve operations by enabling field crews with a mobile DMS that they can use to have real-time situational awareness of the distribution system.

The DMS Upgrade project was delayed due to a later than anticipated release of a version of the relevant DMS software that accommodates distributed energy resource management and integrates the broad set of distribution modernization functions (such as mobility solutions). This software version was originally thought to be released in mid-2014, but is now scheduled to be released in 2017.

The Demand Response for Operations project will pilot a system that optimizes electric load and supply on a local basis leveraging all of the variable load (electric vehicle, energy storage, residential/commercial demand response) and generation (dispatchable renewable, energy storage) available. The Demand Response for Operations project was delayed to find more cost effective energy storage solutions.

Alternatives:

Not proceeding with the DMS Upgrade project will see the system go out of support. It will also delay the operational benefits associated with the new version of the software which include management of distributed energy resources. Failing to proceed with this investment would result in an increased risk of application failure which would impact Hydro One ability to manage its deployed smart grid assets.

Not proceeding with the Demand Response for Operations project will impact Hydro One's ability to manage the increasing volumes of customer-owned generation and microgrids expected to proliferate in the coming years.

Investment Description:

Planned investments for the DMS Upgrade project include hardware refresh, server operating system upgrade, DMS software upgrade as well as rollout of the DMS to be available for field crews.

Planned investments for the Demand Response for Operations project will see Hydro One install assets that monitor and control customer-side generation and storage assets and integrate them with control systems at the substation and the control centre.

Risk Mitigation:

<u>DMS Upgrade Project</u>

- As with all complex control system upgrade projects, the project entails system integration and technology risks. Hydro One has assigned an experienced team that worked on the original DMS implementation.
- As the DMS is being deployed to field crews for the first time, there are change management risks associated with training and adoption. A comprehensive change management program is planned to mitigate these risks.

<u>Demand Response for Operations Project</u>

- As the project will be piloting the integration of several new technologies (energy storage, solar, home energy management systems, etc.), there are system integration and technology risks. Hydro One will bring in external resources who have implemented similar systems elsewhere to mitigate these risks.

- As the project will be piloting technology on both the customer-side and grid-side of the meter, there are risks with the technology failing or customer expectations not being met. A comprehensive customer communication strategy will be developed that ensures clear communication with customers to set realistic expectations. Technology will be selected, engineered and commissioned to ensure they are reliable and safe.

Result:

DMS Upgrade Project

- Provide further integration of smart grid capabilities into the central control system for operators.
- Equip field crews with new mobile systems they can use to restore power more quickly and execute planned outages more efficiently.
- Enables more surgical load shedding during bulk electric system emergencies that would maintain distributed generation and critical loads (hospitals, water treatment plants, etc).

Demand Response for Operations Project

- Defer local distribution investment by maintain load below a set point by leveraging generation and storage assets.
- Increases the load capacity factor of the distribution system and reduces the variability of load and generation.
- Establish the systems and processes to manage the proliferation of customer-side generation and energy storage systems.

Outcome Summary:

Customer Focus	• Enable customer-side generation and storage assets for the benefit of both customers and the grid.
Operational Effectiveness	• Enhanced reliability of distribution system by providing field crews additional situational awareness on the real-time state of the distribution system and location of faults. • Increase operational efficiencies related to how the distribution system is studied in the planning time frame and provide more tools for the control room and field crews in real-time operations. • Improve the efficiency of distribution cycles studies by leveraging the accurate network topology and the state estimation function. • Improve efficiency of storm management by providing an electronic mimic of the distribution system in the operating centres that can replace the paper pinning.
Public Policy Responsiveness	• Comply with the public policy objectives set out in the OEB *Supplemental Report on Smart Grid* (2013) including: ○ improving customer control; ○ enabling power system flexibility; and ○ building adaptive infrastructure.
Financial Performance	

Costs:

DMS Upgrade Project Costs associated with the DMS Upgrade project are primarily driven by:

- Required testing effort;
- Hardware and software costs; and
- Integrations.

These costs have been minimized through:

- Requiring that all customizations be reviewed for priority and approved by the Steering Committee for their approval before proceeding;
- Utilizing a mixed team of contract and internal resources to perform testing of the system;
- Going to competitive bid for all hardware and software components of the upgraded DMS;
- Minimizing the number of integrations and using resources experienced with the existing integrations to design, build and test the new integrations; and
- Demand Response for Operations Project.

Costs associated with the Demand Response for Operations Project are primarily driven by:

- Cost of solar photovoltaic systems;
- Cost of energy storage systems;
- Cost of onsite installation services; and
- Integrations with utility systems (substation protections and the DMS).

These costs have been minimized through:

- Delaying the project start to find more cost effective solar and energy storage systems as they become more commercially viable;
- Leverage experience in performing onsite installations for conservation programs to minimize install cost; and
- Leverage the resources of the inflight DMS project to perform the integrations required to monitor and control.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	5.0	-	-	-	-	5.0	
Less Removals	-	-	-	-	-	0.0	
Gross Investment Cost	**5.0**	-	-	-	-	**5.0**	**61.2**
Less Capital Contributions	-	-	-	-	-	0.0	
Net Investment Cost	**5.0**	-	-	-	-	**5.0**	**61.1**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-01 Transport & Work Equipment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	201.0
Primary Trigger:	F1-Asset renewal / maintenance		
Secondary Trigger:	Capital Program		

Investment Need:

Hydro One controls and manages approximately 8,000 Fleet vehicles which support the various lines of business, including Provincial Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These include, but are not limited to CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. This results in minimized environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

Transport and Work Equipment ("TWE" or "Fleet") expenditures for 2018 through 2022 are primarily required to accomplish the following:

- Replace end of life core TWE;
- Support the growing levels of transmission and distribution capital and OM&A sustainment, development and operations work programs;
- Support the Forestry Mechanical Brushing Program, and Provincial Lines Pole Replacement Program; and
- Replace aging helicopters with newer safer and more capable aircraft.

Alternatives:

TWE plays a wide reaching and integral role in the day-to-day operations, safety and success at Hydro One. Availability of TWE has a direct impact on work programs and this proposal is to maintain the Fleet compliment.

The primary alternative to the proposed plan centres on a reduction in capital spending on TWE in favour of increased use of rental equipment, if the required equipment is available, and extended retention of existing equipment to satisfy work program and staffing requirements. Hydro One employs specialized equipment specifically outfitted to Hydro One safety specifications. Short term rentals are utilized where applicable on light duty vehicles but history has shown that due to the nature of the work, any rental savings is quickly offset by additional costs incurred by the normal wear and tear on the rental vehicles in this type of industry. The result is increased maintenance costs on the retained vehicles, increased vehicle downtime and decreased equipment availability.

Investment Description:

Fleet capital replacement requirements are based on:

1. Industry standards (manufacturer's recommendations) for life cycle expectancy;
2. Net Book Value (NBV) to Original Capital Value (OCV) ratios; and
3. Operating cost drivers which are then linked to the Business Plan and Work Programs.

Currently, the fleet is at 39% NBV to OCV where industry standards, established through a combination of Canadian Utility Fleet Manager workshops, direction from Fleet Management Companies and Industry experts, suggest that 45% as an optimum level. Our present replacement criteria are based on manufacturers' recommendations and repair history.

Key contributors to the 2018-2022 capital program include:

- The replacement of core transport and work equipment (about 8%, approximately 650 vehicles, of Fleet annually);
- Incremental vehicle and equipment requirements to support the increase in the Mechanical Brushing Program and the Provincial Lines Pole Replacement Program; and
- Replacement of aging helicopters.

Table 1 – Forecast of Acquisitions for 2018 to 2022

Equipment Type	2018		2019		2020		2021		2022	
	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units
Light[1]	7.3	322	8.4	369	7.9	348	8.3	365	7.4	323
Heavy[2]	14.0	108	15.8	121	16.9	129	17.8	136	21.0	159
Off-Road[3]	6.3	26	7.1	29	7.3	30	7.6	31	8.0	33
Miscellaneous[4]	4.0	173	4.6	197	4.6	201	4.6	198	3.9	166
Helicopter	2.4	0.5	2.4	0.5	2.4	0.5	2.4	0.5	2.4	0.5
Incremental Additions [5]	1.1	9	1.3	12	1.3	12	1.3	12	1.4	12
Total	**35.0**	**639**	**39.5**	**729**	**40.4**	**720**	**42.0**	**743**	**44.1**	**694**

Note: Number of units is based on average unit costs per category of equipment and is subject to change based on specific LOB staff and work program requirements.
Numbers of units are based on the Tx and Dx Capital Investment Costs

[1]Light – cars, SUVs, pickups, vans
[2]Heavy – service trucks, highway tractors, radial boom derricks (RDB), bucket trucks
[3]Off Roads – rubber tire, tracked equipment
[4]Miscellaneous – boats, chippers, tensioners, manlifts, forklifts
[5]Incremental Additions – Tracked and Rubber Tired Grinding/Mulching units, Tag-a-long Chippers, Bulldozers are used for the Forestry Mechanical Brushing Program and RDB for the Provincial Lines Pole Replacement Program.

Risk Mitigation:

Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers.

Light vehicles are replaced after six years or 180,000 km. Heavy vehicles have several replacement guidelines depending on the type of equipment; service trucks are replaced after six years or 300,000 km, and work equipment-single axle is replaced after eight to ten years or 400,000 km. Work equipment-tandem axle is replaced after twelve to fourteen years or 400,000 km. Off-Road and Miscellaneous equipment is replaced on a case by case basis depending on utilization and condition of the equipment and ongoing need.

Helicopters are replaced on a case by case basis depending on utilization, condition of the aircraft and the cost of refurbishment. This asset strategy is designed to address the following risks:

- Equipment failure - Retaining and operating older equipment increases the probability of failure, which creates costly downtime for crews and increases safety risk for employees and the public;
- Scheduled Outages - Customers (especially large industrial) are impacted when equipment is unavailable because the outage must be rescheduled;
- Emergency response - Unplanned work (i.e., storm response, trouble calls) requires timely dispatch and lack of available equipment will impact customers by exacerbating outages;
- Work Schedules - Delay in work programs impact the Line of Business (LOB) project costs and decrease operational effectiveness;
- Increasing costs - Repair time and maintenance costs are reduced since aging equipment requires more maintenance as seen in table 2; and
- Environmental goals - Environmental Impact to the public is affected by operating aging equipment as newer, maintained vehicles tend to have a lower carbon footprint.

Result:

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process and to plan for future TWE requirements based on work program and staffing forecasts. The TWE Replacement Program annually analyzes its five-year business planning cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital replacement program, on an annual basis, is evaluated against the business plan and is subject to the LOB’s work program prioritization and forecasting process.

The objective is to maintain a stable fleet replacement program and minimize capital investment fluctuations year-over-year. A reduction in capital spent in a given year will result in increased operating costs, which could ultimately result in increased equipment rates.

This investment will:

- Ensure compliance with all safety standards, as well as Ministry of Transportation (MTO) and regulatory requirements;
- Allow Hydro One to maintain and improve its present core fleet level of 39% versus the industry standard of 45% NBV. At the end of 2022 it is forecasted to be 41%.

Fleet Services will leverage the telematics data to institute the baseline metrics with respect to equipment utilization and productivity;

- Maximize, productivity efficiencies and utilization; and
- Optimize repair time and fleet size.

Outcome Summary:

Customer Focus	• Optimize Fleet Service levels to mitigate potential delays in response time to unplanned incidents, such as trouble calls and storm response.
Operational Effectiveness	• Fleet vehicles and other specialized equipment at optimal levels of availability reduce human effort and minimize risk of personal injury. • Optimal investment levels allow employees to have the right equipment to do their job, increase employee engagement levels, minimize risk of injury and increase work satisfaction.
Public Policy Responsiveness	• Optimal investment levels allow for maximum equipment efficiencies and minimize Hydro One's carbon footprint. • Ensure compliance with all codes, standards and regulations to maximize shareholder value and sustainably manage our environmental footprint. • Vehicles will be maintained at an optimum level to ensure public and employee safety and to meet Ministry regulations.
Financial Performance	• Ensure savings from operational effectiveness are sustainable. Control maintenance costs (external repair, parts and internal labour), potential rental costs and maintain equipment rates at optimal levels to ensure OEB mandated ROE is achieved.

Costs:

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	35.0	39.5	40.4	42.0	44.1	201.0
Less Removals	-	-	-	-	-	-
Gross Investment Cost	35.0	39.5	40.4	42.0	44.1	201.0
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	35.0	39.5	40.4	42.0	44.1	201.0

**Includes Overhead at current rates.*

GP-02 Real Estate Field Facilities Capital

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	185.9
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Non-System Physical Plant		

Investment Need:

The Field Facilities Capital work program addresses the accommodation portfolio of administrative and service facilities in terms of improvements, building additions and new facilities as determined by Hydro One's operational requirements and asset condition. This program ensures that essential and supportive improvements are made to administration and service facilities to minimize building and site related risks to the operations; serve operational requirements; and promote efficiencies in the maintenance and operation of the facilities in the longer term.

Capital investment is periodically required in order to continue to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. The investment need is driven by the following key factors:

- deteriorating facilities that are at or near the end of life;
- compliance with current regulatory requirements, such as Accessibility for Ontarians with Disabilities Act and the Ontario Building Code;
- expanding work programs;
- new accommodation needs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity.

More than 40% of administration and service facilities are estimated to be more than 40 years old. These facilities are largely undersized, ill configured and underperforming to current operational requirements with resulting increase to operating costs for maintenance and repair and inefficiency to facility and business operations.

The Field Facilities Capital work program focuses on undertaking facility work encompassing improvements, additions or new facilities. Work is undertaken on a priority and timely basis at a level of expenditure required to support the business operations to fully deliver the prescribed various work programs addressing network requirements, customer needs, corporate and government policy and regulatory/licensing directives in a safe, efficient and cost effective manner. This work is conducted on a project basis.

Alternative 1: Status Quo

This alternative is to effectively curtail future investment on a minimal basis in an attempt to operate within the outdated facilities.

This alternative is not sustainable. Without necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where efficiency and safety become impaired. Incidents arising from this alternative will hamper Hydro One's ability to perform its work and serve customers.

This alternative would require additional operating expense for maintenance repairs, which have not been factored into this Application. The risk created by this alternative, and the additional operating maintenance expense it would create, caused it to be rejected without further analysis.

Alternative 2: Update Facilities *(Recommended)*

This alternative would bring field facilities to an acceptable state of repair and make strategic additions or replacements where beneficial.

The spending requested herein is an estimate of the work to be performed over the planning period. The development of field facilities entails an on-going, comparative evaluation of alternatives, which entails the expansion and/or renovation of existing facilities, the lease or purchase of suitable facilities and greenfield developments against maintenance of the status quo condition. The ultimate investment will be dictated by the circumstances in place. The objective is to pursue the most cost effective strategy that addresses operational requirements and manages risk. Operational considerations are for both existing and future requirements; the latter considers changes to the business, e.g., volumes and delivery strategy. Regardless, each substantial investment will be subject to analysis and approval based on its benefit prior to implementation.

The prime consideration throughout is to extract the value of existing facilities through ongoing operations, maintenance and sustainment investments in line with operational requirements. Where facility and/or operational conditions/requirements dictate an examination of facility alternatives, the objective is to derive the greatest net assessable benefit to the company.

Investment Description:
The key program work activities include:

- replacement of major building system/components, including roof structures; windows and cladding; heating, ventilating and air conditioning (HVAC) systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at end of life;
- site replacements and additions, including drainage; asphalt, fencing; and septic/well (servicing); and
- addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements.

The required capital investment for field facilities is outlined in the Costs section below. These amounts are needed to fund required improvements of existing facilities and the development of new accommodation solutions through renovation and/or expansion and the acquisition or development of new facilities as required by the company's work programs. Projects can be multi-year; and the work is contingent in several projects on the successful identification and acquisition of development sites and in all instances obtaining the requisite municipal planning approvals. Furthermore, certain projects are tied to the successful and timely completion of utility acquisitions or others may be adjusted for emerging acquisition opportunities.

The current estimate of the volume of work to be completed annually at individual sites/facilities is as follows:

Work	**Annual Completed Projects**
New Facilities and Major Renovations	2 – 4
Site Improvements (asphalt; drainage; servicing; fencing; security)	20 – 25
Building Envelope (roof; windows/doors; cladding)	20 – 30
Mechanical & Electrical (HVAC; lighting; generators)	15 – 20
Minor Building Renovations and Additions	10 – 15

Witness: Rob Berardi

Benefit is realized through a number of factors, such as lower cost, improved operational performance, regulatory compliance, enhanced health & safety, reduced risk, enriched life cycle management and adaptability to address known or anticipated change.

Risk Mitigation:

Cost certainty for new operating centres is established through the use of a scalable template design and experience from recently completed projects. Developments are completed in accordance to prevailing commercial standards and practices.

Developments of new facilities are in various instances dependent on the availability of suitable sites and requisite municipal approvals, which is managed through advance planning and acquisition. Development interests are cultivated by leveraging municipal officials/departments and utilizing the services of the real estate and development community.

Facilities redundancy and low value investments are managed by conducting regular reviews with the various lines of business to understand and align with current and emerging work programs and identify common requirements and workplace synergies. Furthermore, planning is integrated with utility acquisition strategies and objectives to identify opportunities, create flexibility and manage facilities investments.

Result:

- Field Facilities that serve current operating requirements of the various lines of business.
- Field Facilities commitments and investments aligned with known and emerging operating requirements and corporate business decisions.
- Maintenance of existing Field Facilities through timely replacement of major building systems/components.
- Enhanced health & safety of employees operating within Field Facilities.

Outcome Summary:

Customer Focus	• Improve the ability of the lines of business to address customer needs through facilities that commensurately align with operational requirements.
Operational Effectiveness	• Maintain and improve operational effectiveness of the lines of business through timely and strategic facilities investments.
Public Policy Responsiveness	• Comply with government policy and regulatory/licensing directives.
Financial Performance	• Cost savings realized through the broad consideration of facilities alternatives. • Cost effectiveness realized through regular assessment and timely investment. • Cost efficiency realized through facilities investments that align with current and emergent operating requirements and business decisions.

Costs:

The development of facilities and resulting final cost of a project are influenced by various factors beyond the typical realm of design, such as market, regulatory and site conditions/factors. Regulatory and site conditions are somewhat predictable through assessment, but not overly influenced by design considerations. Whereas, the market is highly influential to final cost for availability of suitable sites, market opportunity and interest and competing demand. These market factors could have a significant negative or positive influence to the cost of the project. Furthermore, existing facility conditions, site and/or building, may have significant latent defects that, irrespective of early assessments, are undetectable until implementation and could contribute to significantly higher costs.

The cost for the development and/or renovation of facilities is controlled where applicable through template design, consistency of application, and the adoption of commercial building standards and practices.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	35.4	42.9	36.9	36.9	33.9	185.9
Less Removals						
Gross Investment Cost	35.4	42.9	36.9	36.9	33.9	185.9
Less Capital Contributions						
Net Investment Cost	35.4	42.9	36.9	36.9	33.9	185.9

**Includes Overhead at current rates.*

GP-03 MFA Servers and Storage

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	16.0
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. Hydro One's Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping the business running effectively. This investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time.

Key systems and the data generated must always be available (99.5%) to customers and employees involved with the delivery of customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities. As more customers are integrated into the SAP landscape and generate more business analytics the need for SAP capability increases. Move-to-Mobile and Customer High Bill Alerts are projects that require new hardware. Merger and Acquisition activity is another component that drives an increase to our server landscape.

Enterprise applications being refreshed (to stay within vendor supported levels) drive refresh of the overall environment. Hardware refresh is also required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Without refreshed assets, Hydro One would have difficulty enforcing performance agreements with vendors and could potentially be exposed to large, un-warranted costs. Conversely, refreshing as per vendor requirements allows for sustainment costs due to technology improvements being implemented as part of new deployments to be favourably re-negotiated.

HONI continues to increase its virtualization footprint for any new/existing applications that are refreshed. With virtualization, several operating systems can be run in parallel on a single server. This parallelism and allows Hydro One to better manage updates and changes to the operating system and applications without disrupting the user. Virtualization can improve the efficiency and availability of resources and applications in an organization.

Hydro One continues to explore opportunities to leverage cloud based application/infrastructure services while complying with HONI's corporate data security policies around NERC, CCAI, and PIPEDA.

IT system availability directly impacts the productivity of employees who use the technology. IT availability also has direct impacts on the availability and security of the power network itself given the modern suite of tools that are relied upon to monitor and operate the grid.

Alternative 1: Delay Refresh

This alternative would seek to delay the replacement of equipment past its current life-cycle expectancy.

Not refreshing end-of-life servers or delaying investment in storage devices beyond the current level will impact the reliability of IT systems and increase the incidents of failure. This reduced reliability will impact application uptime and overall system availability for customers and internal users alike. It will also drive additional sustainment costs, as many vendors commonly charge their services at a premium rate to support end of life products. It will remove the ability to build out capacity on-demand capability and will cause hardware to be added frequently and incrementally. This "just-in-time" server add strategy comes at a significant premium due to the lack of bulk buys, multiple complex setup and staging processes and potentially costly delays to important Business IT projects if hardware procurement has any issues.

Alternative 2: Refresh In-line with Life Cycle Guidelines (Recommended)

This alternative would keep assets current and refreshed. This option will support the maintenance of up-time requirements and ensure that data and processing ability is available to customer and employees.

Investment Description:

Wintel servers are refreshed on a three- to five-year cycle and UNIX servers are refreshed on a five- to seven-year cycle. These cycles fall within industry best practices and maintain warranties within an acceptable level. Virtualization technology is being leveraged to further increase the life of our physical servers. The replacement cycle for refresh of Wintel and Unix servers is to maintain vendor-supported levels and includes hardware upgrades, capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing.

In determining when systems require replacement, the functionality, operating and maintenance (i.e., standard warranty or extended warranty) costs are assessed. The funding for the servers and storage refresh/replacement program varies year over year depending on hardware lifecycles and business requirements for increased processing capacity.

Costs in 2018 to 2022 reflect typical lifecycle refresh of end of life storage hardware.

Risk Mitigation:

Replacement of infrastructure as proposed in this investment is a fairly routine occurrence that has been performed many times within the Hydro One environment by the staff that will be involved in this project. While issues occur, the risk of project failure is very low and most adverse situations can be anticipated and addressed from experience.

Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome. In the event of hardware failure, defects discovered, or resource constraints the project will work the systems integrator equipment manufactures to resolve issues or modify scope timelines until the issue can be resolved or architected.

Result:

A proactive investment approach reduces the risk of prolonged IT system outages and reduces the costs of unplanned investment for problem resolution. It also reduces the risk to

Hydro One's ability to respond to business requirements and project delivery due to IT system integration and scalability impacts.

Outcome Summary:

Customer Focus	• Support information availability to customers ensuring that systems are supported and reliable. • Improve customer satisfaction around ease of use and experience of our customers when accessing billing information on e-customer.
Operational Effectiveness	• Increase productivity by ensuring that applications / systems function as designed and provide Hydro One employees with the information they require to perform their daily work effectively.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost by minimizing the potential for costly outages and unplanned refreshes or upgrades. • Maintain vendor support and the ability to enforce performance or availability SLA's thus avoiding increased costs.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs. The market for these products has matured significantly over the last decade. Major cost fluctuations are not anticipated and, in any event, are foreseeable and addressable through sound procurement strategy.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.2	3.2	3.2	3.2	3.2	16.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	3.2	3.2	3.2	3.2	3.2	16.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**16.0**

**Includes Overhead at current rates.*

Witness: Lincoln Frost-Hunt

GP-04 Minor Fixed Assets - Desktop, Laptop, Printer

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	9.8
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System (GIS). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. Minor Fixed Assets ("MFA") are the method by which the information and capability of these enterprise systems are provided to employees. Currency and functionality of the MFA fleet is critical to allowing employees perform their work productively.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of customer service programs and Distribution work management programs linked to H1 Customer satisfaction goals/KPIs – Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

MFA equipment includes:

- Desktops, Laptops, and Printers used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications;
- Tablets used with, among other things, Geospatial Information Systems ("GIS") applications for undertaking system design work and for asset condition assessments;
- Rugged Tablets and mobile devices used by field staff for entry of work related data; and
- Plotters commonly used by Hydro One engineering and operations staff for design work and to plot system maps.

Witness: Lincoln Frost-Hunt

Replacement of MFA that have reached the end of their useful life is necessary to address warranty considerations and to maintain hardware reliability, as well as to upgrade existing equipment to meet business performance needs.

Equipment refresh maintains or reduces maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty.

Alternative 1: Delay Hardware Refresh

This alternative would delay the refresh of assets and address increased failure and performance of the obsolete assets.

A delay in hardware refresh would affect operational effectiveness and our ability to serve customers. Aging hardware impacts application performance which in turn impacts ability to provide timely responses to customers in a call centre environment. In other areas of the business aging PC's perform poorly as new state of the art applications are deployed demanding more processing power and memory.

Delaying the equipment replacement or reducing funding beyond the current level will negatively impact the ability of employees to support the business and customers due to the increased risk of breakdown and lost productivity.

Other investment changes intended to reduce replacement would increase sustainment costs and the time to restore IT services. This is because technology beyond the vendor-supported life is normally outside of service agreements, and parts and labour are difficult and costly to secure.

Alternative 2: Refresh Per Plan (Recommended)

This alternative would strive to purchase and refresh MFA within asset life cycle guidelines.

New models are selected as part of technology refresh to meet user needs based on business requirements (USB Ports, Processing & Memory requirements, indoor versus outdoor usage, etc). Newer models provide additional compatibility with new business applications, operating systems, modern browsers, etc. The hardware refresh allows Hydro One to enforce service levels and performance based SLAs with vendors.

The option of renting/leasing MFA was reviewed. However, most of this equipment is made up of small, relatively inexpensive items whose usefulness is generally exhausted by end of life. Therefore it was deemed not feasible to rent or lease these items on a long term basis since leasing vendor margins would be purely accretive to the cost and would be higher than any cost of capital benefits from leasing. As a result, this alternative was not pursued.

Old equipment that is past the end of its useful life becomes unreliable and negatively impacts the ability of the business to perform their day to day work, thereby increasing costs to Hydro One and its customers. In addition, existing equipment may need to be upgraded to meet the changing needs and applications of the business.

Investment Description:

Hydro One’s practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. Historically, Hydro One’s refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

The estimated units to be replaced over the program are as follows:

	2018	**2019**	**2020**	**2021**	**2022**
Desktop/Laptop	1050	950	950	950	950
Printers	50	47	47	47	47
Other	21	19	19	19	19

Risk Mitigation:

Refresh programs run year over year, assets not deployed in one year are leveraged first the next year. Total number of machines deployed over 3-5 years remains constant.

Issues around software compatibility are addressed as part of certification process where a standard locked down image is deployed to all users with packaged/certified software applications.

Issues around hardware failure are addressed via the warranty process with the vendor.

Result:

The PC and Printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems, promoting workforce productivity.

Outcome Summary:

Customer Focus	• Support customer services by ensuring employees have the necessary equipment to meet customer needs.
Operational Effectiveness	• Maintain productivity by ensuring reliability of IT tools required by Hydro One employees to perform their daily work.
Public Policy Responsiveness	
Financial Performance	• Overall costs are minimized by enabling general employee productivity.

Costs:

Estimates are driven by historical costs, which are driven by the inherent lifecycle of the devices.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.1	1.9	1.9	1.9	1.9	9.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	2.1	1.9	1.9	1.9	1.9	9.8
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	2.1	1.9	1.9	1.9	1.9	9.8

**Includes Overhead at current rates.*

GP-05 Hardware/Software Refresh and Maintenance

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	20.1
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for the field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of our customer service programs and work management programs linked to Hydro One customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

Investments are needed to build contingency so as to ensure that critical systems are available and can survive the failure (result of a manufacturer bug, security patch, etc) of any single supporting technology component. Investments in supporting technology components include telecom, IT hardware and software. Leveraging these investments with effective vendor maintenance means that the assets can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Alternative 1: Delay Refresh

This alternative would defer replacement of assets due for refresh and address additional issues with higher failure rates of the systems.

Increasing the current life-cycle asset refresh strategy takes Hydro One beyond industry practice and significantly increases risk to the business in the following areas:

- Increases in employee dissatisfaction and decreased productivity due to frequent and/or prolonged service outages;
- Degraded regulatory relationship from disruptions to market operations of IT systems that interact with market participants;
- Decrease in customer satisfaction due to failure of enterprise wide applications such as SAP, ihub/Tivoli, Microsoft Exchange, mobile applications, customer billing, relationship management, and call centre systems; to meet service quality index for customer service; and
- Productivity declines due to the high unit cost of supporting and servicing applications without vendor support.

Alternative 2: Refresh Per Plan (Recommended)

This would replace servers within life cycle guidlelines. A number of factors drive the refresh of an application. Hardware or Applications out of vendor support is one component, while additional application functionality or performance considerations will also drive a refresh. This investment covers the cost to build the new servers along with any data migration activities and decommissioning.

Server hardware is refreshed every 3-7 years based on hardware type. Hardware refresh is required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Refreshing per plan allows for sustainment costs to be favourably negotiated due to technology improvements being implemented as part of new deployments.

This investment covers the capital costs, including Professional Services, to build new Web/Database/Application and Infrastructure servers along with all relevant data migration, Operating System, hardening, and decommissioning activities. There are a number of factors that drive hardware refresh – vendor supportability being a primary driver. There are other important considerations as well, including hardware age, and the general availability of supported replacement parts.

From an application perspective, today's business demands performance levels that are only offered by the latest server hardware and network technologies. While from a technology perspective, the entire IT market continues to virtualize and optimize key areas that are common across all data-centres – virtualizing server compute, storage and network. Refreshing this aging hardware allows for greater scalability and higher server densities, since it is possible to run addititional virtual servers with a smaller hardware footprint.

Investment Description:

Included in 2018 to 2022 the planned investments relate to the implementation of enterprise resource planning ("ERP") applications and related tools including SAP, further IT security access control and monitoring capabilities, middleware and databases, productivity tools, and server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms. Refreshes for applications in sustainment are funded from this investment. The only exception is if the refresh is going to drive new functionality that can be tied to a Business Case. Lastly, a system being refreshed in order to accommodate its inclusion into the Disaster Recovery Program (DRP) would also be funded by this investment.

Risk Mitigation:

No concerns are foreseen with completing the completing the Hardware/Software refresh program. Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome.

Any risks around resourcing (specific skillset) will be addressed prior to project award with systems integrators. The award will ensure proper expertise is maintained during the life of the project and is well documented as part of scope execution.

Result:

This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments for problem resolution. This investment in IT system reliability enables general employee productivity because users have access to the tools they require to work, and it enables customer satisfaction through availability of enterprise wide applications, customer call centre and outage management systems.

1 **Outcome Summary:**

Customer Focus	• Ensure IT Hardware / Software is supported and reliable to prevent information gaps for customers. Performance and Stability of IT Hardware / Software directly impact ability to service customers in a timely manner (ie: Outages, Billing Inquiry, Program Enrollment, etc).
Operational Effectiveness	• Maintain the reliability of IT Hardware/Software to allow applications / systems to function as designed and provide Hydro One employees with the information they require to perform their daily work.
Public Policy Responsiveness	• Maintain efficacy of the of IT systems that interact with market participants and support the IESO in its market oversight mandate.
Financial Performance	• Overall costs are minimized serves to reduce the potential for costly outages and unplanned refreshes or upgrades.

2

3 **Costs:**

4 Estimates are driven by historical costs, which are driven by the inherent lifecycle of the
5 devices.

6

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.9	4.1	4.1	4.1	4.0	20.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	3.9	4.1	4.1	4.1	4.0	20.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.9**	**4.1**	**4.1**	**4.1**	**4.0**	**20.1**

**Includes Overhead at current rates.*

7

GP-06 MFA Telecom Infrastructure

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	6.7
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through the call centre. The Enterprise systems also provide the backbone of Hydro One's business operations within finance, human resources, supply chain as well as asset and work management for its field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Company's Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to Hydro One's customers and employees involved with the delivery of the Company's customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

This investment is required to replace end-of-life assets and to maintain service reliability and security, by refreshing network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source system, and upgrading the security solutions for external network interfaces.

Telecom infrastructure is the underlying hardware to support the business telecom network which is used to transmit data required to run business applications. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Alternative 1: Delay Refresh

This alterative would defer purchase of Minor Fixed Assets ("MFA") and deal with the incremental sustainment issues arising as a result.

Delaying the equipment replacement or reducing funding beyond current level will increase time between hardware refreshes, which may cause degraded voice and data network, reduced capacity to accommodate Move, Adds or Changes activities and poor network performance. Network availability and performance directly impacts customer interaction (ability to respond to customers in a timely manner in a call centre settings) and Lines of Business efficiency (performance from remote field sites will impact end user efficiency on applications as a result of poor network connectivity).

Alternative 2: Refresh Per Plan (Recommended)

This alterative would purchase and refresh equipment purchases according to their life cycle requirements.

Today's business applications demand the higher performance offered by current server and network technologies. The integration of systems, their applications, and sharing and dissemination of underlying data also drive higher complexities in order to fulfill expected business objectives and outcomes. In conjunction with this, from a raw hardware perspective, performance requirements also increase as more and more virtual servers are stacked onto fewer and fewer physical assets. Physical network bandwidth requirements increase proportionately in all these respects. Additionally, today's networking devices offer more mature degrees of network virtualization, and enable network segmentation and micro-segmentation which fulfills security requirements by further securing the data-centre environments.

Refreshing per plan allows HONI to deploy current generation technology in order to meet and exceed the demands put upon the underlying network technologies. For example, Move 2 Mobile project will rely on increased bandwidth from remote sites to ensure work being done is updated in SAP as quickly/timely as possible so the Company can reassign crews to other jobs if they are finished early. As Hydro One introduces new applications into its eco system, the aggregate need for more bandwidth increases. Current network technologies also allow for new functionality to be explored to further optimize network traffic making packet transmission more efficient and helping the prioritization of network traffic.

Investment Description:

The investment in Networks for voice and data is undertaken to replace end-of-life assets and to maintain service supportability, network reliability and network security. The strategy is to replace equipment that is no longer vendor supported. For network equipment, the refresh occurs about every five years for voice and data network related hardware. The funding for voice and data networks varies year to year depending upon hardware lifecycle refreshes, and incrementally as increasing business demands necessitate increased network bandwidth. As more business work flows are introduced and automated, there is generally always an impact to the underlying network. In other cases, additional workloads are pushed to remote field offices, which sometimes require a more efficient network infrastructure. In general terms, as business functionality increases and demand grows at a given Hydro One location (for example, Business Admin Support center (BASC) or an Operations (OPS) centre), network bandwidth is taken into consideration and if warranted, is incrementally increased to support the business. Costs in 2018 to 2022 reflect normalized refresh program covering Voice Networks, Telecom Networks, Data Centers and Perimeter Security.

Risk Mitigation:

All MFA assets are purchased in a just in time approach and in serviced in the same year of purchase. Any risk of assets not being installed will be managed as part of project scope with timelines being reflected in current or following year.

Result:

The Telecom Infrastructure refresh will provide a secure and reliable network to support core business applications, address Hydro One's communication needs and maintain hardware supported levels required by our contractual commitments with vendors and outsourcing partners.

Outcome Summary:

Customer Focus	• Ensures reliable voice and data network to address Hydro One customer's communication needs to service customers.
Operational Effectiveness	• Maintain efficiency of the reliability of voice and data infrastructure to allow all IT applications to function as designed.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost to maintain its IT environment proactively and minimize the potential for costly outages and unplanned upgrades.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.3	1.4	1.4	1.4	1.3	6.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	1.3	1.4	1.4	1.4	1.3	6.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.3**	**1.4**	**1.4**	**1.4**	**1.3**	**6.7**

**Includes Overhead at current rates.*

GP-07 Corporate Performance Reporting

Start Date:	Q3 2018	**Priority:**	Low
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	3.5
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

The Corporate Performance Reporting ("CPR") application is required to produce key high-profile, corporate reporting deliverables (e.g. OEB mandated reliability reports, reports to government, customer reports, and industry benchmarking reports) including SAIDI and SAIFI.

The Business has been using a custom, third-party software tool built approximately 7 years ago. It is still being supported by an external vendor. This tool is not supported by Corporate IT processes and Service Agreements.

There are limited knowledgeable resources available. As a result, it continues to incur costs and present unacceptable business reliability and continuity risks, unavailability of IT sustainment processes/agreements, and potential lack of vendor resource stability. There is limited availability of design and functional documentation on the algorithms, data sources and process chains. For a successful migration, any upgrade project must document these algorithms. This makes modifications for new requirements and standards difficult and risky to implement.

With the information contained on a stand-alone, proprietary system, resources in the Performance Management department are typically needed to fulfill other Hydro One Lines of Business ("LOB") with ongoing data requests. These requests can be labour-intensive.

