THUNDER BAY SUB-REGION INTEGRATED REGIONAL RESOURCE PLAN

Part of the Northwest Ontario Planning Region | December 16, 2016

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Integrated Regional Resource Plan

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 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)
- Thunder Bay Hydro Electricity Distribution Inc.

The Working Group assessed the adequacy of electricity supply to customers in the 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 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. In accordance with the regulatory principles outlined within the Transmission System Code[1], where growth in the sub-region is directly related to potential large industrial developments, the onus to initiate implementation of the connection facilities lies with the customer(s).

[1] http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Transmission_System_Code.pdf

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List of Abbreviations

Abbreviation	Description
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
C&S	Codes and Standards
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
EE	Energy Efficiency
FIT	Feed-in Tariff
GS	Generating Station
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
ICI	Industrial Conservation Initiative
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
MVA	Mega Volt Ampere
MW	Megawatt
NOMA	Northwest Ontario Municipal Association
NUG	Non-Utility Generator
OEB or Board	Ontario Energy Board
OMA	Ontario Mining Association
OPA	Ontario Power Authority
OPG	Ontario Power Generation
ORTAC	Ontario Resource and Transmission Assessment Criteria

Abbreviation	Description
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
Resolute FP	Resolute Forest Products
RIP	Regional Infrastructure Plan
ROW	Right of Way
SCRE	Simple-Cycle Reciprocating Engine
SLD	Single Line Diagram
SS	Switching Station
Thunder Bay Hydro	Thunder Bay Hydro Electricity Distribution Inc.
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt-hours
ULTC	Upper Load Tap Changer
Working Group	Technical Working Group for Thunder Bay Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") for the Thunder Bay Sub-region addresses the electricity needs for the sub-region over the next 20 years from 2016 to 2035 (study period). The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group (the "Working Group") for the Thunder Bay Sub-region. The Working Group is composed of the IESO, Hydro One Distribution and Hydro One Transmission,[2] and Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay Hydro").

The area covered by the 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 extending from the north shore of Lake Superior to the southern shore of Lake Nipigon, and from the Township of Nipigon to Kakabeka Falls. This sub-region is characterized by:

- **Diverse communities**: In addition to the "unorganized areas"[3] in the Thunder Bay area, there are 10 municipalities and two First Nation communities in the sub-region, all of which are listed in Section 4.1. Each of the communities has different local priorities and electricity needs.
- **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 prices and changes in economic growth. These factors can cause material changes in annual industrial electricity demand and uncertainty in the sub-region's electricity demand forecast.
- **Complex electricity infrastructure network:** The sub-region's electricity system is comprised of a 115 kilovolt ("kV") regional system, local distribution networks and variable, local generation resources. This system not only supplies the communities and customers in the Thunder Bay Sub-region, it also provides an important source of supply to the Greenstone sub-system. The interactions between the bulk, regional and distribution network have an impact on the reliability of supply for the Thunder Bay Sub-region.

This IRRP was developed in consideration of these characteristics. Given the uncertainties associated with the timing and magnitude of potential industrial developments, the Working

[2] 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.
[3] 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.

Group studied regional electricity needs and solutions under three demand forecast scenarios (Medium, High and Low) as described in Section 5.3.4., and developed a flexible, comprehensive, integrated plan to accommodate them. 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 sub-region's 115 kV regional transmission system. However, given the complex nature of the electricity system and the diverse needs in this sub-region, there are also bulk, distribution and community energy planning activities. Section 3 describes the linkages between different types of electricity planning in Ontario and the importance of coordinating regional planning with both bulk and distribution system planning to consider any overlaps as it bridges all levels of planning.

This IRRP fulfills the requirements of 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 Thunder Bay is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in 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 the Thunder Bay Sub-region are presented in Section 6;
- A summary of community, Indigenous and stakeholder engagement to date is provided in Section 7; and
- A conclusion is provided in Section 8.

2. The Integrated Regional Resource Plan

The 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, flexibility and also the diverse needs and specific 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 in anticipation of these varying conditions.

In addition to regional planning, there are also bulk, distribution and community energy planning activities underway in the sub-region. While these activities are beyond the scope of the regional planning process, they were considered in the development of this IRRP.

The needs and recommended actions are summarized below.

2.1 The 20-Year Plan (2016-2035)

The Working Group identified one minor need in the Thunder Bay Sub-region that requires near-term action – increasing the thermal rating of 115 kV circuit R2LB. No other investment or development work is required to be undertaken at this time.

Under the Low and Medium demand forecast scenarios, supply and reliability on the Thunder Bay 115 kV system is adequate for the entire planning period. Under the High demand forecast scenario, there is a need for 20 megawatts ("MW") of additional supply capacity by 2030. Additionally, a station capacity need could arise at Port Arthur Transformer Station ("TS") by 2033.

Given that the potential needs are over 13 years away, development work is not required at this time. Instead, the Working Group has sought to lay the groundwork for the next planning cycle by exploring potential options for the Thunder Bay 115 kV system and Port Arthur TS and monitoring demand growth closely to determine if and when an investment decision would be required.

End-of-life replacements or sustainment activities were also identified in this area, and their potential implications on regional planning are discussed in Section 6.

Recommended Actions

1. Increase the thermal rating of 115 kV circuit R2LB

The Working Group recommends increasing the thermal rating of circuit R2LB to that of the companion circuit R1LB, or higher, by increasing the clearance of its limiting span between Lakehead TS and Birch TS. This line work was completed by Hydro One in Q4 2016.

2. Monitor electricity demand growth closely to determine if and when an investment decision for the Thunder Bay 115 kV system is required

On an annual basis, the Working Group will review electricity demand growth in the Thunder Bay and the Greenstone areas with the members of the Local Advisory Committees[4] ("LACs") in each of the respective areas. This information will be used to determine if and when an investment decision for the Thunder Bay 115 kV system is required.

3. Monitor electricity demand growth closely to determine if and when a decision for Port Arthur TS is required

The Working Group will review electricity demand growth in the area served by Port Arthur TS on an annual basis with the members of the LAC. This information will be used to determine if and when an investment decision for the transformer station is required.

[4] Local Advisory Committee Terms of Reference - http://www.ieso.ca/Documents/Regional-Planning/LAC-Terms-of-Reference.pdf

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 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 ("PPWG Report"), [5] 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 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 straightforward "wires" solution is the only option, in which case 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 regional issues where infrastructure investments do not require regional coordination and may be planned directly by the distributor and/or transmitter outside of the coordinated 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 two-week comment period prior to being finalized.

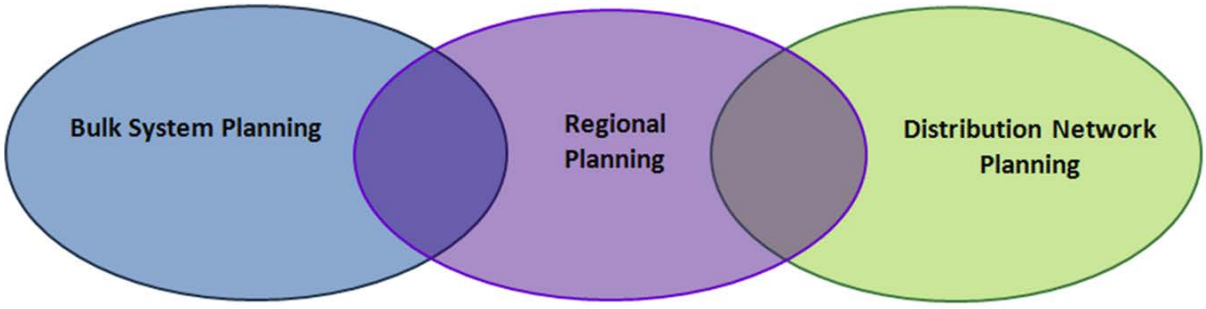
The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and they may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, Indigenous 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



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

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 enables 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

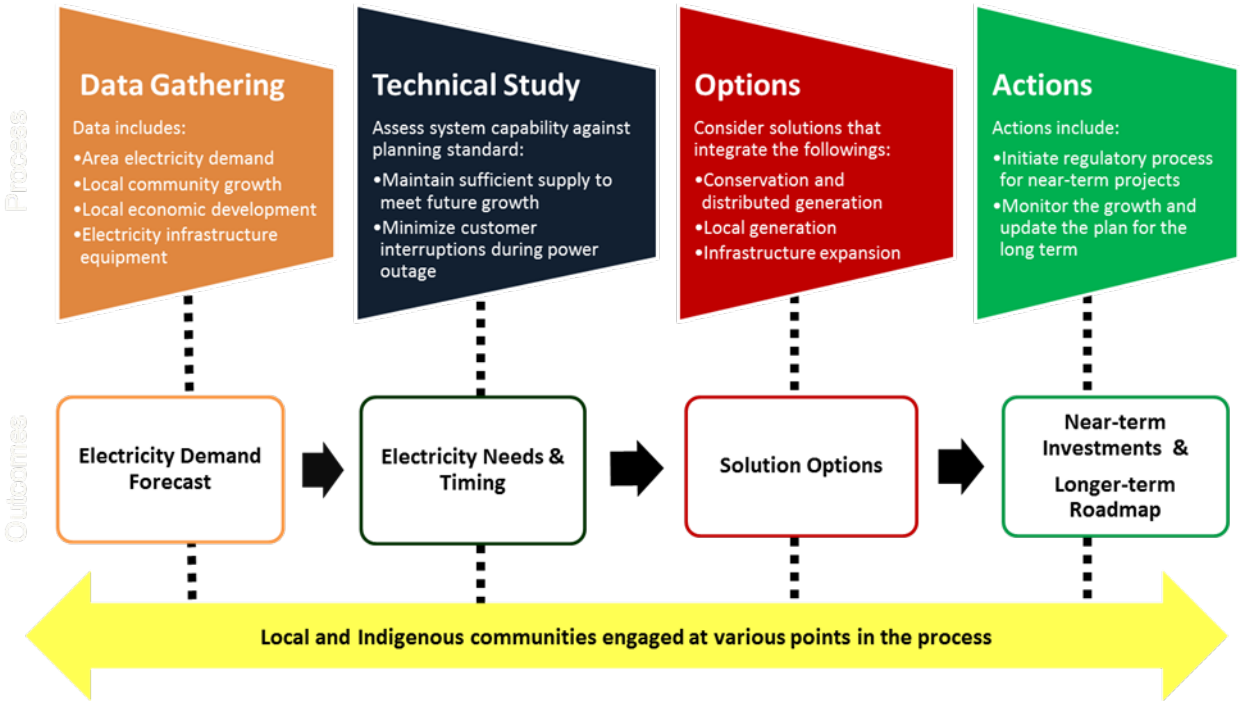
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply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

