EXHIBIT 1

ADMINISTRATIVE DOCUMENTS

EB-2017-0073

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Exhibit 1: Administrative Documents

1.2 Executive Summary

On September 1, 2000 Sioux Lookout Hydro Inc. ("SLHI") was incorporated pursuant to the *Business Corporations Act*, of Ontario, and is the successor corporation to the Sioux Lookout Hydro-Electric Commission for the Town of Sioux Lookout. SLHI is 100% owned by The Corporation of the Municipality of Sioux Lookout.

On October 18, 2012, the Ontario Energy Board (the "Board" or "OEB") issued its "Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach", and subsequently commenced implementation of the Renewed Regulatory Framework ("RRFE"). This report set out a comprehensive performance-based approach for the Renewed Regulatory Framework which promotes the achievement of outcomes that will benefit existing and future customers; will align customer and distributor interests; will continue to support the achievement of important public policy objectives; and will place a greater focus on delivering value for money. Under this approach, a distributor is expected to demonstrate continuous improvement in its understanding of the needs and expectations of its customers and its delivery of services.

On March 5, 2014, the Board issued its report on "Performance Measurement for Electricity Distributors: A Scorecard Approach". The report sets out the Board's policies on the measures that will be used by the Board to assess a distributor's effectiveness and improvement in achieving customer focus, operational effectiveness, public policy responsiveness, and financial performance to the benefit of existing and future customers.

This has once again been re-established through the Pacific Economics Group research, LLC 2016 Benchmarking Update Report to the Board issued July 2017 that places SLHI in Group 3.

Management of SLHI continues to review its business strategy and objectives from time to time to ensure compliance and a direct alignment between the OEB's RRFE and SLHI's business strategy.

The key elements of this Application are as follows:

- SLHI is requesting the approval of its proposed service revenue requirement of $2,200,916 and increase of $137,078 or 7% over 2018 revenue at existing rates.
- The main driver of the revenue deficiency, as outlined in Exhibit 6 are the increases in Administrative costs due to on-going consulting fees required to respond to regulatory requirements and policy direction. However, these increases in administration costs are offset by decreases in the return on rate base resulting from a lower working capital allowance of 7.5% in 2018. SLHI considered and decided not to conduct a lead lag study.
- SLHI is requesting a Rate Base of $5,983,945. This rate base is also used to determine the proposed Revenue Requirement found at Exhibit 6. The Rate Base for the 2018 Test Year has been forecasted to decrease by $674,545 (10.1%) over the 2017 Bridge Year and decrease by $130,270 (2.13%) over the 2013 Board Approved Rate Base and is further described in Exhibit 2.
- SLHI is also proposing to adjust its revenue to cost ratios in order to fall within the Board's minimum and maximum levels, specifically as they relate to Street Lighting and General Service > 50 kW, and further described in Exhibit 7.
- SLHI has described its approach for major capital investments as part of the Five Year Distribution System Plan (DSP) in Exhibit 2. Specifically, in the area of System Renewal, SLHI relies on asset demographic and condition data to develop investment levels, which are then tied to portfolio performance and relative reliability outcomes. Although there are no System Service projects planned for this period, a prioritization method would be used to objectively assess material investments against customer feedback and corporate objectives as described. In addition, projections for System Access have been developed that include a forecast of new connections over the plan period, against which historic unit costs have been applied. Exhibit 2 provides details on SLHI's capital plan over the five-year DSP period.

Mission

SLHI's Mission Statement:

Sioux Lookout Hydro Inc. is committed to:

- Ensure that health and safety to employees and the public is a priority;

- Supply safe and reliable electricity to residents and businesses in the Municipality of Sioux Lookout;
- Provide superior customer service; and
- Provide value to our shareholder, the Municipality of Sioux Lookout.

Core Objectives

SLHI's priorities are defined in its Corporate Goals:

- Provide a safe and reliable electricity distribution system with the capacity to meet the expectations of our customers and support local economic growth.
- Promote and practice excellence in safety
- Establish the lowest retail rates possible without compromising the financial integrity of the Corporation in compliance with our Shareholder's direction.

While SLHI does not have a formal written business plan, the following strategic approach has been taken and forms its business plan in order to position itself to deliver on its goals and objectives. The goals and objectives are:

Maintain an adequate and skilled employee base to meet ongoing demand and meet SLHI's Capital Investment Plan through training programs and succession planning (tied to RRFE Customer Focus and Operational Effectiveness Outcomes)

This goal was previously introduced in SLHI's 2013 Cost of Service Application, through effective succession planning. The remoteness of SLHI makes it difficult to attract and retain skilled staff. Therefore, in 2012, SLHI hired two apprentice powerline technicians, one as a result of a vacancy and the other as a succession planning tool to prepare for the retirement of a long time employee. The objective was to allow the transfer of valuable information with respect to SLHI's distribution system to the newly hired staff before their retirement, In 2017 SLHI will have two long-time operational staff retire. Complexities and informational knowledge collected and experienced over twenty years will be required to be learned and passed on to the next generation of staff. SLHI expects that as a result of on-going training programs and SLHI's succession plan customer service will be enhanced as well as operational effectiveness and the ability to carry out the capital investment plan as set out in the Distribution System Plan.

Develop a Five Year Distribution System Plan through asset condition assessments and careful asset management planning (tied to RRFE Operational Effectiveness, Financial Performance and Customer Focus Outcomes)

The capital investment plan is described in detail in the DSP in Exhibit 2. The DSP provides the OEB and all interested parties with an overview of SLHI's asset planning objectives and goals, a review of SLHI's asset-related operation performance over a 5 year historical period, and a preview of planned expenditures.

This DSP serves to outline how SLHI will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost effective distribution system.

Chapter 5 requirements for the OEB are referenced by sections and subsections. Within this DSP SLHI has followed the outline of the OEB regulation in numerical order by section number.

The DSP identifies the major initiatives and projects to be undertaken over the planning period, to meet customer and stakeholder requirements. Preparation of the DSP in this format is intended to supplement SLHI's rate application for its distribution rates to the OEB.

The intent of SLHI is to meet the filing requirements set out by the OEB in Chapter 5 (Consolidated Distribution System Plan), and to provide the information required by the Board under the RRFE to facilitate assessment of SLHI's application, in the areas involving planned expenditures on the distribution system and other infrastructure. For the purposes of the filing, the DSP has consolidated documentation of SLHI's Asset Management Process and Capital Expenditure Plan to maximize overall value to stakeholders in areas like service quality, customer satisfaction, safety, asset renewal and financial performance.

The DSP is consistent with Board expectations for distributors to optimize investments with present and future customers in mind. This Plan is focused on delivering good value for money and aligns the interests of SLHI with those of its customers; it also supports the achievement of public policy objectives and sustaining financial viability. SLHI wants to ensure that the performance outcomes, as established by the OEB for electricity distributors, are being achieved in a planned manner. Planning for the DSP began late in 2015 with the asset condition assessment.

Plan to continue to meet SLHI's Service Quality Objectives by increasing formal customer engagement activities (tied to RRFE Customer Focus Outcome)

SLHI has consistently exceeded the OEB's Service Quality Indicator standards, and as set out in Exhibit 2, it is targeting to maintain and/or improve its performance at or above the OEB standards for 2017 and 2018. SLHI has a close relationship with all of its customers and the shareholder. In the past customer engagement was largely informal, SLHI plans to implement more formal methods of customer engagement through the use of surveys designed to address more specific needs of the customer. These surveys will be conducted during the planning stages of any large projects that will impact our customers.

Plan to meet SLHI's Conservation and Demand Management Objectives (tied to RRFE Customer Focus and Public Policy Responsiveness Outcomes)

The 2015-2020 Conservation First Framework developed by the Independent Electricity System Operator ("IESO), allocated 3,700 MWh's of 7 terawatt-hours of savings for the entire province of Ontario. The implementation of these CDM programs are mandatory, and will encompass all customer segments including residential, small business, industrial and low-income.

SLHI submitted a joint CDM plan with the other four Northwest District LDCs (Atikokan Hydro, Fort Frances Power Corp, Kenora Hydro and Thunder Bay Hydro). The Plan is a detailed road map that is a year by year plan for meeting the savings targets. It includes an achievable potential calculator that identifies the area of local CDM opportunities by sector, end-use and building type based on local information. Further, a cost effectiveness calculator is used that calculates cost effectiveness metrics required for the CDM Plan. Program savings are forecasted through program archetypes and different program scenarios. Lastly, within this plan, a detailed financial modelling tool is to be included.

SLHI selected Greensaver to assist with the Low Income Conservation Program, as well as hired a Regional Energy Services Advisor to travel to the smaller four LDCs to promote the programs. A Roving Energy Manager was approved through the collaboration fund, but the group has, as of this application, not been able to fill the position.

1.3 Administration

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

AND IN THE MATTER OF an Application by Sioux Lookout Hydro Inc. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2018.

(This "Application")

Applicant's Name: Sioux Lookout Hydro Inc.
(The "Applicant" or "SLHI")

Background

1. The Applicant is a corporation incorporated pursuant to the *Business Corporations Act* (Ontario) with its office in the Municipality of Sioux Lookout. The Applicant carries on the business of distributing electricity serving more than 2,800 customers within a service territory that covers 539 square kilometers with 533 square kilometers of rural service area. The total municipal population is 5,080 (2015). In April 2017 SLHI completed the transfer of Long Term Load Transfers as set out in the Board's letter dated March 30, 2016. As a result, SLHI's service territory increased by 3.42 square kilometers and 36 new customers were acquired.

   The Sioux Lookout Hydro service territory is more specifically described in SLHI's Distribution Licence ED-2002-0514, as encompassing the following:

   - The Municipality of Sioux Lookout as at January 1, 1998, including customers located at the following addresses:
     - Minnitaki Lodge Road, Pickerel
     - 82 Minnitaki Road, Pickerel
     - 61, 77 and 81 Balsam Road, Pickerel
     - 120, 160, 162, 168, 184, 188 and 200 Monia Road, Pickerel
     - 4804 and 5105 Highway 72, Pickerel
     - Alcona Road, Benedickson
     - Kirk Lake Road, Benedickson

- 3760 Alcona/Kirk Lake Road, Benedickson
- 3816, 3820, 3822 Highway 642 Benedickson
- Highway 642, East of Kirk Lake Road, Benedickson

2. The Application has been prepared pursuant to the OEB's Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the "RRFE").

3. Unless specifically stated otherwise in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on July 20, 2017 (the "Filing Requirements") in preparing the Application.

4. The Applicant has prepared a Consolidated Distribution System Plan ("DSP") in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications.

5. The Applicant acknowledges that the OEB will publish an update to the cost of capital parameters after this application is submitted and that these matters will affect the Revenue Requirement that the Applicant has requested in this Application.

Proposed Effective Date of Rate Order:

1. The Applicant requests that the OEB make its Rate Order effective May 1, 2018 in accordance with the Filing Requirements.

2. In the event that the OEB is unable to provide a Decision and Order in this application for implementation by the Applicant as of May 1, 2018, the Applicant requests that the OEB declare its current rates interim, effective May 1, 2017, pending the implementation of the OEB's Rate Order for the 2018 rate year.

Certification:

I, Deanne Kulchyski, President/CEO of Sioux Lookout Hydro Inc., certify that the evidence filed is accurate, consistent, and complete to the best of my knowledge.

Original signed by

Deanne Kulchyski, CPA, CGA, BComm(Hons)
President/CEO

Contact Information

The Applicant's Address for Service:

The Applicant:

Sioux Lookout Hydro Inc.
25 Fifth Avenue, PO Box 908
Sioux Lookout, Ontario
P8T 1B3

Primary Application Contact:

Sioux Lookout Hydro Inc.
Deanne Kulchyski, CPA, CGA, BComm(Hons)
President/CEO
25 Fifth Avenue, PO Box 908
Sioux Lookout ON,
Tel.: 807-737-3800, extension 24
Fax: 807-737-2832
Email: dkulchyski@tbaytel.net

The Applicant's Legal Representation

Borden Ladner Gervais LLP

Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto, ON M5H 4E3

Primary Legal Contact:

John A.D. Vellone, LL.B., M.B.A., B.A.Sc. (Electrical Engineering)
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Bruce Bacon, Senior Utility Rate Consultant
Telephone: 416-367-6087
Fax: 416-361-7366
Email: bbacon@blg.com

Confirmation of Internet Address

SLHI's website address is https:/www.siouxlookouthydro.com

Individual Customers or Groups materially affected:

The following Customers and/or Customer Groups are identified as being materially impacted by the proposed changes in this rate application:

- Street Lighting Rate Class – Reduction in total revenue required by this rate class by $56,106 or 65.2%, to bring the revenue to cost ratio in line with OEB policies. This is explained in more detail in Exhibit 7.

Publication Information

Residents, businesses and institutions in the Municipality of Sioux lookout as well as individuals in the communities of Benedickson and Pickerel who receive electricity distribution services from SLHI will be affected by the Application.

The Applicant recommends that the Application and related materials be posted on the SLHI's website, and to be available for viewing at the following internet address: https://www.siouxlookouthydro.com/rates.

A newspaper ad could also be utilized for customers without access to the internet. SLHI's local newspaper is The Sioux Lookout Bulletin.

The Applicant also uses a Facebook page to communicate with its customers. The address is www.facebook.com/siouxlookouthydro.

Bill Impacts

Further information pertaining to the causes of these bill impacts can be found in Exhibit 8.

In preparing this application, SLHI has considered the impacts on its customers, with a goal of minimizing those impacts. Table 1-1 provides a summary of bill impacts ($ and %) for typical customers in all rate classes using only distribution cost changes from sub-total A of the Tariff Schedule and Bill Impacts spreadsheet model. The bill impacts for the Residential Rate Class do not take into consideration the Distribution Rate Protection Program.

Table 1-1: Distribution Cost Bill Impacts

Rate Class	Monthly kWH	Monthly kW	$ Change	% Change
Residential	750		$ 6.77	16.91%
Residential (lowest 10th percentile)	518		$ 7.40	19.14%
General Service less than 50 kW	2,000		$ 7.62	12.71%
General Service 50 to 4,000 kW	65,700	100	$ (12.53)	-2.40%
Street Lights	12,340	33	$ (3,302.39)	-49.75%

Statement as to the Form of Hearing Requested

SLHI requests that, pursuant to Section 34.01 of the Board's rules of Practice and Procedure, this proceeding be conducted by way of written hearing. SLHI submits that this is the most efficient and cost effective manner to process the Application.

Requested Effective Date

The requested effective date for the application is May 1, 2018.

Statement of Deviations

SLHI has adhered to Board's filing documents listed below in preparing this application.

- Chapter 2 of the Board's "Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications – Chapter 2: Cost of Service", issued July 20, 2017;

- The Board's "Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements", issued March 28, 2013.

Statement of Changes to Methodologies

The pro-forma projections for the 2018 Test Year have been prepared in accordance with SLHI's usual process, with the following exception:

Regulatory costs have been normalized over the five year application period. In non-COS years, the total regulatory expense is accounted for in the specific year in question.

Identification of Board Directives from Previous Board Decisions

There are no Board Directives from Previous Board Decisions that need to be addressed in SLHI's 2018 COS application.

Conditions of Service

SLHI's current Conditions of Services are found at https:/www.siouxlookouthydro.com

The document was updated March 1, 2014. The changes are summarized in the table below:

Section	Page	June 5, 2007 Version	2013 Revision – Effective January 1, 2014
1	5	N/A	These Conditions of Service describe Sioux Lookout Hydro Inc. (SLHI) operating practices and connection policies and set out the terms and conditions upon which SLHI offers and the Customer accepts Distribution Services. Your safety and the safety of others are of primary concern to Sioux Lookout Hydro Inc.. As such, these Conditions of Service do not authorize or encourage any person or entity including, but not limited to, a Customer, a Customer's officers, directors, agents and/or employees and successors and assigns to engage in any activity that may cause personal injury or damage to property including, but not limited to, property belonging to Sioux Lookout Hydro Inc., a Customer or any other party. Sioux Lookout Hydro Inc., its officers, directors, agents and/or employees and successors and assigns are not responsible for any damages, claims, liabilities, costs, demands, actions, expenses or compensation that may arise from these Conditions of Service. If you have any questions regarding these Conditions of Service, please

	5		contact SLHI's Customer Service. Terms contained in these Conditions of Service or in any contract for the supply of electricity by SLHI shall not prejudice or affect any rights, privileges, or powers vested in SLHI by law under any Act of Legislature of Ontario or the Parliament of Canada, or any Regulations there under. Public Works on a highway is a higher hierarchy. The definitions of terms used in these Conditions of Service appear in section 4.0. GLOSSARY OF TERMS.
1.1	5	In these Conditions of Service, "Hydro" refers to Sioux Lookout Hydro Inc. The service area of Hydro coincides with The Municipality of Sioux Lookout geographical boundaries as at January 1, 1998.	SLHI is an electricity distributor licensed by the Ontario Energy Board to distribute electricity pursuant to Part V of the *Ontario Energy Board Act, 1998*. In accordance with its electricity distribution license, SLHI owns and operates its Distribution System in the service area described therein. Schedule 1 of SLHI's Distribution License, ED-2002-0514, describes SLHI's service area as "The Municipality of Sioux Lookout as at January 1, 1998.
1.2	5	1. Electricity Act, 1998 Ontario Energy Board Act, 1998 3. Distribution License 4. Affiliate Relationships Code 5. Transmission System Code 6. Distribution System Code Retail Settlement Code 8. Standard Service Supply Code	The supply of electricity or related services by SLHI to any Customer shall be subject to various laws, Regulations, and Codes, including the provisions of the latest editions of the following documents: 1. Electricity Act, 1998 2. Ontario Energy Board Act, 3. Distribution License 4. Affiliate Relationships Code 5. Transmission System Code 6. Distribution System Code; 7. Retail Settlement Code; 8. Standard Service Supply Code; and 9. Ontario Electrical Safety Code. In the event of a conflict between this document and the Distribution License or regulatory Codes issued by the Ontario Energy Board, the Electricity Act, 1998 (the "Act"), the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail in the order of priority indicated above. If there is a conflict between a Connection Agreement with a Customer and this Conditions of Service, this Conditions of Service shall govern. When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian Electrical Codes, and all other applicable federal, provincial, and municipal laws,

			Regulations, Codes and By-Laws to also ensure compliance with their requirements. Without limiting to the foregoing, the work shall be conducted in accordance with the latest edition of the Ontario Occupational Health and Safety Act (OHSA), the Regulations for Construction Projects and the harmonized Electric Utility Safety Association (EUSA) rulebook.
1.3	6	Words referring to a gender include any gender. Words referring to the singular include the plural and vice versa.	**In these Conditions of Service:** (a) Headings are for reference only and shall not affect the interpretation of this document. (b) Works importing the singular include the plural and vice versa. (c) a reference to a person includes a reference to the persons, executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation), and assigns; (d) an agreement, representation or warranty on the part of, or in favor of, two or more persons binds or is for the benefit of them jointly and severely; (e) specified periods of time refer to business day, and dates from a given day or the day of an act or event is to be calculated exclusive of that day; (f) a reference to a day to be interpreted as the period of time commencing at midnight and ending 24 hours later and does not include weekends and SLHI recognized holidays. (g) Recognized holidays means the days designated by SLHI from time to time. Until otherwise designated these holidays are: New Year's Day — Thanksgiving Day Good Friday — Remembrance Day Victoria Day — Christmas Day Canada (Dominion) Day — Boxing Day August Civic Holiday Labour Day (h) A reference to a document or a provision of a document includes any amendment or supplement to, or a replacement of, that document or that provision of that document. (i) A request for clarification shall be submitted in writing, and the final arbitrator between Customer and distributor shall be the Ontario Energy Board.
1.4	6		The provisions of these Conditions of Service and any amendments made from time to time form part of any

		The provisions of this Conditions of Service and any amendments made from time to time form part of any Contract made between Hydro and any connected Customer, Retailer, or Generator, and this Conditions of Service supersedes all previous Conditions of Service, oral or written, of **Sioux Lookout Hydro Inc.** as of its effective date.	contract between SLHI and any Customer, retailer, and these Conditions of Service supersede all previous Conditions of Service oral or written. This document may be amended only in accordance with the procedures set out by the Ontario Energy Board in the Code. In addition to the amendment procedures as set out in the Code, SLHI's senior management must give approval of any proposed amendments.
1.5	7	Sioux Lookout Hydro after hours number for customers 737-3806 Sioux Lookout Hydro Business Hours 8:00 AM – 4:30 PM CST 737-3800 **OFFICE STAFF** **LINEMEN** Gord Maki – **President/CEO** 737-2215 Tom Sayers (Leadhand) 737-2423 Cell 737-0442 Cell 737-9609 Deanne Kulchyski 737-4825 Tony George 737-2849 Cell 737-9218 Tracey Ellek 737-3050 Sheldon Hackl 737-7749 Lineman on call 737-0443	For general inquiries SLHI can be reached as follows: **Main Office:** Sioux Lookout Hydro Inc. Phone: 807-737-3800 25 Fifth Avenue, PO Box 908 Fax: 807-737-2832 Sioux Lookout, ON P8T 1B3 email: slhydro@tbaytel.net Website: www.siouxlookouthydro.com **Operations Centre**: Operations Manager Phone: 807-737-1080 842 Hwy 516 Fax: 807-737-1149 Sioux Lookout, ON P8T 1B3 **Hours** **Office:** **Operations Centre:** Regular Business Hours: Regular Business Hours: 8:00 am – 4:30 pm (CST) 8:00 am – 4:00 pm (CST) **Emergency Contacts** After Hours Emergency Calls: 807-737-3806

1.6	8	Hydro shall only be liable to a Customer and a Customer shall only be liable to Hydro for any damages that arise directly out of the wilful misconduct or negligence: • Of Hydro in providing distribution services to the Customer; • Of the Customer in being connected to Hydro's distribution system; or • Of Hydro or Customer in meeting their respective obligations under these conditions, their licences and any other applicable law. Notwithstanding the above, neither Hydro nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.	SLHI shall only be liable to a Customer and a Customer shall only be liable to SLHI for any damages that arise directly out of the willful misconduct or negligence: (a) of SLHI in providing Distribution Services to the Customer (b) of the Customer in being connected to SLHI's Distribution System; or (c) SLHI or the Customer in meeting their respective obligations or exercising their respective rights under these Conditions of Service, their licenses and any other Applicable Laws. Notwithstanding the above, neither SLHI nor the Customer shall be liable under any circumstances, whatsoever, for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise. The Customer shall indemnify and hold harmless SLHI, its directors, officers, employees and authorized agents from any claims made by any third parties related to the construction, installation, or connection of a Generation Facility by or on behalf of the Customer. The Customer has the right to choose to purchase electricity from any licensed retailer. SLHI agrees to use diligence in providing a regular and uninterrupted supply of electricity, but does not guarantee a constant supply of electricity and will not be liable to the Customer for damages for failure to supply electricity to the said premises.
1.7.1	8	**1.7.1 Access to Customer Property** Hydro shall have access to Customer property in accordance with ***Section 40 of the Electricity Act, 1998.***	**1.7.1 Space and Access** The Customer shall provide SLHI, free of charge or rent, with a convenient and safe place for SLHI Facilities and Equipment on the Customer's premises or approaches thereto. SLHI assumes no risk and under no circumstances will SLHI be liable for any damages resulting from, arising out of,

			or related to the presence of SLHI Facilities and Equipment. The Customer shall not allow anyone other than an employee, or authorized agent of SLHI, or person lawfully entitled to do so, to repair, remove, replace, alter, inspect and tamper with SLHI Facilities and Equipment on the Customer's premises. The Customer hereby grants Sioux Lookout Hydro Inc. (SLHI), its successors and assigns, the unrestricted right, privilege and easement, free of charge or rent, to use so much of the service location and to enter on, in, upon, along and over the service location at any time as SLHI may, in its sole discretion, deem it necessary or desirable for purposes of performing the work and for its employees, servants, agents, contractors and subcontractors to pass and re-pass with or without vehicles, supplies, machinery and equipment, on, in upon, along and over the service location at any time to perform the work and for all purposes necessary or convenient to the exercise and enjoyment of the right, privilege and easement hereby granted.
1.7.2	8,9	1.7.2 Safety of Equipment – renumbered to 1.7.3 (see below	New: **1.7.2 Liability for Damage to SLHI Equipment** SLHI facilities and equipment located on the Customer's premises are in the care of and at the risk of the Customer. If any of SLHI facilities and equipment are damaged or destroyed by willful misconduct or negligence of the Customer including fire or any other cause other than ordinary wear and tear, the Customer shall pay SLHI the value of said SLHI facilities and equipment or the cost of repairing or replacing same.
1.7.3	9	1.7.1 – Operating Control – removed 1.7.2 Safety of Equipment The Customer will comply with all aspects of the Ontario Electrical Safety Code with respect to insuring that equipment is properly identified and connected for metering and operating purposes. The Customer will take whatever steps necessary to correct any deficiencies, in particular	**1.7.3 Safety of Equipment** The Customer shall not build, or cause to be built, plant or maintain any structure, tree, shrub or landscaping that would obstruct or endanger any SLHI Facilities and Equipment, interfere with the proper and safe operation of the Distribution System or any part thereof or affect SLHI compliance with any Applicable Laws. The Customer shall comply with all Applicable Laws, including, but not limited to the Ontario Electrical Safety Code. The Customer shall ensure that the Customer equipment is properly identified and connected for metering and operation purposes and will take whatever steps necessary to correct any deficiencies in a timely fashion.

		cross wiring situations, within **72 Hours** of written notice by Hydro to the Customer. If the Customer does not take such action within this time frame, Hydro shall disconnect the supply of power to the Customer. The policies and procedures of Hydro with respect to the disconnection process are further described in these Conditions of Service. The Customer shall not build, plant or maintain trees, shrubs, landscaping or structures etc. that, in the sole opinion of Hydro, may affect the safety , reliability, or efficiency of Hydro facilities. The Customer shall not access, use or interfere with the distribution facilities of Hydro except in accordance with a written agreement. The Customer must also grant the right to sea, secure and/or prevent from tampering any point where a connection may be made on the line side of metering equipment.	Where applicable, Customer equipment shall be subject to the reasonable acceptance of SLHI and the approval of the Electrical Safety Authority. SLHI approval of any Customer equipment is solely for the purposes of SLHI protecting its Distribution System and the Customer is solely responsible for protecting its own property.
1.7.4	9	**Repairs of Defective Customer Electrical Equipment** The Customer will be required to repair or replace any equipment owned by the Customer that may, in the sole opinion of Hydro, affect the integrity or reliability of the Hydro distribution system. If the Customer	**1.7.4 Testing Customer's Load** The Customer shall allow SLHI to install and use meters and other equipment to conduct tests to determine the electrical characteristics of the Customer's load.

		does not take such action within **72 hours** of written notice, Hydro shall disconnect the supply of power. Policies and procedures with respect to the disconnection process are further described in **Section 2.2** of these Conditions of Service.	
1.7.6	9	**N/A**	1.7.6 SLHI Automatic Re-closing Facilities In order to safeguard and protect the Distribution System, SLHI installs facilities for automatic re-closing of circuit breakers, re-closing facilities, and from time to time may change the re-closing time of any such re-closing facilities. The Customer shall be responsible for protecting at his own expense: 1.7.1.1 adequate protective equipment for any electrical apparatus which might be adversely affected by re-closing facilities; and 1.7.1.2 such equipment as may be required for the proper reconnection of any apparatus or equipment of the Customer, without adversely affecting the proper functioning of the re-closing facilities.
1.7.7	9,10	**N/A**	1.7.7 Registration as a Wholesale Market Participant In order for SLHI to make the necessary changes to its billing systems, Customers who wish to register or de-register with the Independent Electricity System Operator (IESO) as Wholesale Market Participant shall notify SLHI in writing at least 60 days in advance. The Customer must ensure that sufficient time is provided for IESO registration or de-registration.
1.7.8	10	**N/A**	1.7.8 Force Majeure Other than for any amounts due and payable by the Customer to SLHI or by SLHI to the Customer, neither SLHI nor the Customer shall be held to have committed an event of default in respect of any obligation under these Conditions of

			Service if prevented from performing that obligation, in whole or in part, because of a Force Majeure event. If a Force Majeure event prevents either party from performing any of its obligations under these Conditions of Service, that party shall: 1.1.1.1 notify the other party, as soon as commercially reasonable, of the Force Majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practical; 1.1.1.2 Not be entitled to suspend performance of any of its obligations under these Conditions of Service to any greater extent or for any longer time than the Force Majeure event requires it to do; 1.1.1.3 use its best efforts to mitigate the effects of the Force Majeure event, remedy its inability to perform, and resume full performance of its obligations; 1.1.1.4 keep the other party continually informed of its efforts; 1.1.1.5 provide written notice to the other party, as soon as commercially reasonable, when it resumes performance of any obligations affected by the Force Majeure event; and 1.1.1.6 if the Force Majeure event is a strike or a lock out of SLHI employees or authorized agents, SLHI shall be entitled to discharge its obligations to notify its Customers in writing by means of placing an ad in the local newspaper.
1.8	10	To resolve disputes, Hydro will follow the terms of Section 23 of the Transitional Distribution Licence. ***Section 23 of the Transitional Distribution Licence states:*** **The Licensee shall:** a) Establish proper administrative procedures for resolving complaints by Consumers and other market participants' complaints regarding	Any Dispute between a Customer or retailer and SLHI shall be settled according to the dispute resolution process specified in Section 23 of the Distribution License. A copy of this resolution process shall be provided at the request of any member of the public. Customer complaints that cannot be resolved by calling SLHI's Customer Service Department will be escalated to SLHI's Customer Service Supervisor (the 'CSS'), which will serve as the primary point of contact with SLHI. The CSS will make contact with the Customer, coordinate internal complaint activities, research, investigate, and follow up (when necessary) on the complaint to ensure resolution and closure. In the event that issues cannot be resolved between SLHI and the Customer, complaints can be escalated to a third

		services provided under the terms of this Licence. b) Publish information, which will facilitate its Customers accessing its complaints resolution process. c) Refer unresolved complaints and subscribe to an independent third party complaints resolution agency, which has been approved by the Board. d) Make a copy of the complaints resolution procedure available for inspection by members of the public at each of the Licensee's premises during normal business hours. e) Give or send free of charge a copy of the procedure to any person who reasonably requests it; and f) Keep a record of all complaints whether resolved or not including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution. Hydro's complaints resolution procedure is as follows: For power outages, or issues	party complaints resolution agency, which has been approved by the Board. Until such time as the Board approves an independent third party dispute resolution agency, the Board will assume this role.

		related to power supply and delivery, you should contact Sioux Lookout Hydro Inc. at (807) 737-3800 during normal business hours and at (807) 737-3806 after normal business hours. For complaints related to you electricity contract with a retailer, we suggest that you start by contacting you retailer's Customer Service Department. Keep notes of your actions, including the names of the company representatives you talk to. Follow up with a letter it you don't get satisfaction. If the problem cannot be resolved, you should call the Ontario Energy Board at 1-877-632-2727.	
2			Revised entire section to provide updated information and more detail and comply with new customer service rules
3			Revised entire section to provide updated information and more detail.
5			Replaced entire section with updated forms and tables

After completion of SLHI's Cost of Service OEB approval, SLHI will amend its condition of service to include the following points in relation to unmetered loads:

- The rights and obligations of unmetered load (street lighting) customers and the distributor in relation to each other.
- The process by which unmetered load customers are to file updated data and evidence necessary to validate the data.
- The process by which unmetered load customer billing updates will take place.
- Communication and engagement with unmetered load customers in relation to the preparation of cost allocation studies, load profile studies and other rate-related materials which may materially affect unmetered load customers.

- Removal of reference to unmetered scattered loads which are not street lights to reflect the removal of the unmetered scattered load class.

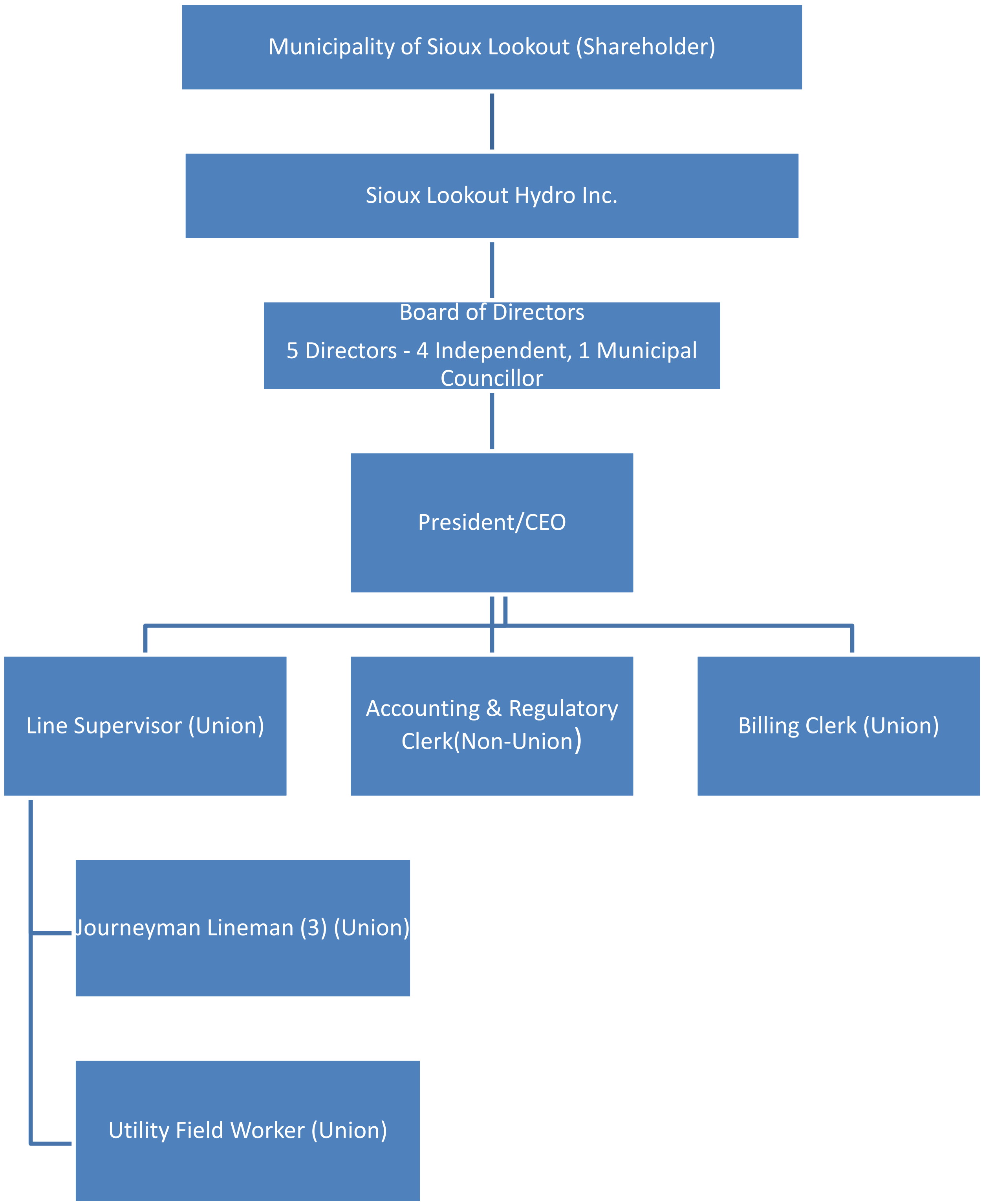
Charges Listed in Conditions of Service

SLHI confirms there are no rates or charges listed in the Conditions of Service that are not on the SLHI's Tariff of Rates and Charges.

Corporate and Utility Organizational Structure

A chart illustrating SLHI's corporate and utility organizational structure (including main units and management positions) is provided in Chart 1-1 below. The chart illustrated below also shows the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management is described in section 2.2.

Chart 1-1: Corporate & Utility Organizational Structure



Corporate Governance

Board Meetings:

SLHI holds monthly Board Meetings.

SLHI's Board Representation:

The SLHI Board is appointed by SLHI's shareholder. The Municipality of Sioux Lookout identifies and selects new members of the Board.

SLHI's Board of Directors consists of five directors, none of which is an employee or officer of the utility. Of the five directors, four are independent, and one is a Municipal Councillor. This conforms to the Affiliate Relationship Code ("ARC") whereby at least one-third of its directors must remain independent from Affiliate Boards.

Board and Management:

The SLHI Board and Management work together. Some general principals of corporate governance include:

Each of the Board and Management has a fiduciary duty in relation to the Company.

The Board and Management must work together and in harmony and collaborate together not independent from one another.

Management develops plans, procedures, guidelines and reports; the Board provides advice, feedback and perspective.

A tone of trust and respect is important to the relationship between Management and Board.

Open, frank and honest discussions are encouraged at all Board meetings. Management provides the SLHI Board with written reports, oral reports, and verbal and written responses to SLHI Board inquiries, that are crucial to the successful realization of SLHI's corporate goals and objectives. These practices, enable SLHI Board members to understand the issues facing the utility, and assist the Board in exercising its independent judgement in carrying out its responsibilities. The SLHI

Board conducts an annual assessment of SLHI's performance and discusses individual management's member's performance.

Board Mandate:

The board's primary duty is to supervise the management of the business and affairs of SLHI and to protect the investment of the Shareholder by managing the exposure of inherent risks.

The Board's oversight relationship with management and accountability to the Shareholder is to be guided by the Company's Mission and Vision Statement.

Directors are expected to work with their fellow Directors to fulfill the mandates of the Board.

Board members have diverse and complementary skills that can be leveraged to the Benefit of the Company.

Reporting Relationships:

The Board of Directors and the President/CEO report to the Shareholder, The Municipality of Sioux Lookout. The President/CEO also reports to the Board of Directors of SLHI. Reporting to this position as it relates to the LDC are the following:

Line Supervisor

Accounting and Regulatory Clerk

Billing Clerk

Reporting to the Line Supervisor are the Journeymen and Utility Field Worker.

Orientation and Continuing Education:

The SLHI Board receives education through Board Reports and Board Meetings. From time-to-time, external subject matter experts are utilized to assist with the education process. SLHI Board members, through their professional careers are also active in industry related issues and receive continuous education through this experience.

Code of Conduct:

There is no formal ethical code of conduct, although SLHI and its Board conducts itself with some rules and common sense approach ideas such as (i) respect for people, treating others as you would like to be treated (ii) providing a healthy and safe working environment (iii) working to the best of your ability and listening to customers and staff and acting in a professional manner.

Planned Changes in Corporate and Operational Structure

SLHI is not planning any material changes to its corporate or operational structure.

List of Specific Approvals Requested

In this proceeding, SLHI is requesting the following approvals as described in Appendix 2-A attached as Appendix 1A.

1. Approval under Section 78 of the Ontario Energy Board Act, 1998 to charge distribution rates effective May 1, 2018 to recover a service revenue requirement of $2,200,916 which includes a revenue deficiency of $137,078 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
2. Approval of the Distribution System Plan as outlined in Exhibit 2.
3. Approval of revised low voltage rates as proposed and described in Exhibit 8.
4. Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.
5. Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of SLHI's 2017 Distribution Rates (EB-2016-0103).
6. Approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of SLHI's 2017 Distribution Rates (EB-2016-0103).
7. Approval to remove the Unmetered Scattered Load rate Class.
8. Approval of the proposed loss factors as detailed in Exhibit 8.
9. Approval of the rate riders for a one year disposition of the Group 1 Variance Accounts as detailed in Exhibit 9.

10. Approval to dispose of Group 2 Accounts 1508, Sub-Account Deferred IFRS Transition Costs, 1518 Retail Cost Variance Account – Retail, and 1548 Retail Cost Variance Account – STR, as outlined in Exhibit 9 over a one year disposition.
11. Approval to dispose of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") for lost revenue from 2011 to 2015 resulting from 2011 to 2015 IESO (formally OPA) programs as detailed in Exhibit 4.
12. Approval to dispose of Account 1525 IFRS-CGAAP Transition PP&E Amounts over a five year disposition period as outlined in Exhibit 9.
13. Approval to change the wording under Specific Service Charges from Returned Cheque (plus bank charges) to Returned Item (Plus bank charges).
14. SLHI may request such other approvals as counsel for SLHI may submit and the Board may allow.

1.4 Distribution System Overview

As previously detailed, SLHI is a local distribution company serving more than 2,800 customers in the Municipality of Sioux Lookout.

Service Area:

	Description of the Applicant:
COMMUNITY SERVED:	The Municipality of Sioux Lookout, including the community of Hudson and individuals in the communities of Benedickson and Pickerel
TOTAL SERVICE AREA:	539 sq. km
RURAL SERVICE AREA:	533 sq. km
DISTRIBUTION TYPE:	Electricity Distribution
SERVICE AREA POPULATION:	5,080
MUNICIPAL POPULATION:	5,080

A map of SLHI's distribution service territory is provided in Appendix 1B.

Host/Embedded Distributor

SLHI is a fully embedded distributor who receives electricity at distribution level voltages from Hydro One Networks Inc.

Transmission or High Voltage Assets

SLHI does not have any transmission or high voltage assets (>50kV) deemed previously by the Board as distribution assets and does not have any such assets for which SLHI is seeking Board approval to be deemed as distribution assets in this application.

1.5 Application Summary

Below, SLHI presents summarized information on the following key elements of its application:

A. Revenue Requirement

B. Budgeting and Accounting Assumptions

C. Load Forecast Summary

D. Rate Base and DSP

E. Operations, Maintenance and Administration Expense

F. Cost of Capital

G. Cost Allocation and Rate Design

H. Deferral and Variance Accounts

I. Bill Impacts

A. Revenue Requirement

SLHI is requesting the approval of its proposed service revenue requirement of $2,200,916 which reflects a revenue deficiency of $137,078 which is shown in Table 1-2: Service Revenue Requirement.