Alternative 1: Maintaining the Status Quo

Maintaining the status quo leads to continued high risk and dependency on a custom, third-party application. In a qualitative sense, tight dependency on the limited vendor resources and limited support for a non-commissioned environment are high Business Reliability and Continuity risks given the importance of the data. Status quo will also keep Performance Management resources engaged in supporting other LOB's versus responding to new OEB requests and focus on core tasks and new LDC reporting requirements.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 2: Migrate Existing Servers into Commissioned Environment

The option to migrate the application and data servers used for the current Performance Management tools into the sustainment (commissioned) environment was reviewed. This would place the support for the functioning of the servers and their interconnectivity with Inergi under the Enterprise umbrella for day-to-day operational support. This alternative was rejected because it would not materially reduce risks.

In a qualitative sense, the primary drivers of Business Reliability and Continuity risk are the diminishing availability of qualified resource pool for the existing tool combined with the lack of documentation about the applications. Neither of these would be reduced by this alternative.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 3 *(Recommended)*: Integration of CPR with SAP system

The plan is to transition the application and data to an enterprise supported platform (SAP). A Discovery phase was conducted to document the Business requirements and functional recommendations and to estimate costs and timelines for the delivery of this project.

The Quantitative and qualitative analyses of risk mitigation and benefits for the proposed project are summarized as follows:

1. <u>Business Continuity Risk:</u> The number of vendor expert staff who currently supports this program has shrunk down to two individuals. One of the benefits of integrating CPR into the SAP ERP tool is that internally trained FTE will support this program, further improving business continuity and lowering cost.
2. <u>Commissioned System:</u> CPR is a stand-alone application that is not integrated as a Hydro One enterprise application. Integrating CPR into SAP further improves its business continuity benefit.
3. <u>System Documentation:</u> Currently there is a lack of visibility of stored procedures (algorithms and logics) in the CPR program. Through this project, all such embedded algorithms and stored procedures will be documented and be more visible.

4. <u>Optimization of Resources:</u> Integration with enterprise SAP self-service tools results in avoidance of the current third-party vendor support (operational, maintenance and enhancement) costs.
5. <u>Migration to an Enterprise Platform:</u> will allow for a redistribution of Performance Management resources by allowing LOB's to access data directly from SAP. Performance Management Staff to join the "Planning" organization and engage in asset management and reliability related analyses particularly those focusing on new/evolving OEB and LDC reporting requirements.

Savings from the above are expected to be achieved beginning in 2020. These savings include a potential reduction in staff necessary to support the current program, avoided vendor enhancement work, and elimination of vendor annual support fees, which are currently $500k per year, (50% of which is attributable to Hydro One Distribution).

Investment Description:

This project is to build the new reliability reporting tools used by Regulatory / Performance Management teams. The project will involve the migration of the application and data servers and install new code into a sustainable SAP-BI solution to be used for the Performance Management functionality and rules. The project will also involve the migration of historic data, and leverage available SAP and enterprise tools including self service capabilities, reporting and other tools. In contrast to the current Oracle platform, SAP is a commissioned and fully supported environment.

The recommended execution plan will take approximately 18 months to complete both the distribution and transmission reliability components by the fourth quarter of 2019.

Risk Mitigation:

<u>Business Requirements</u>

There is no expectation of major gaps given the extent of the requirements and discovery workshops, however, it is possible and likely that new reporting requirements evolve and some details will require refining as the design and build steps move ahead. All issues will be addressed using standard SAP code. The plan will include provision for these and will address both time and cost implications.

Data Quality:

Early engagement and contact with the teams contributing to identifying data entities, data gathering, data conversion and data migration has to take place to monitor their progress and alignment to the CPR Delivery plan.

Solution Complexity:

The new tools will incorporate numerous, and in some cases complex calculations to derive the performance metrics. A concern is that the build may result in components of such complexity as to make testing and error detection difficult. The project team has to engage with the Vendor to build the new tools such that testing of each and isolation of the source of issues is readily possible. The plan will include provision for this and will address both time and cost implications.

Change Management

One of the goals for this project is to provide greater access outside of the Performance Management Team to reliability related data and scores via the enterprise self-service tools. Change Management is a key player to deliver the vision, training and job aids to the LOB's wishing to access this data.

Result:

Through the delivery of the Corporate Performance Reporting project, the following performance improvements would be achieved:

1. Stability and Optimization of Resource: The number of vendor expert full time employees who support this program has decreased from four to two individuals. One of the benefits of integrating CPR into SAP tool is that internally trained employees will support this program, further improving business continuity of this program. This will also optimize resource deployment in the Performance Management department.
2. Commissioned / Supported System: The current CPR tool is a stand-alone program that is not integrated as a Hydro One enterprise application and is not supported by Corporate IT processes and Service Agreements. Integrating CPR into SAP further improves its business continuity benefit.

3. Increased Visibility: The knowledge of stored procedures (algorithms and logics) in the CPR program resides with the third party. Through this proposed project, all such embedded algorithms and stored procedures will be documented and become visible.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Reduce continuity risk to the production of corporate performance metrics. • Improved efficiency and resource deployment by focusing on evolving reporting requirements.
Public Policy Responsiveness	• The outputs from the CPR system are frequently used for regulatory agency reporting (OEB & NERC & IESO & NEB), government agency reporting (Min of Energy), customer queries, and industry associations (CEA & NATF).
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the following application components and processes: Data Collection, Data Cleansing, Calculations, Reporting and Visualization.

The estimated cost was derived from the CPR Discovery work, in which Inergi was engaged to provide an estimate for the delivery work. At this time the estimate itself is high quality, however, it will be validated prior to submission of the business case to account for the time lapse between Discovery and Delivery phases (~ 4 years). Given the 10+ weeks of workshops to review the requirements; the gap is expected to be small and manageable.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs******
Capital* and Minor Fixed Assets	1.5	2.0				3.5	4.4
Less Removals						0.0	0.0
Gross Investment Cost	1.5	2.0				3.5	4.4
Less Capital Contributions	0.0	0.0				0.0	0.0
Net Investment Cost	1.5	2.0				3.5	4.4

**Dx components only and includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-08 PCMIS Modernization and Optimization

Start Date:	Q3 2019	**Priority:**	Low
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	1.6
Primary Trigger:	Cyber Security		
Secondary Trigger:	Reliability		

Investment Need:

The Protection and Control Management Information System ("PCMIS") tool is a critical platform used to support the Company's power system operations and ensure compliance with reliability and cyber security regulations. PCMIS is the single system of record for all Protection and Control ("P&C") device settings. PCMIS is utilized by Hydro One engineering, operations, and field personnel, as well as technical personnel in Local Distribution Companies across Ontario. The tool contains 'Bulk Electric System Cyber System Information' ("BESCSI"), sensitive data that must be strictly controlled and protected in accordance with Critical Infrastructure Protection regulations, as mandated by the North American Electric Reliability Corporation.

The primary function of PCMIS is to maintain device settings for the Intelligent Electronic Devices ("IED") that protect and control the grid. Over the years, PCMIS has been modified to meet various business and regulatory requirements, and has become a highly customized tool. The application and associated infrastructure are approaching end-of-life (EOL) and need to be upgraded.

PCMIS is a key Hydro One enterprise system that the company depends on to operate the Ontario electrical grid. In 2013, Accenture assessed the PCMIS platform and prepared a detailed report. The report highlighted numerous gaps in existing processes and significant deficiencies in the technology. System scalability, sustainability, and data integrity were all rated 'Poor'.

Alternative 1: Maintain the "Status Quo"

This option would have us leave the legacy system as is. However, maintaining the status quo and running an important application on unsupported infrastructure, exposes the company to the following risks:

- Inability to operate, repair, and replace critical P&C equipment;

- Failure to comply with cyber security regulatory requirements; and
- Failure to comply with reliability regulatory requirements.

Alternative 2: System Redesign and Replacement. (Recommended)

The planned changes will provide an opportunity to replace servers, operating systems, and databases with current technology to ensure operational and support longevity of the platform.

A modern PCMIS platform will be built on new infrastructure with secure, robust technology offering high availability (HA) and disaster recovery (DR). The PCMIS application will be replaced with fully supported commercial software. Functionality and integration interfaces will be optimized, consolidated with other Hydro One enterprise platforms or eliminated.

This is the preferred alternative, as this option will provide a modern robust system that will meet regulatory requirements. The company would like to address the project at the first possible opportunity, which based on available funding is expected to be in 2019.

Investment Description:

The project will maintain and further strengthen PCMIS as the single source of record for all P&C device settings. PCMIS supports users across the enterprise as well as engineering and field personnel in external utilities, providing centralized, controlled access to cyber-sensitive data. The system ensures that the configuration of critical grid protection systems is accurate and manages approval of any settings changes, supporting numerous key business processes including planning, construction, maintenance, repair, network operating and outage management. PCMIS data is used by the Distribution Management System (“DMS”) to support advanced power system application analytics.

The PCMIS platform is aging and upgrades are required to the underlying infrastructure. This investment focuses on delivering a modern technological stable solution to address gaps in existing process and deficiencies in technology as highlighted in a recent third-party assessment. Processes will be optimized. Proven, secure technology will be implemented, resulting in a system that will provide years of efficient and reliable service.

The scope of this investment is to:

Replace existing PCMIS software and infrastructure;

Develop detailed system requirements and performance criteria. Design new infrastructure with proper development, quality assurance (QA), and DR environments. Build, setup, secure, configure, and test new infrastructure and integrate with secure, encrypted communication links. Assess available commercial software and select optimal solution. Purchase, install, configure, and test new PCMIS software.

Introduce process improvements and efficiencies;

Conduct comprehensive assessment of current processes. Working with the business groups we will optimize processes and leverage opportunities for consolidation with other Hydro One enterprise systems. Rationalize and eliminate customizations where possible.

Migrate data and launch new system.

Develop, test, and execute detailed data migration plan; provide orientation and training following proven change management principles; establish effective sustainment contracts.

Risk Mitigation:

To mitigate risk associated to the implementation of a new system and the time required to provide access and train all the LDC's, the 2 new and old systems will be run in parallel for a short period of time.

To mitigate risk associated with change resistance, the project will employ a full organizational change strategy. This will include the stakeholder management at the earliest stages, performing a change impact assessment and following resistance management plans will help secure buy-in from the user community.

Result:

The anticipated outcomes of this investment include:

- a fully supported platform,
- improved system redundancy and high availability, and
- optimized operational processes.

Witness: Lincoln Frost-Hunt

Outcome Summary:

Customer Focus	• Provide secure and reliable access to the protection and control information that will allow efficient system access support and maintenance.
Operational Effectiveness	• Ensure improved system availability. • Reduce system downtime and facilitate maintenance and upgrade work. • Improve access to critical configuration information allowing Hydro One and LDC's to be more responsive to operational issues.

Costs:

Cost estimates are based on historical costs of similar projects of this type.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets		1.6				1.6
Less Removals						
Gross Investment Cost		1.6				1.6
Less Capital Contributions						
Net Investment Cost		1.6				1.6

**Includes Overhead at current rates.*

GP-09 ECM Phase C

Start Date:	Q2 2017	Priority:	Low
In-Service Date:	Q4 2022	Plan Period Cost ($M):	2.1
Primary Trigger:	Public Policy Responsiveness		
Secondary Trigger:	Privacy		

Investment Need:

Enterprise Content Management ("ECM") is the technology used to capture, manage, store, preserve, and deliver content and documents related to organizational processes. ECM tools and strategies allow the management of an organization's unstructured information, wherever that information exists. Documents are centralized, searchable and retained or disposed as per requirements of regulatory bodies.

Hydro One is obligated to meet the requirements of many different regulatory bodies and programs with respect to document management. These include the North American Electric Reliability Corporation ("NERC") / Critical Infrastructure Program ("CIP"), the Ontario Energy Board, the Ontario Securities Commission ("OSC") and many others. Failure to meet these requirements will result in undue legal and regulatory risk for Hydro One.

Hydro One has commenced an Enterprise Content Management ("ECM") initiative comprised of three Phases.

- Phase A represents the classification of a majority of non-complex unstructured data. This was completed March 2015.
- Phase B (started November 25th, 2016 and is currently in progress) will develop several Proofs-Of-Concept (POC) offering options and alternatives for the implementation of records schedules (POC-1), email management (POC-2), management of physical documents (POC-3) and Records Management reporting (POC-4). Upon completion of Phase B, the proofs-of-concept will be configured for immediate implementation.
- Phase C will implement the POC across the company including records schedules, email management, management of physical documents and Records Management reporting (The purpose of this request is to seek funding to implement Phase C).

Alternative 1: Status Quo - Do Not implement Records Schedules POC

This alternative would not proceed with implementation of the Phase C Proofs of Concept and effectively defer the project indefinitely.

Maintaining the status quo is "high" risk because there are currently no records schedules (retention dates, disposition dates) activated on any Hydro One company record (emails and physical documents).

If the status quo were to be maintained, Records Schedules (retention dates, disposition/destruction dates) would not be affixed to physical documents or emails (company records). Without a "trigger" to demonstrate the requirement to retain company records or dispose of company records, Hydro One may be unwittingly storing company records that should be destroyed or inadvertently destroying company records that should be retained.

Alternative 2: Implementation of POC – 1 only

This alternative proposes the implementation of POC-1 only (records schedules POC only).

This strategy would not reduce the risk to Hydro One as the value of records schedules is in its application to company records. Records schedules need to be applied to company records as this POC cannot reduce company risk as a stand-alone product. The value of this POC is derived from its application to company records. As such, this alternative was eliminated.

Alternative 3: Full Implementation of Phase C (Recommended)

The recommended alternative is to proceed with the 3rd Phase of the ECM project - full implementation of all POCs including the implementation of records schedules, POC-1 (data retention dates, disposition activation, etc.) email management (POC-2) and physical document management (POC-3) and records management reporting and administration (POC-4) after the completion of Phase B. reporting and administration.

Investment Description:

ECM Phase C will result in the activation of records schedules including the retention, and destruction dates applied to the physical and email documents. In addition, dashboards demonstrating the growth in SharePoint usage and Open Text publishing (archiving) would allow Hydro One to monitor user adoption.

Risk Mitigation:

As ECM Phase C is the implementation of proofs-of-concepts developed in Phase B, there is a "risk" associated with the scalability of each proof-of-concept. Full implementation is the preferred alternative. However, there is risk associated with the cost to implement several solutions enterprise-wide. To mitigate this risk, the "actual" cost of implementation of POC-1 (data retention dates, disposition activation, etc.) will be reviewed and a "go-no-go" decision will be taken to determine if any or all addition POCs should be implemented.

Result:

Records Management ensures that institutional records of vital historical, fiscal, and legal value are identified and preserved and that regulatory mandated records are discarded in a timely manner according to established guidelines and identified legislation.

Benefits of Records Management include:

- More effective management, access and discovery of current records (both paper and electronic) and related enterprise content;
- Increased institutional accountability and timely access to information; and
- Greater adherence to regulatory requirements.

Outcome Summary:

Customer Focus	• Ensures the privacy, integrity of records and the security of record keeping processes.
Operational Effectiveness	
Public Policy Responsiveness	• Compliance with policy guidelines set by NERC/CIP and OEB.
Financial Performance	

1 **Costs**

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	-	-	0.2	0.9	1.0	2.1	3.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	-	-	0.2	0.9	1.0	2.1	3.4
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**-**	**-**	**0.2**	**0.9**	**1.0**	**2.1**	**3.4**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

2

GP-10 Work Management & Mobility

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	10.5
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

The existing processes and applications used to manage work within the Provincial Lines, Stations, Forestry and some central organizations involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

All work and information needs to be scheduled, dispatched, executed and reported through a standard set of processes and technologies across all of these lines of business within Hydro One. For example, the existing applications used by the Provincial Lines organization to schedule, dispatch and report work lacks the functionality and integration to support the productivity gains that are possible.

The "Move to Mobile" project to implement work management and mobility improvements for the provincial lines organization is presently underway. This was described in the investment summary document IT-05 ("Field Workforce Optimization and Mobile IT"), which was provided in Exhibit D2-2-3 filed in support of Hydro One Distribution's revenue requirement application (EB-2013-0416).

Alternative 1: Status Quo

This alternative was considered and rejected as a result of the following:

- significant, achievable productivity gains would not be realized;
- would continue to rely on manual and untimely paper processes for recording work accomplishments;
- data entry would remain labour intensive, and errors and poor data quality would continue to be prevalent resulting in multiple visits to the same customer site;
- dispatchers would not be able to leverage geospatial capability related to the location of assets, crews and work in order to achieve more work in any given day; and
- the existing mobile platform would remain inconsistent with SAP's future direction.

Alternative 2: Introduce Mobility across All Lines of Business in a Single Initiative

The development and implementation of a company-wide solution incorporating all LOBs and workflows was considered. The complexity of analyzing each component of the planning, scheduling, dispatching, work execution, closeout and reporting processes for key business scenarios for all LOBs within a single initiative would require a multi-year effort and a significant level of risk. It would also introduce a very large company-wide Change Management component related to business processes and applications impacting thousands of employees. This alternative was rejected due to its size, complexity, risk and timing.

Alternative 3: Move to Mobile Implementation Projects at Individual Lines of Business (Recommended)

This alternative involves the implementation of mobile technologies and related business process changes within the Forestry, Stations and Corporate LOBs in a number of discrete, focused projects over the next few years. Each of these projects contains elements of process change, coupled with enabling technology which will result in productivity improvements being realized as the process changes are phased in across each line of business.

Building on the experience gained in the Provincial Lines Move to Mobile Project and from other utilities, particular attention will be paid to the change management strategy. The expected benefits are highly dependent on the field workers wanting to use, and continue to use the new processes and technology over time.

This alternative will result in both quantitative benefits similar to those expected from the Provincial Lines project, and qualitative benefits within Customer Care.

Investment Description:

Through a competitive procurement process in 2014, the decision to standardize using SAP's mobile capabilities was made and a systems integrator was retained to help configure and deploy the solution across the Provincial Lines organization. The systems integrator is currently designing the improved business processes to be consistent with the industry best practices they have experienced working with other clients. A commitment to achieve at least a five percent productivity gain was established, with a projected return on investment of 21.3% and projected ongoing annual savings of $12 million. This project is currently under way with an in-service date in the first quarter of 2017.

Subsequent projects for Stations, Forestry and Corporate LOBs are expected to mobilize during 2017 and 2018, using the standard business and technical solutions established during the Provincial Lines project.

This investment will streamline Hydro One work management processes and deliver an enhanced, integrated scheduling, dispatching and mobile solution for the three lines of business, achieving significant productivity benefits in each.

The projects for Provincial Lines, Stations, Forestry and the Corporate LOBs involve implementing the following:

- SAP's mobile technology for use by Hydro One's field workforce;
- new/upgraded planning & scheduling software, integrated with SAP and the SAP mobile capability;
- SAP mobile platform integration with Hydro One's geographical information system (GIS); and
- Standardized processes for work planning, scheduling, dispatch, execution and reporting, as well as for company-wide processes such as purchase requisition and invoice approvals, timesheet preparation and submission, expense management, and workplace safety inspection form preparation and submission. This includes the monitoring and reporting of the expected benefits, and if these benefits are not being fully realized, initiating remedial action to help ensure the expected benefits are realized.

Risk Mitigation:

The major risks for these projects are similar to the ones faced by the current Provincial Lines "Move to Mobile" project. For example, field workforce acceptance of the new processes and technical solution; system performance of the technical solution; the post go-live approach to supporting the changes all have risks that must be managed. Experience gained during the Provincial Lines project is a major risk mitigation element for the follow-on projects. Any combination of these risks could result in a project in-servicing delay however the same approach used in the "Move to Mobile" project will be applied in these projects. They will be led and owned by the line of business, solid project governance, similar to that being practiced in the current Provincial Lines project will be applied to these follow-on projects. The projects will also take into account the relevant lessons-learned from Provincial Lines.

Following Project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The projects will be led by a field operations VP who is familiar with the culture and challenges associated with a process improvement implementation of this scale with the field work force.

Result:

These projects will provide the schedulers and field staff with real-time or near real-time work status update capability, present staff with a consolidated view of work information, provide a geographic scheduling tool on mobile devices, and enable timely, quality data capture at source.

These projects will also provide a near paperless and automated work environment which will help save paper and fuel, reduce vehicle emissions as well as save corporate operation expenses. Reducing manual steps and providing data validation at time of entry, will result in higher data quality and increased staff productivity.

In addition to a minimum five percent productivity gain for the Forestry, Stations and Corporate LOBs, there are also qualitative benefits in the areas of employee safety, customer service and employee engagement.

Outcome Summary:

Customer Focus	• Improved information reliability for customers with validation of data at source of input. • Improved service levels for customer-related processes like new-connects.
Operational Effectiveness	• Improve work processes by eliminating / automating as much of the manual & paper handling work activities as possible. • Increase efficiency by employing better scheduling and more efficient status of work accomplishment. Forestry, Stations and Corporate LOB should expect to see productivity gains of at least 5%.
Public Policy Responsiveness	
Financial Performance	• Reduce one-time costs including the mobility, planning & scheduling software.

Costs:

The following costs are based on previous experience with the first Work Management and Mobility project for the Provincial Lines organization which started in 2015 and which is planning go-live during Q1 2017.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	4.0	4.6	0.0	1.4	0.6	10.5
Less Removals						
Gross Investment Cost	4.0	4.6	0.0	1.4	0.6	10.5
Less Capital Contributions						
Net Investment Cost	**4.0**	**4.6**	**0.0**	**1.4**	**0.6**	**10.5**

**Includes overhead at current rates.*

GP-11 Enterprise Geographical Information System

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.5
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

Geospatial technology is a key information technology (I/T) infrastructure component that improves the effectiveness and efficiency of a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. While the technology is common to both distribution and transmission functionality, the investments and costs described in this document are specific to the distribution rate filing only.

Hydro One's current GIS software has been in place for roughly 15 years. Existing investments in the Enterprise GIS Program have enabled the integration of SAP and GIS achieving a synchronized, composite asset registry, including distribution and transmission assets, comprised of SAP and Hydro One's other major asset management systems. GIS infrastructure and software need to be updated periodically to take advantage of new functions and software performance improvements, and when possible to further enhance the technology to enable additional productivity in Hydro One's lines of business. All of the major vendor software components are reaching end-of-life during the planning period, and need to be replaced or upgraded. These products are no longer vendor supported after the end of 2017. Hydro One also proposes to address gaps and redundancies in business processes to author, maintain and utilize data from the geospatial databases.

Enhanced GIS functionality is needed to better support various business operations such as load forecasting, outage management, and protection and control, all of which help drive a more reliable network. The implementation of the unregistered easement public interface, for example, will reduce customer service staff effort to respond to numerous requests for assistance and complaints.

Increase in customer satisfaction and revenue are possible as more members of the public use the new easements search system. The integration of new customer-facing web maps would reduce calls to customer care to check rate class or associated concerns.

To summarize, the planned GIS work in the 2018 to 2022 period is comprised primarily of software replacement and / or technical upgrades, as well as moving the existing vendor (ESRI) software from the 10.1 to 10.4 version. One of the software components used for field design work (ArcFM) has reached end of life after 10 years in service and will be upgraded or replaced with a better / more cost-effective vendor solution.

Alternative 1: Status Quo

This alternative was considered and rejected because if this investment is not undertaken, the currency and quality of geospatial information will suffer and impact many key business functions.

For example, one impact of this is safety related. Up-to-date geospatial information resources assist safety practices as crews have easier access to accurate and timely views of the network model. Accurate GIS records complement HONI's Work Protection Code practices.

Alternative 2: Prudent Replacement of End of Life GIS Assets (Recommended)

Upgrade or replace the GIS system components and the integration between GIS and satellite systems it supports. Invest in new technologies that improve data governance and data quality, and leverage the GIS data to provide better and more useful information to the lines of business.

This investment is intended to both sustain the software at vendor release levels that the vendor is prepared to support, and to enhance the existing functionality through a series of projects from 2017 to 2022. Each project will be justified based on return-on-investment and related corporate objectives. Some of the planned enhancements are required to support the Work Management & Mobility investments for Provincial Lines and Forestry projects.

The proposal plans on the following:

- Software version upgrades to the vendor software that will no longer be supported after the end of 2017;
- Upgrade or replace the existing field design software (ArcFM) with a more modern package that provides better functionality and system performance at a cost per tablet lower than it is today;

- Conduct a discovery period to assess the value of implementing new SAP software that more seamlessly integrates Hydro One's map layers with the corresponding asset data in SAP; and
- Rationalize, where possible, the existing custom systems.

Investment Description:

The project will maintain and further strengthen Enterprise GIS as a single system of record comprising the location and connectivity of both transmission and distribution assets. GIS is the only technology that fully supports both logical connectivity and physical location of assets. It also supports asset properties and condition which facilitate planning and outage management, supports mobile workforce management through more effective crew routing, manages real estate records and Hydro One property, and provides the underpinnings of smart grid applications.

Over the years, as various asset-related systems have evolved at Hydro One, use of the GIS as system of record for location, connectivity and phasing has not always been respected. In some cases, complex bi-directional integrations have been built due to improper data governance practices and workflows. This investment focuses on remediating the inconsistent storage of location and connectivity between systems such as the Power System Database ("PSDB") and GIS as well as issues between the Customer Information System ("CIS") and GIS for storage of service point location. Both of these issues have led to increased cost to maintain overly-complicated integrations as well as the deterioration of data quality. Finally, some additional minor data governance issues with Health, Safety and Environment GIS data will be remediated.

Risk Mitigation:

For the version upgrade projects, lessons learned from a similar GIS software upgrade project that was carried out during 2012 and 2013 will be leveraged. This project was completed on budget and close to schedule, using some of the key Hydro One and Inergi resources who will be assigned to these projects. For the replacement of the field design software (ArcFM), an RFP will be issued to select the best value for replacement. Formal project delivery methodology will be applied to ensure adequate governance. The only known risk that could be considered significant is maintaining the data synchronization between the Corporate GIS data base and the SAP Asset inventory. The Information Technology Architects will be looking towards technology enhancements with SAP to centralize both the asset and GIS data in one location to minimize costs of maintaining data synchronization across multiple databases.

Result:

The core vendor software products will be upgraded during the period of this investment and, as is typical, will provide stability and the required level of vendor support for the next four to five years.

Outcome Summary:

Customer Focus	• Improved service to customers and Ontario property owners who should have access to information about outages and unregistered easements.
Operational Effectiveness	• Improved Decision Quality - Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions. • Improved productivity and reduced cost in both sustainment costs and labour.
Public Policy Responsiveness	
Financial Performance	

Costs:

The following costs are based on previous experience with the set of GIS software technical upgrades which occurred in 2012 and 2013.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	2.0	1.9	0.9	0.9	0.9	6.5	7.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**2.0**	**1.9**	**0.9**	**0.9**	**0.9**	**6.5**	**7.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.0**	**1.9**	**0.9**	**0.9**	**0.9**	**6.5**	**7.6**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

Witness: Lincoln Frost-Hunt

GP-12 Business Process Consolidation

Start Date:	Q2 2020	**Priority:**	Medium
In-Service Date:	Q4 2021	**Plan Period Cost ($M):**	2.7
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The SAP Business Planning Consolidation (BPC) system is required to provide planning, budgeting, forecasting, and financial consolidation and reporting capabilities. The Investment planning maps projects & programs to specific strategic objectives. The budgeting process allocates funds to these investments. The forecasting process allows the company to track how the projects and programs are progressing.

The Business is currently using the BPC system which is a component of SAP Enterprise Performance Management portfolio and is designed to handle financial processes on a unified platform. The functional capabilities of the existing system are limited to project forecasting and legal and management consolidations.

Although Hydro One uses this application with available features, the system is not being used to its full potential due to numerous limitations. Specifically, enabled features do not support a fully integrated planning, budgeting and forecasting framework to enable continuous allocation of resources to support the business strategy and operational efficiency.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue its limited use of the BPC application. This is alternative does not allow for Hydro One to take advantage of process and operational efficiencies available through the application.

Alternative 2: Expand Use of BPC by Enabling Other Features and Functionality (Recommended)

This option would go ahead with implementation of the additional features available in the BPC application. Hydro One can continue to use the BPC system for project forecasting and legal consolidation and make use of additional functional capabilities that the system can enable, which are currently not being used.

This recommended option will allow Hydro One to fully realize the benefits of the BPC system by leveraging its potential of delivering planning, budgeting, forecasting, and financial consolidation capabilities in a single application. Hydro One will be able to adjust plans and forecasts, speed up budget and closing cycles, and ensure compliance with financial reporting standards. This in turn will bring about needed process and operational efficiencies.

Investment Description:

This project will provide enhancements to the current BPC system to become a unified & single planning & consolidation tool. It will add software and analytics features to realize additional business capabilities and benefits. These sought after capabilities include:

- What-if modeling and scenario planning to assess budget suitability in real time;
- Forecast models and to quickly update and adjust forecasts as needed;
- Automated aggregations, allocations, and other manual processes to speed up planning cycles; and
- What-if scenarios to allow the business user to identify quick course corrections.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

SAP BPC is a complex application and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

Any combination of these risks could cause the project to be delayed and this will cause any of the following: Projects will be over-budget, behind schedule or will not deliver the scope it was intended to deliver. Solid project governance will be applied, taking into account the relevant 'lessons-learned' from other similar project in order to complete the project on-time and on-budget.

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities based on what-if analyses and scenario planning. It will improve accountability and planning accuracy. It will shorten cycle time, allows for financial information to be reported faster and align the company's plans with its strategic goals.

Outcome Summary:

Customer Focus	• Improve customer experience by providing timely budget and forecast data to the Business which will in turn improve the ability to manage programs and projects that affect customer-related investments.
Operational Effectiveness	• Improve decision-making capabilities and increase efficiency based on the ability to perform what-if analyses and scenario planning. • Improve accountability and planning accuracy due to shortened cycle time allowing for books to be closed faster.
Public Policy Responsiveness	• The outputs from the BPC system contribute to financial input used for regulatory agency reporting (e.g. OEB), government agency reporting (Ministry of Finance) and customer queries.
Financial Performance	• Improve financial performance and lower cost by reducing manual intervention.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management (such as training and job aids to the target user community wishing to access the new features), Project Management and Post Deployment. It includes vendor costs as well as direct LOB resource costs, and indirect costs of implementing the solution.

The cost estimate is based on a historical cost of enabling new functionality within the Consolidation Module of BPC. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One review process.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets			1.5	1.2		2.7
Less Removals						
Gross Investment Cost			1.5	1.2		2.7
Less Capital Contributions						
Net Investment Cost			**1.5**	**1.2**		**2.7**

Includes Overhead at Current Rates

GP-13 HR & Pay Related Technology Investments

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	5.0
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The Human Resources ("HR") Division is responsible for a range of functions in support various processes and activities such as employee time reporting, board and travel recruitment, payroll, Offer Letter Creation and Processing, master data management and search, information for employees and managers as well as reporting of employee-related issues.

The current HR and Payroll functions utilize native SAP ECC system features and transactions to fulfill above mentioned functions and processes. Currently, there's significant reliance on manual, fragmented and inefficient processes and tools.

The existing HR application framework poses numerous challenges and features many inefficiencies such as: Inadequate Knowledge Database for staff, inconsistencies and confusion around the multiple templates to be used, inadequate Knowledge Base Self Service for Managers and Employees, lack of a Case Management/Ticket-Tracking System, lack of an Automated Workflow for certain processes, reliance on a multitude of workarounds and customizations that are costly to sustain as well as insufficient HR metrics and analytics.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue to use the existing HR applications with their existing features.

This is not to Hydro One's advantage as there will be continued reliance on manual, fragmented and inefficient processes and tools. Also, this alternative would miss out on efficiencies and improved productivity opportunities.

Alternative 2: Implement Various System Enhancements (Recommended)

Hydro One would seek to leverage technology improvements and improve operational efficiency in the HR and Pay areas.

Hydro One will realize benefits such as a ticket tracking system for HR issues, a knowledge database for HR staff, managers & employees, automated letter creation & processing, an automated workflow for HR forms, mobility for HR applications, additional HR reports & analytics, online access to electronic pay advice and T4s, pay optimization, board & travel route optimization.

In addition, the intended enhancements will facilitate achieving the cultural change necessary to meet key strategic objectives.

Investment Description:

This investment is required to improve efficiency / productivity in the HR & Pay Area. This will be accomplished through 2 main initiatives.

<u>HR Process Optimization (start in 2018 & complete by 2019)</u>

This investment will address the following needs:

- Lack of a Case Management/ Ticket Tracking System for HR issues. In addition to improving the response time, this system will provide better insight into the types of issues coming to the HR Support Centre, which in turn allows HR to proactively respond to issues;
- Inadequate Knowledge Database for HR staff. By implementing a knowledge base comprised of answers to questions and solutions to problems from previous HR activities, this would reduce the amount of time spent by HR Assistants searching for information and thus improve response times;
- Inadequate Knowledge Base Self Service for Managers and Employees. This would provide quicker access to accurate HR information for employees and managers and minimize the time spent searching for information. Information will be more accurate and consistent;
- Manual Offer Letter Creation and Processing. This eliminates the requirement for multiple template letters to be drafted and maintained. It also reduces the amount of time involved in maintaining content for letters;

- Lack of an Automated Workflow for all HR forms/Smart Forms. A series of Smart Forms would improve efficiency and reduce errors in completing primarily by eliminating additional data input;
- Lack of Mobile Access to HR SAP applications. Mobile applications would provide HR Consultants, Managers and employees with more convenient access to information;
- Lack of Remote Recruitment Tool. Such a tool would reduce travel time for HR Consultants, Managers and employees; and
- Limited HR Metrics and Analytics. An analytics function would allow for improved reporting and analysis on HR issues to better inform decision making with clients.

<u>HR Pay - Phase 2 (start in 2019 & complete by 2020)</u>
Hydro One's payroll and master data management is managed using its SAP ECC system. Payroll business processes need to be further aligned with industry best practices and enhanced to fully utilize the available system capability for those processes which are currently administered through manual data entry. This investment is required to improve efficiency / productivity in the Pay and Time Reporting related processes by addressing the following needs:

- On-line Access to Electronic Pay Advice and T4s This would provide all employees an opportunity to access their pay advice and T4s online;
- Mobile/Remote Access for Time Reporting. This project would develop a mobile application that utilizes the Hydro One's SAP environment. The application will allow employees to access Time Self Serve (TSS) to input time via their smart phone or tablet and increase efficiency;
- Pay Optimization. HR would streamline current pay processes to utilize standard SAP functionality by removing workarounds and customizations that are costly to sustain; and
- Board & Travel Route Automation. This would allow the automatic creation of routes based on Google Maps. Routes are used to calculate amounts owing to Trades personnel to reimburse them for travel from home locations (or city centres) to assembly points.

Risk Mitigation:

<u>Solution Complexity</u>

HR and Pay Related Technology Enhancements are expected to be complex and finding the right skill set to support a successful implementation could be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and HR resources; all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to upgrade current HR and Payroll applications. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates. In addition, the project will be led by someone from the LOB who has deep expertise within the HR Process area.

Result:

This investment will yield operational efficiencies including enabling self-serve analytics and improved decision-making capabilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Improve HR performance by providing better insight to the types of issues coming to the HR Support Centre and better capabilities to address those issues. • Reduce travel time for HR Consultants, Managers and employees. • Allow for improved reporting and analysis on HR issues to better inform decision making with clients and with HR initiatives. • Allow for streamlined pay process & removal of work-arounds and customizations that are otherwise costly to maintain.
Public Policy Responsiveness	
Financial Performance	• Due to integrations in the system & better access to information, this translates to improved decision making abilities which in turn can lead to better financial performance.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as Hydro One direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex SAP changes. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.5	2.9	1.6			5.0
Less Removals						
Gross Investment Cost	0.5	2.9	1.6			5.0
Less Capital Contributions						
Net Investment Cost	**0.5**	**2.9**	**1.6**			**5.0**

Includes Overheads at Current Rates

Witness: Lincoln Frost-Hunt

GP-14 Warehouse Scanning Device Replacement

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	1.8
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

In order to effectively perform material and inventory handling operations, Hydro One has been using Bar Code technology at its warehouses since 2011. A barcode is an optical, machine-readable, representation of data. Using a scanning device (typically hand-held), the bar code is scanned and this provides information about the material such as type, quantity, price. As the information is automatically acquired through the barcode, it minimizes errors and increases speed compared to key entry. This makes operations at the warehouse more efficient.

By 2019, the current system will be at its end of life. As a result, there will either be limited or no vendor support for the scanning device and system that Hydro One uses. In addition, there have been many advances in bar coding technology that would make warehouse operations more efficient but the current system cannot take advantage of these improvements.

Alternative 1: Status Quo

This alternative continues to use the current equipment past its forecast end-of-life.

Maintaining the status quo leads to the business continuity risk of relying on a system and equipment that may no longer be supported by the vendor. Status quo is therefore not a recommended option.

