Integrated Regional Resource Plan Appendices

Northwest Region
Jan 2023

Connecting Today.
Powering Tomorrow.

Table of Contents

Appendix A – Overview of the Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined.[1] The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required the OPA to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

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

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs that should be considered for regional coordination. If further consideration of the needs is required, the IESO conducts a Scoping Assessment to determine what type of planning should be carried out for a region. A Scoping Assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

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

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

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies ("LDCs"), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

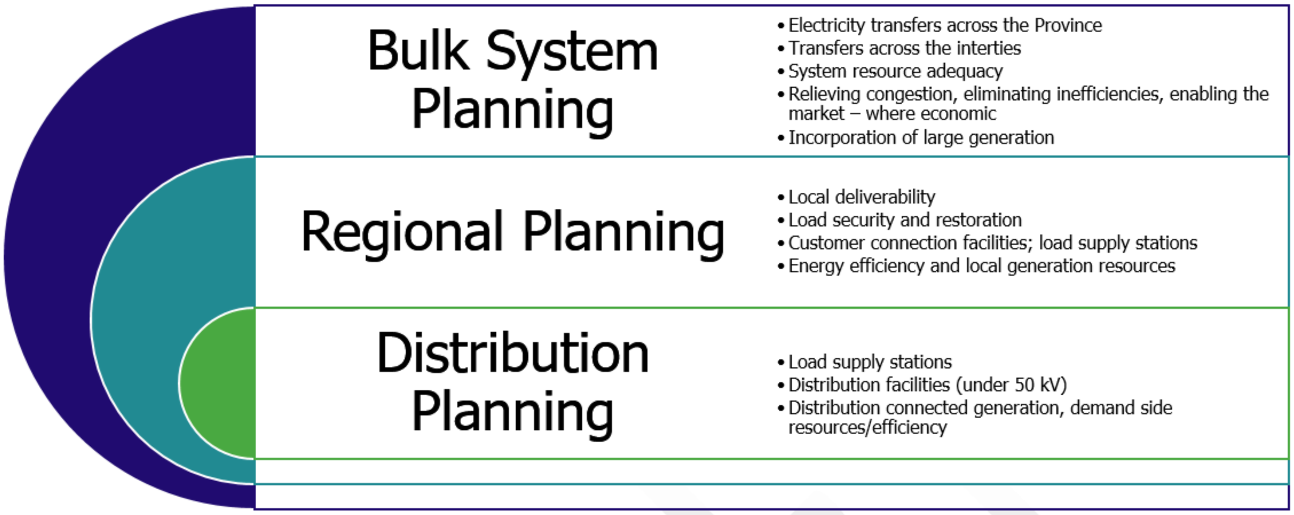


Figure 1 | Levels of Electricity System Planning

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

Appendix B – Demand Forecast

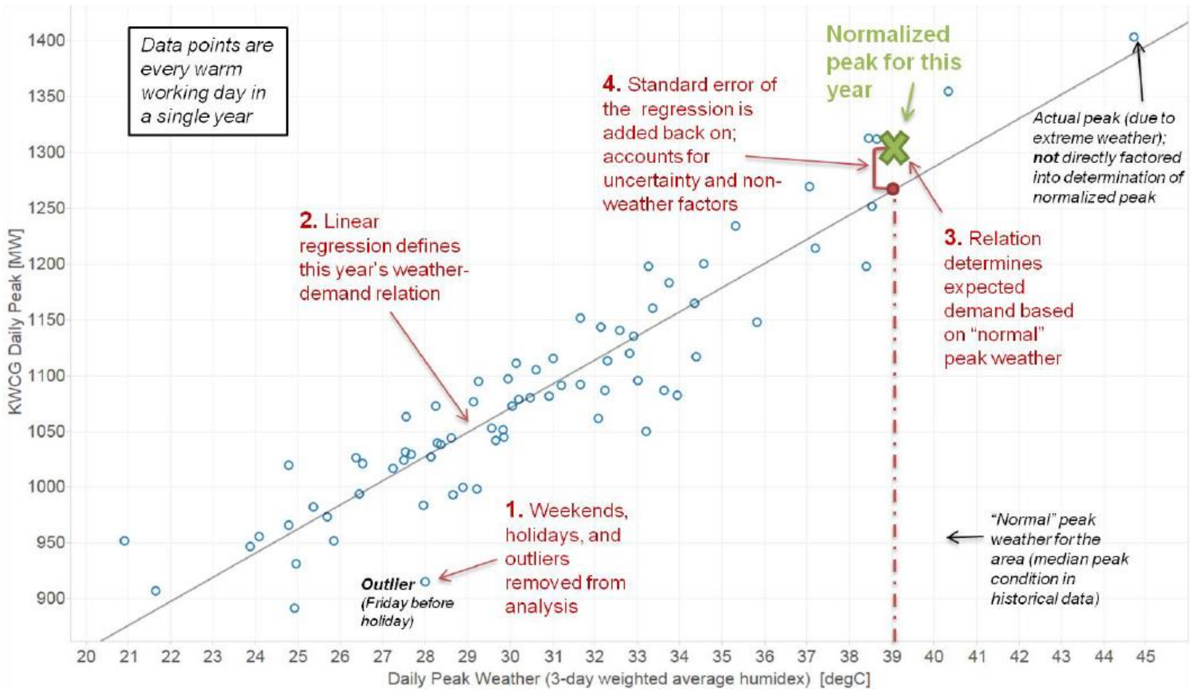
Appendix B describes the methodologies used to develop the demand forecast (peak and duration) for the Northwest IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the weather correction methodology, the approaches and methods used by each LDC to forecast demand in their respective service area, and the conservation and DG assumptions.

B.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (i.e. 2020 for the Northwest IRRP). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 2.

Figure 2 | Method for Determining the Weather Normalized Peak (Illustrative)



The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a start point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

B.2 Hydro One Forecast Methodology

Hydro One's demand forecast includes all areas in the Northwest region that are not reflect in the other distributors' service territories. The area served by Hydro One are mostly rural areas in the region. It is expected that the growth would occur mostly close to urban / built-up areas. Hydro One's forecast also includes demand from Sioux Lookout Hydro (embedded distributor).