Planning in northwestern Ontario requires specific consideration. 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. 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 the sub-region based on different demand forecast scenarios and seeks to ensure flexibility is maintained so 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 Thunder Bay Sub-region Working Group and IRRP Development

In 2014, the lead transmitter – Hydro One – initiated a Needs Screening process for the Northwest Ontario Region. The North of Dryden IRRP[6] and Remote Community Connection Plan[7] were already underway prior to the regional planning process being formalized and were therefore not included within the scope of the Needs Screening process.

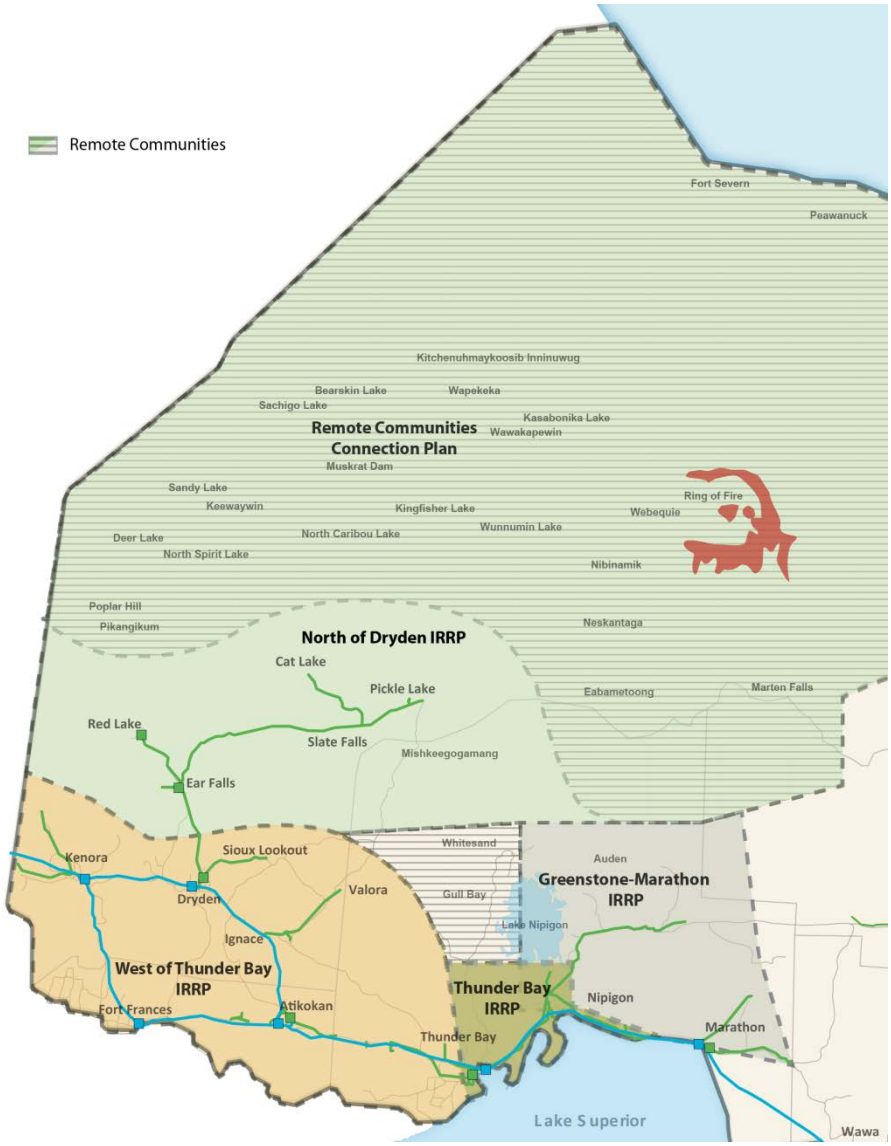
The Northwest Ontario Region Needs Screening study team determined that the need for coordinated regional planning had already been established and that a formal Needs Screening process was not required for the Northwest Ontario Region. A Scoping Assessment was then

[6] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/North-of-Dryden.aspx
[7] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan.aspx

initiated to identify new planning sub-regions within the Northwest Ontario Region that were not already identified in previous planning studies.

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, which incorporated feedback from communities, stakeholders and meetings with First Nation communities and Métis council representatives. The Scoping Report identified Thunder Bay as one of three new planning sub-regions for coordinated regional planning, as illustrated in Figure 3-3.

Figure 3-3: Northwest Ontario Planning Region and Sub-regions



Subsequently, the Working Group was formed to carry out the IRRP for Thunder Bay Sub-region. The Working Group is led by the IESO and consists of representatives from Hydro One Transmission, Hydro One Distribution and Thunder Bay Hydro Electricity Distribution Inc.

3.4 Community and Stakeholder Engagement

For the purpose of regional planning, municipal and community meetings were held at the start of the IRRP development process and a LAC was established for this sub-region. The LAC was informed of the planning activities in the area and the members provided input to the Working Group on the status of local growth and developments, local planning priorities, energy planning activities, local electricity concerns and opportunities to implement community-based energy solutions. Greater detail regarding community and stakeholder engagement activities is provided in Section 7 of this report.

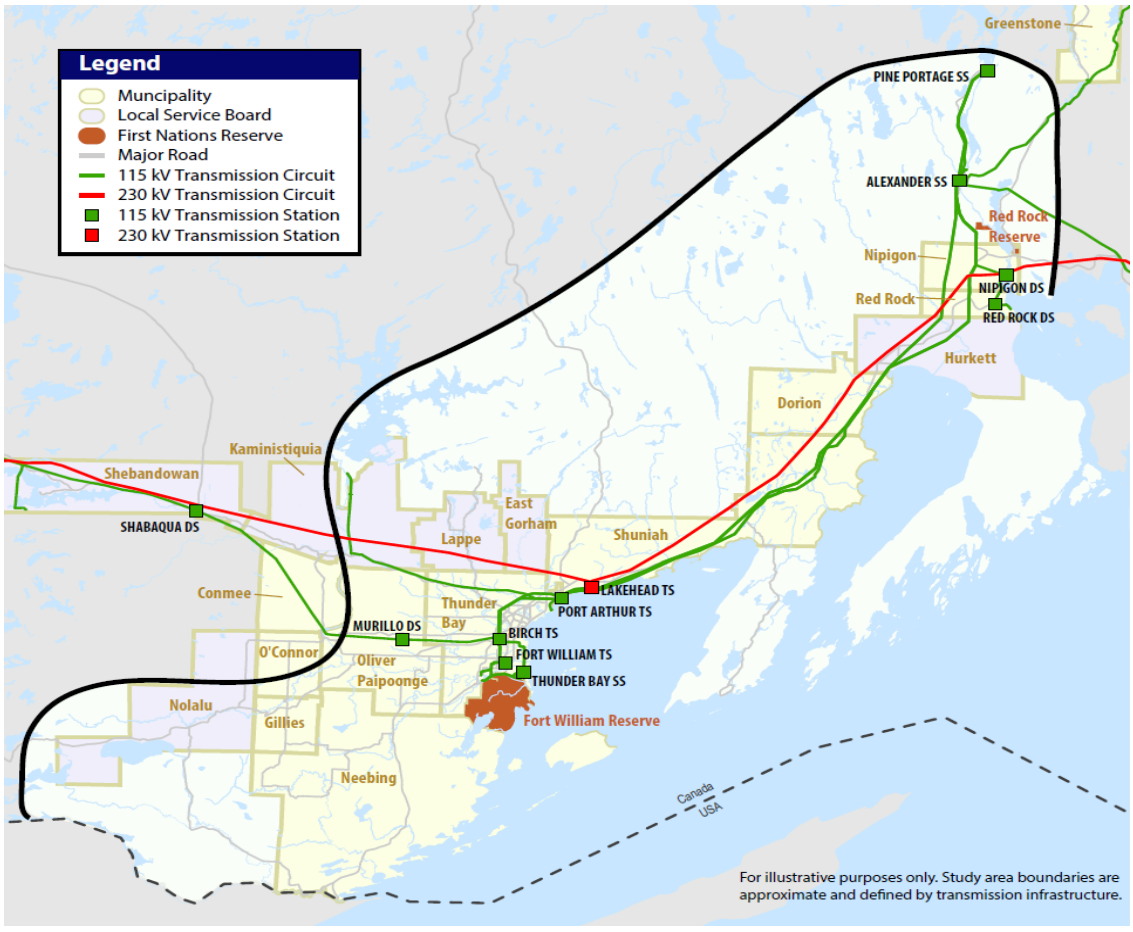
4. Background and Study Scope

The scope of this IRRP and description of the sub-region are set out in Section 4.1. Section 4.2 details the electricity system supplying the sub-region.