Alternative 2: Upgrade Bar Code Technology (Recommended)

This alternative upgrades the bar coding equipment used at Hydro One warehouses.

By upgrading the bar code technology, Hydro One will be able to leverage improvements in technology in this area. It is anticipated that the technology will provide better tracking of inventory within Hydro One's Barrie Warehouse and Central Maintenance

Shop but also at the various remote field sites including offsite storage depots and construction project sites. This will bring about higher accuracy for tracking of available inventory.

Investment Description:

This investment will upgrade the bar coding devices used at the Barrie Warehouse & Central Maintenance with up-to-date mobile applications that sit atop the approved tablet infrastructure.

Risk Mitigation:

<u>Solution Complexity</u>

Upgrading the Bar Code Technology is expected to be complex and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Supply Chain resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities.

<u>Change Management and User Adoption</u>

The goal of this project is to upgrade or replace its current warehouse scanning device with a more current version. This could potentially pose both process and technology challenges to impacted staff particularly at the Barrie Warehouse, Central Maintenance as well as several other remote locations as they learn to use the technology.

Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

In addition, the project will be led by someone from the LOB who has deep expertise within the Supply Chain and Warehouse area.

The timing took into consideration that the last time the bar code technology was implemented at Hydro One was in 2011. Typical software lifespan is 5 – 7 years. By 2019, it would already be time for Hydro One to upgrade to a more current version or replace its current warehouse scanning device with a new technology or solution.

Result:

This investment will yield operational efficiencies. By proceeding with this investment, Hydro One will be able to monitor its inventory with better accuracy and speed, leading to greater efficiency.

Outcome Summary:

Customer Focus	• Improve customer experience by providing efficient material availability to the Business which will in turn improve the ability to deliver timely programs and projects that affect customer-related investments.
Operational Effectiveness	• Provide accurate inventory count within warehouses and in remote field depots and construction sites.
Public Policy Responsiveness	
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on historical estimate of when Hydro One last implemented bar coding technology. When the discovery phase is complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.7	1.1				1.8
Less Removals						
Gross Investment Cost	0.7	1.1				1.8
Less Capital Contributions						
Net Investment Cost	**0.7**	**1.1**				**1.8**

Includes Overheads at current rates.

GP-15 SAP Treasury Implementation

Start Date:	Q2 2019	**Priority:**	Medium
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.7
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

Treasury Management includes management of enterprise's debt, cash and short-term investments, currency and derivatives exposures, with the ultimate goal of managing the Company's liquidity and mitigating its operational, financial and reputational risk. Common Treasury functions include cash flow forecasting, investment recording and settlements as well as financial reporting. Treasury functions support all lines of business at Hydro One.

Currently, the business operates on a Sungard Integrity v.8.2 platform while most of Hydro One's finance functions operate on the SAP platform. Vendor support for the current Treasury system (Sungard Integrity) ended in December 2016. The company needs to upgrade to Integrity v.8.5 by April 2017 in order to retain vendor support.

There are certain intercompany transactions generated by Treasury in Sungard Integrity that impact the general ledger in SAP. This interaction of data requires technical interfaces between the two different systems, increasing complexity and reducing processing time efficiency.

Alternative 1: Status Quo

This alternative would continue to use Sungard's Integrity application.

Integration between Integrity and SAP will continue to be via batch process rather than real-time. With real-time processing, data is processed immediately when it is received. As a result, data is more up-to-date and potentially more accurate as data can be accessed and corrected immediately by the user. Batch processing, on the other hand, takes time to process. If there are errors, these are typically not caught immediately.

Alternative 2: Implement SAP Treasury & Risk Management (Recommended)

This alternative proposes to replace Sungard Integrity with the implementation of a new SAP Treasury and Risk Management (TRM) module. The estimated cost for licensing is $1 million with an associated maintenance of $220,000 per year (22% of the license cost). Implementation costs were based (business case estimate) on a medium sized complex new SAP module.

The Licensing, implementation, and first year maintenance costs are considered to be a capital cost. Maintenance costs from year 2 onwards would be considered an OM&A cost.

This investment improves business performance through:

- Using standard SAP automated processes for cash and liquidity management, risk analysis and transaction management. Access to real time accounts receivable and accounts payable payment data in SAP will help improve cash flow forecasting and working capital management;
- Simplifying integration and movement of data with existing SAP core financial modules;
- Real time availability of data permits mitigation of issues and errors throughout the month rather than only at the end of the month. This will help Corporate Accounting meet aggressive deadlines;
- Reducing manual work by sending wire and EFT payments directly from SAP to the banks;
- Eliminating manual process in valuation of derivatives and managing exposures by direct feed of valuation data to SAP for financial reporting; and
- Timely update of bank transactions data in SAP for bank account reconciliations to identify any unusual transactions.

Investment Description:

The implementation of SAP Treasury & Risk Management includes the SAP modules: Cash and Liquidity Management; In House Banking; Bank Communication Management; Treasury and Risk; Hedge Management.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The implementation of the SAP Treasury and Risk Management module is expected to be complex and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to replace its existing treasury system with SAP. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities. The SAP Treasury and Risk Management module will provide the Treasury department with a functionally complete set of solutions to support Hydro One's business. Being an SAP integrated solution will promote the harmonization of the system landscape and application rationalization. In addition, integrations between Treasury and other SAP modules will move away from batch processing towards real-time processing, which improves productivity, processing efficiencies and decision-making abilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Simplify the application landscape and integrate more tightly with the existing core SAP solutions. • Increase efficiency through reduced interface requirements, real-time data availability and the leveraging of recent technology upgrades in the SAP stack.
Public Policy Responsiveness	
Financial Performance	• Reduce reliance on IT support by migrating to a common enterprise platform that allows direct access data. • Improve financial management of Hydro One's debt, cash, short term investments, currency and derivatives.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs, as well as Hydro One's direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex new SAP module. When discovery phases are complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are appropriate. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	1.5	1.2	-	-	2.7
Less Removals	-	-	-	-	-	-
Gross Investment Cost	-	1.5	1.2	-	-	2.7
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	-	**1.5**	**1.2**	-	-	**2.7**

Includes overheads at current rates.

GP-16 Customer Self-Service Technology

Start Date:	Q2 2019	**Priority:**	High
In-Service Date:	Multiple	**Plan Period Cost ($M):**	12.9
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Self-serve technology has now become common in our society - from banks which offer ATM machines to grocery stores where a customer can scan purchases and make payments without going through a cashier. For the customer, this is convenient and often saves time. For the company, this fosters increased productivity and cost savings. Offering these service capabilities is rapidly becoming a demand from customers and a necessity of doing business.

Hydro One can provide similar convenience to its customers. Customers can view their bill, understand their usage, find out what conservation tools are available to them, submit a meter reading when communication is unreliable, report outages, pay bills and many other activities; all online. This improves customer satisfaction and engagement. These offerings may also represent a time-saver compared to having to call the call centre. From the Company's perspective, by empowering customers with self-serve technology, this improves productivity through a reduction of the volume of calls into the call centre. This can then be factored into future outsourcing arrangements.

Mobile access is a key channel going forward. In 2016, 40% of customers accessed Hydro One's website on their mobile device. This number is expected to grow over the coming years as new technology is introduced.

Hydro One does offer certain online services to its customers currently. These include:

- HydroOne.com - Hydro One's corporate website provides customers with safety education, energy conservation tools, a breakdown of their bill, payment options, conditions of service, etc.; and
- Mobile App - Hydro One's current mobile app provide information on power outages, including number of customers and affected estimated restoration time.

These offerings are high value. However, customers are saying that they want more of these services. For instance, the ability to send meter readings by uploading a photo of the meter read, the ability to report power outages through a mobile phone and the ability to pay bills through mobile application.

The customer facing infrastructure used by the current online system is aging. If Hydro One were to offer enhanced online services, the current infrastructure would be inadequate to ensure that customers accessed the material in a timely and efficient manner. High system latency and insufficient bandwidth would negatively offset the benefits of offering the new features and could even cause customer satisfaction to be negatively impacted.

Alternative 1: Status Quo

This alternative would stay with the current suite of online tools and not introduce new self-serve capabilities.

If the status quo alternative is selected, although this would not have any impact in terms of reliability of the distribution of electricity, Hydro One would likely experience deterioration in customer satisfaction. Without enhancing the usability of these self-service tools, Hydro One will not realize benefits associated with greater use of self-service channels. Aging infrastructure and software which are no longer under vendor support would pose an unacceptable risk to Hydro One.

Alternative 2: Upgrade Existing Self-Service Technology (Recommended)

This alternative would implement new self-serve technologies in the Customer Service area.

This alternative is recommended since this will improve customer service and maximize the ability of the company to establish a digital channel. This alternative will allow Hydro One to easily increase capacity of the solution as additional customers leverage web based, self-service solutions across multiple devices. In terms of the impact to the customer rate, the cost to implement this investment will be partially offset by operational savings gained by implementing this technology.

Investment Description:

This investment is required to upgrade customer self-service technology to enhance the customer experience and upgrade the underlying technology since it has reached the end of its useful life.

This investment will cover rolling out various mobile application enhancements in 2019 and 2020. These include providing customers the ability to send meter readings by uploading a photo of their meter reading.

This investment will also provide funding for website upgrades and enhancements in 2022. Hydro One is currently upgrading & enhancing its website in 2017 to provide a better digital customer experience. This new website that will be rolled out in 2017 will be mobile-friendly, will provide customers ability to access an interactive bill, will provide interactive tool to assist with energy conservation, will make it easier for customers to submit and track service requests. However, as technology evolves and as customers' needs grow and change, by 2022, this website will already be out-dated and will require another round of upgrades.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

The timing of this investment is based on the useful life of the existing technology and the need to ensure the self-service tools remain relevant and up-to-date.

Result:

This investment will allow customers to interact with Hydro One via their channel of choice and better manage their electricity usage, thereby increasing satisfaction.

The solution will enable customers to conveniently access information, services, and transactions online, in an easy-to-use and intuitive manner, using both mobile and conventional desktop access.

The new technology will increase adoption of self-service channels by providing customers with additional self-service options, thereby reducing call centre interactions. A mobile first design approach will also ensure that our customers can access the website using the technology of their choice.

The new mobile application will allow customers to report outages and will potentially include other functions, including meter reading, payment options, and billing history to provide another avenue for customers to interact with Hydro One.

Outcome Summary:

Customer Focus	• Improve customer engagement by providing a mechanism for customers to conveniently interact with the company. • Provide customers a streamlined online and mobile experience.
Operational Effectiveness	• Increase in productivity since call centre agents can focus on helping customers with issues that can't be addressed via self-serve technology. • Reduce risk of operating on an aging infrastructure and software which are no longer under vendor support.
Public Policy Responsiveness	• Promote government policy on energy conservation by providing consumers easy access to information and interactive portals.
Financial Performance	• Minimize costs by reducing calls to the call centre.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost, as well as indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized after a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets		2.3	1.4	2.3	6.9	12.9
Less Removals						
Gross Investment Cost		**2.3**	**1.4**	**2.3**	**6.9**	**12.9**
Less Capital Contributions						
Net Investment Cost		**2.3**	**1.4**	**2.3**	**6.9**	**12.9**

Includes overheads at current rates.

GP-17 S4 HANA for Finance

Start Date:	Q2 2020	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.4
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

IT Need
SAP has announced that they will stop improving the current enterprise BI platforms immediately and vendor support for the current platform altogether will end in 2025. SAP will shift development to their new SAP S/4 HANA platform. All business functions performed on the current platform will ultimately have to migrate to the new platform.

Business Need – Finance
Multiple systems are required to produce the monthly financial statements at Hydro One. They include SAP BI, SAP ECC, SAP BPC and MS Excel. This drives delay and complexity into the month end processes.

The company faces higher requirements for financial reporting and has a need for improved month end, quarterly and year-end financial reporting procedures and processes.

SAP has, over the past 3 decades, created a platform that can be configured to perform any one business function in multiple ways. While "best practice" has always been built into every SAP transaction, user interpretation of what data needs to input has led to inconsistent transaction processing and erroneous or missing data. SAP has re-architected the Enterprise Resource Planning ("ERP") system, consolidated into ERP the financial functions that currently reside on the BI system, streamlined the financial consolidation processes and simplified the reporting functions. Business Planning has been moved from BW (business warehouse) and incorporated directly into the SAP ERP platform. This means that the impact of planning changes can be immediately reviewed.

More recently, further improvements have taken place in the continued simplification of processes that removes the need for data replication. This provides end users with faster access to data to generate real time reporting and ultimately reduce the time to close the books by 10 – 20% according to SAP estimates. Additionally, new systems provide the ability to facilitate predictive forecasts and dynamic simulations using real time data to provide greater reasonability to the numbers. Embedded predictive algorithms and simulation capabilities enable management to better monitor and forecast business needs.

Alternative 1: Status Quo

This alternative would continue to use the current BI and ECC platforms in conjunction with other applications to produce statements and reporting.

IT

The current SAP platform will reach end of life status, by 2025 at which time SAP will cease providing any support for the current platform.

Business

Continue to plan and manage and report financials in less than optimal manner.

Alternative 2: Replace SAP with an alternative software system

This alternative would replace the current SAP BI platform with competing ERP software and/or adopt a multi-vendor approach by replacing the various business functions with Commercial off-the-shelf ("COTS") applications.

Not justifiable due to the investment Hydro One has made in SAP.

Alternative 3: Migrate to the S/4 HANA platform (Recommended)

IT Benefit

Migrating to S/4 HANA will ensure continued vendor support to reduce IT costs and ensure ongoing, timely performance.

Business Benefit General

Hydro One has significant investment and experience in implementing and maintaining SAP. Over the past 10 years, Hydro One has consolidated over 130 applications, and the functions they performed, into SAP leading to IT and business process savings.

S/4 HANA is proven to offer superior query performance, faster load times thus increasing performance in the numerous business areas that use the ECC platform.

S/4 HANA has a streamlined user interface which has been built upon the same design concept that most mobile applications use which is to present the user with exactly the data they require and limit input options. On the S4 HANA platform business functions or processes have been simplified resulting in less time required to perform the associated processes and improved data quality. The database structures have been greatly simplified. SAP has done away with the sub ledger/ledger construct thus increasing performance.

Business Benefit Finance

Over and above the general business benefits finance functions such as business planning, consolidation and disclosure, financial accounting and financial reporting have been consolidated on the S4. This will reduce the time required perform many of the finance processes.

Investment Description:

Planned investments include HANA which is SAP's new database technology; S4 which is SAP's new application software, SAP's new software configuration guides. This investment will also include, but is not limited to: integration with other enterprise systems; and data migration of financial data from the existing ECC to the new S4. With S4 Finance the business planning and consolidation (BPC) functions that used to be performed on SAP BW have been incorporated into S4 Finance. Data will have to be migrated to S4 from ECC and BPC. When complete all Finance functions can be performed in S4. The S4 version of BPC offers improved plan and forecast capabilities.

This investment will not be impacted by other investments such as SAP Treasury, Business Planning and Consolidation and others. However, it should be noted that anything added to SAP through some other investment will ultimately have to be migrated into SAP and implementation collisions must be managed.

Risk Mitigation:

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The following are the risks that the project plans to address and manage:

Solution Complexity

The SAP HANA delivery is expected to be a complex implementation and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

Configuration guides will remove significant amounts of implementation inconsistency normally introduced by 3rd party implementers.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP, and Enterprise Architecture resources. All of these resources are integral to success of the project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Any combination of these risks could result in a project in-servicing delay. To minimize the risk, solid project governance will be applied taking into account the relevant lessons-learned from other similar projects.

Result:

This investment will yield operational efficiencies, improved decision-making through real time reporting, process simplification, better data driven by standard and consistently performed transactions, better user adoption due to a simpler and modern interface.

Outcome Summary:

Customer Focus	• Leverage out-of-the-box, customer functions that represent the full spectrum of utility customer interactions.
Operational Effectiveness	• Increase operational effectiveness through simplified user interfaces, superior performance and more consistent processes. • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting
Public Policy Responsiveness	• Improve capability to meet statutory reporting capabilities.
Financial Performance	• Reduce the inconsistencies in month end reporting through simpler user interfaces and consistent process execution.

Costs:

The underlying premise is that S/4 HANA will help us fine tune what we have today, not reinvent it. This will extend the investment in the current SAP ERP that was implemented in phases between 2008 and 2013. The cost estimate for this investment assumes the use of the standardised configuration and that the project will be based on migrating data from our existing ERP platform to the new S/4 HANA platform, without the need for lengthy business requirements gathering and interpretation. This is what commonly results in very expensive SAP implementations.

Hydro One will also launch an open competition so multiple vendors can submit their proposals and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets			1.2	1.7	3.6	6.4
Less Removals						
Gross Investment Cost			**1.2**	**1.7**	**3.6**	**6.4**
Less Capital Contributions						
Net Investment Cost			**1.2**	**1.7**	**3.6**	**6.4**

Includes overheads at current rates.

GP-18 Integrated System Operating Centre

Start Date:	Q1 2015	**Priority:**	High
In-Service Date:	Q3 2020	**Plan Period Cost ($M):**	56.4
Primary Trigger:	Asset Driven – Failure Risk & Capacity		
Secondary Trigger:	Regulatory		

Investment Need:

The Network Operating Divisions ("NOD") Backup Control Centre ("BUCC") facility was placed in-service in 1956, and is the means that regulatory, business and operational requirements are sustained for monitoring and control operations to North American Electricity Reliability Corporation ("NERC") standards, Distribution and Transmission System Code ("DSC") requirements and Hydro One standards respectively. The BUCC facility consists of the building, computer tools and systems that support Operations in the event of a partial or total loss of the primary Ontario Grid Control Centre.

A risk of future extended outages, inability to execute necessary upgrades /replacements and increase capacity to required computer systems and tools, could result in significant disruption to business continuity and Hydro One's ability to meet customer's service level expectations. The facility is currently at capacity in computing space, HVAC, power and due to the age of the structure, among other factors, remedial efforts are either not viable alternatives, cannot be mitigated or are cost prohibitive to execute. In addition, a prolonged activation would impede supporting Operations; i.e., Outage Planning, Operations studies and support due to a lack of back office support space. Current Operations support groups that are fundamental in daily Operations, are unable to occupy the BUCC during any event, and would require current staff at the Richview facility to be relocated, procurement and set up of required computer equipment and would take vital time to implement.

Alternative 1: Status Quo/ Use Offsite Leased Space

Hydro One Network Operating maintains the existing Control Room, and Security Operations maintain existing facilities. A new offsite leased Data Centre facility (to mirror capacity of OGCC data centre based on 20 year lease and initial setup costs) could be provisioned and additional office space would be required and furnished for prolonged activations. This alternative includes additional leased space for the Backup Integrated Telecommunications Management Centre's ("BUITMC") control room and compute needs.

The total cost of this option is estimated to be $78M, of which, the distribution portion will be 50.07%.

This alternative has been rejected as the current BUCC for Network Operating and the Backup ITMC do not meet operational requirements.

- The current facility imposes a high level of risk to both regulatory compliance and, Hydro One's reputation and customers, if any failures are experienced.
- This alternative fails to provide for the Security Operations Centre's ("SOC") need for an adequate primary control centre.
- Even with extensive investment in the existing facilities, this option does not adequately remediate all risk factors (e.g., basement flooding, power capacity constraints, electrical hazards due to proximity to TS).
- This alternative cannot accommodate current or projected growth, requiring further investment in leased facilities in the future.
- This alternative would require the relocation of the existing compute space and critical support infrastructure, currently housed at the BUCC, to a new leased BUITMC.
- This alternative cannot mitigate all known risks due to site conditions, size and location. In the event of a prolonged activation, some existing staff of the Richview facility would be asked to leave to make space for operating activities, and even if this arrangement can be made, there is not sufficient onsite parking, work space, or basic facility infrastructure for the overflow of staff.

Further information relating to the rejection of Alternative 1 is found on pages 22-24 of this Investment Summary Document.

Alternative 2: Build NOD Backup Control Centre and Data Centre exclusively.

This alternative was reviewed in light of the 2013 Toronto rainstorm and ensuing flooding that occurred in the GTA. This event required the ITMC to activate the BUITMC located in Kitchener Ontario. During this event, it was made apparent that a failure in the ITMC function or delays in Backup activation, created an inability to remediate, troubleshoot telecommunication outages, and had a significant impact on Network Operating's ability to monitor and control. Loss of communications had severe impacts on the Control Room's ability to monitor and control field assets and clearly showed that a new NOD Backup Control Centre and Data Centre would not remediate all risks currently identified. This alternative proved that a more robust BUITMC is required.

Due to the importance of the ITMC, the identified need for a new BUITMC and the economies that would be foregone with this alternative, this alternative was removed from further consideration. The estimate for this alternative is $104.8M, of which, the distribution portion will be 50.07%.

Alternative 3: Build Backup Control Centre's for Hydro One Networks and ITMC including shared critical infrastructure, back office support areas and an integrated Data Centre.

This alternative includes Control Rooms, an integrated Data Centre and shared back office support areas for prolonged activation and is considered the minimum requirement to address known operational risks that currently exist. This alternative also includes the purchase of the preferred site. This alternative is estimated at a cost of $124.7M, of which, the distribution portion will be 50.07%.

While this alternative meets Network Operating and the Integrated Telecommunications Management Centre's minimum requirements, it has been rejected as it fails to maximize investment utilization through synergistic lines of business occupancy as well as shared use of critical infrastructure. The incremental cost of the SOC inclusion is $ 6.5M. This also fails to take advantage of operation synergies for operational response to security threats, both physical and cyber.

Alternative 4: Acquire an existing facility that could be retrofitted / utilized to accommodate NOD Backup Control Centre, BUITMC and an integrated Date Centre.

A market assessment was completed that reviewed potential sites against identified requirements for size, location, travel times, power infrastructure, telecommunications and occupancy. This also included an internal assessment of Hydro One owned sites. At the completion of the assessment, it was determined that no suitable site was available in the market or within Hydro One's owned locations. As a result, this alternative was excluded from further consideration.

Retrofitting an existing facility was also considered. In order to suit the environments and critical support infrastructure required for Data Centre reliability, real time 24x7 Control Rooms, Security considerations including dual power supply and telecommunications expansions, extensive investment would be required. At the time of the assessment, no suitable site / facility was available and as such it was removed from further consideration. In addition, the total cost to retrofit was anticipated to be equal to or greater than greenfield construction and as such was removed from further consideration.

Alternative 5: Build ISOC with incremental capacity for a Primary NOD Control Centre, SOC Primary Centre, and BUITMC including an Integrated Data Centre, Shared critical support infrastructure and back office support space.

This option involves building the ISOC as described in alternative 6 and making the necessary arrangements to utilize the ISOC as the Primary Operating Control Centre from Day 1. The OGCC, which is the existing primary operating control centre, will then be converted to be the backup centre.

The additional cost for the building, site and the uplift / upgrades to current mission critical Operating systems and IT architecture to initiate the ISOC as a primary NOD Control Centre, from inception, was determined to be high when weighed against the initial benefits; therefore, this option was rejected. The total cost of this option is estimated to be $141.9M, of which, the distribution portion will be 50.07%.

A strategy to enable a "Dual Control" operational strategy was pursued in an effort to leverage current upgrade investments for their useful life. This alternative does not facilitate the Dual-Control strategy and, without costly upgrades, there will not allow the transition to occur in a more organic nature, representing less cost impacts and less disruption to the Operating functions and staff.

Alternative 6: (Recommended) Initiate Build of the Integrated System Operations Centre (ISOC).

This alternative provides for:

1. a Network Operating Control Centre;
2. a Backup Control Centre for the Integrated Telecommunications Management Centre; and
3. primary facilities for Security Operations.

This Alternative also includes the provision for a shared integrated Data Centre, all critical support infrastructures at the preferred site. This alternative will maximize Operational flexibility for Hydro One Networks and associated lines of business while eliminating the need to duplicate investments in multiple sites, and costly critical support infrastructure (emergency generators, uninterrupted power supplies, telecommunications etc.). The total distribution share of this option is estimated to be $64.6M, and the specific amount for this plan period would be $56.4M.

The ISOC strategy will enable a "Dual Primary" scenario where both Centres can be live as compared to the current live/passive (standby) model. Functionality required to facilitate this strategy is not expected until 2022 and will be implemented within current/future lifecycle schedules for the primary applications (i.e. ORMS, DMS, NMS etc.). This effectively negates the need to prematurely replace, re-architect and implement newer systems prior to their lifecycle expiration while providing the benefits and future flexibility of Primary Control ability.

Further details about the project are included in Appendix A.

A detailed option comparison is included in Appendix B.

Investment Description:

The Integrated System Operations Centre will house multiple lines of business through the provision of dedicated Control Centres: an integrated Data Centre and shared back office areas. This facility will be a hardened facility employing emergency preparedness criterion, industry best practices that meets physical and cyber security standards. This strategy provides flexibility for Hydro One Networks to enable future dual control through a systematic and cost effective approach with planned lifecycle upgrades. These facilities are essential in maintaining adequate redundancy for Operation of the Bulk Electric System, management of the Distribution network and associated customer responsiveness (i.e., outage and storm management). In addition, this will ensure Telecom Communication Network management and adherence to mandated North American Electricity Reliability Corporation (NERC) requirements for Emergency Operating Procedure 008-1 "Loss of Control Centre Functionality". It ensures achievement of reliability and availability targets commensurate with the criticality of these facilities. The ISOC will provide in house security operations, mitigating reliance on third party services and provides needed compute capacity for Security Event Monitoring (SEM).

The ISOC design provides the following:

<u>Facility:</u>

- Provide NOD with a new backup control centre including a control room, back office space and a shared data centre, employing the following strategies; provides the operating flexibility that allows Network Operating to duplicate the current OGCC functionality mitigating the current heightened risk profile with the current BUCC.

- Provides additional training synergies through the use of simulation technologies, allowing use of the facility while not required for backup activation (dual purpose).
- Enables future dual control potential, increasing the readiness and customer response times for any future event that may impact the Ontario Grid Control Centre and NODs ability to manage, monitor, control and dispatch on the distribution system.
- Ensures security requirements, both physical and cyber, including a hardened facility to guard against physical and environmental threats (i.e., tornadoes).
- Provides the ITMC with a new backup operations control centre including a control room, back office and integrated computing facilities mitigating the current risks at the BUITMC and the risks a failure of ITMC Operations poses on Network Operating.
- Provide the Security Event Management centre with needed integrated computing facilities.
- Provide Security Operations with a headquarter location including a control centre, office space, investigative rooms, emergency operations centre (room) and integrated computing facilities.
- Shared and redundant critical support infrastructure.

The total distribution portion cost of the construction build, including contingency and escalation, is estimated to be $43.3M.

Site:

Provides a 16.4 acre site in Orillia Ontario at a cost of $3.0M, and 50.07% of this is the total distribution portion cost. The site was selected based on an extensive Market Assessment in Q1 of 2015. The Orillia site met essential criteria, and included material advantages and associated cost savings in terms of; location, current site development activities completed, forgoing of water detention requirements, improved commute and activation times, and significant municipal development charge savings realized through the Industrial Development Charge Moratorium offered by the City of Orillia.

Architecture and IT design:

The detailed design is expected to be completed by the middle of 2017. The distribution portion of the total engineering and IT consultant costs, for the detailed design, is estimated at $7.7M.

Connectivity and Telecommunication:

Connectivity and SONET at the new ISOC facility allows the ISOC data center to communicate with the OGCC and the rest of the Hydro One telecommunication network. The distribution portion cost to establish this communication connectivity and SONET is estimated to be at $6.8M.

Network Infrastructure:

Lastly, an additional $5 million (distribution portion only) has been budgeted for IT infrastructure. This covers the cost associated with connecting each individual workstation console to the ISOC data hall.

Compliance

In order for Hydro One Network Operating to be compliant, there are many requirements, Regulatory Standards and internal Hydro One Standards that must be satisfied. In addition, industry best practices are respected to build on reliability and availability of critical system. The ISOC investment must adhere to; but not limited to the following:

1. North American Energy Reliability Corporation (NERC) –EOP-008 "Loss of Control Centre Functionality" necessitating backup activation to be equal to or less than two hours.
    a. In a related Federal Energy Regulatory Commission (FERC) order (Docket No. RD11-4-000 at 14) FERC signalled its concern that the two hour activation requirement is too long and that "it is imperative that full backup functionality occur as soon as possible after the loss of primary control functionality". FERC also noted that "…it may revisit this transition timeframe". This signalled that the new BUCC facility must take into consideration that activation timelines could be reduced in the future.
    b. NERC and FERC also require the Backup to be "capable of operating for a prolonged period and providing functionality sufficient to maintain compliance with all reliability standards that depend on primary control functionality."
2. Restoration Participant Attachment as required by the IESO administered 'Market Rules' for the Ontario Power System Restoration Plan (OPSRP).
    a. The BUCC is listed as one of the key facilities which comprise Hydro One's contribution to the Ontario Basic Minimum Power System.

3. Required as per EOP-005-2 NPCC-D8 (NPCC Directory 8) and IESO Market Rules & Manuals (Market Rules Chapter 5 – Power System Reliability, Market Manual 7: System Operations, Part 7.8: Ontario Power System Restoration Plan.
4. NERC Critical Infrastructure Protection (CIP) Requirements – ensuring assets are protected logically (electronic security perimeter) and physically (physical security perimeter).
5. Communications: NERC & IESO Market Rules:
   - NERC-COM-001-2;
   - Chapter 2, Appendix 2.2, Section 1.1.4- Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities;
   - Chapter 2, Appendix 2.2, Section 1.2.3 – Transmitter Submission to the Energy Management System;
   - Chapter 5, Section 12.1.1 – Voice Communications Methods;
   - Chapter 5, Section 12.1.6 & Section 12.2.12 – Alternatives During Loss of Communications;
   - Chapter 5, Section 12.2.3 – Required Voice Communication Facilities;
   - Chapter 5, Section 12.2.4 – Voice Communication Reliability;
   - Chapter 5, Section 12.2.11 - Voice Communication Monitoring and Testing; and
   - Chapter 5, Section 12.3.2 - Required Data Communication Facilities.

Additional Design Criteria

In addition to the above requirements, the following Industry Best Practices have been incorporated into the ISOC design:

- Designed for Dual Hot Centre's with Increased Security
  - Provides additional functionality that improves operational proficiency;
  - Improved system security and redundancy; and
  - Meets minimum provincial anti-terrorism standards (i.e., blast protection).
- Multifunctional Facility / Business Continuity
  - Increased building utilization (multipurpose, real time, simulation and future Dual Control);
  - Operational flexibility and scalability (modular expansion); and
  - Emergency Preparedness criteria – facility separation for common mode failure.
- High Availability / Reliability 99.95%
  - Employing an Uptime Institute guiding principles for a Tier III facility; and
  - Provides for redundancy in computing, communications, cooling and power.

- Emergency Preparedness risk considerations were factored into site selection and facility design, mitigating the current risk the BUCC is exposed to (i.e., not in a flight path, transformer station, etc.).

Risk Mitigation:

- Construction commencement is contingent on the required OEB approvals and if not planned accordingly, could pose project schedule risk. This has been mitigated through a schedule adjustment that will initiate commencement in alignment with OEB schedules.
- Municipal Approvals impose risk to the project schedule however during the current detailed design stage, the municipality has been consulted throughout the process mitigating the risk of future change requests or delay for approvals.
- Site development and environmental risk due to discovery of adverse subsoil conditions. This risk has been mitigated through several borehole assessments of subgrade soil conditions to determine: (a) foreign objects; (b) soil contaminants; and (c) suitability of soil cohesion for adequate foundation strength and no notable issues have been discovered.
- Construction risk due to change requests, lack of performance of proponent and increased costs have been mitigated through plans for Hydro One's and the external designer monitoring on site activities throughout construction ensuring issues are discovered and addressed early and that required contract quality is delivered to schedule.
- Alignment of dependent sub-projects has been identified as a potential risk as a delay in delivery of communication path connectivity to the control network would delay future in-service and commissioning activities. This risk is mitigated through early commencement of this activity to ensure adequate lead times.
- Factors affecting implementation timing and priority are those identified in the Investment need section which speak to the increased reliability risk for backup Operations. These factors have been reviewed and the priority has been set to "high" given the high cost for remedial efforts and the impacts on Operations and Hydro One customers if further failures are experienced.

Result:

The integrated strategy behind the ISOC facility maximizes investment utilization as well as value generated by eliminating the need for additional sites and facilities that would otherwise be required. By building one centralized site to house all stakeholders, economies of scale synergies will be realized. These come in the form of negating the need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment, limiting overall rate impacts.

All proposed tenants require critical support infrastructure to meet an availability target commensurate with the criticality of the systems and functions they support (99.95%). The requirements are prescribed by Hydro One internal reliability standards and guided by industry best practices (Uptime Institute Availability "Tier" levels). Critical support infrastructure and IT investment to achieve this objective represent significant investment. With the current ISOC strategy, critical support infrastructure is shared and represents incremental cost to achieve rather than replicating with several installations that would be required to support several sites across Ontario.

- Enhanced monitoring, control and coordinated Customer response (Operating, ITMC, Security and Emergency Preparedness);
- Examples include;
    - Coordinated response for all system vulnerabilities i.e. system events, telecommunication events, cyber events or physical threats through integrated communication within the ISOC facility.
    - Enables future dual active sites, removing activation timelines of backup Operations.
- Share enhanced building protection design and security (physical facility hardening to protect against severe weather or man made threats);
- Share redundant backup generator power supply and other emergency supplies;
- Enhanced site location for improved activation response, elimination of NOD's interim BUCC, adherence to emergency preparedness criteria, dual purpose use for training (negating need for additional training facilities) and other business operations; and
- Enhanced security with centralized operations, improved monitoring and analysis trending for proactive response, and situational awareness for coordinated resolution. An Emergency Operations Centre for Business Continuity and Emergency Preparedness will also be provisioned as part of the Security Operations Centre.

Outcome Summary:

Customer Focus	• Improve the reliability and availability of emergency activation, response and restoration in the event any failure is experienced in the Primary Control Centres. • Reduced rate impacts from a single integrated solution as compared to multiple standalone investments. • Retiring of the current interim NOD BUCC and removal of the risk of costly remedial efforts in the event further failures are experienced.
Operational Effectiveness	• Mitigates the critical risks (infrastructure failures, capacity constraints, location and activation timelines etc.) that exist at the Network Operating Backup Control Centre and the Backup Integrated Telecommunication Management Centre. • Monitoring and control reliability will be sustained under all system contingency scenarios improving Hydro One's compliance risk, customer responsiveness and Operational agility.
Public Policy Responsiveness	• Accommodate all regulatory requirements for physical protection, cyber security and activation timelines responsiveness. (See Appendix A and Compliance section of this document for further details).
Financial Performance	• Reduce the cost impact to Hydro One customers through the realization of economies of scale, mitigating the need to provide multiple sites, buildings and shared critical support infrastructure. • Negate the need to maintain an Interim NOD BUCC and reduce the risk of costly mitigation in the event additional failures are experienced at the main BUCC.

Costs:

Key considerations affecting the final cost of the project consist of the following:

- Availability and Reliability Standards including the need for redundancy in system and building architecture to maintain the existing target of 99.95%. The largest cost element revolves around the Data Center and critical support infrastructure, and the "Tier" or "Redundancy" level can weigh heavily on the investment required. Given the criticality of the Control Centre functions, with leading industry advice, a Tier III level was recommended and designed. This category includes the investment required in the SONET control telecommunications network required to connect the BUCC to field assets for monitoring and control.

- Security Requirements impose additional cost considerations ensuring the facility can withstand both natural and human events i.e. Tornado's, blast protections. Included in this consideration are prescribed regulatory requirements for six sided secure perimeters, cyber security (IT architecture), site access and monitoring of critical assets.
- Costs have been managed through an extensive and thorough assessment with various third party industry experts, internal subject matter experts as it relates to industry best practices, cost saving initiatives (i.e., free cooling), alternative option assessment for independent project elements (site selection, industry comparators), integration of solutions for various business units, functions and needs across Hydro One at a single site. An independent cost consultant has provided costing of the current stage of detail designs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	10.5	42.6	3.3	-	-	56.4	64.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**10.5**	**42.6**	**3.3**	-	-	**56.4**	**64.4**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**10.5**	**42.6**	**3.3**	**0**	**0.0**	**56.4**	**64.4**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

APPENDIX A – DETAILED PROJECT DESCRIPTION

This investment, formerly known as the Backup Control Centre – New Facility Development, has expanded to include other operational synergistic lines of business that require facilities to perform similar functions (operating, monitoring, control and response functions) that are critical to support Network Operating and to secure Hydro One's assets. An integrated solution was sought to ensure costs are minimized, maximizing the effective utilization of critical infrastructure, office space and the site with the intent to maximize capital investments and reducing customer rate impacts. Below is a description of the Security Operations (SOC), Security Event Monitoring (SEM) and the Integrated Telecommunications Management Centre (ITMC) identified investment need.

