WEST OF THUNDER BAY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the Northwest Ontario Planning Region | July 27, 2016

ieso
Connecting Today. Powering Tomorrow.

West of Thunder Bay Sub-region IRRP

Appendix A: Demand Forecast – Methodology and Assumptions

A.1 Gross Demand Forecast

Figures A-1 to A-6 show the gross demand forecast scenarios developed for the West of Thunder Bay Sub-region. The gross demand forecast reflects the regional peak demand and was developed based on customer connection requests, projections for new and existing industrial customers and the growth projections developed by the Local Distribution Companies. Appendices A.1.1 through A.1.5 describe the LDCs' gross demand forecasting methodologies and assumptions. The gross demand also includes expected peak demand consumption from various existing and potential transmission connected customers in the West of Thunder Bay Sub-region. Appendix A.1.6 describes how these assumptions were developed.

Table A-1: Reference Gross Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

Reference Scenario Gross Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	0	24	49	49	49	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Dryden 115kV	67	73	79	84	85	86	121	122	122	123	124	125	125	126	127	128	129	129	130	131	132
Kenora 115kV	48	48	48	49	49	49	67	68	68	68	68	68	69	69	69	69	69	70	70	70	70
Fort Frances 115kV	87	58	58	58	59	59	59	59	60	60	60	60	61	61	61	61	61	62	62	62	62
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	14	14
TOTAL West of Thunder Bay	**211**	**191**	**222**	**252**	**254**	**256**	**327**	**328**	**329**	**331**	**332**	**333**	**334**	**336**	**337**	**338**	**340**	**341**	**342**	**344**	**345**

Table A-2: Reference Gross Demand Forecast by Customer Segmentation

Reference Scenario Gross Demand Peak by Customer Segmentation (MW)																					
Customer Type	**2014 (Historic)**	**2015**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
LDC	139	152	154	154	156	158	159	160	161	162	163	165	166	167	168	170	171	172	174	175	177
Industrial Customer	72	39	69	98	98	98	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168

Table A-3: High Gross Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

High Scenario Gross Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	17	41	65	65	119	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Dryden 115kV	67	75	82	88	90	92	160	161	163	164	166	167	169	171	172	174	176	177	179	181	183
Kenora 115kV	48	48	48	49	49	49	67	68	68	68	68	68	69	69	69	69	69	70	70	70	70
Fort Frances 115kV	87	58	58	91	91	91	92	92	92	92	92	93	93	93	93	94	94	94	94	95	95
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	14	14
TOTAL West of Thunder Bay	**211**	**210**	**242**	**305**	**308**	**364**	**521**	**523**	**525**	**527**	**529**	**531**	**533**	**536**	**538**	**540**	**542**	**544**	**547**	**549**	**551**

Table A-4: High Gross Demand Forecast by Customer Segmentation

High Scenario Gross Demand Peak by Customer Segmentation (MW)																					
Customer Type	**2014 (Historic)**	**2015**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
LDC	139	152	154	154	156	158	159	160	161	162	163	165	166	167	168	170	171	172	174	175	177
Industrial Customer	72	58	88	151	152	206	362	363	364	365	366	367	368	368	369	370	371	372	373	374	375

Table A-5: Low Gross Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

Low Scenario Gross Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	0	24	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Dryden 115kV	67	73	73	72	72	73	72	72	72	72	71	71	71	71	71	71	71	71	71	71	71
Kenora 115kV	48	48	48	48	48	48	48	48	48	48	48	47	47	47	47	47	47	47	47	47	47
Fort Frances 115kV	87	58	58	57	58	58	58	58	57	57	57	57	57	57	57	57	57	57	57	57	57
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	14	14
TOTAL West of Thunder Bay	**211**	**191**	**216**	**239**	**239**	**240**	**239**	**239**	**238**	**238**	**238**	**238**	**238**	**238**	**237**	**237**	**237**	**237**	**237**	**237**	**237**

Table A-6: Low Gross Demand Forecast by Customer Segmentation

Low Scenario Gross Demand Peak by Customer Segmentation (MW)																					
Customer Type	**2014 (Historic)**	**2015**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
LDC	139	152	154	154	156	158	159	160	161	162	163	165	166	167	168	170	171	172	174	175	177
Industrial Customer	72	39	62	85	83	82	80	79	77	76	75	73	72	70	69	68	66	65	63	62	60

A.1.1 Atikokan Hydro Inc.: Gross Forecast Methodology and Assumptions

Atikokan Hydro Inc. ("Atikokan Hydro") provides service to the Township of Atikokan.

Atikokan Hydro distributes electricity to approximately 1661 customers, over 320 square kilometers, of which 85% are residential and 15% are commercial.

Electricity is transmitted from Hydro One Network's Moose Lake TS to Atikokan Hydro's substations via Atikokan Hydro's two 44 KV circuits; comprised of the 3M2 and 3M3. Atikokan Hydro has three substations in the most densely populated customer area that distributes the electricity at 8320/4800 volts. Atikokan Hydro has one substation in a sparsely populated area that delivers electricity at 4160 volts. Atikokan Hydro's distribution system then delivers electricity at the appropriate voltage to residential and commercial customers. Atikokan Hydro territory has both rural and urban; totaling 92 km of line that serves the Town of Atikokan.

Factors that Affect Electricity Demand

Atikokan Hydro is a winter peaking utility with a pelletizing plant representing a significant portion of base load demand. The pelletizing plant opening in 2014/2015 increased demand, and is assumed to essentially be the same going forward. There are no new local developments projected to significantly drive electricity requirements. Potential for slight increase as a result of local hospital expansion (addition of approx. 15,000 sq. ft) and development of transitioning the existing swimming pool and arena into a re-vamped multi-purpose recreation and wellness complex, but it is not certain at this time.

There is no forecast load reduction, but if Atikokan's pelletizing plant were to shut down, the forecast could change significantly as a significant portion of the electricity demand is associated with the plant. Of recent, no reduction to electrical demand other than CDM savings and a decline in customer accounts due to abandoned buildings and an aging population. Further, if the Town of Atikokan were to convert its existing streetlights to LEDs, a load reduction may be noticed. No commitments have been made at this time but discussions have occurred.

All demographic and economic conditions have been assumed to remain status quo. Trends in population have been declining. Statistics Canada Census profile indicates Atikokan with a population of 3,293 in 2006 and a population of 2,787 in 2011. This represents a 15% decline in overall population in the community. Any growth potentials break even with a reduction in customers.

Forecast Methodology and Assumptions

Atikokan Hydro's forecast was developed by examining historical actual system peak load data for each year and local applying knowledge of any known economic developments. Historically new development has not driven the local electricity demand.

The peak demand historically has been impacted by the forestry industry in Ontario and the closure of sawmills and a particle board plant, and of recent the re-opening of an existing plant with the recent innovation and investment in the forestry industry.

To account for potential, additional load from the local hospital expansion (addition of approx. 15,000 sq. ft), development of transitioning the existing swimming pool and arena into a re-vamped multi-purpose recreation and wellness complex as well as potential for increased load from the local pelletizing plant, 0.5 MW has been added to 2016 in the forecast. Otherwise, the overall forecast assumption is that the existing peak will remain the status quo and only assumes a marginal growth of 1% for 2017 and thereafter for near term forecast in event the local developments contributes to a rise in peak demand. Medium and Long-term forecast have assumed 0.05% annual growth.

A.1.2 Fort Frances Power Corporation: Gross Forecast Methodology and Assumptions

Fort Frances Power Corporation ("Fort Frances Power") provides service to the Town of Fort Frances, Ontario. The Town of Fort Frances is located approximately 300 km west of Thunder Bay, Ontario, approximately 250 km east of the Manitoba Border and is adjacent to the Town of International Falls, Minnesota, USA. The town is located on the edge of the Canadian Shield and is subjected to extreme weather conditions (cold winters and hot summers). Located on the international border with the United States where Rainy Lake narrows to become Rainy River, it is connected to International Falls, Minnesota, by the Fort Frances-International Falls International Bridge. The town is currently the third largest community of northwestern Ontario, after Thunder Bay and Kenora.

Fort Frances Power distributes electricity to approximately 3737 customers, of which 87.6% are residential and 12.4% are commercial over an area of about 26 square kilometers. Fort Frances Power and is a customer of Hydro One Networks Inc. and serves its customers through transformers Fort Frances MTS. Fort Frances Power’s primary distribution voltage is 12.7 kV.

Fort Frances Power’s distribution system was entirely rebuilt during a system wide voltage conversion project that lasted from the mid 1970’s until the mid-1980’s. The distribution system was converted from a 2.4 kV system to a 7.2/12.47 kV system. Essentially all of Fort Frances Power’s distribution assets were replaced during the rebuild. Over the next five to ten years Fort Frances Power will be gradually intensifying its capital programs to keep pace with the increasing number of transformers and underground cables that are reaching the end of their useful service life. Fort Frances Power is planning on extending its distribution system by approximately 1.5 km in 2016 through the acquisition of a feeder section from Hydro One Networks Inc. as well as from several feeder expansions in order to connect to all customers located within Fort Frances Power's licensed service territory.

Factors that Affect Electricity Demand

Fort Frances has a relatively extreme humid continental climate with bitterly cold winters and temperate summers. Temperatures beyond 34 degrees Celsius have been measured in all five late spring and summer months. Summer highs are comparable to Paris and the Los Angeles Basin coastline in California, whereas winter lows on average resemble southern Siberia and polar subarctic inland Scandinavia. As such Fort Frances is a winter peaking region with more electricity being required for the purpose of heating as opposed to cooling.