4.1 Thunder Bay Sub-region - Study Scope

The Thunder Bay IRRP assesses the adequacy and reliability of the regional electricity system supplying the Thunder Bay area and identifies integrated solutions for the 20-year period from 2016 to 2035. The Thunder Bay Sub-region is defined as the area extending from the north shore of Lake Superior to the southern shore of Lake Nipigon, and from the Township of Nipigon to Kakabeka Falls. In addition to the City of Thunder Bay, a number of municipalities and local service boards are located within this area, as well as Fort William First Nation and Red Rock Indian Band. The approximate geographical boundaries of the sub-region are shown in Figure 4-1.

Figure 4-1: Geographical representation of Thunder Bay Sub-region



The sub-region includes the following municipalities:

- City of Thunder Bay
- Township of Red Rock
- Township of Nipigon
- Municipality of Neebing
- Municipality of Oliver Paipoonge
- Municipality of Shuniah
- Township of O'Connor
- Township of Conmee
- Township of Dorion
- Township of Gilles

In addition, there are communities within a number of unorganized areas in the sub-region.

The Thunder Bay Sub-region includes the following First Nations communities:

- Fort William First Nation
- Red Rock Indian Band

The focus of this IRRP is on the reliability and adequacy of the 115 kV regional transmission system in the Thunder Bay area. The adequacy and reliability of the 230 kV bulk transmission and local distribution system supplying in the Thunder Bay area are not within the scope of the Regional Planning Process; however, relevant bulk and distribution system conditions are taken into account in the regional planning process.

It is also important to note that connection assessments of generation resources for procurement programs, such as the Feed-in-Tariff ("FIT"), are not within the scope of this IRRP. Generation projects participating in procurement programs will be assessed according the rules and specifications of the procurement programs. However, potential generation projects are considered in the IRRP.

4.2 Thunder Bay Electricity System

The Thunder Bay electricity system consists of local generation resources, 230 kV bulk transmission, 115 kV regional transmission and low-voltage distribution networks. Through the Lakehead TS autotransformers, power is delivered from the 230 kV bulk transmission system to the customers connected to the regional 115 kV system and low-voltage distribution networks.

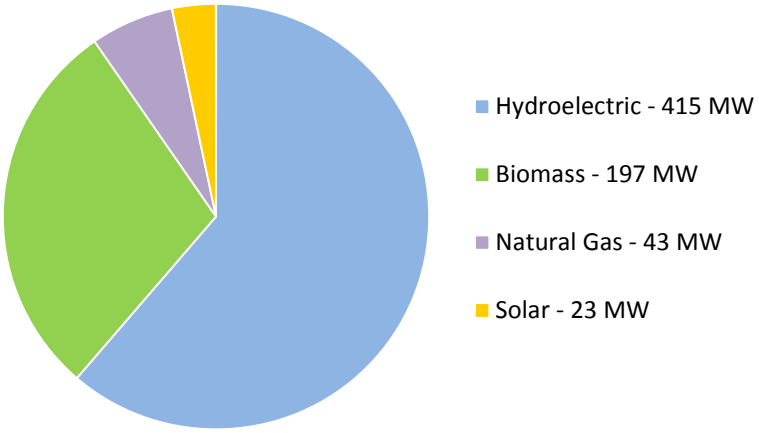
Generation resources connected to the 115 kV system provide a significant source of additional supply to the area. Notably, generator output in the area often exceeds local demand, and the surplus energy is delivered to the rest of the province through the Lakehead TS autotransformers.

The following sections discuss these components in more details.

4.2.1 Local Generation Resources

There are four types of generation resources totaling 678 MW of installed capacity in the Thunder Bay Sub-region: hydroelectric, biomass, natural gas and solar, as shown in Figure 4-2.

Figure 4-2: Installed Capacity of Generation Resources in the Thunder Bay Sub-region



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 (or sub-region) is the highest. The above resources are all potential sources of energy, but only a certain amount of capacity from these resources can be relied upon at the time of peak due to their variable nature. Reliable capacity varies by resource type and is discussed further below and in Appendices A and B.

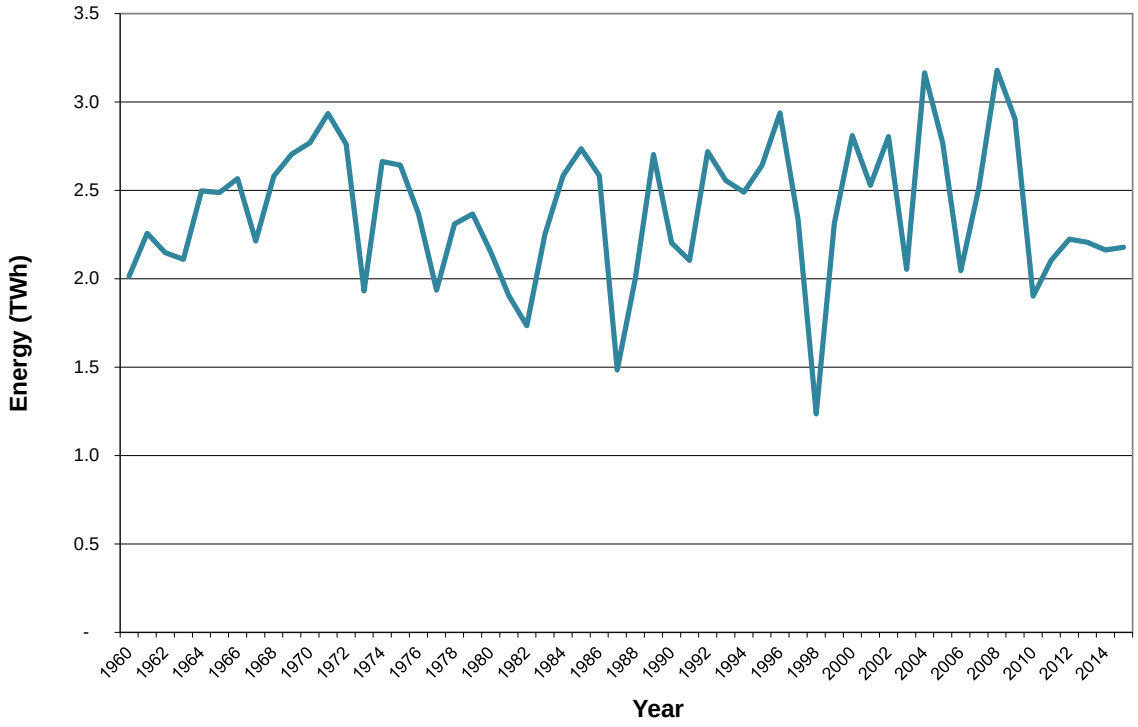
In the Thunder Bay Sub-region, electricity demand typically peaks during the evening in the winter. For the purposes of infrastructure planning, the installed capacity of local generation is adjusted to reflect the reliable capacity or power output at the time of the local winter peak.

Below is a description of the resources types and their expected power output at the time of the Thunder Bay winter peak.

- **Hydroelectric:** Hydroelectric resources account for over 60% of the installed capacity in the sub-region. The major facilities are Alexander Generating Station ("GS"), Aguasabon GS, Cameron Falls GS, Kakabeka GS, Pine Portage GS and Silver Falls GS. Hydroelectric output is highly variable and is dependent on water conditions. As prescribed by ORTAC, this study assumes drought water conditions, in which reliable power output from the hydraulic facilities in the Thunder Bay Sub-region is reduced to about half of installed capacity. This is described in more detail in Appendix B.

  To illustrate the variability of water conditions in the Thunder Bay Sub-region, Figure 4-3 shows the annual energy output from the local generators over the last 55 years.

Figure 4-3: Thunder Bay Sub-region Annual Hydraulic Generation Production (1960-2015)



- **Biomass:** In 2014, Thunder Bay GS, then a coal-fired generation facility located in the City of Thunder Bay, was converted to burn advanced biomass (wood pellets). This facility currently is contracted with the IESO until 2019 and has the capacity to generate up to 150 MW. Due to fuel restrictions and a slow start-up time, the facility is considered unable to provide firm supply capacity to the Thunder Bay Sub-region for the purposes of this study. Thunder Bay GS, however, could provide some back-up capability to this sub-region in the event of major transmission and generation outages.

Resolute Forest Products ("Resolute FP") has two active biomass generating units at its Thunder Bay facility with installed capacities of 78 MW and 38 MW, operating at a combined 60% annual capacity factor. The boilers feeding the generating units use biomass as the primary fuel. Operation of the generators is closely tied the facility`s pulp production processes as the main fuel source for the boilers is biomass, a by-product of pulp production. Resolute FP is under contract with the IESO until 2023 for an average annual generation capacity of 40 MW. For the purpose of this study the generators at Resolute FP were considered to operate at a combined 70 MW output during local system peak.

- **Natural Gas:** The Thunder Bay Sub-region has one natural gas generating station - Nipigon GS, with an installed capacity of 43 MW. Nipigon GS is a natural gas fueled combined-cycle generating facility with a Non-Utility Generator ("NUG") contract that expires in 2022. The facility used enhanced combined-cycle generation, producing electricity from a gas turbine and a steam turbine generator set that uses steam produced from exhaust gases from nearby natural gas transmission compressor station turbines. Nipigon GS operates at an average annual capacity factor of approximately 90% and is considered to provide 38 MW of reliable supply capacity to the Thunder Bay Sub-region for the purpose of this study for the duration of its contract.