The Backup Integrated Telecommunications Management Centre (BUITMC), in-serviced in 1950, requires extensive setup during activation and cannot accommodate back office support staff and regulatory security requirements for access control for critical computing equipment. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure. In the event the ITMC cannot meet its service objectives, and Hydro One experiences an issue with telecommunications paths, Network Operating will be unable to monitor or control the respective field assets. ITMC requires a new Backup Control Centre to alleviate the risk at the current location.

Security Event Monitoring (SEM) is accountable to provide cyber surveillance monitoring services and requires Data Centre capacity, (not a physical tenant) to support primary and backup operations. SEM monitors Network Operating's Compute Network to ensure threats are detected, assessed and remediated so that critical cyber assets are not negatively impacted. Loss of visibility, control or erroneous operations of equipment due to a cyber-vulnerability, poses a serious threat to Hydro One's Operating functions. The risk of cyber related events has increased rapidly due to the relative increase in the amount of IT critical cyber assets employed in Hydro One Networks.

A Security Operations Centre (SOC) and an Emergency Operating Centre are required to provide a primary site for operations, monitoring and coordinated response for physical security threats and are imperative for business continuity. Currently, Security Operations are dispersed across the province and is reliant on third party services. In the event the current vendor cannot meet service obligations, Hydro One will be unable to monitor its critical sites. An integrated security presence at the ISOC will ensure physical threats can be detected, assessed and appropriate response dispatched. If a physical threat goes undetected, catastrophic impacts can result, in the event critical assets are damaged, which has potential to result in sever impacts to the Transmission and Distribution system networks. In addition, a lack of detection has potential to expose Hydro One to safety and environment risk for staff and the general public.

The current ISOC investment has evolved through a significant collaborative effort with Hydro One Network Operating, ITMC, SEM, Security Operations, industry participants and external subject matter experts. Initiation of this investment was predicated on current asset driven deficiencies / requirements (documented safety hazards, capability constraints, Reliability/Performance Impacts and risks, failures, condition, age, obsolescence, and regulatory and/or Hydro One standards (as described above).

Below is a detailed description of the ISOC investment planning process and execution strategy, which has been developed with the aim to a) fully understand requirements and needs across Hydro One; b) gather leading industry best practices, lessons learned; c) develop detailed programmed space and sizing requirement and asses against industry benchmarks; d) project costing from leading industry experts; e) ensures cost controls and oversight.

Planning Needs Assessment: Phase One

Requests for Proposals (RFP) were issued to conduct a Market scan and a Planning Needs assessment. This provided a detailed assessment of sites available in the market that met a set of specific "essential location requirements" and to provide expertise into the conceptualization and documentation of business needs and requirements of Hydro One Networks, ITMC, SEM and Security operations. The main focus was balancing needs and costs against reliability requirements, industry best practices (including Industry participant's feedback (New York ISO, New England ISO)) and lastly with lessons learned from the current Primary Ontario Grid Control Centre (OGCC). In addition, business requirements were translated into programmed space requirements based on Hydro One's experience and at the advice of industry experts. A basis of design was developed, capturing the stated requirements and a cost estimate was provided by an external estimator (for building and support infrastructure) and internal Hydro One engineering groups (for Telecommunications and Dual Power and Power System IT).The final basis of design and cost estimate were utilized to initiate the subsequent Detailed Design Phase.

The sizing of the ISOC is predicated on duplicating the OGCC current functions for Backup Control, including parallel use for training simulation and controller / dispatcher training.

The training facilities at the OGCC are currently at capacity. This effectively reduced the size of the ISOC facility by negating the need to program space for training simulation and instead uses technology to use real-time operating space while not active (in backup mode). In the event the OGCC is rendered inoperable or uninhabitable, the new ISOC facility will be able to continue all day to day functions indefinitely with a limited transition period, expected to be one hour or less.

Security Operations sizing was predicated on defined needs of operators, support staff, an investigation room and an Emergency Operations Centre (which will utilize a shared conference rooms when required).

ITMCs Backup Control Centre duplicated the current Primary Centre exclusively, including Control Room space, Data Centre requirements and provisions a back office support compliment to ensure adequate facilities are available for prolonged activation redundancy and assurance of Operations.

SEMs compute needs were documented, forecasted and the incremental capacity was added to the Data Centre white tile space.

Future growth has been accommodated and captured in the detail design however not all space will be built in the initial ISOC build. Data Centre growth has been included up to and including 2035 due to the sensitivity of the equipment and the risk future construction would pose; however the support infrastructure will be purchased on an as needed basis. Future facility expansion will be enabled for future consideration by way of footings and ensuring construction can be achieved without impacting operations (designing connection points etc.) Future extension of the facility, when required will be included in future OEB rate cases.

Detailed Design: Phase Two

At the completion of the Planning Needs Assessment Phase, a Detailed Design phase commenced with the objective to provide all required documentation, designs and costing to tender the end state solution for construction. During this phase, all drawings, facility programing (space definition), IT architecture etc. will be completed, including site procurement (~$3M), Proof of Concept for IT architecture and a final estimation. This information will be packaged and ready for submission for RFP for the construction phase. It is expected to be completed in 2017.

Pending completion of the Detailed Engineering Design and receipt of required approvals, Hydro one will leverage its internal Supply Chain, an Open Market Construction Tender process in two phases.

Phase One: Request for Pre-Qualification ('RFPQ")

Hydro One will seek to pre-qualify a select number of vendors in an open market process, who demonstrate "required competencies" (e.g., proven large project construction experience, defined safety/environmental programs, change control process controls, demonstrated ability to deliver large construction projects on time and to budget, etc.) related to the construction of the ISOC and acceptance of HONI required market-based Terms and Conditions.

Phase Two: Request for Proposal ("RFP")

Hydro One will release to only the pre-qualified vendors a detailed RFP with a complete set of construction documents. Pre-qualified vendors will be required to review the construction documents, offer input with respect to area's which could result in increased costs if not addressed before construction and provide a "fixed" price proposal to a defined scope of work and schedule, linked to a delivery penalty.

Construction Phase: Phase Three

The successful proponent will commence construction and is planned for Q4 2017.

Post Construction award: Hydro One's external designer will monitor on site activities throughout the construction to ensure any issues are addressed early and that required contract quality is delivered. HONI and designates will participate in interactive Bi-weekly onsite construction process meetings to gauge progress to requirements and address concerns which may impact the process.

The ISOC investment has been identified and assessed as a high priority and was subsequently prioritized and planned due to risk and considerations described below.

Site location risks that will continue to be present as there are no viable remedial alternative to the following risks:

- The current site location, and required travel time, requires maintaining an interim backup facility to perform limited functions in the event the OGCC is rendered inoperable and staff have to transition to the BUCC. The ISOC will eliminate this requirement;

- Structure is landlocked, and no expansion potential exists as the facility is surrounded by a Transformer Station;
- Current emergency preparedness risks will remain:
  - In a flight paths (Pearson International Airport);
  - Between two major highways (Hwy 427 & Hwy 401) in the event of hazardous spills;
  - Gas pipe lines located underneath property;
  - Adjacent to transformer station (electrical, fire and asset failure hazard). In 2011, T7 and T8 transformers at Richview both failed catastrophically, resulting in loss of the station and a major fire. This removed the BUCC from use for an extended period of time;
  - Congested area in the event of wide spread emergencies i.e. Civil unrest, blackout, natural disaster, and commute;
  - Adjacent to public storage facilities.
- Facility risks that could render the Hydro One Networks Control Centre or critical equipment unavailable for an extended period of time, eliminating redundancy of critical monitoring and control of the Distribution system include:
  - Flooding in basement, roof and cable entrances, where computer rooms, power rooms, telecom rooms, switchgear, and SONET communications are currently located;
  - Failures of critical support infrastructure including; the fire panel, HVAC, emergency backup power (generator);
  - Inability for expansion and a high cost for retrofit / maintenance activities;
  - Relocation of the equipment located in the basement of the facility is not viable given the space required on the main floor (Computer rooms, telecommunication gear (SONET), Uninterrupted Power Supply units, switchgear etc.;
  - Competing demands for physical space, power, cooling from multiple tenants; and
  - Electric power system is undersized (Station Service).
- ITMC's current BUITMC has documented the following risk and constraints;
  - Located in a shared space with an inability to expand;
  - Requires extensive setup during activation as the facility cannot accommodate a permanent active installation;
  - Cannot accommodate current back office support requirements;
  - Cannot meet security requirements for access control for critical computing equipment;
  - The current HVAC is not adequate for net new occupancy or equipment;

- Lacks the necessary facilities should a prolonged activation be required; and
- ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure.

Hydro One’s Security Operations are currently reliant on an external facility that is owned and operated by a third-party creating corporate and regulatory risks given that Hydro One lacks a contingency site that is capable of monitoring the physical security of its sites and assets. Should the facility or 3rd party services no longer be available to Hydro One due to factors outside of Hydro One’s control, Hydro One will not be in a position to monitor the real-time security (including door alarms, motion sensors etc.) of its critical sites, creating both a security and public and employee safety risk. Such an occurrence would also lead to a regulatory non-compliance violation with NERC Standards and possible sanctions, financial penalties and risk to corporate reputation.

APPENDIX B – DETAILED ALTERNATIVE COMPARISON

Detailed Alternative Comparison

Alternative	Description	Cost ($)	Size (Sq.Ft)	Site (Acres)	Cost / Sq.Ft	OM&A**	Benefits / Risks
Alternative One: Status Quo	Maintain existing facilities. (BUCC remediation activities, lease new data hall space and for BUITMC Requirements).	$78M*	18,921	N/A	N/A	N/A	No provision for SOC. BUCC existing location, space, and site constraint risk remains. Significant difficulties for prolonged activation. Includes a leased space for BUITMC, leased Data Centre space for NOD and remedial work to retrofit office space to better accommodate prolonged activation.
Alternative Two	Build NOD BUCC and Data Centre.	$104.8M*	95,420	10+	$1,098	$3.72M	Site, SONET, Dual Power and critical support infrastructure included.
Alternative Three	Build ISOC as BUCC, BUITMC with back office and Data Centre.	$124.7M*	99,716	16.41	$1,251	$4.0M	This includes the preferred site and all critical support infrastructures including but not limited to: SONET, Dual Power, redundant generation, UPS, cooling, shared office and common space. This excludes SOC from inclusion.

Alternative	Description	Cost ($)	Size (Sq.Ft)	Site (Acres)	Cost / Sq.Ft	OM&A**	Benefits / Risks
Alternative Four	Acquire an existing facility for BUCC and BUITMC and integrated Data Centre	Not available. Building specific market scan by Andrew Thompson and Associates (ATA) indicated no suitable site for consideration at time of assessment. Hydro One owned sites were reviewed internally; however also found that no suitable site or facility existed.					
Alternative Five	Build Primary NOD Control Centre, primary SOC, and BUITMC.	$141.9M*	146,200	16.41	$971	$4.47M	This option assumes that the existing OGCC staff would be moved to the new ISOC and the current OGCC used a Backup. Additional compute / system investment required which is not included in total cost.
Alternative Six	Initiate Build of ISOC with future dual operating capabilities.	$130.0M*	126,200	16.41	$1,030	$4.47M	Provides a NOD BUCC, BUITMC, and Primary SOC including shared integrated Data Centre, and back office support. Current lifecycles for critical applications respected, alleviating addition IT requirements to enable Primary operability. Dual Primary enabled for future implementation.
Ontario Grid Control Centre (data for comparison purposes)		$144.9M	68,000	9.25	$2,131	N/A	Presented in 2016 dollars (originally $118M investment in 2003) Provided for comparison.

*The Distribution portion of this total is 50.07% of the total cost.

**The OM&A cost estimates are the full total cost, and these have not been adjusted to show the distribution portion only.

Data Centre Construction vs. Leased Data Centre

In addition to the above alternatives, a comparison between the option of construction versus a comparable colocation or leased data centre option was conducted by engineering firm Morrison Hershfield, to ensure the most cost effective means of providing needed Data Centre space. This is the largest cost consideration in the overall project total. This assessment was based on a 15 year term based on market prices in the Toronto area. The Toronto area was utilized for this study as it provided a much larger pool of lease options with the required reliability / Tier level standards. The results are shown below which indicated that the co-location/lease option ($122.1M), based on the current design criteria, far exceed the cost of the build option ($73.2M) ($30M in Capital + Incremental annual OMA at $2.5M escalated at 2% per year for 15 years, $43.2M).

	IT/POWER MRC*	**Annual Cost of Rent**
Year 1	$ 341,144.00	$ 4,093,728.00
Year 2	$ 372,529.25	$ 4,470,350.98
Year 3	$ 406,801.94	$ 4,881,623.27
Year 4	$ 444,227.72	$ 5,330,732.61
Year 5	$ 529,725.56	$ 6,356,706.73
Year 6	$ 529,725.56	$ 6,356,706.73
Year 7	$ 578,460.31	$ 6,941,523.75
Year 8	$ 631,678.66	$ 7,580,143.93
Year 9	$ 689,793.10	$ 8,277,517.17
Year 10	$ 753,254.06	$ 9,039,048.75
Year 11	$ 822,553.44	$ 9,870,641.24
Year 12	$ 898,228.35	$ 10,778,740.23
Year 13	$ 980,865.36	$ 11,770,384.33
Year 14	$ 1,071,104.97	$ 12,853,259.69
Year 15	$ 1,169,646.63	$ 14,035,759.58
	Total 15 Year Spend	$122,101,320.25
*MRC = Monthly Recurring Charges include IT load rent, estimated power charges and PUE of 1.6		

Other factors that affected this consideration are; a) no co-location facility provides NERC certified space which would require additional upfront capital cost in year one, b) many facilities have policies that dictate access, upgrade, expansion and security for the facility without renter input which exposed Hydro Ones critical equipment to further risks.

ISOC Breakdown	**Est. Cost**	**Ft2**	**$ / ft^2**	**Report Findings of Morrison Hershfield on Build Comparisons**
Building Shell Cost	$23M	120,534	$250	Includes shell and basic Mechanical Electrical Power services. This is considered at the bottom of the range of $250/ft2 -$1000/ft2 for hardened facilities of this type, which equals the cost per square foot for SaskPower's most recent facility design. Variance consisted of EF3 Tornado rate vs. EF4 for SaskPower with less office space and did not have Control Room space. Average generic office space range from $150 - 250/sq. ft. dependent on finish and furnishings.
Data Centre Cost	$30M	11,990*	$2502	SaskPower's estimates cost per sq. ft. for data centre space was $3,000 / sq. ft. and it is MH's conclusion that $2502 is within range of similar facilities. A similar telecom project in 2015 with a similar Tier level as HONI was $2575/sq.f.t.
ISOC Total	$130M**	127,703	$1018	This includes Building Shell, Outdoor Yard and Data Centre.

- **Included support galleries (cooling, power distribution).*
- ***Note: The Distribution portion of this total is 50.07% of the total cost.*

<u>Comparisons to Similar Facilities at Other Utilities</u>

Lastly, NOD reviewed a number of utilities investments in facilities and data centre development projects to ascertain the reasonableness of the ISOC scope as compared to the rest of the industry. Below is a table summarizing these findings; which show the ISOC is in line with the cost per square foot for comparable projects.

Industry Comparators	**Description/Name**	**Cost ($M)**	**Size (Sq. ft.)**	**Year Built**	**Adj. Cost to 2016 $ (CPI)**	**Cost (2016 $) / Sq. ft.**
New York Independent System Operator	NYISO Control Center	$59.4M	64,000	2014	$60.82M	$950
American Electric Power	Transmission Operations center	$57.2M	83,500	2007	$65.92M	$789
ISO-New England	Windsor Backup Control Centre	$50.7M	70,000	2014	$51.91M	$742
Pacific Gas & Electric	Distribution Control Center	$52.0M	37,674	2015	$52.57M	$1,395
	Distribution Control Center	$37.05M	24,000	2014	$37.97M	$1,582
	Distribution Control Center	$46.8M	50,000	2016	$46.8M	$936
First Energy	FirstEnergy Tx Control Centre	$58.5M	70,000	2013	$61.16M	$874
BC Transmission Corporation	System Control Modernization Project	$133M	113,022	2008	$148.07M	$1,310
	System Control Centre (building ONLY)	$40M	64,584	2008	$44.53M	$689
	Backup Control Centre (building ONLY)	$30M	48,438	2008	$33.4M	$690
Average Cost :				-	$60.3M	$996
Distribution Portion of ISOC.		$64.4M	63,851.5	2016	$64.4M	$1,009
Proposed ISOC Cost Comparison		$130M	127,703	2016	$130M	$1018

Converted from USD to CDN at an exchange of 1 USD to 1.3CDN

Note: The ISOC is comprised of Distribution, Transmission, ITMC and SOC.

Site Assessment

As the table below shows, sites south of Barrie were higher cost and the sites North of Barrie were considerably less expensive. Orillia, given its relative location compared to the Primary Centre, was optimal given the City size, access, lodging, development and emergency services, including the OPP headquarters. Communities further away were ranked lower due to distance, access to emergency services, development and lodging, winter driving hazards and relative site suitability among other factors.

Ranking	Community	# of Sites	Ave. Cost / Acre
1	City of Orillia	4	$114,935 - $181,200
2	Town of Bradford	3	$346,636
3	Town of Collingwood	3	$135,469
4	Town of Midland	6	$90,000
4	Town of Penetanguishene	3	$87,500
5	Town of Alliston (New Tecumseth)	3	$273,900
6	Town of Newmarket	2	$850,000
7	Town of Orangeville	1	$215,000
8	East Gwilliambury	6	$400,000
9	Angus	1	$80,000
10	Innisfill	0	$ -
11	Schomberg (King Township)	1	$475,000
12	Wasaga	0	$ -

Note: An assessment of internal Hydro One TS sites was reviewed against available acreage and emergency preparedness criteria and was determine that there was no existing Hydro One site that could accommodate the proposed facility. This represented a departure for previous assumptions with impacts of land purchase and support infrastructure that must be extended to the preferred site.

GP-19 Operating - Common Information Technology Infrastructure

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	11.0
Primary Trigger:	Asset Driven		
Secondary Trigger:	Reliability/Performance		

Investment Need:

The Common IT ("Information Technology") infrastructure is the shared IT backbone of Network Operating's critical enterprise systems. It is technically more efficient and maintains a lower total cost of ownership as compared to multiple discrete instances to support specific systems. This translates into less sustainment and total system component purchases. Common IT infrastructure is further defined into sub categories, which include:

- Data storage (devices that retain, retrieve and archive digital computer data "information");
- Compute servers (processors that fetch, decode, execute and write data in response to system processes and application inquiries);
- Computer consoles (microcomputers used by Operating Dispatchers, Operators and Managers to interface with applications);
- Information Technology networks (a series of communication paths interconnecting IT devices); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS.

Each sub category includes hundreds of individual assets, both hardware and software products. IT products have lifecycles for a number of reasons, for example market performance, and technology innovation and development, drive change in products or the product matures and is replaced by functionally richer technology. As new technologies are developed, support and the ability to purchase spares or replacements equivalent to in-serviced assets is more costly and difficult to achieve. Regardless of the reason for change, supporting products beyond their lifecycle poses increased risk to Operations.

If extended support agreements are made available, the costs are typically a minimum of two to three times that of current supported market products, which drives consumption to the latest offering. Furthermore, product replacement parts become scarce and inflated in price and run the risk of non-compatibility with other more current devices. These factors and others make the employment of products beyond their lifecycles untenable. As each device is interdependent and the future replacement technology attributes are almost always unknown, pacing and prioritizing is an ongoing effort. Vendors often announce lifecycle support conclusion dates with minimal notice. The continuous process of assessing device compatibility at its lifecycle conclusion requires careful architectural consideration to ensure system reliability and performance standards are constantly being met.

This investment is comprised of multiple asset groupings, and is required to maintain the viability of the common IT infrastructure for Operating's computer applications such as the Outage Response Management System, Network Outage Management System, Network Management System, and Distribution Management System. (Discrete application infrastructure is not included in this investment). These applications are leveraged by both Distribution and Transmission. However this investment represents the Distribution portion exclusively.

Alternative 1: Status Quo:

This alternative is to maintain status quo: do nothing and continue to use the existing IT infrastructure. As each device represents an important interconnected component of the common infrastructure, not proceeding with these lifecycle replacements could result in the following:

- Hydro One's diminished capacity to serve and respond to customers;
- Regulatory non-compliance with the potential for heavy fines;
- Potential loss of one or more mission critical applications;
- Significant increase in Operating maintenance costs;
- Loss of the original equipment manufacturer/vendor support;
- Increased probability of system failures;
- Inability to recover from system failures;
- Increased vulnerability of cyber terrorist attacks;
- Potential to strand future application upgrades and enhancements; and
- Risk of costly remedial efforts in the event of a failure.

Alternative 2: Maintain Supported IT Infrastructure (Recommended*)*:

Lifecycle management based on industry best practices and vendor support schedules ensures the viable operation of Operating IT infrastructure assets, including the enablement and continued reliability of critical application systems. The dynamic architectural model requires Operating to plan and replace devices with the appropriate current technology and is recommended as the only viable option. This option offers the following benefits:

- Continued compliance with availability and reliability standards;
- Current market product maintenance and support costs;
- Original Equipment Manufacturer ("OEM")/vendor provided updates and software patches;
- OEM/vendor available replacement parts at current market prices;
- System compatible infrastructure devices; and
- Improved ability to recover from random failures.

Through systematic replacement of common IT infrastructure Hydro One Networks can sustain business functions by ensuring the tools and systems used to support Operations are functioning as designed, are fully supported, and ensure any failure can be readily remediated. This provides the assurance to Hydro One customers that IT failures will be minimized and if a failure is experienced it will be returned to service in a timely fashion. This approach maintains Hydro One's commitment to customer satisfaction by ensuring responsiveness through system availability.

Investment Description:

These IT infrastructure investments include the following asset sub categories and are located at both the Ontario Grid Control Centre ("OGCC") and the Back-up Control Centre ("BUCC"). Servers, PCs and disc drive counts are always fluctuating depending on the current state of lifecycle management projects. Lifecycles of the various components are dynamic, and can at times be interdependent, influencing other components. The hardware is generally problem-free, however lifecycle management means keeping it in a supportable state as dictated by the vendor. Disc drives do fail but are replaced under service agreements. All devices would be current to the year they were "lifecycled" and there isn't a single "project" that replaces everything at once in a single year therefore the age distribution will always vary. Lifecycle planning forecasts in each category has leveraged historical trends, however careful consideration regarding the lifecycle replacement and transferability of the infrastructure will be provided as Operating relocates the BUCC into the Integrated System Operations Center beyond 2020 including:

- Data Storage (i.e., storage area network devices "SAN"; achieve data storage backups);
- Compute Servers (i.e., secure file transfer devices; monitoring systems; server operating systems);
- Computer Consoles (i.e., Windows operating systems; peripheral devices);
- IT Networks (i.e., remote access devices; satellite time clocks); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS. Oracle and SQL database applications.

A failure of a single component has the potential to cause cascading impacts including; a failure of a critical application and the business function it supports, removal of system redundancy, or worst case, render the OGCC and/or computer systems unavailable. The resulting impact on work execution and customers could be as follows:

- Cancellation or delay of outages requiring planned field work causing customer or Hydro One work to be delayed, requiring rescheduling, reprioritization and rework;
- Unresponsive distribution outage management and lack of communication with customers and staff posing work delays, safety risks and inability to respond to emergency events (i.e. if failure occurs during Storm event); and
- Backup activation which limits full business function and hinders critical response.

Risk Mitigation:

Replacing end of life infrastructure assets is recommended as "best practice" in order to maintain Network Operating's current supported, compatible and redundant IT infrastructure and equipment. The ongoing dynamic processes to cost effectively assess, prioritize and stage each product in its respective category must remain in focus by Hydro One's Power System IT architecture team and supporting management and staff at all times in order to achieve success now and in the future. The driving focus behind these processes is to maintain current reliability and service levels with the continued support of mission critical applications and their function is to serve Hydro One's customers in the most cost effective manner possible.

Result:

These investments will provide cost conscious ongoing product support and dynamic lifecycle management for all common Operating IT infrastructure assets.

Outcome Summary:

Customer Focus	• Provides continued support to key customer applications such as the Outage Management System supporting emergency storm response, communication, and outage coordination. • Minimizes customer risk and associated impacts of outages of the system.
Operational Effectiveness	• Provides Operating IT infrastructure the required facilities to holistically support mission critical Operations applications, systems and their functions. • Decreases risk of reduced performance, or an inability to meet service levels in the event of a failure.
Public Policy Responsiveness	• Ensures mission critical Operations applications and systems are supported with the current, compatible and supported IT infrastructure to maintain reliability and availability targets and meet regulatory requirements with regards to cyber security, reliability (redundancy), etc.
Financial Performance	• Provides cost effective management of IT lifecycles with current and supported common “shared” IT infrastructure. • Reduce OM&A and negate the need for costly extended support. • Improved asset performance, and greater ability to recover from a failure. A single failure can impose significant costs from the disruption to business function, increased labour cost for emergency break fix needs and other remedial efforts.

Costs:

This group of investments is estimated based on historical cost, subject matter and industry experts input, assessments and will be adjusted for the project scope, local condition and market pricing at the time of the investment.

Controllable cost have been minimized through the continued use and shared costs of common platforms, maximizing space, storage, and networking; maintaining current versions / latest technologies to maintain or reduce OM&A costs; and bundling of work to minimize outages or impacts to Network Operating.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.7	1.4	0.8	2.1	4.1	11.0
Operations, Maintenance & Administration Removals	-	-				-
Gross Investment Cost	**2.7**	**1.4**	**0.8**	**2.1**	**4.1**	**11.0**
Less Capital Contributions	-	-				-
Net Investment Cost	**2.7**	**1.4**	**0.8**	**2.1**	**4.1**	**11.0**

**Includes Overhead at current rates.*

GP-20 Network Outage Management System (NOMS) Refresh

Start Date:	Q1 2016	Priority:	High
In-Service Date:	Q2 2018	Plan Period Cost ($M):	1.1
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Reliability -Regulatory		

Investment Need:

The Network Operating Divisions ("NOD") Network Outage Management System ("NOMS") is Hydro One's primary outage planning tool. The associated hardware and software is specific to NOMS and does not include any shared storage in the Common Information Technology infrastructure. As required by the Ontario Energy Board ("OEB") Distribution System Code ("DSC") and Hydro One's Conditions of Service, NOMS provides essential coordination and scheduling of planned outages through integration with enterprise systems and the internal lines of business for reduced customer impact, optimized outage performance and improved communication amongst stakeholders (i.e., Local Distribution Companies, Large Distribution and Transmission customers, Hydro One work groups).

NOMS is an essential tool for planning, scheduling, assessing and executing distribution equipment outages. The viability of the tool is being reviewed and investigated for potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors being considered are availability, sustainment cost, system growth, the availability of new technologies, and compatibility with other critical Operations systems and applications, such as the Equinox Control Room Operations Window ("CROW"), Utility Work Protection Code, Electronic Log, and SAP applications. The system must be supported by the vendor or Original Equipment Manufacturer (OEM) as the risk of system downtime directly affects distribution operations and Hydro One customers.

The investment in a new NOMS tool must also satisfy regulatory requirements such as the OEB DSC Section 4, Operations; specifically Section 4.4.7 which requires a utility to provide as much advance notice as possible for the duration and frequency of a planned outage. This outage tool must also ensure compliance with Hydro One's Conditions of Service policy, Section H, Outage Notifications Process with customers.

The current version of NOMS was placed in service in 2010 after an application software upgrade to version 2.0 (NOMS V2). The software upgrade did not include a hardware upgrade at that time. The NOMS system consists of application servers, primary database servers, reporting database servers and a backup disaster recovery database server. An investment is now needed to upgrade the NOMS application and hardware to address four inadequacies of the current system that pose operational risks to Hydro One:

- Vendor support has expired and extended support is no longer available on servers running Oracle's 10g software;
- Application and Database servers have reached end of life; and
- The Windows 2003 Operating System used for the NOMS application server is no longer supported and update patches are no longer available.

The results of these operational risks of running an unsupported application will only increase Hydro One's inability to recover outage planning systems in the event of a system failure. The impacts to Hydro One's business in the event of these failures would be loss of outage planning and coordination abilities, higher maintenance costs, failure to efficiently communicate outage planning efforts with stakeholders, and decreased safety for Hydro One employees.

Alternative 1: Status Quo:

The Status Quo alternative would maintain the existing NOMS unsupported software and end of life hardware. This alternative has been rejected for the following reasons:

- Continuing operations with end of life system hardware will increase the likelihood of a NOMS failure;
- Continuing operations on end of life hardware without vendor support will hinder Operations ability to recover systems in the event of a failure;
- Maintaining end of life hardware results in increased maintenance costs and workarounds; and
- The risk of increased frequency and duration of customer outages and reduced distribution system performance.

The risk and impact in the event of a failure of NOMS will be significant given the primary function of NOMS is to plan and coordinate all Hydro One work execution activities. This will have a significant effect on the operation of the Hydro One distribution system and its customers.

Alternative 2: Upgrade NOMS *(*Recommended*)*

This alternative would upgrade both hardware and software for the current NOMS application and address the unsupported software and the operational risks currently faced by Hydro One.

A new application, upgraded servers and operating systems will provide Hydro One with improved outage planning capabilities as part of the version upgrade and the ability to recover systems in the event of a failure that would otherwise not be possible with the Status Quo option. A reliable outage planning tool is a requirement of the OEB's Distribution System Code and Hydro One's Conditions of Service. It is prudent that a full NOMS upgrade is performed to maintain Hydro One's outage and work planning capabilities and to ensure the distribution system reliability and availability.

Investment Description:

Planned investments include a hardware refresh, operating system upgrade and the integration with other enterprise systems such as the Electronic Log, Utility Work Protection Code, SAP and the Outage Grouping and Assessment System Tool. These are either a part of the version upgrade or existing stand-alone systems that when integrated will enhance the flow and assimilation of information that will enhance the outage planning and reporting processes.

Risk Mitigation:

IT Infrastructure investments are complex and dependent on multiple technology factors including: application software, server capacity, physical constraints (i.e., cooling capacities), hardware compatibility and vendor support terms. Given these complexities, a development phase is being conducted as a part of the full NOMS upgrade to more effectively determine project costs and manage the risks and requirements associated with the project implementation. Additionally, an assessment of the enterprise systems; Electronic Log, Utility Work Protection Code, SAP, and the Outage Grouping tool will be performed to ensure value creation when merging the systems with NOMS.

Result:

This investment will result in the following accomplishments:

1. Increased stability of the NOMS system with upgraded hardware and software that has vendor support;
2. Reduced risk of a NOMS system failure;
3. Ensured regulatory compliance with the OEB Distribution System Code, IESO Market Rules and adherence to Hydro One's Conditions of Service;
4. Assessment and integration of internal and enterprise systems; and
5. Improved operational efficiencies and outage performance gained through the integration of enterprise systems and new technologies.

Outcome Summary:

Customer Focus	• Mitigate Customer impacts by providing as much advance notice as possible for the duration and frequency of a planned outage.
Operational Effectiveness	• Ensure reliability and availability of NOMS to ensure scheduling, coordinating and planning of Hydro One Distribution and Transmission System Outages. • Ensure operational efficiencies and process changes are fully leveraged by improving current workflow, coordination, grouping and execution of outage planning activities.
Public Policy Responsiveness	• Deliver outage management service obligations related to OEB Distribution System Code, Section 4, Operations, and IESO Market Rules part 7.3 Outage Management. • Maintain compliance with Hydro One's Conditions of Service.
Financial Performance	• Reduce extended support and maintenance costs associated with maintaining the system to mitigate failures.

Costs:

Costs are being controlled via an initial development phase, which will finalize scope, system architecture, and an execution strategy prior to full execution of this investment. In addition, several vendor products will be reviewed and assessed to determine which are the most cost effective and provide the most value. Lastly, through a full capital replacement, testing and commissioning activities will be completed simultaneously. This will negate the need for independent system component testing and allow the more efficient use of resources.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.1	-	-	-	-	1.1	2.2
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	1.1	-	-	-	-	1.1	2.2
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**1.1**	**-**	**-**	**-**	**-**	**1.1**	**2.2**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-21 Data Centre Remediation

Start Date:	Q4 2016	Priority:	Demand
In-Service Date:	Q3 2020	Plan Period Cost ($M):	4.6
Primary Trigger:	Asset Driven – End of Life – Capacity		
Secondary Trigger:	Reliability -Regulatory		

Investment Need:

Hydro One maintains substantial Information Technology ("IT") infrastructure to operate, manage and control the Bulk Electric System ("BES") and Provincial Distribution Networks. These systems must operate in compliance with various regulatory bodies including North American Electric Reliability Corporation, Independent Electricity System Operator's market rules and Hydro One standards.

The Ontario Grid Control Centre (OGCC) Data Centre facilities can no longer accommodate the immediate and short term capacity requirements, given that the existing facility is beyond its space, power distribution and cooling thresholds.

The OGCC IT infrastructure is critical to the reliable operations of the Bulk Electric System and ensuring that NERC requirements are addressed in a timely and focus manner. The Power System IT (PSIT) department which (a part of the Hydro One Information Solutions Division (ISD)) focuses exclusively on the tools and IT equipment that are used by the OGCC to monitor and control the Bulk Electric System. An analysis by PSIT has determined that in order to maintain the following 24/7 Operating applications and systems over the next four years: Distribution Management System ("DMS"); Outage Response Management System ("ORMS"); Network Outage Management System ("NOMS"); Control Room Information System ("CRIS"); and Information Technology Service Management ("ITSM"), additional Data Centre capacity will be required.

These systems are used exclusively by Operating to monitor and control the distribution and transmission system asset in a 24/7 environment. They are physically separated from any other H1 network or domain. However, due to the aforementioned space, cooling and power distribution constraints at the OGCC and the BUCC, and given that ISOC (ISD –GP-18) will not be in service until 2020, PSIT has determined that remediation of the OGCC Data Centre is the most strategic option for the following reasons:

- A number of the major infrastructure at the OGCC is either approaching or has reach its end of life and will have to be replaced. These will include PDU, CRAC units and the Cooling tower;
- Remediation of the OGCC Data Centre addresses the current capacity constraints as it relates to space, power distribution and cooling; and
- Ensures that the OGCC Data Centre which will become the Backup Data Centre once ISOC is built is fully operational and can provide redundancy to meet the required NERC standards and maintain operational best practices.

Alternative 1: Status Quo

This option assumes Hydro One maintains the current over capacity state specific to the Ontario Grid Control Centre's computer room facilities and continues utilization beyond asset useful life. This is not considered a prudent approach due to the criticality of the systems that reside within the Data Centre and could result in the following:

- Increased risk from use of equipment and system components beyond end of life;
- Hydro One's diminished capacity to serve and respond to customers;
- Potential loss of one or more mission critical applications;
- Increased probability of system failures;
- Inability to recover quickly from system failures; and
- Risk of costly remedial efforts in the event of a failure.

Alternative 2: Remediate the OGCC Data Center *(Recommended)*

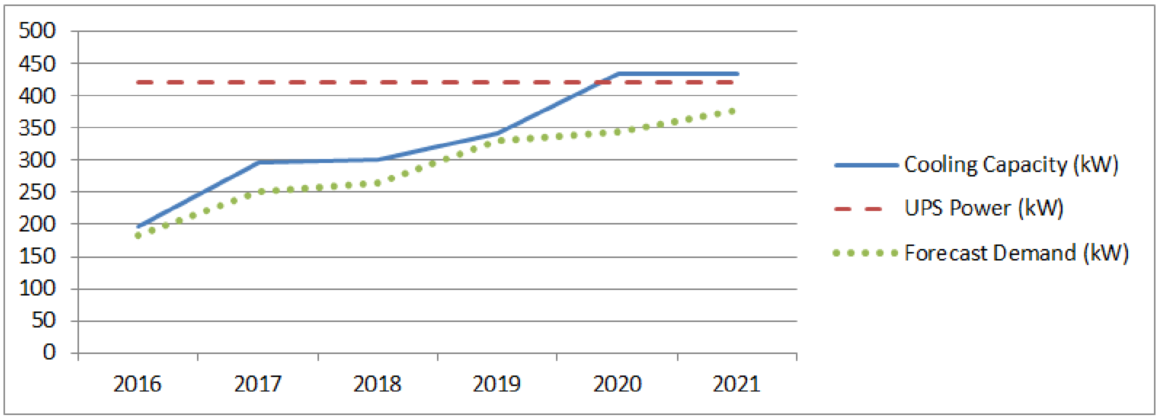
This alternative will remediate both computer rooms (A and B) located in the OGCC Data Centre in order to maintain system lifecycles and provide required capacity for system lifecycle management of critical operating systems and applications. This alternative remediates constraints and deficiencies to mitigate the increasing risk that the Data Centre environment and support infrastructure are posing on reliability of the system that reside within it. This will be accomplished by the following updates and changes such as:

- End of life replacements including increased capacity;
- Rack consolidation and defined infrastructure standardization;
- Decommission end-of-life powered IT infrastructure;
- Controlled air flow to enhance cooling efficiencies;

- Balance critical system loads over two Uninterrupted Power Supplies (UPSs) for redundancy; and
- Enhance Data Center protection, security monitoring and fire suppression.