Table 1-2: Service Revenue Requirement

	2013 Board Approved (A)	2018 Revenue at Existing rates Allocated in Proportion to 2013 Approved (B)	2018 Proposed (C)	Revenue Deficiency (D) =(C) - (B)	2018 Test Year Increase from 2013 Board Approved (E) = (C) - (A)	
					$	%
OM&A	$1,416,259	1,499,818	$1,572,092	$72,274	$155,833	11.00%
Amortization/Depreciation	$182,961	193,756	$234,839	$41,083	$51,878	28.35%
Property Tax	$4,986	5,280	$5,394	$114	$408	8.18%
Income Taxes (Grossed Up)	$2,180	2,309	$23,005	$20,696	$20,825	955.28%
LEAP		0	$2,600	$2,600	$2,600	-
Return on Rate Base	$342,470	362,676	$362,986	$310	$20,516	5.99%
Total	**$1,948,856**	**$2,063,838**	**$2,200,916**	**$137,078**	**$252,060**	12.93%
Rate Base	**$6,114,215**		**$5,983,945**		**-$130,270**	-2.13%

The major contributors to the increase in service revenue requirement from the last 2013 rebasing application of $252,060 or 12.9% are related primarily to increases in OM & A expenses and are fully discussed in Exhibit 4. These are offset somewhat by the change in working capital allowance and projected load forecast and customer growth in the 2018 Test year to create a revenue deficiency of $137,078. The computation of revenue deficiency is shown in Exhibit 6.

Therefore, SLHI seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 8 to this application.

The information presented in this application sets out SLHI's forecasted results for its 2018 Test Year. SLHI is also presenting the historical actual information for fiscal years 2013, 2014, 2015, 2016 and forecasted results for the 2017 Bridge Year.

The main drivers of the revenue deficiency, as outlined in Exhibit 6 are:

- Increased on-going consulting fees to respond to regulatory requirements and policy direction.
- Inflationary increases back to 2013 Cost of Service.
- Costs incurred by SLHI for assistance in the preparation and support of this application

B: Budgeting and Accounting Assumptions

Developing SLHI's budget is a key process as it identifies past successes as well as future initiatives and projections for capital and operating costs. SLHI used general inflation, prior year actuals and specific cost drivers for its 2017 Bridge Year and 2018 Test Year forecasts. For 2018 SLHI used an inflation rate of 1.9%. Labour costs reflect the annual wage rate adjustments that SLHI is required to pay under its collective agreement for its unionized employees. For non-unionized employees, the labour cost forecast is largely driven by increases that reflect market competitive compensation.

In conjunction with known or planned requirements, SLHI reviews its process through a benefit–risk lens for new, large and key budget items. Benefits include the additional capability and service being added, and risks include identifying the impact on outcomes of excluding some of the desired purchases and/or hires. All assessments are made through informed decision making points that are also guided by SLHI's customer feedback received, whether verbal, in writing or through formal surveys, as well as through the understanding of the OEB's RRFE objectives.

Both the 2017 Bridge and 2018 Test Years have been compiled using the MIFRS method of presentation. SLHI reviewed and changed the overhead capitalization policy in fiscal 2012; therefore no other change affecting capitalization of overhead costs is required during the transition to MIFRS:

SLHI compiles budget information for the three major components of the budgeting process:

1. Revenue forecasts;
2. Operating, maintenance and administration (OM&A); and
3. Capital costs under the RRFE categories:
    a. System access
    b. System renewal
    c. System service
    d. General plant

SLHI's budget is prepared annually by management and is reviewed and approved by SLHI's Board of Directors. The budget is prepared and approved in Q4 of the previous year each year. Once approved, it does not change and provides a plan against actual results.

C. Load Forecast Summary

SLHI's weather normalized load forecast, it is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on multivariate regression model that incorporates variables that impact energy usage. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. The forecast of customer numbers is based on historical growth patterns and the addition of the 36 customers due to the acquisition of Long Term Load Transfer Agreement customers from Hydro One.

As outlined in Exhibit 3, SLHI has used the same regression analysis methodology used in 2013 cost of service application (EB-2012-0165). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2018. The weather normalized purchased 2018 forecast is adjusted by a historical loss factor to produce a weather normalized billed 2018 forecast which is allocated to each rate class using historical billing data by rate class.

Based on the load forecast methodology, the total billed 2018 Test Year kWh forecast is 72,064,101 which is a 0.0% increase over the 2013 Board Approved kWh forecast of 72,077,404.

The 2018 forecast of customers by rate class was determined using a geometric mean analysis for the Residential and General Service < 50 kW rates classes. The customer/connection forecast for all other classes was maintained at the 2016 level. The expected number of customers/connections for the 2018 Test Year is 3,372 which is a 2.0% increase over the 2013 Board Approved customers/connections of 3,293.

D. Rate Base and DSP

SLHI has calculated its 2018 Test Year rate base to be $ 5,983,945. This rate base is also used to determine the proposed Revenue Requirement found at Exhibit 6. Table 1-3 illustrates SLHI's Rate Base Calculations for the Test Year.

Table 1-3: SLHI Rate Base Calculation for 2018 Test Year

Rate Base	**2018 Test Year**
Fixed Assets Opening Balance	5,145,360
Fixed Assets Closing Balance	5,426,734
Average Fixed Asset Balance	**5,286,047**
Working Capital Allowance	697,898
Total Rate Base	**5,983,945**
Working Capital Allowance	
Eligible Distribution Expenses	**2018 Test Year**
Distribution Expenses - Operations	514,586
Distribution Expenses - Maintanance	226,447
Billing & Collecting	355,718
Administrative and General Expenses	475,341
Donations - LEAP	2,600
Property Taxes	5,394
Total Eligible Distribution Expenses	1,580,086
Power Supply Expenses	7,725,226
Total Expenses for Working Capital	**9,305,312**
Working Capital Factor	7.5%
Total Working Capital Allowance	**885,053**

SLHI has provided its rate base calculations for the years 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge Year and 2018 Test Year in Table 1-4 below:

Table 1-4: Summary of Rate Base

Particulars	**2013 Board Approved**	**2013 Actual**	**2014 Actual**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Bridge**	**2018 Test**
	MCGAAP	**MCGAAP**	**MCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Net Capital Assets in Service:								
Opening Balance	4,947,872	4,934,100	4,936,886	4,936,886	4,959,502	4,948,733	4,984,438	5,145,360
Ending Balance	4,921,716	4,936,886	4,994,934	4,959,502	4,948,733	4,984,438	5,145,358	5,426,734
Average Balance	4,934,794	4,935,493	4,965,910	4,948,194	4,954,118	4,966,586	5,064,898	5,286,047
Working Capital Allowance	1,179,422	1,161,016	1,216,620	1,216,620	1,245,515	1,320,872	1,593,591	697,898
Total Rate Base	**6,114,216**	**6,096,509**	**6,182,530**	**6,164,814**	**6,199,633**	**6,287,458**	**6,658,489**	**5,983,945**

The Rate Base for the 2018 Test Year has been forecasted to decrease $674,545 (10.1%) over the 2017 Bridge Year. Furthermore, the Rate Base for the 2018 Test Year has been forecasted to remain relatively neutral over the last Board Approved Rate Base, decreasing 2.13% or $130,274. The reasons for the variance between the 2018 Test Year and 2017 Bridge and 2018 Test and 2013 last Board Approved is mainly attributed to:

- The decrease in the working capital allowance rate has reduced the Rate Base for the 2018 Test Year. The working capital rate was decreased from the 13% in SLHI's last COS to 7.5% for the 2018 Test Year.
- The annual changes in cost of power and increases in OM&A expenses. SLHI has forecast an increase in eligible distribution expenses since the last Board Approved Rate.
- The implementation of the Ontario Fair Hydro Plan has decreased forecasted Cost of Power expenses from 2017 to 2018 by $2,905,557 or 2.7%.
- The change from 2013 Board Approved Cost of Power expenses to the 2018 Test year is an increase of $73,996 or 1.0%. The reduction of the working capital allowance from 13% to 7.5% has resulted in a lower Rate Base for the 2018 Test Year.
- The average net capital asset in service has also increased. The main drivers behind this the continued investment back into the distribution system.

SLHI has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge Year and 2018 Test Year in Table 1-5 below. Further details of SLHI's calculation of its cost of power calculations are provided Exhibit 2.

Table 1-5: Summary of Working Capital Calculation

	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Distribution Expenses - Operations		535,159	581,576	526,730	574,153	540,346	514,586
Distribution Expenses - Maintenance		215,047	190,949	159,501	194,875	236,866	226,447
Billing and Collecting		296,239	310,022	329,917	351,771	350,791	355,718
Administrative & General Expenses		370,323	501,286	398,869	405,987	491,972	475,341
Donations - LEAP		2,130	2,340	2,340	2,340	2,340	2,600
Property Taxes		3,813	3,850	5,230	2,881	5,294	5,394
Total Eligible Distribution Expenses	**1,421,245**	**1,422,710**	**1,590,024**	**1,422,588**	**1,532,008**	**1,627,609**	**1,580,086**
Power Supply Expenses	7,651,230	7,508,181	7,768,594	8,158,299	8,628,548	10,630,783	7,725,226
Total Working Capital Expenses	**9,072,475**	**8,930,891**	**9,358,618**	**9,580,887**	**10,160,556**	**12,258,392**	**9,305,312**
Working Capital Allowance %	13%	13%	13%	13%	13%	13%	7.5%
Working Capital Allowance	**1,179,422**	**1,161,016**	**1,216,620**	**1,245,515**	**1,320,872**	**1,593,591**	**697,898**

Capital Expenditures

In creating the Distribution System Plan (the "DSP" as attached in Exhibit 2), SLHI has applied its overarching corporate goals, which are to distribute electricity safely and reliably with the highest operating efficiency to provide good value service and provide the shareholder the full regulated return on equity. To meet these goals, SLHI developed protocols and strategies to ensure optimized and efficient planning. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments), and investments into asset repair, rehabilitation and preventative maintenance are planned and implemented. Therefore, the DSP and SLHI's Capital Expenditure Plan seeks to find the right balance between capital investments in new infrastructure and operating & maintenance costs so that the combined total cost over the life of the asset is minimized.

SLHI's DSP is focused on:

- System renewal and expansion
- Customer connections
- Regional planning

SLHI's DSP builds on SLHI's Asset Management Plan that is submitted as part of the DSP with this application. The DSP is a first generation plan which will evolve over time. 2017 and 2018 capital budgets have been prepared based on identified projects which are required to sustain and enhance the distribution system. As is demonstrated in the DSP as well as the remainder of this summary, SLHI is forecasting capital spending will increase for the 2017 year and through to 2018. SLHI has budgeted strategically for a more smoothed spending pattern in the system renewal category. The average change in spending is 1.0% over the forecast period. The variances in the general plant category are attributed to SLHI's Vehicle Replacement Program. Due to the small size of the utility, the purchase of new equipment such as line trucks and bucket trucks impacts capital spending immensely. These capital expenditures are spread out over four categories (as seen in Table 1-6 below): System Access, System Renewal, System Service and General Plant.

Table 1-6: Proposed Capital Investment 2018 to 2022

	Forecast Years						
Investment Category	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**Average**
System Access	100,000	101,800	103,632	105,498	107,397	518,327	103,665
System Renewal	154,329	220,456	138,836	141,335	143,879	798,835	159,767
System Service	-	-	-	-	-	-	-
General Plant	364,000	79,000	315,000	44,000	9,000	811,000	162,200
Total:	**618,329**	**401,256**	**557,468**	**290,833**	**260,276**	**2,128,162**	**425,632**
Removal of Vehicle Replacement	**(355,000)**	**(60,000)**	**(300,000)**	**(35,000)**			
	263,329	**341,256**	**257,468**	**255,833**	**260,276**	**1,378,162**	**275,632**

Capital Expenditures Requested for the 2018 Test Year

Capital expenditures for the 2018 Test year are $618,329. This is a $298,389 increase from the last Board approved 2013 Test Year of $319,940. The main reason for this variance is the inclusion of the purchase of a Line Truck in 2018 for an estimated $355,000. With the exclusion of this expenditure the change over the 2013 to 2018 capital expenditures is a decrease of $55,611 or 17%.

SLHI's capital investment plan mainly focuses on system renewal from year to year. Due to the cost of larger vehicles and equipment, when these purchases occur in a particular year, it will have a significant overall impact on the capital purchases.

Summary of Any Costs Requested for Renewable Energy Connections/Expansions, Smart Grid, and Regional Planning Initiatives

SLHI is not requesting any costs related to renewable connections/expansions, smart grid, or Regional planning initiatives. Therefore no amount is included for recovery from our ratepayers.

Regional Planning

The final Regional Infrastructure Plan (RIP) for the Northwestern Region was issued on June 9, 2017 and included as Appendix 1C. Also an Integrated Regional Resource Plan has been completed for SLHI's service territory and is included in the DSP in Exhibit 2. SLHI will incorporate future capital expenditure planning processes and future rate applications as necessary. SLHI confirms that no projects listed in the RIP impact SLHI's distribution system. Therefore, SLHI has not included any specific costs for Regional Planning investments in its capital plan.

E. Operations, Maintenance and Administration Expense

SLHI is proposing recovery through distribution rates of $1,572,092 in Operating, Maintenance and Administration (OM&A) costs for the 2018 Test Year.

OM&A expenditures in the 2018 Test Year represent an increase of $150,846 or 10.6% over the 2013 Board Approved OM&A expenditures of $1,421,246. The following Table 1-7 summarizes the changes.

Table 1-7: OM&A for 2013 Board Approved and 2018 Test Year

Summary of OM&A Expenses			
Description	**2013 Board Approved**	**2018 Test Year**	**Variance From Board Approved**
Operations	543,617	514,586	-29,031
Maintenance	201,605	226,447	24,842
Billing & Collecting	316,965	355,718	38,753
Administration and General	359,059	475,341	116,282
Total OM&A	**1,421,246**	**1,572,092**	**150,846**
Percentage Change Year over Year		**10.6%**	

The proposed OM&A expenditures for the 2018 Test Year have been derived through a detailed budgeting and business planning process aligned to meet SLHI's core business objectives. These expenditures are required to allow SLHI to maintain and provide improved value upon the distribution business service quality and reliability standards in compliance with the Distribution System Code and other regulatory bodies (IESO, Ministry of Energy, ESA, etc.), as well as the value our customer's receive. The OM&A costs in the 2018 Test Year reflect the resourcing mix and investments required to meet customer and broader public policy. Without these resources and investments, SLHI will struggle to meet customers increased expectations, future workloads and better service SLHI is planning for our customers. The main drivers for the increased administration and general expenses, is the need for additional resources to respond to regulatory and policy directions.

SLHI used a general inflationary rate of 1.9% where the expense increase could not be specifically identified for non-wage related expenses, based on the Ontario Energy Board's inflation rate released on October 27, 2016. Inflationary impacts are not material enough to be identified separately.

Provided below In Table 1-8 is the total compensation for the test year as well as the last OEB approved. The management (including Executive) row is blank as there is only one employee in that category so the information is aggregated into the Non-Management (union and non-union) category.

Table 1-8: Total Compensation - 2013 Board Approved and 2018 Test Year

Total Compensation (Salary, Wages & Benefits)				
	Last Rebasing Year - 2013 Board Approved	2018 Test Year	Difference	% Change
Management (including Executive)				
Non-Management (union and non-union)	785,445	825,715	40,270	
Total Compensation (Salary, Wages & Benefits	**785,445**	**825,715**	**40,270**	**5%**

The increased primarily relates to the effect of year over year wage increases defined in the collective agreement for union employees, and is offset by a decrease of one staff member in 2018, as explained in Exhibit 4.

F. Cost of Capital

SLHI has prepared its Application in accordance with the Board's guidelines provided in the Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "Cost Report") issued on December 11, 2009. For the purposes of preparing this Application, SLHI has used the cost of capital parameters issued by the Board on October 2, 2016 for 2017 cost of service rate applications for rates with effective dates in 2017. SLHI acknowledges that the Board will issue updated cost of capital parameters. SLHI will update its cost of capital parameter to reflect the Board issued cost of capital parameters for rates with effective dates in 2018 at a later date, as SLHI's COS was submitted before these were released. SLHI proposes no deviation from the Board's cost of capital methodology.

G. Cost Allocation and Rate Design

SLHI has not deviated from the Board's cost allocation and rate design methodology.

Cost Allocation

The data used in the updated 2018 cost allocation study is consistent with SLHI's cost data that supports the proposed 2018 revenue requirement outlined in this Application. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed in the original cost allocation study in 2007. There have been no significant changes to SLHI's system to warrant a change in the breakout.

As shown in Table 1-9, the resulting 2018 cost allocation study indicates the revenue to cost ratios for Street Lights and the General Service over 50 kW are outside the Board's range. For 2018, it is proposed the ratio for Street Lights be set at the maximum range of 120.00% and the ratio for General Service > 50 KW also be set at 120.00%. The General Service < 50 kW and Residential rate classes would be adjusted upward to maintain revenue neutrality.

Table 1-9: Revenue to Cost Ratios

Rate Class	Previously Approved Ratios Most Recent Year 2014 (EB-2013-0170)	2018 Updated Cost Allocation Study	2018 Proposed Ratios	2019 & 2020 Proposed Ratios	Policy Range
Residential	96.35%	91.02%	95.88%	95.88%	85% - 115%
General Service < 50 kW	109.85%	95.80%	100.00%	100.00%	80% - 120%
General Service 50 kW to 4,999 kW	115.80%	131.57%	120.00%	120.00%	80% - 120%
Street Lights	83.08%	325.34%	120.00%	120.00%	80% - 120%
Unmetered Scattered Loads	81.30%	-	-		80% - 120%

Rate Design

Except for the Residential rate class, SLHI proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges.

In regards to the Residential class, on April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This will be implemented over a period of four years, beginning in 2016. In 2016 and 2017 SLHI implemented the first and second year's movement of this policy. In 2018, SLHI proposes to implement the third year of this policy.

Table 1-10 outlines a comparison between the 2017 current and the 2018 proposed distribution rates.

SLHI does not propose any mitigation plans to address rate impacts on specific customer classes or overall.

Table 1-10: Distribution Charges

	Monthly Service Charge				Distribution Volumetric Charge		
Rate Class	2017 Current	2018 Proposed	% Difference	Unit of Measure	2017 Current	2018 Proposed	% Difference
Residential	35.56	44.14	24.13%	kWh	0.006	0.0034	-43.33%
General Service < 50 kW	43.55	46.5	6.77%	kWh	0.0082	0.0101	23.17%
General Service 50 to 4,999 kW	386.97	376.38	-2.74%	kW	1.3481	1.3129	-2.61%
Street Lights	10.74	3.96	-63.13%	kW	28.3225	11.096	-60.82%
Transformer Discount				kW	0.3741	0.3741	0.00%

H. Deferral and Variance Accounts

As outlined in Exhibit 9, SLHI is requesting approval of disposition of Group 1 Accounts, Group 2 Accounts 1508 – Deferred IFRS Transition Costs, 1518 Retail Cost Variance Account – Retail, and 1548 Retail Cost Variance Account – STR, Account 1568 LRAM Variance Account, and 1575 – IFRS-CGAPP Transition PP&E Amounts.

The total disposition requested is $(144,763) owed to customers. Group 1 Accounts not including Account 1589 – Global Adjustment totals $(179,633) owed to customers. The Balance to be refunded to Non-RPP Customers for Account 1589 – Global Adjustment is $(78,754). The balance requested for disposition from Group 2 Accounts is $38,364 owed by customers. The LRAM Variance Account – 1568 balance requested for disposition is $6,030. All of the above is requested to be disposed over one year.

The balance in Account 1575 – IFRS-CGAAP Transition PP&E Amounts plus Return Component requested for disposition is $69,230 owed by customers. The amount was updated in Appendix 2-EA to include the forecast 2017 amount of $5,438 plus the WACC of $16,261. This amount is requested to be disposed over a five year period to coincide with the cost of service term and reduce the impact to customers.

SLHI is not requesting any new Deferral and Variance Accounts.

I. Bill Impacts

In preparing this application, SLHI has considered the impacts on its customers, with a goal of minimizing those impacts. Table 1-11 provides a summary of total bill impacts ($ and %) for typical customers in all rate classes.

Table 1-11: Total Bill Impacts

Rate Class	Monthly kWH	Monthly kW	$ Change	% Change
Residential	750		$ 7.80	6.19%
Residential (lowest 10th percentile)	518		$ 8.44	8.54%
General Service less than 50 kW	2,000		$ 7.48	2.53%
General Service 50 to 4,000 kW	65,700	100	$ (317.69)	-2.75%
Street Lights	12,340	33	$ (3,811.58)	-40.36%

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts;
- Revised Retail Transmission rates;
- Wholesale Market Service Rates; and
- Loss Factors.

1.6 Customer Engagement

The Report of the Board, RRFE: A Performance Based Approach (the "RRFE Report") contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. SLHI always has, and always will focus on its customers by striving to provide superior service to its customer base, because this is what adds value to our customers. SLHI communicates with its customers on a daily basis through face-to-face interaction in the office as well as out in the field. In order to improve communication at times of unexpected outages, SLHI created a Facebook page to provide updates on expected restoration times and other information. In this section, SLHI has provided an overview of customer engagement activities that it has undertaken with respect to its daily operations and illustrates how customer feedback has been used to continually improve the customer experience.

Customer preferences and behaviours are ever changing and that means that the utility must adapt and transform as well. SLHI understands it must be seen as accessible, responsive, accountable, transparent and trustworthy. A customer centric focus with an emphasis on lowering costs must be a priority. This is in keeping with the requirements of the RRFE which contemplates enhances engagement between distributors and their customers to better align a distributor's operational plans with its customers' needs and expectations.

As a small utility SLHI feels that we are very well connected with our customers and they have better access to information than the larger utilities. For example, when a customer calls, the phone is answered by one of the office staff, or even the President in some cases. They get first-hand information from the people who are most knowledgeable about the company. Any requests for information are answered in most cases on-the-spot or the same day.

SLHI conducted a survey beginning August 19, 2017 informing customers of the main drivers of the capital and OM&A increases and the bill impacts for Residential and small general service classes. The survey was conducted online and was posted on the home page of the SLHI website as well as promoted through the Sioux Lookout Hydro Facebook page, and was open until August 27, 2017. The Facebook page post reached almost 5,800 people. SLHI received 57 responses, of which 48 could be validated, which is 2% of Residential and Small General Service customers. The survey and results are attached as Appendix 1F.

The results indicate that just over 50% of customers do not want SLHI to invest in its capital or OM&A if it means an increase to rates. Forty-eight percent (47.7%) have also indicated the distribution rate increase is unreasonable. There was a section at the end of the survey where the customer could provide general comments, there were also comments received through Facebook.

These remarks were mostly questions and comments about the costs not related to SLHI's distribution charges, and referred to Hydro One on a number of them. Since Hydro One has a large presence in our area many customers often don't separate SLHI from Hydro One and simply refer to "Hydro". In general, people are not happy about the hydro rates in Ontario and seem to feel any increase whatsoever would be unacceptable. SLHI feels that these circumstances have swayed peoples' perceptions and many did not understand that the proposed expenditures and costs only related to distribution costs. Also, at the time of this application customers have not yet felt the impact of the Ontario Fair Hydro Plan, and Distribution Rate Protection Program since the first bills for July consumption were sent out August 23rd.

SLHI feels that going forward more effort should be made to educate consumers about the make-up of the hydro bill so there is no confusion as to the role SLHI plays in their bill and what services they provide. SLHI plans to do this mostly on-line through Facebook, keeping the costs as low as possible to customers.

In light of these customers' concerns and in line with our Corporate Goals, SLHI has endeavored to keep the increase as low as possible. SLHI has reviewed all costs and determined that the costs presented are needed in order to manage the business going forward, however upon the review discovered there was some room to adjust the revenue to cost ratios to decrease the impact to the residential and small general service classes that were presented in the survey. The application reflects these adjustments.

Table 1-12 below details SLHI's Customer Engagement activities and is consistent with Appendix 2-AC.

Table 1-12: Customer Engagement Activities Summary

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
2014 Customer Satisfaction Survey	Overall Customer Satisfaction, Reliability, Conservation Programs Offered, Planned Outage Communication, Satisfaction with unplanned outages, Impact of Power Outages on Customers, Customer Expectations with respect to Unplanned outages, Customer needs with respect to Electric Vehicles, Renewable Generation, Energy Storage and Outage Management Systems	Customers indicated they were generally satisfied overall with SLHI. There was a very low level of interest with respect to customer needs (Electric Vehicles etc.) Therefore no action was taken.
2016 Customer Satisfaction Survey	Overall Customer Satisfaction, Power Quality and Reliability, Price, Billing Accuracy, Payment Options, Customer Service, Communications and Suggestions for Improvements	There were no identifed needs of the customer in this survey, except for Lower costs and less power outages. The DSP sets out SLHI's plan for continued system renewal in order to decrease the number of power outages due to equipment failure and aging infrastructure.
Facebook	As a communication tool mainly for unexpected power outages to provide customers with information on restoration times etc. It is also used to promote conservation programs and any other important industry related news.	No needs identified
In Office Customer Service and Face-to-face interaction	Customers need local office for customer payments and inquiries including assistance and suppport for arrears management.	Local office open five days a week accepting bill payments and handling inquiries face to face.
Electrical Safety Awareness Survey	Good general knowledge of electrical hazards and safety	No concerns at this time.
Leap Funds to Social Agency	Low-income customers need assistance to pay high heating costs.	SLHI, among other LDCs are mandated to contribute funds to social agencys for the LEAP to support low-income customers in need of resources for paying bills in arrears. The distribution of these funds show this program is highly utillized and needed.
E-Billing and Online Account Services	SLHI provides on-line access to consumption information for customer who sign up for e-billing	Customers find it useful to be able to see their hourly consumption patterns and when they use on, mid and off peak consumption in order to more effectively manage their bill.
Website	Responds to the customers' need for information about the utility, programs offered and other regulatory information.	Important information is found on the SLHI website relating to contact information, scheduled power outage notices, rate information, information on our Online management tool, Programs available for financial assistance (OESP). SLHI Scorecard and Regulatory proceedings.
CDM Programs - RESA	SLHI was under-target in the last Conservation Framework, and identified a need for greater communication with customers	A regional energy services advisor was hired in order to provide customers with on-going information about conservation programs offered in our area, as well as assistance completing paper work for the programs.
Face to Face with large customers	Meeting with the hospital to discuss future plans for retrofits with respect to conservation.	There were no needs identified.
Annual Shareholder's Meeting	As a major customer with several large facilities along with the Street Lighting Account. The Annual Shareholder's Meeting allows SLHI to communicate issues and allows the Shareholder to voice concerns and ask questions on their needs and preferences. At the Shareholder's meeting in June 2017, SLHI made the Municipality aware that the Street Lighting rate class would be materially affected as a result of updated the Cost Allocation Study from 2013.	No needs identifed.
2018 Investment and Bill Impact Survey	Inform customers of planned capital expenditures, OM&A costs and bill impacts for the 2018 cost of service and ask if they are acceptable to our customers. Just over 50% of Customers indicated SLHI should decrease their capital investment and did not feel the proposed budget was reasonable. 47% indicated that the rate increase was unreasonable.	The increased costs were determined to be necessary in order to operate SLHI going forward. The majority of responses were received by residential customers, and in order to lessen the impact the revenue to cost ratios for the residential and general service classes were adjusted downward from what was initially proposed in the survey to decrease the impact. SLHI has kept increases as low as possible in light of customers' concerns.

1.7 Performance Measurement

This Section details the steps SLHI has taken in respect of each of the Board's four RRFE outcomes. In connection with the RRFE outcomes, the Board issued a scorecard to SLHI on September 22, 2016, which is attached as Appendix 1E.

Renewed Regulatory Framework for Electricity Distributors (RRFE)

The Board introduced a new approach to rate setting at the end of 2012 with the RRFE. The RRFE is a performance based approach to regulation that focuses on the achievement of outcomes such as efficiency, reliability, sustainability, and financial viability. The Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach ("RRFE Report") issued on October 18, 2012, outlines the following four (4) performance outcomes the Board expects distributors to achieve.

1. **Customer Focus:** services are provided in a manner that responds to identified customer preferences;
2. **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. **Financial Performance:** financial viability is maintained; and savings from operational effectiveness are sustainable.

Scorecard

On March 5, 2014, the Board issued a report for the Performance Measurement for Electricity distributors: A Scorecard Approach (EB-2010-0379). The report details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvements in achieving the four performance outcomes mentioned above, and to eventually facilitate distributor benchmarking. During the implementation period of the scorecard, the Board recognized that new measures may not have uniform definitions and therefore the Board has not yet determined industry targets for these measures. The Board intends for all measures on the scorecard to be uniform and have industry targets by 2018 for comparability and benchmarking purposes.

SLHI has published its most recent scorecard for public viewing on its website at http://www.siouxlookouthydro.com/.

SLHI's scorecard for 2011-2015 is presented below and in Appendix 1E in full.

Scorecard - Sioux Lookout Hydro Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	96.40%	95.00%	100.00%	100.00%	↑	90.00%	
		Scheduled Appointments Met On Time		97.30%	92.90%	98.50%	98.20%	96.20%	↑	90.00%	
		Telephone Calls Answered On Time		97.10%	98.10%	98.60%	100.00%	96.20%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution					100%	100%			
		Billing Accuracy					99.67%	99.90%	↑	98.00%	
		Customer Satisfaction Survey Results					89.51%	89.51%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.71	0.47	0.23	1.28	0.68	↓		0.92
		Average Number of Times that Power to a Customer is Interrupted [2]		0.77	0.17	0.28	0.74	0.36	↓		0.50
	Asset Management	Distribution System Plan Implementation Progress					Stage 1	Stage 2			
	Cost Control	Efficiency Assessment			3	3	3	3			
		Total Cost per Customer [3]		$742	$814	$802	$869	$818			
		Total Cost per Km of Line [3]		$7,219	$7,928	$7,845	$8,445	$8,273			
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).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						14.52%			3.70 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.35	1.15	1.00	0.96	0.95			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.86	0.80	0.71	0.64	0.58			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.57%	8.98%	8.98%	8.98%			
			Achieved	9.67%	9.22%	12.30%	6.38%	7.38%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend: 5-year trend: ↑ up ↓ down → flat; Current year: target met, target not met

Customer Focus

Service Quality

New Residential/Small Business Connected on Time

SLHI has improved performance in 2014 and 2015 at 100% connected on time. SLHI's experience with connecting New Residential/Small Business Services on time continues to be above the industry target of 90% through commitment to SLHI's customers and SLHI's process for new connections. SLHI will continue to strive for 100% in this area category.

Scheduled Appointments Met On Time

SLHI's experience with meeting Scheduled Appointments on time continues to be above the industry target of 90% through a continued commitment to SLHI's customers and SLHI's process for completing appointments within the 5 day window. In the future, SLHI will continue to follow current practices for continued success of this service quality indicator to be 90% or better.

Telephone Calls Answered on Time

Calls answered within 30 seconds continues to be well above the industry target of 65% and trending upward through a commitment to SLHI's customers and SLHI's process for telephone calls answered on time. SLHI will continue with current practices to attain their target of 95% for calls answered on time.

Customer Satisfaction

First Contact Resolution ("FCR")

SLHI continues to develop this measure as no firm methodology from the OEB has been presented. A tool SLHI uses is how many customer complaints get escalated to upper management as well as the OEB level. For 2014 and 2015, there were zero concerns that were escalated to upper management or complaints to the OEB. Therefore a score of 100% was given. SLHI will maintain current practices to achieve 100% going forward.

Billing Accuracy

Any cancelled bill after the bill is issued is tracked and recorded manually through the examination of all cancelled bills. SLHI has adopted the target of 98% for its own purposes. In 2014 and 2015 SLHI has exceeded the industry and utility target of 98% with percentages of 99.67% and 99.9% respectively.

Customer Satisfaction Survey

Active engagement with customers helps SLHI understand its customer preferences and assist the organization in shifting focus in order to deliver services in alignment with customer needs. The recent survey conducted in the summer of 2016 (found in Appendix E of the Distribution System Plan in Exhibit 2, Appendix 2A), indicated an overall satisfaction score of 82.99%. Please refer to Table 1-13 of this Exhibit for details of SLHI's Customer Engagement Activities. SLHI has adopted a target of 80% or higher for customer satisfaction. SLHI will endeavour to increase its customer engagement through such outlets as Facebook to improve customer satisfaction.

Operational Effectiveness

Board Staff recommended 9 measures to assess a distributor's operational effectiveness: three safety measures, two system reliability measures, one asset management measure, and three overall cost performance measures.

Safety

SLHI's target is full compliance and zero serious electrical incidents for this measure. SLHI receives data from the Electrical Safety Authority providing performance data for the SLHI Distributor Scorecard. The data was for Component B (Compliance with Ontario Regulation 22/04) and Component C (Serious Electrical Incident Index) under the 'Safety' Performance Category of the Scorecard. SLHI has always been compliant with Ontario regulation 22/04 and has had zero electrical incidents occur over the life of the scorecard.

The level of public awareness for 2015 was 79%. SLHI does not currently have a utility specific target for this measure, however is planning to run ads in conjunction with the Electrical Safety Authority to further promote public safety awareness.

System Reliability

SAIDI and SAIFI

SLHI's system reliability statistics for both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) falls below the five year average for 2015. In 2011 and 2014 Sioux Lookout experienced an increase in storm activity which caused the measures to be above average. More detail on this is included in Exhibit 2 and the DSP section 5.2.3.3. With the implementation of adjusting these measures for major events, SLHI forecasts that this measure will be met each year.

SLHI continues to invest in new infrastructure as well as preventative maintenance which is intended and will allow SLHI to continue to meet its system reliability targets.

Asset Management

Distribution System Plan Implementation Progress

Performance metrics added by the OEB in 2014 include monitoring the cost efficiency and effectiveness with respect to planning quality and DSP implementation. Since SLHI is submitting its first DSP with this application these metrics have not historically been tracked, however processes will be developed to monitor and report in these areas going forward. Metrics will include:

- Physical project progress vs. plan;
- Financial project progress vs. plan; and
- Actual vs. planned cost of work completed.

SLHI's Distribution System Plan is completed and filed with this application in Exhibit 2, Appendix 2A.

Cost Control

Efficiency Assessment

SLHI has been working hard to improve its performances, to reduce costs, and to be more efficient. Using the PEG Forecasting Model, SLHI expects to remain in Group 3. The model shows that SLHI moves from -4.3% to -8.83% in the 2018 Test year. Focusing on customer satisfaction, SLHI details below some of the initiatives which all align with the objectives of the RRFE. SLHI will continue to find ways to respond to customer needs, and add more value to its customer if it is cost efficient. The Summary of the PEG Benchmarking model is attached as Appendix 1F, and the live excel model will be submitted with the application.

<u>24 Hours After Hours Call and On-Call Staff</u>

In order to respond to customers' needs, SLHI possesses a 24 hour after-hours call centre telephone answering service that processes calls from customers and the general public in accordance with instructions from SLHI. On call staff is available 24 hours a day, including evenings, weekends and statutory holidays.

<u>Facebook Page</u>

SLHI has begun to utilize a Facebook page in order to provide information to customers about major scheduled and non-scheduled outages, such as customers affected, cause and restoration time of outages. The Facebook page was created in July 2016. Providing customers with information through social media reduces the number of phone calls to our after-hours number during times when there are multiple or wide-spread outages.

<u>Shared Services</u>

SLHI aims to reduce expenses by procuring materials and services at the lowest possible cost. With this in mind, SLHI is part of the Northwest Group of utilities (Thunder Bay Hydro, Atikokan Hydro, Fort Frances Power Corp and Kenora Hydro) who collaborate together in order to share services to reduce costs. These services include the Billing System and Conservation and Demand Management. Thunder Bay Hydro is the largest LDC in the region; therefore they provide services to SLHI and the other small utilities providing cost savings to each utility.

SLHI is also a member of the Utility Standards Forum (the "USF"). This Forum has a membership of 54 Ontario LDCs. The USF provides SLHI with valuable resources with respect to engineering, regulatory and information technology. These resources allow SLHI to achieve cost savings due to collaboration amongst the group to develop such things as engineering standards, templates for reports and training opportunities.

Total Cost per Customer/Total Cost per Km of Line

SLHI's total costs per customer of $818 in 2015 are a decrease over 2014 amount of $869 due to a one-time expense in 2014 due to Group 1 variance amount disallowed by the OEB (EB-2013-0170). After removing this amount the cost per customer for 2014 is $816, and shows that the metric is stable over the five year period from $814 in 2012 to $818 in 2015. Further, the total cost per Km of line has remained stable from 2012 to 2015.

In the future, SLHI will continue to be committed to measures under operational effectiveness, maintaining its strong safety and system reliability measures. Even with the increased OM&A, SLHI will continue to find efficiencies and cost improvements.

Public Policy Responsiveness

In the Board's Scorecard Report, Board Staff recommended four measures to assess a distributors' public policy responsiveness: two CDM measures and two measures for connection of renewable generation.

Conservation and Demand Management

SLHI submitted a joint CDM Plan for the 2015 – 2020 Conservation First Framework with the four other Northwest District LDCs (Thunder Bay Hydro, Atikokan Hydro, Fort Frances Power Corp and Kenora Hydro). The group contracted with the IESO to deliver a portfolio of IESO-contracted province-wide CDM programs ("IESO Programs") to all customer segments including residential, commercial, institutional and low income. SLHI does offer all province-wide programs that are applicable to the area. Since Sioux Lookout does not have natural gas available, there are certain programs that are ineligible.

In 2015 SLHI achieved 14.52% of its first year savings, which exceeded the 7% target. This was mainly due to a Municipal Street Light LED Conversion project being completed in 2015, which was initially scheduled for 2014.

Future reports on Conservation will be provided by SLHI to the IESO who will report annually to the OEB.

Connection of Renewable Generation

Renewable Generation Connection Impact Assessments Completed on Time

SLHI has not had any requests to connect generation projects over 10 kW to date.

New Micro-embedded Generation Facilities Connected on Time

All microFITs have been connected on time. SLHI works closely with customers and their contractors to address any connection issues and ensure the project is connected on time.

Financial Performance

In the Board's Scorecard Report, Board Staff recommended three measures to assess a distributor's financial viability: current ratio, total debt-to-equity ratio, and achieved regulated rate of return.

Current Ratio

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates the company can pay its short term debts and financial obligations. SLHI's 2014 current ratio of .96 and 2015 current ratio of .95 are very close to the expected 1.0. SLHI's practice to fund capital investments with short term funds (i.e. cash) rather that incur debt which would lead to increased interest payments to its customers contributes to the current ratio. SLHI continually monitors its short term assets to ensure that all of its short term obligations are met.

Total Debt to Equity

The current deemed debt to equity ratio is 1.5. SLHI's debt to equity ratio has been declining since 2011 (0.86 in 2011 to 0.58 in 2015) as the company pays down its long term debt while not requiring any new debt to fund capital projects over the years. Once the Distribution System Plan is implemented SLHI will require additional long term debt to finance the replacement of key equipment, which will increase the debt to equity ratio.

Regulatory Return on Equity

SLHI's current distribution rates were approved by the OEB effective May 1, 2017 and include an expected return on equity of 8.98%. In 2015, the actual return on equity was 7.38%. In 2013 SLHI's return on equity exceeded the expected by 3.31%. The main reasons for this were a slight increase in the expected revenues due to the mill operations and the smart meter rate riders along with a decrease in operations expenses due to lower wages rates for apprentice linemen.

1.8 Financial Information

Non-Consolidated Audited Financial Statements

SLHI has filed the non-consolidated audited financial statements of the utility for the three most recent historical years i.e. for the years ending December 31, 2014 to 2016 respectively. SLHI does not have any affiliates. Copies of SLHI's Audited Financial Statements are provided in Appendices 1G, and 1H.

Reconciliation between Audited Financial Statements and Regulatory Accounting

SLHI has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this application. SLHI's reconciliation between financial statements and regulatory financial results is provided as Appendix 1I.

Annual Report and MD&A

SLHI does not publish an annual report or an MD&A. Therefore this requirement is not applicable.

Rating Agency Reports

SLHI does not possess any Rating Agency Reports. Therefore this requirement is not applicable.

Prospectus, Information Circulars for Recent and Planned Issuances

SLHI has not prepared any prospectuses or information circulars for recent of planned issuances. Therefore this requirement is not applicable.

Change in Tax Status

SLHI is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service Application dated February 22, 2013, EB-2012-0165.

Accounting Orders

SLHI does not have any current accounting orders.

Uniform System of Accounts

SLHI is not aware of any departures from the Uniform System of Accounts.

Accounting Standards

The Accounting Standards Board ("AcSB") deferred mandatory adoption of IFRS for qualifying rate-regulated entities to January 1, 2015. However, per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP were required to implement regulatory accounting changes for depreciation expenses and capitalization policies by January 1, 2013. SLHI confirms it implemented the regulatory accounting changes for depreciation in 2012. SLHI attests that it does not and will continue to not capitalize administration and other general overhead costs no longer permitted under IFRS, as clarified by the Board in its letter dated February 24, 2010. SLHI understands the need for comparability between distribution utilities. These changes were reflected in SLHI's last Cost of Service Application, EB-2012-0165.

SLHI adopted IFRS in 2015, with 2014 being the transition year, therefore the 2018 Cost of Service Application is to be filed on an IFRS accounting basis.