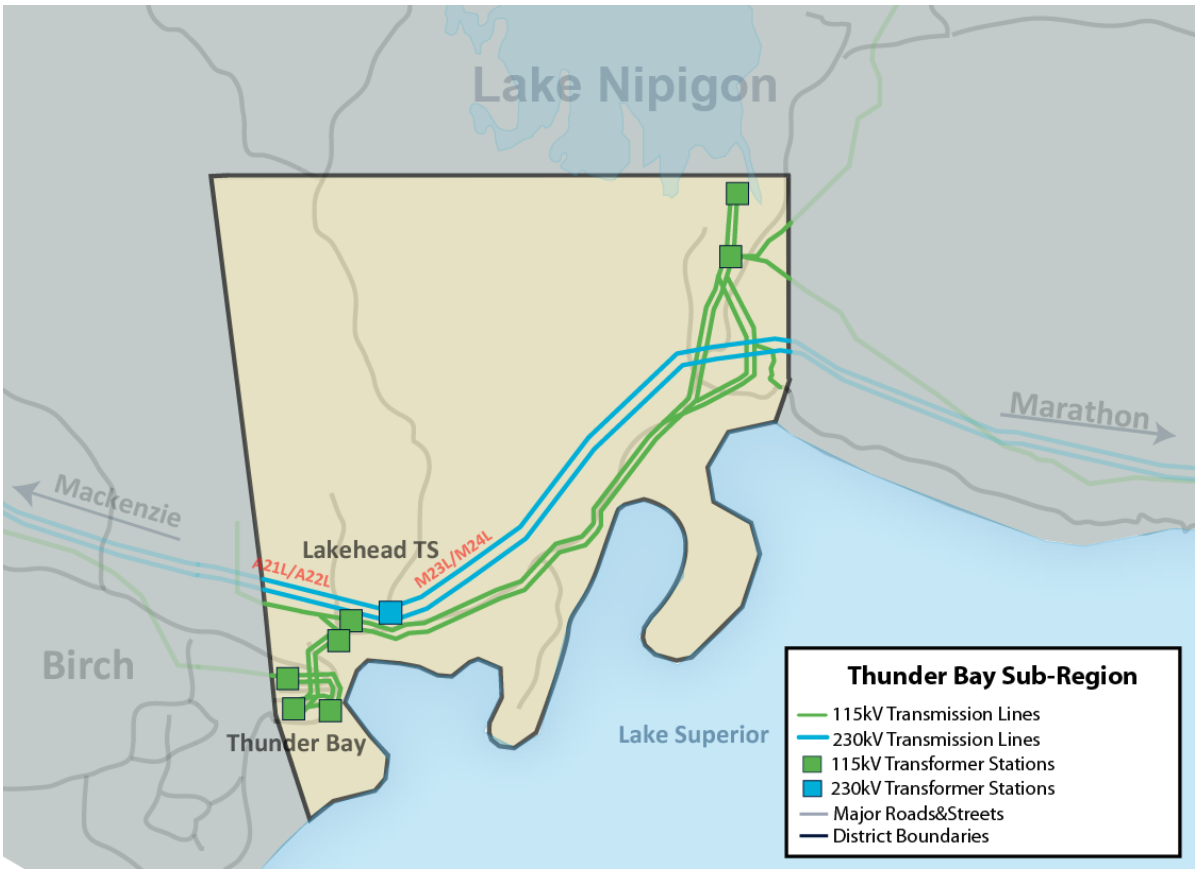
- **Solar:** The Thunder Bay Sub-region has over 300 distribution-connected solar facilities with a combined installed capacity of about 23 MW. Facilities range from 3 kW rooftop microFIT projects to 10 MW solar farms procured under the Renewable Energy Standard Offer Program. Solar is an intermittent 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 in the evening or overnight in the winter, solar resources are not expected to contribute to the reduction of the local peak demand.

  As mentioned above, all the solar projects in the sub-region are distribution-connected and their capacity contribution is embedded in the historic load data recorded at the 115 kV step-down transformer station meters. Therefore, solar projects installed in 2015 or earlier are inherently included in the base year of the demand forecast. Those expected to come into service within the study period (2016 to 2035) were de-rated to a 4% effective capacity factor when developing the net demand forecast for this study. More information on distribution-connected solar facilities is available in Appendix A.

4.2.2 Transmission System

The transmission system within the Thunder Bay Sub-region consists of 230 kV and 115 kV lines and stations, as shown in Figure 4-4.

Figure 4-4: Thunder Bay Sub-region Transmission System



The Thunder Bay transmission system consists of the 115 kV network tied to the bulk-230 kV system at Lakehead TS, just east of Thunder Bay. There are two 230/115 kV autotransformers at Lakehead TS and they provide a significant source of supply to the area from the provincial grid.

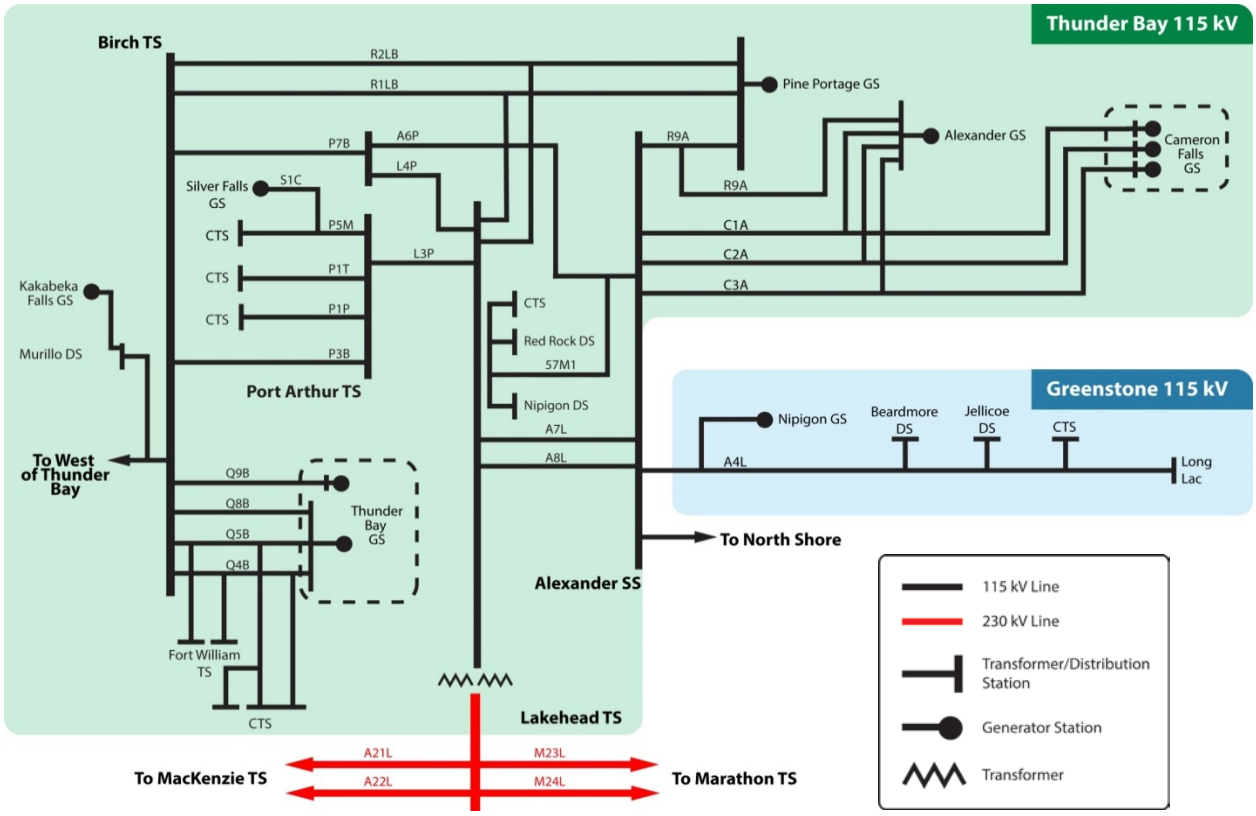
Loads in the area, including those supplied by the area's two LDCs – Thunder Bay Hydro and Hydro One Distribution, - as well as the transmission-connected customers, are supplied by step-down transformer stations connected to the 115 kV system. This network also integrates the generation stations described in Section 4.2.1 and provides links to the West of Thunder Bay

Sub-region (through circuit B6M) and to the Greenstone sub-system within the Greenstone-Marathon Sub-region[8] at Alexander Switching Station ("SS").

Regional 115 kV System

The Thunder Bay 115 kV system, shown in Figure 4-5, enables power to be delivered to the customers and communities within the Thunder Bay Sub-region.

Figure 4-5: Thunder Bay Sub-region 115 kV system



The focus of this IRRP is on the reliability and adequacy of the Thunder Bay 115 kV regional transmission system. However, the Greenstone sub-system, shown in Figure 4-5, shares supply points with the Thunder Bay system (Lakehead TS and Nipigon GS) and can impact the supply capability of the Thunder Bay area. Growth in the Greenstone sub-system is therefore considered in this study and discussed further in Section 5.4.