The Data Centre's UPS power is reflected in the "dash line" at the top of the graph below. To utilize the 420kW of UPS power the project's activities will increase the cooling capacity (step function) from 197kW "solid line" and ultimately provide the Data Centre net capacity of 420kW. The "dotted line" represents the accommodated forecast demand over the project duration.

OGCC Data Centre – Cooling, Power and Demand (Computer Rooms A & B)



The remediation of the OGCC Data Centre to provide the needed facility capacities will support Operations functions over the next five years. This provides the assurance to Hydro One customers that Operations IT facilities are resilient with the capacity to facilitate mission critical applications and systems. This approach maintains Hydro One's commitment to customer responsiveness.

Investment Description:

This investment will provide an additional 223kW in Data Centre capacity through increased cooling and the redistribution of the available power based on the optimal physical space redesign of the computer rooms. This represents an increase from the Data Centre's current capacity of 197kW and provides the required Information Technology infrastructure into the foreseeable future.

This investment will ensure business continuity by maintaining the appropriate IT infrastructure to operate, manage and control the BES and Provincial Distribution

Networks. This is achieved via "mission critical" power system application lifecycle sustainment, maintaining continued vendor support, and without undue risk or threat of failure. This provides the assurance to Hydro One customers that IT failures will be minimized and if a failure is experienced, it will be returned to service in a timely fashion. As failures affect critical applications and tools, any failure can result in the OGCC being rendered unavailable for an extended period of time. A recent UPS failure and resulting equipment fire has shown that failures of support infrastructure have impacts on downstream elements. This investment approach maintains Hydro One's commitment to customer responsiveness by ensuring IT availability to maintain Network Operating key Operating and Dispatch functions. Below are the key activities of this investment:

- Reduce Data Center Load Risks:
  - Free Data Center floor space from rack consolidation activities and build new hosting standardization;
  - Reduce IT Infrastructure load to Power and Cooling by building new Pre-Prod and Prod environments at the Co-Location facility (ORMS, ITSM, NOMS, DMS); and
  - Decommission End of life powered IT infrastructure.
- Cooling:
  - Short term - Fix and control data center air flow to enhance cooling efficiencies;
  - Remediation of under floor cabling which is restricting airflow (utilized as the main plenum). This will include relocating cabling above the racks and improvements to the perforated tile system;
  - Define infrastructure standardization;
  - Expand cooling system infrastructure by using standalone (independent) cooling units with redundancy; and
  - Reduce the bottleneck demand on one type of cooling system inside Data Center.
- Power:
  - Build modern core power distribution;
  - Increase remote power distribution high-availability and flexibility at the rack level; and
  - Balance critical system loads over two Uninterrupted Power Supply (UPSs).
- Management and Remote Monitoring:
  - Implement remote management system and automated processes;
  - Enable proper monitoring system and automated reporting; and
  - Enhance data centre protection and security monitoring.
- Improved Fire Suppression and Monitoring:

- o Build level one first protection system (Gas system);
  - Gas protection systems can extinguish quickly, minimize damages lowering repair costs and providing a speedy recovery time.

Risk Mitigation:

Increasing the available capacity of OGCC Data Centre facilities to facilitate applications and system lifecycles is recommended as "best practice". The driving focus behind these facilities is to maintain current reliability and service levels and their function to serve Hydro One customers in the most cost effective means possible.

Ongoing work at the primary production Data Centre has potential to cause an unplanned system outage. This is mitigated by thorough failover automation and practices to the redundant production system located at the Back-Up Control Centre. In addition, co-location facilities will be leveraged to provide further redundancy and staging space.

In order to provide required interim capacity to enable this investment, a Co-location Data Centre facility will be leased during the remediation of the Ontario Grid Control Centre's onsite Data Centre. This ensures the work at the existing Data Centre can be accommodated in off-peak cooling seasons (the winter months) without outages or a significant reduction in the redundancy requirements, and ensures that both current and planned system lifecycle upgrades are not stranded.

Result:

This investment will provide a cost conscious approach and ongoing IT infrastructure resiliency supporting dynamic lifecycle management for IT assets located at the OGCC Data Centre. More specifically it will achieve the following results:

- Maximized cooling efficiency in both Data Centre rooms:
  - o Reduced load on chilled water cooling system;
  - o New cooling units to support Data Centre demand and enhance redundancy; and
  - o Eliminate the need to rent a mobile chiller unit during the summer months.
- Modern power distribution with enhanced monitoring and remote management system;
- Replacement of End Of Life (EOL) hardware infrastructure resulting in lower operating costs;

- Gain valuable data centre space for current planned investments and future growth; and
- Enhanced fire detection and suppression.

Outcome Summary:

Customer Focus	• Maintain Network Operating Customer service level agreements and meet reliability expectations. • Support customers by maintaining ability to provide storm or emergent response activities, communication outage coordination, dispatching functions, etc.
Operational Effectiveness	• Provide greater output capacity through optimization of support infrastructure and ensure adaptability to respond to business, regulatory or technological change. • Maximize available space, allow full utilization of existing assets and allow for future consolidation and standardization among IT racks, cabling, etc.
Public Policy Responsiveness	• Ensure that the primary Data Centre can maintain availability and reliability targets to a 99.95% target and maintain overall viability of the OGCC. • Maintains regulatory compliance to NERC, IESO Market Manual (Reliability of System Operations) and OEB Distribution & Transmission System codes.
Financial Performance	• Avoid costly new build or long-term rentals of a new facility for capacity offsite. This effectively negates further investment in net new equipment.

Costs:

The project will meet reliability / redundancy requirements by procuring interim short term co-location capacity to allow for Data Centre elements to be taken out of service while maintaining redundancy in critical applications. This will include a staged approach to ensure limited downtime / outages during execution.

A third party industry expert has reviewed the current requirements and has provisioned a detailed plan and cost estimate leveraging industry best practices, and market pricing with an aim to minimize ongoing maintenance (through Data Centre standardization and optimal configuration design).

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	2.4	1.6	0.6	-	-	4.6	10.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	2.4	1.6	0.6	-	-	4.6	10.0
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.4**	**1.6**	**0.6**	**-**	**-**	**4.6**	**10.0**

**Includes overhead at current rates. ** Total Project includes amounts spent prior to 2018.*

GP-22 OGCC Office Remediation

Start Date:	Q2 2020	Priority:	Medium
In-Service Date:	Q4 2022	Plan Period Cost ($M):	1.6
Primary Trigger:	Business Operations - Efficiency		
Secondary Trigger:	Health, Safety & Productivity		

Investment Need:

The Ontario Grid Control Centre ("OGCC") is Hydro One's primary facility that operates and controls the Distribution System. The facility is the headquarters for Network Operations and Hydro One's primary Control Room, and the Distribution Outage Management Centre among other supporting functions, essential in operations, monitoring and control of the Distribution System. The OGCC building has been in-service and operational, 24 hours a day, seven days a week, and 365 days a year since inception in 2003. Since this time, there has been minimal investment to maintain it as a productive office environment beyond normal break-fix remediation.

The OGCC building now accommodates more people and technology than was originally forecasted. The interior office space requires renovation to replace end of life fixtures, furnishings, floor coverings, walls, and other items. A thorough review of the security features (windows, doors, mantraps) is required to ensure efficient entry and egress, while respecting regulatory requirements including monitoring. The office furnishings including cubicles, cabinets and tables were in "used condition" when installed at the OGCC in 2003. The furnishings are end of life and will be over 20 years old when this investment is implemented in 2020. Life cycle assessments recommend that the useful life for carpeting and wall paint is roughly ten years for an office environment. The disrepair of floor coverings has created a safety concern for employees. As the OGCC houses the main control room with 24/7/365 operations, it must be brought up to current safety standards.

Alternative 1: Status Quo

This option assumes Hydro One maintains the current conditions at the Ontario Grid Control Centre. This approach poses risks to Hydro One employees and Hydro One's public image. This alternative has been rejected for the following reasons:

- Safety concerns including floor coverings are lifting and creating hazards;

- Amenities such as fixtures, carpeting, furnishings and wall paint are all well beyond their useful life and are showing signs of disrepair; and
- The diminishing office condition can affect employee engagement over time.

Alternative 2: Remediate OGCC Office *(Recommended)*

The recommended alternative for the OGCC Office Centre remediation is to proceed with the investment as a refurbishment of the current facility in line with the construction of the ISOC. The existing fixtures, carpeting, cubicles and paint have diminished below acceptable standards since it was established in 2003 and will be refreshed. Control Room consoles will be replaced and or retrofitted to include sit /stand functionality to improve ergonomics for staff and to reduce the risk for potential musculoskeletal injuries which will reduce lost time. A remediation of the facility is the least costly option and operationally disruptive due to the magnitude of the current investment in the OGCC and the business functions it supports. This option also allows scheduling flexibility to align with the construction of the new ISOC facility. This recommended investment will address the concerns of degrading working conditions and safety at the OGCC while delivering the most cost effective approach.

Investment Description:

This investment will involve Control Room renovations and office area/hallways refresh of the OGCC. Expenditures include replacing carpeting, repainting areas, enhancing lighting, upgrading conference rooms, and replacing furnishing to meet Hydro One Corporate standards, Ontario Building codes and Health and Safety objectives. This investment will review and implement security upgrades to replace the “PODS” (mantraps with dual authentication) in the front lobby as well as enhance security in the reception area to maintain six sided security in compliance with NERC standards.

Risk Mitigation:

Safety is the number one mandate at Hydro One and should be considered in this investment. As fixtures and carpeting age and deteriorate at the OGCC, lifted flooring has posed an increasing safety risk to the employees working in the facility. A remediation of the office facility will avert this safety risk and aligns with Objective OS3 of the Ontario Building Code which aims to minimize the probability that a person is exposed to an unacceptable risk of injury due to hazards caused by tripping.

A remediation to the OGCC facility is warranted. To mitigate the risk of cost escalation, the remediation is scheduled to occur in 2020 and 2021 to capitalize on the available space at the new Integrated System Operations Centre ("ISOC") facility allowing the temporary relocation of staff during construction. The ISOC is the closest and most cost effective site for the temporary relocation of Control Room employees. This will also eliminate the cost of a leased/rented third party office. Remedial efforts are currently hampered by the impacts that would result on the real-time operations environment. Alignment with the ISOC will ensure remediation efforts are not restricted by health and safety concerns (i.e. off gassing) and facilitates the completion of remediation work during regular hours for the support office areas, avoiding overtime costs. This investment timing offers the most strategic and cost effective approach to remediating the OGCC and will minimize the cost burden to rate payers. The current BUCC is limited by space and cannot support both the Control Room and the supporting offices currently working out of the OGCC and therefore is not an option.

Remediation will focus on furnishings that offer the best durability for economic value so that the expected life of the office remediation can be maximized. This will include leveraging office cubicles that maximize occupancy thresholds in the building. A proactive approach is more cost effective than a break fix strategy by mitigating costs for overtime, emergency material orders and a disruption to daily events in a real-time work environment.

Result:

Completion of the necessary improvements to OGCC office and control room space to gain efficiencies and mitigate the health and safety hazards associated with a deteriorating workplace infrastructure. The timing of the investment will provide a cost effective solution for providing an effective work location during the office remediation and a more productive work environment on completion.

Outcome Summary:

Customer Focus	• Ensure fulfillment of Hydro One's mandate to its customers by maintaining a healthy/safe working 24/7/365 working environment.
Operational Efficiency	• Ensure that aging infrastructure is replaced in a timely manner to minimize disruption to operations resulting from the unavailability of the equipment or facility.
Public Policy Responsiveness	• Align with objectives set out in the Ontario Building Code that aim to minimize preventable safety risks inside and outside of Ontario buildings. • Address Occupational Health and Safety considerations to ensure staff are provided with the appropriate tools to prevent injury (i.e., Musculoskeletal risk requiring ergonomic requirements for 24/7 shift environment). • Maintain NERC requirements for six sided physical security perimeter for access control to the Ontario Grid Control Centre.
Financial Performance	• Reduction of OM&A costs for break fix / remedial efforts (at project completion).

Costs:

This investment is being timed to coincide with the construction of the ISOC project to minimize cost impacts for staff relocation to a third party site, or labour premiums and enhanced work efforts to isolate areas during construction.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	0.0	0.0	0.0	0.5	1.1	1.6
Operations, Maintenance & Administration Removals	-	-	-	-	-	-
Gross Investment Cost	0.0	0.0	0.0	0.5	1.1	1.6
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.5**	**1.1**	**1.6**

*Includes Overhead at current rates

GP-23 Integrated Voice Communications and Telephony Refresh

Start Date:	Q1 2021	**Priority:**	Demand
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.5
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Regulatory		

Investment Need:

The Integrated Voice Communications and Telephony System ("IVCT") is a mission critical system that provides voice communication management between the control centre, the IESO, Hydro One field staff, connected customers, and emergency services. The IVCT system provides integrated access and intelligent call routing via multiple communication methods incorporating multiple technologies to adequately manage the hundreds of control room calls each day. The IVCT system runs on various software, operating system, and hardware with vendor support, software patching and service lifecycles. Based on the current vendor support schedules and hardware lifecycles the IVCT system will require replacement in 2021 to maintain support and reliability of the system and the ability to recover in the event that a failure is experienced. The IVCT system allows Hydro One to meet various compliance regulations (Distribution System Code, NERC, Market Rules) that require redundant voice communications, and emergency communications that ensure constant communications paths.

The loss of voice communication between the Control Room (the primary users of the IVCT system), Hydro One customers and field staff, will result in the cancellation of planned outages and work activities until communication has been re-established. Without effective communication, there is a heightened risk to worker and customer safety (cannot dispatch emergency services or field staff), and a lack of situational awareness of local activities or external system events. This can have dire impacts on the Distribution System.

Alternative 1: Status Quo

This alternative maintains the existing IVCT system at end of life. This will expose Hydro One to reliability and sustainment risk as the current IVCT system will no longer be supported by the vendor. In addition, the ability to recover from a system failure will be negatively impacted and the maintenance cost for extended repairs or replacement components (old technology at this time) will be higher and more difficult to procure.

Witness: Colin Penny

The IVCT system is mission critical, as it handles all calls coming into and out of the Ontario Grid Control Centre (“OGCC”) and Back Up Control Centre (“BUCC”) control rooms. This includes communication with field staff, customers, and the IESO among others. A failure of the system would eliminate control room communication efforts, therefore impeding the operational effectiveness of the OGCC.

Alternative 2: “Off the Shelf” IP Phone

This alternative proposes the current system be replaced with generic IP phones utilized by back office staff, after the existing IVCT system reaches end of life. The generic IP phones do not have the same call handling functionalities or rolodex of frequent calls capabilities requiring additional tools and processes to ensure that control room staff efficiency is maintained and not subject to additional effort to complete the same tasks. These processes, which must be recreated for this Alternative, are more error prone and can impact employee and customer safety. Furthermore, the generic IP phones do not have any call recording capabilities to meet NERC compliance requirements. Lastly, the IVCT system includes the OGCC Interactive Voice Response (“IVR”) system which is used to direct incoming calls to the appropriate OGCC department and sort calls into queue(s) for processing. To ensure normal work flow can continue, integration with the IVR system is needed. Due to the aforementioned issues and concerns, and the inability to provide needed functionality, and integration with key elements, such as IVR, this alternative has been rejected from further consideration.

Alternative 3: IVCT System Refresh Project (Recommended)

It is recommended that Hydro One proceeds with the IVCT system replacement to ensure system reliability and sustainability. This alternative provisions the necessary replacement of the IVCT system in 2021, with a “like for like” system, taking advantage of productivity enhancements, and leveraging newer technologies when the existing IVCT system has reached end of life. This will maintain operational effectiveness and reliability of the control room by maintaining the communication channels utilized daily. This will also mitigate risk of control room downtime, work execution, planned outage cancellations, and the resulting impacts on Hydro One customers that these incidents cause. Control room staff utilizes the IVCT system when coordinating storm restoration, planned system maintenance outages, fulfilling IESO notification obligations, managing helicopter services, and, most importantly, emergency response assistance for field staff and Hydro One customers.

Investment Description:

Network Operating Division operates two Grid Control Centres. The IVCT system is used on a 24/7 basis at both control centres (OGCC & BUCC) and the Operating Planning department. The IVCT system is mission critical and provides effective voice communication management from both control centres with the IESO, interconnected utilities, Hydro One customers, emergency services and field staff. Due to the critical nature of the IVCT system, and the impact of a failure on Hydro One's work execution, customer outages, responsiveness, and inability to effectively dispatch for emergencies, this system is planned to be replaced based on recommended lifecycle schedules. The failure of the IVCT system would severely impair Hydro One's ability to monitor and mitigate system events.

This investment will replace or upgrade the application software, and associated hardware (dedicated servers) at the OGCC and BUCC (which is ultimately planned to be relocated to the Integrated System Operating Centre ("ISOC")).

This investment is scheduled based on historical IT life cycles for previous instalments of the IVCT system with consideration of software, operating system, and server hardware lifecycles. An asset condition assessment review may be made closer to the investment start date to determine how best to proceed.

Risk Mitigation:

To reduce project execution risk, a pilot IVCT system will be designed and tested prior to full deployment, including parallel system use prior to final cutover. Furthermore, an experienced system integrator vendor, with expertise in deploying similar IVCT systems, will be retained to oversee the project.

Productivity enhancements and new technologies, such as automated voice-to-text capabilities, will be individually evaluated through a cost-benefit analysis closer to the project start date to ensure value for the required investment. Timing of this activity is required prior to commencement, as technologies and improved functionality today may differ significantly in 2020/2021.

Result:

This investment will ensure reliability of the IVCT system and promote productivity in the control room while meeting all regulatory requirements. The IVCT is set with user friendly touchscreen interface, quick dial functionalities, and a customized Rolodex contact database to help controllers do their job more accurately, more efficiently, and faster. The IVCT helps Hydro One operations meets its obligations under the OEB Distribution System Code, IESO Market Rules, and NERC (see Public Policy Responsiveness section below for full details).

Outcome Summary:

Customer Focus	• Support customer reliability by maintaining low call handling time and fast storm restoration response. • Keep customers informed of outage status using Autodialer functions and therefore improving customer satisfaction.
Operational Effectiveness	• Allows Hydro One control room staff to more efficiently co-ordinate storm restoration, protection maintenance work, system events with field staff, other LDC, and end use customers. • Ensure effective response and minimizing outage times.
Public Policy Responsiveness	• Allow Hydro One to meet obligations under OEB Distribution System Code (Section 4) regarding operations requirements. • Allow Hydro One to meet obligations under IESO Market Rules (Part 7.3) regarding outage management procedures. • Allow Hydro One to meet event reporting and investigation obligations as specified in NERC standard EOP-004, and COM.
Financial Performance	• Effective communications ensure the quickest dispatch for faster restoration times which translates into less hours spent by field crews during unscheduled events, reducing field costs.

Costs:

This is a reoccurring investment and the budget cost has been determined based on estimates by the Power System Information Technology ("PSIT") division utilizing historical IVCT investments. Based on lessons learnt from previous IVCT projects, this proposed budget takes into consideration all relevant costs (including license fees, changes to interest/overhead charges) which may not be initially obvious. The ongoing sustainment upkeep cost of the new IVCT system will have to be submitted by prospective vendors as part of their solution proposal. The OM&A cost for the current IVCT system is approximately $1 million annually. Hydro One will strive for the new IVCT system to have OM&A cost equivalent to the current system or less. Final costs of the project are influenced by the change in technologies and costs associated with the infrastructure supporting it, including market pricing at that time. Technological uncertainties and obsolescence are always a challenge for capital projects that are expected to start four to five years later. Hydro One is continuously monitoring technological developments and industry best practices to ensure the most cost effective solution.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	-	-	3.0	3.5	6.5
Operations, Maintenance & Administration Removals	-	-	-	-	-	-
Gross Investment Cost	-	-	-	3.0	3.5	6.5
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**-**	**-**	**-**	**3.0**	**3.5**	**6.5**

**Includes Overhead at current rates.*

Witness: Colin Penny

GP-24 Station Security Upgrades

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	5.7
Primary Trigger:	Security		
Secondary Trigger:	Safety		

Investment Need:

Grounding systems are used in stations to safely dissipate fault currents into the ground in the event of equipment failure and to safely dissipate neutral currents into the ground to protect Hydro One employees and the public. Copper in station and fence grounding systems, ground connections and neutral connections for electrical equipment are often targeted for theft in Hydro One distribution stations. The removal of ground and neutral copper connections compromises the electrical integrity of the grounding system. This can pose safety hazards to Hydro One employees and the general public, which can result in physical injury, including death.

Thieves have gained access into stations by cutting through chain-link fence fabric or breaking lock mechanisms. This investment addresses break, enter and theft at stations through the installation of improved security measures to reduce such occurrences. These upgraded security measures will improve health and safety, benefiting Hydro One employees and the general public.

The Distribution Station Security Upgrades investment addresses the need to implement increased security methods to mitigate break, enter and theft occurrences within distribution stations.

Alternative 1: “No Funding Alternative”

If no funding is provided to allow for security upgrades in distribution stations, then stations will continue to have break-in occurrences, and copper and neutral grounds will continue to be stolen. Hydro One maintenance staff will continue to replace the stolen grounds under corrective maintenance programs, and thieves will continue to return to the same stations to steal the ground and neutral conductors once they are replaced, jeopardizing the health and safety of those involved.

Urban stations are inspected by maintenance staff monthly and rural stations are inspected every 6 months. If station fences are cut, locks are broken and/or grounds are stolen, the public could be exposed to these dangerous conditions until the next station inspection.

Alternative 2: Install Security Upgrades *(Recommended)*

The preferred alternative is to install security upgrades including more robust perimeter protection and alternatives to copper in distribution stations to deter break and enter occurrences, and prevent thieves from stealing copper grounds and neutral conductors in specific areas. Installation of security upgrades will mitigate the exposure of the public to compromised grounding systems, as well as compromised station perimeters.

Investment Description:

The scope of work for this investment involves the installation of upgraded security measures at distribution stations to mitigate break and enter occurrences, and prevent thieves from stealing copper grounds and neutral conductors. Over the past five years, there has been 120 break, enter and/or theft occurrences at Hydro One distribution stations. During this period, the total number of occurrences has been reduced by 50% through minor security upgrades which are addressing fence perimeter grounding. However, break and enter occurrences have been increasing each year. Yearly candidates for distribution station security upgrades under this investment will include those which have had multiple break, enter and/or theft occurrences in recent years. The proposed funding level will allow for three stations to receive major security upgrades each year over the planning period. The major security upgrades will mitigate break and enter occurrences in addition to addressing perimeter grounding. Stations which are candidates for station refurbishment projects will also be considered for major security upgrades.

Risk Mitigation:

The risk associated with completion of the security upgrades projects includes the lead time required to procure the security upgrade materials, which Hydro One does not typically purchase. Completion of the projects within the planned years could be at risk if long lead time materials are not procured in a timely matter. The risk is mitigated by the procurement of long lead time materials in the year before the project is planned for completion, to allow the construction to be completed in the planned year.

Result:

Station security upgrades will result in the following:

- Break, enter and copper theft occurrences at stations which have received multiple occurrences in recent years will be mitigated;
- The electrical integrity of station and fence grounding systems in distribution stations will be preserved, allowing for the safe dissipation of fault currents and neutral currents into the ground;
- Exposure of the public to compromised station perimeters and grounding systems will be mitigated; and
- The safety of Hydro One employees and the general public will be improved.

Outcome Summary:

Customer Focus	• Improve integrity of station perimeters and grounding systems to maintain public safety.
Operational Effectiveness	• Maintain safe operation of distribution stations by addressing stations with multiple break, enter and theft occurrences. • Introduction of innovative ways of upgrading security measures to reduce theft.
Public Policy Responsiveness	• Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	• Reduce high cost of material theft; primarily copper.

Costs:

Factors affecting the cost of each project can include the type, manufacturer and magnitude of the material to be installed. Vendors with the most cost effective and practical material will be selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.2	1.2	1.2	1.2	1.3	6.1
Less Removals	0.1	0.1	0.1	0.1	0.1	0.5
Gross Investment Cost	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**5.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**5.7**

**Includes Overhead at current rates.*

GP-25 Leamington TS Capital Contribution

Start Date:	Q2 2016	**Priority:**	High
In-Service Date:	Q2 2018	**Plan Period Cost ($M):**	2.2
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Load Growth		

Investment Need:

To increase transformation capacity to accommodate the forecast customer load growth and to improve reliability in the Windsor-Essex region, as documented in the Windsor-Essex Regional Infrastructure Plan as well as in Exhibit B1, Tab 3, Schedule 11, ISD# D-14 of Hydro One's 2017-2018 cost of service transmission application (EB-2016-0160). Not proceeding with this investment would result in further degradation of load supply reliability in the region.

Alternatives:

Alternative 3 was approved by the Ontario Energy Board under s.92 application for the transmission investment (EB-2013-0421).

Alternative 1: Do Nothing

This alternative is not recommended because Hydro One Distribution would not be able to meet the supply needs for normal load growth and the additional capacity requirements for large distribution load customers and distributed generation customers.

Alternative 2: Build a New Transformer Station near Woodslee Junction and Upgrade the 115 kV Connection Line Supplying Kingsville TS

One alternative is to strengthen the existing 115 kV system and replace the assets reaching their end of expected service life. The existing 115 kV transmission system would be strengthened by building a new transformer station near Woodslee junction and upgrading the 115 kV connection line between the new TS and Kingsville TS. The three transformers at end of expected service life at Kingsville TS would be replaced like-for-like. In addition, two new feeders would be built to address the load growth in Leamington. This alternative is not recommended because the total project cost would be approximately $97 million, which is significantly higher than the recommended alternative.

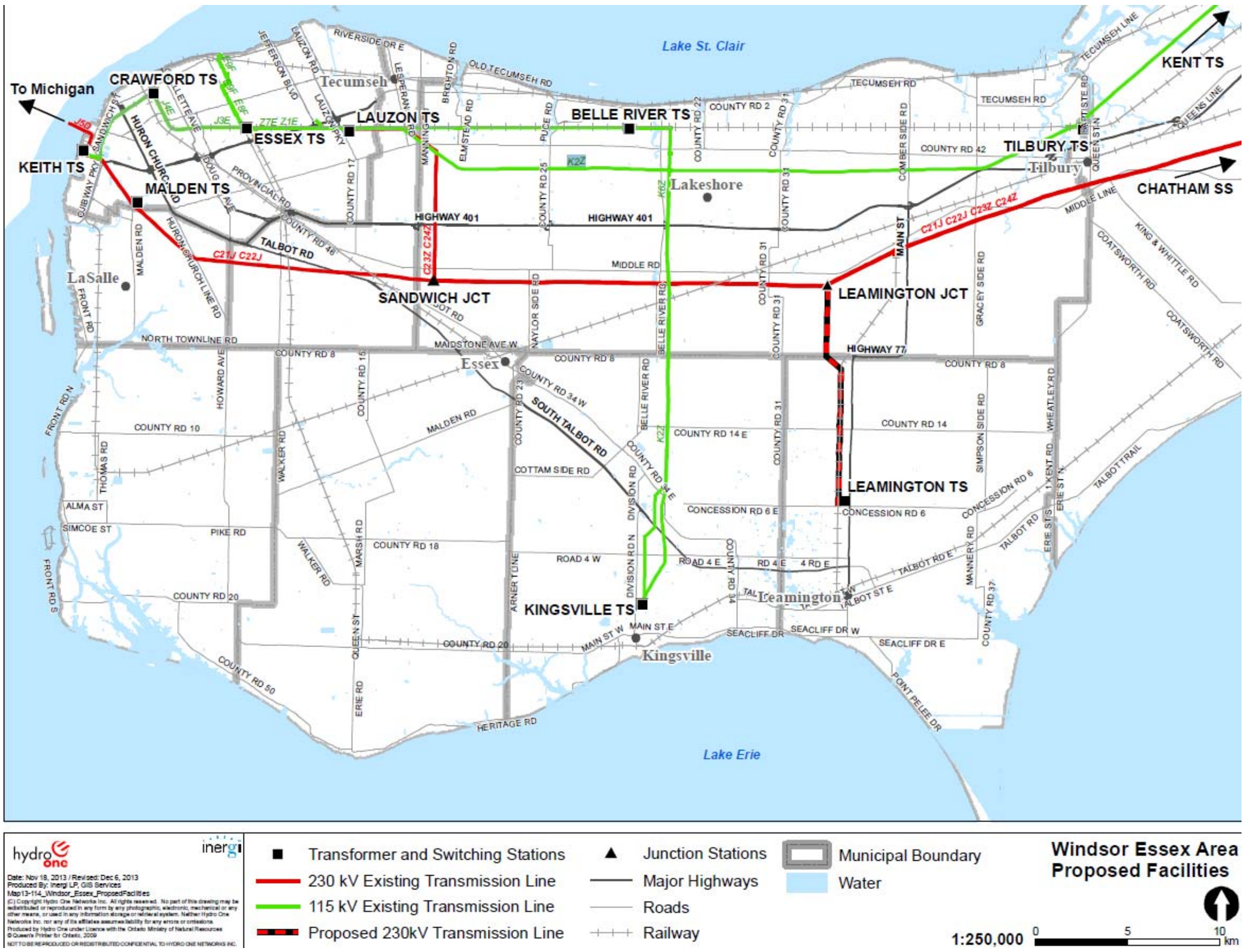
Alternative 3: Supply to Essex County Transmission Reinforcement ("SECTR") project *(Recommended)*

The preferred alternative is to build a new 230 kV – 27.6 kV DESN station at Leamington TS. This alternative offers significant reliability, efficiency and operational improvements. It enables the decommissioning of two of the transformers at Kingsville TS that are reaching the end of their expected service life, and replacement of a third which has also reached its service life. It also addresses the concerns with limited thermal capacity and short circuit levels. Furthermore, distribution feeder lengths supplying the Leamington area would be reduced from 15-20 kilometres to 5-10 kilometres, providing improved supply reliability, supply voltage and reduced line losses. This alternative meets all the identified transmission system needs as well as providing additional capacities for both load growth and distributed generation. The total project cost would be approximately $72 million with a Hydro One Distribution capital contribution of $21 million. It is expected that a portion of the contribution will be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area, subject to OEB approval under the Regional Planning and Cost Allocation proceeding (EB-2016-0003).

Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area. This investment provides the most cost effective solution for meeting the needs in the Kingsville-Leamington area and the surrounding Windsor-Essex area.

Investment Description:

The map below depicts the existing and proposed electricity transmission systems in the area:



The preferred solution includes construction of a new transmission station, Leamington TS and approximately 13 kilometres of new 230 kV double-circuit line. The installation of a new 230 kV – 27.6 kV DESN at Leamington improves reliability, provides capacity to accommodate the load growth within the Kingsville-Leamington area, and provides restoration capability for the Windsor-Essex area. With the new DESN in the area, Kingsville TS capacity can be reduced. Only one of the three transformers at the end of their expected service life will be replaced and the other two transformers will be decommissioned.

Hydro One Transmission will build the new Leamington TS and the new 230 kV double-circuit line and they have already commenced work on the project. Hydro One Distribution will pay capital contributions to Hydro One Transmission. A portion of these contributions is anticipated to be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area. The capital contribution amounts provided in the "Costs" section below are preliminary and will be determined and finalized in accordance with the Transmission System Code.

Risk Mitigation:

This project is subject to the outcome of the Regional Planning and Cost Allocation Review proceeding (EB-2016-0003) which is currently before the OEB. The cost table below is based on the latest estimate of project cost, and assume the OEB approves the Hydro One proposed methodology described in its application for leave to construct a new transmission line and facilities in the Windsor-Essex Region (EB-2013-0421). Revised project costs or approval of a different cost allocation methodology may affect these numbers.

Hydro One Distribution has been in direct contact with affected LDCs and Hydro One Transmission on the SECTR project since the Windsor Essex Regional planning initiative began in 2014. Furthermore, Hydro One Distribution met with the impacted LDCs in March 2016 to review the distribution work in the SECTR project and the overall transmission project status.

Result:

- Increase transformation capacity to meet future load requirements for the Kingsville-Leamington area as per section 3.3.1 of the Distribution System Code;
- Improve operational effectiveness by increasing reliability of supply for customers in the Kingsville-Leamington area and the surrounding Windsor-Essex area; and
- Savings financially through reduction in costs and resources by addressing multiple issues simultaneously.

Outcome Summary:

Customer Focus	• Increase capacity to allow connection of large distribution customers and promote economic development in the area. • Allow more distributed generation customers to connect to the system.
Operational Effectiveness	• Leamington TS will provide 230kV service in the area and shorten feeder lengths which increase efficiency and reliability of the system.
Public Policy Responsiveness	• Meet the requirements of the Distribution System Code and distribution license to respond to embedded LDCs and large customer requests for increased capacity and to accommodate load growth.
Financial Performance	• Cost savings are realized by addressing multiple issues simultaneously in one project.

Costs:

The estimated cost of the contribution to the project is based on detailed estimates prepared by Hydro One Transmission, which have been determined using a cost allocation methodology submitted to the OEB for approval in proceeding EB-2016-0003. In the current planning period, the capital contribution to Hydro One Transmission is approximately $21 million. Of this amount, the LDC's and large customers' share is approximately $14 million, and Hydro One Distribution's share is approximately $6.7 million.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	6.7	-	-	-	-	6.7	20.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**6.7**	-	-	-	-	**6.7**	**20.6**
Less Capital Contributions	4.5	-	-	-	-	4.5	13.9
Net Investment Cost	**2.2**	-	-	-	-	**2.2**	**6.7**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-26 Hanmer TS Capital Contribution

Start Date:	Q2 2017	**Priority:**	Medium
In-Service Date:	Q1 2019	**Plan Period Cost ($M):**	3.7
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Failure Risk		

Investment Need:

To address end-of-life assets, load growth and reliability in the East Sudbury area. The corresponding transmission investment was described in Exhibit B1, Tab 3, Schedule 11 of Hydro One's 2018-2018 transmission cost-of-service application (investment summary document #D18).

There are a range of needs to be addressed in the northeast Sudbury region including:

- The Valley East community within the City of Greater Sudbury has experienced steady load growth and is expected to continue growing at 2% per year. Martindale TS M6 is presently approaching its planned loading limit;
- Martindale TS M6 feeder is in poor condition and has demonstrated very poor reliability. There are also accessibility issues as portions of the M6 feeder are off-road through a mining reserve;
- Hydro One Transmission has concluded that the T2 and T3 transformers at Coniston TS are reaching end of life, and in need of replacement. The transformers are 76 and 67 years old, respectively. Coniston TS currently feeds a 22 kV network, which is an obsolete sub-transmission voltage that does not exist anywhere else in the province. The 22 kV network is an electrical island which cannot be supplied from any other source. When an outage occurs, the load cannot be easily restored due to lack of a back-up supply. All new 22 kV load connections in the past 20 years have been equipped with dual-voltage transformers for eventual operation at 44 kV; and
- Clarabelle TS M7 and Coniston TS M1 have exhibited poor reliability for feeders supplying an urban area with a large number of commercial and industrial customers.

The transmission needs at Coniston TS and Martindale TS presented an opportunity for Hydro One Distribution to work with the transmitter, Hydro One Transmission, and review the transmission connection facilities in order to determine the most appropriate and cost-effective options for meeting needs in the area.

Alternative 1: Do Nothing

This alternative is not acceptable because it will not resolve the issues in the area. In addition to being one of the worst performing feeders in the province, sections of the Martindale TS M6 feeder are in poor locations and difficult to access. Coniston TS operates at 22 kV, an obsolete voltage level, and the two transformers are reaching end of life. Furthermore, Clarabelle TS M7 and Coniston TS M1 have poor reliability for feeders supplying an urban area with a large number of commercial and industrial customers.

Alternative 2: Replace Assets Reaching End of Life on a Like for Like Basis

One alternative is to retain the existing system configuration and replace assets reaching end of life. The transformers at Coniston TS could be replaced with new 22kV units. A new feeder could be built and double circuited with the M6 to address any future overloading on the Martindale TS M6. The Martindale TS M7 would be rebuilt double circuiting with Martindale TS M6 and Clarabelle TS M7. While this would be a less expensive replacement alternative, it would not be cost effective because retaining a 22 kV voltage requires continued use of non-standard equipment leading to higher costs and limited suppliers. The shortage of supply of non-standard equipment often leads to prolonged outages. Not standardizing the voltage will eventually lead to deteriorated reliability and reduced operational efficiency in the area.

Alternative 3: New Assets at Hanmer TS *(Recommended)*

The preferred alternative is for Hydro One Transmission to build two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS to supply the Valley East load currently connected to longer feeders out of Martindale TS and Clarabelle TS. Coniston TS would be decommissioned, by converting its load to 44 kV and connecting it to Martindale TS M6 feeder.