Accounting Treatment of Non-Utility Businesses

SLHI confirms it does not conduct non-distribution business.

1.9 Distributor Consolidation

SLHI has not acquired or amalgamated with any other distributor(s) since its last rebasing application.

Appendix 1A: List of Specific Approvals Requested

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

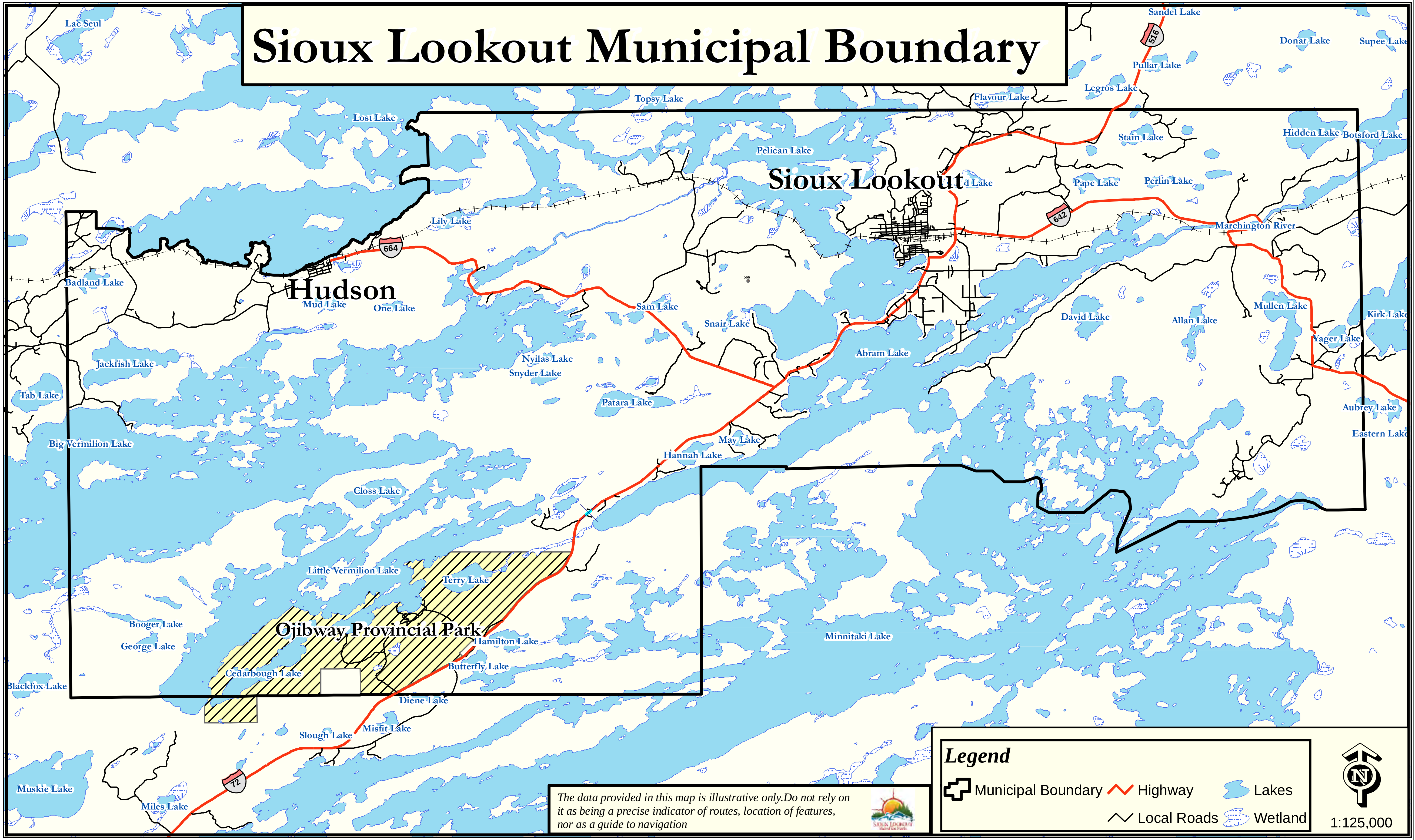
Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Sioux Lookout Hydro Inc. is seeking the following approvals in this application:

1		Approval under Section 78 of the Ontario Energy Board Act, 1998 to charge distribution rates effective May 1, 2018 to recover a service revenue Requirement of $2,200,916 which includes a revenue deficiency of $137,078 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
2		Approval of the Distribution System Plan as outlined in Exhibit 2.
3		Approval of revised low voltage rates as proposed and described in Exhibit 8.
4		Approval to adjust the Retail Transmission Rates - Network and Connection as detailed in Exhibit 8.
5		Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of SLHI's 2017 Distribution Rates (EB-2016-00103).
6		Approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of SLHI's 2017 Distribution Rates (EB-2016-0103).
7		Approval to remove the Unmetered Scattered Load Class.
8		Approval of the proposed loss factors as detailed in Exhibit 8.
9		Approval of the rate riders for a one year disposition of the Group 1 Deferral and Variance Accounts as detailed in Exhibit 9.
10		Approval to dispose of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") for lost revenue from 2011 to 2015 resulting from 2011 to 2015 IESO (formally OPA) programs as detailed in Exhibit 4.
11		Approval to dispose of Group 2 Accounts 1508, Sub Account IFRS, 1518 Retail Cost Variance Account - Retail, 1548 Retails Cost Variance Account - STR as outlined in Exhibit 9 over a one year dispostion.
12		Approval to dispose of Account 1575 IFRS-CGAAP Transition PP&E Amounts over a five year disposition period as outlined in Exhibit 9.
13		Approval to change the wording under Specific Service Charges from Returned Cheque (plus bank charges) to Returned Item (plus Bank Charges).
14		SLHI may request such other approvals as counsel for SLHI may submit and the Board may allow.

Appendix 1B: Map of SLHI's Distribution Service Territory

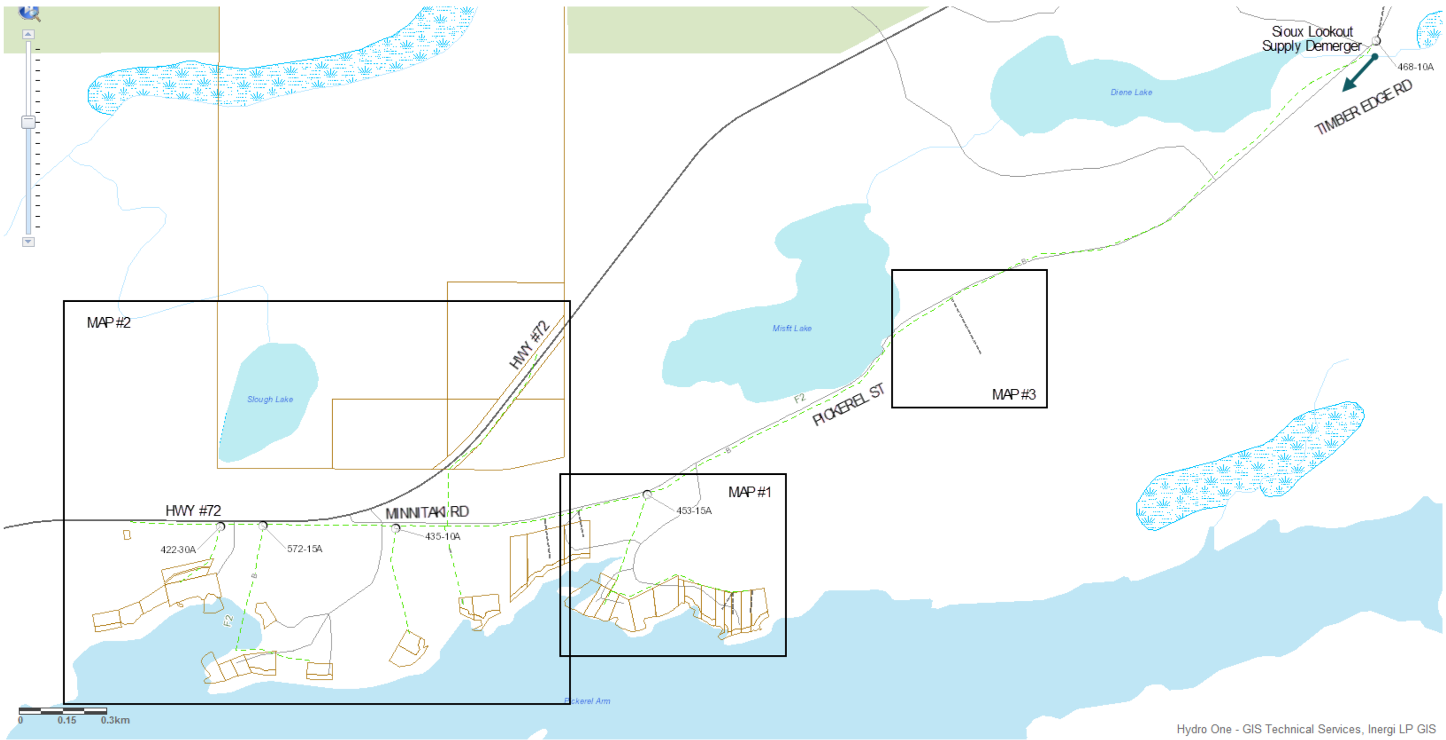

Sioux Lookout Municipal Boundary
Sioux Lookout
Hudson
Ojibway Provincial Park
Lac Seul
Sandel Lake
Donar Lake
Supee Lake
Pullar Lake
Legros Lake
Flavour Lake
Topsy Lake
Lost Lake
Stain Lake
Hidden Lake
Botsford Lake
Pelican Lake
Pape Lake
Perlin Lake
Lily Lake
Marchington River
Badland Lake
Mud Lake
One Lake
Sam Lake
Snair Lake
David Lake
Allan Lake
Mullen Lake
Kirk Lake
Yager Lake
Abram Lake
Nyilas Lake
Snyder Lake
Jackfish Lake
Tab Lake
Patara Lake
Aubrey Lake
Eastern Lake
May Lake
Hannah Lake
Big Vermilion Lake
Closs Lake
Little Vermilion Lake
Terry Lake
Booger Lake
George Lake
Hamilton Lake
Minnitaki Lake
Butterfly Lake
Cedarbough Lake
Blackfox Lake
Diene Lake
Misfit Lake
Slough Lake
Muskie Lake
Miles Lake
516
664
642
72
The data provided in this map is illustrative only.Do not rely on it as being a precise indicator of routes, location of features, nor as a guide to navigation
Legend
Municipal Boundary
Highway
Lakes
Local Roads
Wetland
N
1:125,000

Hydro One Geographical LDC Maps for LTLT Elimination with Sioux Lookout Hydro as Physical LDC

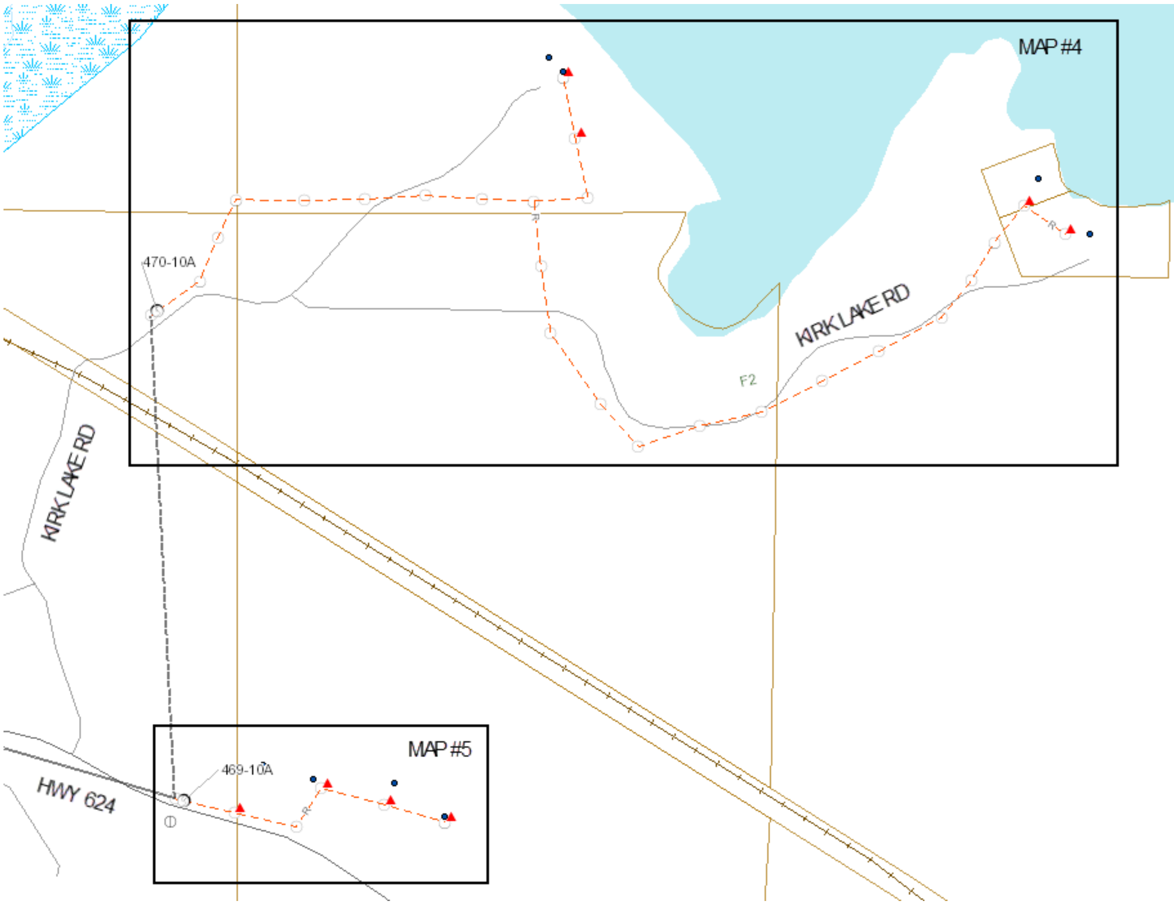
Maps Legend

MAPS

Overview #1-



Overview #2 -




Hwy72/Minnitaki Rd.
2.64sq Km
Diene Lake
Misfit Lake
Slough Lake


Yager Lake
Sioux Lookout
Kirk Lake
Sioux Lookout
Hwy 642/Kirklake Rd.
.78sq Km

Appendix 1C: Regional Infrastructure Plan for the Northwestern Region

Northwest Ontario

REGIONAL INFRASTRUCTURE PLAN

June 9, 2017

hydro one

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

With support from:

Company
Atikokan Hydro Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Kenora Hydro Electric Corporation Ltd.
Thunder Bay Hydro Electricity Distribution Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation

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DISCLAIMER

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

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

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

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EXECUTIVE SUMMARY

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

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

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Atikokan Hydro Inc.
- Kenora Hydro Electric Corporation Ltd.
- Thunder Bay Hydro Electricity Distribution Inc.
- Sioux Lookout Hydro Inc.
- Fort Frances Power Corporation

This RIP is the final phase of the regional planning process and it follows the completion of Integrated Regional Resource Plan ("IRRP") by the IESO for the North of Dryden Sub-Region in January 2015, Greenstone-Marathon Sub-Region in June 2016, and West of Thunder Bay in July 2016 and for Thunder Bay Sub-Region in December 2016 [2-5]. This report also references the IESO Draft Remote Community Connection Plan report [6].

This RIP provides a consolidated summary of needs and recommended plans for North of Dryden, Greenstone-Marathon, West of Thunder Bay, and Thunder Bay Sub -Regions that make up the Northwest Ontario Region. The potential needs of the bulk system is not within the scope of the Regional Planning, however, some aspects of the bulk system needs and plans are discussed in this report in the context of regional plans.

The Working Group has reassessed and updated the LDC load forecasts, which have remained consistent with the forecasts used in the IRRPs. Accordingly, this RIP has confirmed the needs and the proposed or recommended infrastructure (wires) plans for the sub-regions as indicated in the IRRP reports.

The needs in the region are largely driven by the industrial load growth, particularly the mining sector. Considering the uncertainties in the forecast of the industrial loads, this RIP uses the forecast scenarios and assumptions developed for the Northwest IRRPs. The connection of remote communities to the electricity grid, as well as the load growth as a result of economic developments, are also contributing factors. Since the development timelines and plans for connection of the mining and other industrial loads are uncertain and frequently depend on the customer decision, the IRRP and RIP have both considered low, medium (or reference) and high load growth scenarios and identified alternatives and recommended plans to address the needs under each scenario in near-term (present-5 years), mid-term (5-10 years) and long term (10-20 years).

The following is the summary of the currently recommended or proposed near/mid/long-term wires plans for the sub-regions under low, medium and high load growth scenarios. The current status of these plans is also indicated in the following.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

[1] The Medium growth scenario for North-of-Dryden sub-region corresponds to the "Reference Scenario" in the IRRP
[2] The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario "A" of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario "B" of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario "D" of Greenstone, scenario "C" of Marathon and scenario "A" of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

West of Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

The IRRP for Thunder Bay sub-region identified a near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This upgrade has been completed in Q4 2016.

Most of the above plans are highly dependent on the needs of industrial customers in the region. Proceeding to the Development phase for the customer-driven projects requires request by, and agreement with, the customer(s). Currently, only Project No. 1 has proceeded to the Development phase. The only supply point in the region which is presently at its load-meeting capability limit is Pickle Lake and Project No. 1 will address the need at this location.

Additionally, the IESO Draft Remote Community Connection Plan report [6] has recommended the connection of 21 First Nations communities in the northern part of the region to the electricity grid. An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's transmitter licence to develop and seek approvals for the connection of sixteen remote communities and the Dryden-Pickle Lake transmission line, i.e. Project No. 1 identified above.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. There is adequate time to review the proposed or recommended plans to meet the long-term needs and develop preferred alternatives in the next planning cycle. Should there be a need that emerges prior to the next planning cycle such as but not limited to change in load forecast, the regional planning cycle will be started earlier to address the need.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. - Transmission ("Hydro One") with input and on behalf of the Working Group that consists of Hydro One, Hydro One Networks Inc. - Distribution, the Independent Electricity System Operator ("IESO"), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Thunder Bay Hydro Electricity Distribution Inc., Sioux Lookout Hydro Inc. and Fort Frances Power Corporation in accordance with the Regional Planning process established by the Ontario Energy Board in 2013.

Northwest Ontario region is divided into 4 sub-regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, and Greenstone-Marathon. The IESO has also assessed the economic case for connecting the Remote Communities north of Red Lake and Pickle Lake to the provincial grid. Electrical supply to the Region is provided by fifty two 230kV and 115kV transmission and distribution stations. Some of the stations are shown in Figure 1-1.

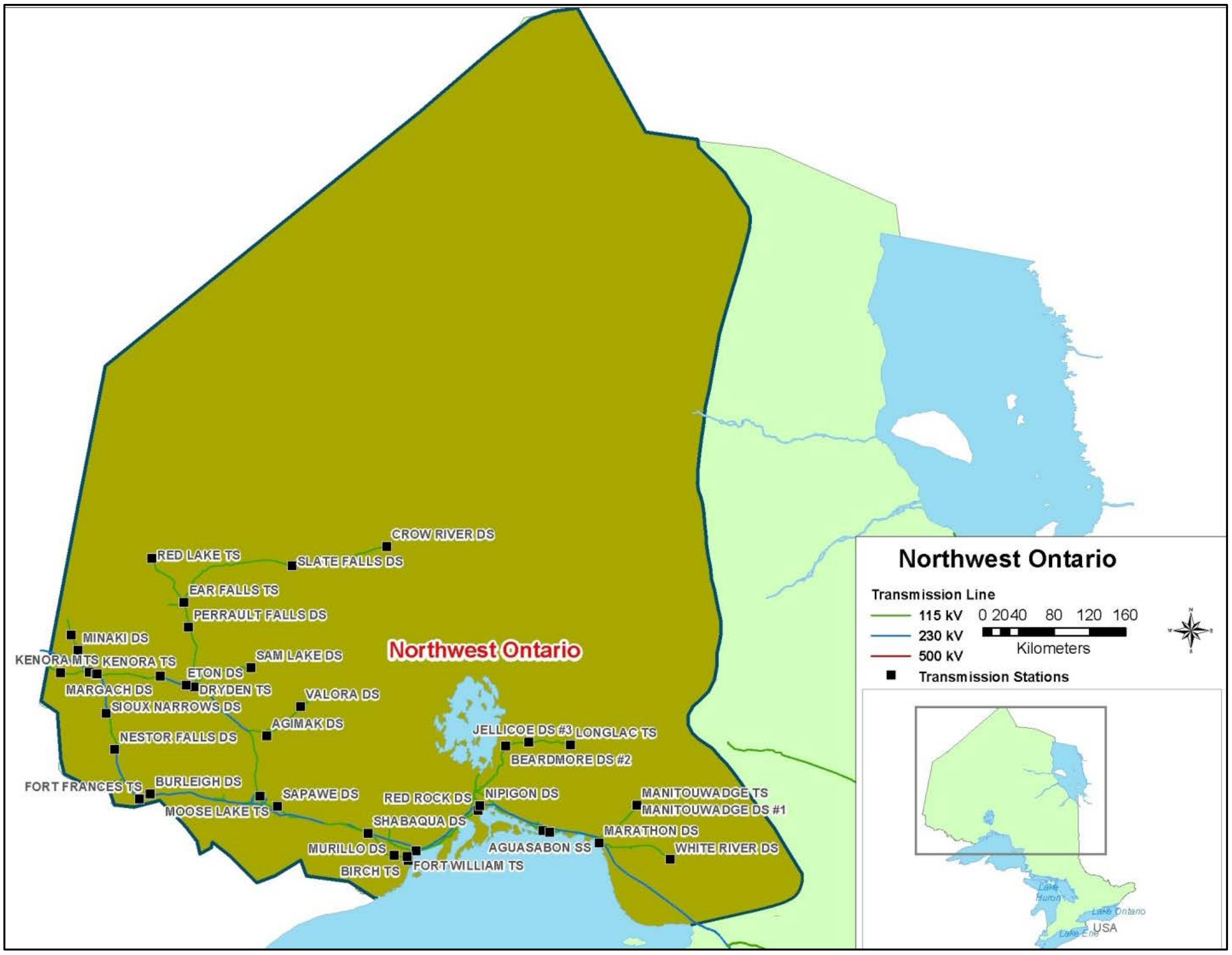


Figure 1-1 Map of Northwest Ontario Region

1.1 Scope and Objectives

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Review of needs (near and medium-term) identified through the IRRP process.
- Develop a wires plan to address all needs where wires solution is the most appropriate.
- Discuss long-term needs identified during the planning process

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period;
- Develop an approach to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [3] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address one or more of the needs. If no further regional coordination is required and localized needs cannot be met by non-wires solutions, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and a Local Plan ("LP") is developed to address localized needs. Ultimately, local plans are also incorporated into the RIP report.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions and/or different needs.

The IRRP phase will generally assess integrated alternatives consisting of infrastructure (wires) and/or resource (CDM and Distributed Generation). Detailed information regarding wires options may not be available or necessary within the scope of the IRRP. The level of detail for wires options as part of the IRRP will be to a level which is sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and refine the assessment of specific wires alternatives, and recommend a preferred

[3] Also referred to as Needs Screening.

wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and may establish Local Advisory Committees (LAC) in the region or sub-region. For the Northwest Ontario Region, community engagement through a number of LACs is on-going.

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

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

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

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

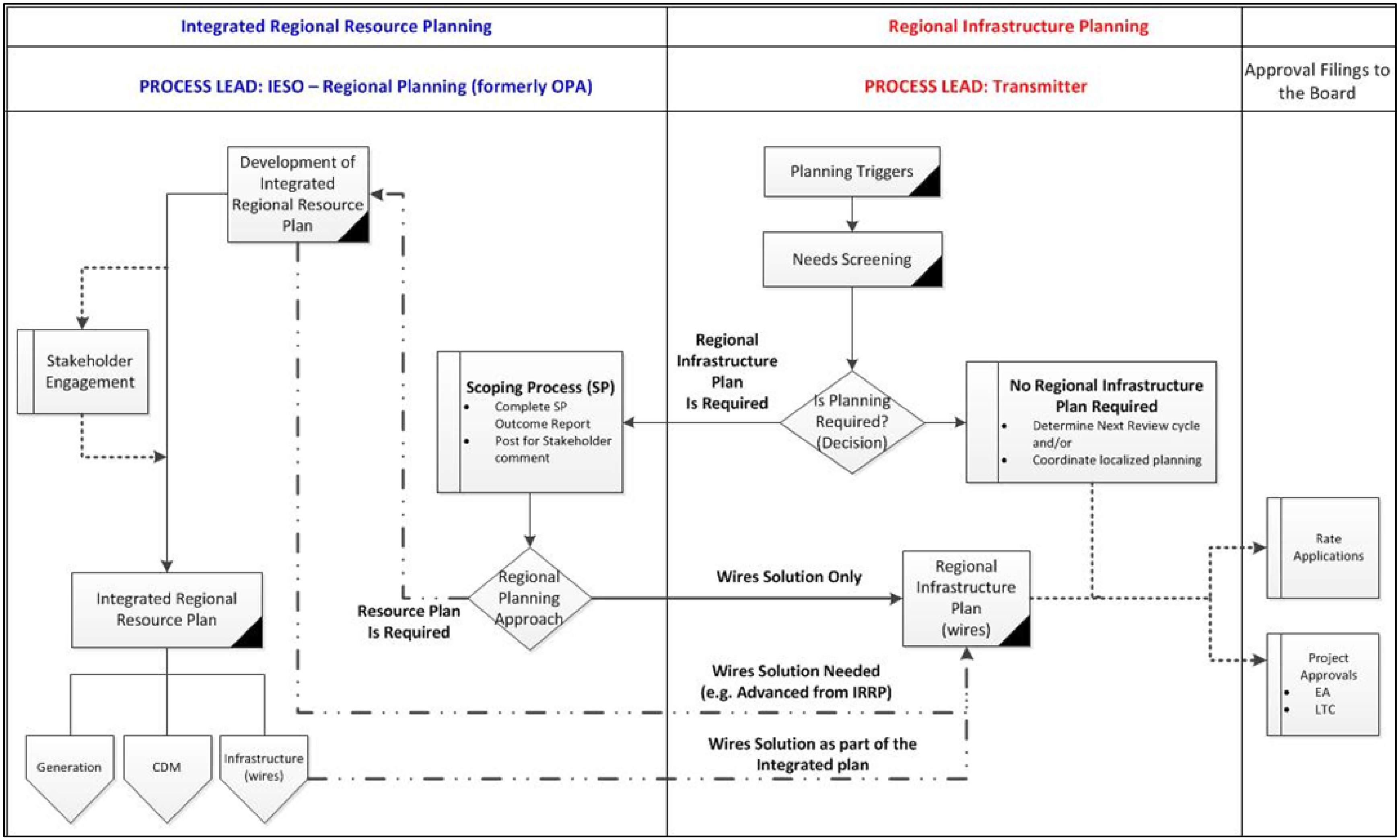


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

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

The extent and scope of each step naturally depends on the outcome of the previous step. The outcome of the previous stage of the regional planning process, i.e., IRRP, also influences the scope of Step 2 to a large extent.

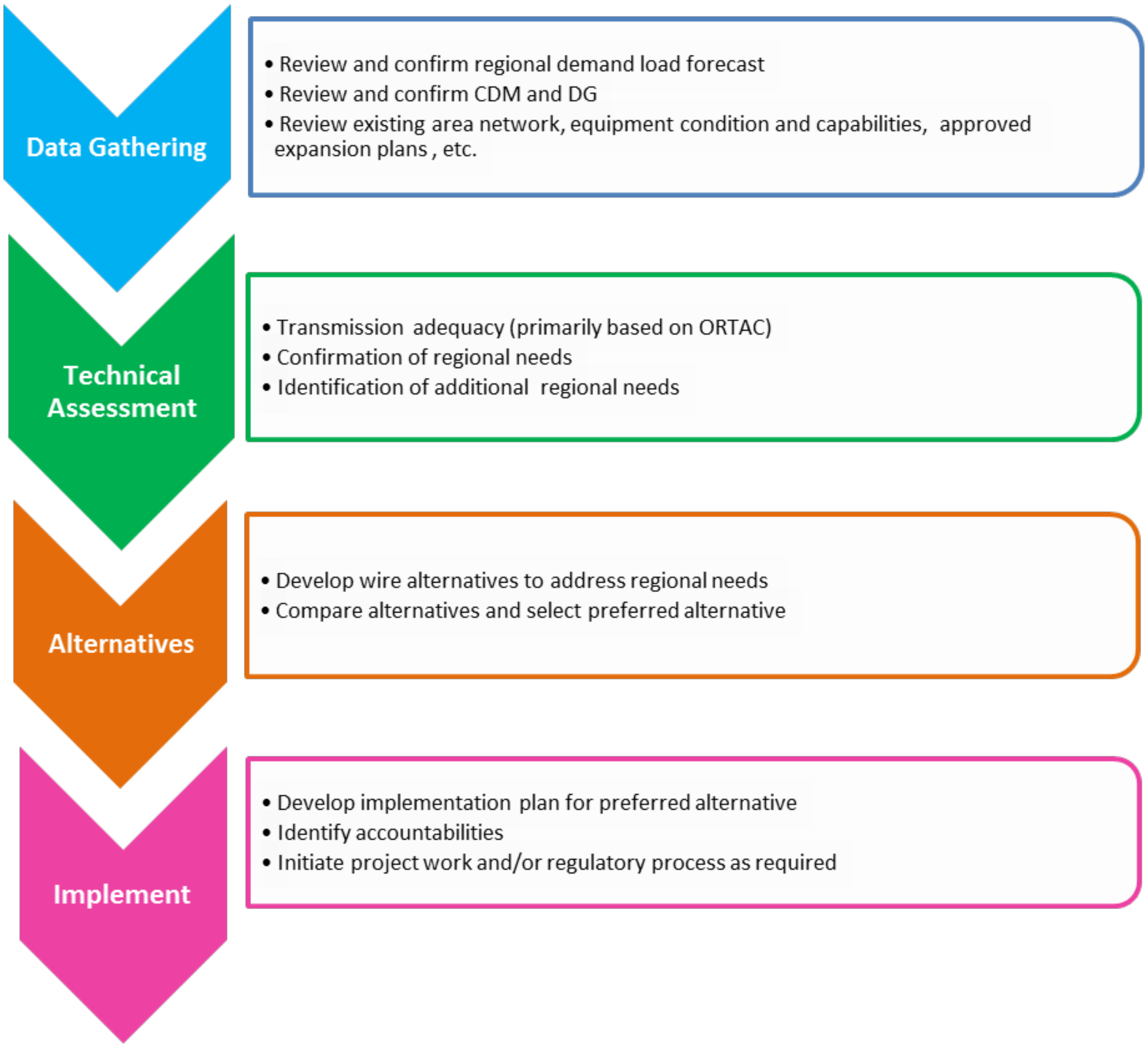


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

NORTHWEST ONTARIO REGION IS ROUGHLY BORDERED BY WEST OF HUDSON BAY AND JAMES BAY, NORTH AND WEST OF THE LAKE SUPERIOR, AND EAST OF THE CANADIAN PROVINCE OF MANITOBA. THE REGION CONSISTS OF THE DISTRICTS OF THUNDER BAY, KENORA AND RAINY RIVER. ALMOST 54 PERCENT OF REGION'S ENTIRE POPULATION LIVES IN THUNDER BAY. THE REGION ACCOUNTS FOR APPROXIMATELY 60 PERCENT OF LAND AREA OF THE PROVINCE AND ABOUT TWO PERCENT OF ONTARIO'S TOTAL POPULATION.

Bulk electrical supply to the Northwest Ontario Region is provided through a combination of local generation stations connected to the 230 kV and 115 kV network, and the East-West Tie transmission corridor.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Sioux Lookout Hydro Inc., Thunder Bay Hydro Electricity Distribution Inc., and Fort Frances Power Corporation. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDC. A map and a single line diagram showing the electrical facilities of the Northwest Ontario Region, consisting of the sub-regions, is shown in Figure 3-1 and Figure 3-2, respectively.

3.1 North of Dryden Sub-Region

A radial single-circuit 115 kV transmission line ("E4D") supplies electricity to the customers in the North of Dryden sub-region from Dryden TS. The major supplying station for this sub-region is Dryden TS, where the voltage is stepped down from the 230 kV to 115 kV, to serve local and industrial customers. Electricity demand in the North of Dryden sub-region is also supplied by local hydroelectric generation.

3.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station ("SS"). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with two 230 kV lines - W21M and W22M. Marathon TS steps down 230 kV to 115 kV and supplies customers in the

Town of Marathon, White River and Manitouwadge through a 115 kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS.

Alexander SS connects Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - to the system. A 115 kV single-circuit A4L, connected to the Alexander SS, supplies electricity to the Municipality of Greenstone and its surrounding areas. Nipigon GS is also connected to the circuit A4L.

3.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230 kV transmission system consisting of the Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230 kV to 115 kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230 kV transmission lines – K21W and K22W. Fort Frances TS steps down 230 kV to 115 kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115 kV transmission line – F3M. Dryden TS steps down 230 kV to 115 kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230 kV to 115 kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities

3.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230 kV step-down transformation facility which steps down 230 kV to 115 kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115 kV by three step-down transformer stations - Birch TS, Fort William TS, and Port Arthur TS #1.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

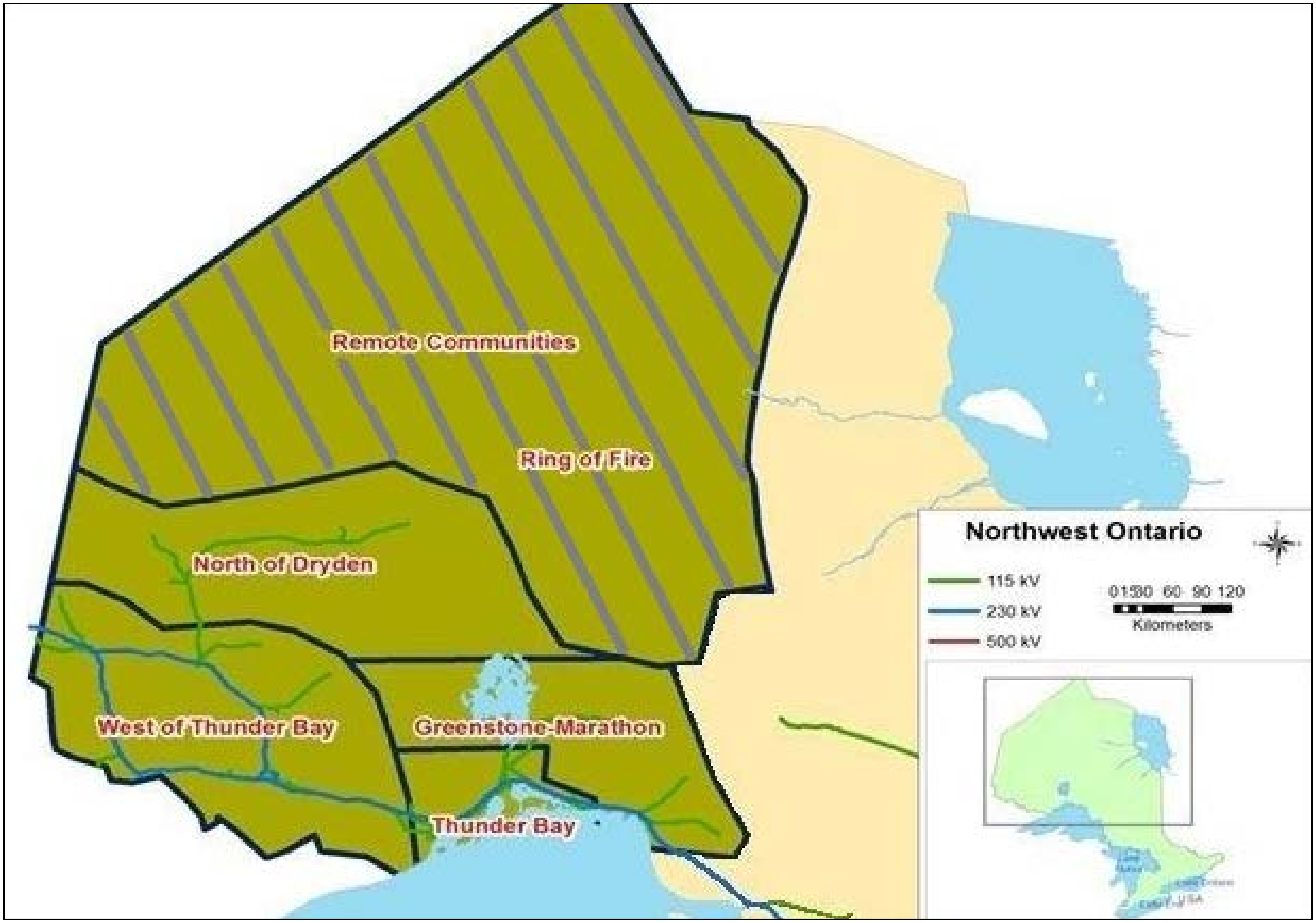


Figure 3-1 Northwest Ontario Region – Supply Areas

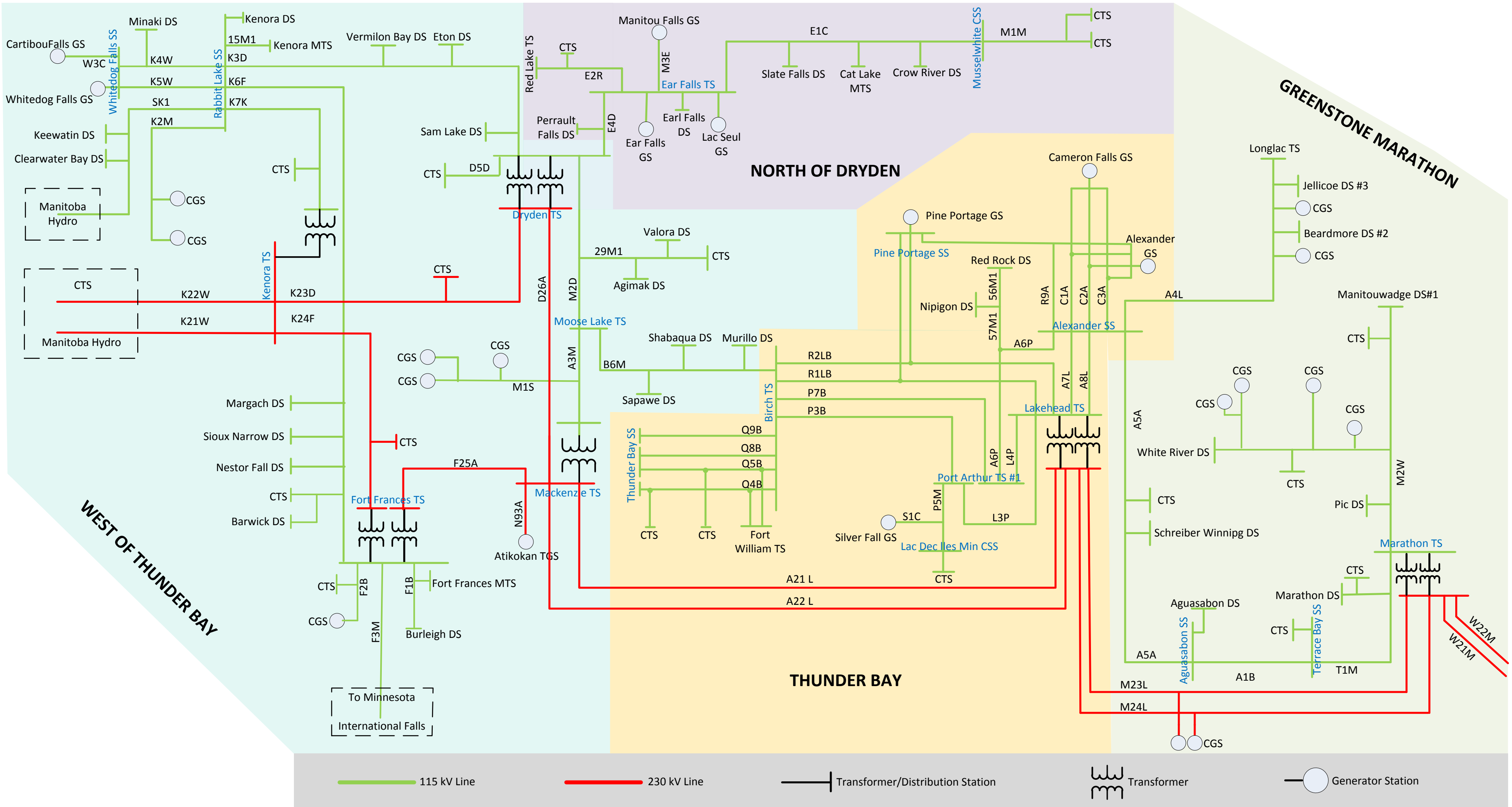


Figure 3-2 Northwest Ontario Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS AND PLANNED FOR NEAR FUTURE

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, ARE UNDERWAY, OR ARE PLANNED FOR THE COMING YEARS, AIMED AT IMPROVING THE SUPPLY TO THE NORTHWEST ONTARIO REGION IN GENERAL.

This section describes the completed development and sustainment projects in the region, as well as the sustainment projects that are in the execution stage or planned for the coming years.

4.1 Past Major Projects

In the past 10 years, the following are some of the major projects completed in the Northwest Ontario Region.