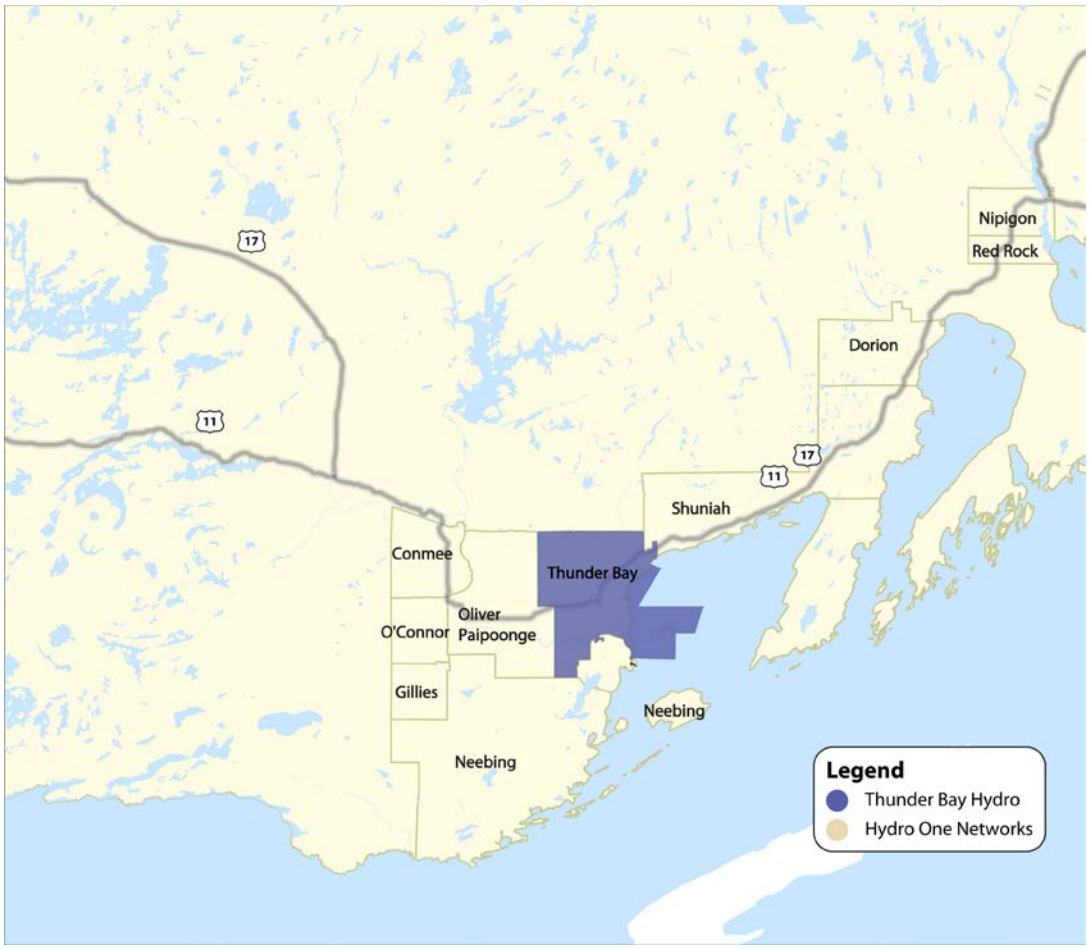
[8] Link to the Greenstone-Marathon Regional Planning webpage - http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

4.2.3 Distribution System

From the regional 115 kV system, power is delivered through transformer stations to the low-voltage distribution systems. There are 11 transformer stations, which are customer- or utility-owned, servicing the communities and industrial customers in the sub-region. Given the large geographic and sparsely populated area, some communities and customers in the Thunder Bay Sub-region are supplied by long radial distribution lines, which provide only a single source of supply.

The low-voltage distribution systems in the sub-region are managed and operated by two LDCs: Thunder Bay Hydro and Hydro One Distribution. The service areas for the two LDCs are illustrated in Figure 4-6.

Figure 4-6: LDC Service Area



Distribution system planning is a separate process led by the LDCs and is generally beyond the scope of regional planning. However, the regional planning process allows for coordination with distribution system planning with respect to shared infrastructure such as the step-down transformer stations that transfer power from the 115 kV transmission system to the low-voltage distribution system.

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 peak demand – the one-hour period each year when total regional demand for electricity is the highest.

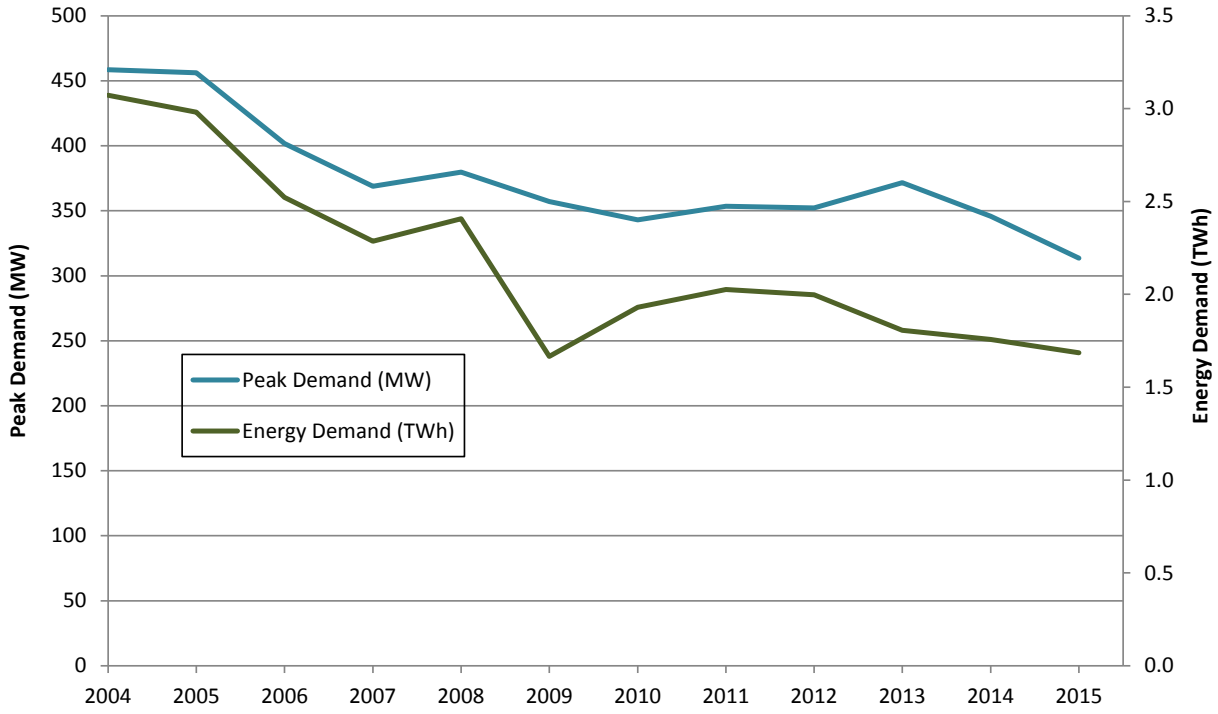
This section describes the development of the demand forecast for the Thunder Bay Sub-region. Section 5.1 describes electricity demand trends in the sub-region from 2004 to 2015. Section 5.2 provides an overview of the demand forecast methodology used in this study and Section 5.3 summarizes the various demand scenarios. Finally, Section 5.4 discusses how load growth in the Greenstone sub-system can impact the Thunder Bay 115 kV system.

5.1 Historical Electricity Demand

The Thunder Bay Sub-region's peak electrical demand typically occurs overnight in the winter. This is driven by a relatively large electrical heating demand in the residential sector as well as by large industrial customers who increase production overnight to reduce their electricity costs.

As shown in Figure 5-1, peak demand in the region decreased from a high of 460 MW in 2004 to 310 MW in 2015. This decline is primarily due to closures and reduced production from large industrial customers in the pulp and paper and forestry sectors.

Figure 5-1: Historical Peak Demand in the Thunder Bay Sub-region (2004-2015)



5.2 Methodology for Establishing Planning Forecast Scenarios

Demand scenarios were developed to assess the supply capability and reliability of the Thunder Bay electricity system over the planning period. For the purpose of regional planning, these demand scenarios take into consideration the following components:

- Gross winter demand forecasts developed by the LDCs and gross, winter forecast scenarios developed for existing and potential transmission-connected customers
- Estimated peak demand savings from provincial energy conservation targets
- Expected peak capacity contribution of contracted DG

Gross demand forecast scenarios were developed based on the expected peak demand requirements from LDCs and from transmission-connected customers in the Thunder Bay area. For each scenario, growth projections were modified to reflect the estimated peak demand savings from provincial energy conservation targets and contracted DG to produce the planning forecast scenarios that are used to assess the needs.

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 for this sub-region will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan.

The methodology and assumptions used for the development of demand forecast scenarios are described in detail in Appendix A.

5.3 Development of Planning Forecast

As a first step to developing a planning forecast, the Working Group developed forecasts for the gross electricity requirement from distribution-connected customers and forecast scenarios for transmission-connected customers in the Thunder Bay Sub-region.

5.3.1 Gross Demand Forecast Scenarios

Distribution-Connected Customers

The gross demand forecasts for distribution-connected customers were provided by the two LDCs in the Thunder Bay Sub-region. Gross LDC electrical consumption is expected to see a relatively strong growth rate, about 1.5% per year on average (ranging from about 0.5 to 3.5% per year depending on the area). Most of this growth can be attributed to the residential and commercial sectors with some growth coming from small industrial customers. Descriptions of the LDCs' forecast assumptions and methodology can be found in Appendix A.

Transmission-Connected Customers

The gross demand forecasts for transmission-connected customers were developed based on information gathered from and projections developed by the customers. The IESO and Hydro One Transmission regularly communicate with existing and potentially new transmission-connected customers to understand their electricity demand requirements and development status.

Over the planning period, there is potential for significant demand growth in Thunder Bay Sub-region from large transmission-connected industrial customers. This includes TransCanada's proposed Energy East Project and new mining development north of Thunder Bay. Growth in transmission-connected industrial customers could potentially add up to 40 MW of incremental electricity demand in the Thunder Bay Sub-region by 2035. Industrial customers are

particularly sensitive to changes in economic conditions. The timing, location and scale of industrial developments is therefore uncertain and will depend on a number of external factors such as commodity prices, the economic viability of industrial projects, environmental approvals and considerations, and the ability to secure capital. Often these factors can lead to material increases or decreases in annual demand.

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 (Medium, High and Low) are described in Section 5.3.4.