Alternative 3 costs approximately ten percent more than Alternative 2, but offers more benefits, specifically, significant reliability, efficiency and operational improvements. Alternative 3 allows for elimination of the non-standard 22 kV operating voltage in Coniston, and provides new connection capacity right in the Valley East load center making it much better positioned for future growth in this area as well as the rest of the north-east Sudbury area. Alternative 3 reduces the length of 44 kV feeders supplying the Valley East area from 20-25 km in length to less than 2 km. Therefore, Alternative 3 is more cost effective.

Under Alternative 3, feeder lengths supplying the Hanmer area would be reduced from 12-14 km to about two kilometres, which would reduce line exposure to faults and improve reliability. Line losses would be reduced by 40%. This alternative also allows for the elimination of the non-standard 22 kV operating voltage at Coniston TS and provides new connection capacity to accommodate forecast load growth in the area and new generation.

This investment provides the most cost effective solution for meeting the needs in northeast Sudbury. The two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS provide an alternate solution to simply replacing assets in the area. Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area.

Investment Description:

To meet growing customer load in Valley East and address assets reaching end of life at Coniston TS, Hydro One will redirect load from Coniston TS to Martindale TS. It will then redirect Valley East load from Martindale TS and Clarabelle TS to Hanmer TS. This will involve:

1. Hydro One Transmission constructing two new 50/83 MVA step-down transformers and associated switchgear at Hanmer TS to supply Valley East load;
2. Hydro One Distribution conversion of the northeast Sudbury area supply to 44 kV; and
3. Hydro One Transmission decommissioning the existing Coniston TS.

The map below depicts the existing and proposed electricity transmission and distribution systems in the area:

The preferred solution is for Hydro One Transmission to construct two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS, which is an existing 500kV – 230kV station connected to the Bulk Electricity System. This new installation at Hanmer TS would replace end-of-life station assets, improve reliability, and provide capacity to accommodate the load growth within the City of Greater Sudbury. This would provide Martindale TS with the capacity to service the Coniston area for both load and generation (for example allowing an increase in existing hydraulic generation), removing the requirement to replace the assets reaching their end of life at Coniston TS.

The existing Clarabelle TS M7 and Martindale TS M7 feeders and the Valley East Branch of the Martindale TS M6 feeder would be transferred to Hanmer TS. The placement of the two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS would remove the requirement to rebuild the Martindale TS M6 and M7 feeders on-road. Hanmer TS would also provide new connection capacity in the Valley East load centre to better accommodate future load growth in the northeast Sudbury area. This solution would also eliminate Coniston TS by extending Martindale TS M6 and converting the load to 44kV.

The capital contribution amount from Hydro One Distribution to Hydro One Transmission is considered preliminary and will be determined and finalized in accordance with the Transmission System Code once the Capital Cost Recovery Agreement is signed and the project is placed in service.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

- Increased transformation capacity to meet future load requirements;
- Improved reliability of Martindale TS M6 feeder; and
- Improved operating efficiency by eliminating obsolete 22kV operating voltage from Coniston TS and the Hydro One system.

Outcome Summary:

Customer Focus	• Accommodate customer load growth and improve reliability in the Greater Sudbury area.
Operational Effectiveness	• Improve operating efficiency by eliminating obsolete 22kV voltage from Coniston TS.
Public Policy Responsiveness	• Comply with license requirements to respond to load growth needs.

Costs:

The estimated cost of the contribution to the project is based on planner's estimates prepared by Hydro One Transmission.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	3.4	0.3	-	-	-	3.7	5.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**3.4**	**0.3**	-	-	-	**3.7**	**5.4**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.4**	**0.3**	-	-	-	**3.7**	**5.4**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-27 Enfield TS Capital Contribution

Start Date:	Q2 2017	**Priority:**	High
In-Service Date:	Q2 2019	**Plan Period Cost ($M):**	3.0
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Load Growth		

Investment Need:

To increase transformation capacity to accommodate the forecast customer load growth and to improve supply reliability in the Oshawa – Clarington area, as documented in the GTA East Regional Infrastructure Plan and Hydro One's 2017-2018 transmission cost-of-service application Exhibit B1, Tab 3, and Schedule 1, investment summary document #D21. Not proceeding with this investment would result in inadequate supply capacity in the area.

Alternative 1: Do Nothing

This alternative is not recommended because Wilson TS is currently overloaded and is expected to exceed its capacity by a significant amount due to load growth and increased generation in the Durham region.

Alternative 2: Upgrade Wilson TS

This alternative requires upgrade of Wilson TS to provide additional supply capacity in the area. This alternative addresses the Hydro One Distribution short-term capacity needs in the area. However, based on the load forecast, it will result in shortfall of supply capacity in another ten years. Also, this alternative would potentially result in high costs due to development of new distribution feeders in developed and congested surroundings.

Alternative 3: Contribute to Build New Enfield TS (Recommended Alternative)

The recommended solution is to contribute to a new transmission station at Enfield TS to provide the capacity required to accommodate long-term growth. The feeders out of Enfield TS will also diversify the feeder routes and increase load transfer flexibility for improved outage response times and increased reliability in the region.

Investment Description:

The proposed plan is to build a new 230/44 kV 170 MVA transformer station at Enfield TS with 44 kV feeders shared between Hydro One Distribution and Oshawa PUC to serve the increasing needs in the Region of Durham and City of Oshawa. The Enfield TS will have provision for two future additional 44 kV feeders. The overloading at Wilson TS will be addressed by transferring some load to the two new Hydro One Distribution feeders at Enfield TS. The new feeders will also improve reliability in the region by diversifying feeder routes. Additional load transfer options between Wilson TS and Enfield TS will reduce the number and duration of outages.

Hydro One Distribution and Oshawa PUC will be required to pay their portion of the capital contribution to Hydro One Transmission. The capital contribution amounts provided under the "Costs" section of this document are considered preliminary and will be determined and finalized in accordance with the Transmission System Code.

Risk Mitigation:

At this point of time, the contribution cost to Enfield TS is based on planner's level estimate. The total contribution cost will be determined once the cost estimate for the Enfield TS is available, and actuals will be determined after the completion of Enfield TS project work.

Result:

- Increased transformation capacity to meet future load growth requirements; and
- Improved supply reliability by increasing redundancy of transmission supply.

Outcome Summary:

Customer Focus	• Increased reliability of supply to existing customers in the Durham area. • Accommodate connection of future customers.
Operational Effectiveness	• Improved supply reliability by increasing redundancy of transmission supply and by diversifying feeder routing to allow for better load transfer capability.
Public Policy Responsiveness	• Meet the requirements of the DSC and Distribution Licence to provide increased capacity to meet load growth.
Financial Performance	

Costs:

The estimated cost of the contribution to the project is based on budgetary cost estimates prepared by Hydro One Transmission.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	2.0	1.0	-	-	-	3.0	5.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**2.0**	**1.0**	-	-	-	**3.0**	**5.0**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.0**	**1.0**	-	-	-	**3.0**	**5.0**

**Includes overhead at current rates. ** Total Project includes amounts spent prior to 2018. This cost estimate has been modified since the last Hydro One distribution rate application (EB-2013-0416) based on updated estimates provided by Hydro One Transmission.*

GP-28 Call Centre Technology

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	17.5
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One has two call centres. One is located in Markham, Ontario and the other is located in London, Ontario. Billing and service inquiries are handled from 7:30 am to 8:00 pm, Monday to Friday in the call centres. Hydro One also offers a 24 hour emergency hotline to report power outages, fallen trees or other emergency issues.

To handle these calls, the call centre relies on technology to operate effectively. Key systems that the call centre relies upon include the Interactive Voice Response ("IVR") System, the Computer Telephony System and SAP CRM / iCare System. IVR is an automated telephony system that interacts with callers, gathers information through voice prompts and routes calls to the appropriate recipient. The Computer Telephony Integration ("CTI") allows interactions on a telephone and a computer to be integrated or coordinated.

Hydro One uses SAP Customer Relationship Management for its customer information system integrated with an interface called iCare. When a customer calls the call centre, the screen that pops up with customer information is iCare gathering information from the underlying SAP CRM system. Through SAP CRM / iCare, the call centre agent is able to access wide amounts of data and handle most all customer inquiries (manage account information, provide billing information, maintain budget billing, payment and collections, etc.) in a fast and efficient manner.

Hydro One's CTI & IVR systems were last replaced in 2004 and there were subsequent enhancements to the IVR system since then. The CTI & IVR technology allows Hydro One's customer information system ("CIS") to interact with the telephone system used by the call centre as well as other forms of communication (email, text messaging, web messaging, fax, etc.). There have been advances in technology in this space since the previous implementation such as better analytics and speech recognition. Words spoken by the caller are used to determine what command to execute or which agents to route the calls to. This allows for a better customer experience since this will result in less likelihood that the call will have to be transferred from one agent to another, thereby reducing the time the customer has to be on the call. Newer systems also offer more effective monitoring of agent, department and call centre performance.

The CTI & IVR system that Hydro One uses is past the recommended service life of 5 – 7 years. The current IVR is at risk of not being supported by vendors from a break fix perspective. Extended maintenance contracts only address existing defects but will not develop or release new code for legacy versions of software. The extended maintenance contract for the CTI&IVR systems will not cover any new code development for any issues experienced during normal operations. This introduces a high risk around recovery time when system outages are experienced, thus in turn impacting not only the customers who have billing or service related inquiries, but also those who are calling to report emergencies.

The SAP CRM system went live in 2013. Technology changes at a fast pace. This investment is required to implement system enhancements from the vendor to keep current and ensure continued functionality for customers. The enhancements are discussed in the various alternatives below.

Alternative 1: Status Quo

This alternative would continue to operate with the current CTI/IVR system and refrain from investing in the newest SAP upgrades.

The existing system was last replaced in 2004. If the status quo alternative was selected, Hydro One would continue to rely on existing systems that are past their recommended useful life. Not retaining systems in vendor supportable levels prevents Hydro One from enforcing Service Level Agreements (SLA) with our outsourced partner in the event of an outage or issue. As the vendor would not be able to release new code for legacy software, Hydro One would be unable to have our outsourced service partner maintain key system uptime SLA's. If the system is unavailable, our customers will potentially be unable to reach the call centre, which directly impacts customer satisfaction.

Status quo would also mean there no enhancements to SAP CRM / iCare. Enhancements are new functionality or improvements to existing functionality that SAP develops. These are rolled out in terms of patches (minor enhancements) or upgrades (significant changes to the software). Enhancements improve customer’s experience. In addition, for SAP to support the application, Hydro One needs to be at a certain software level.

Witness: Colin Penny

Alternative 2: Upgrade the Telephony Technology Suite (Recommended)

This alternative would replace the aging CTI and IVR technologies and enhance the existing SAP CRM / iCare System.

This investment is recommended since it will replace end of life technology in the call centre and improve customer interaction on various platforms. The enhancements in SAP CRM / iCare will provide improved service to customers who call our call centre and ensure that the software continues to be supported by SAP. Improvements to the overall customer experience are discussed in the Result and Outcome sections below.

Investment Description:

This includes both hardware and the software replacements, including a possible switch to a cloud-based solution or a hybrid consisting of on-premise and off-premise hardware/software. This investment will also introduce new call routing and call monitoring capabilities for Hydro One's commercial and industrial customers.

This investment also covers the funding required to implement enhancements to Hydro One's SAP CRM / iCare system.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected. Thorough testing will be performed to minimize system defects which can impact customers significantly – from ability to reach the call centre, get calls routed to the proper agent and system enhancements that otherwise would improve the ability to serve our customers.

Result:

The primary driver for this investment is to ensure reliability of Hydro One's technology within the call centre. Since these systems are past their recommended useful life, they are more prone to system failure.

Upgrading this technology will improve customer service with modern speech recognition and text-to-speech technologies, more intuitive graphical user interfaces, improved performance, integration of relevant caller information into a unified dashboard, more efficient call routing, more effective monitoring of call centre agents, and more effective monitoring of call centre performance.

Implementing enhancements will also result in improvements in how we serve our customers. Based on feedback received during Hydro One's Customer Consultation, commercial and industrial customers were dissatisfied with the level of customer service. The end result of these investments will be improved customer communication and satisfaction.

Outcome Summary:

Customer Focus	• Ensure a reliable system is available for customers. • Improve customer service with modern speech recognition and text-to-speech technologies, thereby improving how call centre agents interact with customers.
Operational Effectiveness	• Improve performance and provide more efficient call routing inside the call centre. • Integrate relevant caller information into a unified dashboard.
Public Policy Responsiveness	• Ensure that emergency services continue to be available to customers on a 7/24 basis.
Financial Performance	• Provide better call centre analytics to improve performance and lower cost.

Costs:

The final cost of the project covers deliverables and supports activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the solution.

This project has a high degree of complexity; it includes a new technology platform and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital and Minor Fixed Assets	7.5		7.2	2.9		17.5
Less Removals						
Gross Investment Cost	**7.5**		**7.2**	**2.9**		**17.5**
Less Capital Contributions						
Net Investment Cost	**7.5**		**7.2**	**2.9**		**17.5**

GP-29 Customer Service Billing Investments

Start Date:	Q4 2021	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	10.4
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One's paper bill is the most common communications vehicle with customers. About 14 million invoices are mailed annually to customers.

Hydro One's 2016 survey results indicated that only 62% of customers find their bill easy to understand. The design of the current bill has been identified by customers as a weakness and an area of opportunity (via customer satisfaction surveys and the Distribution Customer Engagement results the Ontario Ombudsman, and Hydro One's Ombudsman). As a result, Hydro One is introducing a redesigned bill in 2017. Additional capital funding will be required in 2022 to introduce further enhancements to ensure customers remain satisfied and understand their bill.

In addition to the need for producing bills that customers find easier to understand, there's also a need to improve billing for non-energy services. Hydro One provides specialized work for non-energy services to external parties. These include:

1. IESO Charges;
2. Retailer Settlements;
3. Secondary land use;
4. Land corridor leases;
5. Training for other municipalities and utilities;
6. Damage claims;
7. Trouble calls / Storm damage;
8. New service connections;
9. Service Upgrades;
10. Forestry Clearing;
11. Distributed Generation & MicroFit set up;
12. Long term load transfer;
13. Key Account Management connected customers (i.e. Ontario Power Generation);
14. Joint use pole rentals; and

15. Stations Modifications.

A review of the non-energy billing process identified inconsistencies in how the various non-energy services are handled. There is also inconsistency on the customer service policies between energy related billing versus non-energy related billing. The processes, tools and technology for non-energy billing are inefficient.

Alternative 1: Status Quo

Hydro One could elect not to embark on another bill redesign project in 2022 and not to integrate its non-energy billing practice in 2021. This alternative was considered and rejected because Hydro One is committed to improving its' relationship with its customers.

Alternative 2: Redesign Customer Bills and Improve Non-Energy Billing (Recommended)

This alternative is recommended since this will enhance customer service. The bill redesign project will improve customer understanding of their bill and more effectively promote and market new programs and services. The Non-Energy Billing investment will ensure consistency with energy billing customer service policies and will improve customer satisfaction.

Investment Description:

This investment is required to fund the following initiatives:

1. Bill Redesign – The Hydro One bill will be redesigned in 2022 to make it easier for customers to understand. The redesigned bill will also encourage energy conservation by providing customers information on how they can manage their usage better to take advantage of off-peak rates; and
2. Non Energy Billing Enhancements – Hydro One generates bills for the following non-energy services: damage claims, new service connections, service upgrades, forestry clearing, Distributed Generation and MicroFit set up, joint use pole rentals, secondary land use, land corridor leases, etc. This investment is required to enhance the entire end-to-end process, including invoicing, collections, and customer service.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Risk of Customers Not Trusting Their Bills

For the Bill Redesign Project, one risk of implementing this project is the customers may again not trust the billing system if there are any issues during implementation. The Bill Redesign Project will not change how the bill is calculated. It will only change how the bill is presented. Energy billing redesign will continue to comply with prescribed provincial regulation. Yet any defects during implementation may cause customers to believe that their bill is not being calculated properly. This risk will be minimized through thorough testing and by hiring consultants who have expertise in bill print functionality.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. In addition, follow up workshops will be conducted at appropriate project stage gates.

Result:

Redesigning the Hydro One bill will make it easier for customers to understand the bill. As a result, it is expected to lower calls to the call centre and improve customer satisfaction. It will also encourage energy conservation as the bill will break down consumption based on on-peak and off-peak usage.

The Non-Energy Billing investment is expected to improve the entire end-to-end process, including invoicing, collections, and customer service. For example, these customers do not have access to electronic bills or self-service capabilities. New tools, processes, and technology will improve customer satisfaction.

Outcome Summary:

Customer Focus	• Improve customer experience and satisfaction through bills that are easier to understand.
Operational Effectiveness	• Reduce calls to the call centre through reduction of billing related questions and reducing call centre costs overall. • Ensure consistency between energy billing customer service policies and non-energy billing.
Public Policy Responsiveness	• Encourage energy conservation as bills will better display usage consumption into on-peak & off-peak hours.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as Hydro One direct and indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	-	-	-	4.5	5.9	10.4	15.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	-	-	-	**4.5**	**5.9**	**10.4**	**15.0**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	-	-	-	**4.5**	**5.9**	**10.4**	**15.0**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-30 Customer Service Regulatory Related

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Multiple	**Plan Period Cost ($M):**	14.0
Primary Trigger:	Public Policy Responsiveness		
Secondary Trigger:	Customer Focus		

Investment Need:

This investment would implement the Demand to Interval change which is required by the Ontario Energy Board. It would also implement the Dynamic Pricing Pilot which is a pilot program offered by the government to encourage energy conversation.

Alternatives:

This investment would implement the Demand to Interval change which is OEB required. This is a non-discretionary investment. It would also implement the Dynamic Pricing Pilot which is a pilot program offered by the government to encourage energy conversation. Finally, it will implement the new rate design for Commercial & Industrial customers. This new rate is not OEB required. Hydro One will seek OEB's approval, via current process for changing rates, for this new rate design which is intended to encourage energy conservation among Commercial & Industrial customers.

Not performing the mandated changes, such as 'Demand to Interval Meter' that is non-discretionary, means Hydro One will not be compliant with regulatory changes.

For the Dynamic Pricing investment, while not specifically required by regulatory code at this time, Hydro One proposes to implement the pilot program offered by the government to encourage energy conservation. This will assist the government in its efforts to address the issue of high electricity cost in Ontario.

Investment Description:

This investment will implement the following regulatory and government changes and introduce pricing options for customers:

1. Demand to Interval Migration - Funding is required to implement system changes to support the Distribution System Code amendments that came into force on August

21, 2014. Section 5.1.3 requires a distributor to install an interval meter on any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW and pay the hourly Ontario energy price from the IESO-administered real-time energy market based on their actual usage by August 21, 2020.

2. Dynamic Energy Pricing - On July 18, 2016, the Ontario Energy Board (OEB) issued its Regulated Price Plan Roadmap: Guideline for Pilot Projects on RPP Pricing. Hydro One submitted an application to develop and implement price and non-price pilots, including the continuation of Hydro One's existing pilot which allows customers to have different variations of Time of Use rates. Dynamic Energy Pricing encourages customers to reduce electricity usage and shift usage away from peak hours. Some participants also receive enabling technologies such as Wi-Fi thermostats and in-home displays to assess the associated incremental savings. On September 23, 2015, the OEB agreed that there is value in extending Hydro One's existing pilot until April 30, 2017. Capital funding is required to extend the pilot beyond April 2017.

3. New Rate Design for Commercial and Industrial Customers - Hydro One plans to develop an innovative rate design for commercial and industrial customers that incents customers and influences their behavior. This is not OEB required but is included in this Investment Summary Document as this will require approval from the OEB before the new rate is changed.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective platform. As such, a market scan will be conducted to determine best-in-class programs. Hydro One will also engage with customers to solicit input and ensure their needs are met.

The timing of this investment is based on the need to comply with upcoming regulatory changes and introduce programs to assist customers with their electricity costs and affordability issues.

Result:

This investment will ensure Hydro One complies with regulatory and government changes. This investment will also provide customers with new pricing options, thereby reducing affordability issues for customers.

Outcome Summary:

Customer Focus	• Make electricity more affordable and improve customer satisfaction through the new pricing model. • Reduce electricity cost by encouraging usage in off-peak hours. • Improve customer satisfaction by providing enabling technologies such as Wi-Fi thermostats and in-home displays to assess the associated incremental savings.
Operational Effectiveness	
Public Policy Responsiveness	• Encourage energy conservation by incenting customers to reduce electricity usage and shift usage away from peak hours. • Comply with regulatory requirements and government policy changes.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs, as well costs Hydro One's direct and indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs[**]**
Capital[*] and Minor Fixed Assets	3.4	5.6	3.9	1.0	-	14.0	19.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**3.4**	**5.6**	**3.9**	**1.0**	-	**14.0**	**19.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.4**	**5.6**	**3.9**	**1.0**	-	**14.0**	**19.6**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-31 Collection Enhancements

Start Date:	Q1 2022	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	6.1
Primary Trigger:	Financial Performance		
Secondary Trigger:	Customer Focus		

Investment Need:

Overdue accounts present a financial risk to Hydro One. There is a need to improve the collections process and associated technological options for mitigating the financial risks.

The cost of electricity in Ontario has been steadily increasing. This has resulted in a number of customers having difficulty in paying their bills on-time. The Allowance for Doubtful Accounts has increased from 3.8% of its gross accounts receivable (as of December 2013) to 7.3% of its gross accounts receivable (as of December 2015). The portion of net accounts receivables that were aged more than 60 days went from 4% in 2013 to 6% in 2015.

When customers are in arrears, they are contacted by HONI through the Collections “Dunning” process. Dunning is the process of methodically communicating with customers to ensure the collection of accounts receivable. Communications progress from gentle reminders to pointed letters and phone calls to location visits as accounts become in more serious arrears.

One method of enabling customer control of their electricity consumptions, while in arrears condition, and minimizing Hydro One Network’s financial risk, is through the use of pre-paid meters. Pre-paid meters are a type of energy meter that requires users to pay for energy before using it. This is done via a smartcard, token or key that can be "topped up" at a corner shop, via a smartphone application or online. For customers who are high collection risk, the financial risk will be minimized by rolling out this type of meter. With a pre-paid meter, electricity is paid up-front. Once the pre-paid amount is used up, power is cut-off until the customer is able to load the meter with more credits.

Alternative 1: Status Quo – No enhancements to Collections Process & Technology. No implementation of pre-paid metering.

With the status quo scenario, Hydro One will not be implementing technology & process changes that are geared towards improving collections such as redesigning the collections process and implementing pre-paid meters.

If Hydro One does not proceed with this project, Hydro One's current increased level of uncollected accounts receivables will continue. This is not preferred since Hydro One's financial performance can be improved if the Company can improve its ability to collect money from its customers. This also does not provide the customer with new technology tools to manage their electricity consumption and reduce their outstanding overdue amounts while in arrears.

Alternative 2: Implement Process & Technology Enhancements for Collections. Roll Out Pre-Paid Meters (Recommended)

With this alternative, Hydro One will implement technology & process changes to encourage customers to promptly pay their bills. Hydro One will be able to implement pre-paid metering which is an effective way to collect payment from its customers. For the rest of the customers who are not high collection risks, the redesigned Dunning process will encourage customers to be prompt in paying their bills. This is the recommended approach as this is expected to increase collections and payment and therefore improve Hydro One's financial performance.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class functionality and technology. Hydro One will partner with vendors that have the experience and expertise to complete the work successfully. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

Another risk is potentially the negative customer reaction to the pre-paid meter technology. This risk will be mitigated through proper customer stakeholdering and customer engagement.

The timing of this investment is based on the need to introduce new functionality and technology to encourage collections and payment. Although there is no legislative requirement that is driving this change, delaying this investment any further will result in delayed achievement of benefit which impacts financial performance.

This project has a high degree of complexity; it includes a new technology platform and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

Result:

Collection enhancements will increase likelihood of payment and reduce uncollectable accounts receivables moving forward. Other Canadian and American utilities have successfully implemented this technology and are yielding financial benefits from the deployment.

Outcome Summary:

Customer Focus	• Help customers manage their electricity usage. Active and timely actions to address customers in arrears will help customers stay current with their invoices and will improve payment.
Operational Effectiveness	• Increase operational effectiveness by not having to send field staff to disconnect or reconnect meters for customers who are on pre-paid meter. Meters will automatically shut off once the credit has been consumed on the meter and activate once credit has been loaded.
Public Policy Responsiveness	
Financial Performance	• Encourage customers to be prompt in paying their bills. • Reduce risk of non-payment from high risk customers by through implementing pre-paid meters.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the solution.

The project is expected to take 2 years to implement. The remaining expenditures relating to this project will be spent in 2023 and are estimated to be $3.0M.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets					6.1	6.1
Less Removals						
Gross Investment Cost					**6.1**	**6.1**
Less Capital Contributions						
Net Investment Cost					**6.1**	**6.1**

**Includes Overhead at current rates.*

GP-32 Customer Data and Analytics

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Multiple	**Plan Period Cost ($M):**	9.9
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Customers have told Hydro One that they are concerned about the high cost of electricity. Customers have the right to know and understand what makes up the fees they are being charged.

One way to support customers is through high bill alert functionality. Customers can sign up for e-mail or text messages to alert them if their consumption is trending to exceed a certain threshold that they also are able to set. With high bill alerts, customers may be able to adjust their energy usage and potentially avoid an unusually high bill.

An enhanced web portal provides interactive access to energy-usage information and personalized energy savings recommendations based on usage patterns. By having information available to customers on the website, this reduces the need for customers to call the call centre and the additional effort that comes along with that call.

Equipping Hydro One's Customer Service Agents with tools and systems that provides a comprehensive view of customer information improves the agent's ability to provide good service to customers and get them what they need in a single call. It can be quite frustrating for customers if they call and the Agent they speak with has limited information about the customer's usage and what they can do to reduce their energy bill.

Alternative 1: Status Quo

If the status quo alternative was selected, Hydro One would not be providing customers with the tools they require to effectively manage their electricity account. As such, Hydro One would likely experience deterioration in customer satisfaction, as measured by Hydro One's reputational and transactional surveys.

Alternative 2: Implement Customer Tools and Analytics (Recommended)

This alternative is recommended since it aligns with feedback received from customers via the Distribution Customer Engagement and provides customers with the service they want.

Investment Description:

This investment is required to upgrade the following technology which will enhance customer analytics. The majority of the $9.9 million is allocated to High Bill Alerts.

1. High Bill Alerts - Hydro One will proactively deliver high bill alerts to customers if their bill in a particular billing period is trending higher than a predefined threshold. Customers will also receive guidance on how they can adjust their energy use before the end of the billing period. The alerts are triggered based on the customer's smart meter data combined with historical usage and weather patterns.
2. Enhanced Web Portal for Commercial and Industrial Customers - Hydro One will implement an enhanced web portal for commercial and industrial customers that provides interactive access to energy-usage information and personalized energy savings recommendations based on usage patterns.
3. Customer Analytics and Insights – This investment will allow Hydro One to have a comprehensive view of customer information and will provide analytics and insights, which will allow Hydro One to better understand customer needs and energy patterns.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

This investment involves implementation of 3 complex projects. Each project will require multiple vendors to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

The timing of this investment is based on the need to introduce these customer facing tools to residential, commercial, and industrial customers based on feedback from the Distribution Customer Consultation.

Result:

Overall, this investment caters to diverse customers' needs, thereby improving customer education and customer satisfaction.

High Bill Alerts are expected to reduce average handle times within the call centre for high bill calls and first call resolution will improve. Hydro One expects these initiatives to measurably strengthen Hydro One's relationship with its customers and drive greater credibility and trust.

The Enhanced Web Portal for Commercial and Industrial Customers will deliver energy consumption analysis, building specific insights and savings tips that are personalized for each and every customer – driving awareness, engagement, and action throughout a progressive customer journey. Hydro One seeks to become a trusted advisor by helping customers understand their energy usage.

Outcome Summary:

Customer Focus	• Improve customer service and increase customer satisfaction by providing customers with tools to help manage their energy usage. • Serve customers better by providing Customer Service Agents with tools and resources to enhance call centre operations.
Operational Effectiveness	• Improve efficiency at the call centre by providing Customer Service Agents access to tools and information to better serve customers and reducing average call handling time.
Public Policy Responsiveness	• Encourage energy conservation management by providing consumers the resources to help manage their energy usage.
Financial Performance	• Improve financial performance through more efficient call centre operations and reduction of cost to operate the call centre due to anticipated drop in call volume.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as direct and indirect Hydro One costs for implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.8	-	2.6	5.5	-	9.9	11.7
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**1.8**	-	**2.6**	**5.5**	-	**9.9**	**11.7**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**1.8**	-	**2.6**	**5.5**	-	**9.9**	**11.7**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-33 Customer Service Complaint Management Tool

Start Date:	Q4 2017	**Priority:**	Medium
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	3.3
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One receives approximately 3,000 complaints from customers on an annual basis. Complaints vary in nature but the majority are associated with billing. Customers who log complaints are already experiencing a certain level of frustration. Failing to act promptly and effectively to address the customer's complaint can understandably cause significant additional aggravation.

Currently, complaints are handled on a MS Access database that is not integrated to SAP. As a result, complete and robust customer information is often not available to the staff member handling the complaint and sub-optimal service may result. These databases are not robust enough to contain automatic workflows and related tools to help better serve the customer. Workflows help customer service staff by routing the complaint to the appropriate group(s) that is in the best position to address the customer's complaint. Other customer centric workflows include reminders designed to alert staff if they are lagging on tasks that impact the resolution of a customer's complaint. There are no analytics available to do trending of the root causes of customer's complaints so that the company can handle these issues pro-actively and in turn, reduce the number of complaints going forward.

Alternative 1: Status Quo

If the status quo alternative were selected, Hydro One would continue to use spreadsheets and databases to log customer complaints. This option is not ideal since these spreadsheets and databases are not integrated within Hydro One's SAP system and customer information may not be readily available to assist in addressing the customer's complaint.

Alternative 2: Implement a Dedicated Complaint Management System (Recommended)

This alternative is recommended since the Complaint Management System will be integrated with our SAP Customer Relationship Management. SAP offers a complaint management bundle that enable users to create and store customer complaints about products or services directly in SAP Customer Relationship Management (CRM). Although the decision on whether this will be the tool that will be used has not been determined, this will be the most logical choice given SAP is Hydro One enterprise system. The Complaint Management System will contain workflows to improve productivity. It will document sources, trends, and assist with root cause analyses. As such, it will be utilized to develop a culture of continuous improvement.

Investment Description:
This investment is required to implement an integrated complaint management tool that tracks customer complaints from initiation to resolution. The tool will record and respond to customer complaints and will be fully integrated into Hydro One's SAP Customer Information System (CIS).

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

The implementation of the Complaint Management System which is integrated into SAP system is expected to be complex. Finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement a complaint management system that is integrated into SAP. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

This is a complex project requiring multiple lines-of-business across the company to deliver a robust, secure, and cost effective technology platform. A project governance team will be established and corporate risk workshops will be conducted.

Result:

Customer complaints will be logged in the new Complaint Management Tool. The solution will enable employees to conveniently access the customer's complaint (including previous complaints), account information, and status update. The call center agent will be able to respond to the customer with the latest information on the status of the customers' complaint. This investment will allow Hydro One to manage customer complaints effectively, which in turn improves customer service.

Outcome Summary:

Customer Focus	• Improve customer satisfaction through more efficient and faster handling of customer complaints.
Operational Effectiveness	• Achieve operational efficiencies by identifying trends and root-causes of complaints. • Handle complaints more effectively via built-in task notifications.
Public Policy Responsiveness	
Financial Performance	• Reduce calls to the call centre and the associated effort.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as direct and indirect Hydro One costs.

The cost estimate is based on historical business case estimates of a medium size, complex new SAP module. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing & challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs******
Capital* and Minor Fixed Assets	3.0	0.3	-	-	-	3.3	4.1
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	3.0	0.3	-	-	-	3.3	4.1
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.0**	**0.3**	**-**	**-**	**-**	**3.3**	**4.1**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-34 Smart Meter Network Investments

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	14.7
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One was one of the first LDCs to implement a smart meter network in the province of Ontario. The smart meter project started in 2006 and ended in 2014. This project delivered the advanced meter infrastructure (AMI) in the field and installed approximately 1.2 million smart meters across its customer premises. The CIS billing project started in 2011 and ended in 2014. Its purpose was to replace the legacy billing CSS system in production at that time that was 20 years old and long past its end of life. Both projects were complex and difficult to implement because there was no ubiquitous end to end solution available on the market at the time. The systems had to be "stitched" together using in-house custom development to integrate the smart meter systems, the IESO Meter Data Management and Repository (MDM/R) and the billing systems to create the meter to bill processes that met regulatory requirements set by the Ontario Energy Board.

The Advanced Meter Infrastructure consisted of the Trilliant head end system, collectors and smart meters. The smart meters installation was completed by the 2010 OEB target date. The smart meter communication network was initially completed by 2013 but Hydro One experienced issues in that the network was not providing consistent communications due to factors such as topology, seasonal effects and availability of reliable cellular network services in its rural and remote territory. These constraints required the development of custom applications to handle the exception in the communications network. The smart meter project was concluded in December 2014 once it was determined that there was adequate consistency in the smart meter communications to meet OEB billing accuracy of greater than 98% accuracy.

The 20 year old CSS billing system was replaced with an SAP / Itron IEE solution. The Customer Information System (CIS) project was started in 2011 and implemented in 2013. The synchronization of the CIS with the smart meter network required further customization in order to integrate it with the smart meter systems. The remediation phase of the CIS project concluded in 2014 once it was determined that billing accuracy of greater than 98% could be maintained.

During the smart meter project lifecycle, Hydro One hired consultants to design and implement a number of applications to resolve issues that arose during the integration of the MDM/R. While integrating the Smart Meter network with the SAP CIS billing system additional customized solutions were required to report, track and resolve exceptions. This practice was necessary to create the smart meter to bill processes which was considered new territory for advanced meter infrastructure billing. Today Hydro One continues to operate those customized systems. However, there is both a cost and risks to maintaining this practice because the customized applications are not supported by vendors and they are reaching end of life. Hydro One must rely on very specialized knowledge from a few consultants to maintain these applications that are limited in their scalability and performance. Also costly modifications are required when adding new meter equipment.

Alternative 1: Status Quo

If the status quo alternative was selected, Hydro One would continue to rely on existing technology. This alternative is not recommended since the systems are past their recommended useful life and they are costly to maintain. As such, there is a higher risk of system failure. If the systems were to fail then our customers would receive estimated bills until such time the systems were restored. Furthermore, custom solutions developed internally are no longer consistent with the Company's IT strategy.

Alternative 2: Replace EOL Smart Meter Network tools with new Technology (Recommended)

This alternative is recommended since it will replace end of life technology and reduce the risk of system failure and impact to our 98% billing accuracy performance indicator.

Investment Description:

This investment is required to replace the following tools that support the Smart Meter network. Note that some of the tool replacements or upgrades will be grouped under one or multiple projects depending on the current and future level of integration. Each project will be assessed base on individual business cases that will define the specific costs, return on investments and timeline to implement.

A. Customer Migration Tool - Required to support mass migration of customers from two-tier RPP to Time of Use billing. Hydro One continues to have a number of customers for which a smart meter solution was not available at the time of conversion. This tool will be required to manage the migration of these customers to smart meters.

B. Customer Meter Order Management Tool - Tracks new smart meter installations.

C. Collector Design and Deployment Tool - Coordinates the activities and handoffs for design and deployment of the smart meter network equipment, including regional collectors and repeaters.

D. Customer Service Order Network Tool - Provides reporting for all service orders (planned and unplanned).

E. Index Read Tracking Tool (IRTT) – This tool is the core of the daily meter reading delivery process and serves to provide meter triage, meter reliability metrics, network performance metrics, manual estimation generator, missing read tickets and demand meter reading support.

F. Itron Enterprise Edition Meter Data Management Tool - This tool is an enterprise-wide data management solution that stores interval and register data for residential, commercial, and industrial customers. This tool will have reached end of life and will require an upgrade from the vendor.

G. Network Infrastructure performance reporting – These reports provide the Company's Advanced Meter Infrastructure support team with statistics as to the health of the network.

Risk Mitigation:

This is a complex investment that will require a phased projects approach with multiple vendors in order to deliver a robust, secure, and cost effective technology platform to replace or upgrade the tools listed above. As such, a market scan will be conducted as part of the discovery phase and business case development to determine best-in-class technology and cost to implement.

Result:

The key result is reduction in risk of using meter related customized applications that are not vendor supported. In addition, this is expected to bring efficiencies in the meter-to-bill process through improved reporting & analytics.