1. **Barwick TS** –Barwick TS was built in the second and third quarter of 2013 to replace load-serving facilities at Fort Frances TS as majority of these assets were reaching the end of their useful life. The new facilities include: two 42 MVA 115/44 kV transformers and the associated breakers, switches, surge arresters, etc. and two cap banks, each rated 4.9 MVAR at 44 kV, and the associated breakers and switches.

2. **Birch TS –** One of three 42 MVA step down transformers (115/25 kV) at Birch TS was replaced in December 2015.

3. **Dryden TS** – In addition to replacing 5 HV breakers, 2 LV breakers and 12 switches between 2014-2016, 2x40 MVAR Shunt reactors at Dryden TS were installed in Q3 2014.

4. **Fort Frances** – In addition to replacing 2 LV breakers and 8 switches (2010-2016), 21.6 MVAR/13.8 kV capacitor bank was installed at Fort Frances in November 2010.

5. **Kenora TS** – 1 LV breaker and 4 switches were replaced between 2009 and 2015.

6. **Lakehead TS** – 3 HV breakers, 1 LV breaker, 5 switches, and 1 autotransformer (230/13.9 kV) were replaced between 2009 and 2016 as part of the sustainment work. In addition, one synchronous condenser at Lakehead TS was replaced by a +60/-40 MVAR SVC in December 2009.

7. **Longlac TS** –Transformers T2 and T3 were replaced with two 42 MVA 115/44 kV transformers and associated equipment protections i.e. breakers, switches, surge arresters, etc. In addition, four capacitor banks; each rated at 4.9 MVAR at 44 kV with associated breaker and switches were installed. This work was completed mid-2011.

8. **Manitouwadge TS** – 1 LV breaker, 1 switch, and 1 step down transformer (115/44 kV) were replaced in July 2016.

9. **Marathon TS** – In addition to replacing 1 HV breaker, 2 LV breakers, and 4 switches between 2009 and 2016, 2x40 MVAR shunt reactors were installed in December 2013 and March 2014.

10. **Moose Lake TS** – 5 HV breakers were replaced in 2014.

11. **Port Arthur TS #1** – 10 switches were replaced between 2009 and 2015. In addition, 2x0.5 ohms LV current limiting reactors were replaced with 2x1 ohm reactor. Work was completed in December 2014.

12. **Rabbit Lake SS** – 2 HV breakers and 4 switches were replaced between 2011 and 2016.

13. **Red Lake TS** –Five capacitor banks were upgraded by 2.5 MVAR each to 7.4 MVAR (at 44 kV). This work also included upgrading associated breakers and switches and was completed between December 2015 and July 2016.

4.2 Current or Planned Major Sustainment Projects

The following major sustainment projects are currently under execution or planned for the coming years. These projects are based on the assessment of end of life issues of the aging station's equipment and replacing those that represent risk to the security of the bulk transmission system and reliability for connected customers.

1. **Dryden TS**– is located in the city of Dryden and supplies majority of the customers in the area. It consists of three 115/44 kV power transformers rated at 15MVA each, which are non-standard units and are about 69 years old.

   Hydro One has planned to replace the three EOL transformers with two new standard-size transformers, rated at 42MVA each. The scope of work also includes the replacement of other deteriorating infrastructure, such as LV switchyard (which will be built to current standard), 115 kV OCBs, and select switches.

   This project is currently planned to be completed in 2018.

2. **Ear Falls TS** – supplies customers in the city of Ear Falls in the North of Dryden Sub-Region, through a single transformer T5 (115/44 kV, 19 MVA), backed-up by a spare transformer T5SP (115/44 kV, 8 MVA). The 44 kV LV voltage is further stepped-down to 12.5 kV through Ear Falls DS transformer T1 (44/12.5 kV). Ear Falls TS transformers T5 and T5SP are approximately 47 and 69 years old, respectively, while Ear Falls DS T1 is currently 49 years old.

   Hydro One has planned to eliminate the need for 44 kV to 12.5 kV conversion at Ear Falls DS by replacing T5 and T5SP transformers with 115/13.2 kV transformer units (rated at 12.5 MVA each). The scope of work also involves replacing 44kV equipment with 13.2 kV, replacing 115 kV circuit breakers, and replacing EOL protections, controls, and telecom in new relay building to ensure the integrity of power system protection is maintained.

   This project is currently planned to be completed in 2018.

3. **Alexander SS** – is a 115 kV switching station located in the Thunder Bay Sub-Region and was originally built in 1955. The station terminates five 115 kV circuits for the supply of customers in the area and connects 161 MW of generation from the Nipigon River and Cameron Falls. It consists of ten 115 kV breakers, nine of which are non-standard.

Hydro One has planned to replace all non-standard and EOL equipment at the station. The scope of work involves replacing 115 kV oil circuit breakers with new SF6 breakers, replacing select switches, upgrade of all protection & control facilities and AC station service system.

This project is currently planned to be completed in 2019.

4. **Birch TS** – is a 115 kV transmission station located in City of Thunder Bay in the Thunder Bay Sub-Region and was put in-service in 1955. Birch TS is comprised of a DESN station which supplies local load in the port area of Thunder Bay, as well as being a 115 kV bulk station with 9 lines and the three DESN transformers connected to it.

   Due to the criticality of the station to both transmission and distribution systems, protection and control equipment that is presently located in the basement will be relocated to a new relay building. The scope of work involves replacing 115 kV circuit breakers and 25 kV capacitor banks, and replacing/relocating end of life protections in the new relay building.

   This project is currently planned to be completed in 2019.

5. **Pine Portage SS** – is a 115 kV switching station located in the Greenstone-Marathon Sub-Region and was put in-service in 1954. The switching station has three outgoing 115 kV transmission lines connecting to Lakehead TS, Birch TS and Alexander SS. Pine Portage GS is also connected to this switching station.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing five 115 kV oil circuit breakers with new 2000A SF6 breakers, associated disconnect switches, protection, control and teleprotection facilities.

   This project is currently planned to be completed in 2020-2023.

6. **Aguasabon SS** – is a 115 kV switching station in Greenstone-Marathon Sub-Region and was put in-service in 1948. The station has two transmission lines connecting to Alexander SS and Terrace Bay SS. The station is also critical to the connection of Aguasabon DS.

   Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service, and replacing equipment protections.

   This project is currently planned to be completed in 2021-2024.

7. **Port Arthur TS #1** – Port Arthur TS #1 is a 115/25 kV station located in the Thunder Bay Sub-Region and was put in-service in 1950.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing AC/DC station service systems, 25kV switchyard and associated protection equipment in the new building, and 115 kV associated protection equipment in the existing building

   This project is currently planned to be completed in 2021-2024.

8. **Rabbit Lake SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has seven 115 kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection

with Manitoba Hydro. There are six 115 kV oil circuit breakers and two 115 kV SF6 circuit breakers in the yard.

Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing EOL 115 kV circuit breakers, select switches, and equipment protections.

This project is currently planned to be completed in 2021-2024.

9. **Terrace Bay SS** – is located in the Greenstone-Marathon Sub-Region and was put in-service in 1973. The switching station has two 115 kV transmission lines connecting to Marathon TS and Aguasabon SS. The station is also critical to the connection of a Customer Transformer Station (CTS).

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing protections, controls, telecom, select switches, and AC/DC station service system.

   This project work is currently planned to be completed in 2021-2024

10. **Whitedog Falls SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has three 115 kV transmission lines, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing 115 kV circuit breakers and select switches. In addition, scope of work includes replacing/upgrading of DC station supply system.

    This project is currently planned to be completed in 2021-2024.

11. **Moose Lake TS** – is a 115/44 kV transformer station built in 1948. It is located on Moose Lake near Atikokan in the West of Thunder Bay Sub-Region. Moose Lake TS consists of two non-standard step-down transformers T2 and T3 rated at 8MVA and 15MVA, respectively. In addition, the two transformers are 69 years old.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing the two non-standard power transformers (T2, T3) with standard 110-44 kV, 25/41.7 MVA units, two low voltage oil circuit breakers with new SF6 breakers, and replacing and upgrading the protection, control and AC/DC station service facilities

    This project is currently planned to be completed in 2022-2025

12. **Kenora TS** – is a 230/115 kV station located in the West of Thunder Bay Sub-Region and critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service systems and replacing protection equipment.

    This project is currently planned to be completed in 2024-2027.

13. **Mackenzie TS** – is a 230/115 kV station is located in the West of Thunder Bay Sub-Region. Mackenzie TS has six 230 kV breakers which are about 46 years old.

Hydro One has planned to replace all EOL equipment at the station. The scope of work involves replacing 230 kV circuit breakers, select protections, and AC/DC station service system.

This project is currently planned to be completed in 2024-2027.

14. **Fort Frances TS** – is located in the Town of Fort Frances and was put in-service in 1947.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service system and protection equipment.

    This project is currently planned to be completed in 2025-2028.

15. **Lakehead TS** – is a 230/115 kV transformer station located in the Thunder Bay Sub-Region and was put in-service in 1955. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing four LV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115 kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

    This project is currently planned to be completed in 2025-2028.

16. **Marathon TS** – is a 230/115 kV transformer station, located in the City of Marathon in the Greenstone-Marathon Sub-Region. It was put in-serviced in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115 kV oil circuit breakers at the station are about 40 years old. Whereas, three 230 kV circuit breaker at the station are about 48 years old.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to customers. The scope of work involves replacing three EOL 230 kV circuit breakers with new SF6 breakers, and four EOL 115 kV circuit breakers with new SF6 breakers. In addition, the scope of work also includes replacing disconnect switches, protection equipment, and AC station service system.

    This project is currently planned to be completed in 2025-2028.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast Scenarios

For the purpose of this RIP, the LDCs reviewed their load forecasts and confirmed that they have not changed significantly from the load forecasts reported in the Northwest IRRPs. Based on the load forecasts from the LDCs and the industrial (mining) load forecasts of the Northwest IRRPs, three scenarios of future demand has been considered for each Northwest sub-region in this RIP. Table 5-1, Table 5-2, Table 5-3, and Table 5-4 show the forecasted load for the Low, Medium and High growth scenarios.

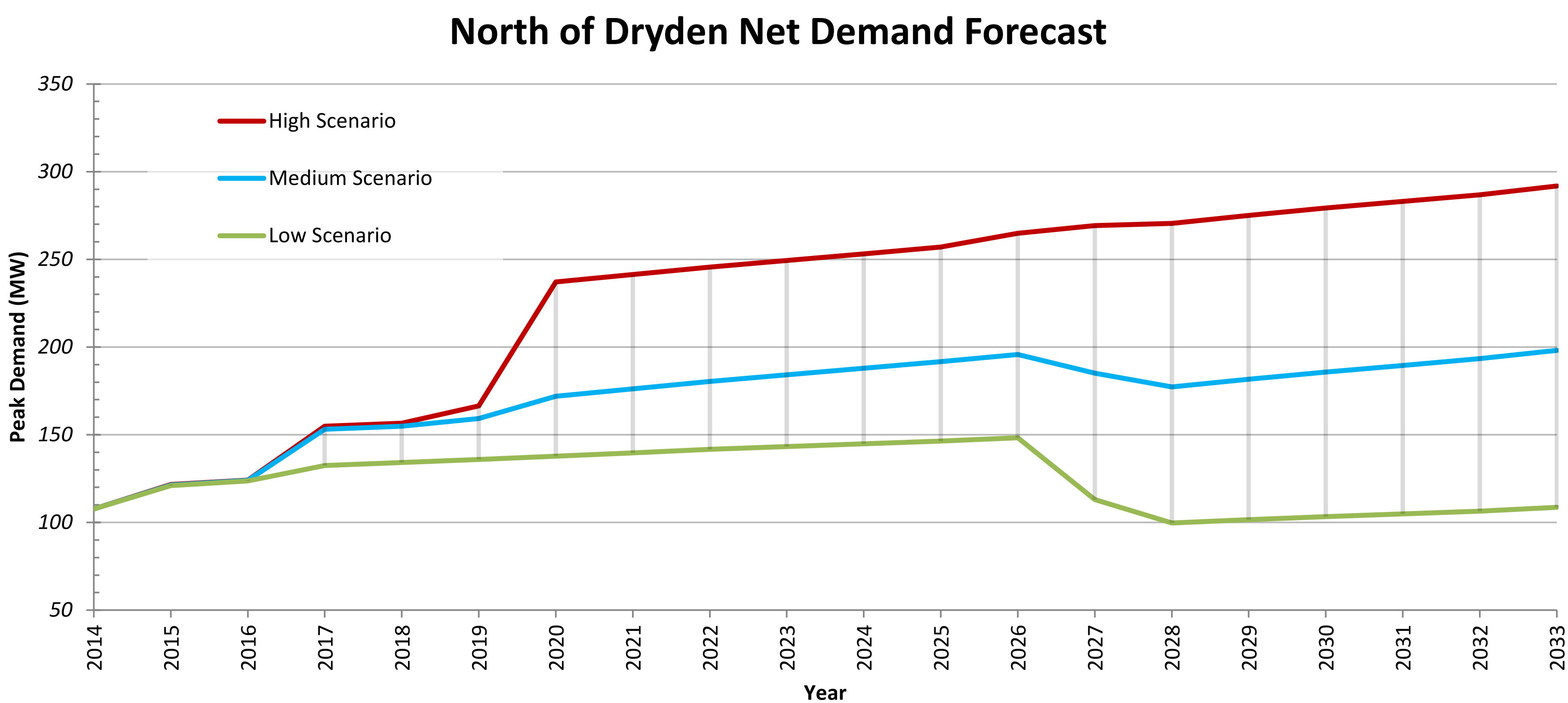
5.2 Other Study Assumptions

The other assumptions made in this RIP report include,

- The study period is 2016-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be available by the specified in-service dates.
- Since in the Northwest region winter peak is more critical than the summer peak, the study is based on winter peak conditions.

Table 5-1 North of Dryden Load Forecast Scenarios

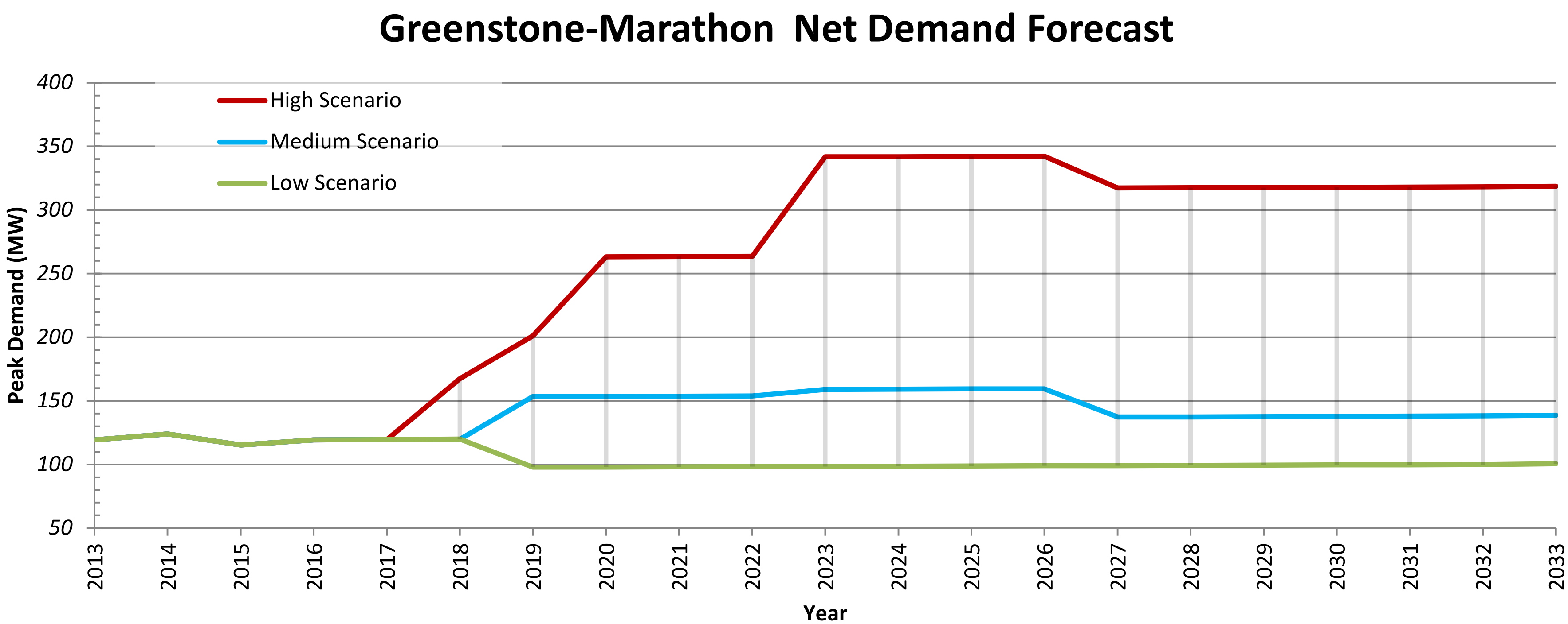
Net Demand Forecast (MW)																				
Scenario	2014 Historic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low		121.1	123.7	132.4	134.1	135.9	137.8	139.7	141.7	143.3	144.8	146.5	148.2	113.0	99.7	101.6	103.3	104.9	106.5	108.7
Medium[5]	107.6	121.4	124.0	153.1	154.8	159.3	171.9	176.1	180.3	184.1	187.9	191.7	195.7	185.2	177.3	181.6	185.7	189.5	193.3	198.0
High		121.6	124.2	154.9	156.6	166.5	237.1	241.3	245.5	249.3	253.1	256.9	264.9	269.3	270.6	275.0	279.2	283.1	286.8	291.7



[4] In the North of Dryden IRRP, load forecast starts from year 2015. For consistency, instead of the actual load in 2015 and 2016, the above table shows the IRRP load forecast for these years.
[5] The Medium scenario in the above table corresponds to the Reference scenario in the North of Dryden IRRP

Table 5-2 Greenstone-Marathon Load Forecast Scenarios[7]

Net Demand Forecast (MW)																					
Scenario	2013 Historical	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low		124.0	115.2	119.3	119.5	120.0	97.9	97.9	98.2	98.3	98.5	98.6	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.6
Medium	119.2	124.0	115.2	119.3	119.5	119.9	153.4	153.4	153.7	153.8	159.0	159.1	159.3	159.5	137.3	137.4	137.6	137.8	137.9	138.1	138.7
High		124.0	115.2	119.3	119.5	167.4	201.0	263.3	263.5	263.6	341.8	341.9	342.1	342.2	317.4	317.5	317.6	317.8	317.9	318.1	318.6

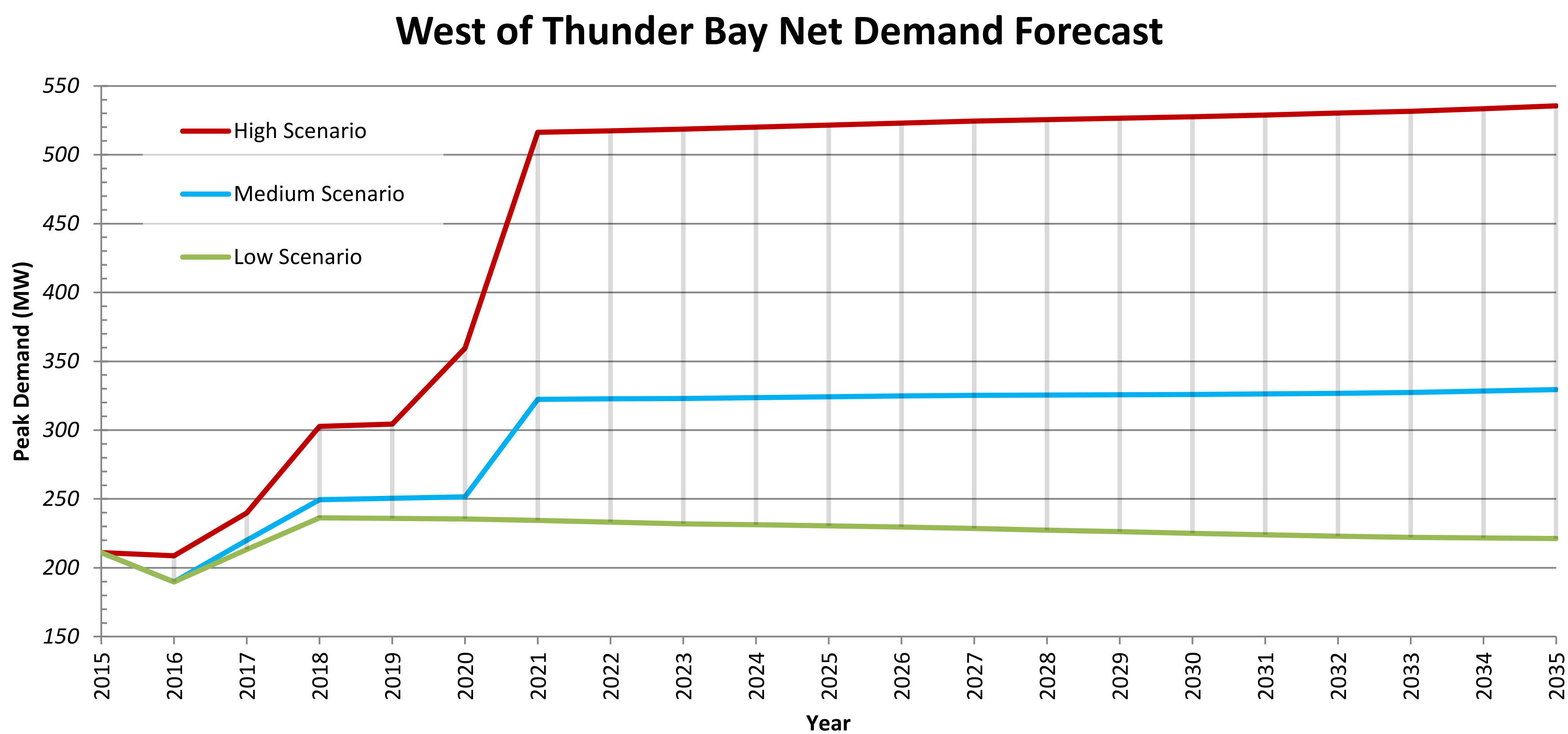


[6] In the Greenstone-Marathon IRRP, load forecast starts from year 2014. For consistency, instead of the actual load in 2014 to 2017, the above table is based on the IRRP load forecast for these years.

[7] . The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario “A” of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario “B” of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario “D” of Greenstone, scenario “C” of Marathon and scenario “A” of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

Table 5-3 West of Thunder Bay Load Forecasts Scenarios

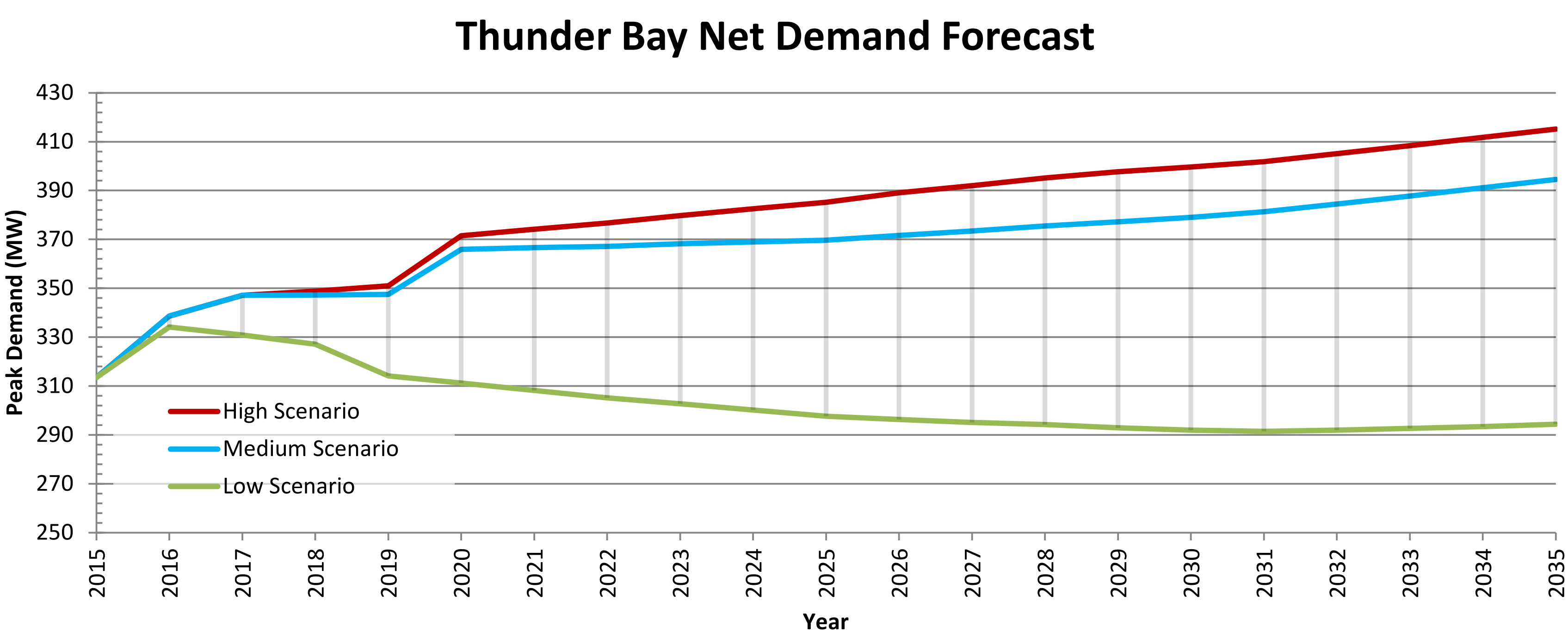
Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low		189.7	213.4	236.3	235.9	235.5	234.4	233.2	232.0	231.2	230.4	229.5	228.6	227.4	226.2	225.0	223.9	223.0	222.1	221.7	221.3
Medium	211.1	189.8	220.1	249.6	250.5	251.6	322.4	322.7	322.9	323.6	324.2	324.8	325.3	325.4	325.7	325.9	326.3	326.8	327.3	328.3	329.4
High		208.8	239.9	302.6	304.5	359.6	516.3	517.4	518.5	520.0	521.5	523.0	524.4	525.4	526.6	527.6	528.9	530.2	531.6	533.5	535.4



[8] In the West of Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

Table 5-4 Thunder Bay Load Forecast Scenarios

Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low	313.6	334.1	330.9	327.1	314.2	311.2	308.2	305.1	302.7	300.2	297.6	296.4	295.1	294.2	292.9	292.0	291.5	292.0	292.6	293.4	294.3
Medium		338.7	347.1	347.3	347.5	365.9	366.7	367.1	368.2	369.0	369.7	371.6	373.4	375.5	377.1	379.0	381.3	384.5	387.8	391.2	394.6
High		338.7	347.1	348.8	351.0	371.5	374.2	376.7	379.7	382.5	385.2	389.1	391.9	395.1	397.7	399.6	401.9	405.1	408.4	411.7	415.1



[9] In the Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

6. SUMMARY OF REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE WIRE NEEDS FOR THE NORTHWEST ONTARIO REGION AND SUMMARIZES THE RECOMMENDED WIRES PLANS FOR ADDRESSING THE NEEDS.

This section provides a summary of the needs and plans for the four Northwest sub-regions. The load forecasts from the LDCs have not materially changed since the completion of the previous phase (IRRP) of Regional Planning for the Northwest. Therefore, the assumptions and load growth scenario for industrial loads, as well as the needs and plans identified in this RIP are consistent with the Northwest IRRPs. The needs and recommended plans in the region are largely driven by the industrial load growth, particularly the mining sector. Proceeding to the Development phase of the customer-driven projects requires formal request by the customers and commercial agreements between Hydro One and the customers.

6.1 North of Dryden Sub-Region

Most of the demand in the North of Dryden sub-region is from the mining sector. The demand growth is driven by the expansion of this sector, as well as the connection of up to 21 remote communities in the northern parts of the region to Red Lake and Pickle Lake and growth in the mining sector, including potential developments in the Ring of Fire which may be supplied from Pickle Lake.

The North of Dryden IRRP [2] for this sub-region has assumed Low, Medium (referred to as Reference in IRRP [2]) and High load growth scenarios. Based on these scenarios, it has identified the needs and recommended wires plans in near-term, mid-term and long-term. The following are summaries of the needs and recommended plans for this sub-region, which consists of Pickle Lake sub-system, Red Lake sub-system, and Ring of Fire sub-system.

6.1.1 Pickle Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the existing single supply to Pickle Lake, i.e. the 115 kV circuit E1C, is serving 24 MW of load and is at its capacity. Any load growth in the near-term from the existing mine or connection of remote communities will require increase of LMC. The additional capacity needs, based on the medium (reference) load growth scenario are 18 MW, 28 MW and 47 MW in near-term, mid-term and long-term, respectively.

Pickle Lake LMC is limited by voltage stability. Providing dynamic voltage support, e.g. installing Static VAR Compensator (SVC) at Pickle Lake offers moderate increase in LMC, assuming the remaining capacity of circuit E4D will be available for this load increase. One alternative assessed in the IRRP is to install a new 115 kV single-circuit line from Valora, south of Dryden, to Pickle Lake to provide additional LMC that meets the near-term needs of Pickle Lake and releases some capacity on circuit E4D. However, in the long-term, with the development of new mines and potential for connection of the Ring of Fire to Pickle Lake (one the alternatives identified in the IRRP), an increase of over 130 MW in LMC may be required under the high growth forecast. As a result, the recommendation is to proceed with a plan required to meet the needs of the medium (reference) and high growth scenarios in the long-term. This plan can make the full capacity of circuit E4D available to serve the Red Lake sub-system.

<u>Recommended Plan:</u>

- Install a new 230 kV transmission line to Pickle Lake from either the Dryden area (e.g. Dinorwic) or Ignace area;

- Install a new 230 kV switching station to connect the new line to the existing circuits D26A;
- Install a new 230/115 kV auto-transformer at the end of the new line in Pickle Lake;
- Install new 115 kV switching facilities (circuit breakers) to connect the existing circuit E1C, existing customers at Pickle Lake and the new connections of the remote communities to the new auto-transformer; and
- Install required reactive compensation for voltage control

An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's (Watay Power) licence for Watay Power to develop and seek approvals for the Line to Pickle Lake and the connection of sixteen remote communities. Watay Power has initiated the Development phase of the project for these connections. Currently the planned in-service date of the 230 kV line to Pickle Lake is Q2 2020, based on Watay Power's active connection assessment with the IESO.

6.1.2 Red Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the current LMC of 61 MW at Red Lake, supplied by circuits E2R and E4D, is insufficient to meet the needs of the mining load, based on the expected growth at this location, even in near-term. The additional capacity needs, based on the medium (reference) load growth scenario are 30 MW, 44 MW and 48 MW in near-term, mid-term and long-term, respectively. Additional capacity needs increase to 75 MW under high load growth scenario.

The wires plans to meet the near-term needs are the following.

<u>Recommended Plan:</u>

- Upgrade circuit E4D to a summer rating of 660 A
- Upgrade circuit E2R to a summer rating of 610 A
- Provide additional voltage control at Ear Falls and/or Red Lake

However, since the load increase in the mining sector has not materialized at the same pace as previously anticipated, the initial plans for the upgrade of circuits E4D and E2R have been put on hold, awaiting customer request. A recent System Impact Assessment by the IESO for a load increase at Red Lake has determined that although the existing system can meet the demand, circuit E4D is reaching its thermal limit. Therefore, the above plan for the upgrade of circuit E4D (and E2R) can proceed in case of a request by, and agreement with, customers for additional load. Alternatively, operating measures can be used until additional firm capacity becomes available in the mid-term.

In the mid/long-term, assuming that the planned 230 kV line to Pickle Lake (see the previous section) is completed, which can make the full capacity of circuit E4D available to serve the Red Lake sub-system, there will be sufficient capacity to meet the needs under medium (reference) and high load growth scenarios. Only if the needs exceed the high growth forecast of this planning horizon, or the planned 230 kV line to Pickle Lake is not completed, a new 115 kV or 230 kV line from Dryden to Ear Falls will be one of the alternatives for meeting the demand.

6.1.3 Ring of Fire Sub-system Needs and Potential Options

The North of Dryden IRRP [2] has indicated that as the Ring of Fire sub-system is remote from the existing transmission system, any additional capacity needs would require new facilities. The IRRP has also indicated that transmission supply is the most economic option under all of the forecast scenarios, which considers the five remote communities in the vicinity of the Ring of Fire that have been identified as being economic to connect in the IESO's Remote Community Connection Plan [6] as well as possible mining customers. If mining load does not fully materialize, the North of Dryden IRRP [2] concluded that an east-west supply from the Pickle Lake area was the most economic option. If mining load fully materializes, the IRRP concluded that the economic option is either an east-west supply from the Pickle Lake area or a north-south supply from a point along the East-West Tie. Development in the area is still at an early stage and no firm recommendations can be made at this time.

6.2 Greenstone-Marathon Sub-Region:

The identified needs and recommended wire plans for this sub-region are directly related to a few large industrial developments. Based on the current load meeting capability (LMC) of the sub-region, all circuits except circuit A4L in Greenstone-Marathon sub-region are adequate to meet the projected demand forecast under all scenarios during the planning cycle. Circuit A4L is also adequate under the low demand scenario. The IRRP report [3] has recommended near term (present-5 years), medium term (5-10 years) and long term (10-20 years) actions to address the A4L limitations under the medium and high demand scenarios as described below.

6.2.1 Low Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Low Scenario assumptions are as follows:

- Hydro One Distribution customer growth
- Two saw mill re-starts

The existing circuits have sufficient LMC to meet Low Scenario's forecasted demand.

No wire plans are required for this scenario.

6.2.2 Medium Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Medium Scenario assumptions are as follows:

- Low Scenario assumptions
- Development of Geraldton mine
- Development of Beardmore mine
- Life extension of the existing Marathon Area mine

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Geraldton mine – Increase Circuit A4L Capacity:

Single-circuit 115 kV line A4L runs from Alexander SS to Longlac TS. A mining development in Geraldton area, with the proposed in-service date of 2019, would increase the near-term demand on circuit A4L to 51 MW, which is higher than its current LMC of approximately 25 MW. The LMC of circuit A4L is limited by voltage.

A major deciding factor in the recommendation for meeting the forecasted demand is the lead time relative to the proposed timelines for the mine development.

<u>Recommended Plan:</u>

If the proposed in service date of 2019 does not change, Installing Reactive Compensation and gas-fired generation in the near term is the recommended solution.

Installing reactive compensation of about +40 MVARs in the form of either synchronous condenser or Static Synchronous Compensators (STATCOM) at the Geraldton mine site would increase the LMC of circuit A4L to 45 MW, making full thermal capability of the circuit available. This form of Reactive Compensation is recommended considering the low short-circuit level at the end of circuit A4L relative to the requirements of the mine. The remaining short fall of approximately 6 MW to meet the needs of the mine can be provided by a customer-based grid-connected gas-fired generation plant with sufficient redundancy, for example, installing two 10 MW gas-fired units.

If the in-service date of the mine is delayed, replacing a section of circuit A4L, between Nipigon and Longlac, along with the installation of the above reactive compensation, would increase the LMC of circuit A4L to about 60 MW. Replacing the section of circuit A4L has a lead time of approximately five years.

Accommodate Beardmore mine – Increase Circuit A4L Capacity

A potential gold mine near Beardmore may be operational within the medium term. If Geraldton mine doesn't connect to circuit A4L as described above, the existing system would be sufficient to support the Beardmore mine.

If the Geraldton mine connects to circuit A4L and the plans for the high-demand scenario (described below) do not proceed, in order to accommodate the Beardmore mine, additional capacity would be required.

Recommended Plan:

Upgrading a section of circuit A4L from Alexander SS to Beardmore Junction is a medium term wires option for supplying the potential mine.

6.2.3 High Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, High Scenario assumptions are as follows

- Medium Scenario assumptions
- Development of the proposed Energy East pipeline
- Development of additional mines in Marathon Area
- Development of Ring of Fire, with connection to the Greenstone area

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Energy East Pipeline and, potentially, the Ring of Fire – Install New Wires:

Potential Energy East load is subjected to customers' request for connection of the pumping stations to the provincial electricity grid. The medium or long term recommended plans for the High Scenario depend on the Energy East plans and timelines for connecting some or all of the pumping stations, in one or two phases.

The Greenstone-Marathon Sub-Region IRRP [3] also indicates that the Ring of Fire could be potentially connected by an east-west corridor to Pickle Lake or by a north-south corridor to the Nipigon or Marathon areas.

Recommended Plan:

According to the IRRP report [3], the preferred option under the High Scenario, with or without the potential connection of the Ring of Fire, is the following wires plan.

- Install a new 230 kV transmission line to Longlac TS from either from the Nipigon area or from the Marathon (or Terrance Bay) area;
- Install a new 230 kV switching station to connect the new line to the existing circuits M23L-M24L;
- Install a new 230/115 kV auto-transformer at Longlac TS;

- Install required reactive compensation for voltage control and short-circuit level requirements at the mine; and
- Install a new 115 kV Line from Longlac TS to Manitouwadge TS to supply all the pumping stations in the area, possibly in the second phase.

Advancing the plan for the new transmission line and transformer, in order to meet the timelines of the Geraldton mine and the Beardemore mine developments, is an alternative to the upgrade of circuit A4L described under the Medium Scenario above. During outages of the new line or transformer, the new mines and industrial loads need to be interrupted to maintain the loading on circuit A4L below its LMC.

The above plan will improve the reliability for the customers served from Longlac TS by maintaining their supply through the new transmission line and transformer during outages of circuit A4L.

6.3 West of Thunder Bay Sub-Region

This sub-region, as described in the IRRP report [4], consists of four main sub-systems, Moose Lake, Fort Frances, Kenora and Dryden. The West of Thunder Bay Sub-Region is also a source of supply to the North of Dryden sub-region (through the Dryden 115 kV system) and therefore the needs and recommendations from the North of Dryden IRRP (described in the previous sections) were considered in the West of Thunder Bay IRRP.

Similar to the other sub-regions described above, because of the uncertainty in the development plans and connection options, the IRRP has considered low, medium (or reference) and high load growth scenarios in the West of Thunder Bay sub-region and has identified near/mid/long-term needs and recommendations for each scenario.

The low load growth scenario has forecasted a peak demand of close to 240 MW in 2017 (with the startup of a new mine near Rainy River) which will remain fairly flat until 2034.

In the medium load growth scenario, involving new mines and industrial load (pumping stations of the pipeline conversion project), the load forecast increases from 252 MW in 2017 to 345 MW in 2034.

In the high load growth scenario, involving additional mines, the load forecast increases from 305 MW in 2017 to 551 MW in 2034.

6.3.1 Dryden Needs and Plans

The Dryden 115 kV sub-system can provide up to 240 MW of continuous supply to the Dryden and North of Dryden Sub-Region. Under the low and medium (reference) load growth scenarios, this LMC is sufficient to meet the demand of this sub-system.

Under the high load growth scenario, additional capacity of 50 MW will be required on the 115 kV system at Dryden by the mid-2020s. This scenario considers high growth in the North of Dryden Sub-Region, and assumes that all load on circuit E1Cwill be supplied by the proposed 230 kV line to Pickle Lake. The IRRP identified one option for meeting the need of the 115 kV system to install a third autotransformer at Dryden TS. A recommended plan has not been finalized at this time given the long lead time and uncertainty associated with potential developments in the area. The next cycle of Regional Planning will reassess the need.

6.3.2 Kenora Needs and Plans

The transformer station supplying the City of Kenora and surrounding areas ("Kenora MTS") can supply 25 MW. This transformer station currently supplies up to 20 MW. Since the increase in the residential and commercial load in the Kenora area is forecast to be modest over the planning period, the remaining 5 MW margin will be adequate for the Kenora area.

The IRRP has identified that an industrial customer, currently supplied by a local generating station is considering pursuing an alternative supply arrangement from Kenora MTS. Furthermore, potential developments at the former Abitibi mill site may also require additional transformer station capacity in the Kenora area. The magnitude and timing of these developments remains uncertain and is not expected to have major regional implications. No actions were recommended in the IRRP to address the need at this time.

6.3.3 Moose Lake Needs and Plans

The Moose Lake 115 kV sub-system has sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.3.4 Fort Frances Needs and Plans

The Fort Frances 115 kV sub-system was found to have sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.4 Thunder Bay Sub-Region

The IRRP for the Thunder Bay sub-region [5] considered low, medium and high load growth scenarios and identified near/mid/long-term needs and recommendations for each scenario. The assessments of this sub-region have assumed that the most impactful scenario in the Greenstone sub-system will materialize, resulting in 60 MW supply need from the Thunder Bay sub-region (i.e. on circuit A4L in case it would be upgraded).

The low load growth scenario has forecast the peak demand of close to 325 MW in 2015 will decline to about 300 MW by 2035 as a result of continuing decline in the pulp and paper sector and without new mining or industrial developments in Thunder Bay.

In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035. This is comparable to the sub-region's historic peak demand in 2006/2007.

In the high load growth scenario, involving additional transmission connected mining developments north of Thunder Bay; the load is forecasted to increase to 415 MW by the end of planning period.

In addition to the potential long-term wires options for medium/high growth scenarios described below, the IRRP for Thunder Bay sub-region identified the near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This work has been completed.

6.4.1 Long-Term Needs and Plans

Port Arthur TS - Transformation Capacity

The long-term load forecast indicates that the demand from the customers supplied by Port Arthur TS will exceed the station's current capacity by 2033, and additional station capacity will be required if this load growth materializes.

Currently, the low voltage equipment at Port Arthur TS are limiting the station capacity to 55 MW. The station transformers provide up to 59 MW of capacity.