Hydro One's conducts econometric and end-use forecasting. The main forecast drivers are Ontario GDP and housing starts. Load growth in the area relative to provincial trends was also taken into account. The following demand growth rate were assumed:

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Growth Rate (%)	4.5	4.2	2.2	2.0	2.1	2.0	1.9	1.8	1.8	1.8

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Growth Rate (%)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

New developments where assumed to have an average demand of 4.5 kW per residential unit with non-electric heat source 14.5 kW per residential unit with electric heat source. Residential demand growth was estimated based on Ontario housing starts (in thousands) shown below:

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Housing Starts	75.2	76.5	77.0	76.9	75.3	69.9	69.6	69.2	68.6	68.6
Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Housing Starts	68.6	68.5	68.4	68.4	68.3	68.2	68.2	68.1	68.0	68.0

Provincial/regional development plans and known private/First Nations developments were taken into account.

B.4 Fort Frances Power Forecast Methodology

Fort Frances Power Corporation ("Fort Frances Power") provides service to all consumers residing within the town of Fort Frances. 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 including cold winters and hot summers. The town is currently the third largest community of northwestern Ontario, after Thunder Bay and Kenora.

Fort Frances Power distributes electricity to approximately 3746 customers, over 32 square-kilometers, of which 88% are residential and 12% commercial. The community receives its supply of electricity from a Hydro One Networks Inc. owned transmission line. The transmission line supplies Fort Frances Power's transformer station Fort Frances MTS with a single 115 kV point of supply. The Fort Frances MTS transformer station steps down the incoming transmission supply to a distribution voltage of 12.47 kV, which is the primary distribution voltage of the entire distribution network within Fort Frances.