Prolonged periods of hot or cold weather have a material impact on local electricity demand, as heating and cooling represents a significant portion of the energy requirements of essentially all of Fort Frances Power's customers. Demand forecasts are based on projecting historic actual measured energy consumption. No consideration has been given to climate change in development of the local forecast.

Over the last decade winter peak loads have decreased by 1 MW, from approximately 18 MW to 17 MW. They are usually set in the month of January, coinciding with seasonal temperature lows. Similarly summer peaks have also decreased by 1 MW, from approximately 13.5 MW to 12.5 MW. Summer peaks are experienced in the months of July or August coinciding with seasonal temperature highs. The community has a base load demand of approximately 8 MW that is primarily driven by residential, small commercial and institutional needs.

The town of Fort Frances is benefiting from the construction of a New Gold gold mine located approximately 75 outside of Fort Frances, in Black Hawk Ontario. The construction has boosted the local economy and is essentially negating the impacts of the 2014 closure of the pulp and paper facility located in Fort Frances. New Gold is projecting to have the mine operational in July of 2016, with a labour force of approximately 600 employees (compared 800 jobs lost in Fort Frances due to mill closure) Electrical demand and consumption is therefore expected to remain at current levels, as dictated by the impacts of hot or cold weather. Customer growth is expected to improve from approximately -0.4% per year to 0%, based on Census population count data mirrors Fort Frances Power's customer count data.

Fort Frances Power is a municipally owned local distribution company that works closely with its municipal planning office. The utility is notified and asked to provide feedback on all active local planning activities. Fort Frances Power relies on Census data as well as its own customer's data with respect to the number of residents in the community, and load growth. According to the population data the community has been decreasing at a rate of 0.4% per year, which is very close to the loss in the utilities customer base. This rate is expected to improve to 0% in the near term as the gold mine begins productions in 2017.

Fort Frances is an ideal location for a large scale solar installation, due to the high Photovoltaic Potential for the area as published by NRCAN. A project of this nature has the potential of significantly impacting the load profile of Fort Frances; however, the impacts have not been included in this forecast.

Forecast Methodology and Assumptions

2016 base demand has been set to equal the historic five year average of actual measured demand peak. The short term growth rate has been increased to 0% to reflect anticipated negating of mill closure by mine opening. Long terms growth has been set to 0.25% in anticipation slight growth from commercial and residential spins offs from the new mine.

Embedded renewable generation reduces the supply point volume of electricity delivered by approximately 0.2%. Fort Frances Power did not include the affects of existing renewable generation on its forecast due to the low overall impact.

A.1.3 Hydro One Distribution: Gross Forecast Methodology and Assumptions

Hydro One Distribution provides service to the rural area and small towns in the sub-region with the exception of those served by Fort Frances Power Corporation, Atikokan Hydro, and Kenora Hydro.

Hydro One Distribution distributes electricity to approximately 24,000 customers in the sub-region, of which 85% are residential and 15% are commercial. Their primary distribution voltages are 25kV and 12.5 kV.

Factors that Affect Electricity Demand

Hydro One's load in the sub-region is winter peaking and weather can affect demand on Hydro One's system by up to 10%. No new loads are expected to be connected and none have recently disconnected.

Forecast Methodology and Assumptions

Historical load growth was used with a provision for CDM.

A.1.4 Kenora Hydro: Gross Forecast Methodology and Assumptions

Kenora Hydro Electric Corporation ("Kenora Hydro") provides service to:

1. The Municipality of Kenora as of December 31, 1999; with the exception of the area encompassed by the eastern boundary of the City of Kenora, west to the western side of Lot 16, north of the northern boundary of the City of Kenora and the Township of Jaffray, south to the Winnipeg River, that is served by Hydro One Networks Inc.

2. The former Town of Keewatin, December 31, 1999, from the easterly boundary of Keewatin, westerly to Keewatin Beach Road, southerly to Lake of the Woods and northerly to Darlington Bay;

3. Plan M456, lots 1 – 5 inclusive in the City of Kenora (formerly the town of Jaffray Mellick as of December 31, 1999); and

4. Island E211 and E212 situated in Lake of the Woods

5. Plan M28 PT BLK D, RP 23R10703, Part 1 PCL 29790 in the City of Kenora

Kenora Hydro distributes electricity to approximately 5,571 customers, of which 85% are residential and 15% are commercial.

Kenora Hydro's service area covers 24 square kilometers. Kenora Hydro is a customer of Hydro One Networks Inc. and serves its customers from 115kV/12.5kV step-down transformers at Kenora MTS. Kenora Hydro's primary distribution voltage is 7.2 kV.

Factors that Affect Electricity Demand

Kenora Hydro is a winter peaking utility. Its electrical base load demand is primarily driven by a hospital, recreational facilities, city operations including the water treatment and sewer treatment plants, and retail space such as Walmart, Loblaws, and Safeway. There is currently no industry driving base load demand served by Kenora Hydro, however by 2019 a saw mill with an approximately 5 MW demand may connect.

Forecast Methodology and Assumptions

The methodology used to develop Kenora Hydro's demand forecast was an analysis of 2013 hourly load data. The forecast developed by Kenora Hydro assumes little local growth and does not include the saw mill expected to connect in 2019.

A.1.5 Sioux Lookout Hydro: Gross Forecast Methodology and Assumptions

Sioux Lookout Hydro Inc. ("Sioux Lookout Hydro") provides service to the Municipality of Sioux Lookout and Hudson Ontario.

Sioux Lookout Hydro distributes electricity to approximately 2,770 customers, of which 84% are residential and 16% are commercial.

Sioux Lookout Hydro's service area covers 536 square kilometers and is an embedded customer of Hydro One Networks Inc. at Sam Lake DS. Sioux Lookout Hydro's primary distribution voltage is 14.4 kV.

Factors that Affect Electricity Demand

Sioux Lookout is a winter peaking utility due to customer heating loads. Since Sioux Lookout does not have access to natural gas - oil and electricity are the main types of heating. Electrical consumption peaks are set during nights of extremely cold weather, usually in January.

In September, 2015 a saw mill served by Sioux Lookout Hydro with a peak capacity of 5 MW and an average load of approximately 3 MW closed down. It is unknown if it will reopen in the near future.

Sioux Lookout has experience very little change in population and employment opportunities and does not expect any significant local developments which could affect electrical demand.

Forecast Methodology and Assumptions

A five year average of measured peak, adjusted for the closure of the local saw mill, was used as the baseline for electrical demand forecast. The forecast also considered the local, community development plan.

A.1.6 Industrial Customer Gross Forecast Methodology and Assumptions

The IESO regularly communicates with existing and potential transmission-connected industrial customers to ensure there is an understanding of their future electricity demand. In the West of Thundery Bay Sub-region, new industrial customers account for the majority of the forecast demand growth. However, the magnitude and timing of the electrical demand growth associated with large industrial customers, especially those in the natural resource sector (e.g., mining, oil, forestry) depend on a number of external factors such as the commodity price of the resource, the economic viability of the industrial project, and the ability to secure capital. In order to account for uncertainty of natural resource-based customers, the IESO developed multiple demand scenarios for potential and existing transmission-connected industrial customers by considering a number of factors, including:

- Customer plans
- Stage of development (e.g., under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g., results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g., commodity prices, customers and demand)

A.2 Estimated Peak Demand Savings from Provincial Energy Conservation Targets

Table A-7 shows the estimated peak demand savings from provincial conservation energy targets in the West of Thunder Bay Sub-region. These estimates were developed using the methodology described in Appendix A.2.1 below, and were considered in the development of planning forecasts.

A-7: Estimated Peak Demand Savings from Provincial Energy Targets in the West of Thunder Bay Sub-region - 2015-2035

Estimated Peak Demand Savings from Provincial Energy Conservation Target (MW)																				
Subsystems	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dryden 115kV	0	0	1	1	1	2	2	2	2	3	3	3	4	4	5	5	5	6	6	6
Kenora 115kV	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	4	4	4	4	4
Fort Frances 115kV	0	0	0	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3
Moose Lake 115kV	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
TOTAL West of Thunder Bay	**1**	**1**	**2**	**2**	**3**	**4**	**5**	**5**	**6**	**7**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**14**	**15**

A.2.1 Methodology to Estimate Peak Demand Savings from Provincial Energy Targets

The estimated peak demand savings assumptions considered in the planning forecast were derived from the CDM Plans submitted to the IESO by the LDCs in the West of Thunder Bay Sub-region as in addition to the provincial conservation forecast, which aligns with the conservation targets described in the 2013 LTEP: "Achieving Balance: Ontario's Long-Term Energy Plan". The LTEP set an electrical energy conservation target of 30 TWh in 2032, with about 10 TWh of the energy savings coming from codes and standards ("C&S"), and the remaining 20 TWh from energy efficiency ("EE") programs.