Wires Option:

The low voltage equipment, which are limiting the station capacity are nearing end-of-life and are planned to be replaced and upgraded in mid-term. This upgrade would bring the station capacity up to 59 MW, sufficient to meet the need beyond 2035. No additional plan is required at this time and load at Port Arthur TS will be monitored and supply options will be assessed in the next cycle of Regional Planning.

Lakehead TS and Birch TS - Transformation Capacity

Currently the Thunder Bay 115 kV system can accommodate approximately 150 MW of additional load growth. This capacity is sufficient under the low and medium load growth scenarios in the long-term.

Under the High growth scenario, and assuming the most impactful Greenstone sub-system scenario (60 MW, as described above), the Thunder Bay system would require additional supply capacity of approximately 20 MW by 2030.

The Thunder Bay IRRP indicates that a firm plan to increase the LMC of the Thunder Bay 115 kV system is not required at this time, as the large margin remaining on the system provides significant lead time for the Working Group to monitor demand growth and study options. The IRRP report explored various wires and non-wires options as potential long term solutions to increase the LMC of the system, however no action beyond monitoring is recommended at this time.

The wires options discussed in the Thunder Bay IRRP are described below:

1. Installing a third 230/115 kV 250 MVA autotransformer at Lakehead TS to increase the LMC of Lakehead TS by approximately 240 MW.

2. A new 230 kV line from Lakehead TS to Birch TS and a 230 kV 250 MVA autotransformer at Birch TS to create a supply point for the southern part of Thunder Bay, with a supply capacity of 240 MW. The new 230 kV line would require a new Right-of-Way and would take 5 years or longer to build.

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7. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE NORTHWEST ONTARIO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This section provides a summary of the Needs and Plans for the Northwest Region as identified in this RIP.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

West of Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

8. REFERENCES

[1]. Northwest Region Scoping Assessment (SA) Outcome Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf

[2]. North of Dryden Sub-Region Integrated Regional Resource Plan (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf

[3]. Greenstone-Marathon Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/2016-Greenstone-Marathon-IRRP-Report.pdf

[4]. West of Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/West_of_Thunder_Bay/2016-West-of-Thunder-Bay-IRRP.pdf

[5]. Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Thunder-Bay-IRRP.pdf

[6]. 2014 Draft Remote Community Connection Plan
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Remote_Community/OPA-technical-report-2014-08-21.pdf

Appendix A. Stations in the Northwest Ontario Region

Sub-Region	Station	Voltage (kV)	Supply Circuits
North of Dryden	Ear Falls TS	115/44	M3E, E4D, E1C, E2R
	Red Lake TS	115/44	E2R
	Cat Lake MTS	115/25	E1C
	Crow River DS	115/25	E1C
	Perrault Falls DS	115/12.5	E4D
	Slate Falls DS	115/24.9	E1C
Greenstone-Marathon	Longlac TS	115/44	A4L
	Manitouwadge TS	115/44	M2W
	Marathon TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
	Beardmore DS #2	115/25	A4L
	Jellicoe DS #3	115/12.5	A4L
	Manitouwadge DS #1	115/12.5	M2W
	Marathon DS	115/25	T1M
	Pic DS	115/25	M2W
	Schreiber Winnipeg DS	115/12.5	A5A
	White River DS	115/25	M2W
West of Thunder Bay	Barwick TS	115/44	K6F
	Dryden TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
	Fort Frances TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
	Kenora TS	230/115	K24F, K7K, K21W, K23D, K22W
	Mackenzie TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
	Moose Lake TS	115/44	A3M, M1S, M2D, B6M
	Fort Frances MTS	115/12.47	F1B
	Kenora MTS	115/12.5	15M1
	Agimak DS	115/25	29M1
	Burleigh DS	115/12.5	F1B
	Clearwater Bay DS	115/25	SK1
	Eton DS	115/12.48	K3D
	Keewatin DS	115/12.5	SK1
	Margach DS	115/25	K6F
	Minaki DS	115/25	K4W
	Nestor Falls DS	115/13.2	K6F
	Sam Lake DS	115/26.4	K3D
	Sapawe DS	115/12.5	B6M
	Shabaqua DS	115/12.5	B6M
	Sioux Narrows DS	115/12.5	K6F
	Valora DS	115/25	29M1
	Vermilion Bay DS	115/12.5	K3D
Thunder Bay	Birch TS	115/28.4	Q9B, P7B, Q8B, Q5B, R2LB, P3B, Q4B, R1LB, B6M
	Fort William TS	115/25	Q5B, Q4B
	Lakehead TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
	Port Arthur TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
	Murillo DS	115/26.40	B6M
	Nipigon DS	115/4.16	57M1
	Red Rock DS	115/12.5	56M1

Appendix B. Transmission Lines in the Northwest Ontario Region

Circuit(s)	Location	Voltage (kV)
D26A	Mackenzie x Dryden	230
F25A	Mackenzie x Fort Frances	230
K23D	Dryden x TCPL Vermill Bay x Kenora	230
K24F	Fort Frances x Kenora	230
N93A	Mackenzie x Marmion Lake x Atikokan	230
K21W, K22W	Kenora x Whiteshell (Manitoba Hydro)	230
A21L, A22L	Mackenzie x Lakehead	230
M23L, M24L	Marathon x Lakehead	230
15M1	Kenora x Rabbit Lake	115
29M1	Ignace x Camp Lake x Valora x Mattabi	115
A3M	Mackenzie x Moose Lake	115
B6M	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	115
D5D	Dryden x Domtar Dryden	115
F1B	Fort Frances x Burleigh	115
F3M	Fort Frances x Internat Fls (Minnesota Power)	115
K2M	Kenora x Norman	115
K3D	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	115
K4W	White Dog x Minaki x Rabbit Lake	115
K6F	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	115
K7K	Kenora x Weyerhaeuser Ken x Rabbit Lake	115
M1S	Moose Lake x Valerie Falls x Mill Creek	115
M2D	Moose Lake x Ignace x Dryden	115
SK1	Rabbit Lake x Keewatin x Forgie	115
W3C	White Dog x Caribou Falls	115
56M1	Nipignon x Red Rock	115
57M1	Reserve x Nipignon	115
A6P	Alexander x Port Arthur	115
L3P, L4P	Lakehead x Port Arthur	115
P3B, P7B	Port Arthur x Birch	115
P5M	Port Arthur x Conmee	115
Q4B, Q5B, Q8B, Q9B	Thunder Bay x Birch	115
R1LB, R2LB	Lakehead x Pine Portage x Birch	115
S1C	Silver Falls x Lac Des Iles x Conmee	115
A1B	Aguasabon x Terrace Bay	115
A4L	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	115
A5A	Alexander x Minnova x Schreiber x Aguasabon	115
C1A, C2A, C3A	Alexander x Cameron Falls	115
GA1	Upper White River x Lower White River	115
M2W	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	115
R9A	Alexander x Pine Portage	115
E1C	Ear Falls x Selco x Slate Falls x Cat Lake x Crow River x Musselwhite	115
E2R	Ear Falls x Balmer x Red Lake	115
E4D	Ear Falls x Scout Lake x Dryden	115
M3E	Manitou Falls x Ear Falls	115
T1M	Terrace Bay x Marathon	115

Appendix C. Distributors in the Northwest Ontario Region

Distributor Name	Station Name	Connection
ATIKOKAN HYDRO INC.	Moose Lake TS	Tx
FORT FRANCES POWER CORPORATION	Fort Frances MTS	Tx
HYDRO ONE NETWORKS INC.	Agimak DS	Tx
	Aguasabon GS	Tx
	Barwick TS	Tx
	Beardmore DS #2	Tx
	Burleigh DS	Tx
	Cat Lake MTS	Tx
	Clearwater Bay DS	Tx
	Crow River DS	Tx
	Dryden TS	Tx
	Ear Falls DS	Tx
	Ear Falls TS	Tx
	Eton DS	Tx
	Fort Frances TS	Tx
	H2O Pwr SturgFls CGS	Tx
	Jellicoe DS #3	Tx
	Keewatin DS	Tx
	Kenora DS	Tx
	Longlac TS	Tx
	Manitouwadge DS #1	Tx
	Manitouwadge TS	Tx
	Marathon DS	Tx
	Margach DS	Tx
	Minaki DS	Tx
	Murillo DS	Tx
	Nestor Falls DS	Tx
	Nipigon DS	Tx
	Perrault Falls DS	Tx
	Pic DS	Tx
	Port Arthur TS #1	Tx
	Red Lake TS	Tx
	Red Rock DS	Tx
	Sam Lake DS	Tx
	Sapawe DS	Tx
	Schreiber Winnipg DS	Tx
	Shabaqua DS	Tx
	Sioux Narrows DS	Tx
	Slate Falls DS	Tx
	Valora DS	Tx
	Vermilion Bay DS	Tx
	White River DS	Tx
	Whitedog Falls GS	Tx
	Whitedog DS	Tx
KENORA HYDRO ELECTRIC CORPORATION	Kenora MTS	Tx
SIOUX LOOKOUT HYDRO INC.	Sam Lake DS	Dx
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	Birch TS	Tx
	Fort William TS	Tx
	Port Arthur TS #1	Tx

Appendix D. Northwest Ontario Stations Non Coincident Load Forecast (2016-2025)

Table D-1 Stations Non Coincident Net Load Forecast (MW)

Station LDCs
Atikokan Hydro
Fort Frances Power Corp
Kenora Hydro
Thunder Bay Hydro
Hydro One Distribution

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Moose Lake TS*	Non Coincidental Gross						6.10	6.16	6.22	6.28	6.35	6.38	6.41	6.44	6.48	6.51
		CDM						0.04	0.07	0.12	0.17	0.21	0.24	0.28	0.31	0.33	0.37
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.50	4.30	4.53	4.93	6.06	6.06	6.09	6.10	6.11	6.14	6.13	6.13	6.13	6.14	6.13
West of Thunder Bay	*Fort Frances MTS*	Non Coincidental Gross						17.10	17.02	16.93	17.10	17.27	17.45	17.62	17.80	17.97	18.15
		CDM						0.11	0.18	0.32	0.46	0.56	0.66	0.76	0.85	0.92	1.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	16.93	16.29	17.17	17.92	16.79	16.99	16.83	16.61	16.64	16.70	16.78	16.85	16.95	17.05	17.11
West of Thunder Bay	*Fort Frances TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	15.60	16.37	16.73	16.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Barwick TS*	Non Coincidental Gross						17.07	17.07	17.29	17.56	17.69	17.81	17.93	18.04	18.19	18.33
		CDM						0.11	0.19	0.32	0.47	0.58	0.68	0.78	0.86	0.93	1.04
		DG						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Non Coincidental Net					14.00	15.96	15.88	15.96	16.08	16.11	16.13	16.15	16.18	16.25	16.28
West of Thunder Bay	*Kenora MTS*	Non Coincidental Gross						21.45	21.66	21.88	22.10	22.10	22.32	22.32	22.54	22.76	22.99
		CDM						0.14	0.24	0.41	0.59	0.72	0.85	0.97	1.07	1.17	1.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	20.49	20.77	21.27	21.62	20.57	21.30	21.41	21.46	21.49	21.37	21.46	21.34	21.45	21.58	21.66
Thunder Bay	*Birch TS*	Non Coincidental Gross						77.88	78.54	78.80	79.31	79.81	80.32	80.55	81.34	81.96	82.52
		CDM						0.51	0.85	1.48	2.13	2.60	3.06	3.50	3.87	4.21	4.70
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Non Coincidental Net	70.48	70.02	86.01	87.04	74.01	77.33	77.64	77.28	77.14	77.17	77.22	77.01	77.43	77.71	77.77

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thunder Bay	*Fort Williams TS*	Non Coincidental Gross						77.90	78.14	80.46	81.23	83.61	87.49	91.88	91.11	89.64	89.29
		CDM						0.51	0.85	1.51	2.18	2.73	3.33	3.99	4.33	4.60	5.09
		DG						4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45
		Non Coincidental Net	74.99	73.18	80.22	80.81	79.20	72.94	72.84	74.50	74.59	76.43	79.70	83.44	82.33	80.59	79.76
Thunder Bay	*Port Arthur TS#1*	Non Coincidental Gross						37.00	37.40	37.90	38.50	39.10	39.60	40.20	40.90	41.50	42.20
		CDM						0.24	0.41	0.71	1.03	1.27	1.51	1.74	1.94	2.13	2.40
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	34.92	35.73	35.36	39.98	30.70	36.74	36.98	37.18	37.45	37.81	38.08	38.44	38.94	39.36	39.78
Thunder Bay	*Port Arthur TS #1*	Non Coincidental Gross						8.54	8.65	8.77	8.80	8.94	9.10	9.19	9.28	9.36	9.44
		CDM						0.06	0.09	0.16	0.24	0.29	0.35	0.40	0.44	0.48	0.54
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.12	7.48	8.52	8.52	7.90	8.49	8.56	8.60	8.56	8.65	8.76	8.79	8.84	8.88	8.90
West of Thunder Bay	*Agimak DS*	Non Coincidental Gross						3.32	3.33	3.39	3.46	3.50	3.53	3.57	3.60	3.65	3.69
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.19	0.21
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.96	3.04	3.24	3.70	4.30	3.30	3.30	3.33	3.36	3.38	3.40	3.41	3.43	3.46	3.48
Greenstone-Marathon	*Beardmore DS #2*	Non Coincidental Gross						1.23	1.23	1.25	1.28	1.29	1.30	1.31	1.33	1.34	1.36
		CDM						0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.19	1.30	1.21	1.17	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Burleigh DS*	Non Coincidental Gross						4.12	4.12	4.18	4.24	4.27	4.30	4.33	4.35	4.39	4.42
		CDM						0.03	0.04	0.08	0.11	0.14	0.16	0.19	0.21	0.23	0.25
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.63	3.80	4.10	4.05	3.70	4.09	4.08	4.10	4.13	4.13	4.14	4.14	4.14	4.16	4.17
North of Dryden	*Cat Lake MTS*	Non Coincidental Gross						0.82	0.83	0.85	0.86	0.88	0.89	0.90	0.91	0.92	0.94
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.79	0.69	0.80	0.72	0.74	0.82	0.82	0.83	0.84	0.85	0.85	0.86	0.87	0.88	0.88
West of Thunder Bay	*Clearwater Bay DS*	Non Coincidental Gross						5.47	5.47	5.54	5.61	5.65	5.68	5.71	5.74	5.78	5.83
		CDM						0.04	0.06	0.10	0.15	0.18	0.22	0.25	0.27	0.30	0.33
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.66	4.94	5.38	5.32	4.50	5.43	5.41	5.43	5.46	5.47	5.47	5.46	5.47	5.49	5.49
West of Thunder Bay	*Crilly DS*	Non Coincidental Gross						2.17	2.21	2.25	2.29	2.33	2.36	2.40	2.43	2.46	2.49
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.02	1.98	2.02	1.99	2.05	2.15	2.19	2.21	2.23	2.25	2.27	2.29	2.32	2.33	2.35

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW) Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North of Dryden	*Crow River DS*	Non Coincidental Gross						2.70	2.70	2.74	2.79	2.81	2.84	2.86	2.88	2.90	2.93
		CDM						0.02	0.03	0.05	0.07	0.09	0.11	0.12	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.89	2.52	2.64	2.58	2.12	2.68	2.68	2.69	2.72	2.72	2.73	2.73	2.74	2.75	2.76
West of Thunder Bay	*Dryden TS*	Non Coincidental Gross						21.14	21.33	21.80	22.31	22.65	22.99	23.31	23.63	24.02	24.41
		CDM						0.14	0.23	0.41	0.60	0.74	0.88	1.01	1.12	1.23	1.39
		DG						0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
		Non Coincidental Net	18.66	19.07	20.21	19.94	19.61	20.59	20.69	20.99	21.31	21.51	21.71	21.89	22.10	22.38	22.62
North of Dryden	*Ear Falls DS*	Non Coincidental Gross						4.29	4.32	4.34	4.37	4.39	4.42	4.44	4.46	4.49	4.51
		CDM						0.03	0.05	0.08	0.12	0.14	0.17	0.19	0.21	0.23	0.26
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.43	2.46	2.74	4.23	4.55	4.26	4.27	4.26	4.25	4.25	4.25	4.25	4.25	4.26	4.25
West of Thunder Bay	*Eton DS*	Non Coincidental Gross						5.04	5.04	5.10	5.17	5.21	5.24	5.27	5.30	5.34	5.38
		CDM						0.03	0.05	0.10	0.14	0.17	0.20	0.23	0.25	0.27	0.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.06	4.16	4.00	3.97	3.74	5.00	4.98	5.00	5.03	5.03	5.03	5.04	5.04	5.06	5.07
Greenstone-Marathon	*Jellicoe DS #3*	Non Coincidental Gross						0.47	0.47	0.48	0.49	0.49	0.50	0.50	0.50	0.51	0.51
		CDM						0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.48	0.47	0.46	0.45	0.33	0.47	0.47	0.47	0.48	0.48	0.48	0.48	0.48	0.48	0.48
West of Thunder Bay	*Kenora DS*	Non Coincidental Gross						6.88	6.88	6.97	7.10	7.17	7.24	7.30	7.37	7.44	7.51
		CDM						0.05	0.07	0.13	0.19	0.23	0.28	0.32	0.35	0.38	0.43
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	11.44	12.50	6.73	6.67	5.93	6.83	6.80	6.84	6.90	6.93	6.96	6.98	7.02	7.06	7.08
West of Thunder Bay	*Keewatin DS*	Non Coincidental Gross						5.55	5.55	5.62	5.73	5.79	5.84	5.89	5.95	6.00	6.06
		CDM						0.04	0.06	0.11	0.15	0.19	0.22	0.26	0.28	0.31	0.35
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net		5.29	5.43	5.41	4.62	5.51	5.49	5.52	5.57	5.60	5.62	5.64	5.66	5.70	5.72
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						12.79	13.00	18.00	18.19	18.38	18.57	18.76	18.96	19.15	19.35
		CDM						0.08	0.14	0.34	0.49	0.60	0.71	0.81	0.90	0.98	1.10
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	10.78	12.66	12.60	11.94	12.70	12.86	17.66	17.70	17.78	17.86	17.95	18.06	18.17	18.25

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Manitouwadge DS #1*	Non Coincidental Gross						1.56	1.56	1.59	1.61	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.01	0.02	0.03	0.04	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.86	1.36	1.54	1.34	1.29	1.55	1.55	1.56	1.56	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Manitouwadge TS*	Non Coincidental Gross						11.07	11.10	11.28	11.48	13.21	13.33	13.44	13.55	13.69	13.83
		CDM						0.07	0.12	0.21	0.31	0.43	0.51	0.58	0.64	0.70	0.79
		DG						7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84
		Non Coincidental Net	9.48	10.37	10.79	9.66	9.05	3.15	3.14	3.23	3.33	4.94	4.98	5.02	5.06	5.15	5.20
Greenstone-Marathon	*Marathon DS*	Non Coincidental Gross						11.16	11.21	11.42	11.64	11.78	11.91	12.03	12.16	12.31	12.47
		CDM						0.07	0.12	0.21	0.31	0.38	0.45	0.52	0.58	0.63	0.71
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	7.22	8.08	10.71	10.57	7.56	11.08	11.09	11.20	11.33	11.39	11.45	11.51	11.58	11.68	11.76
West of Thunder Bay	*Margach DS*	Non Coincidental Gross						9.60	9.60	9.73	9.88	9.95	10.01	10.07	10.12	10.21	10.29
		CDM						0.06	0.10	0.18	0.27	0.32	0.38	0.44	0.48	0.52	0.59
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.77	9.38	9.44	9.37	8.82	9.53	9.50	9.55	9.61	9.62	9.63	9.63	9.64	9.68	9.70
West of Thunder Bay	*Minaki DS*	Non Coincidental Gross						0.99	0.99	1.00	1.02	1.02	1.03	1.03	1.04	1.05	1.06
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.94	1.06	0.97	0.93	1.00	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	1.00
Thunder Bay	*Murillo DS*	Non Coincidental Gross						19.37	19.61	19.88	19.95	20.27	20.64	20.84	21.03	21.21	21.39
		CDM						0.13	0.21	0.37	0.54	0.66	0.79	0.90	1.00	1.09	1.22
		DG						0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.12	0.12
		Non Coincidental Net	12.12	12.93	12.43	11.34	15.35	19.22	19.37	19.48	19.39	19.59	19.83	19.91	20.01	20.00	20.05
West of Thunder Bay	*Nestor Falls DS*	Non Coincidental Gross						3.36	3.36	3.41	3.46	3.48	3.50	3.52	3.54	3.56	3.59
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.18	0.20
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.22	3.32	3.33	3.29	3.05	3.34	3.33	3.34	3.36	3.36	3.37	3.36	3.37	3.38	3.39
Thunder Bay	*Nipigon DS*	Non Coincidental Gross						2.21	2.24	2.27	2.29	2.33	2.38	2.41	2.44	2.47	2.50
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.32	2.19	2.31	2.23	2.17	2.19	2.21	2.23	2.23	2.26	2.29	2.31	2.32	2.34	2.36
North of Dryden	*Perrault Falls DS*	Non Coincidental Gross						0.79	0.80	0.81	0.83	0.83	0.84	0.85	0.86	0.87	0.88
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.89	0.91	0.78	0.86	0.86	0.79	0.79	0.79	0.80	0.81	0.81	0.81	0.82	0.82	0.83

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Pic DS*	Non Coincidental Gross						6.57	6.58	6.67	6.78	6.84	6.89	6.94	6.98	7.05	7.11
		CDM						0.04	0.07	0.12	0.18	0.22	0.26	0.30	0.33	0.36	0.41
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.96	6.94	6.37	6.50	6.38	6.52	6.50	6.55	6.60	6.61	6.62	6.63	6.65	6.68	6.71
North of Dryden	*Red Lake TS*	Non Coincidental Gross						26.58	26.81	27.04	27.27	27.41	27.64	27.88	28.12	28.36	28.61
		CDM						0.18	0.29	0.51	0.73	0.89	1.05	1.21	1.34	1.46	1.63
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	45.06	47.55	48.55	49.17	50.28	26.40	26.52	26.53	26.54	26.51	26.59	26.67	26.78	26.91	26.98
Thunder Bay	*Red Rock DS*	Non Coincidental Gross						4.01	4.02	4.04	4.02	4.06	4.09	4.10	4.10	4.11	4.11
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.21	0.23
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.23	0.23
		Non Coincidental Net	3.97	3.87	4.08	4.09	4.02	3.95	3.94	3.93	3.88	3.88	3.90	3.88	3.87	3.67	3.64
West of Thunder Bay	*Sam Lake DS*	Non Coincidental Gross						23.97	24.05	24.44	24.88	25.12	25.36	25.57	25.79	26.07	26.36
		CDM						0.16	0.26	0.46	0.67	0.82	0.97	1.11	1.23	1.34	1.50
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	19.80	22.25	23.23	23.00	23.42	23.80	23.78	23.98	24.20	24.30	24.38	24.46	24.56	24.73	24.85
West of Thunder Bay	*Sapawe DS*	Non Coincidental Gross						0.95	0.95	0.97	0.98	0.99	1.00	1.01	1.01	1.02	1.03
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.95	0.80	0.94	0.92	2.61	0.95	0.94	0.95	0.96	0.96	0.96	0.96	0.97	0.97	0.97
Greenstone-Marathon	*Schreiber Winnipg DS*	Non Coincidental Gross						5.19	5.20	5.29	5.38	5.43	5.48	5.52	5.57	5.63	5.69
		CDM						0.03	0.06	0.10	0.14	0.18	0.21	0.24	0.26	0.29	0.32
		DG						0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.47	5.21	5.19	5.07	5.32	5.15	5.15	5.19	5.22	5.24	5.26	5.27	5.29	5.33	5.35
West of Thunder Bay	*Shabaqua DS*	Non Coincidental Gross						2.80	2.81	2.85	2.89	2.92	2.94	2.96	2.98	3.01	3.04
		CDM						0.02	0.03	0.05	0.08	0.10	0.11	0.13	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.64	2.83	2.83	2.81	2.74	2.78	2.77	2.79	2.81	2.82	2.83	2.83	2.84	2.85	2.86
West of Thunder Bay	*Sioux Narrows DS*	Non Coincidental Gross						4.49	4.49	4.55	4.62	4.65	4.68	4.71	4.73	4.77	4.81
		CDM						0.03	0.05	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.27
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.09	4.25	4.37	4.34	4.22	4.46	4.44	4.46	4.49	4.50	4.50	4.50	4.51	4.53	4.54
North of Dryden	*Slate Falls DS*	Non Coincidental Gross						0.64	0.64	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.70
		CDM						0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.56	0.63	0.62	0.61	0.61	0.64	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.66

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Valora DS*	Non Coincidental Gross						0.77	0.78	0.79	0.81	0.83	0.84	0.85	0.86	0.88	0.89
		CDM						0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.64	0.70	0.74	0.73	0.69	0.77	0.77	0.78	0.79	0.80	0.81	0.81	0.82	0.83	0.84
West of Thunder Bay	*Vermilion Bay DS*	Non Coincidental Gross						3.95	3.97	4.01	4.06	4.09	4.12	4.15	4.18	4.21	4.25
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.22	0.24
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.22	2.36	2.37	2.43	2.10	3.93	3.92	3.94	3.95	3.96	3.96	3.97	3.98	3.99	4.00
West of Thunder Bay	*Whitedog DS*	Non Coincidental Gross						2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56	2.59
		CDM						0.02	0.03	0.05	0.07	0.08	0.09	0.11	0.12	0.13	0.15
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.97	2.19	2.30	2.40	2.31	2.35	2.36	2.37	2.37	2.38	2.39	2.40	2.42	2.43	2.44
Greenstone-Marathon	*White River DS*	Non Coincidental Gross						7.02	7.06	7.18	7.32	7.41	7.49	7.56	7.64	7.73	7.83
		CDM						0.05	0.08	0.13	0.20	0.24	0.29	0.33	0.36	0.40	0.45
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.20	3.20	6.80	6.74	6.44	6.98	6.98	7.05	7.13	7.16	7.20	7.23	7.28	7.34	7.38

Appendix E. Past Sustainment Activities in Northwest Ontario

Station	I/S Date	Asset Class
ALEXANDER SS	8-Dec-16	Breaker: SF6_115 kV
BIRCH TS	3-Dec-15	Transformer: Step-down_115 kV
DRYDEN TS	29-Aug-16	Breaker: SF6_115 kV
	14-Jul-16	Breaker: SF6_115 kV
	20-Oct-16	Breaker: SF6_115 kV
	10-Nov-16	Breaker: SF6_115 kV
	29-May-16	Breaker: SF6_115 kV
	23-Jul-14	Breaker: SF6_13.8 kV
	4-Sep-14	Breaker: SF6_13.8 kV
	29-Aug-16	Switch: Air Break_115 kV
	29-Aug-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	31-Aug-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	10-Nov-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	29-May-16	Switch: Air Break_115 kV
	1-Nov-16	Switch: Air Break_115 kV
	23-Jul-14	Switch: Air Break_13.8 kV
	4-Sep-14	Switch: Air Break_ 13.8 kV
FORT FRANCES TS	23-Nov-10	Breaker: SF6_13.8 kV
	2-Sep-10	Breaker: SF6_13.8 kV
	2-Oct-13	Switch: Air Break_115 kV
	27-Nov-15	Switch: Air Break_230 kV
	2-Oct-13	Switch: Ground_115 kV
	27-Nov-15	Switch: Ground_230 kV
	2-Sep-10	Switch: Air Break_ 13.8 kV
	2-Oct-16	Switch: Air Break_115 kV
	12-Sep-14	Switch: Ground_ 44 kV
	23-Nov-10	Switch: Air Break_ 13.8 kV
LAKEHEAD TS	27-Sep-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	1-Dec-09	Breaker: SF6_13.8 kV
	4-Apr-12	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Air Break_ 13.8 kV
	21-Oct-09	Switch: Ground_ 13.8 kV
	21-Oct-09	Switch: Air Break_ 13.8 kV
	12-Sep-16	Transformer: Autotransformer_230 kV

Station	I/S Date	Asset Class
KENORA TS	15-Jul-2009	Breaker: SF6_13.8 kV
	29-May-2015	Switch: Air Break_230 kV
	29-May-2015	Switch: Ground_230 kV
	26-Feb-2013	Switch: Air Break_230 kV
	15-Jul-2009	Switch: Air Break_ 13.8 kV
MACKENZIE TS	17-Jun-2010	Breaker: SF6_13.8 kV
MANITOUWADGE TS	2-Jul-2016	Breaker: SF6_27.6 kV
	10-Jul-2016	Switch: Air Break_ 44 kV
	9-Jul-2016	Transformer: Step-down_115 kV
MARATHON TS	25-May-2009	Breaker: SF6_230 kV
	26-Mar-2014	Breaker: SF6_13.8 kV
	18-Dec-2013	Breaker: SF6_13.8 kV
	23-Dec-2016	Switch: Air Break_230 kV
	23-Dec-2016	Switch: Ground_230 kV
	26-Mar-2014	Switch: Air Break_ 13.8 kV
	18-Dec-2013	Switch: Air Break_ 13.8 kV
MOOSELAKE TS	8-Sep-2014	Breaker: SF6_115 kV
	31-Jul-2014	Breaker: SF6_115 kV
	29-May-2014	Breaker: SF6_115 kV
	8-Sep-2014	Breaker: SF6_115 kV
	11-Jul-2014	Breaker: SF6_115 kV
PORT ARTHUR TS #1	11-Aug-2015	Switch: Air Break_115 kV
	25-Nov-2009	Switch: Air Break_115 kV
	11-Nov-2009	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	20-Nov-2009	Switch: Air Break_115 kV
	6-Nov-2009	Switch: Air Break_115 kV
	22-Jun-2015	Switch: Air Break_115 kV
	2-Jun-2015	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Ground_115 kV
RABBIT LAKE SS	16-Dec-2011	Breaker: SF6_115 kV
	10-Nov-2011	Breaker: SF6_115 kV
	22-Oct-2011	Switch: Air Break_115 kV
	25-Nov-2016	Switch: Air Break_115 kV
	15-Nov-2016	Switch: Ground_115 kV
	23-Oct-2011	Switch: Air Break_115 kV

Appendix F. List of Acronyms

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

Appendix 1D: 2018 Investment and Bill Impact Survey for 2018 COS

Investment and Bill Impact Survey for 2018 COS

1. First, we want to make sure you are a Sioux Lookout Hydro customer! Please input your hydro account number in the box below. The number should contain 12 digits, with a hyphen in between. e.g. xxxxxx-xxxxxx

2. How familiar are you with the local electricity distribution system?

- Very familiar
- Somewhat familiar
- Not very familiar
- Not familiar at all

3. Given what you know and what you have read so far, how well do you feel you understand the parts of the Ontario electricity system, how they work together and which services Sioux Lookout Hydro is responsible for?

- very well
- Somewhat well
- Not very well
- I don't understand at all

4. With regards to the projects focused on replacing aging equipment and infrastructure in poor conditions (i.e vehicle replacements, pole replacements), which of the following statements best represents your point of view?

- Sioux Lookout Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
- Sioux Lookout Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
- Don't know
- No opinion

5. Now that you have a better sense of the operations of Sioux Lookout Hydro, including cost drivers, do you feel the proposed operating budget is reasonable?

- ◯ Yes
- ◯ No
- ◯ I don't know

6. Considering the costs of Sioux Lookout Hydro's application, would you say....

- ◯ The rate increase is reasonable
- ◯ I don't like it, but I think the rate increase is necessary
- ◯ The rate increase is unreasonable
- ◯ I don't know

7. AGE: Can you tell me what age category you fall into?

- ◯ Less than 18
- ◯ 18-24
- ◯ 25-34
- ◯ 35-44
- ◯ 45-54
- ◯ 55-64
- ◯ 65 years or older
- ◯ Prefer not to answer

8. Do you own or rent your home?

- ◯ Own
- ◯ Rent
- ◯ Prefer not to answer

9. How would you describe your primary residence? Would you say you live in..

- ◯ A fully-detached home
- ◯ A semi-detached home
- ◯ An apartment or condo building
- ◯ Prefer not to answer

10. Counting yourself, how many people live in your household?

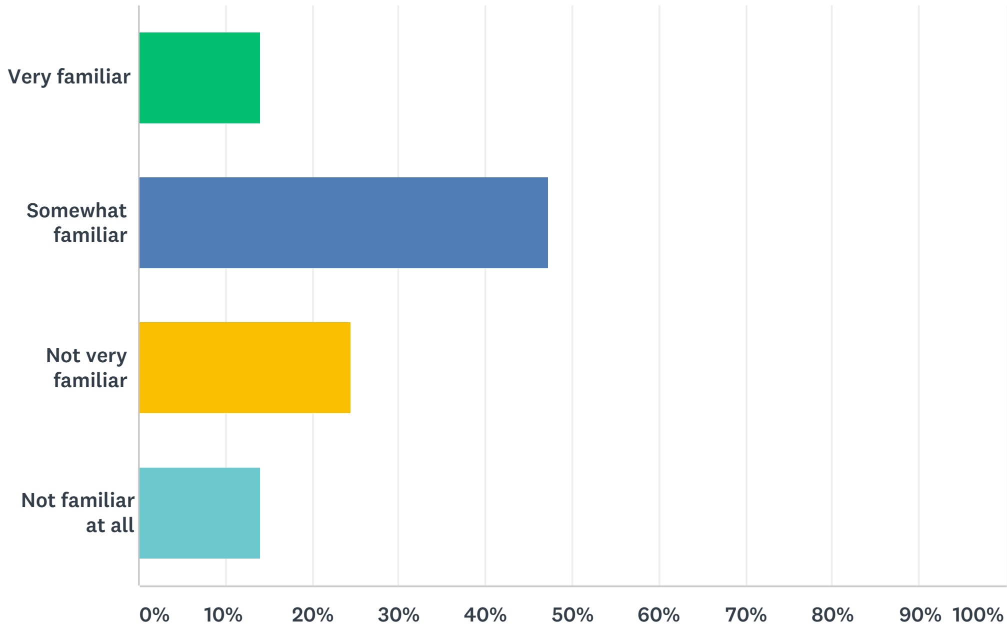
- ◯ 1 person
- ◯ 2-7
- ◯ 8 or more than 8
- ◯ Prefer not to answer

Q1 First, we want to make sure you are a Sioux Lookout Hydro customer! Please input your hydro account number in the box below. The number should contain 12 digits, with a hyphen in between. e.g. xxxxxx-xxxxxx

Answered: 51 Skipped: 6

Q2 How familiar are you with the local electricity distribution system?

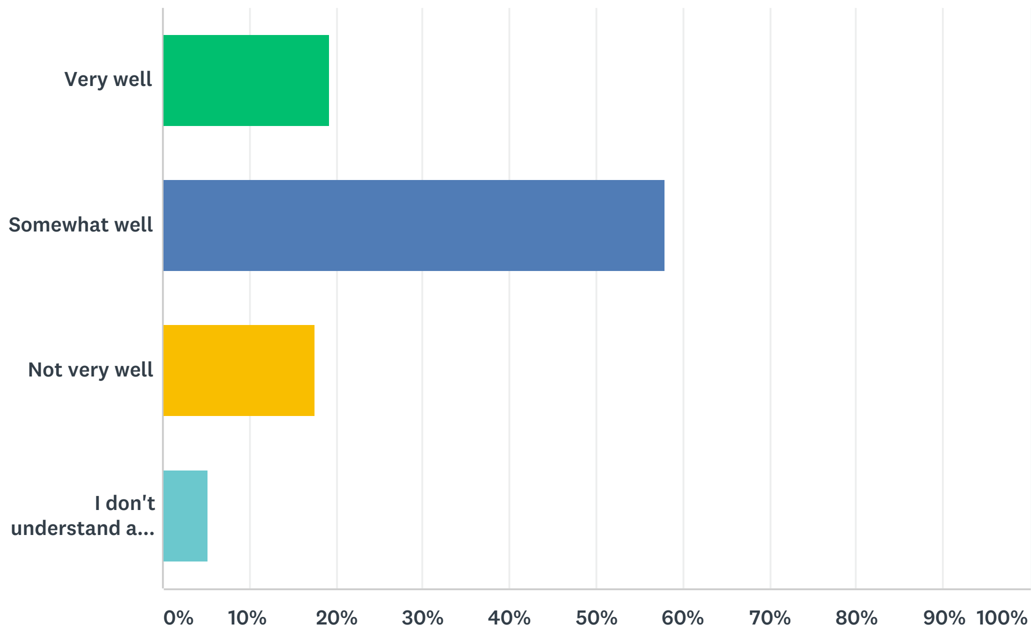
Answered: 57   Skipped: 0



ANSWER CHOICES	RESPONSES	
Very familiar	14.04%	8
Somewhat familiar	47.37%	27
Not very familiar	24.56%	14
Not familiar at all	14.04%	8
TOTAL		57

Q3 Sioux Lookout Hydro is responsible for issuing your hydro bill each month. Your bill includes other charges such as electricity, transmission, connection and regulatory costs which we pay to other agencies. We control only the distribution portion or about 20% of the amount you pay. Given what you know and what you have read so far, how well do you feel you understand the parts of the Ontario electricity system, how they work together and which services Sioux Lookout Hydro is responsible for?

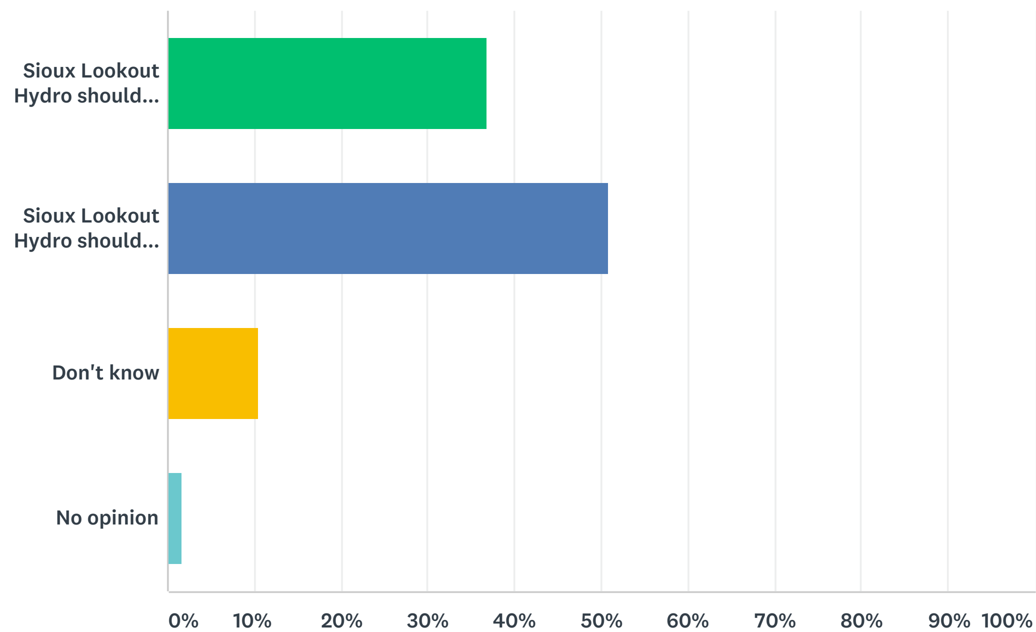
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
Very well	19.30%	11
Somewhat well	57.89%	33
Not very well	17.54%	10
I don't understand at all	5.26%	3
TOTAL		57

Q4 Sioux Lookout Hydro is proposing to spend $100,000 per year to replace old and deteriorating poles, and $355,000 to replace our 2001 Line truck. This will amount to $26,000 per year passed on to you or about 64 cents per month. So, with regards to the projects focused on replacing aging equipment and infrastructure in poor conditions (i.e vehicle replacements, pole replacements), which of the following statements best represents your point of view?

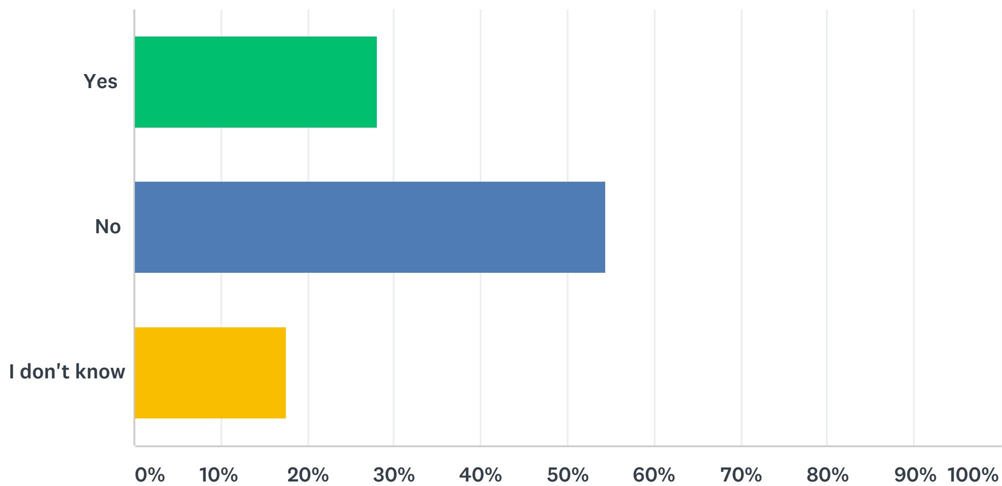
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
Sioux Lookout Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.	36.84%	21
Sioux Lookout Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.	50.88%	29
Don't know	10.53%	6
No opinion	1.75%	1
TOTAL		57

Q5 The proposed operating budget is $1.57 million, an increase of $150,000 since 2013 when our last cost of service application was approved by the Ontario Energy Board. Sioux Lookout Hydro operates under a highly regulated environment. Therefore we need extra funds in order to respond to new public policy direction and regulatory requirements, which accounts for $64,000 of the increase we are asking for.Now that you have a better sense of the operations of Sioux Lookout Hydro, including cost drivers, do you feel the proposed operating budget is reasonable?