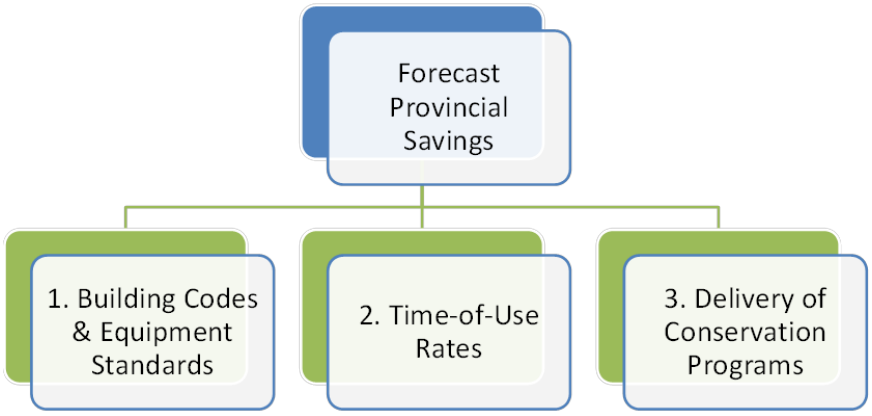
The specific forecasting methodology and assumptions for the gross demand forecast scenarios are included in Appendix A.

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 use of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is incentivised and 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 an updated 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 sub-region and, as further described below, was 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 CFF 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 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 portion of the 7 TWh of provincial energy savings target allocated to the Thunder Bay Sub-region is estimated to offset approximately 27 MW of the forecast peak demand between 2016 and 2035. 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 same conservation assumptions were applied to the gross demand scenarios discussed in Section 5.3.1.

The estimated annual peak demand savings from the provincial energy conservation targets in the Thunder Bay Sub-region are summarized in Appendix A.

5.3.3 Expected Peak Demand Contribution of Existing and Contracted Distributed Generation

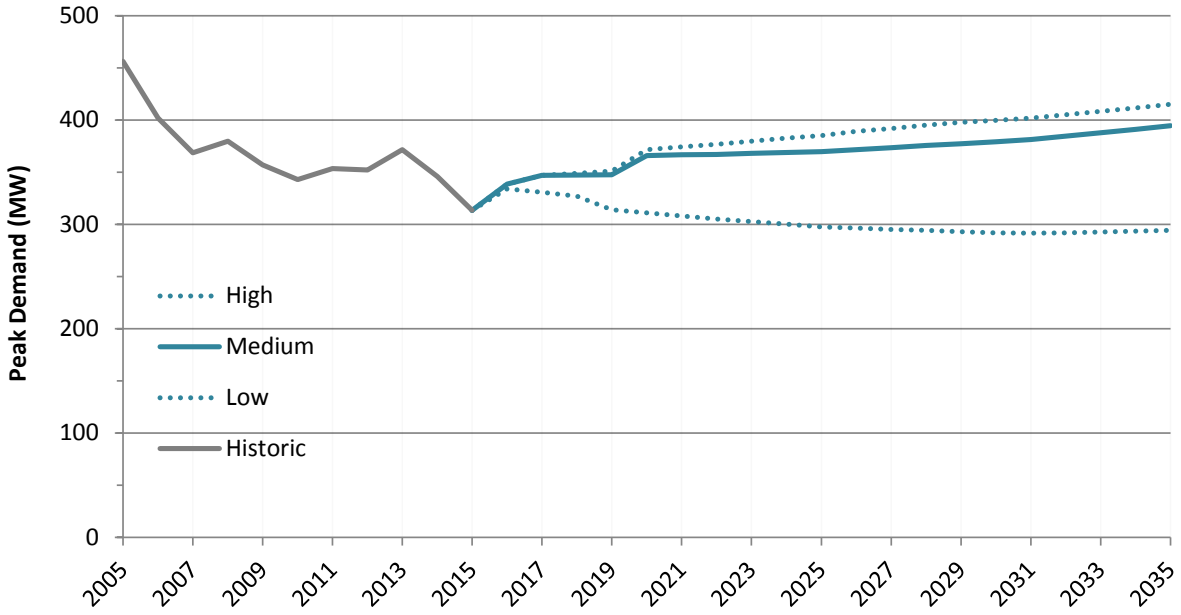
As of 2015, about 27 MW of DG was installed in the Thunder Bay Sub-region and is estimated to have reduced the regional peak demand by about 5 MW. Only contracted future DG was included in the planning forecast and any other future uptake is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the 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 Thunder Bay Sub-region for the planning period 2016 to 2035. The scenarios all represent plausible outcomes that are 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



Medium Scenario:

Under the Medium scenario, the peak electricity demand in the Thunder Bay Sub-region is expected to increase from 325 MW (2015 historic peak) to 400 MW by 2035. As shown in Figure 5-3, by the end of the planning period, the peak demand will be similar to the 2006/2007 historic levels under the Medium scenario. The growth in this scenario includes growth in the residential and commercial sectors and increased production in mining north of Thunder Bay. This scenario also assumes stabilization of the pulp and paper sector (i.e., no further decline in production from 2015).

For the purpose of regional planning, it is also assumed that the proposed Energy East pipeline will proceed and that one oil pumping station will be supplied from the Thunder Bay transmission system under the Medium scenario. The pumping station would require approximately 17 MW of electricity supply by 2020.

High Scenario:

In addition to the growth identified in the Medium scenario, the High scenario assumes additional transmission-connected mining developments north of Thunder Bay. With these

additional developments, the total demand could grow to 415 MW by the end of the study period.

Low Scenario:

The Low scenario assumes production in the pulp and paper sector continues to decline and no new mining developments materialize in the area. It also assumes that the proposed Energy East gas-to-oil pipeline development will not proceed. This scenario results in a continued decline in electricity demand in the Thunder Bay area to about 300 MW by the end of the planning period.

Further details related to the demand forecast scenarios can be found in Appendix A.

5.4 Potential Growth in the Greenstone Area

The Thunder Bay electricity system is an important source of supply to the Greenstone sub-system. Today, the Thunder Bay electricity system transfers up to 12 MW of power to circuit A4L, which serves the Greenstone sub-system.

The Greenstone-Marathon 2016 IRRP[9] presents various demand scenarios and supply options for the Greenstone sub-system, which is currently supplied by the 115 kV circuit A4L. For the purpose of this study, it is assumed that the Greenstone scenario that most impacts the Thunder Bay 115 kV transmission system will materialize. In this scenario, circuit A4L is upgraded to allow a 60 MW transfer limit. This study assumes the full 60 MW transfer limit into the Greenstone sub-system must be available to be supplied from the Thunder Bay 115 kV system over the long term.

[9] http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/2016-Greenstone-Marathon-IRRP-Report.pdf

6. Needs

To determine whether the electricity system is able to provide a reliable source of supply to customers in the Thunder Bay area over the 20-year planning period, the system is assessed under the various demand scenarios described in Section 5.3.4. This section outlines the needs assessment methodology and identifies regional electricity supply and reliability needs over the planning period. In addition, other considerations such as sustainment activities and power quality are also discussed in this section.

6.1 Needs Assessment Methodology

The IESO's ORTAC,[10] the provincial standard for assessing the supply capability and reliability of the transmission system, was applied to assess supply capacity and reliability needs for the sub-region. 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** 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 limited time rating of a station's smallest transformer(s) under the assumption that the largest transformer is out-of-service. However, other equipment such as breakers, switches or other auxiliary equipment can also limit the station rating if they are undersized.
- **Supply Capacity** or Load Meeting Capability ("LMC") describes the electricity system's ability to provide a continuous source of electricity to supply load in a local area. The LMC of a region is determined using power system simulation analysis under various transmission and generation outage scenarios prescribed by ORTAC. The LMC of a system is often limited by its single largest source of supply (e.g., an autotransformer, a generating unit, etc.). The ability to transmit power throughout the system, as well as voltage stability issues can also limit the LMC. Supply capacity needs are identified when peak demand on a system exceeds its LMC.

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

- **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 customers affected by a major transmission outage within 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 power quality, equipment end-of-life and planned sustainment activities. Power quality refers to the stability of voltage, current and/or frequency of power. It is particularly important for customers with sensitive electronic equipment as their power supply can be interrupted if equipment is tripped due to power quality issues. Power quality is discussed further in Section 6.2.5.

Equipment reaching its end-of -life and planned sustainment activities may have an impact on the needs assessment and option development. Transmission assets reaching end-of-life have typically been 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 and needs. 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 strengthening to improve system resilience. Equipment end-of-life and planned sustainment activities are discussed further in Section 6.2.4.

6.2 Needs Assessment Findings

For the purpose of regional planning, this IRRP focuses on identifying and addressing needs on the regional 115 kV systems defined in Section 4.2.2. The regional 115 kV systems are assessed based on the methodology discussed in Section 6.1.

Through the needs assessment the ability to supply load on the Thunder Bay 115 kV system under the most limiting contingency scenarios, as prescribed by ORTAC, was studied. These scenarios included single (N-1) and double (N-2) circuit contingencies as well as the loss of a single autotransformer at Lakehead TS (N-1) and the loss of one autotransformer at Lakehead TS while the other is out-of-service (N-1-1).

The needs assessment identified one minor need for which near-term action is recommended – increasing the thermal rating of 115 kV circuit R2LB. No other investment or development work is required at this time.

Further, the needs assessment identified two potential long-term needs that should be monitored but do not require investment or further development work at this time – supply capacity on the Thunder Bay 115 kV system and station capacity at Port Arthur TS. These findings are discussed in more detail in the following sections.

End-of-life replacements and sustainment needs were also identified in this region and are discussed in Section 6.2.4.