Projected peak savings from EE programs were developed based on the LDC's CDM Plans which specify persisting summer peak demand reductions from 2015 to 2020. The savings are adjusted to represent winter peak demand reductions based on winter/summer peak savings ratios developed from provincial hourly demand profiles. These savings are extended for the remainder of the forecast by extrapolating the trend specified in the 5 year CDM Plans. The estimated, peak demand savings in the West of Thunder Bay Sub-region from EE programs are represented in shown in table A-5. The CDM Plans are available on the IESO website - http://www.ieso.ca/Pages/Conservation/Conservation-First-Framework/Conservation-and-Demand-Management-Plans.aspx

Savings from C&S and Time-of-use ("TOU") rates were developed based on provincial targets. To assess the peak demand savings from the provincial conservation targets, two provincial demand forecasts are developed. A gross demand forecast is produced that represents the anticipated electricity needs of the province based on growth projections, for each hour of the year. This forecast is based on a model that calculates future gross annual energy consumption by sector and end use. Hourly load shape profiles are applied to develop province-wide, gross hourly demand forecasts. Natural conservation impacts are included in the provincial gross demand forecast, however the effects of the planned conservation are not included. A net hourly demand forecast is also produced, reflecting the electricity demand reduction impacts of C&S, EE programs, and TOU. The gross and net forecasts were then compared in each year to derive the peak demand savings. In other words, the difference between the gross and net peak demand forecasts is equal to the demand impacts of conservation at the provincial level. The above methodology was used to derive the combined peak demand savings from three categories: (1) TOU rates, (2) C&S and (3) EE programs. Peak demand savings associated with load shifting in response to TOU rates were estimated using an econometric model based on customers' elasticity of substitution and the TOU price ratio. The remaining peak savings were allocated between C&S and EE programs based on their energy saving projections, with about 1/3 attributed to C&S and 2/3 to EE programs. For the purposes of the West of Thunder Bay study, the EE portion was subsequently backed out and replaced with the savings identified in the CDM Plans using the methodology specified above. The resulting peak demand savings from TOU and C&S in each year are represented as a percentage of total provincial peak demand shown in Table A-6, using 2014 as a base year.

Table A-8: Estimated EE Peak Demand Savings from West of Thunder Bay Sub-region LDC's CDM Plans (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
EE (MW)	0	0	1	1	1	2	2	2	3	3	4	4	5	5	5	6	6	7	7	8	8	8

These values were subtracted to the LDC gross demand forecasts at the TS level to determine the peak demand, net of EE based on the LDC's CDM Plans.

Table A-9: Estimated C&S and TOU Peak Demand Savings from Provincial Energy Conservation Targets (percent of gross load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%	2.8%	2.9%	3.1%	3.6%	4.1%	4.4%	4.8%	5.1%	5.4%	5.4%	5.4%	5.4%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Total	0%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	3%	4%	4%	4%	5%	5%	5%	6%	6%	6%	6%
ratio (winter / summer)	61%	61%	61%	61%	65%	69%	69%	72%	74%	76%	76%	79%	81%	82%	82%	85%	86%	86%	86%	86%	86.0%	286%

These percentages were applied to the gross demand forecasts at the TS level to determine the winter peak demand savings from C&S and TOU rates assumed in the planning forecast. Actions recommended in the West of Thunder Bay IRRP to monitor actual demand savings, and to assess conservation potential in the Region, will assist in developing region-specific conservation assumptions going forward.

A.3 Expected Peak Demand Contribution of Contracted Distributed Generation

The installed capacity of contracted DG is adjusted to reflect the expected power output at the time of local area peak, based on resource-specific peak capacity contribution values. The expected peak demand contribution of contracted DG in the West of Thunder Bay Sub-region is show in table A-5. The total installed capacity of contracted DG in the West of Thunder Bay Sub-region can be found in Appendix A.3.1. All of the DG in captured below is from solar projects, and have an expected winter peak demand contribution factor of 4%. This factor was applied to the installed capacity to reflect the expected power output from DG at the time of local area peak.

Table A-10: Expected Peak Demand Contribution from Contracted Distributed Generation

Expected Peak Demand Contribution from Contracted Distributed Generation (MW)																					
Subsystems	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Dryden 115kV	0.000	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Kenora 115kV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fort Frances 115kV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Moose Lake 115kV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL West of Thunder Bay	**0.000**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**	**0.006**

A.3.1 Installed Capacity of Contracted Distributed Generation in the West of Thunder Bay Sub-region

Table A-11 shows the installed capacity of contracted DG in the West of Thundery Bay Sub-region, which was active as of March, 2016.

Table A-11: Installed Capacity of Distributed Generation in the West of Thunder Bay Sub-region

Installed Capacity of Distributed Generation in the West of Thunder Bay Sub-region																										
Subsystems	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Dryden 115kV	0.0	0.0	0.1	10.1	10.1	10.1	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Kenora 115kV	0.1	0.4	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Fort Frances 115kV	0.1	0.9	1.2	1.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
Moose Lake 115kV	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TOTAL West of Thunder Bay	**0.2**	**1.4**	**2.5**	**12.7**	**37.7**	**37.8**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**

A.4 Planning Forecast Scenarios

As described in the main report, three Planning forecasts were developed for the West of Thunder Bay IRRP driven by the uncertainties surrounding various, potential industrial developments. Tables A-12, A-13 and A-14 show the Planning Demand Forecasts for the Reference, High and Low scenarios respectively.

Table A-12: Reference Scenario Planning Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

Reference Scenario Planning Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	0	24	49	49	49	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Dryden 115kV	67	72	78	83	84	85	120	120	120	121	121	122	122	122	123	123	124	124	125	125	126
Kenora 115kV	48	48	48	48	48	48	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Fort Frances 115kV	87	57	57	57	57	57	57	57	57	57	58	58	58	58	58	58	58	58	58	58	58
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	12	12	12	12	12	12	12
TOTAL West of Thunder Bay	**211**	**190**	**220**	**250**	**251**	**252**	**322**	**323**	**323**	**324**	**324**	**325**	**325**	**325**	**326**	**326**	**326**	**327**	**327**	**328**	**329**

Table A-13: High Scenario Planning Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

High Scenario Planning Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	17	41	65	65	119	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Dryden 115kV	67	75	81	87	89	90	158	159	160	162	163	164	166	167	168	169	171	172	173	175	177
Kenora 115kV	48	48	48	48	48	48	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Fort Frances 115kV	87	57	57	89	89	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	91
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	12	12	12	12	12	12	12
TOTAL West of Thunder Bay	**211**	**209**	**240**	**303**	**304**	**360**	**516**	**517**	**519**	**520**	**522**	**523**	**524**	**525**	**527**	**528**	**529**	**530**	**532**	**534**	**535**

Table A-14: Low Scenario Planning Demand Forecast 2015-2035 – West of Thunder Bay Sub-region

Low Scenario Planning Demand Forecast (MW)																					
Subsystems	**2014 (Historic)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
230kV Bulk	0	0	24	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Dryden 115kV	67	73	72	72	71	71	71	70	70	69	69	68	68	67	67	67	66	66	65	65	65
Kenora 115kV	48	48	48	47	47	47	47	46	46	46	46	45	45	45	44	44	44	43	43	43	43
Fort Frances 115kV	87	56	56	56	56	56	56	55	55	55	55	55	54	54	54	53	53	53	53	53	53
Moose Lake 115kV	9	13	13	13	13	13	13	13	13	13	13	13	13	13	12	12	12	12	12	12	12
TOTAL West of Thunder Bay	**211**	**190**	**213**	**236**	**236**	**236**	**234**	**233**	**232**	**231**	**230**	**230**	**229**	**227**	**226**	**225**	**224**	**223**	**222**	**222**	**221**

West of Thunder Bay Sub-region IRRP

Appendix B: Needs Assessment

Appendix B: Needs Assessment

B.1 Application of Ontario Resource and Transmission Assessment Criteria (ORTAC)

In accordance with Ontario Resources and Transmission Assessment Criteria ("ORTAC"), the system must be designed to provide continuous supply to a local area, under specific transmission and generation outage scenarios summarized in Table B-1. Voltage and thermal limitations should be respected under these outage conditions.

Table B-1: ORTAC Criteria – Transmission and Generation Outage Scenarios

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE[2]	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N-0	Continuous	None
		N-1	LTE[2]	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600 MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage); N-G refers to local generation not available (for example, out of service due to planned maintenance).

2. LTE: Long-term emergency rating (50-hr rating for circuits, 10-day rating for transformers).

3. Only to account for the capacity of the local generating unit out of service.

ORTAC Load Security and Restoration

With respect to supply interruptions, ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe.