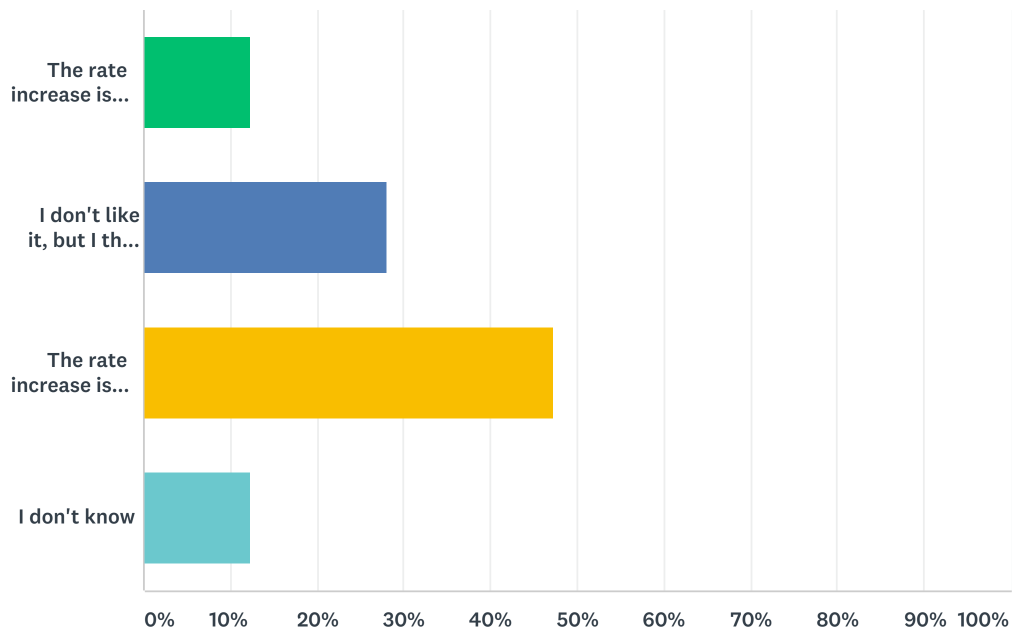
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
Yes	28.07%	16
No	54.39%	31
I don't know	17.54%	10
TOTAL		57

Q6 Here are what the bill impacts will be if our application is approved:To the Distribution portion of your bill only: Rate Class Monthly kWh $ Change % Change With DRP $/% Change Residential* 750 $6.10 15.21% $0.00/0% General Service less than 50 kW 2,000 $6.61 11.03% n/a To the Total Bill (i.e. All charges like transmission, connection, regulatory and electricity): Rate Class Monthly kWh $ Change % Change With DRP $/% Change Residential* 750 $7.48 5.95% $1.08/0.89% General Service less than 50 kW 2,000 $7.55 2.56% n/a *For our residential customers, the Distribution Rate Protection (DRP) adjustment implemented on July 1, 2017 will be applied to your bill. Therefore the impact on Distribution charges will be 0%.Considering the costs of Sioux Lookout Hydro's application, would you say....

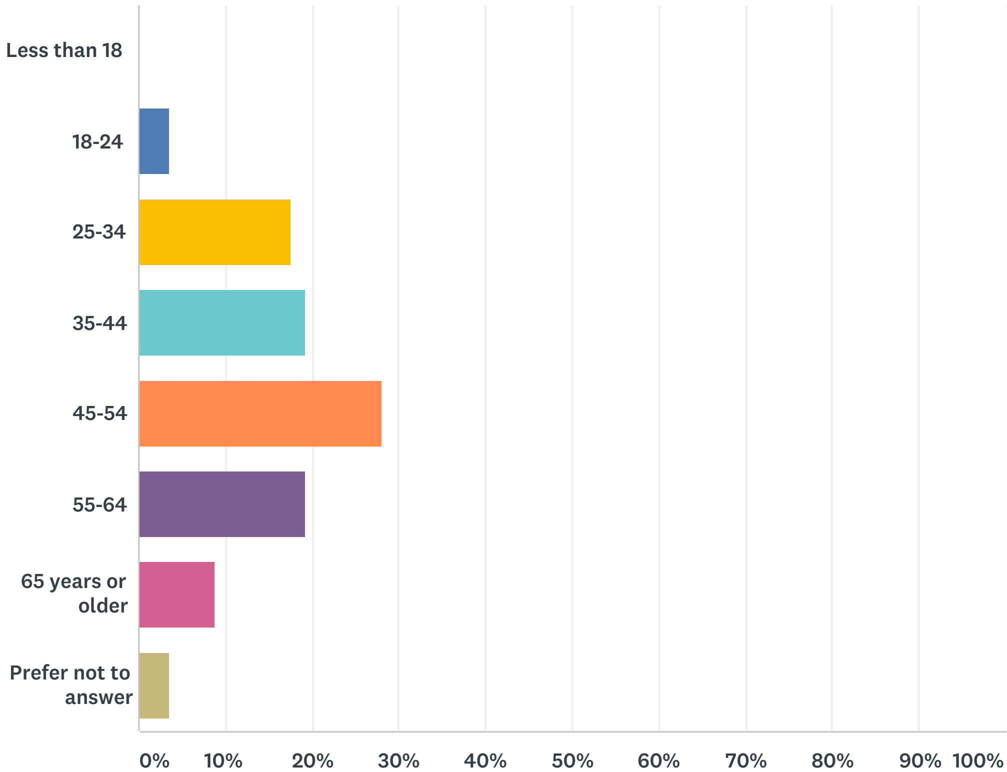
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
The rate increase is reasonable	12.28%	7
I don't like it, but I think the rate increase is necessary	28.07%	16
The rate increase is unreasonable	47.37%	27
I don't know	12.28%	7
TOTAL		57

Q7 AGE: Can you tell me what age category you fall into?

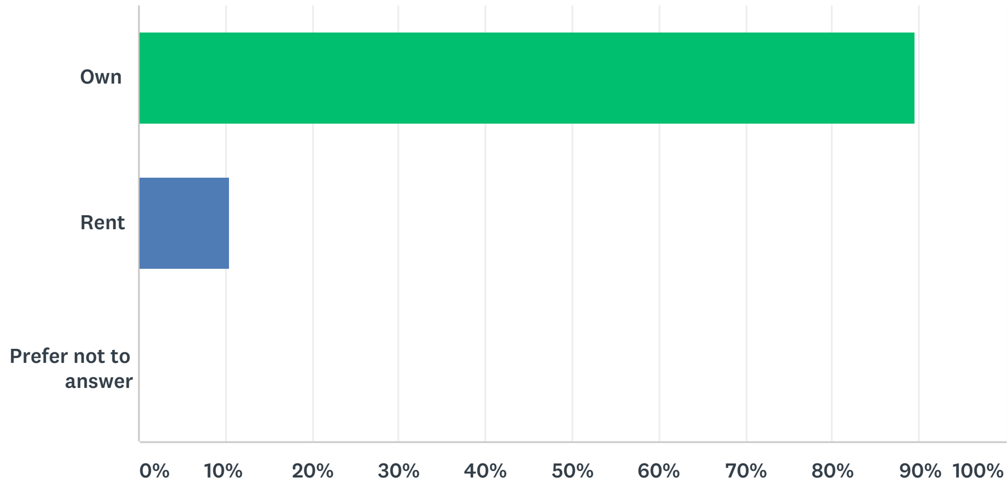
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
Less than 18	0.00%	0
18-24	3.51%	2
25-34	17.54%	10
35-44	19.30%	11
45-54	28.07%	16
55-64	19.30%	11
65 years or older	8.77%	5
Prefer not to answer	3.51%	2
TOTAL		57

Q8 Do you own or rent your home?

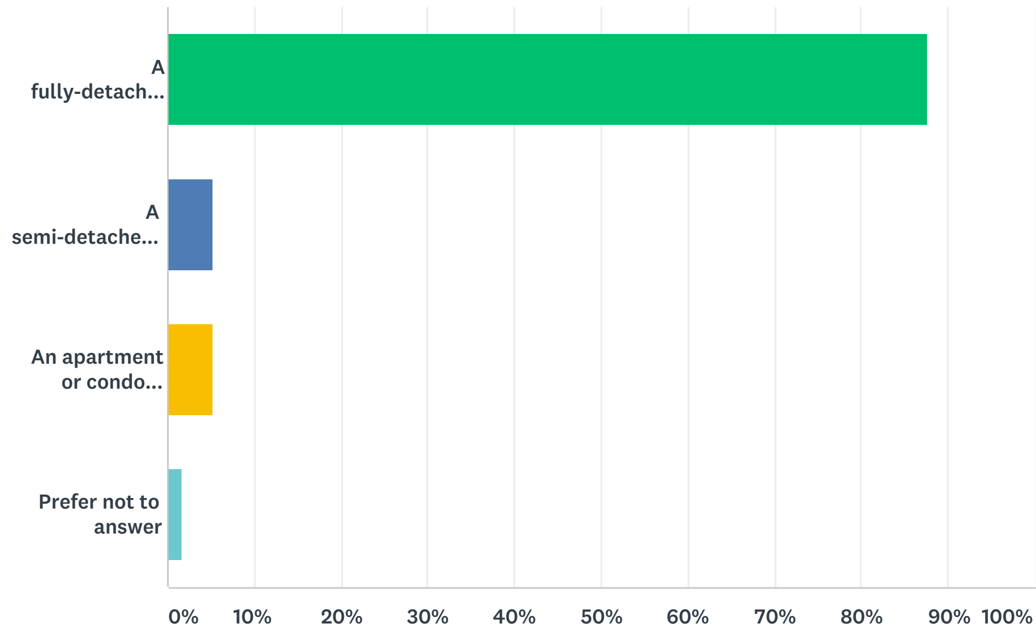
Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
Own	89.47%	51
Rent	10.53%	6
Prefer not to answer	0.00%	0
TOTAL		57

Q9 How would you describe your primary residence? Would you say you live in..

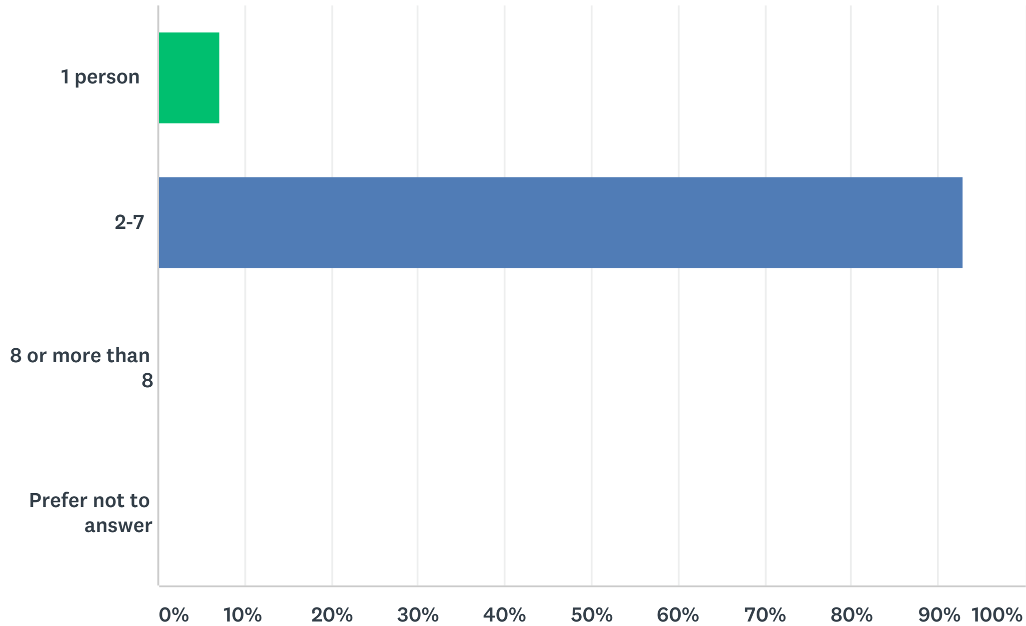
Answered: 57   Skipped: 0



ANSWER CHOICES	RESPONSES	
A fully-detached home	87.72%	50
A semi-detached home	5.26%	3
An apartment or condo building	5.26%	3
Prefer not to answer	1.75%	1
TOTAL		57

Q10 Counting yourself, how many people live in your household?

Answered: 57 Skipped: 0



ANSWER CHOICES	RESPONSES	
1 person	7.02%	4
2-7	92.98%	53
8 or more than 8	0.00%	0
Prefer not to answer	0.00%	0
TOTAL		57

Q11 Please provide any comments you may have.

Answered: 20 Skipped: 37

Appendix 1E: Scorecard – Sioux Lookout Hydro Inc.

Scorecard - Sioux Lookout Hydro Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	96.40%	95.00%	100.00%	100.00%	↑	90.00%	
		Scheduled Appointments Met On Time		97.30%	92.90%	98.50%	98.20%	96.20%	↑	90.00%	
		Telephone Calls Answered On Time		97.10%	98.10%	98.60%	100.00%	96.20%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution					100%	100%			
		Billing Accuracy					99.67%	99.90%	↑	98.00%	
		Customer Satisfaction Survey Results					89.51%	89.51%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.71	0.47	0.23	1.28	0.68	↓		0.92
		Average Number of Times that Power to a Customer is Interrupted [2]		0.77	0.17	0.28	0.74	0.36	↓		0.50
	Asset Management	Distribution System Plan Implementation Progress					Stage 1	Stage 2			
	Cost Control	Efficiency Assessment			3	3	3	3			
		Total Cost per Customer [3]		$742	$814	$802	$869	$818			
		Total Cost per Km of Line [3]		$7,219	$7,928	$7,845	$8,445	$8,273			
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).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						14.52%			3.70 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.35	1.15	1.00	0.96	0.95			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.86	0.80	0.71	0.64	0.58			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.57%	8.98%	8.98%	8.98%			
			Achieved	9.67%	9.22%	12.30%	6.38%	7.38%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: target met · target not met

Appendix 1F: Summary from PEG Benchmarking Model

Summary of Cost Benchmarking Results

Sioux Lookout Hydro Inc.

Cost Benchmarking Summary	2016 (History)	2017 (Bridge)	2018 (Test Year)	2019	2020	2021
Actual Total Cost	2,377,225	2,499,904	2,493,101	na	na	na
Predicted Total Cost	2,459,823	2,570,485	2,660,549	na	na	na
Difference	(82,598)	(70,581)	(167,448)	na	na	na
Percentage Difference (Cost Performance)	**-3.4%**	**-2.8%**	**-6.5%**	**na**	**na**	**na**
Three-Year Average Performance			-4.2%	na	na	na
Stretch Factor Cohort						
Annual Result	3	3	3	na	na	na
Three Year Average			3			

Appendix 1G: 2015 Audited Financial Statements

(Includes prior year 2014)

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2015 and 2014

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Independent Auditor's Report

To the Shareholder of Sioux Lookout Hydro Inc.

We have audited the accompanying financial statements of Sioux Lookout Hydro Inc., which are comprised of the statement of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, and the statements of comprehensive income, changes in equity, and cash flows for the years ended December 31, 2015 and December 31, 2014, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly in all material respects, the financial position of Sioux Lookout Hydro Inc. as at December 31, 2015, December 31, 2014 and January 1, 2014, and the results of its operations and cash flows, for the years ended December 31, 2015 and December 31, 2014, in accordance with International Financial Reporting Standards.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

Dryden, Ontario
May 24, 2016

Sioux Lookout Hydro Inc.
Statement of Financial Position (Expressed in Canadian Dollars)

As at	December 31, 2015	December 31, 2014	January 1, 2014
Assets			
Current assets			
Cash	$ **391,689**	$ 60,311	$ 56,203
Trade and other receivables (Note 6)	**1,445,713**	1,424,508	1,133,420
Unbilled revenue	**1,379,819**	1,632,174	1,736,015
Inventory	**78,217**	55,798	58,324
Prepaids	**49,519**	37,277	42,805
Payments in lieu of taxes receivable	**-**	10,937	13,037
Total current assets	**3,344,957**	3,221,005	3,039,804
Non-current assets			
Property, plant and equipment (Note 4)	**4,952,365**	4,941,182	4,907,453
Deferred tax	**124,850**	82,886	102,423
Total non-current assets	**5,077,215**	5,024,068	5,009,876
Regulatory deferral account debits (Note 3)	**185,714**	189,499	222,236
	$ **8,607,886**	$ 8,434,572	$ 8,271,916

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Financial Position (Expressed in Canadian Dollars)

As at	December 31, 2015	December 31, 2014	January 1, 2014
Liabilities and Shareholder's Equity			
Current liabilities			
Accounts payable and accrued liabilities	**$ 3,035,220**	$ 2,932,187	$ 2,579,784
Customer deposits	**137,708**	106,181	118,231
Payments in lieu of taxes payable	**12,626**	-	-
Due to parent company (Note 9)	**240,000**	200,000	235,000
Demand installment loan (Note 16)	**1,725,037**	1,943,439	2,154,939
Total current liabilities	**5,150,591**	5,181,807	5,087,954
Non-current liabilities			
Employee future benefits (Note 8)	**160,259**	158,244	156,528
Contributions in aid on construction (Note 5)	**80,217**	42,201	-
Total liabilities	**5,391,067**	5,382,252	5,244,482
Shareholder's equity			
Share capital (Note 11)	**2,789,823**	2,789,823	2,789,823
Retained earnings	**282,366**	205,291	229,210
Total shareholder's equity	**3,072,189**	2,995,114	3,019,033
Total liabilities and shareholder's equity	**8,463,256**	8,377,366	8,263,515
Regulatory deferral account credits (Note 3)	**144,630**	57,206	8,401
Total equity, liabilities and regulatory deferral account credits	**$ 8,607,886**	$ 8,434,572	$ 8,271,916

On behalf of the Board:

________________________ Director

________________________ Director

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Comprehensive Income (Expressed in Canadian Dollars)

For the year ended December 31	2015	2014
Revenue		
Electricity sales	**$ 11,691,454**	$ 11,839,474
Street lighting	**140,682**	156,438
Other (Note 13)	**169,038**	129,748
	12,001,174	12,125,660
Expenses		
Administration	**654,874**	755,849
Amortization (Note 14)	**214,481**	211,187
Operations and maintenance	**697,944**	781,379
Purchased power	**9,919,664**	9,804,735
Loss on disposal of property, plant and equipment	**2,042**	6,074
	11,489,005	11,559,224
Income from operating activities	**512,169**	566,436
Finance income (Note 15)	**4,132**	6,452
Finance cost (Note 15)	**(129,710)**	(135,226)
Income before provision for payment in lieu of taxes	**386,591**	437,662
Provision for payments in lieu of taxes		
Current (Note 7)	**34,506**	11,047
Deferred (Note 7)	**(41,964)**	19,537
	(7,458)	30,584
Profit for the year before net movements in regulatory deferral account balances	**394,049**	407,078
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement	**(76,974)**	(230,997)
Profit for the year and net movements in regulatory deferral account balances	**$ 317,075**	$ 176,081

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Changes in Equity (Expressed in Canadian Dollars)

	Share Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total
Balance at January 1, 2014	$ 2,789,823	$ -	$ 229,210	$ 3,019,033
Profit for the year and movements in regulatory deferral account balances	-	-	176,081	176,081
Dividends	-	-	(200,000)	(200,000)
December 31, 2014	2,789,823	-	205,291	2,995,114
Profit for the year and movements in regulatory deferral account balances	-	-	317,075	317,075
Dividends	-	-	(240,000)	(240,000)
December 31, 2015	**$ 2,789,823**	**$ -**	**$ 282,366**	**$ 3,072,189**

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows (Expressed in Canadian Dollars)

For the year ended December 31	2015	2014
Cash flows from operating activities		
Profit for the year after net movements in regulatory deferral accounts	$ 317,075	$ 176,081
Items not involving cash		
Amortization	312,640	313,457
Loss on disposal of property, plant and equipment	2,042	6,074
Payments in lieu of taxes	23,563	2,100
Deferred taxes	(41,964)	19,537
Increase in future employee benefits	2,015	1,716
Amortization of contributions in aid of construction	(2,497)	(1,293)
	612,874	517,672
Changes in non-cash working capital balances		
Trade and other receivables	(21,205)	(291,088)
Unbilled revenue	252,355	103,841
Inventory	(22,419)	2,526
Prepaids	(12,242)	5,528
Accounts payable and accrued liabilities	103,033	352,403
Customer deposits and deferred contributions	31,527	(12,050)
	943,923	678,832
Cash flows from investing activities		
Proceeds from disposal of property, plant and equipment	-	4,774
Purchase of property, plant and equipment	(333,933)	(362,899)
Contributions in aid of construction received during year	40,513	43,494
Changes in regulatory deferral account balances	99,277	86,407
	(194,143)	(228,224)
Cash flows from financing activities		
Repayments of long-term debt	(218,402)	(211,500)
Dividends paid	(240,000)	(200,000)
Repayments to parent company	40,000	(35,000)
	(418,402)	(446,500)
Increase in cash during the year	331,378	4,108
Cash, beginning of year	60,311	56,203
Cash, end of year	$ 391,689	$ 60,311

The accompanying notes are an integral part of these financial statements.

1. Corporate Information

Sioux Lookout Hydro Inc.'s (the "Company") main business activity is the distribution of electricity under authority of the Ontario Energy Board ("OEB") Act, 1998. The Company owns and operates an electricity distribution system, which delivers electricity to approximately 2,785 customers located in Sioux Lookout, Ontario.

Operating in regulated environment exposes the Company to regulatory and recovery risk.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations, including the recovery of expenses incurred for the benefit of other market participants in the electricity industry, such as transition costs and other regulatory balances. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. Sioux Lookout Hydro Inc. is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The address of the Company's corporate office and principal place of business is P.O. Box 908, Sioux Lookout, Ontario, Canada.

The sole shareholder of the Company is the Corporation of the Municipality of Sioux Lookout.

2. Basis of Preparation

a) Statement of Compliance

The financial statements of Sioux Lookout Hydro Inc. have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). These are the Company's first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. They should be read in conjunction with the 2014 Canadian generally accepted accounting principles ("Canadian GAAP") financial statements and related notes. In this context, the term "Canadian GAAP" refers to generally accepted accounting principles before the adoption of IFRS.

The financial statements were authorized for issue by the Board of Directors on May 24, 2016.

2. Basis of Preparation (continued)

b) First Time Adoption of IFRS

The transition to IFRS resulted in a decrease of shareholders equity of $116,552 and $121,764 at January 1, 2014 and December 31, 2014 respectively, and a decrease in Comprehensive Income of $5,212 for the year ended December 31, 2014. In addition, the adoption of IFRS 14, Regulatory Deferral Accounts, resulted in a significant change in presentation, as regulatory deferral accounts are now presented separately from assets and liabilities and the change in regulatory deferral accounts is presented separately from net profit.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance, and cash flows of the Company is provided in Note 19.

c) Basis of Measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Company's functional currency, and all values are rounded to the nearest dollar, unless when otherwise indicated.

d) Judgement and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgement in applying the Company's accounting policies. The areas involving critical judgements and estimates in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The calculation of the impairment of accounts receivables (Note 6);
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 7);
- The determination of useful lives of property, plant and equipment (Note 4);
- The calculation of regulatory deferral account balances (Note 3); and
- The calculation of the net future obligation for certain unfunded health, dental and life insurance benefits for the Company's retired employees (Note 8).

In addition, in preparing the financial statements, the notes to the financial statements were ordered such that the most relevant information was presented earlier in the notes and the disclosures that management deemed to be immaterial were excluded from the notes to the financial statements. The determination of the relevance and materiality of disclosures involved significant judgement.

3. Regulatory Deferral Account Balances

The Company has early adopted IFRS 14 Regulatory Deferral Accounts. In accordance with IFRS 14, the Company has continued to apply the accounting policies it applied in accordance with the pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation. These are referred to as regulatory deferral account balances. Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets.

Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s) that are expected to be returned to consumers in future periods through the rate-setting process.

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s) that are expected to be recovered from consumers in future periods through the rate-setting process. Management continually assesses the likelihood of recovery of regulatory balances. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

The balances and movements in the regulatory deferral account balances shown below are presented net of related deferred taxes. These deferred taxes are not presented within the total deferred tax asset balances shown in Note 7. All amounts deferred as regulatory deferral account balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	Remaining recovery/ reversal period (years)	2015	2014
Debit balances consist of the following:			
IFRS transition costs and adjustments	1 - 4	$ 184,628	$ 126,721
SME variances	1 - 4	1,150	2,176
Stranded meters	0	(64)	60,602
		$ 185,714	$ 189,499
Credit balances consist of the following:			
Cost of power	1 - 4	$ (126,485)	$ (40,015)
Lost revenue adjustment mechanism	1 - 4	(11,252)	(12,252)
Settlement variances	1 - 4	(6,893)	(4,939)
		$ (144,630)	$ (57,206)
Net		$ 41,084	$ 132,293

3. Regulatory Deferral Account Balances (continued)

In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the year in which they relate. As a result, the net effect on income for the period as stated below:

i) Cost of Power

This account is comprised of the variances between amounts charged by the company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service charged to the company for the operation of the wholesale electricity market and grid, including commodity and global adjustment, various wholesale market settlement charges, and transmission charges. Under the OEB's direction, the company has deferred the settlement variances that have occurred since May 1, 2002 in accordance with the AP Handbook. Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. The Company did not recognize carrying charge income related to the retail settlement variance accounts for external reporting purposes prior to December 31, 2003.

As a component of the yearly Incentive Regulation Mechanism (IRM) rate application process, "Group 1" account balances (which are composed of Low Voltage, Wholesale Market, Network, Connection, Power, and the Smart Meter Entity charge) are reviewed and will qualify for disposition if balances, including carrying charges, exceed a preset threshold per kWh.

ii) IFRS Transition Costs

This regulatory balance includes one-time administrative incremental IFRS transitional costs and the differences arising from accounting policy changes for property, plant and equipment ("PP&E") to the transition from GAAP to IFRS effective January 1, 2014.

One-time administrative incremental IFRS transitional costs of $286 (2014 - $353) relates to the transition of accounting policies, procedures, systems, and processes to IFRS, for costs which were not already approved and included for recovery in distribution rates. The OEB has permitted these costs to be captured for future rate recovery. As at December 31, 2015, the total for IFRS transitional costs are $25,300 (2014 - $25,013).

Costs associated with accounting policy changes for PP&E due to the transition from GAAP to IFRS deferred for future recovery were $57,621 (2014 - $57,670). As at December 31, 2015, the total for GAAP to IFRS transition costs are $159,328 (2014 - $101,708).

The Company expects to request disposition of these balances in its next rate application, for rates to be effective May 1, 2018.

3. **Regulatory Deferral Account Balances** (continued)

iii) Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

This regulatory balance relates to the variance between the OEB approved Conservation and Demand Management ("CDM") forecast and the actual results at the customer rate class level for the period 2011-2014.

The Company expects to request disposition of these balances in its next rate application, for rates to be effective May 1, 2018.

iv) SME Variances

A Smart Meter Disposition Rider (SMDR) recovered, over a specified period of time, the variance between: 1) the deferred revenue requirement for the installed smart meters up to the time of disposition; and 2) the Smart Meter Funding Adder ("SMFA") revenues and related interest collected from 2006 to April 30, 2012. The resulting SMDR liability was $162,501.

The OEB approved the recovery of this balance through a two year rate rider to Residential and General Service < 50kW rate payers ending August 31, 2014. The balance was fully recovered in 2014.

v) Settlement Variances

This regulatory account includes the variances between the amounts billed to ratepayers based on regulatory rates, and the corresponding costs of electricity and non-competitive electricity service costs incurred to service those customers.

The settlement variances relate primarily to commodity charges, non-competitive electricity charges and the global adjustment, and in accordance with the criteria set out in the accounting principles prescribed by the OEB, these variances have been deferred. These variances are for future disposition and the regulator determines in all cases, when the balances are material enough to warrant an adjustment to rates.

The Company expects to request disposition of this balance in its next rate application, for rates to be effective May 1, 2018.

vi) Stranded Meters

The provincial government mandated the installation of smart meters for all residential and small business rate payers in Ontario by 2010.

The OEB recognized that the installation of smart meters would mean that older meters would be retired earlier than planned and that the costs associated with retired meters would not have been fully depreciated. As a result, in August 2013 the OEB approved these stranded costs to be recoverable and approved the recovery of the stranded asset cost from Residential and General Service < 50 kW ratepayers for a one year period, ending August 31, 2015.

3. **Regulatory Deferral Account Balances** (continued)

The Company expects to request disposition of this remaining credit balance of $64 in its next rate application, for rates to be effective May 1, 2018.

4. **Property, Plant and Equipment**

Property, plant and equipment is stated at cost less accumulated amortization. Costs may include direct material, labour, contracted services, overhead, engineering costs, and interest on funds used during construction that are considered applicable to construction.

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company's distribution system reliability.

Upon disposal the cost and accumulated amortization of assets are relieved from the respective accounts and any gain or loss is reflected in operations.

Depreciation of PP&E is recorded in the Statements of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values, and depreciation methods are reviewed at the end of each annual reporting period.

The estimated useful lives are as follows:

Distribution Assets:	
Poles, towers and fixtures	45 years
Overhead conductor and devices	45 years
Underground conduit and conductor	50 years
Distribution transformers	40 years
Overhead and underground services	40 - 60 years
Distribution Meters	10 - 25 years
General Assets:	
Buildings	25 - 50 years
Computer equipment	3 - 5 years
Office equipment	5 - 15 years
Transportation equipment	5 - 15 years
Small tools and miscellaneous equipment	10 years
Load management controls	6 years
System supervisory equipment	15 - 20 years
Land is not depreciated.	

4. Property, Plant and Equipment (continued)

	Electrical Distribution Assets	General Assets	Construction in Progress	Total
Cost				
Balance as of January 1, 2014	$ 7,450,718	$ 1,133,490	$ 7,714	$ 8,591,922
Additions	265,822	104,791	-	370,613
Disposals	(29,965)	(34,972)	(7,714)	(72,651)
Balance as of December 31, 2014	7,686,575	1,203,309	-	8,889,884
Additions	267,420	33,196	33,317	333,933
Disposals	(33,697)	-	-	(33,697)
Balance as of December 31,2015	$ 7,920,298	$ 1,236,505	$ 33,317	$ 9,190,120
Accumulated depreciation				
Balance as of January 1, 2014	$ 2,829,802	$ 854,667	$ -	$ 3,684,469
Depreciation for the year	236,140	77,317	-	313,457
Disposals	(14,407)	(34,817)	-	(49,224)
Balance as of December 31, 2014	3,051,535	897,167	-	3,948,702
Depreciation for the year	238,363	74,277	-	312,640
Disposals	(23,587)	-	-	(23,587)
Balance as of December 31,2015	$ 3,266,311	$ 971,444	$ -	$ 4,237,755
Carrying amounts				
At January 1, 2014	$ 4,620,916	$ 278,823	$ 7,714	$ 4,907,453
At December 31, 2014	$ 4,635,040	$ 306,142	$ -	$ 4,941,182
At December 31, 2015	$ 4,653,987	$ 265,061	$ 33,317	$ 4,952,365

5. Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on an accrual basis. Distribution revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the fiscal year. Actual results could differ from estimates made of customer electricity usage.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Other revenues, which include revenues from pole use rental, collection charges, street lighting, and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions vary by project and are based on the criteria set forth in the Distribution System Code. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The continuity of deferred contributions in aid of construction is as follows:

	December 31 2015	December 31 2014	January 1 2014
Deferred contributions, net, beginning of year	**$ 42,201**	$ -	$ -
Contributions in aid of construction received	**40,513**	43,494	-
Contributions in aid of construction recognized as revenue	**(2,497)**	(1,293)	-
Deferred contributions, net, end of year	**$ 80,217**	$ 42,201	$ -

All contributions in aid of construction are cash contributions. There have not been any contributions of property, plant and equipment.

6. Trade and Other Receivables

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 1,341,356	$ 1,345,219	$ 973,766
Less: allowance for doubtful accounts	(88,663)	(92,701)	(47,499)
Trade receivables - net	1,252,693	1,252,518	926,267
HST receivable	193,020	171,990	207,153
	$ 1,445,713	$ 1,424,508	$ 1,133,420

Due to its short-term nature, the carrying amount of the trade receivable and HST receivable approximates its fair value. In determining the allowance for doubtful accounts, the Company considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in the statement of comprehensive income. Subsequent recoveries of receivables previously provisioned are credited to the income statement. The balance of the allowance for impairment at December 31, 2015 is $88,663 (2014 - $92,701). An impairment loss of $24,094 (2014 - $39,857) was recognized during the year. The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2015, approximately $155,775 (2014 - $155,160) is considered 60 days past due. The Company has approximately 2,785 customers, the majority of which are residential.

Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as deposits, which are reported separately from the Company's own cash and cash equivalents. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 1%.

Customer deposits represents cash deposits from electricity distribution customers and retailers, as well as construction deposits. Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

7. Payments in Lieu of Taxes Payable

The Company is a Municipal Electricity Utility (“MEU”) for purposes of the payments in lieu of taxes (“PILs”) regime contained in the Electricity Act, 1998. As an MEU, the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each taxation year, PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

PILs expense is comprised of current and deferred tax. Current tax and deferred tax are recognized in comprehensive income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances.

Significant judgement is required in determining the provision for PILs. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provision in the period in which such determination is made.

The income tax expense varies from amounts which would be computed by applying the Company’s combined statutory income tax rate as follows:

	2015	2014
Earnings before provision for taxes	**309,617**	206,665
Statutory Canadian federal and provincial income tax rate (%)	**39.5**	39.5
Expected provision	**122,299**	81,633
Increase (decrease) in income tax resulting from:		
Permanent differences	**310**	103
Apprenticeship tax credit	**(1,310)**	(12,520)
Other timing differences	**(17,720)**	(7,159)
Small business deduction	**(69,073)**	(51,010)
Provision for payments in lieu of taxes	**34,506**	11,047
Effective tax rate	**11.14**	5.34

7. **Payments in Lieu of Taxes Payable** (continued)

The movement in the 2015 deferred tax assets is:

	Opening balance January 1, 2015	Recognize in net income	Recognize in OCI	Closing balance at December 31, 2015
2015				
Deferred tax asset				
Property, plant and equipment	$ 69,098	$ 5,655	$ -	$ 74,753
Contributions in aid of construction	-	12,434	-	12,434
Employee future benefits	-	24,840	-	24,840
Cumulative eligible capital	13,788	(965)	-	12,823
	$ 82,886	$ 41,964	$ -	$ 124,850

	Opening balance January 1, 2014	Recognize in net income	Recognize in OCI	Closing balance at December 31, 2014
2014				
Deferred tax asset				
Property, plant and equipment	$ 87,442	$ (18,344)	$ -	$ 69,098
Employee future benefits	-	-	-	-
Cumulative eligible capital	14,981	(1,193)	-	13,788
	$ 102,423	$ (19,537)	$ -	$ 82,886

8. Employee Future Benefits

Defined Contribution Plan

OMERS provides pension services to approximately 461,000 active and retired members and approximately 1,000 employers. Each year an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2015. The results of this valuation disclosed total actuarial liabilities of $82,369 million in respect of benefits accrued for service with actuarial assets at that date of $75,392 million indicating an actuarial deficit of $6,977 million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Corporation does not recognize any share of the OMERS pension surplus or deficit. The employer portion of amounts paid to OMERS during the year was $73,909 (2014 - $70,223).

Defined Benefit Plan

The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Company's net obligation for these benefits is calculated by estimating the amount of future benefits that are expected to be paid out, discounted, to determine its present value. Any unrecognized past service costs are deducted. The Company has also provided for a provision for non-vested sick leave benefits to current employees.

The cost of these benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, the cost of these benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

The calculation is performed by a qualified actuary using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. The valuation is performed every third year or when there are significant changes to workforce.

Remeasurements of the defined benefit obligation are recognized directly within equity in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs include current and past service costs as well as gains and losses on curtailments.

Net interest expense is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

8. Employee Future Benefits (continued)

Other Long-Term Service Benefits

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities. Other employee benefits that are not expected to be settled wholly within 12 months after the end of the reporting period are presented as non-current liabilities and calculated using the projected unit credit method and then discounted using yields available on high quality corporate bonds that have maturity dates approximating to the expected remaining period to settlement.

The plan is exposed to a number of risks, including:

Interest Rate Risk

Decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation

Longevity Risk

Changes in the estimation of mortality rates of current and former employees.

Health Care Cost Risk

Increases in cost of providing health, dental, and life insurance benefits.

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

	Defined benefit liability	
	2015	2014
Accrued benefit obligation at January 1	$ **158,244**	$ 156,528
Current service cost	**3,996**	3,834
Interest cost	**5,070**	4,997
	167,310	165,359
Benefits paid during the year	**(7,051)**	(7,115)
	$ **160,259**	$ 158,244

8. **Employee Future Benefits** (continued)

The main actuarial assumptions underlying the valuations are as follows:

i) General Inflation:

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% (2014 - 2.0%).

ii) Interest (Discount) Rate:

The obligation at year end, of the present value of future liabilities and the expense for the year ended, were determined using a discount rate of 4.2% (2014 - 4.2%). The discount rate for 2015 is based on the yield on high quality bonds at the date of the valuation. It has been developed using the Company's expected projected benefit cash flows for post-retirement non-pension benefits and the December 31, 2015 spot rate curve published by Fiera Capital.

iii) Salary Levels:

Future general salary and wage levels were assumed to increase at 2.5% per annum [2014- 2.5%]

iv) Medical Costs:

Medical costs were assumed to increase at a rate of 6.50% in 2015 graded-down by .25% per annum leveling off at 4.50% in 2024 and thereafter [2014 - 6.70% graded-down by .30% per annum leveling off at 5.25% in 2021].

If the discount rate increased to 5.2% the accrued benefit obligation would decrease to approximately $152,200 at December 31, 2015. If the discount rate decreased to 3.2% the accrued benefit obligation would increase to approximately $190,000 at December 31, 2015.

9. Related Party Transactions

	2015	2014
Due to Corporation of the Municipality of Sioux Lookout	$ 240,000	$ 200,000

These balances are unsecured, interest free, payable on demand, and have arisen from the transfer of assets, dividends declared, and provision of services referred to below.

There was dividends declared and payable of $240,000 (2014 - $200,000). During the year, the Company billed electricity and services to the shareholder in the amount of $677,878 (2014 - $697,707).

10. Inventory

Cost of inventories comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value.

Inventory consists of parts, supplies and materials held for future capital expansion or maintenance and are valued at the lower of cost, determined by the weighted average method, and net realizable value.

11. Share Capital

The authorized share capital is as follows:

Unlimited Common Shares

Unlimited non-voting Class A preferred shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

Unlimited non-voting Class B preferred shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

Unlimited non-voting Class C preferred shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

11. Share Capital (continued)

Unlimited non-voting Class D preferred shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The issued share capital is as follows:

	December 31, 2015	December 31, 2014	January 1, 2014
100 Common shares	**$ 2,789,823**	$ 2,789,823	$ 2,789,823

Movement in Share Capital

No movement in share capital has occurred during 2015 and 2014.

12. Operating Expenses by Nature

	December 31, 2015	December 31, 2014
Repairs and maintenance	**$ 158,861**	$ 201,605
Administration	**491,722**	531,032
Professional fees	**47,361**	48,742
	$ 697,944	$ 781,379

13. Other Operating Revenue

	2015	2014
Late payment charges	$ 46,091	$ 52,468
Pole rentals	43,981	42,949
Reconnection charges	1,210	1,760
Change in occupancy charges	15,990	15,930
Sentinel light rental	10,724	10,952
Sundry	51,042	5,689
	$ 169,038	$ 129,748

14. Amortization of Property, Plant and Equipment

	2015	2014
Amortization of building and distribution equipment	$ 223,244	$ 217,905
Amortization of office equipment	20,732	22,866
Amortization of sentinel lights	1,263	1,314
Amortization of contributions and grants	(30,758)	(30,898)
	214,481	211,187
Amortization of other capital assets included in relevant expense categories		
Rolling stock	23,890	24,153
Operations and maintenance	24,717	25,311
Amortization of capital assets included in regulatory account	49,552	52,806
	$ 312,640	$ 313,457

15. Finance Income and Finance Cost

	2015	2014
Finance Income		
Interest income of bank deposits	$ 4,132	$ 6,452
Finance Cost		
Interest on long-term debt	(129,710)	(135,226)
	$ (125,578)	$ (128,774)

16. Long-term Debt

	December 31, 2015	December 31, 2014	January 1, 2014
Demand installment loan, repayable at $5,814 per month including interest at 4.7%, maturing 2019	$ 492,032	$ 537,513	$ 580,910
Demand installment loan, repayable at $17,540 per month including interest at 2.83%, maturing 2022	1,233,005	1,405,926	1,574,029
	$ 1,725,037	$ 1,943,439	$ 2,154,939

The demand installment loans are secured by a general security agreement covering all assets and are guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an unused operating line of credit of $300,000, due on demand and bears interest at the bank's prime rate, calculated and payable monthly.

At December 31, 2015, the fair value of the demand installment loans was approximately $1,642,000, calculated based on the amount of future cash flows associated with each instrument and discounted using 5%, which is an estimate of what the company's current borrowing rate for similar debt instruments of comparable maturity would be.