The Thunder Bay Sub-region planning forecast, associated needs and options were discussed with the Thunder Bay LAC members at meetings throughout 2015 and 2016 for feedback and local input. The details of these discussions can be found in the LAC meeting summaries found in Appendix E.

6.2.1 Thermal Rating of Circuit R2LB

R2LB is a 115 kV circuit extending from Lakehead TS to Birch TS. Its thermal rating is lower than the other 115 kV circuits serving Birch TS due to a minor clearance issue. Under the High scenario, with the loss of the two nearby circuits L3P and L4P (N-2), post-contingency flow on R2LB will exceed its thermal rating.

The Working Group recommends uprating R2LB by increasing the clearance of its limiting span between Lakehead TS and Birch TS to that of the companion circuit R1LB, or higher. This line work was completed by Hydro One in Q4 of 2016.

6.2.2 Supply Capacity of the Thunder Bay 115 kV System

Today the Thunder Bay 115 kV system is adequate. The system can accommodate approximately 150 MW of load growth beyond 2015 levels before additional supply would be required. Under the Medium and Low scenarios, the system is adequate for the entire planning period. Under the High scenario, and assuming the most impactful Greenstone sub-system scenario as described in Section 5.4, additional supply capacity would be required by 2030.

There is sufficient lead time for the Working Group to monitor growth in the Thunder Bay Sub-region and Greenstone sub-system before making a decision on whether investment or

development work is required. No action beyond monitoring is recommended at this time. Details of the potential need and options are described below.

The largest sources of supply on the Thunder Bay 115 kV system are the two autotransformers at Lakehead TS. As prescribed by ORTAC, the needs assessment considered the loss of a single autotransformer at Lakehead TS (N-1) and the loss of one autotransformer at Lakehead TS when the other is out-of-service (N-1-1). Under the High scenario, in which more than 150 MW of growth in the Thunder Bay 115 kV and Greenstone sub-systems occurs, following the loss of both autotransformers at Lakehead TS, supply to the area would be restricted by the thermal rating of the 115 kV connections from Marathon TS in the east and Mackenzie/Moose Lake TS in the west. Under the conditions described above, the need for approximately 20 MW of new supply would arise by the year 2030.

The Working Group has identified options to increase the supply capacity of the Thunder Bay system, including transmission reinforcement, generation and various other options.

Two potential transmission reinforcement options were identified to increase the LMC of the Thunder Bay 115 kV system in the long term should the High growth scenario materialize – (1) a third 230/115 kV autotransformer at Lakehead TS; and (2) – a new 230 kV line from Lakehead TS to Birch TS and a 230/115 kV autotransformer at Birch TS.

The two transmission options are estimated to cost approximately (1) $30 million – with a lead time of approximately two to five years and (2) $100 million - with a lead time of five years or more depending on the project scope. The two alternatives are described in more detail in Appendix D.

There are several alternatives for the development of generation resources to increase the Thunder Bay area's supply capacity in the long term. Ontario Power Generation's ("OPG") - Thunder Bay Generating Station[11] with a contract structured specifically to the Thunder Bay Sub-region, including sufficient fuel supply, may be a feasible option. However, the annual operating costs are at least $30 million per year of fixed cost, plus additional costs for the advanced biomass fuel, which is currently bought and shipped from a supplier in Norway.

[11] More information available on OPG's website - http://www.opg.com/generating-power/thermal/stations/thunder-bay-station/Pages/thunder-bay-station.aspx

Natural gas generation is another option to increase the supply capacity of the Thunder Bay 115 kV system. Re-contracting an existing facility such as the Nipigon Project[12] or building a new facility utilizing simple-cycle reciprocating engines ("SCRE") were identified as potentially feasible options.

In the case of the Nipigon Project, the costs of re-contracting would be subject to negotiations between the IESO and Atlantic Power. The capital cost of a new 20 MW SCRE facility is estimated to be approximately $50 million, with typical lead times ranging from three to five years. Long-term fuel costs are uncertain given the limited natural gas storage availability in the area. Locally sited renewable generation facilities such as hydraulic, solar or wind are not feasible options to meet the potential capacity need in the area due to the variable nature of the fuel source.

DR is another potential option to address the long-term capacity need on the Thunder Bay 115 kV system. A locally tailored program would need to be developed for Thunder Bay for DR to effectively meet the specific need in the area. More information on DR is available in Appendix D.

Other options to address the supply capacity need on the Thunder Bay 115 kV system could include additional conservation above the provincially allocated targets, distributed energy resources or a combination of options. Further details on the options listed above are provided in Appendix D.

The large margin remaining on the Thunder Bay 115 kV system (150 MW) provides significant lead time for the Working Group to monitor demand growth and further study the options outlined above. No action beyond monitoring is required at this time.

6.2.3 Capacity Needs at Port Arthur TS

Port Arthur TS, a transformer station supplying the City of Thunder Bay, can supply up to 55 MW at the time of peak. Today it supplies up to 35 MW and there is accordingly about 20 MW of supply margin remaining.

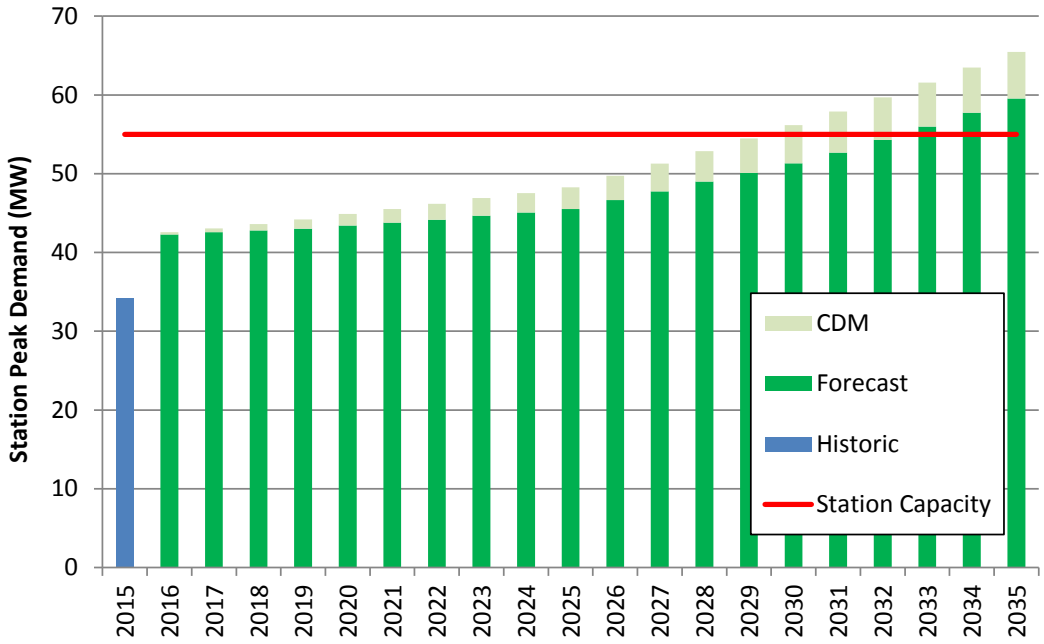
Electrical demand at Port Arthur TS is forecast by the LDCs to grow by almost 3% per year. If this growth materializes, demand supplied by Port Arthur TS will exceed 55 MW by 2033 and

[12] More information available on Atlantic Power's Website - http://www.atlanticpower.com/nipigon

additional transformer station capacity will be required. No action beyond monitoring is required at this time as there is sufficient lead time to monitor demand growth in the areas served by Port Arthur TS.

Port Arthur TS's supply capacity is currently limited by low-voltage equipment with lower ratings than the station transformers. Upgrading this equipment would increase the station's capacity by 4 MW, extending the need beyond the planning period. Should equipment upgrades be required at Port Arthur TS, they will be coordinated with sustainment activities at Port Arthur TS, as described in Section 6.2.4, to explore opportunities for long-term planning and cost reduction. The station peak forecast, with the expected impact of CDM, at Port Arthur TS is compared to the station capacity in Figure 6-2.

Figure 6-2: Port Arthur TS Station Peak Forecast and Station Capacity



The long-term need at Port Arthur arises close to the end of the planning period, which allows sufficient lead time for the Working Group to explore options while monitoring demand growth and ensuring any sustainment work at the station is consistent with the long-term needs. No action beyond monitoring is required at this time.

6.2.4 Transmission End-of-Life Replacements and Sustainment Activities

The end-of-life replacement of the two autotransformers at Lakehead TS is advancing. One autotransformer was replaced in Q3 of 2016 and the second is scheduled for replacement in Q2 of 2017. The new autotransformers are of equal or higher capacity.

Hydro One's May 31, 2016, Transmission System Plan[13] recommends replacing multiple assets at Birch TS due to poor condition, obsolescence, declining performance and high maintenance costs. The equipment in need of replacement includes: (i) in the high-voltage switchyard: circuit breakers, disconnect switches, the associated protection and control facilities and auxiliary components; and (ii) in the low-voltage switchyard: oil and spill containment facilities, capacitor banks, disconnect switches, protection and control systems and other associated auxiliary components. The targeted start date of sustainment activities is Q4 2016, and the targeted in-service date of the new equipment is Q3 2019.

Two transformers at Birch TS are more than 40 years old and may need to be replaced within the planning period. The replacement of any major transmission assets in the Thunder Bay Sub-region, such as the Birch TS transformers, will be coordinated with the Thunder Bay Working Group.

Low-voltage equipment at Port Arthur TS is nearing end-of life and may need to be replaced within the planning period. This sustainment work will be coordinated with the Thunder Bay Working Group, to ensure the long-term capacity need at Port Arthur TS is adequately considered.

Finally, Nipigon DS will be refurbished by Hydro One in 2017 to replace aging equipment.