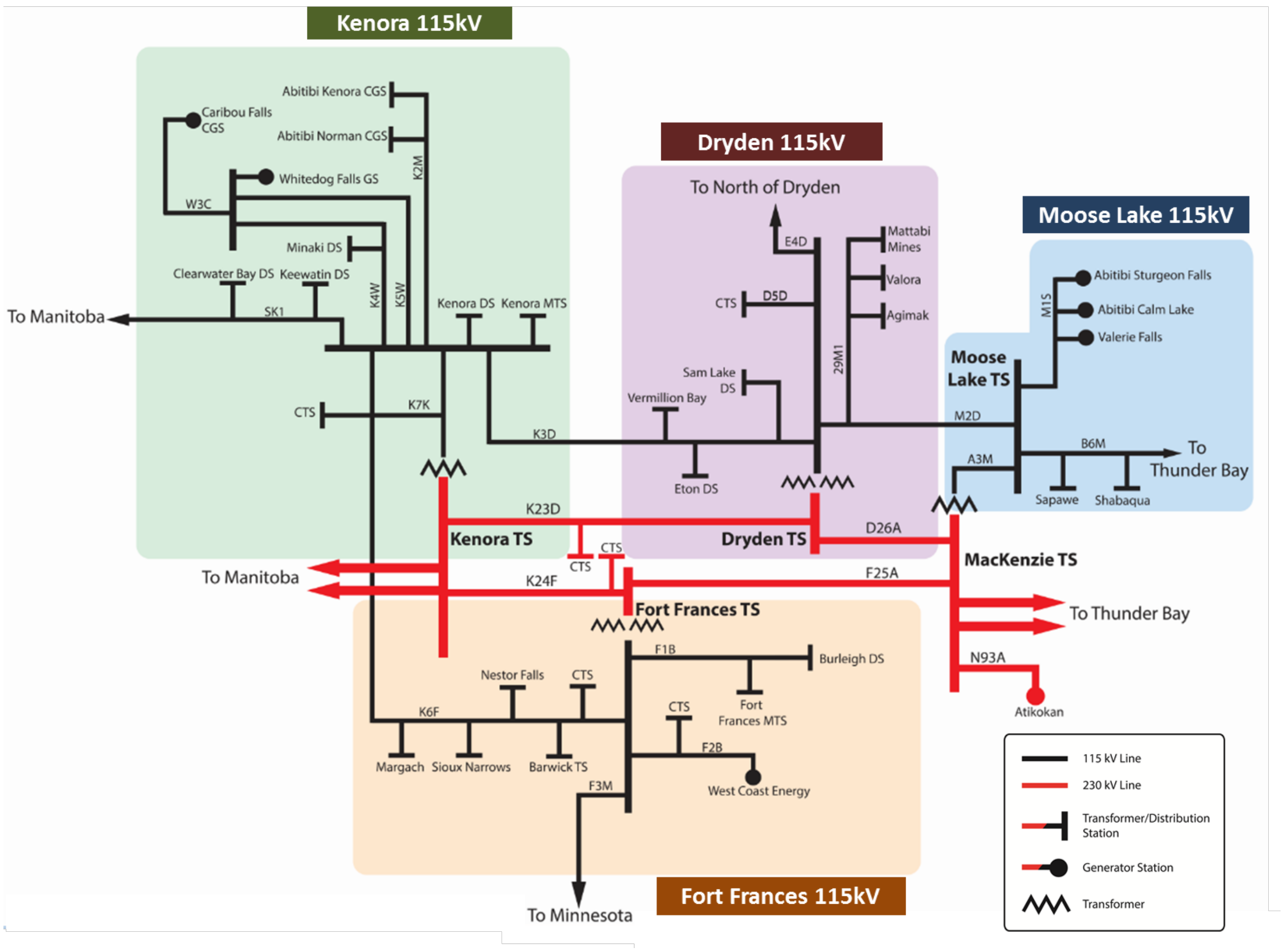
Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage is to be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

B.2 Study Assumptions

Planning criteria was applied to assess supply capacity and reliability needs of the West of Thunder Bay transmission system.

Figure B-1: West of Thunder Bay Transmission System



PSS/E Base case and Bulk System Conditions

The West of Thunder Bay transmission system was assessed using PSS/E Power System Simulation software. The PSS/E base case for the planning study was adapted from the 2015 base case that was produced by the IESO.

Hydraulic Generation Assumptions

The total dependable (98%) capacity of hydraulic generation in the West of Thunder Bay Sub-region was assumed to be 80 MW.

Equipment Rating

For transmission facilities, continuous and limited time ratings based on an ambient temperature of 30°C and a wind speed of 4 km/hour were respected.

Demand Forecast

The West of Thunder Bay transmission system is assessed under the reference, high and low planning forecast scenarios provided in Appendix A.4. .

West of Thunder Bay Sub-region IRRP

Appendix C: K3D and F2B Reliability Performances

Appendix C: K3D and F2B Reliability Performances

Prepared by: Hydro One Networks

The customers at Sam Lake DS and Ft. Frances MTS have a single-supply from the grid and are affected by interruptions to that single-supply. However, as described in this section, the interruptions to these two customers do not exceed Hydro One's Customer Delivery Point Performance standards.

Hydro One monitors the number (frequency) and duration of outages at customer delivery points and measures them against performance standards and benchmarks. This information is used to allocate budget and plan for improving the customer deliver point performance. In addition, Hydro One inspects the poles and insulators of the old circuits and plans for testing and replacement of facilities that are not in good condition.

The following is a summary of the performance measures for Sam Lake DS and Ft. Frances MTS. It is based on the available information at the time of preparation of this report.

Sam Lake DS

Sam Lake DS is supplied by the 115 kV circuit K3D, which has two sections: 1) Dryden TS to Sam Lake DS, and 2) Dryden TS to Rabbit Lake SS. In case of sustained faults and planned outages on the Dryden-Rabbit Lake section, that section is isolated by a switch at Dryden TS and the power to Sam Kale DS is restored.

Table 1 shows the 3-year rolling average of the frequency of the momentary and sustained forced outages of Sam Lake DS from 2007 to 2014. The Frequency Upper Bound for this group of delivery points is 9 and performance of Sam Lake DS has not only meet this standard since 2008, it has been better than the group's Target Frequency, which is 4.1, since 2012.

Table 1: Sam Lake DS 3-Year Rolling average of Forced Outage Frequency

Period	14-12	13-11	12-10	11-09	10-08	09-07	08-06	07-05
Outage Frequency	3.0	2.3	4.0	4.7	8.0	7.7	9.0	9.3

Table 2 shows the 3-year rolling average of the accumulated duration of the sustained forced outages of Sam Lake DS from 2007 to 2014. The Duration Upper Bound for this group of delivery points is 360 minutes and performance of Sam Lake DS has met this standard since 2008. From 2011 to 2014 there has been only one forced outage with a duration of 3 minutes.

Table 2: Sam Lake DS 3-Year Rolling average of Forced Outage Duration

Period	14-12	13-11	12-10	11-09	10-08	09-07	08-06	07-05
Outage Duration (minutes)	1.0	1.0	152.0	151.0	151.0	19.3	167.0	436.3

Beside the above forced outages, there have been one or two planned outages in each of the past few years for repair or maintenance work on circuit K3D or its terminal stations. The planned outages, when not urgent, are scheduled and the customers are informed in advance.

Ft. Frances MTS

Fort Frances MTS is supplied from the termination of 115 kV circuit F1B at Ft. Frances TS. In case of sustained faults and planned outages on circuit F1B, this circuit is isolated by a switch at Ft. Frances TS and the power to Ft. Frances MTS is restored.

Table 3 shows the 3-year rolling average of the frequency of the momentary and sustained forced outages of Ft. France MTS from 2007 to 2014. The Frequency Upper Bound for this group of delivery points is 9 and the Target Frequency is 4.1. The frequency of Ft. Frances MTS outages has been not only below the Upper Bound, it has been below the Target for this group of delivery points.

Table 3: Ft. Frances MTS 3-Year Rolling average of Forced Outage Frequency

Period	14-12	13-11	12-10	11-09	10-08	09-07	08-06	07-05
Frequency	2.3	1.7	2.0	1.3	1.7	1.3	1.0	1.0

Table 4 shows the 3-year rolling average of the accumulated duration of the sustained forced outages of Ft. Frances MTS from 2007 to 2014. The Duration Upper Bound for this group of delivery points is 360 minutes and the Target Duration is 89 minutes. The duration of Ft. Frances MTS forced outages has been well below the Target.

Table 4: Ft. Frances MTS 3-Year Rolling average of Forced Outage Duration

Period	14-12	13-11	12-10	11-09	10-08	09-07	08-06	07-05
Duration (minutes)	5.3	4.7	5.0	7.3	4.3	2.3	0.0	3.3

Beside the above forced outages, there have been one or two planned outages in each of the past few years for repair or maintenance work on circuit F1B or stations facilities at Ft. Frances TS. The planned outages, when not urgent, are scheduled and the customers are informed in advance.

In 2015, during a maintenance outage, the single switch which connects Ft. Frances MTS to Ft. Frances TS had a mechanical failure, resulting in prolonged outage of the customer. The customer and Hydro One may explore the options of having redundancy for the Ft. Frances MTS connection to the grid to avoid similar incidents in the future.

West of Thunder Bay Sub-region IRRP

Appendix D: Distribution Reliability Performances

Appendix D: Distribution Reliability Performances

Prepared by: Hydro One Distribution

The overall reliability of the Hydro One distribution system is measured by SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). SAIDI is the average number of hours in a year that power to a customer is interrupted, represented as a ratio of the total customer hours of interruption to the total number of Hydro One distribution customers. SAIFI is the average number of times that power to a customer is interrupted in a year, represented as a ratio of the total number of interruptions to the total number of Hydro One distribution customers. In 2014, the Hydro One distribution system SAIDI was 9.42 hours and the system SAIFI was 2.96 outages.

The feeders in the West of Thunder Bay area were screened and analyzed taking into account the duration and frequency of unplanned interruptions, as well as the trend of those interruptions in the past seven years. Planned outages were excluded from this screening.

The average feeder length, including all feeder sections, in the Hydro One distribution system is 45 km. Long feeders typically exhibit lower levels of reliability because they are more exposed to tree contact, wildlife contact, and poor weather. Outages in rural areas that have difficult terrain, which limits access by repair crews, can also lead to increased restoration time.

The analysis showed that the majority of feeders in the west of Thunder Bay area perform well relative to other feeders in the province, with the exception of the two feeders below.

Shabaqua DS M2

Shabaqua DS M2 has a total feeder length of 193 km including all sections. The feeder runs along the Trans-Canada Highway and feeds the towns of Raith, Savanne, and Upsala along the highway. The feeder also serves the Lac des Milles Lac First Nation community.

The primary causes of outages on this feeder are tree contact, defective equipment and unknown/others where a specific cause could not be identified. The analysis shows that outages occur throughout the length of the feeder with no evidence that any particular section of the feeder is problematic and experiences significantly worse performance than the rest of the feeder.