The agreement governing the demand installment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must approve any material change to the company. The company has complied with its debt covenants.

17. Contingencies

The Company belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2015, the Company has not been made aware of any assessments for losses.

The Company did not meet certain targeted energy savings for the period 2011 to 2014 and as a result was not in compliance with Part VII of the Ontario Energy Board Act, 1998. As at the date of these financial statements, no decision has been made by the Ontario Energy Board as to the impact of the breach of compliance. The result, if any, of any loss to the Company, will be recorded in the year determinable.

18. Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt, are analyzed by management and approved by the board of directors.

The main objectives of the Company, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The company is meeting its objective of managing capital through its detailed review and preparing short-term and long-term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

As at December 31, 2015, the Company's definition of capital is shareholder's equity. As at December 31, 2015, shareholder's equity amounts to $3,112,189 (2014 - $2,995,114). There have been no changes in the Company's approach to capital management from the previous years.

19. First Time Adoption of International Financial Reporting Standards

IFRS 1, *First Time Adoption of International Financial Reporting Standards,* requires that comparative financial information be provided. As a result, the first date at which the Company has applied IFRS was January 1, 2014 (the "Transition Date"). IFRS 1 requires first-time adopters to retrospectively apply all effective IFRS standards as of the reporting date, which for the Company will be December 31, 2015. However, it also provides for certain optional exemptions and certain mandatory exceptions for first-time IFRS adoption. Prior to transition to IFRS, the Company prepared its financial statement in accordance with Canadian generally accepted accounting principles ("pre-changeover Canadian GAAP").

The IFRS 1 applicable exemptions and exceptions applied in the conversion from pre-changeover Canadian GAAP to IFRS are as follows:

Mandatory Exceptions:

Derecognition of Financial Assets and Liabilities

The Company has applied the derecognition requirements in IAS 39 prospectively for transactions occurring on or after January 1, 2014. As a result any non-derivative financial assets or non-derivative financial liabilities derecognized in accordance with pre-changeover Canadian GAAP as a result of a transaction that occurred before January 1, 2014, have not been recognized in accordance with IFRS unless they qualify for recognition as a result of a later transaction or event.

Estimates

The estimates previously made by the Company under pre-changeover Canadian GAAP were not revised for the application of IFRS, except where necessary to reflect any difference in accounting policy or where there was objective evidence that those estimates were in error. As a result, the Company has not used hindsight to revise estimates.

Government Loans

The company classifies government loans received as financial liabilities or equity instruments in accordance with IAS 32 Financial Instruments: Presentation. At the date of transition, these loans are measured at the pre-changeover Canadian GAAP carrying amount as a government grant. No benefit element is recognized for below market interest rate loans. The loans are subsequently measured using an effective interest rate calculated at the date of transition and the guidance in IAS 20 Accounting for Government Grants and Disclosure of Government Assistance is applied after the date of transition.

19. First Time Adoption of International Financial Reporting Standards (continued)

Optional Elections:

Business Combinations

The Company has elected not to retrospectively apply IFRS 3, Business Combinations, to business combinations that occurred prior to its Transition Date and such business combinations have not been restated.

Borrowing Costs

The Company has elected to apply the transitional provisions of IAS 23 Borrowing Costs which permits prospective capitalization of borrowing costs on qualifying assets from the Transition Date.

Deemed Cost for Operations Subject to Rate Regulation

The Company has elected the deemed cost exemption applicable to entities subject to rate regulation as described under IFRS 1. The election permits the Company, at the date of transition to IFRS, to use the previous Canadian GAAP carrying amount of items of PP&E and intangible assets as deemed cost; hence there will be no impact on retaining earnings for opening balances of PP&E and intangible assets at the date of transition. In accordance with the election, the Company has tested these items of property, plant and equipment and intangible assets at the date of transition to IFRS. No impairment losses were recognized.

Transfers of Assets from Customers

The Company has elected to apply the IFRS 1 election to only apply IFRIC 18 prospectively from the date of transition to non-repayable supply contribution made by customers.

Reconciliation's of Pre-changeover Canadian GAAP Equity and Comprehensive Income to IFRS

IFRS 1 requires an entity to reconcile cash flows, equity, and comprehensive income for prior periods as shown below.

In the statement of cash flows, there is a reclassification from the movement in regulatory assets and regulatory liabilities to a movement in the regulatory deferral account balance. These are both shown as movements within investing activities and as such do not result in material adjustments to the net cash flow balance.

19. First Time Adoption of International Financial Reporting Standards (continued)

The explanations for the impact of the transition to IFRS on the specific accounts is described below. Reconciliation of equity and comprehensive income as previously reported under Canadian GAAP to IFRS are provided below. Other than the employee future benefits, all other items have no impact on Equity or Comprehensive Income, as they are reclassifications within the relevant statements.

Equity	December 31, 2014	January 1, 2014
Equity as reported under Canadian GAAP	$ 327,055	$ 345,762
Adjustments to retained earnings:		
Employee future benefits prior period adjustment	(87,764)	(82,552)
Provisions for unvested sick leave	(34,000)	(34,000)
Equity as reported under IFRS	$ 205,291	$ 229,210

Comprehensive Income	December 31, 2014
Net income as reported under Canadian GAAP	$ 181,293
Adjustments to net income due to prior period adjustment relating to employee future benefits under Canadian GAAP	(5,212)
Adjustments to net income due to IFRS conversion	-
Comprehensive Income as reported under IFRS	$ 176,081

i) Regulatory Assets and Liabilities

Regulatory assets and liabilities that were recognized under pre-changeover Canadian GAAP have been reclassified to the regulatory deferral account balance as either a debit balance or a credit balance. The amount recorded as a regulatory asset, under pre-changeover Canadian GAAP was $30,585. This transitional adjustment is a reclassification on the Statement of Financial Position and has no impact on the Statement of Equity or the Statement of Comprehensive Income.

19. First Time Adoption of International Financial Reporting Standards (continued)

ii) Employee Future Benefits

Prior Period Adjustment

In the previous years the Company did not consider the probability that all employees may eventually receive vested sick leave benefits or become eligible for post-employment benefits. Management, with the use of an actuary, determined that the employee future benefits liability was understated on January 1, 2014 by $82,552 and understated on December 31, 2014 by $87,764.

Transitional Adjustment

Under IFRS, the Company recognizes remeasurements in Other Comprehensive Income. These amounts are not reclassified in subsequent periods. Employee benefits expected to be settled wholly within 12 months after the end of the reporting period are short-term benefits, and are not discounted. There are no remeasurements to be reclassified to Other Comprehensive Income as there are no actuarial gains or losses in the periods.

In addition, under IFRS, a liability is recognized for both non-vested accumulating and vested sick leave benefits, unlike Canadian GAAP which only required a liability for the vested sick leave component. As a result, a liability of $34,000 was set-up at January 1, 2014 and December 31, 2014 which represents unvested sick leave.

The transitional adjustment and prior period adjustment for employee future benefits results in a decrease in operating and increase in finance expenses on the Statement of Comprehensive Income.

iii) Contributions in Aid of Construction

Under IFRS Contributions in aid of construction are recognized as deferred revenue and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset in the Statement of Comprehensive Income. Contributions in aid of construction under Canadian GAAP at January 1, 2014 which totaled $1,038,135 are shown net of property, plant and equipment upon transition. The impact of this transitional adjustment related to Contributions in Aid of Construction at December 31, 2014 is an increase in assets and an increase in liabilities on the Statement of Financial Position. On transition, $42,201 was reclassified as Contributions in Aid of Construction from property, plant and equipment for the period ended December 31, 2014.

iv) Borrowing Costs

Borrowing costs that were not recognized as a regulatory asset or liability were previously expensed under pre-changeover Canadian GAAP. Under IFRS, borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset, are capitalized as part of the cost of that asset. Since the Company has elected to take the Borrowing Costs exemption, there is no transitional adjustment.

20. Standards, Amendments and Interpretations not yet Effective

Certain pronouncements were issued by the IASB or the IFRS Interpretations Committee that are mandatory for accounting years beginning after January 1, 2016 or later years. As discussed in note 2, the Company early adopted IFRS 14, Regulatory Deferral Accounts. In addition as disclosed in note 2 under significant judgements and estimates, the Company applied judgements related to the order and exclusion of immaterial disclosures, consistent with the amendment to IAS 1, Presentation of Financial Statements, which were also adopted early.

The Company has not yet determined the extent of the impact of the following new standards, interpretations and amendments, which have not been applied in these financial statements:

- IFRS 9 Financial Instruments
- IFRS 15 Revenue from Contracts with Customers
- IFRS 16 Leases

Appendix 1H: 2016 Audited Financial Statements

Sioux Lookout Hydro Inc.
Financial Statements
For the year ended December 31, 2016

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BDO Canada LLP
1095 Barton Street
Thunder Bay ON P7B 5N3 Canada

Independent Auditor's Report

To the Shareholder of Sioux Lookout Hydro Inc.

We have audited the accompanying financial statements of Sioux Lookout Hydro Inc., which are comprised of the statement of financial position as at December 31, 2016, and the statements of comprehensive income, changes in equity, and cash flows for the year then ended and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly in all material respects, the financial position of Sioux Lookout Hydro Inc. as at December 31, 2016, and the results of its operations and cash flows, for the year then ended in accordance with International Financial Reporting Standards.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

Thunder Bay, Ontario
April 13, 2017

Sioux Lookout Hydro Inc.
Statement of Financial Position (Expressed in Canadian Dollars)

As at December 31	2016	2015
Assets		
Current assets		
Cash	$ -	$ 391,689
Trade and other receivables (Note 6)	1,443,095	1,445,713
Unbilled revenue	1,498,214	1,379,819
Inventory (Note 10)	51,287	78,217
Prepaids	68,563	49,519
Payments in lieu of taxes receivable	27,638	-
Total current assets	3,088,797	3,344,957
Non-current assets		
Property, plant and equipment (Note 4)	5,174,521	5,068,284
Deferred tax (Note 7)	99,154	124,850
Total non-current assets	5,273,675	5,193,134
Regulatory deferral account debits (Note 3)	94,460	69,858
	$ 8,456,932	$ 8,607,949

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Financial Position (Expressed in Canadian Dollars)

As at December 31	2016	2015
Liabilities and Shareholder's Equity		
Current liabilities		
Bank indebtedness (Note 15)	$ 31,260	$ -
Accounts payable and accrued liabilities	2,898,421	3,035,219
Customer deposits (Note 6)	133,094	137,708
Payments in lieu of taxes payable	-	12,626
Due to parent company (Note 9)	150,000	240,000
Demand installment loans (Note 15)	1,499,492	1,725,037
Total current liabilities	4,712,267	5,150,590
Non-current liabilities		
Employee future benefits (Note 8)	161,485	160,259
Contributions in aid on construction (Note 5)	107,436	80,217
Total liabilities	4,981,188	5,391,066
Shareholder's equity		
Share capital (Note 11)	2,789,823	2,789,823
Retained earnings	287,695	282,366
Total shareholder's equity	3,077,518	3,072,189
Total liabilities and shareholder's equity	8,058,706	8,463,255
Regulatory deferral account credits (Note 3)	398,226	144,694
Total equity, liabilities and regulatory deferral account credits	$ 8,456,932	$ 8,607,949

On behalf of the Board:

____________________ Director

____________________ Director

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.

Statement of Comprehensive Income (Expressed in Canadian Dollars)

For the year ended December 31	2016	2015
Revenue		
Electricity sales	$ 11,786,177	$ 11,691,454
Street lighting	111,008	140,682
Other (Note 13)	123,826	169,038
	12,021,011	12,001,174
Expenses		
Administration	752,662	724,401
Depreciation (Note 14)	216,390	214,481
Operations and maintenance (Note 12)	779,028	697,944
Purchased power	9,740,269	9,887,095
Loss on disposal of property, plant and equipment	1,337	2,042
	11,489,686	11,525,963
Income from operating activities	531,325	475,211
Finance income	3,493	4,132
Finance cost	(58,959)	(60,184)
Income before provision for payment in lieu of taxes	475,859	419,159
Provision for payments in lieu of taxes (Note 7)		
Current	9,362	34,506
Deferred	25,696	(41,964)
	35,058	(7,458)
Profit for the year before net movements in regulatory deferral account balances	440,801	426,617
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement	(285,472)	(109,542)
Profit for the year and net movements in regulatory deferral account balances	$ 155,329	$ 317,075

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Changes in Equity (Expressed in Canadian Dollars)

	Share Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total
December 31, 2014	$ 2,789,823	$ -	$ 205,291	$ 2,995,114
Profit for the year and movements in regulatory deferral account balances	-	-	317,075	317,075
Dividends	-	-	(240,000)	(240,000)
December 31, 2015	2,789,823	-	282,366	3,072,189
Profit for the year and movements in regulatory deferral account balances	-	-	155,329	155,329
Dividends	-	-	(150,000)	(150,000)
December 31, 2016	**$ 2,789,823**	**$ -**	**$ 287,695**	**$ 3,077,518**

The accompanying notes are an integral part of these financial statements.

Sioux Lookout Hydro Inc.
Statement of Cash Flows (Expressed in Canadian Dollars)

For the year ended December 31	2016	2015
Cash flows from operating activities		
Profit for the year after net movements in regulatory deferral accounts	$ 155,329	$ 317,075
Items not involving cash		
Depreciation	261,761	312,640
Loss on disposal of property, plant and equipment	1,337	2,042
Payments in lieu of taxes	(40,264)	23,563
Deferred taxes	25,696	(41,964)
Increase in future employee benefits	1,226	2,015
Amortization of contributions in aid of construction	(2,477)	(2,497)
	402,608	612,874
Changes in non-cash working capital balances		
Trade and other receivables	2,618	(21,205)
Unbilled revenue	(118,395)	252,355
Inventory	26,930	(22,419)
Prepaids	(19,044)	(12,242)
Accounts payable and accrued liabilities	(136,798)	103,033
Customer deposits and deferred contributions	(4,614)	31,527
	153,305	943,923
Cash flows from investing activities		
Purchase of property, plant and equipment	(375,373)	(334,226)
Contributions in aid of construction received during year	29,696	40,513
Changes in regulatory deferral account balances	234,968	99,570
	(110,709)	(194,143)
Cash flows from financing activities		
Repayments of long-term debt	(225,545)	(218,402)
Dividends paid	(150,000)	(240,000)
Repayments to parent company	(90,000)	40,000
	(465,545)	(418,402)
Increase (decrease) in cash during the year	(422,949)	331,378
Cash, beginning of year	391,689	60,311
Cash and cash equivalents, end of year	$ (31,260)	$ 391,689
Represented by		
Cash	$ -	$ 391,689
Bank Indebtedness	(31,260)	-
	$ (31,260)	$ 391,689

The accompanying notes are an integral part of these financial statements.

1. Corporate Information

Sioux Lookout Hydro Inc.'s (the "Company") main business activity is the distribution of electricity under authority of the Ontario Energy Board ("OEB") Act, 1998. The Company owns and operates an electricity distribution system, which delivers electricity to approximately 2,785 customers located in Sioux Lookout, Ontario.

Operating in regulated environment exposes the Company to regulatory and recovery risk.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations, including the recovery of expenses incurred for the benefit of other market participants in the electricity industry, such as transition costs and other regulatory balances. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. Sioux Lookout Hydro Inc. is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and depreciation and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The address of the Company's corporate office and principal place of business is P.O. Box 908, Sioux Lookout, Ontario, Canada.

The sole shareholder of the Company is the Corporation of the Municipality of Sioux Lookout.

2. Basis of Preparation

a) Statement of Compliance

The financial statements of Sioux Lookout Hydro Inc. have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), on a going concern basis, under historical cost convention.

The financial statements were authorized for issue by the Board of Directors on April 13, 2017.

2. Basis of Preparation (continued)

b) Basis of Measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Company's functional currency, and all values are rounded to the nearest dollar, unless when otherwise indicated.

c) Judgement and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgement in applying the Company's accounting policies. The areas involving critical judgements and estimates in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The calculation of the impairment of accounts receivables (Note 6);
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 7);
- The determination of useful lives of property, plant and equipment (Note 4);
- The calculation of regulatory deferral account balances (Note 3); and
- The calculation of the net future obligation for certain unfunded health, dental and life insurance benefits for the Company's retired employees (Note 8).

In addition, in preparing the financial statements, the notes to the financial statements were ordered such that the most relevant information was presented earlier in the notes and the disclosures that management deemed to be immaterial were excluded from the notes to the financial statements. The determination of the relevance and materiality of disclosures involved significant judgement.

3. Regulatory Deferral Account Balances

Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets.

Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s) that are expected to be returned to consumers in future periods through the rate-setting process.

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s) that are expected to be recovered from consumers in future periods through the rate-setting process. Management continually assesses the likelihood of recovery of regulatory balances. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

The balances and movements in the regulatory deferral account balances shown below are presented net of related deferred taxes. These deferred taxes are not presented within the total deferred tax asset balances shown in Note 7. All amounts deferred as regulatory deferral account balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	Remaining recovery/ reversal period (years)	2016	2015
Debit balances consist of the following:			
IFRS transition costs and adjustments	1 - 4	$ 93,222	$ 68,708
SME variances	1 - 4	1,238	1,150
		$ 94,460	$ 69,858
Credit balances consist of the following:			
Cost of power	1 - 4	$ (388,867)	$ (126,549)
Lost revenue adjustment mechanism	1 - 4	(1,497)	(11,252)
Settlement variances	1 - 4	(7,862)	(6,893)
		$ (398,226)	$ (144,694)
Net		$ (303,766)	$ (74,836)

3. **Regulatory Deferral Account Balances** (continued)

In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the year in which they relate. As a result, the net effect on income for the period is stated below:

i) IFRS Transition Costs

This regulatory balance includes one-time administrative incremental IFRS transitional costs and the differences arising from accounting policy changes for property, plant and equipment ("PP&E") to the transition from GAAP to IFRS effective January 1, 2014.

One-time administrative incremental IFRS transitional costs of $20,392 (2015 - $286) relates to the transition of accounting policies, procedures, systems, and processes to IFRS, for costs which were not already approved and included for recovery in distribution rates. The OEB has permitted these costs to be captured for future rate recovery. As at December 31, 2016, the total for IFRS transitional costs are $45,692 (2015 - $25,300).

Costs associated with accounting policy changes for PP&E due to the transition from GAAP to IFRS deferred for future recovery were $4,122 (2015 - $7,977). As at December 31, 2016, the total for GAAP to IFRS transition costs are $47,530 (2015 - $43,408).

The Company expects to request disposition of these balances in its next rate application, for rates to be effective May 1, 2018.

ii) SME Variances

A Smart Meter Disposition Rider (SMDR) recovered, over a specified period of time, the variance between: 1) the deferred revenue requirement for the installed smart meters up to the time of disposition; and 2) the Smart Meter Funding Adder ("SMFA") revenues and related interest collected from 2006 to April 30, 2012. The resulting SMDR liability was $162,501.

The OEB approved the recovery of this balance through a two year rate rider to Residential and General Service < 50kW rate payers ending August 31, 2014. The majority of the balance was recovered in 2014.

iii) Cost of Power

This account is comprised of the variances between amounts charged by the company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service charged to the company for the operation of the wholesale electricity market and grid, including commodity and global adjustment, various wholesale market settlement charges, and transmission charges. Under the OEB's direction, the company has deferred the settlement variances that have occurred since May 1, 2002 in accordance with the AP Handbook. Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. The Company did not recognize carrying charge income related to the retail settlement variance accounts for external reporting purposes prior to December 31, 2003.

3. **Regulatory Deferral Account Balances** (continued)

iii) Cost of Power

As a component of the yearly Incentive Regulation Mechanism (IRM) rate application process, "Group 1" account balances (which are composed of Low Voltage, Wholesale Market, Network, Connection, Power, and the Smart Meter Entity charge) are reviewed and will qualify for disposition if balances, including carrying charges, exceed a preset threshold per kWh.

iv) Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

This regulatory balance relates to the variance between the OEB approved Conservation and Demand Management ("CDM") forecast and the actual results at the customer rate class level for the period 2011-2015.

The Company expects to request disposition of these balances in its next rate application, for rates to be effective May 1, 2018.

v) Settlement Variances

This regulatory account includes the variances between the amounts billed to ratepayers based on regulatory rates, and the corresponding costs of electricity and non-competitive electricity service costs incurred to service those customers.

The settlement variances relate primarily to commodity charges, non-competitive electricity charges and the global adjustment, and in accordance with the criteria set out in the accounting principles prescribed by the OEB, these variances have been deferred. These variances are for future disposition and the regulator determines in all cases, when the balances are material enough to warrant an adjustment to rates.

The Company expects to request disposition of this balance in its next rate application, for rates to be effective May 1, 2018.

4. Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation. Costs may include direct material, labour, contracted services, overhead, engineering costs, and interest on funds used during construction that are considered applicable to construction.

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company's distribution system reliability.

Upon disposal the cost and accumulated depreciation of assets are relieved from the respective accounts and any gain or loss is reflected in operations.

Depreciation of PP&E is recorded in the Statements of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values, and depreciation methods are reviewed at the end of each annual reporting period.

The estimated useful lives are as follows:

Distribution Assets:	
Poles, towers and fixtures	45 years
Overhead conductor and devices	45 years
Underground conduit and conductor	50 years
Distribution transformers	40 years
Overhead and underground services	40 - 60 years
Distribution Meters	10 - 25 years
General Assets:	
Buildings	25 - 50 years
Computer equipment	3 - 5 years
Office equipment	5 - 15 years
Transportation equipment	5 - 15 years
Small tools and miscellaneous equipment	10 years
Load management controls	6 years
System supervisory equipment	15 - 20 years

Land is not depreciated.

Prior Period Restatement:

An error in the calculation of depreciation has been corrected as a prior period restatement. This error has no effect on the statement of comprehensive income as the error impacts capital assets and the OEB approved 'IFRS transition costs and adjustments' regulatory deferral account (Note 3). As a result the 2015 comparative statements were adjusted as follows:

Statement of Financial Position	Previously Reported	Correction	Restated
Property, plant and equipment	$ 4,952,364	$ **115,920**	$ 5,068,284
IFRS transition costs and adjustments (Note 3)	184,628	**(115,920)**	68,708

December 31, 2016

4. Property, Plant and Equipment (continued)

	Electrical Distribution Assets	General Assets	Construction in Progress	Total
Cost				
Balance as of January 1, 2015	$ 7,686,575	$ 1,203,309	$ -	$ 8,889,884
Additions	267,713	33,196	33,317	334,226
Disposals	(33,697)	-	-	(33,697)
Balance as of December 31, 2015	7,920,591	1,236,505	33,317	9,190,413
Additions	309,809	21,011	44,553	375,373
Disposals	(24,877)	(25,290)	-	(50,167)
Balance as of December 31,2016	$ 8,205,523	$ 1,232,226	$ 77,870	$ 9,515,619
Accumulated depreciation				
Balance as of January 1, 2015	$ 2,935,909	$ 897,167	$ -	$ 3,833,076
Depreciation for the year	238,363	74,277	-	312,640
Disposals	(23,587)	-	-	(23,587)
Balance as of December 31, 2015	3,150,685	971,444	-	4,122,129
Depreciation for the year	192,967	68,794	-	261,761
Disposals	(17,502)	(25,290)	-	(42,792)
Balance as of December 31,2016	$ 3,326,150	$ 1,014,948	$ -	$ 4,341,098
Carrying amounts				
At December 31, 2015	$ 4,769,906	$ 265,061	$ 33,317	$ 5,068,284
At December 31, 2016	$ 4,879,373	$ 217,278	$ 77,870	$ 5,174,521

5. Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on an accrual basis. Distribution revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the fiscal year. Actual results could differ from estimates made of customer electricity usage.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Other revenues, which include revenues from pole use rental, collection charges, street lighting, and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions vary by project and are based on the criteria set forth in the Distribution System Code. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The continuity of deferred contributions in aid of construction is as follows:

	2016	2015
Deferred contributions, net, beginning of year	**$ 80,217**	$ 42,201
Contributions in aid of construction received	**29,696**	40,513
Contributions in aid of construction recognized as revenue	**(2,477)**	(2,497)
Deferred contributions, net, end of year	**$ 107,436**	$ 80,217

All contributions in aid of construction are cash contributions. There have not been any contributions of property, plant and equipment.

6. Trade and Other Receivables

	2016	2015
Trade receivables	$ 1,357,224	$ 1,341,356
Less: allowance for doubtful accounts	(83,771)	(88,663)
Trade receivables - net	1,273,453	1,252,693
HST receivable	169,642	193,020
	$ 1,443,095	$ 1,445,713

Due to its short-term nature, the carrying amount of the trade receivable and HST receivable approximates its fair value. In determining the allowance for doubtful accounts, the Company considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in the statement of comprehensive income. Subsequent recoveries of receivables previously provisioned are credited to the income statement. An impairment loss of $25,641 (2015 - $24,094) was recognized during the year. The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2016, approximately $132,275 (2015 - $155,775) is considered 60 days past due. The Company has approximately 2,785 customers, the majority of which are residential.

Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 1%.

Customer deposits represents cash deposits from electricity distribution customers and retailers, as well as construction deposits. Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

7. Payments in Lieu of Taxes Payable

The Company is a Municipal Electricity Utility ("MEU") for purposes of the payments in lieu of taxes ("PILs") regime contained in the Electricity Act, 1998. As an MEU, the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each taxation year, PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

PILs expense is comprised of current and deferred tax. Current tax and deferred tax are recognized in comprehensive income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances.

Significant judgement is required in determining the provision for PILs. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provision in the period in which such determination is made.

The income tax expense varies from amounts which would be computed by applying the Company's combined statutory income tax rate as follows:

	2016	2015
Earnings before provision for taxes	**190,387**	309,617
Statutory Canadian federal and provincial income tax rate (%)	**39.5**	39.5
Expected provision	**75,203**	122,299
Increase (decrease) in income tax resulting from:		
Permanent differences	**210**	310
Apprenticeship tax credit	**-**	(1,310)
Other timing differences	**(50,758)**	(17,720)
Small business deduction	**(15,293)**	(69,073)
Current provision for payments in lieu of taxes	**9,362**	34,506
Effective tax rate	**4.66**	11.14

7. **Payments in Lieu of Taxes Payable** (continued)

The movement in the 2016 deferred tax assets is:

	Opening balance January 1, 2016	Recognize in net income	Recognize in OCI	Closing balance at December 31, 2016
2016				
Deferred tax asset				
Property, plant and equipment	$ 74,753	$ (29,207)	$ -	$ 45,546
Contributions in aid of construction	12,434	4,219	-	16,653
Employee future benefits	24,840	190	-	25,030
Cumulative eligible capital	12,823	(898)	-	11,925
	$ 124,850	$ (25,696)	$ -	$ 99,154

	Opening balance January 1, 2015	Recognize in net income	Recognize in OCI	Closing balance at December 31, 2015
2015				
Deferred tax asset				
Property, plant and equipment	$ 69,098	$ 5,655	$ -	$ 74,753
Contributions in aid of Construction	-	12,434	-	12,434
Employee future benefits	-	24,840	-	24,840
Cumulative eligible capital	13,788	(965)	-	12,823
	$ 82,886	$ 41,964	$ -	$ 124,850

8. Employee Future Benefits

Defined Contribution Plan

OMERS provides pension services to approximately 461,000 active and retired members and approximately 1,000 employers. Each year an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2015. The results of this valuation disclosed total actuarial liabilities of $82,369 million in respect of benefits accrued for service with actuarial assets at that date of $75,392 million indicating an actuarial deficit of $6,977 million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Corporation does not recognize any share of the OMERS pension surplus or deficit. The employer portion of amounts paid to OMERS during the year was $77,402 (2015 - $79,909).

Defined Benefit Plan

The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Company's net obligation for these benefits is calculated by estimating the amount of future benefits that are expected to be paid out, discounted, to determine its present value. Any unrecognized past service costs are deducted. The Company has also provided for a provision for non-vested sick leave benefits to current employees.

The cost of these benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, the cost of these benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

The calculation is performed by a qualified actuary using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. The valuation is performed every third year or when there are significant changes to workforce.

Remeasurements of the defined benefit obligation are recognized directly within equity in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs include current and past service costs as well as gains and losses on curtailments.

Net interest expense is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

8. Employee Future Benefits (continued)

Other Long-Term Service Benefits

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities. Other employee benefits that are not expected to be settled wholly within 12 months after the end of the reporting period are presented as non-current liabilities and calculated using the projected unit credit method and then discounted using yields available on high quality corporate bonds that have maturity dates approximating to the expected remaining period to settlement.

The plan is exposed to a number of risks, including:

Interest Rate Risk

Decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation

Longevity Risk

Changes in the estimation of mortality rates of current and former employees.

Health Care Cost Risk

Increases in cost of providing health, dental, and life insurance benefits.

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

	Defined benefit liability	
	2016	**2015**
Accrued benefit obligation at January 1	**$ 160,259**	$ 158,244
Current service cost	**4,164**	3,996
Interest cost	**5,144**	5,070
	169,567	167,310
Benefits paid during the year	**(8,082)**	(7,051)
	$ 161,485	$ 160,259

8. Employee Future Benefits (continued)

The main actuarial assumptions underlying the valuations are as follows:

i) General Inflation:

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% (2015 - 2.0%).

ii) Interest (Discount) Rate:

The obligation at year end was determined using a discount rate of 4.2% (2015 - 4.2%). The discount rate for 2015 is based on the yield on high quality bonds at the date of the valuation. It has been developed using the Company's expected projected benefit cash flows for post-retirement non-pension benefits and the December 31, 2016 spot rate curve published by Fiera Capital.

iii) Salary Levels:

Future general salary and wage levels were assumed to increase at 2.5% per annum [2015 - 2.5%]

iv) Medical Costs:

Medical costs were assumed to increase at a rate of 6.50% in 2016 graded-down by .25% per annum leveling off at 4.50% in 2024 and thereafter [2015 - 6.70% graded-down by .30% per annum leveling off at 5.25% in 2021].

If the discount rate increased to 5.2% the accrued benefit obligation would decrease to approximately $152,200 at December 31, 2016. If the discount rate decreased to 3.2% the accrued benefit obligation would increase to approximately $190,000 at December 31, 2016.

9. Related Party Transactions

	2016	2015
Due to Corporation of the Municipality of Sioux Lookout	**$ 150,000**	$ 240,000

These balances are unsecured, interest free, payable on demand, and have arisen from the transfer of assets, dividends declared, and provision of services referred to below.

There was dividends declared and payable of $150,000 (2015 - $240,000). During the year, the Company billed electricity and services to the shareholder in the amount of $683,530 (2015 - $677,878).

10. Inventory

Cost of inventories is comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value.

Inventory consists of parts, supplies and materials held for future capital expansion or maintenance and are valued at the lower of cost, determined by the weighted average method, and net realizable value.

11. Share Capital

The authorized share capital is as follows:

Unlimited Common Shares

Unlimited non-voting Class A preferred shares, with a stated value equal to the consideration received on issue, redeemable and retractable at $1,000 per share, and entitled to a non-cumulative annual dividend of 6%.

Unlimited non-voting Class B preferred shares, redeemable and retractable at $100 per share, and entitled to a non-cumulative annual dividend of 6%.

Unlimited non-voting Class C preferred shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

11. Share Capital (continued)

Unlimited non-voting Class D preferred shares, redeemable and retractable at $1 per share, and entitled to a non-cumulative annual dividend of 6%.

The issued share capital is as follows:

		2016	2015
100	Common shares	$ 2,789,823	$ 2,789,823

12. Operating Expenses by Nature

	2016	2015
Repairs and maintenance	$ 207,909	$ 158,861
Administration	516,158	491,722
Professional fees	54,961	47,361
	$ 779,028	$ 697,944

December 31, 2016

13. Other Operating Revenue

	2016	2015
Late payment charges	$ 49,016	$ 46,091
Pole rentals	45,333	43,981
Reconnection charges	1,870	1,210
Change in occupancy charges	15,690	15,990
Sentinel light rental	11,365	10,724
Sundry	552	51,042
	$ 123,826	$ 169,038

14. Depreciation of Property, Plant and Equipment

	2016	2015
Depreciation of building and distribution equipment	$ 229,741	$ 223,244
Depreciation of office equipment	19,513	20,732
Depreciation of sentinel lights	1,240	1,263
Depreciation of contributions and grants	(34,104)	(30,758)
	216,390	214,481
Depreciation of other capital assets included in relevant expense categories		
Rolling stock	16,049	23,890
Operations and maintenance	28,317	24,717
Depreciation of capital assets included in regulatory account	1,005	49,552
	$ 261,761	$ 312,640

December 31, 2016

15. Long-term Debt

		2016		2015
Demand installment loan, repayable at $5,814 per month including interest at 4.7%, maturing 2024	$	444,366	$	492,032
Demand installment loan, repayable at $17,540 per month including interest at 2.83%, maturing 2022		1,055,126		1,233,005
	$	1,499,492	$	1,725,037

The demand installment loans are secured by a general security agreement covering all assets and are guaranteed by Corporation of the Municipality of Sioux Lookout.

The company has an operating line of credit of $300,000, due on demand and bears interest at the bank's prime rate, calculated and payable monthly.

At December 31, 2016, the fair value of the demand installment loans was approximately $1,537,000, calculated based on the amount of future cash flows associated with each instrument and discounted using 2.70%, which is an estimate of what the company's current borrowing rate for similar debt instruments of comparable maturity would be.

Subsequent to year end, the company borrowed $147,842 to purchase assets from Hydro One. The loan is secured by a general security agreement covering all assets and is guaranteed by Corporation of the Municipality of Sioux Lookout. The loan will be repaid in 120 monthly payments of $1,232 plus interest.

The agreement governing the demand installment loan facility contains certain covenants regarding (i) debt servicing ratios, (ii) negative pledge where no lien can be assigned against assets, and (iii) the bank must approve any material change to the company. The company has complied with its debt covenants.

16. Contingencies

The Company belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2016, the Company has not been made aware of any assessments for losses.

The Company did not meet certain targeted energy savings for the period 2011 to 2014 and as a result was not in compliance with Part VII of the Ontario Energy Board Act, 1998. As at the date of these financial statements, no decision has been made by the Ontario Energy Board as to the impact of the breach of compliance. The result, if any, of any loss to the Company, will be recorded in the year determinable.

17. Capital Disclosures

Sioux Lookout Hydro Inc. manages its capital in a manner consistent with the risk characteristics of the assets it holds. All financing, including equity and debt, are analyzed by management and approved by the board of directors.

The main objectives of the Company, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The company is meeting its objective of managing capital through its detailed review and preparing short-term and long-term cash flow analysis to ensure an adequate amount of liquidity and monthly review of financial results.

As at December 31, 2016, the Company's definition of capital is shareholder's equity. As at December 31, 2016, shareholder's equity amounts to \$ 3,077,518 (2015 - \$ 3,072,189). There have been no changes in the Company's approach to capital management from the previous years.

18. Standards, Amendments and Interpretations not yet Effective

Certain pronouncements were issued by the IASB or the IFRS Interpretations Committee that are mandatory for accounting years beginning after January 1, 2017 or later years. In addition as disclosed in note 2 under significant judgements and estimates, the Company applied judgements related to the order and exclusion of immaterial disclosures, consistent with the amendment to IAS 1, Presentation of Financial Statements, which were also adopted early.

IFRS 9 Financial Instruments:
IFRS 9 Financial Instruments is part of the IASB's wider project to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets: amortized cost and fair value. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. The new standard also introduces a new impairment model. IFRS 9 outlines a general approach to impairment that is applicable to financial assets measured at amortized cost and debt instruments at fair value through other comprehensive income. It also applies to loan commitments and financial guarantee contracts. The standard also allows for a simplified impairment approach for trade receivables, lease receivables and purchased credit impaired financial assets. The standard is effective for annual periods beginning on or after January 1, 2018. The Company is in the process of evaluating the impact of the new standard on the accounting for available-for-sale investments.

IFRS 15 Revenue from Contracts with Customers:
IFRS 15, Revenue from Contracts with Customers, is based on the core principle to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

The principle of revenue recognition has moved from a transfer of risks and rewards to the transfer of control of the goods or services to the customer. IFRS 15 focuses on the transfer of control. Risks and rewards may be an indicator of when control transfers, however it will no longer be the primary basis for revenue recognition. The standard is effective for annual periods beginning on or after January 1, 2018. The Company is in the process of evaluating the impact of the new standard.

IFRS 16 Leases:
IFRS 16 contains a single lessee accounting model, which eliminates the distinction between operating and finance leases from the perspective of the lessee. All contracts that meet the definition of a lease, other than short term leases and leases of low value, will be recorded in the statement of financial position with a "right of use" asset and a corresponding liability. The asset is subsequent accounted for as property, plant and equipment or investment property and the liability is unwound using the interest rate inherent in the lease. For many entities the effect of bringing all leases on the statement of financial position will be very significant and will require careful planning. Entities are required to apply IFRS 16 for annual periods beginning on or after January 1, 2019, with earlier application permitted only if IFRS 15 has also been adopted. The Company is in the process of evaluating the impact of the new standard.