Outcome Summary:

Customer Focus	• Improve customer satisfaction as a result of issues being identified quickly and resolved within a timely manner. • Reduce risk to customers in using meter related applications that are no longer supported by the vendor. • Improve operational performance for maintaining billing accuracy.
Operational Effectiveness	• The new technology will result in improved performance.
Public Policy Responsiveness	• Comply with the OEB requirement of 98% billing accuracy.
Financial Performance	

Costs:

This project has a high degree of complexity; it includes a new technology platform and multiple lines of business that require coordination. Given this project is customer facing, thorough testing is required to ensure no impact to the billing process. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.5	6.9	4.0	1.4		14.7
Less Removals						
Gross Investment Cost	2.5	6.9	4.0	1.4		14.7
Less Capital Contributions						
Net Investment Cost	**2.5**	**6.9**	**4.0**	**1.4**		**14.7**

**Includes Overhead at current rates.*

GP-35 Asset Analytics Risk Factor

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.0
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

Asset Analytics (AA) is a major investment planning decision support toolset. It is an SAP-powered application which represents an enterprise asset risk factor program that consistently measures and models Transmission and Distribution asset risks. The Business has been using the AA program since 2013.

The existing AA program collects asset related information from SAP and other non-SAP interfaces. The data received is used to calculate “Controls” such as Supporting Factors which in turn contribute to the calculation of Risk Factor scores that are used to assess the assets. These controls assist planners identify assets whose status indicates that replacement and/or repair is warranted.

Asset Managers leverage AA output information to make decisions regarding power delivery reliability and supply continuity. Consequently they initiate plans for future capital investments and work programs to improve delivery reliability, customer satisfaction and shareholder value.

Since existing calculations have remained unchanged since the initial deployment of AA, it has been identified by the Asset Managers that current Controls require remediation and extension to improve the quality of the asset risk model, and the granularity for decision making. Specifically required Risk Factor upgrades cover:

a. Adding two new Risk Factors, (Obsolescence and Health, Safety and Environment); and
b. Modifying current Risk Factors with improved data feeds, calculations and reporting.

Alternative 1: Maintaining the Status Quo

- With status quo option, Hydro One can continue to use the AA program with its existing features. This is not to Hydro One's advantage since some of the controls of the existing system require remediation and extension in order to be able to fully realize intended business value and operational efficiencies.

Alternative 2 (Recommended): Implement AA Risk Factor Upgrades

In addition to leveraging the capabilities of the existing AA program, this alternative will lead to realizing the needed business values and operational efficiencies including:

a. Adding two new Risk Factors: The Health, Safety and Environment Risk Factor will contribute to further improving decision data and reducing exposure to employee, public and environmental safety, negative regulatory and media attention. The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment; and
b. Modifying current Risk Factors: This will contribute to improving the quality of the asset risk model as well as the granularity for decision making.

Investment Description:

This investment is to upgrade the Asset Analytics Risk Factors which are used by Investment Planners to support asset maintenance programs and future capital investments planning. The high level scope of the project is expected to be as follows:

a) Add two new Risk Factors. These include:
    - Health, Safety & Environment (HS&E) will incorporate key initiatives around health or environment concerns, such as PCB levels in the insulating oil. Legislation has been enacted that PCB needs to be within certain levels to limit exposure of individuals to the health risk and this investment will support that initiative.
    - Obsolescence will assist with planning the asset useful service life including identification of corrective measure related to equipment defects and availability of spare parts.

b) Modify current Risk Factors with improved calculations and reporting. These include:

- Adding additional Supporting Factors_to algorithms or data feeds to improve the granularity and sensitivity of the Risk Factor scores leading to improved prioritization of assets for work and replacements.
- Adjusting the weighting of Supporting Factors in the algorithms to improve Risk Factor score sensitivity. If an algorithm was not correctly_designed and implemented the first time, correcting it improves the confidence in the Risk Factor scores.

c) Train end users on the operation of the changes in AA.

The recommended execution plan will take approximately 12 months to complete by the fourth quarter of 2020.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The Asset Analytics (AA) Tool a complex application and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Asset Management – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. In addition, follow up workshops will be conducted at appropriate project stage gates.

Result:

The delivery of the AA Risk Factor Upgrade project will lead to refining the existing risk factor calculations and will help improve quality of investment planning supporting data and in turn the decision quality and results.

The addition of the new Health Safety & Environmental Risk Factor will further improve this decision data and reduce risks to employee, public and environmental safety, and in turn investor confidence and negative regulatory and media attention.

The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing asset risk data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Upgrades to the AA Risk Factors will ultimately help improve electrical power delivery reliability, supply continuity, data quality, system efficiency and asset investment decision making.
Public Policy Responsiveness	• The outputs from the AA system feed into several information and reports frequently used for regulatory agency reporting (OEB, NERC, IESO, and NEB), government agency reporting (Min of Energy) and customer queries.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on the historical business case estimates of previous AA implementations. Detailed business requirements will be completed during the design phase of the project in order to determine final project costs. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One investment review and approval processes.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	-	2.0	-	-	2.0
Less Removals	-	-		-	-	
Gross Investment Cost	-	-	**2.0**	-	-	**2.0**
Less Capital Contributions	-	-	-	-	-	
Net Investment Cost	-	-	**2.0**	-	-	**2.0**

** Overheads included at current rates.*

ACQUIRED UTILITIES

1. INTRODUCTION

Hydro One, since its last rebasing of rates for 2015-2017, has acquired three local distribution companies – Haldimand County Hydro Inc. ("HCHI"), Norfolk Power Distribution Inc. ("NPDI"), and Woodstock Hydro Services Inc. ("WHSI") (collectively the "Acquired Utilities"). Operationally, all three of the Acquired Utilities have been integrated into normal Hydro One operations. The investment planning for these areas follows the process described in Section 2.1 of the DSP. The Asset registry information and the Asset Strategies employed to monitor and maintain the Acquired Utilities' assets are included in Sections 2.2 and 2.3 of the DSP.

For rate making purposes the Acquired Utilities have been kept separate from Hydro One. The financial information presented in the DSP and the Application excludes the financial information for the Acquired Utilities until January 1, 2021. The purpose of this Exhibit is to present information related to the investment planning process that is unique to the Acquired Utilities until January 1, 2021. This information is provided for each Acquired Utility in the following three areas:

Regional Planning

The Service Areas covered by the LDCs were included in the Regional Planning exercise and the outcomes are included in Section 2 of this Appendix.

Asset Management

The Acquired Utilities are already integrated operationally and from an Asset Registry perspective. Section 3 of this Appendix provides the summary information about each entity and the current respective asset base for each of the Acquired Utilities.

Capital Expenditures

As described in Exhibit A, Tab 7, Schedule 1, the Rate Bases of the Acquired Utilities will be financially integrated into Hydro One for rate making purposes as of January 1, 2021. Details on the capital expenditures for the Acquired Utilities on a historic and forecast basis are provided in Section 4 of this Appendix.

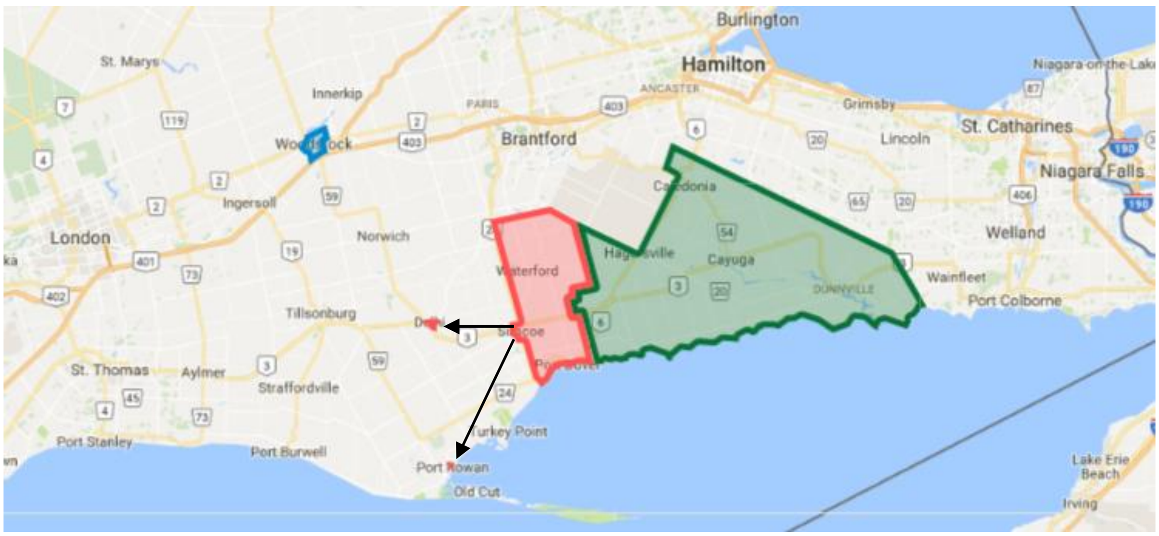


Figure 1 - Map of the former Distribution Territories of the Acquired Utilities

HCHI

NPDI

WHSI

Witness Lyla Garzouzi

2. REGIONAL PLANNING

2.1.1 HALDIMAND COUNTY HYDRO

The area of the former Haldimand County Hydro was part of the Niagara Sub-region in Group 3. HCHI was a participant in the latest round of regional planning. Details of the Regional plan are included in Section 1.2 of the DSP and the Needs Assessment Report for the region is included in Section 1.2.5 – Attachment #24.

No significant actions were determined for Haldimand County Hydro as a result of the Regional Planning activities.

2.1.2 NORFOLK POWER

The area of the former Norfolk Power was part of the Burlington to Nanticoke Sub-region in Group 1. NPDI was not a formal participant in the latest round of regional planning as the company was integrated prior to the last round. Hydro One represented NPDI customers at the meetings. Details of the regional plan for this area are included in Section 1.2 of the DSP and the Local Planning Report for the region is included in Section 1.2.5 – Attachment #5.

Recommendation #7 found that there was a need for Reactive support in the Norfolk Area. However, it was also found that the coincident load at Norfolk TS and Bloomsburg TS can be managed by load transfer and kept below the area supply limit of 87 MW. The study team recommended that Hydro One Distribution can manage the overload in the Norfolk area by performing load transfers to neighbouring stations. As a result, no material capital spending was identified as a result of the Regional Planning exercise for NPDI customers.

2.1.3 WOODSTOCK HYDRO

The area of the former Woodstock Hydro was part of the London Sub-region in Group 2. WHSI was a participant in the latest round of regional planning. Details of the Regional plan are included in Section 1.2 of the DSP and the Needs Assessment Report for the region is included in Section 1.2.5 – Attachment #17.

No significant actions were determined for WHSI as a result of the Regional Planning activities.

3. ASSET MANAGEMENT OF ACQUIRED UTILITIES

3.1 INVESTMENT PLANNING PROCESS

Hydro One's planning process includes determining appropriate investment for the Acquired Utilities. For investments over the planning period, the process will follow that outlined in detail for Hydro One in Section 2.1 of the DSP.

3.2 OVERVIEW OF ASSETS MANAGED

3.2.1 HALDIMAND COUNTY HYDRO INC.

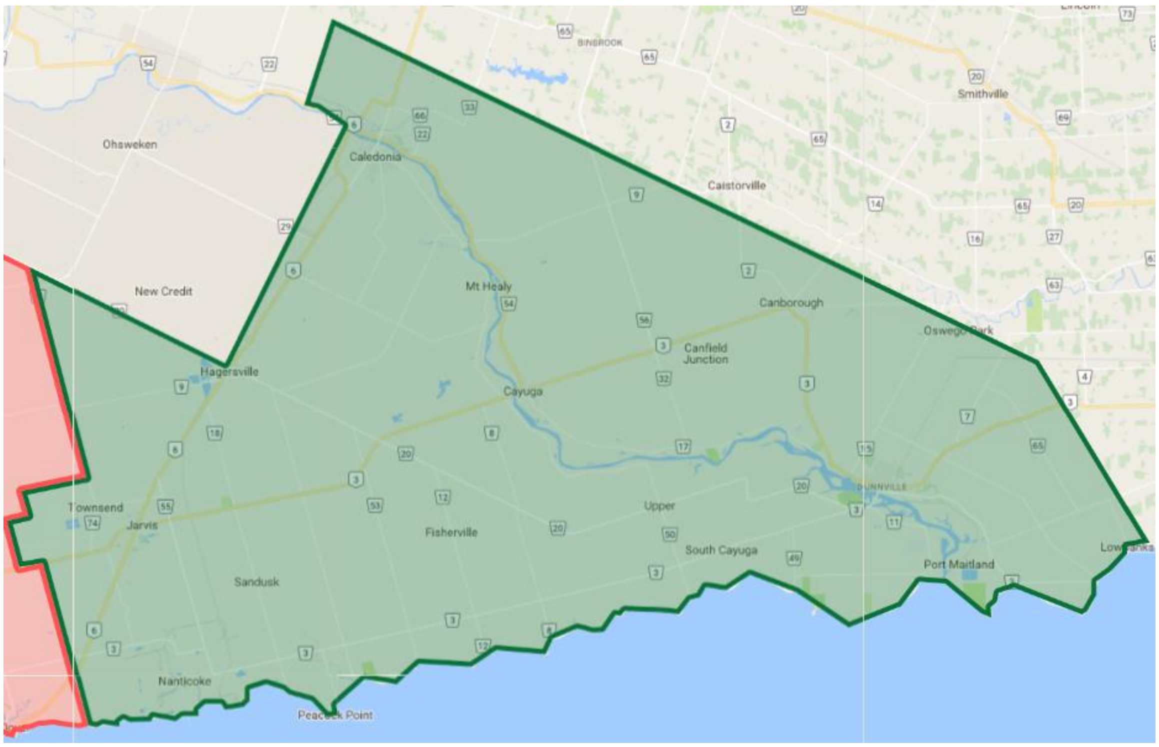


Figure 2 - Map of the Former Service Territory of Haldimand County Hydro Inc.

The former HCHI service territory is 1,252 square kilometres. The area is over 97% rural with a few urban pockets in towns such as Caledonia, Nanticoke and several others.

Prior to integration, HCHI served 21,407 customers – 18,899 residential and 2,508 commercial/industrial. The economic base is mainly made up of agricultural and manufacturing enterprises.

The predominantly rural make-up of the territory leads to a relatively low 12.4 customers per circuit km. Most customers are serviced by overhead assets. Underground lines comprise 6% of total circuit kilometres.

Assets integrated into Hydro One from HCHI include over 1,733 circuit kilometres of feeders, 27,931 poles, 7,259 transformers, and 5 sub-stations. The net book value of fixed assets, including Property, Plant, and Equipment, at the end of 2016 is approximately $53.3 million. Table 1 provides historical continuity of total fixed assets.

Table 1 - HCHI Historical Fixed Assets

Year End Fixed Assets	**2014 Plan**	**2014 Actual**	**2015 Actual**
Utility Plant (Year End)			
Gross Plant at Cost	80.1	79.7	53.4
Less: Accumulated Depreciation	(32.2)	(32.0)	(0.9)
Net Fixed Assets	**47.8**	**47.7**	**52.5**

HCHI's forecast rate base for the years 2016-2020 is shown in Table 2.

Table 2 - HCHI Rate Base

Year End Rate Base	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Utility Plant (Year End)						
Gross Plant at Cost	56.1	59.5	62.9	66.8	70.8	74.8
Less: Accumulated Depreciation	(2.8)	(4.2)	(5.7)	(7.3)	(8.9)	(10.5)
Net Plant	**53.3**	**55.3**	**57.2**	**59.5**	**61.9**	**64.2**
Average Net Plant		54.3	56.2	58.3	60.7	63.1
Working Capital		4.6	4.8	5.0	5.2	5.5
Rate Base		**58.9**	**61.0**	**63.4**	**66.0**	**68.6**

3.2.2 NORFOLK POWER DISTRIBUTION INC

NPDI is a non-contiguous rural service territory of 693 square kilometres. The area is 79% rural with a few urban pockets including Simcoe and Port Dover. The territory also includes the satellite towns of Delhi and Port Rowan.

Prior to integration, NPDI served 19,559 customers – 17,393 residential and 2,166 commercial/industrial.

The former NPDI territory is predominantly rural with a customer per circuit kilometre measure of 24.7. Most customers are serviced by overhead assets, with underground lines comprising 16% of the total.

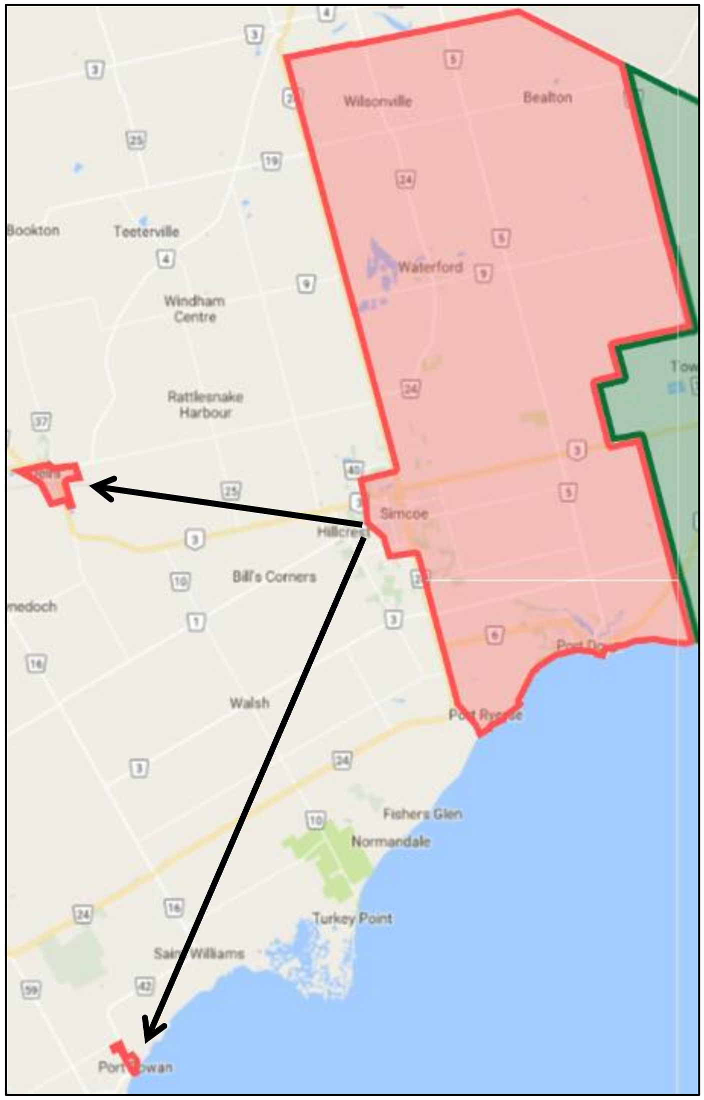


Figure 3 - Map of the Former Service Territory of Norfolk Power Distribution Inc.

Assets integrated into Hydro One from NPDI include 793 circuit kilometres of feeders, 11,020 poles, 4,469 transformers, and 9 sub-stations. The net book value of fixed assets, including Property, Plant and Equipment at the end of 2016 is approximately $54.7 million. Table 3 provides historical continuity of total fixed assets.

Table 3 - NPDI Historical Fixed Assets

Year End Fixed Assets	2012 Plan	2012 Actual	2013 Actual	2014 Actual	2015 Actual
Utility Plant (Year End)					
Gross Plant at Cost	84.7	83.6	86.9	56.6	56.2
Less: Accumulated Depreciation	(30.8)	(29.7)	(32.1)	(0.8)	(2.8)
Net Fixed Assets	**53.9**	**53.9**	**54.8**	**55.7**	**53.4**

NPDI's forecast rate base for the years 2016-2020 is shown in Table 4.

Table 4 - NPDI Rate Base

Year End Rate Base	2016	2017	2018	2019	2020	2021
Utility Plant (Year End)						
Gross Plant at Cost	59.0	61.6	63.7	65.7	67.8	70.9
Less: Accumulated Depreciation	(4.3)	(5.7)	(7.1)	(8.5)	(10.0)	(11.5)
Net Plant	**54.7**	**55.9**	**56.5**	**57.2**	**57.8**	**59.5**
Average Net Plant		55.3	56.2	56.9	57.5	58.6
Working Capital		3.6	3.7	3.9	4.1	4.3
Rate Base		**58.9**	**60.0**	**60.8**	**61.6**	**63.0**

3.2.3 WOODSTOCK HYDRO SERVICES INC.

WHSI is a contiguous, purely urban service territory serving a relatively small geographic area (under 30 square kilometres) comprising the majority of the City of Woodstock.

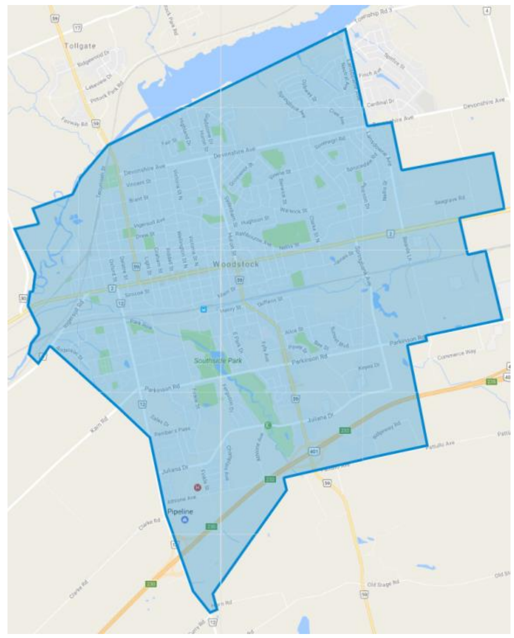


Figure 4 - Map of the Former Service Territory of Woodstock Hydro Services Inc.

Prior to integration, WHSI served 15,966 customers – 14,507 residential and 1,459 commercial/industrial. The economic base is driven by manufacturing including automobile assembly with a large Toyota Plant located on the east side of the city.

WHSI is a pure urban area with a customer per circuit kilometre measure of 62.6 and underground lines comprise 44% of the total.

Assets integrated into Hydro One from WHSI include 255 circuit kilometres of feeders, 4,200 poles, 1,618 transformers, and 7 sub-stations. The net book value of Property, Plant and Equipment at the end of 2016 is approximately $27.2 million. Table 5 provides historical continuity of total fixed assets.

Table 5 - WHSI Historical Fixed Assets

Year End Fixed Assets	**2011 Plan**	**2011 Actual**	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Actual**
Utility Plant (Year End)						
Gross Plant at Cost	42.3	44.6	45.2	48.9	52.1	27.2
Less: Accumulated Depreciation	(19.1)	(19.3)	(20.7)	(22.6)	(24.1)	(0.1)
Net Fixed Assets	**23.1**	**25.3**	**24.4**	**26.3**	**28.0**	**27.1**

WHSI's forecast rate base for the years 2016-2020 is shown in Table 6.

Table 6 - WHSI Rate Base

Year End Rate Base	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Utility Plant (Year End)						
Gross Plant at Cost	28.6	30.8	33.1	34.9	37.0	39.2
Less: Accumulated Depreciation	(1.4)	(2.5)	(3.6)	(4.7)	(5.8)	(6.9)
Net Plant	**27.2**	**28.3**	**29.6**	**30.3**	**31.2**	**32.3**
Average Net Plant		27.8	28.9	29.9	30.7	31.7
Working Capital		4.1	4.3	4.6	4.8	5.0
Rate Base		**31.9**	**33.3**	**34.5**	**35.5**	**36.8**

3.2.4 TOTAL RATE BASE

Table 7 presents the total gross plant, accumulated depreciation, net plant, working capital and rate base for the three acquired utilities. The December 31st 2020 ending balance of gross plant and accumulated depreciation of the Acquired Utilities have been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation effective January 1, 2021. This results in an increase in net fixed assets for Hydro One of $150.9 million. This amount has been included in the Hydro One's total rate base starting in 2021 as presented in Exhibit D1, Schedule 1, Tab 1. The total impact of adding the acquired utilities to Hydro One's rate base is the average net plant for 2021 of $153.5 million plus the associated working capital of $14.9 million.

Table 7 - Total Rate Base All Acquired Utilities

Total Rate Base	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Utility Plant (Year End)						
Gross Plant at Cost	143.7	151.9	159.7	167.4	175.6	184.9
Less: Accumulated Depreciation	(8.5)	(12.4)	(16.4)	(20.5)	(24.6)	(28.9)
Net Plant	**135.2**	**139.5**	**143.3**	**147.0**	**150.9**	**156.0**
Average Net Plant		137.4	141.4	145.1	148.9	153.5
Working Capital		12.3	12.9	13.5	14.1	14.9
Rate Base		**149.7**	**154.2**	**158.6**	**163.1**	**168.3**

4. CAPITAL EXPENDITURE SUMMARY

4.1 TOTAL – ALL ACQUIRED UTILITIES

Table 8 - Total Spending - All Acquired Utilities

	Historical (previous actual)				Forecast		
	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test	2019 Test	2020 Test
CATEGORY	$M	$M	$M	$M	$M	$M	$M
System Access				2.1	2.1	2.1	2.1
System Renewal				4.9	4.5	4.6	4.9
System Service				1.2	1.2	1.1	1.2
General Plant				0.0	0.0	0.0	0.0
Total	13.2	11.1	8.6	8.2	7.8	7.8	8.1
System OM&A*	18.8	17.8	12.5	10.2	10.3	10.6	10.5

Capital spending for the acquired utilities on a total basis is relatively steady over the planning period, varying from $7.8 million in 2018 to $8.1 million in 2020. Approximately 60% of forecast spending is in System Renewal.

The variance in spending over the years of the planning period is almost exclusively in the System Renewal category, varying from a low of $4.5 million in 2018 to a high of $4.9 million in 2020.

Historical data on a combined basis is available since 2014. Spending over the planning period represents a decline from 2015 levels but slightly above 2016.

Specific variance explanations within projects and programs are contained in the material for each individual acquired utility included below.

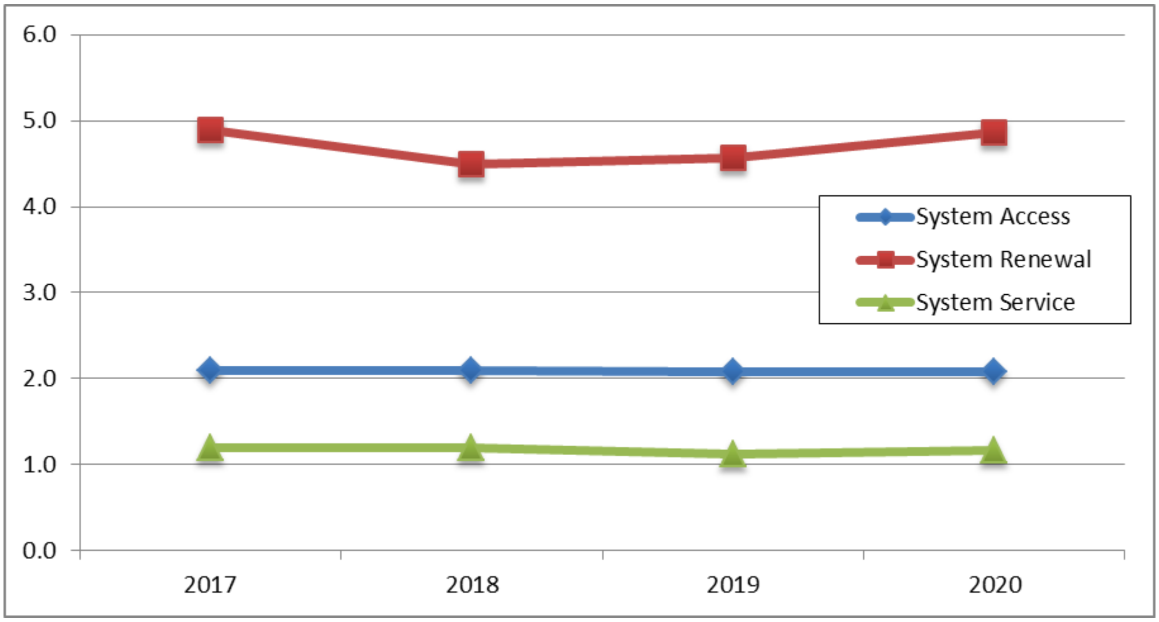


Figure 5 - Total Forecast Capital Spending by Category

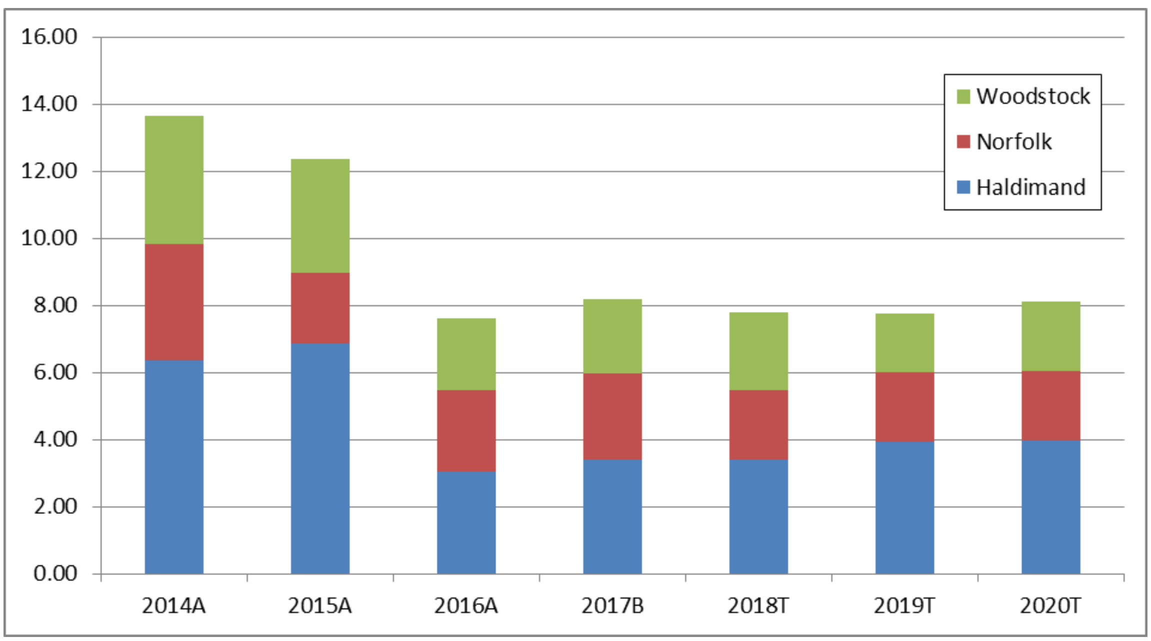


Figure 6 - Total Capital Spending by Acquired Utility

4.1.1 HALDIMAND COUNTY HYDRO INC.

Table 9 - Total Spending - HCHI

CATEGORY	Historical (previous plan and actual)						Forecast (planned)		
	2014			2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Actual	Bridge	Test	Test	Test
	$M		%	$M	$M	$M	$M	$M	$M
System Access						0.9	0.9	0.9	0.9
System Renewal						1.7	1.7	2.3	2.4
System Service						0.8	0.8	0.7	0.7
General Plant						0.0	0.0	0.0	0.0
Total	6.4	6.3	-1.2%	6.9	4.6	3.4	3.4	3.9	4.0
System OM&A*	8.2	7.5	-8.5%	6.0	6.0	5.1	5.1	5.2	5.3

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Forecast vs. Historical Variance

HCHI last rebased in 2014 (EB-2013-0134). Spending against 2014 approved amounts was generally consistent through 2014 and 2015. Spending was reduced in 2016 and 2017. The primary reduction in 2016 occurred due to the deferral of the following significant projects: (i) elimination of Jarvis DS Phase 1; (ii) underground (non-duct) Cable Replacements in Townsend; and (iii) Grand River Crossing in Caledonia.

Spending is expected to be steady throughout the planning period. A modest increase is expected in 2019 and 2020 based primarily on a $150k increase in the Transformer replacement program and a $400k increase in the Underground cable replacement program.

Witness Lyla Garzouzi

4.1.2 NORFOLK POWER DISTRIBUTION INC.

Table 10 - Total Spending – NPDI

	Historical (previous plan and actual)								Forecast (planned)		
	2012			2013	2014	2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Actual	Actual	Actual	Bridge	Test	Test	Test
CATEGORY	$M		%	$M	$M	$M	$M	$M	$M	$M	$M
System Access								0.6	0.6	0.6	0.6
System Renewal								1.8	1.3	1.3	1.3
System Service								0.2	0.2	0.2	0.2
General Plant								0.0	0.0	0.0	0.0
Total	3.9	4.0	2.7%	3.5	3.5	2.1	0.9	2.6	2.1	2.1	2.1
System OM&A*	5.7	6.4	12.5%	6.0	7.2	5.9	2.7	3.1	3.1	3.2	3.2

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Forecast vs. Historical Variance

NPDI last rebased in 2012 (EB-2011-0272). Capital spending was slightly above approved amount in 2012. In 2013 and 2014 spending was reduced due to: (i) a $200k reduction in Transformer inventory; (ii) a $200k reduction in spending on Demand Meter inventory; and (iii) a $200k reduction in spending on Computer and SCADA equipment. For fiscal 2015 to 2017, capital spending came in lower due primarily to a reduction in pole ($300k) and transformer ($200k) replacements along with a deferral of a number of conversion projects that, in total, contributed an additional reduction of $300k. Spending is expected to be steady through 2018 to 2022 at $2.1 million per year.

4.1.3 WOODSTOCK HYDRO SERVICES INC.

Table 11 - Total Spending - WHSI

	Historical (previous plan and actual)									Forecast (planned)		
	2011			2012	2013	2014	2015	2016	2017	2018	2019	2020
	Plan	Actual	Var	Actual	Actual	Actual	Actual	Actual	Bridge	Test	Test	Test
CATEGORY	$M		%	$M	$M	$M	$M	$M	$M	$M	$M	$M
System Access								0.5	0.5	0.5	0.5	
System Renewal								1.4	1.5	1.0	1.2	
System Service								0.3	0.3	0.3	0.3	
General Plant								0.0	0.0	0.0	0.0	
Total	2.9	6.6	127.2%	3.0	3.8	3.4	2.2	3.1	2.2	2.3	1.8	2.1
System OM&A*	4.0	3.8	-5.7%	4.0	4.3	4.1	4.2	3.8	2.1	2.1	2.3	2.1

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Forecast vs. Historical Variance

Woodstock last rebased in 2011 (EB-2010-0145). Capital spending in 2011 was higher than approved primarily due to the Commerce Way Transmission Station Contribution of $2.5 million. Spending was reduced in 2015 through 2017 with the reduction in expenditures for underground conduit, overhead transformers, and general plant, including transportation equipment and software.

Spending throughout the application period is expected to be generally in line with 2017 levels. A decrease in 2019 is forecast based on a temporary $250k reduction in Large Sustainment Initiatives for 2019. There is also a $100k reduction in the Recloser upgrade program and a $150k reduction in the Station Component program in 2019. The increase in 2020 is largely driven by a $150k increase in Small Sustainment Initiatives.

www.aesi-inc.com
aesi@aesi-inc.com

March 14, 2017

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

Attention: Mr. Oded Hubert, P. Eng. MBA
Vice President, Regulatory Affairs

Dear Sir

Re: Hydro One Networks Inc. Distribution System Plan for their 2018 – 2022 OEB Rate filing

As part of the filing requirements set out by the Ontario Energy Board (OEB) for Distributor's, Hydro One Networks Inc. has prepared the attached Distribution System Plan (DSP). Hydro One Networks Inc. prepared the data and furnished the information contained in the plan.

The Plan was prepared in accordance with Good Asset Management Practice, Industry Best Practices and the current Chapter 5 Filing Requirements. AESI critiqued this plan, made recommendations and suggestions, all of which were reviewed by Hydro One Networks Inc.

AESI confirms that the attached DSP satisfies the OEB filing requirements; addressing the goals and achieving the purpose of the OEB *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated March 28, 2013.

Please find attached AESI's Final Report which provides further details regarding AESI's review of Hydro One Networks Inc.'s Distribution System Plan.

Sincerely,

N. Sandford.

Neil Sandford P. Eng.
Senior Vice President
AESI Acumen Engineered Solutions International Inc.

775 Main Street E
Suite 1B
Milton, Ontario
Canada L9T 3Z3
P · 905.875.2075
F · 905.875.2062

1990 Lakeside Pkwy
Suite 250
Tucker, Georgia
USA 30084
P · 770.870.1630
F · 770.870.1629

HYDRO ONE NETWORKS INC. DISTRIBUTION SYSTEM PLAN REVIEW

Client
Hydro One Networks Inc.

Date
March 14, 2017

DSP Reviewed by
Archie Bax P.Eng., Ruth Greey M.Sc., Ted Wojcinski P.Eng.