The last tree clearing for this feeder was completed in 2011, which is within the geographical tree clearing cycle guideline of 8 years for northern Ontario. The feeder is properly sectionalized at approximately 40 km and 80 km, as well as at the start of the branch towards Lac des Milles Lac First Nation. This sectionalization means that faults downstream of the sectionalizing device will not result in sustained interruptions to upstream customers. Maintenance schedule is in place for Shabaqua DS and the rural feeder is patrolled on a 6 year cycle for visual inspection of poles and other equipment on the feeder.

This feeder is 4.3 times longer than the average feeder on the Hydro One distribution system. As a result of the significant exposure due to the length of the feeder as mentioned above, the performance of the Shabaqua DS M2 feeder is below the hydro one distribution system average.

Margach DS F3

Margach DS F3 has a total feeder length of 184 km including all sections. The feeder runs along the Trans-Canada Highway with multiple branches to serve customers around various lakes including Longbow Lake, Big Stone Bay, Storm Bay, Route Bay, Pine Portage Bay and Thunder Bay. The feeder also serves the Rushing River Provincial Park.

The primary causes of outages on this feeder are tree contact, defective equipment and foreign interference (wildlife contact). The analysis shows that outages occur throughout the length of the feeder with no evidence that any particular section of the feeder is problematic and experiences significantly worse performance than the rest of the feeder.

The last tree clearing for this feeder was completed in 2013, which is within the geographical tree clearing cycle guideline of 8 years for northern Ontario. The feeder is properly sectionalized at approximately 18.5 km and 31.5 km, as well as at the start of branches to the various lakes. Maintenance schedule is in place for Margach DS and the rural feeder is patrolled on a 6 year cycle for visual inspection of poles and other equipment on the feeder. Further, there is a plan in place to address overloaded step-down transformers on the feeder, which can reduce the likelihood of outages caused by the failures of overloaded transformers.

This feeder is 4.1 times longer than the average feeder and has 4.1 times more exposure than an average feeder. As a result, the reliability of this feeder is below the hydro one distribution system average.

West of Thunder Bay Sub-region IRRP

Appendix E: Moose Lake Transformer Station End-of-Life Replacements

Appendix E: Relocation of Moose Lake TS as a Potential End-of-Life Replacement Option

Water management activities associated with the former Steep Rock Iron mines, located immediately north of Atikokan, could lead to potential risk of flooding at the existing Moose Lake TS over the longer term. The latest information from the Ministry of Natural Resources and Forestry indicates that the risk of flooding is not expected to occur until 2070.

The relocation of the115kV/44kV transformers at Moose Lake TS was considered as a potential replacement option. However, given that the risk of flooding will not occur within the expected service life of a new transformer station (typically bout 50-60 years) and due to the high cost to relocate the TS at this time, Hydro One and Atikokan Hydro agreed to replace the TS at the existing site. However, the refurbishment activities should consider community and customer input related to local reliability and longer-term developments and should maintain flexibility for future developments and decisions. As some distribution infrastructure on lower elevation points may be affected by the flooding before 2070, it is important to monitor the situation closely and to see whether there will be potential regional and customer impacts. As appropriate, this may need to be revisited in the next iteration of the plan when more information becomes available.

West of Thunder Bay Sub-region IRRP

Appendix F: Local Advisory Committee Summaries

Appendix F: Local Advisory Committee Summaries

Meeting Summary	
Date:	Thursday, November 19, 2015
Location:	Dryden, ON
Subject:	West of Thunder Bay Local Advisory Committee Meeting #1
Attendees:	**Committee Members** John Bath Rod Bosch Ken Carlson Marlene Davidson Rob Ferguson Nicole Gale Bill Greenway Harold Harkonen Chief Jim Leonard Teika Newton Theresa Stendlund Wilf Thornburn **Committee Members - Regrets** R. Cecil Burns **Working Group - IESO** Stephanie Aldersley Bernice Chan Luisa Da Rocha Julia McNally **Working Group - LDCs** Rich Baggerman, Hydro One Deanne Kulchyski, Sioux Lookout Hydro Joerg Ruppenstein, Fort Frances Power Cecilia Pang, Hydro One Jen Wiens, Atikokan Hydro
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

	Key Topics	Follow-up Actions
1	**Opening Remarks and Roundtable Introductions** • Ms. Da Rocha welcomed everyone and discussed the meeting focus; most members attended via webinar due to the inclement weather • Roundtable introductions were made	
2	**Role of Local Advisory Committee and Review of Manual** • Ms. Da Rocha provided an overview of the role of the LAC: ○ Provide a local voice in electricity planning and advice and recommendations in the development of the plan ○ Identify additional stakeholders with regards to the development of the 20-year electricity plan for the West of Thunder Bay area • The LAC Member Manual was reviewed	☐ Binders to be mailed to LAC members participating via webinar

3	**Presentation of West of Thunder Bay Electricity Planning Process** • Presentation delivered by Bernice Chan, Planner, IESO. A copy of the presentation is available on the LAC Meetings Materials link above. • Introduction to the IESO and key participants in the electricity sector • Overview of the electricity planning process in Ontario • Review of the key electricity supply issues and considerations in the area • Purpose and scope of the LAC **<u>West of Thunder Bay Electricity System</u>** *Summary: The LAC discussed the supply-demand situation in the area with much of the load and future demand associated with mining and industrial development. Conservation programs are available to customers through the Local Distribution Companies. The 115 kV lines are adequate; however there is a need for the replacement of some aging infrastructure and possibly a new transformer station if industrial load materializes. LAC members expressed strong interests in exploring natural gas and imports options to address potential bulk system needs.* Questions and feedback from the LAC members: • Most hydro generation is run-of-the-river so not a lot of storage; it was noted that flood years can reduce power output as well. ○ IESO: The 220 MW of installed hydroelectric generation noted on Slide 13 only includes hydroelectric facilities connected in the West of Thunder Bay area (e.g. White Dog, Caribou and other small hydro facilities). Manitou Falls, Ear Falls and Lac Seul hydroelectric generation facilities are located in the North of Dryden area. • Will the availability versus the installed capacity of hydroelectric generation be considered in the plan? ○ IESO: The plan will indicate the available installed capacity. Since hydroelectric output is highly variable and it depends on various water conditions, the plan assesses the system based on varying water conditions, especially during low water years. • This region also has access to natural gas and gas-fired electricity generation can be a potential supply option for the area, if additional supply is required. • Will firm imports from Manitoba be considered in the plan? Can imports be considered for emergency management purposes? It was noted by the committee that there is already an obligation to supply power on an emergency basis; however this is different than a firm contract; it was noted that the tie with Minnesota is limited in capacity. ○ IESO: The IESO meets with US counterparts on an annual basis to understand their capability. If and when imports are an option, it will be considered. This would need to be contracted. <u>*Note*</u>*: the interconnections with Manitoba and Minnesota handle transfers scheduled on an economic basis. However for the purpose of needs assessment, imports are not*	☐ Provide more information about the operating characteristics of the hydroelectric generation in the West of Thunder Bay (e.g. Run of River Facilities) ☐ Provide the winter peak capacity contribution number for solar generation ☐ Follow up with LAC member regarding the federal discussion of the east-west transmission corridors (new direction letters to Prime Minister Trudeau's Cabinet)

relied upon for supply adequacy, as Ontario does not have firm contracts with Manitoba and Minnesota. The IESO is exploring a range of potential supply options including generation, transmission and firm imports from Manitoba to address bulk system supply needs.

<u>Providing Adequate Bulk Electricity Supply to Support Future Growth</u>

Summary: Potential electricity demand growth in the West of Thunder Bay and North of Dryden areas may exceed the capability on the existing 230kV bulk transmission system from Thunder Bay to Dryden. Based on the current forecast, load could increase up to 300 MW by 2033. IESO is exploring potential supply options including generation, transmission and firm imports from Manitoba. Given the lead-time required to develop electricity infrastructure, LAC members expressed concerns about timing and ensuring resources are ready for new development. Hydro One is carrying out early development work on the transmission option to shorten lead-time and maintain viability of the option. Although it is not within the scope of the West of Thunder Bay IRRP, the IRRP will take into consideration bulk system issues and its regional implications.

Questions and feedback from the LAC members:

- Is the 180 MW Rock-Ex Mine included in the forecast; it has an in-service date of 2020? Electricity service needs have to be ready for the mine. There are several mining developments in the North of Dryden area.
  - IESO: Rock-Ex is situated in the North of Dryden region, and therefore it is not included in the West of Thunder Bay forecast. IESO is aware of the Rock-Ex mining development and is monitoring the status and development of this project. Related to this, it was confirmed that one proponent for the 230KV line to Pickle Lake has proposed an in-service date as early as 2019. *<u>Note:</u> The proponent has since revised this in service date to 2020. The other proponent for the line also has an in service date of 2020.*
- Can the existing system accommodate the "high scenario" in 2020? Lead times are a concern.
  - IESO: The status of potential mining and industrial developments in this region are being monitored and LAC members are encouraged to keep the Working Group informed of status and timing of local developments and priorities. If developments materialize faster than expected, interim solutions may be put in place to support the growth.
- What is the cheaper option - generation or transmission?
  - IESO: The cost-benefit/trade-offs of each option is examined accordingly.
- Is Hwy 622 the route for the NW Bulk line?
  - IESO: The routing of the line has not been determined at this time and will be determined as part of the project development.
- Why isn't the North of Dryden information included? Given the location of the supply lines, any developments in the North of Dryden area will impact the supply available at Dryden and developments in the West of Thunder Bay area.
  - IESO: The regional electricity planning activities in the North of Dryden area are not in scope for the West of Thunder Bay IRRP however they are

considered as part of the West of Thunder Bay analysis.