Appendix 1I: SLHI Reconciliation between Audited Financial Statements and Regulatory Results

Sioux Lookout Hydro Inc.
Trial Balance
as at December 31, 2014
as per OEB filing 2.1.7

Account Description	OEB Account No.	Amount	Allocation to Audited Financials
Current Assets			
Cash	1005	$60,311.41	B/S - CA - Cash
Customer Accounts Receivable	1100	$1,242,110.88	B/S - CA - A/R
Other Accounts Receivable	1110	$165,835.26	B/S - CA - A/R
Accrued Utility Revenues	1120	$1,632,173.99	B/S - CA - Unbilled
Accumulated Provision for Uncollectible Accounts - Credit	1130	-$92,700.67	B/S - CA - A/R
Prepayments	1180	$37,277.39	B/S - CA - Prepaid
Plant Materials and Operating Supplies	1330	$55,798.21	B/S - CA - Inventory
Other Assets and Deferred Charges			
Other Regulatory Assets	1508	$25,013.08	B/S Reg Assets/Liabilities
RCVARetail	1518	-$4,842.59	B/S Reg Assets/Liabilities
RCVASTR	1548	-$96.62	B/S Reg Assets/Liabilities
LV Variance Account	1550	$139,394.93	B/S Reg Assets/Liabilities
Smart Metering Entity Charge Variance Account	1551	$2,176.05	B/S Reg Assets/Liabilities
Smart Meter Capital and Recovery Offset Variance	1555	$60,602.02	B/S Reg Assets/Liabilities
LRAM Variance Account	1568	-$12,251.84	B/S Reg Assets/Liabilities
CGAAP Accounting Changes	1576	-$48,592.50	Record for OEB only
RSVAWMS	1580	-$257,934.57	B/S Reg Assets/Liabilities
RSVANW	1584	$3,339.68	B/S Reg Assets/Liabilities
RSVACN	1586	-$13,316.21	B/S Reg Assets/Liabilities
RSVAPOWER	1588	-$83,185.37	B/S Reg Assets/Liabilities
RSVAGA	1589	$84,165.81	B/S Reg Assets/Liabilities
Disposition and Recovery of Regulatory Balances Control Account	1595	$87,520.54	B/S Reg Assets/Liabilities
Distribution Plant			$30,584.91
Buildings and fixtures	1808	$91,864.15	B/S Capital Assets
Poles, Towers, fixtures	1830	$3,957,665.78	B/S Capital Assets
Overhead Conductors and Devices	1835	$1,099,730.89	B/S Capital Assets
Underground Conduit	1840	$185,626.32	B/S Capital Assets
Underground Conductors and devices	1845	$951,670.26	B/S Capital Assets
Line Transformers	1850	$1,801,838.58	B/S Capital Assets
Meters	1860	$820,682.40	B/S Capital Assets
General Plant			
Office Furniture and Equipment	1915	$21,544.09	B/S Capital Assets
Computer Equipment - Hardware	1920	$72,160.71	B/S Capital Assets
Computer Software	1925	$120,634.64	B/S Capital Assets
Transportation Equipment	1930	$493,329.47	B/S Capital Assets
Tools, Shop and Garage Equipment	1940	$89,628.72	B/S Capital Assets
Measurement and Testing Equipment	1945	$18,837.99	B/S Capital Assets
Power Operated Equipment	1950	$221,612.35	B/S Capital Assets
Communication Equipment	1955	$43,010.14	B/S Capital Assets
Sentinal Light Rental Units	1985	$30,686.83	B/S Capital Assets
Contributiions and Grants - Credit	1995	-$1,081,628.77	B/S Capital Assets
Other Capital Assets			
Construction Work-in-progress- Electric	2055	$0.00	B/S Capital Assets
Accumulated Amortization			
Accumulated Amortization of Electric Utility Plant - PP	2105	-$3,986,797.19	B/S Capital Assets add back 48,592.50 for Acct 1576 and 42,200.97 Contributed Capital included in deferred contributions in non-current liabilities for IFRS (Note 5)
Current Liabilities			42,200.97
Accounts Payable	2205	-$2,823,244.87	B/S - CL - A/P
Customer Credit Balances	2208	-$62,727.76	B/S - CA - A/R
Current Portion of Customer Deposits	2210	-$10,618.07	B/S - Customer Deposits
Dividends Declared	2215	-$200,000.00	B/S - CL - due to related parties
Miscellaneous Current and Accrued Liabilities	2220	-$25,971.27	B/S - CL - Employee Benefits Pay
Debt Retirement Charge (DRC) Payable	2250	-$59,121.60	B/S - CL - A/P
Current Portion of Long Term Debt	2260	-$216,521.52	B/S - Bank indebt
Pensions and Employee Benefits - Current Portion	2264	-$5,477.70	B/S - CL - A/P
Accrued Interest on Long Term Debt	2268	-$5,420.90	B/S - CL - A/P
Commodity Taxes	2290	$171,990.15	B/S - CA - A/R
Payroll Deductions/Expenses Payable	2292	-$12,951.22	B/S - CL - A/P
Accrual for Taxes Payment in Lieu of Taxes, Etc.	2294	$10,937.00	B/S - CA - Taxes Rec
Non-Current Liability			
Employee Future Benefits	2306	-$18,189.75	B/S - CL - Employee Benefits Pay
Vested Sick Leave Liability	2310	-$18,292.14	B/S - CL - Employee Benefits Pay
Long Term Customer Deposits	2335	-$95,562.64	B/S - Customer Deposits
Future Income Tax - Non-Current	2350	$82,885.63	B/S - Assets - Future income taxes
Other Liabilities and Deferred Credits			
Long Term Debts			
Term Bank Loans - Long Term Portion	2525	-$1,726,918.01	B/S - Bank indebt
Shareholder's Equity			
Common Shares Issued	3005	-$2,789,823.33	B/S - S/E
Dividends Payable - Common Shares	3049	$200,000.00	B/S - Retained Earnings

Adjustment to Retained Earnings	3055	-$248,575.76	B/S - Retained Earnings incl adjustment for Acc 1576 of 97,185		
Shareholder's Equity Acct 3046					
Balance Transferred from Income	3046	-$181,292.48	B/S - Retained Earnings		
Sales of Electricity					
Revenue Adjustment	4050	$146,781.46	I/S - Revenue		
Energy Sales for Resale	4055	-$6,442,330.80	I/S - Revenue add back 681.36 for RPP settlement and include in OEB 4705		
Billed WMS	4062	-$395,128.52	I/S - Revenue		
Billed NW	4066	-$588,048.09	I/S - Revenue		
Billed CN	4068	-$120,124.89	I/S - Revenue		
Billed LV	4075	-$327,588.02	I/S - Revenue		
Billed-Smart Meter Entity Charge	4076	-$25,541.87	I/S - Revenue		
Revenue from Services - Distribution			Street Light Class Revenue	-156437.94	
Distribution Services Revenue	4080	-$1,966,709.19	I/S - Revenue		
SSS Administration Revenue	4086	-$8,048.77	I/S - Revenue	For AFS - net regulatory movement was recorded	
Other Operation Revenues			-$9,726,738.69	Add back Amount recorded to reduce Power income	2,268,492.01
Rent from Electric Property	4210	-$53,900.64	I/S - Other Operating Income	Add back Amount recorded to reduce Power expense	-2,035,459.64
Other Utility Operating Income	4215	-$999.83	I/S - Other Operating Income	Add Back Amount recorded to reduce Admin Expense	-2,035.00
Late Payment Charges	4225	-$52,423.55	I/S - Other Operating Income		230,997.37
Miscellaneous Service Revenues	4235	-$18,275.00	I/S - Other Operating Income add 1,292.54 for capital contribution amortization recorded as revenue for IFRS and 2,856.68 from 5665		
Other Income / Deductions					
Loss on Disposition of Utility and Other Property	4360	$6,073.82	I/S - Other Operating Income		
Revenues from Non-Utlity Operations	4375	-$145,789.71	I/S - Other Operating Income		
Expenses of Non-Utility Operations	4380	$145,789.71	I/S - Other Operating Income		
Non-Utility Rental Income	4385	$0.00	I/S - Other Operating Income		
Investment Income					
Interest and Dividend Income	4405	-$6,452.07	I/S - Other Operating Income		
Other Power Supply Expenses					
Power Purchased	4705	$5,413,114.42	I/S - Cost of Power Incl amount for RPP settlement of 681.36 from OEB 4055		
Charges - Global Adjustment	4707	$915,505.45	I/S - Cost of Power		
Charges - WMS	4708	$388,157.25	I/S - Cost of Power		
Charges - NW	4714	$584,710.13	I/S - Cost of Power		
Charges - CN	4716	$119,011.77	I/S - Cost of Power		
Charges - LV	4750	$322,503.02	I/S - Cost of Power		
Charges - Smart Metering Entity Charge	4751	$25,591.98	I/S - Cost of Power		
Distribution Expenses - Operation			$7,768,594.02		
Overhead Distribution Lines and Feeders - Operations Labour	5020	$458,820.22	I/S - Operation Maintenance		
Overhead Distribution Lines and Feeders - Operations Supplies and Expense	5025	$79,691.13	I/S - Operation Maintenance		
Overhead Distribution Transformers - Operation	5035	$0.00	I/S - Operation Maintenance		
Miscellaneous Distribution Expense	5085	$43,064.78	I/S - Operation Maintenance		
Distribution Expenses - Maintenance					
Maintenance of Poles, Towers and Fixtures	5120	$54,203.64	I/S - Operation Maintenance		
Overhead Distribution Lines and Feeders - Right of Way	5135	$69,321.93	I/S - Operation Maintenance		
Maintenance of Line Transformers	5160	$9,874.69	I/S - Operation Maintenance		
Sentinal Lights - Labour	5170	$1,317.37	I/S - Operation Maintenance		
Sentinal Lights - Materials and Expenses	5172	$1,730.02	I/S - Operation Maintenance less Amortization - $1313.73		
Maintenance of Meters	5175	$54,501.73	I/S - Operation Maintenance		
Billing and Collecting			$776,167.42		
Meter Reading Expense	5310	$4,955.64	I/S - Operation Maintenance		
Customer Billing	5315	$176,632.24	I/S - Admin less $61,585.80- Interest and Bank Charges		
Collecting	5320	$88,610.30	I/S - Administration		
Collecting - Cash Over and Short	5325	-$33.18	I/S - Administration		
Collection Charges	5330		I/S - Administration		
Bad Debt Expense	5335	$39,857.11	I/S - Administration		
Administr and Gen Expenses			$243,480.67		
Executive Salaries and Expenses	5605	$15,305.03	I/S - Administration		
Management Salaries and Expenses	5610	$213,006.32	I/S - Administration		
General Administrative Salaries and Expenses	5615	$1,069.29	I/S - Administration		
Office Supplies and Expense	5620	$9,091.42	I/S - Administration		
Outside Services Employed	5630	$26,556.25	I/S - Administration		
Property Insurance	5635	$22,693.83	I/S - Administration		
Regulatory Expense	5655	$160,851.48	I/S - Administration		
General Advertising Expense	5660	$3,037.88	I/S - Administration		
Miscellaneous General Expense	5665	$26,708.09	I/S - Administration less 2,856.68 for misc rev add to 4235		
Rent	5670	$20,325.36	I/S - Administration		
Electrical Safety Authority Fees	5680	$2,641.44	I/S - Administration		
Amortization Expenses			$507,476.65		
Amortization Expense - Property, Plant and Equipment	5705	$208,581.15	I/S Amortization - Included -1,292.94 for 2015 capital contributions add to misc revenue/Sential light amorization included in OEB 5172 1313.73		
Interest Expenses					
Interest on Long Term Debt	6005	$68,185.17	I/S - Interest and Bank Charges		
Other Interest Expense	6035	$5,454.69	I/S - Interest and Bank Charges (plus 68506.25)		
Taxes			$142,146.11		
Taxes Other Than Income Taxes	6105	$3,850.26	I/S - Administration		

Income Taxes	6110	$11,047.00	I/S - Payment in Lieu of taxes
Provision for Future Income Taxes	6115	$19,537.18	I/S - Payment in Lieu of taxes
Other Deductions			
Donations	6205	$2,340.00	I/S - Administration

$0.00

$0.00

Key:
B/S = Balance Sheet
I/S = Income Statement
CA = Current Assets
CL = Current Liabilities
A/R = Accounts Receivable
A/P = Accounts Payable

Audited CGAAP

Sioux Lookout Hydro Inc.
Balance Sheet

December 31		2014
Assets		
Current		
Cash and Bank	$	60,311
Accounts Receivable		1,252,518
Unbilled Revenue		1,632,174
Inventory (note 1)		55,798
Prepaid Expenses		37,277
Taxes Receivable		10,937
Regulatory assets (Note 3)		30,585
Capital Assets (Note 4)		5,000,690
Future Income Taxes		82,886
	$	**8,163,176**
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 5)	$	1,943,440
Accounts Payable and Accrued Liabilities		2,734,226
Employee Benefits Payable (Note 6)		62,453
Customer Deposits		106,181
Due to related parties (Note 2)		200,000
		5,046,300
Regulatory liabilities (Note 3)		
		5,046,300
Shareholder's Equity		
Share Capital (Note 7)		2,789,823
Retained Earnings		327,053
		3,116,877
	$	**8,163,176**

*Small differences due to rounding

Statement of Operations

For the year ended December 31		2014
Revenue		
Sale of Energy		
Residential and general	$	
Street Lighting		
Unbilled Revenue adjustment		
		9,726,739
Cost of bulk power purchased		**7,768,594**
Gross Margin on energy sold		**1,958,145**
Other operating revenue (Note 9)		**128,834**
		2,086,979
Expenditures		
Administration		753,814
Amortization		209,895
Interest and bank charges		135,226
Operation maintenance		776,167
		1,875,102
Income before other item and payment in lieu of taxes		**211,877**
Other item		
Loss on impairment of goodwill (Note 15)		-
Income before payment in lieu of taxes		**211,877**
Payment in lieu of taxes		
Payment in lieu of taxes		11,047
Future payment in lieu recoverable		19,537
		30,584
Net Income for the year	**$**	**181,292**

*Small differences due to rounding

Audited IFRS

Sioux Lookout Hydro Inc.

Statement of Financial Position (Expressed in Canadian Dollars)

December 31		**2014**	**FR 2.1.7**
Assets			
Current assets			
Cash	$	60,311	
Trade and other receivables (Note 6)		1,424,508	
Unbilled Revenue		1,632,174	
Inventory		55,798	
Prepaids		37,277	
Payment in lieu of taxes receivable (Note 7)		10,937	
Total Current Assets	**$**	3,221,006	
Non-current Assets			
Property, Plant and equipment (Note 4)		4,941,183	
Deferred Tax		82,886	
Total Non-current assets	**$**	5,024,068	
Regulatory deferral account debits (Note 3)		189,499	
	$	8,434,573	
Liabilities and Shareholder's Equity			
Current liabilities			
Accounts Payable and Accrued Liabilities	**$**	2,932,188	
Customer Deposits		106,181	
Payments in lieu of taxes payable			
Due to parent company (Note 9)		200,000	
Current portion of long-term debt (Note 16)		1,943,440	
Total Current liabilities	**$**	5,181,808	
Non-current liabilities			
Employee future benefits (Note 8)		158,244	
Contributions in aid on construction (Note 5)		42,201	
Total Liabilities	**$**	5,382,253	
Shareholder's Equity			
Share Capital (Note 11)		2,789,823	
Retained Earnings		205,291	
		2,995,114	
Total liabilities and shareholder's equity	$	8,377,367	
Regulatory deferral account credits (Note 3)		57,206	

Total equity, liabilities and regulatory deferral account credits	8,434,573

*Small differences due to rounding

Statement of Operations

For the year ended December 31		**2014**
Revenue		
Electricity sales	$	11,839,474
Street Lighting		156,438
Other		129,748
		12,125,660
Expenses		
Administration		755,849
Amortization		211,187
Operations and maintenance		781,379
Purchased Power		9,804,735
Loss on retirement of property, plant and equipment		6,074
		11,559,224
Income from operating activities		566,436
Finance income (Note 15)		6,452
Finance Cost (note 15)		-135,226
Income before provision for payment in lieu of taxes		437,662
Provision for payments in lieu of taxes		
Current (Note 7)		11,047
Deferred (Note 7)		19,537
		30,584
Profit for the year before net movements in regulatory deferral account balances		407,078
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement		-230,997
Profit for the year and net movements in regulatory deferral account balances	$	176,081

*Small differences due to rounding

Sioux Lookout Hydro Inc.
Trial Balance
as at December 31, 2015
as per OEB filing 2.1.7

Account Description	OEB Account No.	Amount	Allocation to Audited Financials		
Current Assets					
Cash	1005	$391,688.94	B/S - CA - Cash		
Customer Accounts Receivable	1100	$1,242,444.12	B/S - CA - A/R		
Other Accounts Receivable	1110	$192,774.71	B/S - CA - A/R		
Accrued Utility Revenues	1120	$1,379,818.89	B/S - CA - Unbilled		
Accumulated Provision for Uncollectible Accounts - Credit	1130	-$88,663.07	B/S - CA - A/R		
Prepayments	1180	$48,319.41	B/S - CA - Prepaid		
Plant Materials and Operating Supplies	1330	$79,417.41	B/S - CA - Inventory		$3,245,800.41
Other Assets and Deferred Charges					
Other Regulatory Assets	1508	$25,299.28	B/S Reg Assets/Liabilities		
RCVARetail	1518	-$6,779.60	B/S Reg Assets/Liabilities		
RCVASTR	1548	-$113.62	B/S Reg Assets/Liabilities		
LV Variance Account	1550	$90,361.66	B/S Reg Assets/Liabilities		
Smart Metering Entity Charge Variance Account	1551	$1,149.78	B/S Reg Assets/Liabilities		
Smart Meter Capital and Recovery Offset Variance	1555	-$64.01	B/S Reg Assets/Liabilities		
LRAM Variance Account	1568	-$11,251.59	B/S Reg Assets/Liabilities		
IFRS-CGAAP Transitional PP&E Amounts	1575	$159,328.45	B/S Reg Assets/Liabilities		
CGAAP Accounting Changes	1576	-$24,296.25	Record for OEB only		
RSVAWMS	1580	-$155,942.83	B/S Reg Assets/Liabilities		
RSVANW	1584	-$41,017.94	B/S Reg Assets/Liabilities		
RSVACN	1586	-$15,537.73	B/S Reg Assets/Liabilities		
RSVAPOWER	1588	-$375,707.78	B/S Reg Assets/Liabilities		
RSVAGA	1589	$185,753.84	B/S Reg Assets/Liabilities		
Disposition and Recovery of Regulatory Balances Control Account	1595	$185,606.09	B/S Reg Assets/Liabilities		
Distribution Plant				$41,084.00	
Buildings and fixtures	1808	$91,864.15	B/S Capital Assets		
Poles, Towers, fixtures	1830	$4,058,553.11	B/S Capital Assets		
Overhead Conductors and Devices	1835	$1,115,963.42	B/S Capital Assets		
Underground Conduit	1840	$187,356.35	B/S Capital Assets		
Underground Conductors and devices	1845	$976,663.17	B/S Capital Assets		
Line Transformers	1850	$1,798,646.24	B/S Capital Assets		
Meters	1860	$821,250.47	B/S Capital Assets		
General Plant					
Office Furniture and Equipment	1915	$23,861.99	B/S Capital Assets		
Computer Equipment - Hardware	1920	$73,990.71	B/S Capital Assets		
Computer Software	1925	$121,797.64	B/S Capital Assets		
Transportation Equipment	1930	$493,329.47	B/S Capital Assets		
Tools, Shop and Garage Equipment	1940	$90,633.67	B/S Capital Assets		
Measurement and Testing Equipment	1945	$18,837.99	B/S Capital Assets		
Power Operated Equipment	1950	$235,846.35	B/S Capital Assets		

Communication Equipment	1955	$54,132.61	B/S Capital Assets	
Sentinal Light Rental Units	1985	$32,209.99	B/S Capital Assets	
Contributiions and Grants - Credit	1995	-$1,122,141.96	B/S Capital Assets	
Other Capital Assets				
Construction Work-in-progress- Electric	2055	$33,317.40	B/S Capital Assets	
Accumulated Amortization				
Accumulated Amortization of Electric Utility Plant - PP	2105	-$4,306,854.67	B/S Capital Assets add back 72,888.75 for Acct 1576 and 80,217 Contributed Capital included in deferred contributions in non-current liabilities for IFRS (Note 5)	
Current Liabilities			80,217.63	
Accounts Payable	2205	-$2,967,821.39	B/S - CL - A/P	
Customer Credit Balances	2208	-$93,862.50	B/S - CA - A/R	
Current Portion of Customer Deposits	2210	-$13,770.77	B/S - Customer Deposits	
Dividends Declared	2215	-$240,000.00	B/S - CL - due to related parties	
Miscellaneous Current and Accrued Liabilities	2220	-$23,327.73	B/S - CL - Employee Benefits Pay	
Debt Retirement Charge (DRC) Payable	2250	-$44,069.98	B/S - CL - A/P	
Current Portion of Long Term Debt	2260	-$224,739.00	B/S - Bank indebt	
Pensions and Employee Benefits - Current Portion	2264	$0.00	B/S - CL - A/P	
Accrued Interest on Long Term Debt	2268		B/S - CL - A/P	
Commodity Taxes	2290	$193,019.61	B/S - CA - A/R	
Payroll Deductions/Expenses Payable	2292		B/S - CL - A/P	
Accrual for Taxes Payment in Lieu of Taxes, Etc.	2294	-$12,626.00	B/S - CA - Taxes Rec	
Non-Current Liability				-$3,427,197.76
Employee Future Benefits	2306	-$96,955.00	B/S - CL - Employee Benefits Pay	
Vested Sick Leave Liability	2310	-$63,304.00	B/S - CL - Employee Benefits Pay	
Long Term Customer Deposits	2335	-$123,936.94	B/S - Customer Deposits	
Future Income Tax - Non-Current	2350	$124,850.00	B/S - Assets - Future income taxes	
Other Liabilities and Deferred Credits				
Long Term Debts				
Term Bank Loans - Long Term Portion	2525	-$1,500,297.71	B/S - Bank indebt	
Shareholder's Equity				
Common Shares Issued	3005	-$2,789,823.33	B/S - S/E	
Dividends Payable - Common Shares	3049	$240,000.00	B/S - Retained Earnings	
Adjustment to Retained Earnings	3055	-$108,106.13	B/S - Retained Earnings incl adjustment for Acc 1576 of 97,185	
Shareholder's Equity Acct 3046				
Balance Transferred from Income	3046	-$317,075.39	B/S - Retained Earnings	
Sales of Electricity				
Revenue Adjustment	4050	$271,454.54	I/S - Revenue	
Energy Sales for Resale	4055	-$6,903,837.19	I/S - Revenue	
Billed WMS	4062	-$482,405.91	I/S - Revenue	
Billed NW	4066	-$560,269.04	I/S - Revenue	
Billed CN	4068	-$122,186.37	I/S - Revenue	
Billed LV	4075	-$292,279.50	I/S - Revenue	
Billed-Smart Meter Entity Charge	4076	-$25,027.87	I/S - Revenue	
Revenue from Services - Distribution			Street Light Class Revenue	-140682.3
Distribution Services Revenue	4080	-$1,871,346.62	I/S - Revenue	

SSS Administration Revenue	4086	-$7,900.52	I/S - Revenue		For AFS - net regulatory movement was recorded	
Other Operation Revenues				-$9,993,798.48	Add back Amount recorded to reduce Power income	1,838,338.30
Rent from Electric Property	4210	-$47,261.09	I/S - Other Operating Income		Add back Amount recorded to reduce Power expense	-1,761,364.32
Other Utility Operating Income	4215		I/S - Other Operating Income			76,973.98
Late Payment Charges	4225	-$46,090.73	I/S - Other Operating Income			
Miscellaneous Service Revenues	4235	-$17,770.00	I/S - Other Operating Income add 2,496.53 for capital contribution amortization recorded as revenue for IFRS			
Other Income / Deductions						
Loss on Disposition of Utility and Other Property	4360	$2,041.63	I/S - Other Operating Income			
Revenues from Non-Utlity Operations	4375	-$219,152.46	I/S - Other Operating Income			
Expenses of Non-Utility Operations	4380	$174,457.69	I/S - Other Operating Income			
Non-Utility Rental Income	4385	-$10,724.44	I/S - Other Operating Income			
Investment Income						
Interest and Dividend Income	4405	-$4,132.13	I/S - Other Operating Income			
Other Power Supply Expenses						
Power Purchased	4705	$5,020,142.22	I/S - Cost of Power			
Charges - Global Adjustment	4707	$1,722,327.85	I/S - Cost of Power			
Charges - WMS	4708	$463,178.88	I/S - Cost of Power			
Charges - NW	4714	$532,123.04	I/S - Cost of Power			
Charges - CN	4716	$115,726.13	I/S - Cost of Power			
Charges - LV	4750	$280,243.97	I/S - Cost of Power			
Charges - Smart Metering Entity Charge	4751	$24,557.36	I/S - Cost of Power			
Distribution Expenses - Operation				$8,158,299.45		
Overhead Distribution Lines and Feeders - Operations Labour	5020	$429,182.79	I/S - Operation Maintenance			
Overhead Distribution Lines and Feeders - Operations Supplies and Expense	5025	$80,485.00	I/S - Operation Maintenance			
Overhead Distribution Transformers - Operation	5035		I/S - Operation Maintenance			
Miscellaneous Distribution Expense	5085	$17,062.57	I/S - Operation Maintenance			
Distribution Expenses - Maintenance						
Maintenance of Poles, Towers and Fixtures	5120	$35,677.33	I/S - Operation Maintenance			
Overhead Distribution Lines and Feeders - Right of Way	5135	$59,774.95	I/S - Operation Maintenance			
Maintenance of Line Transformers	5160	$5,527.71	I/S - Operation Maintenance			
Sentinal Lights - Labour	5170	$2,628.38	I/S - Operation Maintenance			
Sentinal Lights - Materials and Expenses	5172	$1,364.85	I/S - Operation Maintenance less Amortization - $1263.15			
Maintenance of Meters	5175	$54,527.81	I/S - Operation Maintenance			
Billing and Collecting				$689,450.54		
Meter Reading Expense	5310	$4,532.88	I/S - Operation Maintenance			
Customer Billing	5315	$206,117.41	I/S - Admin less $68,506.25- Interest and Bank Charges			
Collecting	5320	$95,179.04	I/S - Administration			
Collecting - Cash Over and Short	5325	-$6.60	I/S - Administration			
Collection Charges	5330	$0.00	I/S - Administration			
Bad Debt Expense	5335	$24,094.42	I/S - Administration			
Administr and Gen Expenses				$263,798.47		

Executive Salaries and Expenses	5605	$19,624.48	I/S - Administration	
Management Salaries and Expenses	5610	$130,214.68	I/S - Administration	
General Administrative Salaries and Expenses	5615	$80,851.57	I/S - Administration	
Office Supplies and Expense	5620	$7,470.13	I/S - Administration	
Outside Services Employed	5630	$32,307.02	I/S - Administration	
Property Insurance	5635	$21,486.57	I/S - Administration	
Employee Pensions and Benefits	5645	$8,443.02	I/S - Operations Maintenance	
Regulatory Expense	5655	$26,500.82	I/S - Administration	
General Advertising Expense	5660	$2,019.05	I/S - Administration	
Miscellaneous General Expense	5665	$46,621.62	I/S - Administration	
Rent	5670	$20,731.92	I/S - Administration	
Electrical Safety Authority Fees	5680	$2,598.14	I/S - Administration	
Amortization Expenses			$406,439.40	
Amortization Expense - Property, Plant and Equipment	5705	$210,721.58	I/S Amortization - Included -2,496.53 for 2015 capital contributions add to misc revenue/Sential light amorization included in OEB 5172	
Interest Expenses				
Interest on Long Term Debt	6005	$34,171.84	I/S - Interest and Bank Charges	
Other Interest Expense	6035	$27,032.18	I/S - Interest and Bank Charges (plus 68506.25)	
Taxes			$129,710.27	
Taxes Other Than Income Taxes	6105	$5,230.38	I/S - Administration	
Income Taxes	6110	$34,506.00	I/S - Payment in Lieu of taxes	
Provision for Future Income Taxes	6115	-$41,964.37	I/S - Payment in Lieu of taxes	
Other Deductions				
Donations	6205	$2,340.00	I/S - Administration	
				$0.00
		$0.00		

Key:
B/S = Balance Sheet
I/S = Income Statement
CA = Current Assets
CL = Current Liabilities
A/R = Accounts Receivable
A/P = Accounts Payable

Audited

Sioux Lookout Hydro Inc.

Statement of Financial Position (Expressed in Canadian Dollars)

December 31		**2015**
Assets		
Current assets		
Cash	$	391,689
Trade and other receivables (Note 6)		1,445,713
Unbilled Revenue		1,379,819
Inventory		78,217
Prepaids		49,519
Payment in lieu of taxes receivable (Note 7)		
Total Current Assets	**$**	3,344,958
Non-current Assets		
Property, Plant and equipment (Note 4)		4,952,364
Deferred Tax		124,850
Total Non-current assets	**$**	5,077,214
Regulatory deferral account debits (Note 3)		185,714
	$	8,607,886
Liabilities and Shareholder's Equity		
Current liabilities		
Accounts Payable and Accrued Liabilities	**$**	3,035,219
Customer Deposits		137,708
Payments in lieu of taxes payable		12,626
Due to parent company (Note 9)		240,000
Current portion of long-term debt (Note 16)		1,725,037
Total Current liabilities	**$**	5,150,590
Non-current liabilities		
Employee future benefits (Note 8)		160,259
Contributions in aid on construction (Note 5)		80,218
Total Liabilities	**$**	5,391,066
Shareholder's Equity		
Share Capital (Note 11)		2,789,823
Retained Earnings		282,367
		3,072,190

Total liabilities and shareholder's equity	$	8,463,256
Regulatory deferral account credits (Note 3)		144,630
Total equity, liabilities and regulatory deferral account credits		8,607,886

*Small differences due to rounding

Statement of Operations

For the year ended December 31		**2015**
Revenue		
Electricity sales	$	11,691,454
Street Lighting		140,682
Other		169,038
		12,001,174
Expenses		
Administration		654,874
Amortization		214,481
Operations and maintenance		697,944
Purchased Power		9,919,664
Loss on retirement of property, plant and equipment		2,042
		11,489,005
Income from operating activities		512,169
Finance income (Note 15)		4,132
Finance Cost (note 15)		-129,710
Income before provision for payment in lieu of taxes		386,591
Provision for payments in lieu of taxes		
Current (Note 7)		34,506
Deferred (Note 7)		-41,964
		-7,458
Profit for the year before net movements in regulatory deferral account balances		394,049
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement		-76,974

Profit for the year and net movements in regulatory deferral account balances	$	317,075

*Small differences due to rounding

FR 2.1.7

Sioux Lookout Hydro Inc.
Trial Balance
as at December 31, 2016
as per OEB filing 2.1.7

Account Description	**OEB Account No.**	**Amount**	**Allocation to Audited Financials**		
Current Assets					
Cash	1005		B/S - CA - Cash		
Customer Accounts Receivable	1100	$1,284,337.35	B/S - CA - A/R		
Other Accounts Receivable	1110	$72,887.37	B/S - CA - A/R		
Accrued Utility Revenues	1120	$1,498,213.59	B/S - CA - Unbilled		
Accumulated Provision for Uncollectible Accounts - Credit	1130	-$83,771.30	B/S - CA - A/R		
Prepayments	1180	$67,363.34	B/S - CA - Prepaid		
Plant Materials and Operating Supplies	1330	$52,486.68	B/S - CA - Inventory		$2,891,517.03
Other Assets and Deferred Charges					
Other Regulatory Assets	1508	$45,691.59	B/S Reg Assets/Liabilities		
RCVARetail	1518	-$7,730.14	B/S Reg Assets/Liabilities		
RCVASTR	1548	-$132.21	B/S Reg Assets/Liabilities		
LV Variance Account	1550	$65,645.18	B/S Reg Assets/Liabilities		
Smart Metering Entity Charge Variance Account	1551	$1,237.76	B/S Reg Assets/Liabilities		
Smart Meter Capital and Recovery Offset Variance	1555	-$63.57	B/S Reg Assets/Liabilities		
LRAM Variance Account	1568	-$1,496.94	B/S Reg Assets/Liabilities		
IFRS-CGAAP Transitional PP&E Amounts	1575	$47,530.04	B/S Reg Assets/Liabilities		
CGAAP Accounting Changes	1576	$0.00	Record for OEB only		
RSVAWMS	1580	-$31,966.77	B/S Reg Assets/Liabilities		
RSVANW	1584	-$10,531.16	B/S Reg Assets/Liabilities		
RSVACN	1586	$8,206.01	B/S Reg Assets/Liabilities		
RSVAPOWER	1588	-$27,509.22	B/S Reg Assets/Liabilities		
RSVAGA	1589	-$362,878.23	B/S Reg Assets/Liabilities		
Disposition and Recovery of Regulatory Balances Control Account	1595	-$29,768.99	B/S Reg Assets/Liabilities		
Intangible Plant				-$303,766.65	
Computer Software	1611	$121,797.64	B/S Capital Assets		
Distribution Plant					
Buildings and fixtures	1808	$91,864.15	B/S Capital Assets		
Poles, Towers, fixtures	1830	$4,244,761.42	B/S Capital Assets		
Overhead Conductors and Devices	1835	$1,140,593.24	B/S Capital Assets		
Underground Conduit	1840	$193,183.78	B/S Capital Assets		
Underground Conductors and devices	1845	$1,022,997.68	B/S Capital Assets		
Line Transformers	1850	$1,819,124.62	B/S Capital Assets		
Meters	1860	$822,997.07	B/S Capital Assets		
General Plant					
Office Furniture and Equipment	1915	$23,508.25	B/S Capital Assets		
Computer Equipment - Hardware	1920	$73,990.71	B/S Capital Assets		
Transportation Equipment	1930	$468,692.47	B/S Capital Assets		
Tools, Shop and Garage Equipment	1940	$94,578.42	B/S Capital Assets		
Measurement and Testing Equipment	1945	$34,227.29	B/S Capital Assets		

Power Operated Equipment	1950	$236,625.35	B/S Capital Assets	
Communication Equipment	1955	$54,731.61	B/S Capital Assets	
Sentinal Light Rental Units	1985	$32,209.99	B/S Capital Assets	
Contributiions and Grants - Credit	1995	-$1,038,135.26	B/S Capital Assets	
Other Capital Assets				
Construction Work-in-progress- Electric	2055	$77,869.62	B/S Capital Assets	
Accumulated Amortization				
Accumulated Amortization of Electric Utility Plant - PP	2105	-$4,438,282.37	B/S Capital Assets add back 97,185.00 for Acct 1576 (EB-2012-0165)	
Current Liabilities				
Accounts Payable	2205	-$2,708,647.21	B/S - CL - A/P	
Customer Credit Balances	2208	-$121,265.31	B/S - CL - A/P	
Current Portion of Customer Deposits	2210	-$13,309.37	B/S - Customer Deposits	
Dividends Declared	2215	-$150,000.00	B/S - CL - due to related parties	
Miscellaneous Current and Accrued Liabilities	2220	-$22,078.09	B/S - CL - A/P	
Notes and Loans Payable	2225	-$31,260.09	B/S - CL - Bank Indebtedness	
Debt Retirement Charge (DRC) Payable	2250	-$21,375.28	B/S - CL - A/P	
Current Portion of Long Term Debt	2260	-$233,108.61	B/S - Bank indebt	
Pensions and Employee Benefits - Current Portion	2264	-$6,026.48	B/S - CL - A/P	
Accrued Interest on Long Term Debt	2268	-$4,228.78	B/S - CL - A/P	
Commodity Taxes	2290	$169,641.77	B/S - CA - A/R	
Payroll Deductions/Expenses Payable	2292	-$14,799.52	B/S - CL - A/P	
Accrual for Taxes Payment in Lieu of Taxes, Etc.	2294	$27,638.00	B/S - CA - Taxes Rec	
Non-Current Liability				-$3,128,818.97
Employee Future Benefits	2306	-$58,595.66	B/S - CL - Employee Benefits Pay	
Vested Sick Leave Liability	2310	-$102,889.00	B/S - CL - Employee Benefits Pay	
Long Term Customer Deposits	2335	-$119,784.33	B/S - Customer Deposits	
Future Income Tax - Non-Current	2350	$99,154.00	B/S - Assets - Future income taxes	
Other Liabilities and Deferred Credits				
Deferred Revenues	2440	-$107,436.21	B/S - Non-Current Liabilities	
Long Term Debts				
Term Bank Loans - Long Term Portion	2525	-$1,266,383.34	B/S - Bank indebt	
Shareholder's Equity				
Common Shares Issued	3005	-$2,789,823.33	B/S - S/E	
Dividends Payable - Common Shares	3049	$150,000.00	B/S - Retained Earnings	
Adjustment to Retained Earnings	3055	-$185,181.52	B/S - Retained Earnings incl adjustment for Acc 1576 of 97,185	
Shareholder's Equity Acct 3046				
Balance Transferred from Income	3046	-$155,327.70	B/S - Retained Earnings	
Sales of Electricity				
Residential Energy Sales	4006	-$3,193,797.19	I/S - Revenue	For AFS - RPP Settlement Revenue is included in Purchased Power
Street Light Energy Sales	4025	-$17,826.03	I/S - Revenue	For TB RPP Settlment Revenue is included in Account 4006
General Energy Sales	4035	-$3,979,008.32	I/S - Revenue	-851.13
Revenue Adjustment	4050	-$143,653.05	I/S - Revenue	
Billed WMS	4062	-$446,076.10	I/S - Revenue	
Billed NW	4066	-$467,533.65	I/S - Revenue	
Billed CN	4068	-$104,251.82	I/S - Revenue	
Billed LV	4075	-$250,654.76	I/S - Revenue	
Billed-Smart Meter Entity Charge	4076	-$25,746.76	I/S - Revenue	
Revenue from Services - Distribution			Street Light Class Revenue	-$111,007.65

Distribution Services Revenue	4080	-$1,863,303.31	I/S - Revenue			
SSS Administration Revenue	4086	-$8,140.02	I/S - Revenue		For AFS - net regulatory movement was recorded	
Other Operation Revenues				-$3,309,359.47	Add back Amount recorded to reduce Power income	1,398,044.65
Rent from Electric Property	4210	-$45,333.14	I/S - Other Operating Income		Add back Amount recorded to reduce Power expense	-1,112,572.92
Other Utility Operating Income	4215	$0.00	I/S - Other Operating Income			285,471.73
Late Payment Charges	4225	-$48,896.78	I/S - Other Operating Income			
Miscellaneous Service Revenues	4235	-$17,965.00	I/S - Other Operating Income add 2,496.53 for capital contribution amortization recorded as revenue for IFRS			
Gov't and Other Assistance Directly Credited to Income	4245	-$2,477.26	I/S - Depreciation			
Other Income / Deductions						
Loss from retirement of Utility and Other Property	4362	$1,337.33	I/S - Other Operating Income			
Revenues from Non-Utlity Operations	4375	-$87,632.72	I/S - Other Operating Income			
Expenses of Non-Utility Operations	4380	$87,365.74	I/S - Other Operating Income			
Non-Utility Rental Income	4385	-$11,364.86	I/S - Other Operating Income			
Investment Income						
Interest and Dividend Income	4405	-$3,492.78	I/S - Other Operating Income			
Other Power Supply Expenses						
Power Purchased	4705	$5,925,063.83	I/S - Cost of Power			
Charges - Global Adjustment	4707	$1,391,686.58	I/S - Cost of Power			
Charges - WMS	4708	$454,077.61	I/S - Cost of Power			
Charges - NW	4714	$475,212.30	I/S - Cost of Power			
Charges - CN	4716	$107,176.01	I/S - Cost of Power			
Charges - LV	4750	$249,577.69	I/S - Cost of Power			
Charges - Smart Metering Entity Charge	4751	$25,753.66	I/S - Cost of Power			
Distribution Expenses - Operation				$8,628,547.68		
Overhead Distribution Lines and Feeders - Operations Labour	5020	$447,764.81	I/S - Operation Maintenance			
Overhead Distribution Lines and Feeders - Operations Supplies and Expense	5025	$81,679.87	I/S - Operation Maintenance			
Overhead Distribution Transformers - Operation	5035		I/S - Operation Maintenance			
Miscellaneous Distribution Expense	5085	$44,708.62	I/S - Operation Maintenance			
Distribution Expenses - Maintenance						
Maintenance of Poles, Towers and Fixtures	5120	$45,479.94	I/S - Operation Maintenance			
Overhead Distribution Lines and Feeders - Right of Way	5135	$75,683.06	I/S - Operation Maintenance			
Maintenance of U/G Conductors and Devices	5150	$2,212.39				
Maintenance of Line Transformers	5160	$4,553.12	I/S - Operation Maintenance			
Sentinal Lights - Labour	5170	$3,254.67	I/S - Operation Maintenance			
Sentinal Lights - Materials and Expenses	5172	$3,109.28	I/S - Operation Maintenance		For AFS - Sentinel Light Amortization included in Depreciation	
Maintenance of Meters	5175	$60,582.93	I/S - Operation Maintenance		For TB - Sentinel Light Amortization included in Account 5172	
Billing and Collecting				$770,269.86	$1,240.45	
Meter Reading Expense	5310	$2,554.90	I/S - Operation Maintenance			
Customer Billing	5315	$231,194.41	I/S - Administration			
Collecting	5320	$92,276.04	I/S - Administration			
Collecting - Cash Over and Short	5325	$104.97	I/S - Administration			
Collection Charges	5330		I/S - Administration			

Bad Debt Expense	5335	$25,641.03	I/S - Administration		
Administr and Gen Expenses				$287,630.65	
Executive Salaries and Expenses	5605	$9,845.32	I/S - Administration		
Management Salaries and Expenses	5610	$140,246.89	I/S - Administration		
General Administrative Salaries and Expenses	5615	$81,374.43	I/S - Administration		
Office Supplies and Expense	5620	$8,968.28	I/S - Administration		
Outside Services Employed	5630	$36,361.02	I/S - Administration		
Property Insurance	5635	$24,228.71	I/S - Administration		
Employee Pensions and Benefits	5645	$8,685.08	I/S - Operations Maintenance		
Regulatory Expense	5655	$15,117.12	I/S - Administration		
General Advertising Expense	5660	$1,912.79	I/S - Administration		
Miscellaneous General Expense	5665	$55,631.78	I/S - Administration		
Rent	5670	$21,001.32	I/S - Administration		
Electrical Safety Authority Fees	5680	$2,614.33	I/S - Administration		
Amortization Expenses				$411,208.45	
Amortization Expense - Property, Plant and Equipment	5705	$217,627.19	I/S Amortization *		
Interest Expenses					
Interest on Long Term Debt	6005	$32,179.08	I/S - Interest and Bank Charges		
Other Interest Expense	6035	$27,702.34	I/S - Interest and Bank Charges		For AFS - Deposit interest included in Administration
Taxes					For TB - Deposit interest included in Account 6035
Taxes Other Than Income Taxes	6105	$2,881.38	I/S - Administration		$922.36
Income Taxes	6110	$9,362.00	I/S - Payment in Lieu of taxes		
Provision for Future Income Taxes	6115	$25,696.00	I/S - Payment in Lieu of taxes		
Other Deductions					
Donations	6205	$2,340.00	I/S - Administration		
		$0.00			

Key:
B/S = Balance Sheet
I/S = Income Statement
CA = Current Assets
CL = Current Liabilities
A/R = Accounts Receivable
A/P = Accounts Payable

Audited

Sioux Lookout Hydro Inc.

Statement of Financial Position (Expressed in Canadian Dollars)

		FR 2.1.7
December 31		**2016**
Assets		
Current assets		
Cash	$	0
Trade and other receivables (Note 6)		1,443,095
Unbilled Revenue		1,498,214
Inventory (Note 10)		51,287
Prepaids		68,563
Payment in lieu of taxes receivable		27,638
Total Current Assets	**$**	3,088,797
Non-current Assets		
Property, Plant and equipment (Note 4)		5,174,521
Deferred Tax (Note 7)		99,154
Total Non-current assets	**$**	5,273,675
Regulatory deferral account debits (Note 3)		94,459
	$	8,456,931
Liabilities and Shareholder's Equity		
Current liabilities		
Bank Indebtedness (Note 16)	**$**	31,260
Accounts Payable and Accrued Liabilities		2,898,421
Customer Deposits (note 6)		133,094
Payments in lieu of taxes payable		
Due to parent company (Note 9)		150,000
Demand Installment loans(Note 15)		1,499,492
Total Current liabilities	**$**	4,712,266
Non-current liabilities		
Employee future benefits (Note 8)		161,485
Contributions in aid on construction (Note 5)		107,436
Total Liabilities	**$**	4,981,187
Shareholder's Equity		
Share Capital (Note 11)		2,789,823
Retained Earnings		287,694

		3,077,518
Total liabilities and shareholder's equity	$	8,058,705
Regulatory deferral account credits (Note 3)		398,226
Total equity, liabilities and regulatory deferral account credits		8,456,931

*Small differences due to rounding

Statement of Operations

For the year ended December 31		**2016**
Revenue		
Electricity sales	$	11,786,177
Street Lighting		111,008
Other		123,827
		12,021,011
Expenses		
Administration		752,662
Amortization		216,390
Operations and maintenance		779,028
Purchased Power		9,740,269
Loss on retirement of property, plant and equipment		1,337
		11,489,688
Income from operating activities		531,324
Finance income (Note 15)		3,493
Finance Cost (note 15)		-58,959
Income before provision for payment in lieu of taxes		475,857
Provision for payments in lieu of taxes		
Current (Note 7)		9,362
Deferred (Note 7)		25,696
		35,058
Profit for the year before net movements in regulatory deferral account balances		440,799
Net movement in regulatory deferral account balances related		

to profit or loss and the related deferred tax movement		-285,472
Profit for the year and net movements in regulatory deferral account balances	$	155,328

*Small differences due to rounding