AESI

775 Main Street E
Suite 1B
Milton, Ontario
Canada L9T 3Z3
P · 905.875.2075
F · 905.875.2062

1990 Lakeside
Parkway
Suite 250
Tucker, Georgia
USA 30084
P · 770.870.1630
F · 770.870.1629

www.aesi-inc.com

Introduction

As part of the filing requirements set out by the Ontario Energy Board (OEB) for Distributor's, Hydro One Networks Inc. prepared its Distribution System Plan (DSP) addressing the goals and achieving the purpose of the OEB *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated March 28, 2013.

Hydro One Networks Inc. prepared the data and furnished the information contained in the plan. AESI critiqued the plan, made recommendations and suggestions, all of which were reviewed by Hydro One Networks Inc.

Please find below further details regarding AESI's review of Hydro One Networks Inc.'s Distribution System Plan.

Findings and Recommendations

AESI found this DSP demonstrated Hydro One's commitment to the Renewed Regulatory Framework for Electricity Distributors in that it includes a performance based approach that is based on outcomes that provide value for customers.

AESI was impressed with the reliability and robustness of the Asset Management Process. Key strategic messages have been included throughout the DSP. Hydro One has also illustrated an appropriate alignment between the proposed investment levels, customer engagement results and asset need.

AESI was pleased to see that the investment planning process applied in the DSP was iterative. Hydro One created several different asset investment plans with different customer outcomes and rate impacts and chose the plan that best balanced its business objectives with preferred customer outcomes, especially as it focuses on a more competitive business model.

AESI felt that Hydro One showed a good effort at following the Chapter 5 Table of Contents, although the document does not totally line up and Hydro One did not accept all of AESI's suggestions for format. This is Hydro One's first complete, comprehensive DSP and the utility agrees that it will be even more comprehensive in the next filing.

Hydro One received the IESO letter of comment regarding Hydro One Network Inc.'s Distribution System Plan (DSP) on March 9, 2017. Hydro One explained the reasons for the small differences in numbers between the DSP and the IESO numbers. The differences were due to different reference points, Hydro One's reference point was August 31st, 2016 whereas the IESO's was January 31st, 2017 as well as the different interpretation regarding what is included in the MicroFit projects. With this explanation, AESI is satisfied that Hydro One has met IESO's requirements.

AESI did recognize a few specific areas within the DSP that did not follow the prescribed Chapter 5 outline. For example, Section 1.3, Customer Engagement. AESI found its positioning appropriate considering the importance of its customer engagement within its business objectives and planning process. AESI also considered the placement of Sections 1.5 Productivity and Continuous Improvement and Section 1.6 Benchmarking appropriate as this highlights the importance of these topics with Hydro One's increased commercial focus.

Hydro One also made the decision to discuss "How the Plan reflects Regional Planning, Customer Needs and Benchmarking" in its first chapter, with a summary in the later section as prescribed in Chapter 5. This reflects Hydro One's desire to illustrate the complete picture of those activities in one section. AESI is in agreement with this approach.

AESI did identify areas of opportunity to better demonstrate alignment with the OEB requirements.

- In the section 1.4.2 (5.2.3b) - Performance Trends (Table 13 – SAIDI by Outage Cause) Hydro One only reported on 8 causes rather than the 10 prescribed by the OEB. Hydro One explained to AESI that this is due to software application limitations. Hydro One recognizes this difference in reporting and is working on correcting its outage cause data.
- AESI had several questions about Hydro One's use of the term "cost savings". Hydro One explained its interpretation of cost saving; the change in nature of costs within a specific timeframe - the "input/output" cost savings. Hydro One explained that; the "input/output" types of savings are included in the Productivity section. Other references to "cost savings" may include avoided costs, efficiency costs, or process innovation costs which may not directly affect productivity.
- AESI provided Hydro One with suggestions regarding other reporting metrics such as; job estimate to actual. Hydro One acknowledged that this was a meaningful metric and stated that it would be considered in the future.
- AESI suggested that in addition to the raw numbers for SAIDI, SAIFI and CAIDI that Hydro One also compute each to the attributable cause codes. Hydro One appreciated the suggestion and subsequently included that information in the DSP.

AESI provided Hydro One with numerous other points of clarification and suggestions. Hydro One stated that it appreciated AESI's points and suggestions. Hydro One provided AESI with comments on all of the points. In some cases Hydro One did not heed the comments but explained its rationale and appreciated that they would be of assistance in more thoroughly preparing for interrogatories during the hearing process.

AESI confirms that the attached DSP satisfies the OEB filing requirements; addressing the goals and achieving the purpose of the OEB *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated March 28, 2013 and appreciates Hydro One's commitment to further refining its DSP in future filings.

AESI

Ruth Greey, M.Sc.

Professional Summary

Ruth Greey has over 30 years' of in-depth management, interpersonal and leadership experience in the energy industry. She has extensive expertise in many aspects of the energy sector regulatory environment, including environment, LDC rate approvals, energy infrastructure approvals, CDM, customer relations, new energy technologies and First nation relations.

Relevant Project Experience

Regulatory

- Work with numerous Local Distribution Companies in developing their Distribution System Plans and 5 year custom incentive regulation rate applications.
- Liaise with the OEB and the Consumers Council of Canada (CCC) to ensure customer interests are considered and addressed through regulation and public review. Specific projects include:
  - developed and reviewed the process to address the remaining Long Term Load Transfers for all electric utilities in Ontario
  - developed and reviewed the process to address Cost Allocation of Transmission facilities (on-going)
  - participated in all stages of the OEB regulatory approval process related to rate applications for Oshawa PUC, Kingston Hydro, Hydro Ottawa, Toronto Hydro, PowerStream, Enersource Hydro Mississauga and Horizon Utilities
- Prepare and deliver written reports and oral communications to external stakeholders and provincial shareholder to facilitate positive working relationships
- Develop and deliver witness training including working with external facilitator and lawyers
- Lead the development, submission and approval of regulatory filings associated with rate applications for Hydro One's Transmission, Distribution and Remotes businesses
- Work with the OEB to develop new effective generic proceedings for Long Term Load Transfers (LTLTs), Smart Meters, CDM, Incentive Regulation, Minimum Filing Requirements, Development Costs for Transmission Projects and other generic issues.
- Lead all aspects of preparation and execution for Ontario Energy Board Oral hearings
- Manage cooperative, effective relationships with OEB, Hydro staff, Intervenors and other advocacy groups for Hydro One

Advocate

- Lead the development, nurturing and management of the relationships with provincial and municipal government Ministries to ensure the implementation of key corporate priorities and to advocate

Areas of Expertise

- Interpersonal, Communications and Facilitation Skills
- Ontario Regulatory Requirements
- Transmission and Distribution
- Environment

Education

- Ryerson University, Continuing Education, January 2015 - present
- Master of Science, University of Guelph, 1982
- Bachelor of Science (Honours), Queen's University, 1979

Professional Associations

- Canadian Environmental Management Committee
- National Round Table on Environment and Economy
- Steering Committee – Edison Electric Institute
- Steering and Executive Committee – Utility Health

legislative changes to advance Hydro One's interests

- Lead external agency teams and industry associations to influence the direction of the electrical industry priorities and strategies
- Lead the liaison between the provincial government and Hydro One regarding regulatory applications
- Represent Hydro One on inter-agency working groups to ensure the successful implementation of the corporate objectives
- Establish credible and timely communications with the provincial government shareholder and other government Ministries

Environment

- Lead a Team with the Ministry of Environment and Hydro One major industrial customers to amend the Class Environmental Assessment for Transmission Facilities. This involved initiating, planning, setting objectives and targets, leading multi-stakeholder teams, implementing strategies, negotiating, presenting to the public and interest groups. This necessitated strong communication and negotiating skills as well as excellent people management skills.
- Lead a Team for the Ontario Energy Board to amend Hydro One's Transmission System Code. This position necessitated excellent negotiating skills, good internal team leadership skills such as coaching, communicating and translating concepts and knowledge regarding regulatory policies into practice with staff, stakeholders and the public.
- Lead other corporate programs involving setting environmental policy and then implementing and communicating the appropriate programs for the Provincial government, external stakeholders and customers.
- Developed and Lead CEA's Flagship National environmental program. In directing this Program, Ruth advised Utility Executives regarding managing their environmental and related issues at a national level. She worked with federal government agencies to influence proposed federal regulations, and provided advice on Sustainability Reporting across the country. Ruth facilitated a Public Advisory Panel made up of international environmental experts. She facilitated the administration of the program including; preparing an Annual Report; managing the Program Steering Committee, reporting to the CEA Board of Directors and leading an independent verification process.
- Lead federal, provincial and municipal government consultation to influence regulations on PCBs, EMF and other electricity issues

EMF Issue Management

- Corporate Spokesperson for the Electric and Magnetic Fields issue including releasing Ontario Hydro health study results to employees and the public, as well as presenting the results worldwide
- Through coordination, influence, motivation and collaboration with all stakeholders in Ontario interested in EMF, Ruth changed the focus and direction of EMF issue management in Ontario.
- Provided leadership and support to Senior Management regarding issues management techniques. Developed and facilitated the implementation of corporate public and environment programs and policies working with employee and Union representatives
- Chaired several provincial, national and international communication and corporate planning committees. Chaired an international symposium on EMF in Denmark attended by delegates from 45 countries.

AESI

Ruth Greey, M.Sc.

Customer Care

- Manage all contact handling activities for residential customers through an outsourced service provider (for customer billing, meter reading, collections programs), as well as an escalated complaint centre
- Manage the outsourced contract to ensure all service level agreements are met and that the contract demonstrates continuous improvement
- Manage the relationship between customer care, corporate communication, conservation management programs and the customer focused field activities
- Ensure effective business readiness and sustainment in support of our new Customer Information System that was implemented in May 2013
- Provide negotiating expertise and skills, to develop service agreements, statements of work, contractual service and pricing methods, negotiation or pricing approaches, governance or approval needs for Hydro One's outsourced Customer Call Centre, Billing and Collections Department, and special Customer related projects such as Customer Outage strategies
- Manage the contractual interface and overall relationship management with Inergi for outsourced Customer Care services

AESI

Ted Wojcinski, P.Eng., C.I.M., SMIEEE

Professional Summary

Ted Wojcinski has more than 34 years of engineering, operations and management expertise and a proven track record in the electricity distribution utility industry. Ted has worked his way up through the ranks from system engineering to planning, operations, regulatory, environmental and management. His comprehensive experience provides a broad perspective that allows him to bring a full-circle approach to projects enhancing the derived value. His experience is complimented with consistent involvement and research on regulatory obligations and Smart Grid Applications—keeping him up-to-date on requirements, technology and industry trends.

Relevant Project Experience

Regulatory

- Development of consolidated Distribution System Plans and supporting documents, processes, etc. for Newmarket-Tay Power Distribution Ltd. and Milton Hydro Distribution Inc.(2014 – 2015)
- Reviewed Asset Management practices of Peterborough Distribution Inc. to identify practice gaps and recommended actions to address the gaps and guide the preparation of their Distribution System Plan (2014)
- Provided utility expertise in crafting capital related project justifications for PowerStream's IRM submission to the Ontario Energy Board in 2013.
- Providing assistance to Horizon Utilities Corp.in the implementation of its Smart Grid plans (2013)
- Monitoring developments in the Ontario government's Green Energy Act as it pertained to the utility industry to assess its impact on connecting distributed generation
- As a member of the Rate Base and Capital Panel team, successfully defending PowerStream's Green Energy Plan and 2013 $114M capital submission, a 45% increase in spending over 2012 levels, to the Ontario Energy Board (OEB)
- Spearheading a gap analysis study to determine PowerStream's current level of achievement under the PAS-55 Asset Management Standard to comply with future regulatory guidelines
- As a member of PowerStream's Smart Grid Task Force, providing engineering expertise in the development of PowerStream's Smart Grid Strategic Plan in response to provincial government and regulatory guidelines
- Providing engineering and operations expertise to the OEB as a member of the OEB Performance Based Rates and Service Quality consultation working groups

System Planning

- Developing PowerStream's first ever comprehensive Distribution System Planning Report that has since evolved into PowerStream's 5 Year Capital Plan

Areas of Expertise

- System Planning
- Regulatory and environmental
- Utility Operations and Management
- Smart Grid applications

Education

- Masters Certificate in Electricity Sector Leadership (MCESL), York University Schulich School of Business, 2012
- Certified in Management (CIM), Canadian Institute of Management, 1988
- Bachelor of Applied Science in Electrical Engineering, University of Toronto, 1980

Professional Associations

- Senior Member, IEEE
- Professional Engineers of Ontario
- Ontario Society of Professional Engineers

- Providing management and engineering expertise in development of PowerStream's Asset Condition Assessment program through the development and incorporation of asset health models for critical equipment infrastructure to strengthen regulatory rates submissions
- Developing and executing Engineering Planning's 5 year Capital Plans that encompassed asset condition assessment and replacement programs and most recently, successfully managing $20M in 2012 Capital expenditures
- Initiating the York Region Supply Study with the OPA that included external stakeholder groups such as Hydro One, Independent Electricity System Operator (IESO) and other Local Distribution Companies (LDC) and providing distribution engineering expertise in the development of near, medium and long term plan options
- Providing engineering expertise as PowerStream's representative to the 2005 Northern York Region supply study including consultation with ratepayer group representatives

Utility Management

- As a member of the Senior Leadership Team provided the overall strategic direction and management of the Engineering Planning department for the second largest electricity distributor in Ontario
- Presenting engineering related updates and recommendations to PowerStream's Executive Leadership Team, board of directors and municipal politicians on distribution issues
- Providing management and engineering expertise to the review of distribution Inspection and Maintenance practices at PowerStream
- Chairing PowerStream's Reliability Committee to drive the organization's performance towards a 5-9s reliability standard
- As Corporate lead and Committee Chair, developing and coordinating PowerStream's 2010 and 2013 strike contingency planning efforts
- Instituting PowerStream's first annual Environmental Sustainability Report and generating recommendations for PowerStream's 2008 Environmental Program, the first of which was the adoption of PowerStream's Environmental Policy Statement and creation of an Environmental Section
- Creating PowerStream's Environmental Section and developing the associated corporate policies/procedures on environmental sustainment including the identification of Environmental Aspects and Impacts and identification of Environmental Requirements
- Successfully managing a multi-disciplinary team of in-house and contract resources to develop and deliver PowerStream's Conservation and Demand Management programs, including the design, construction and commissioning of Wind and Solar demonstration facilities at PowerStream's Head office, a Gold LEED building

Station Design and Sustainment

- As a member of the Senior Leadership Team provided the overall strategic direction and management of the Station Design and Sustainment department
- Providing oversight of station projects that encompassed the Class Environmental Assessment (EA) approval, design, construction and commissioning of Markham Transformer Station #4, a $20M project
- Conducting a comprehensive organizational assessment of the Stations capabilities and developing action plans to facilitate the effective functioning between engineering and operations Directed and managed all operational functional areas such as system control, lines and station maintenance

Engineering

- Prepared report for PowerStream Inc. that presented various options, for PowerStream's consideration, to effectively "harden" the distribution system against ice storms and severe weather in general (2014)
- Performed a review of the supply options to the Kenora Paper Mill site and adjacent areas for Kenora Hydro to align with regulatory requirements (regional planning, Distribution System Code) and "good utility planning" practices that impact on how new electrical infrastructure is planned. Respective electrical supply and cost allocation obligations of Kenora Hydro and the site developer(s) were identified and recommendations were provided to Kenora Hydro's executive management to guide their infrastructure planning (2013)
- Cultivating PowerStream's Stations department into a high performance team to deliver best in class Distribution Generation assessment and connection services under the Ontario Power Authority (OPA) Feed-In-Tariff (FIT) program
- Underground Engineering Supervisor (Toronto Hydro, 1988 – 1991)
- Network Engineering Supervisor, (Toronto Hydro, 1987 – 1988)
- Low Voltage Services Supervisor (Toronto Hydro, 1985 – 1987)
- Project Engineer (Toronto Hydro, 1980 – 1985)

AESI

Neil J. Sandford, P. Eng.

Professional Summary

- Neil Sandford has over 38 years of experience in the electricity distribution industry, including 17 years as a senior engineering and operations manager with an Ontario distribution utility. As Senior Vice President he provides leadership for and participates in a number of managerial and technical distribution projects for electric utility clients in Canada and the United States. He serves on the Board of Directors of an Ontario distribution utility and acts as the General Manager for the GridSmartCity Cooperative (13 Ontario Local Distribution Companies). He was chair of the Electrical Safety Authority's Utility Advisory Council for 10 years since its establishment, in 2004. He is also past chair of the Electricity Distributors Association Commercial Members Steering Committee.

Relevant Project Experience

Management and Planning

- Utility management and Regulation
- Asset Management and Distribution System Plans
- Green Energy Act Plans
- Consulting
- Administration
- Planning, safety and regulatory requirements
- Established/investigated new business ventures for fibre optic/telecommunications, meter services, co-generation plant opportunities,

Engineering and Operations

- System Performance Reports
- Electrical Safety Authority, Ont. Reg. 22/04 Consulting, Training and managing ESA Annual Audits
- Underground distribution, distribution automation and energy management

Electrical Design

- Specializing in land development and underground electrical distribution systems,
- Sub-station design and system planning,
- Electrical power projects within oil refinery operations
- Power cable contracts and construction

Areas of Expertise

- Utility Management: Strategic Planning, Performance Management, Labour Negotiations
- Electrical Distribution: Engineering, Operations, Planning, Safety
- Electric Industry and Utility Restructuring
- Project Management
- Asset Management
- Risk Management

Education

- Electrical & Electronic Engineering, Portsmouth and Plymouth Polytechnics, U.K.
- Executive Program, University of Western Ontario, 1994

Professional Associations

- PEO - Professional Engineers of Ontario
- Electricity Distributors Association (EDA)

FORM A

Proceeding: EB-2017-0049

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Ruth Greey (*name*). I live at Toronto (*city*), in the Province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Hydro One Networks Inc. (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date March 14, 2017

Signature

FORM A

Proceeding: EB-2017-0049

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is TED WOJCINSKI (*name*). I live at RICHMOND HILL (*city*), in the PROVINCE (*province/state*) of ONTARIO.

2. I have been engaged by or on behalf of HYDRO ONE NETWORKS INC. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date MARCH 14, 2017

Signature

WORK EXECUTION STRATEGY (CAPITAL/OM&A)

1. INTRODUCTION

The purpose of Hydro One's Work Execution Strategy is ensure that Hydro One effectively and efficiently completes its annual distribution work program, while focusing on the Company's business objectives including safety, reliability, innovation, protecting the environment, employee engagement, shareholder value and meeting customer commitments. Hydro One has demonstrated its ability to successfully execute a large work program while maintaining the necessary flexibility to address emergent work and changing priorities. By actively identifying ways to be more efficient and cost-effective, Hydro One can accommodate an increasing working program, provide customers with value for money, and produce distribution system outcomes that reflect customer preferences.

Hydro One's work planning and execution activities are designed to increase efficiency and innovation and contribute to a culture of continuous improvement. The implementation of Move to Mobile technology will improve productivity through geographic bundling and scheduling of work, enhance overall reporting and facilitate access to the latest maps, standards and designs. Move to Moble will also create a safer workplace for Hydro One employees because supervisors will be able to spend more time coaching field staff.

2. FACTORS IMPACTING FUTURE WORK PROGRAMS

The Hydro One Distribution work program has continued to increase and sustained growth is forecast over the next five years. Utility acquisitions, productivity and efficiency initiatives, Move to Mobile, regulation compliance, distribution asset condition and workforce demographics will all have an effect on work programs and projects in the coming years. This Exhibt will discuss these factors and their overall impacts on work programs and projects.

2.1 PRODUCTIVITY AND EFFICIENCY INITIATIVES

Hydro One has undertaken several productivity initiatives which will improve process efficiencies and result in cost savings in the execution of its work programs. Details regarding these initiatives, along with the estimated savings are provided in section 1.5 of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1).

2.2 INCREASING WORK VOLUMES

Hydro One Distribution's overall OM&A and Capital work programs are increasing:

- to satisfy the PCB testing and replacement requirements by 2025 set by Environment Canada regulations;
- to address the significant number of smart meters that require replacement in the next five years;
- to continue to address select areas of overgrown regions under the vegetation management program to manage costs and improve reliability;
- to manage the wood pole population through replacement of end of life wood poles and poles showing signs of premature decay;
- to address aging distribution station transformers and other distribution assets through replacement or refurbishment programs;
- to integrate and manage new customers as a result of LDC acquisitions;

- for the submarine cable maintenance programs to meet challenges as a result of receding water levels in the Great Lakes and to replace deteriorated cable as a result of age; and
- to ensure compliance with Ontario Regulation 22/04. This regulation has established a standard for electrical distribution safety requirements for all licensed electricity distributors in Ontario as well as national technical standards for infrastructure design and construction (including utility plant) with an audit-based compliance system. This has resulted in increased hours and costs to work on existing plant in order to ensure adjacent existing structures meet this regulation.

The wood pole replacement and vegetation maintenance programs are two major areas affected by increased work volumes. However, Hydro One continues to refine its strategies to adapt and become more efficient in work execution.

Wood Pole Replacement: Hydro One owns approximately 1.6 million distribution poles across the province of Ontario. The Company's end of life pole replacement program is the largest funded capital work program within Provincial Lines, with an average of about 14,000 poles to be replaced each year over the next five years. With each pole replaced, system reliability directly improves as poles at risk of failure are replaced with new poles. To become more efficient and cost effective in executing the program, Hydro One strategically selects poles to be replaced based on priority and identified criteria and aligns targeted work with Forestry's annual trimming cycle. By doing so, the costs are significantly reduced as a forestry crew has already cleared the line and an unplanned return trip for forestry is not required. In addition, Hydro One has leveraged local knowledge to bundle poles that are nearing end of life or showing premature signs of decay on the same feeder. Utilizing dedicated project crews that focus on pole replacement has proven to be an efficient and cost-effective strategy, but is dependent on the Company's annual work program and emergent needs. An increased focus on reporting to improve program visibility has been instrumental in monitoring program costs. The implementation of productivity and efficiency initiatives such as Move to Mobile and Perform will further improve scheduling of resources, reduce administrative efforts and enhance reporting, resulting in additional unit cost savings.

Vegetation Management: Hydro One's vegetation management program is required to manage electrical contact risk created from incompatible vegetation growth. There are approximately 7 million trees along the Company's rights-of-way. Trees are the primary cause of distribution outages; vegetation maintenance work programs are therefore crucial as accumulated vegetation will eventually lead to costly unplanned maintenance and frequent, lengthy, and capital-intensive storm restoration efforts. Leveraging integrated vegetation management practices and various optimization opportunities within the Forestry work program is the key focus of the vegetation maintenance plan over the next five years to improve system reliability and reduce program costs.

In addition to the annual Forestry work program, there are several initiatives that are being undertaken to synergize work execution and increase the use of technology. Hydro One's long-term direction is to use a staged approach to re-establishing assets on an appropriate cycle. Long-term strategies that are being considered include increasing focus on high priority and high density urban feeders and maintaining them on an on-going cyclic basis, as well as identifying strategic program kilometers to be completed annually. This strategy includes rural and single-phase sections of the system scheduled for maintenance based on reliability, condition, outage history and age criteria. Managing rights-of-way on a shorter and stricter cycle is part of the strategic vision for Hydro One's vegetation management program. Achievement of a more regular cycle lowers maintenance costs and provides a preventative treatment to mitigate tree-related outages. In addition, environmental and social impacts of operations will be reduced by limiting the quantity of vegetation removed and employee and public safety risks that overgrown power lines can pose will be minimized.

2.3 AGING DISTRIBUTION SYSTEM

Hydro One Distribution manages 1,005 distributing and regulating station facilities which are used for the delivery of power, voltage transformation and switching. An increased capital re-investment program is being undertaken to address the changes in load profile and deteriorating asset condition of the distribution stations fleet. Integrated station refurbishment and replacement programs are required to address the overall condition of the station assets and facilities. Failure to complete this work may result in decreased distribution system performance, negative effects on reliability, and impact the Company’s ability to maintain customer commitments. To prevent these issues from arising, distribution station refurbishment investments are released under an annual program framework. This increases visibility and allows Hydro One to prioritize stations identified for refurbishment to maximize accomplishment each year and minimize schedule delays and inefficiencies.

To align with transmission and distribution capital investments and better deploy resources, the station refurbishment program was transferred from the Stations and Operating Division to Construction Services in 2015. Hydro One is currently implementing productivity and efficiency initiatives to improve the capital estimating process and minimize issues and inefficiencies in the execution phase. A greater emphasis on cross-functional governance and reporting will also drive contiuous review of project scope, costs and timeframes and allow the Company to communicate and mitigate any risks with key stakeholders involved.

2.4 MATERIAL AND EQUIPMENT AVAILABILITY

The materials, equipment and fleet incorporated into the distribution work program account for approximately 25% of the total cost of the work. By actively monitoring equipment enhancement opportunities, Hydro One will improve work execution efficiencies. Increased demand for specialized materials continues to be a challenge as a result of rapid growth in work programs throughout North American utilities and the changing nature of the distribution business to enable distributed generation and Smart Grid technology. Mobile Unit Substation ("MUS") availability has been a challenge as Hydro One has a limited number of units that continue to be in high demand. MUSs are used to perform many maintenance activities, address system failures and support outages. As a result, effective management of fleet and equipment plays a significant role in Hydro One Distribution's ability to complete its annual work program. This becomes even more critical during peak customer demand periods to ensure customers do not experience delays.

2.5 WORK EXECUTION CAPACITY CHALLENGES

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be realized through separate transmission and distribution operations. In order to successfully complete the work program, internal and external resources are utilized. Hydro One and other Electrical Utilities have recently been faced with a shortage of skilled trades, making it difficult to secure resources. To mitigate this shortfall, a greater volume of work will need to be outsourced. Where work is very integrated with existing facilities, it is always managed by Hydro One staff with support from outsourced specialists when required. All categories of external resources and services are becoming more difficult to contract as the North American demand increasingly exceeds available supply. Further details on how these issues are being addressed are discussed in the Staffing Strategy below.

3. IMPLEMENTATION OF WORK EXECUTION STRATEGY FOR 2017-2022 WORK PROGRAM

Hydro One Distribution has taken a number of actions to increase the volume of work the Company can complete in future years. Hydro One Distribution utilizes a fully integrated work planning method that optimizes the use of internal and external resources, manages costs and material availability, minimizes system outages and is mindful of customer needs.

3.1 INCREASED WORK BUNDLING AND OUTAGE OPTIMIZATION

Many of Hydro One's distribution projects and work programs require parts of the system to be electrically isolated while work is being performed. Obtaining the required planned outages becomes increasingly difficult as the distribution system grows larger and more complex with the addition of distributed generation and Smart Grid components, LDC acquisitions and supplied load increases. As a result, additional outages may be required to complete the annual work program and ensure system reliability is maintained. To accomplish this, Hydro One bundles work at common locations to become more efficient. Completing more bundled work enables Sustainment work and Development work to be planned and executed in an integrated manner under a common work plan.

Planned outages are also susceptible to being cancelled. Cancellation can be attributed to storm activity, customer demands and system constraints. When planned outages are cancelled, crews have to be demobilized and the work and required outages are rescheduled for a future date. This can result in increased project costs and limit work accomplishment. To minimize any inefficiency in outage coordination efforts due to these unforeseen issues, Hydro One has made a number of improvements to internal processes and communication with regard to outage planning and bundling of work. Some examples include meetings to review work plans and required outages for large projects to improve coordination between controlling authorities and formally establishing lead times for outage approvals to minimize risk of outage delays. This enables the Company to reduce the number of system outages required, utilize resources more efficiently, increase the total volume of work that can be executed and positively impact customer satisfaction.

Hydro One has also implemented a long-term balancing of preventive maintenance programs for switches, distribution transformers and instrument transformers. Work programs have been aligned into integrated and optimized maintenance frequencies and plan dates to minimize outages. For example, switch maintenance on a given feeder circuit is planned for the same year, with a single outage requirement. Optimized outages and bundled work directly reduces switching time requirements, crew windshield time and the number of required mobilization and demobilization activities for field staff.

3.2 WORK PROGRAM RELEASES

Quality upfront planning is essential for service groups to effectively and efficiently execute work. Hydro One continues to refine this practice to accommodate an increasing work program. In 2016, Provincial Lines separated planning and scheduling from execution of work to drive consistency and efficiencies throughout the province. Asset Management continues to improve the project definitions and timelines by which work is released. When work is released it means that the work and funding are ready for field execution. Earlier releases allow:

- the service groups to more efficiently plan, schedule and execute work;
- sufficient time to order materials with long lead times;
- coordination with other capital or maintenance work;
- the development of new commissioning and maintenance procedures and associated documents; and
- for work to be scheduled when site conditions are optimal. For example, crews take advantage of frozen conditions when access may be an issue.

Moving from annual work releases to multi-year releases for programs enables long term contractual vendor relationships and work to be bundled and scheduled more effectively. Multi-year programs also enable resources to be scheduled beyond the current year so that specific materials, equipment, and resources can be allocated over the entire duration of the program.

3.3 WORK PRIORITIZATION

To become more efficient in work prioritization, Hydro One has developed processes to improve investment prioritization and the assessment of asset risk. The investment prioritization process outlined in Section 2.1.5.1 of the Distribution System Plan (DSP) (Exhibit B1, Tab 1, Schedule 1), is a multi-criteria analysis which quantifies business risks so that objective decisions can be made respecting priorities in order to align cost effectiveness, asset and business needs and customer expectations. The asset risk assessment process outlined in Section 2.1.4.2 of the DSP, is Hydro One Distribution's new methodology for identifying current asset needs and creating a line of sight to future needs. This new methodology enables a holistic view of asset risk that improves decision making through the systematic evaluation of risk associated with distribution assets.

3.4 STRATEGIC SOURCING

Collaborative planning and strategic sourcing are fundamental components of the work execution strategy. Hydro One has an increased focus on streamlining sourcing events in order to drive increased value for the company. These initiatives ensure contracts are in place and long lead-time materials are being effectively managed to mitigate any potential impacts on Hydro One program execution due to delays in availability of materials. Strategic sourcing, which includes "bulk purchasing", is a significant contributor to Hydro One's cost savings initiatives and the Company's ability to complete the work programs.

Strategic sourcing also ensures materials arrive when scheduled so that work can be executed efficiently. Hydro One has implemented an increased focus on supplier performance management that will address any issues with delayed material delivery. Delayed delivery of material can have far reaching impact on many crews, outages and customers. Spend analysis, strategic and tactical sourcing, and developing a sourcing strategy to maximize value through negotiations, vendor management, and continuous improvements, will all play a key role in ensuring the Company's work execution needs are being met.

3.5 LOGISTICS SUPPORT

An important element of the Work Execution Strategy is optimizing the material stocked in the Company's warehouse. Hydro One has embarked on a Logistics approach to support the need for project and program timelines. The strategy provisions core materials from stock rather than waiting to purchase these materials after projects have received final approval. The materials lead times are therefore reduced. Materials are staged from a central warehouse and deployed as soon as they are needed on the work site. The result is that materials delays associated with vendor lead times have been largely eliminated.

3.6 IMPROVED DESIGNS

An increased use of standardized and modular designs are being used to streamline the design process, allowing faster, more consistent, and lower cost work execution. This reduces the demands on specialist engineering resources, improves installation and maintenance efficiency, drives lower costs, optimizes inventory management of standardized materials, and maximizes opportunities for strategic sourcing savings. Standardized designs are already in use for distribution lines and stations. New designs currently under development include standardized generation connection designs. In addition, Engineering designs are being advanced in the project schedule to allow for field design review. This ensures that constructability and maintainability concerns are addressed, promoting safe work execution and minimizing re-design effort.

Hydro One has implemented “virtual designs” using technology to limit travel time of staff in order to complete distribution designs (e.g. railway, water and pipeline crossing designs). The result is a decrease in time required to complete designs and extended availability of resources, therefore increasing the number of designs the Company can complete.

3.7 STAFFING STRATEGY

Hydro One utilizes a work-based approach to staffing, whereby the Company sources staff according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff.

3.7.1 OUTSOURCING

Hydro One has a highly flexible Construction workforce that is able to meet the demands of the work program. Although Hydro One's construction workforce is scalable, there is a practical limit to its size defined by the volume of work that can be safely and efficiently planned and managed by internal staff. The work contracted out, typically greenfield and brownfield projects, as well as some major refurbishment projects, is completed using a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis. Through a combination of regular staff, casual trades, and overtime, skill sets and cost are optimized.

Hydro One utilizes contractors for staff augmentation purposes when it is recognized that some specific skill sets required on a non-regular basis are not available internally. This is necessary to ensure the efficient execution of the work program and address the ongoing variation in requirements for specific skills. Due to the shortage of skilled trades required to complete the Company's growing work program, Hydro One is focusing more on its outsourcing strategy through the use of Request for Proposal ("RFP"). By stipulating the Company's business requirements and necessary skill set, Hydro One maintains control of the scope of work while driving price transparency and efficiency amongst proponents. The success of the Company's cable locate outsourcing initiative has demonstrated the benefits of outsourcing by reducing costs and optimizing the use of internal resources. The significant increase to Hydro One's meter change projects is an example of an area the Company has identified as key outsourcing initiatives in the coming years.

3.7.2 RESOURCES AND ENHANCED EXPERTISE

A key component of the work execution strategy is the optimal deployment of internal resources to maximize work program execution. This includes utilizing Hydro One's robust apprenticeship program with the guidance of experienced tradespersons to learn the required skills as well as integrating experienced acquisition staff into the Company.

This fast tracking of skills development allows projects to be efficiently delivered while ensuring qualified resource succession. To mitigate the shortage of skilled trades, Hydro One maintains relationships with the Ministry of Colleges and Universities and the Ontario College of Trades to influence curriculum, stimulate interest and share resources. These relationships are critical to ensuring Hydro One can execute its work program in future years.

Hydro One's staffing strategy also addresses issues such as staff attrition, enhanced internal training programs, educational partnerships and opportunities, and increased utilization of casual workers and temporary employees. More information regarding Hydro One's staffing strategy is available in Exhibit C1, Tab 2, Schedule 1.

3.8 IMPROVED WORK METHODS

Productivity and cost efficiencies are being recognized in the field through improved work methods. The implementation of Move to Mobile will enable bundling of work geographically and real-time asset validation. Work will be easier to plan, schedule and dispatch, which reduces the administrative workload of field staff. As a result, Hydro One will better utilize its resources and become more efficient in completing its work program. Geographic Information System ("GIS") is an integrated component of business initiatives such as Move to Mobile, cable locate outsourcing and the implemention of smart grid technology to modernize the distribution system. This helps drive the Company in a direction that utilizes technology to streamline workflows, improve asset data, mapping and employee safety. GIS technology also plays a key role in improving daily maintenance of the system to help address reliability concerns and assist in planning capital improvements to the electrical system.

Utilization of equipment enhancements such as the Pole Setter for Provincial Lines and the Feller-Buncher for Forestry has improved work execution efficiencies. The Feller-Buncher is a fleet vehicle that significantly increases the efficiency of the Forestry division by cutting trees and stacking them in clusters. This machine reduces the total labour time required per tree by 80%. The Feller-Buncher is also used to widen and reclaim heavily backlogged and overgrown corridors.

Hydro One's Forestry Management System application is a reporting tool for Forestry programs and is approaching end of life. Hydro One is currently developing a business case to leverage the Move to Mobile core functionalities with added business capabilities to gain program, scheduling, resourcing and fleet efficiencies. These efficiencies will lead to cost-savings and improve overall system reliability as it relates to tree-related outages. Hydro One is also looking to incorporate next generation technologies including Light Detection and Ranging ("LiDAR") to integrate into the program mix. LiDAR is a surveying technology that measures distance by illuminating a target with a laser light. LiDAR technology has been increasingly adopted within the utility industry to patrol transmission lines to assess the vegetation growth and the need for pruning. Hydro One is currently validating the results of this technology through field visits to determine if the Company's requirements identified in the pilot project were met and the technology could be integrated into future vegetation maintenance plans.

Another area of work showing efficiency gains is in storm and outage restoration. The integration of smart meter data with the Outage Response Management System (“ORMS”) to confirm outage locations has greatly reduced interruption time. Prior to this capability, Hydro One relied on customers to call in when there was an interruption or power quality issue and the lines staff would patrol the area to locate the site of the cause. With the GIS enabled, the field staff are able to access GPS coordinates for most of the Company’s distribution assets. This aids greatly in directing staff with limited knowledge of a geographical area to the outage location. Once the cause of the outage has been rectified, the “pinging” of the smart meter again can confirm the restoration of power to all affected customers.

4. SUMMARY

There are many factors changing the volume, characteristics and priorities of Hydro One Distribution’s work program. The Company has developed a comprehensive strategy that embraces these factors while maximizing its work execution capacity. The strategy remains focused on Hydro One’s overall business objectives: safety, reliability, innovation, protecting the environment, employee engagement, shareholder value and meeting customer commitments. Continuing to identify efficient and cost-effective ways to execute work will not only enable Hydro One to complete its expanding work program but will play a critical role in the Company’s long term success.