- Are there any committees looking at gas supply reliability and supply? Will the pipeline conversion impact reliability and supply? Cost of generation (gas-fired) versus transmission will be impacted by whether there is enough gas in the area to meet demand. It was noted that the inability to store gas in the northwest will affect the dependable of this generation resource; the price of gas is also a consideration.
    - IESO: This may be a topic/area of focus for future meetings.

Minimizing Power Outages to Customers

Summary: At community meetings in the summer, concerns were raised frequently about power outages and the negative impact on economic development. Based on historical reliability performance statistics, the West of Thunder Bay transmission system is within the provincial planning standards. Distribution reliability performance will also be examined. IESO acknowledged this is a priority issue for the LAC, and suggested to discuss in more detail the impact of power outages, reliability performances, potential mitigation measures, and cost-benefits and cost-responsibilities at a future meeting.

Questions and feedback from the LAC members:

- In addition to power outages, severe power quality issues affecting large industrial customers should be part of the power outage dialogue
- The decrease in synchronise generation from thermal and hydraulic has increased power quality issues in the region and this should be discussed
- Replacing internal generation with transmission lines (i.e. the East-West Tie Line is designed to replace generation internal to northwest Ontario) is creating a problem for industry; previous improvements in industrial efficiency have now made them far more susceptible to voltage changes
    - IESO: LAC members were invited to provide more information on the impact of power outages/quality to their communities and businesses. This information will help the IESO better understand these issues. It is important to discuss the impacts of these outages to the community, potential mitigations measures, and cost allocations of investments.

Opportunities for Community-Based Energy Solutions

Summary: During the summer engagement, a number of communities expressed interest in community energy solutions, including developing community energy plans. There are a number of programs available to assist communities, including the Municipal Energy Plan funding, saveONenergy efficiency programs, and microFIT. It was noted that small renewable generation, under 500kW, can be sited in the northwest. However, current limitations on the transmission system have prevented northwest Ontario from participating in large-scale renewable generation procurement program.

Questions and feedback from the LAC members:

- Are the current procurement programs a guaranteed or market price? Is there a cap on the number of Feed-In Tariff projects (up to 500kV) that can be accommodated in the area? Will these 500KW projects fit on the existing system as even these can stretch the distribution system?
  - IESO: The Feed-in Tariff (FIT) program is capped at 500kW projects and is a standard offer program with set prices. Larger projects are now part of the Large Renewable Procurement (LRP) which is a competitive procurement. Both FIT and LRP projects need to pass transmission and distribution availability tests to ensure they can be connected.
  - IESO: The IESO has energy efficiency programs targeted at commercial and industrial customers that can get a capital incentive for behind the meter generation
- The lack of capacity in northwest Ontario is a problem as this prevents northwest Ontario from being able to participate in LRP and creates a dilemma for direct connect industrial customers. It's a catch-22 - the need to increase transmission to handle additional generation, but additional generation can't be connected until there is increased transmission capacity.
- Are there incentives for off-grid generation?
  - IESO: Not at the moment. LAC members were asked to identify whether this was something customers would be interested in.
- It was suggested that the IESO contact First Nations and the Metis Nation of Ontario with respect to promoting community energy planning and their processes around this
- Before promoting community based planning, the northwest needs to be moved out of the orange zone
  - IESO: IESO acknowledged the concerns and confirmed that today, only generation projects less than 500 kW can be developed in the northwest through province-wide procurement programs, such as Feed-In Tariff due to limitations on the transmission system. Demand growth may allow some large-scale generation development in the northwest, particularly to address local need. Growth will continue to be monitored.
- If there is capacity from the east, does that take precedence over adding regional generation to the grid? The northwest was completely self-sufficient at one point
  - IESO: Both local and resources from the rest of Ontario as potential supply options will be examined as well as the cost-benefit/trade-offs of each of the options accordingly.
- The biggest supply option is 2,000 MW coming on in Manitoba, and there is an opportunity to set up a contract to mitigate risk with the timing of developments coming online
  - IESO: A contract would be needed for this and cost would need to be taken in to consideration.

<u>Discussion of Community Energy Initiatives</u>

Summary: During summer 2015 engagements, a number of communities expressed

	an interest in community energy solutions, including developing community energy plans. LAC members provided a status update on energy planning activities in the various communities across the West of Thunder Bay area. • City of Dryden - Completed its five-year Economic Development plan; next step is a community wide strategic plan in 2016. No firm plans for a Municipal Energy Plan (MEP). • City of Kenora - Discussions taking place with the City and Kenora Hydro about doing a MEP and this will be investigated in the new year. • Town of Sioux Lookout - Wants to look into an MEP. Province is looking at supplying gas to more communities and this may change their approach to energy planning. • Township of Atikokan – Does the IESO have an incentive program for street lighting? o Yes, it is delivered by the LDC • Town of Fort Frances – New mining project underway, but not in the Fort Frances Power Corporation service territory	
4	**<u>Discussion of Other Community Priorities; Potential Topics for Future LAC Meetings</u>** • Explore the societal impacts and economic benefits of options presented in the plan; there should be a focus on keeping jobs, industry, and electricity generation locally; need a cost/benefit analysis of all options especially in relation to impact on electricity pricing; if power is imported, there is little economic stimulus to the area o IESO: Committee members were asked to provide input on these economic benefits of the options for the area • Discuss how the provincial cap and trade, carbon pricing will impact the plan • Need to have supply within the region and there is a desire for existing generation to be used to greatest extent possible; ensure the north has the necessary bulk transmission infrastructure to support growth and that the costs are socialized across Ontario; have moved to a customer-pay model that wasn't used for southern Ontario; northwest Ontario doesn't have supply the rest of province has and it feels like it is being penalized o IESO: Some of these topics are outside the scope of the regional plan and mandate of the IESO; this is a valuable dialogue including clarifying the Ontario Energy Board's cost responsibility framework *Topics identified earlier in the meeting:* • Given the interactions between the various sub-regions in northwestern Ontario, LAC members indicated that it would be helpful to have a status	☐ Provide information on transmission lines in the area, more specifically a table of key circuits in the area and their key characteristics

	update on other regional planning activities in the northwest (Thunder Bay, Greenstone-Marathon and North of Dryden) • Cost responsibility of electricity infrastructure investments in Ontario and social implications of electricity infrastructure investments • Cost-benefit analysis of potential options to address electricity needs • Availability of natural gas in the northwest and its implications on electricity supply • Considerations associated with imports from Manitoba and Minnesota • Community-based solutions and community energy planning; sharing results of other community energy plans to determine best practices; LAC members should identify any Municipal Energy Plans currently under development • Impact of power outages to customers, reliability performance, and power quality • Customer support programs provided by the Ontario Energy Board, IESO and the government	
5	**<u>Next Steps & Closing Remarks</u>** • The West of Thunder Bay IRRP was initiated in Jan 2015. In accordance to the OEB regional planning process, the Working Group has 18-month to complete this planning process. The final IRRP report will be posted at end of Q2 2016. • The goal is to have two more LAC meetings prior to this time. • Next meeting will be in March/April 2016 and the meeting time will be changed to 11am. LAC members agreed that Dryden is a good location for LAC meetings.	☐ Draft agenda for meeting #2 to be shared with Committee for feedback ☐ Send request to LAC members for release of their contact information

Meeting Summary	
Date:	Wednesday, April 20, 2016
Location:	Dryden, ON
Subject:	West of Thunder Bay Local Advisory Committee Meeting #2
Attendees:	**<u>Committee Members</u>** Rod Bosch R. Cecil Burns Marlene Davidson Nicole Gale Bill Greenway Harold Harkonen Chief Jim Leonard Teika Newton Wilf Thornburn (via webinar) **<u>Committee Members - Regrets</u>** John Bath Ken Carlson Rob Ferguson Theresa Stendlund Lisa Kooshet **<u>Working Group - IESO</u>** Stephanie Aldersley Bernice Chan Luisa Da Rocha Alex Merrick **<u>Working Group - LDCs</u>** Rich Baggerman, Hydro One (via webinar) Deanne Kulchyski, Sioux Lookout Hydro Cecilia Pang, Hydro One (via webinar) Dave Sinclair, Kenora Hydro
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Ms. Da Rocha welcomed everyone and reviewed the meeting agenda • Roundtable introductions were made	
Recap of November 2015 LAC Meeting • The summary from the November LAC meeting was reviewed. • In follow-up to the November meeting, the IESO provided an update on hydroelectric generation in the West of Thunder Bay Sub-region: there are seven hydro generating stations representing a total installed capacity of 220 MW; the facilities are run-of –the –river with no storage capabilities; and the North American Electric Reliability Council (NERC) requires the IESO to	☐ LAC Meeting Summary #1 deemed final and IESO to post summary to the West of Thunder Bay webpage

assume 98% dependable water conditions for planning purposes taken from data during the winter (peak) season. The IESO continues to work with the Ontario Waterpower Association to obtain more data.

  - In response to a committee member question, it was noted that Ear Falls and Manitou Falls are being studied as part of the North of Dryden regional plan. In the West of Thunder Bay plan, the IESO considers flows on the E4D line as a result of operation of these facilities and demand north of Dryden rather than the reliability of the generators, which is considered in the North of Dryden plan.