Table 6-1 provides a summary of transmission end-of-life replacements and sustainment activities in the Thunder Bay Sub-region.

[13] http://www.hydroone.com/RegulatoryAffairs/EB20160160/HONI_Tx_Appl_Ex_B1_20160531.pdf

Table 6-1: Summary of Transmission End-of-Life Replacements and Sustainment Activities

Equipment	Replacement and Sustainment Plan
Lakehead TS – both autotransformers	One autotransformer replaced in September 2016 Second autotransformer is scheduled for replacement in April, 2017
Birch TS – Equipment Replacement	Replacements of circuit breakers disconnect switches, capacitor banks, oil spill containment facilities, disconnect switches, protection and control systems and other associated auxiliary components. Sustainment work is planned to begin in Q4 2016 and be completed by Q3 2019.
	Coordination with the Working Group will be required as the aging station transformers at Birch TS reach end-of-life towards the end of the planning period.
Port Arthur TS – Low-Voltage equipment	Low-voltage equipment at Port Arthur TS may reach end-of-life within the planning period. Replacement will be coordinated with long-term capacity needs at Port Arthur TS.
Refurbishment of Nipigon DS	Nipigon DS will be refurbished by Hydro One in 2017 to replace aging equipment.

6.2.5 Power Quality

Power quality issues experienced by one industrial customer were raised through the LAC meetings. While power quality issues are generally beyond the scope of the regional planning process, they were considered in the development of the plan.

Power quality issues are transient deviations in voltage, current or frequency resulting in customer or utility equipment being interrupted. A customer with sensitive electronic equipment may experience power quality issues due to normal switching actions on the transmission system, which can cause short duration voltage sags or spikes. The solutions for power quality problems, and the cost responsibility for implementation, vary based on the nature of the problem. Accordingly, power quality concerns are normally addressed on a case-

by-case basis between the customer and their service provider (either the LDC or, if they are transmission-connected, the transmitter).

A potential source of power quality issues is the decrease in generators and large industrial customers connected in the area. This issue could be considered when assessing the various options for addressing needs identified in the regional planning process. Generally, synchronous loads and generation can help stabilize the power system. Changes to industrial loads and generation in the area over time may have resulted in a decline in power quality. Transmission-connected industrial customers in the area are particularly concerned about the impact of voltage sags, often caused by a ripple effect from lightning strikes on transmission lines in the broader area. Greater system short circuit levels provided by additional synchronous machines may help mitigate this condition.

Power quality issues can provide context for evaluating the long-term options for the area's supply needs, and the Working Group has studied the impact of various supply options on local power quality by measuring the area's short circuit and transient voltage response (magnitude of the momentary voltage sag at a customer bus) for multiple fault situations. The completed studies showed no meaningful power quality benefit between transmission reinforcement and adding local generation. The study results are summarized in Appendix C.

6.3 Needs Summary and Recommendations

Aside from the uprating of 115 kV circuit R2LB, specific solutions do not need to be committed today. It is appropriate to continue gathering information, monitoring developments, engaging communities and developing 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 Thunder Bay 115 kV system would emerge under the High scenario, but near-term action is not required. Additionally, the Working Group identified a capacity need at Port Arthur TS in 2033; however, a decision on how to address the need is also not required at this time.

The Working Group will monitor demand growth closely to determine if and when investment decisions for the Thunder Bay 115 kV system and at Port Arthur TS are required. In the meantime, the Working Group will keep the communities and stakeholders informed about any developments at the bulk, regional and distribution levels.

For customers who are looking to further improve power quality, they may consider working with the transmitter to develop solutions. However, cost-benefit responsibilities and funding will need to be taken into consideration.

The recommended actions and deliverables for the plan are outlined in Table 6-2, along with the proposed timing and the parties assigned lead responsibility for implementation. The Thunder Bay Working Group will continue to meet on an as-needed basis during the implementation phase of this IRRP to monitor developments in the Thunder Bay Sub-region and track progress of these deliverables.

Table 6-2: Summary of Regional Supply and Reliability Needs

Regional Electricity Supply and Reliability Needs		Need	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	Line Uprating of 115 kV circuit R2LB	R2LB could overload following a double-contingency	Circuit was recently uprated to that of companion circuit R1LB or higher, by increasing the clearance of its limiting span between Lakehead TS and Birch TS.	Hydro One	Q4 2016
2	Supply Capacity of Thunder Bay 115 kV system	20 MW of additional supply capacity required by 2030, under the High scenario, to maintain current levels of reliability.	Provide a status update on planning activities and associated projects at LAC meetings[14]	Working Group	Annually

[14] Status updates will be posted to the IESO's Thunder Bay Regional Planning website annually and will include information such as updated historic electricity demand in the local area, major developments which could affect the sub-region's electricity supply and any progress made towards implementing the deliverables outlined in this IRRP.

Regional Electricity Supply and Reliability Needs		Need	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
3	Transformer Station Capacity at Port Arthur TS	Electrical demand served by Port Arthur TS is expected to exceed the station's LMC by 2033.	Provide a status update on planning activities and associated projects at LAC meetings	Working Group	Annually

7. 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 Thunder Bay IRRP.

A phased community engagement approach was undertaken for the 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 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 7-2: Summary of Thunder Bay Community Engagement Process

7.1 Creating Transparency

To start the dialogue on the 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 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.

7.2 Engage Early and Often

Early communication and engagement activities for the 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, Indigenous community members, Métis, federal and provincial representatives, electricity customers, Common Voice Northwest, transmission and generation project developers, and others.

7.2.1 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.

7.2.2 Indigenous Community and Municipal Meetings

Meetings with area Indigenous communities and municipalities are one of the first steps in engagement for all regional plans. In May 2015, the IESO met with the Chief of Fort William First Nation in Toronto and met with the Chief and a Councillor of Red Rock Indian Band in Thunder Bay to discuss planned developments in the communities, the development of the IRRP and receive comment on the early demand forecast. In May 2015, the Working Group also held a group municipal meeting in Thunder Bay 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 looked forward to the development of the LAC.

7.3 Bringing Communities to the Table

To continue the dialogue on regional planning, the LAC was established for the Thunder Bay area in fall 2015. 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. The LAC is comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information and materials are posted on the dedicated engagement webpage, which in this case is the IESO's Thunder Bay engagement web page.[15] The LAC meetings are also broadcast as live webinars to allow participation from across the planning sub-region.

Development of Thunder Bay 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; localized digital advertising; emails sent to municipal representatives across the region; and an e-blast sent to the IESO's Northwest Ontario Region subscribers list. The IESO reached out to the local First Nation Chiefs and the Métis Nation of Ontario to appoint members to the LAC.

In total, four meetings of the Thunder Bay LAC were held during the development of the plan. The focus of the inaugural meeting on November 26, 2015 was to introduce the regional planning process to the newly formed LAC, highlight key electricity supply considerations in the area, and discuss the purpose and scope of the LAC and the process moving forward.

The second and third meetings of the LAC took place on March 9, 2016 and June 27, 2016 respectively and focused on the needs in the Thunder Bay area and the options to meet these needs. At the March meeting the committee discussed the near-term options and solutions in detail and the long-term options at a high level. At the June meeting, additional information was presented to the LAC members on the costs and comparison of the long-term transmission and generation options, along with information on other options for consideration. The LAC members discussed the benefits and drawbacks of the various options and provided feedback on how each of the options could best serve local needs.

The fourth LAC meeting was held on November 2, 2016 with the purpose of reviewing the draft recommendations prior to the publication of the IRRP. At this meeting, it was noted that the solution to the near-term need has already been implemented and no decisions were required at

[15] http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

this time in addressing the long-term needs. In terms of next steps, the Working Group indicated that they will continue to monitor needs and produce an annual update report that will be shared with the LAC members. The November meeting was followed by a two-week comment period for LAC members to provide additional feedback on the draft recommendations.

Copies of the Thunder Bay LAC meeting summaries can be found in Appendix E.

Moving forward, the Working Group will provide the final IRRP to the Thunder Bay LAC and based on member feedback at the November 2016 LAC meeting, will hold annual meetings with the committee to discuss the annual IRRP update and seek feedback and input on the latest local developments and considerations.

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 Thunder Bay IRRP can be found on the IESO webpage and updates will continue to be sent to all Northwest Ontario Region email subscribers.

7.4 Additional Meetings and Presentations

The IESO recognizes Common Voice Northwest's specific mandate that includes investigating and making recommendations to Northwest Ontario Municipal Association ("NOMA") on issues related to energy in the Northwest Ontario Region. The IESO continues to meet regularly 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 ("OMA") Conference, among others. These presentations have included high-level status updates on the development of the Thunder Bay IRRP, along with other electricity topics.

8. Conclusion

This report documents the IRRP that has been carried out for the Thunder Bay Sub-region and identifies electricity needs in this sub-region over the 20-year period from 2016 to 2035. The IRRP fulfills the OEB's regional planning requirement for the sub-region.

There are no major regional needs identified in the Thunder Bay Sub-region. An additional 20 MW of supply may be required on the Thunder Bay 115 kV system under the High scenario, towards the end of the planning period, in order to maintain current levels of reliability. Furthermore, additional transformation capacity may be required at Port Arthur TS, also towards the end of the planning period. However, early development work for major electricity infrastructure projects is not required at this time given the potential needs are over 13 years away. The Working Group will monitor demand growth closely to determine if and when an investment decision is required. LAC meetings and other outreach activities in the northwest will be used as an opportunity to share information and obtain feedback on the continued development of regional and electricity planning.

The Thunder Bay Working Group will continue to meet as needed 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. 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. Responsibility for these actions has been assigned to the appropriate Working Group members. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the Thunder Bay Sub-region. The plan will be revisited according to the OEB-mandated 5-year schedule or sooner, if required.