- In follow-up to the November meeting, the IESO provided an update on the winter peak capacity contribution for solar generation. It was noted that the area is a winter-peaking region therefore the IESO assesses solar to provide peaking capacity during time when West of Thunder Bay demand peaks, which is usually overnight and in the winter. The analysis is undertaken using the top 5% of peak hours in the region (generally from 7 – 9pm) combined with data from solar sensors in the region. In West of Thunder Bay, the potential peak contribution from solar is about 4% of the 35MW of solar currently installed in the area.
  - In response to a question from committee member, it was noted that the IESO looks at the summer peak as well as the winter peak, but needs in the area are driven by the winter peak since it is significantly higher and the highest peak demand drives electricity planning.
  - In response to a comment from a committee member that the area cannot generate renewable energy, it was clarified that there are already 35MW of solar installed in the West of Thunder Bay region. The "orange" zone limitation relates to new procurement of large-scale renewable generation through the provincial procurement process. These projects currently can't connect in northwest due to transmission connection limitations.
- In follow-up to the discussion at the previous meeting regarding the east-west transmission corridor through the area, a committee member provided the update that Minnesota's plan to use Lake of the Woods reservoir for storage capacity for wind generation in Minnesota.
- A committee member inquired about a note in the meeting summary that the Rock-Ex mine connection is considered part of the North of Dryden regional plan. The member noted that the mine can only be supplied from the new 230kV line to Pickle Lake which will have a direct impact on the West of Thunder Bay area, therefore it should be considered as part of the West of Thunder Bay plan. The mine will be releasing their feasibility study in the coming months.
- A committee member suggested that municipalities in the North of Dryden area be advised as to the status of the implementation of the North of Dryden plan. It was also suggested that there be a stronger link between the North of Dryden and West of Thunder Bay plans.
    - The IESO noted that planning is a continuous process and

planners in different regions work together to monitor development and adjust as appropriate. o The IESO provided an update on connecting the First Nations communities noting that all of the lines North of Dryden are customer lines and upgrades to these lines are based on a customer commitment to pay for the upgrades. Hydro One Distribution should be notified if upgrades are needed. o For supply to the Red Lake area, the IESO noted that the current bottleneck is the line between Dryden and Ear Falls. Once the line to Pickle Lake is in-service, line E1C will be offloaded from Ear Falls and this will open an additional 30MW of capacity at Ear Falls. Demand for the remote communities is 6MW by 2033 so this capacity will accommodate demand for 20 years. Once this capacity is available (E1C is normally open at Ear Falls), other customers may use this capacity first and the remote communities may require upgrades to connect the communities, which would be paid for by the parties who benefit from connection of communities - the provincial and federal governments, and Ontario ratepayers. • A committee member expressed frustration over the pace of development of the new line to Pickle Lake. o The IESO noted that currently there is a process in place to select between the two proponents that want to build the line. The government has been Consulting with First Nations in the area on the use of Bill 112 and Bill 135 to support remote community connections and the new line to Pickle Lake including the selection of a proponent.	
Update on Northwest Planning Activities • Bulk system planning • Regional planning – review of planning process and status of plans • Local energy planning activities • A copy of the presentation is available on the LAC Meetings link above. **Bulk System Planning** *Presentation Summary: An overview was provided on the two bulk transmission projects in the area – the East-West Tie expansion and the Northwest Bulk transmission line, both identified as priority projects in the Long-Term Energy Plan. The East-West Tie expansion project is a new double-circuit 230kV line approximately 400km in length from Wawa to Thunder Bay. The purpose of the line is to increase the power transfer capability with northeastern Ontario in order to supply demand growth forecast for the northwest in the coming decade. The second bulk project, the Northwest Bulk line, is a new 230 kV line between Thunder Bay and Atikokan and a single circuit 230 kV line from Atikokan to Dryden. The purpose of the line is to provide*	

adequate bulk electricity system capability to supply potential growth in the West of Thunder Bay and North of Dryden areas, including future mining. Hydro One is currently undertaking the development work on this project; however this line is not committed at this time and other options are still being considered. Questions and feedback from the LAC members: • If all of the thermal generation (500MW) in the northwest is removed, about 300MW of supply remains in the area to serve a much bigger load, therefore the northwest will always be importing through the East-West Tie, especially in low water years. The Thunder Bay and Atikokan Generation facilities are limited by their fuel supply. o IESO: Based on the current contract terms, the Atikokan Generation Station can only operate for a limited amount of hours at the maximum capacity given the fuel limitations. As such, the study takes into consideration situations where Atikokan may not be available due to fuel limitation. • The Northwest Bulk line doesn't address mining in the North of Dryden area. Is the Northwest Bulk Line going forward? Will the Northwest Bulk line help bring power from Manitoba? o IESO: The purpose of the Northwest Bulk Transmission Line is to provide adequate bulk electricity system capability to supply potential growth in the West of Thunder Bay and North of Dryden areas; system reinforcement projects that address the need to supply and connect mining development and growth in North of Dryden are discussed in the North of Dryden Integrated Regional Resource Plan (IRRP). The Northwest Bulk Line is currently in the development phase and has not been committed at this time. A number of alternative options are still being explored including generation and imports. There is some uncertainty as to the timing of growth in the area, so development work has been initiated in order to ensure that transmission remains a viable option. Even though there are interconnections with Manitoba, there are currently no firm contracts in place to ensure that imports are available during peak demand. • All of Manitoba's power has been committed elsewhere, therefore the West of Thunder Bay plan should not assume supply from Manitoba to defer investment in northwest Ontario. o IESO: The IESO meets with Manitoba Hydro on an annual basis and the availability of imports is discussed from a technical standpoint. The determination of provincial imports is done at the policy level and is based on broader provincial needs which go beyond the scope of regional planning. The government is currently starting the broader policy discussion with the next Long-Term Energy Plan (LTEP). • Frustration was expressed as to why the bulk system is not being put in place now to meet growth as economic development is a priority. How can mines proceed if the electricity infrastructure takes seven years to develop?	☐ Request that Hydro One provide an

<table>
<tr>
<td>

<li style="list-style:none">

IESO: The IESO monitors growth and acts accordingly. Hydro One is currently undertaking the development work on the Northwest Bulk line so that it can be in-service in the early 2020s. Mining development is tracked and decisions are made accordingly.

The LTEP indicated the two bulk lines are priority projects so why are both not going ahead?

IESO: The 2013 LTEP included a number of priority projects for the northwest. The East-West Tie has received an order to proceed. The Northwest Bulk line is at an early stage of development and is still being considered in relation to other options.

Where is the decision made comparing imports versus transmission lines?

IESO: The IESO looks at the need for a particular project and assesses the best way to address the need.

<u>Regional Planning – Review of Status of Other Regional Plans in NW Ontario</u>
Presentation Summary – Remote Community Connection Plan: An update was provided on the 2014 draft Remote Community Connection Plan which concluded that it was economic to connect 21 of the 25 remote communities. IESO is seeking to engage with the communities and is working with proponents. IESO is also supporting discussions with provincial and federal governments.
Questions and feedback from the LAC members:

How is the Ontario Energy Board (OEB) process different for the Remote Community Connection plan than regional plans? Will it be faster?

IESO: The remote community connection plan is a unique planning process and does not meet the classification of a regional plan, however it will still follow other OEB regulated processes such as Leave to Construct. It is anticipated that the new legislation will result in a faster Leave to Construct process because the need can be directed.

Has the proponent been selected for the line to Pickle Lake? Will the line to communities be 230kV or 115kV?

IESO: The government has issued a Bill, which when passed would allow a transmitter to be selected. Letters were recently issued to communities indicating that the government will only support proponents that connect remote communities. They will not support an incomplete project that is just a line to Pickle Lake. Once the Bill is passed, there will be an ability to select a transmitter. The proposals for the line to Pickle Lake indicate that it will be built to 230 kV standards. The lines to communities will be 115kV as community demands aren’t high enough to merit larger lines.

Has distributed generation been considered in the plan?

IESO: The plan included assessment of renewable generation integrated with the existing microgrids in communities. This assessment found that from a cost and diesel avoidance perspectives, it wasn’t as good of an option as transmission connection.

</td>
<td>update on the development work for the NW Bulk</td>
</tr>
</table>

- Transmission circuits, whether distribution or transmission lines, allow for other opportunities that local distributed generation does not, such as connecting hydro generation which will contribute to the stability of supply.
    - IESO: Proponents are also looking at building lines to a standard that will accommodate community initiatives.
- With respect to supply to communities from the Nipigon area vs. from the Pickle Lake area, how does choice of routing for communities relate to connection to the mines?
    - IESO: Both alternatives are cost comparable with all of the mines contributing – both are still viable alternatives. Any development will be discussed with the First Nations. If the Ring of Fire is serviced from the Line to Pickle Lake, the mines would be required to contribute to the cost of the line or if the mines connect in the Nipigon area, the mines would contribute to the cost of any upgrades required in the Nipigon area.

Presentation Summary: Updates were provided on the three other regional plans in Northwest Ontario. The North of Dryden plan is complete and was posted on the IESO website in January 2015. Drivers for North of Dryden include upgrades to lines for the Remote Communities and Ring of Fire. The Greenstone-Marathon plan is on-going and the drivers include mines, the gas to oil pipeline conversion, recovery of the forestry sector and community growth. An interim plan was posted in June 2015 and the final plan will be posted this summer. The Thunder Bay plan is also currently under development and the key drivers are community growth, mining growth, the pipeline conversion and the impact of growth in the Greenstone area on the Thunder Bay electricity system.

Questions and feedback from the LAC members:

- How will the lines identified in the North of Dryden plan be upgraded?
    - IESO: Hydro One initiated upgrading two lines due to a customer request; however this is currently on pause.

<u>Local Community Energy Planning</u>

Committee members were asked to provide an update on local community energy initiatives.

- A LAC member expressed frustration that there can be no potential for growth as there is no capability to accept growth since none of the plans have reached commitment or implementation.
- Red Lake: There are two mines moving forward - one is drilling and another is doing an economic assessment. However, if they proceed, they don’t have the ability to move forward. Red Lake lost a mill looking to connect 10MW because of the connection cost and the result was the loss of $90 million in foreign direct investment. The municipality is replacing their 600 street lights which has resulted in a considerable load reduction. They have also

completed a sustainability plan that identified a number of green initiatives including water, recycling, reduction of waste etc. ◦ IESO: The IESO can produce the plans, but project implementation is not under the IESO's control. • The region has great potential and investors are looking for electricity to be cheaper. This is a quality of life issue for northern communities. Mines are pulling out. • Dryden: The municipality is currently updating its community plan. It is looking at a Community Energy Plan, but has not yet applied for funding. • First Nations: A number of communities are looking at their electricity usage and conservation, as well as undertaking energy audits to reduce usage. • Kenora: The municipality has replaced all of its streetlights with LEDs. Work on the Community Energy Plan once some key vacancies are filled. Currently working with QUEST (Quality Urban Energy Systems of Tomorrow) and has found this to be a valuable resource for learning about community energy planning. ◦ IESO: The IESO is currently funding QUEST to deliver community energy sessions across Ontario and have discussed the possibility of a webinar specifically for Northern Ontario. • One of the Committee members recently attended a Bio-Energy Conference and found that there is lots of potential for communities and dealing with municipal loads. Marathon is trying to establish a bio-heat system using biomass and plans to build a pellet plant. • Sioux Lookout: The municipality is working on a Community Energy Plan and they are currently in the information gathering stage.	☐ Share information on QUEST resources ☐ Share information from Bio-Energy Conference
<u>West of Thunder Bay IRRP</u> • Review of regional planning • Clarify West of Thunder Bay study scope • Review key findings/draft outcomes of the West of Thunder Bay plan • A copy of the presentation is available on the LAC Meetings link above. *Presentation Summary: A review was provided on the types of electricity planning and the scope of the regional planning process. A review was also provided on the West of Thunder Bay information presented at the inaugural LAC meeting including the electricity system in the area, local generation resources, electricity demand growth and the resulting needs to be considered as part of the West of Thunder Bay regional planning process. A distinction was made between the needs that are to be addressed through the regional planning process and those to be addressed through other planning processes. All processes will be documented and are summarized on presentation slide 26. Options were presented on how to provide additional supply capacity on the Dryden 115kV sub-system under the high growth scenario, and it was noted that no decision is required at this time. The three draft recommendations to be*	

included in the West of Thunder Bay IRRP were presented to the LAC members for feedback as well as potential areas for coordination on community energy planning. Questions and feedback from the LAC members: • A funding and cost allocation update was provided by a LAC member who noted that NOMA has been very active on this and there have already been some changes. It was noted that northwest Ontario wants to be on the same footing as the rest of the province and is asking for projects that are currently deemed to be proponent funded to be rate-payer funded. Another member noted that an upgrade in Southern Ontario may be for a 4km line, whereas it may be hundreds of kilometres in Northern Ontario and both proponents are being asked to fund the project. o IESO: The Ontario Energy Board recognises this as an issue. LAC members are encouraged to get involved in the cost allocation process. • The load forecast shows that by 2020 the load may reach 520MW. How will this be accommodated? This number is lower than that of the Energy Task Force. Which of the multiple scenarios is built to? o IESO: This is accommodated by starting development work on projects such as the Northwest bulk line. The IESO monitors load and engages with communities so that commitments are at the right time. Evidence of load is needed before committing to projects; otherwise the investments are being made too early. • Reliability of the 115kV radial line is an issue. In 2011, there was a 36-hour outage in Red Lake that cost a local mine $6 million. o IESO: Service reliability concerns have been noted in the West of Thunder Bay area. Many of the communities in this area are supplied by long distribution and transmission networks. In response to these concerns, the Working Group assessed the reliability performance of the distribution and transmission system in the West of Thunder Bay Sub-region. The results are documented in the IRRP report. • Will the transformer station for the line to Pickle Lake be in Sioux Lookout or Ignace? If the line goes past Sioux Lookout, it was suggested that Sioux Lookout Hydro lobby for a station to connect the existing system. o The location of a transformer station has not yet been determined. With respect to connecting the existing Sioux Lookout system to the new station, there would be significant costs to the local ratepayers since the existing infrastructure is 115kV and the new line is a 230kV. • Results from the assessment show that the majority of distribution lines in this area perform well relative to other distribution lines in the province. However, the Working Group has identified two distribution lines supplying electricity from Shabaqua and Margach areas that are performing below the provincial distribution system. A member noted that Hydro One has started a pole replacement project on Shabaqua and Margach areas.	☐ Send link to OEB cost allocation regulatory filling to the LAC members

- On E2R and E4D, Manitou Falls is being used as a condensing station. Is this approach used in other regions?
  - IESO: This is evaluated on a case-by-case basis.
- On slide 27, is option #3 gas –fired generation?
  - IESO: Gas is often challenging in the north because of the lack of storage facilities. Cost will be a consideration when looking at the options.
- On slide 27, how would option #1 be implemented without significant infrastructure and does this option include voluntary load shedding?
  - IESO: This recommendation is being included because there may be potential interest. Option 1 is not voluntary load shedding.
- For the three scenarios, can cost allocation be added? What differentiates if it is regional or bulk level?
  - IESO: Cost allocation is an important consideration when evaluating the various options. Since no decisions are being made at this time, the detailed discussion related to cost allocation will be considered in the next iteration of the plan.
- Currently the paper mill generates their own needs; how is this taken into consideration in planning?
  - IESO: Their load is included in the load forecast.
- On slide 28, power quality (i.e. voltage sag) has the same impact as outages, and this should be included in the second last bullet.
  - IESO: It will be included.
- Who paid for the Red Lake Transformer Station upgrade six years ago?

☐ Determine who paid for the Red Lake TS upgrade

LAC Member Feedback on the Discussion Questions (slide 30):

- Awareness of the planning process is not getting out. For example, the Domtar Mill is unaware of this planning process.

☐ Nicole to provide Domtar contact after the meeting

- The recommendations are to continue to monitor, however projects are coming on stream in the next 3-4 years. What is the purpose of a LAC if decisions are not being made?
  - IESO: Given the nature and uncertainty of the load, commitments cannot be made too early for the bulk line – there needs to be a certain level of certainty of demand growth before the project can go ahead. Sharing information is an important part of the process.
- Credibility isn't given to a project until they get a System Impact Assessment (SIA), however by then it is too late.
  - IESO: The IESO tracks mining development including reviewing loads, published materials, how far along the mine is in the development process etc. Even an SIA is not a good indicator that a project will proceed as there have been examples of projects that have reached the SIA stage that don't get developed. Scenarios are developed by making assumptions about which mines will go ahead and when, but there is a high level of uncertainty. Development work is proceeding on projects to ensure they are ready when needed.
  - A LAC member noted that they are encouraged by IESO's interest in

community energy planning. Due to the unique energy planning challenges in the northwest, the LAC member suggested that it would be helpful to have a call, webinar, or workshop to help facilitate knowledge sharing and coordinate community energy planning activities with municipalities in the northwest who are interested in community energy planning. LAC Member Feedback on Future Discussion Topics (slide 32): • Change 'cost responsibility' to 'impact of cost responsibility' ○ IESO: It would be helpful for the committee to provide an update at the next meeting on their work with the OEB on cost responsibility • Socio-economic impacts are important to explore and is the basis of the Energy Task Force discussions with the OEB. Will this be in the report? ○ IESO: This can be documented in the plan, but is outside the scope of regional planning. The committee is welcomed to provide insights into the differences between the system in northern and southern Ontario. Dialogue should be continued, but it was noted that the ability to influence this is limited in regional planning. • If many of the topics are outside the scope of regional planning, what is the role of the LAC on these issues? ○ IESO: The purpose of the LAC is to provide advice on regional planning, for example, is the load forecast correct, what is the LAC's feedback on the plan recommendations etc. These conversations ensure the plan analysis has been thorough and that the local perspective and voice has been added. In the West of Thunder Bay plan, there are no major infrastructure projects being proposed but the local perspective in the discussions has been valuable and will be included in plan. While the report is focused on regional planning, and there may be limited ability to affect change in some of the other priority topics, the conversations are still important.	☐ LAC members to provide an update on their cost allocation work with the OEB
Public Questions • A member of the public made a presentation to the Committee on their power plan for the northwest including importing power from Manitoba ○ IESO: Everyone is encouraged to participate in the Long-Term Energy Plan dialogue to discuss province-wide issues such as imports	
Next Steps & Closing Remarks The following next steps were determined based on a discussion with the LAC. • LAC members will be provided with a comment period to provide comments on the draft recommendations • To help scope future LAC meetings, a survey will be sent to committee	☐ Provide comment period for additional feedback

members to prioritize the topics on slide 32 for future discussion. It was noted that many of the topics on this slide are outside the scope of the regional planning process, and some even outside the scope of the IESO. It was suggested that future renewable generation be added to the list. • The West of Thunder Bay plan will be posted at the end of July and the next LAC meeting will be in the fall	☐ Survey LAC members on priorities for future meetings ☐ Next meeting to be in fall 2016