The Fort Frances MTS transformer station is the heart of the electrical distribution system for Fort Frances and will require considerable reinvestment over the next 10 to 15 years. The station was built in the early 1970s with some components being manufactured in the 1960s. The station and is projected to reach the end of its useful service life by 2034. Fort Frances Power is currently in the early stages of planning a complete transformer station rebuild over the next 10 – 15 years. The planned rebuild will also address potential load growth as well as customer reliability concerns associated the station being supplied from a single point of supply. Fort Frances Power is working with Hydro One Networks Inc. to bring a second point of supply to the station which would essentially eliminate Loss of Supply type outages that account for more than 90% of all customer interruption hours.

Factors that Affect Electricity Demand

Over the next 20 years changes to electricity demand for Fort Frances are expected to be dependent on several factors including weather/climate conditions, the economic prosperity of the community, and government policy. 2022 year-to-date metering data indicates increases of 4.8% in electricity consumption and 3.1% in electricity demand, relative to 2021.

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 consumed for the purpose of heating as opposed to cooling. A significant number of customers still use electric heat as their primary heat source due to natural gas only becoming available in the 1990s. Prolonged periods of hot or cold weather have a considerable impact on local electricity demand. Fort Frances Power anticipates that electric heat related demand will remain relatively stable with modest growth due to the increasing affordability of electricity in Fort Frances versus natural gas. The community currently enjoys among the lowest rates for electricity in all of Ontario, which makes electric heat more attractive than in other parts of the Province. Government policy such as carbon taxation and the new ultra-low overnight electricity rate are expected to drive consumer fuel switching from natural gas to electricity. Consumers switching appliances such as furnaces and hot water tanks from natural gas over to electricity is expected to result in modest increases to electricity demand.

The economic prosperity of Fort Frances is anticipated to have the most impactful affect on electricity demand for the community. The community suffered a temporary downturn in 2014 due to the permanent closure of the local pulp and paper mill, resulting in the loss of over 800 direct jobs. The impact from the closure was partially mitigated by the start-up of the New Gold Rainy River Mine just west of Fort Frances in 2017. Considerable effort is being exerted towards sparking new economic development in Fort Frances, and towards the rebuilding a commercial and industrial employment base. The town has received proposals from a variety of investors regarding economic development initiatives, however, they are not included in the forecast as no firm commitments have been received to date.

The electrification of transportation is also anticipated to have a significant affect on increasing the demand for electricity in Fort Frances. Again, government policy such as electric vehicle rebates could have a significant impact on the adoption rate of electric vehicles, however, it is difficult to quantify the overall impact at this time.

Forecast Methodology and Assumptions

Historical peak demands from the years 2016 to 2020 were used to calculate Fort Frances Power's 2021 base (starting point) Peak Demand of 15.2 MW at its transformer station Fort Frances MTS. The 2021 starting point was found by calculating the slope and intercept of the historical peaks and calculating the "projected" 2020 value. The following factors were taken into consideration for the establishment of the 0.5% year-over-year projected increase in demand.

- Embedded Generation: 0% - Peak demands are usually set throughout the extremely cold winter nights, at times where no Photo Voltaic Embedded Generation is being produced.
- Annual Growth Factor: 0.5% - Conservative growth factor, taking into account electric vehicle adoption, natural gas to electricity fuel switching, and increasing customer base.
- Large Commercial/Industrial Developments: 0% - Could have the potential for significant demand increase, however, set to 0% as no firm commitments have been made to date.

B.5 Atikokan Hydro Forecast Methodology

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

Atikokan Hydro distributes electricity to approximately 1630 customers, over 320 square kilometers, of which 85% are residential and 15% are commercial. Commercial customers make up over 50% of Atikokan's base load.

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'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. There are no new local developments projected to significantly drive electricity requirements. Potential for slight increase as a result of local expansions and development of potential new construction but no certainty or known details of impacts to load 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.

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 2,642 in 2021. This represents nearly a 20% 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 applying local 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. The main factors affecting forecast and loads has been the closure of sawmills and a particle board plant, and re-opening of an existing plant. The geographical location and resources of our community limits the growth opportunities. The industry can be volatile and significantly impact with abrupt changes.

For forecast purposes, stability and current load was assumed.

2022 is forecasted to increase to 5.88 mw which is the four-year historical average of 2016 through 2019 (2020 was excluded due to the anomaly of COVID-19). This assumes COVID impacts have flattened, and electrical consumption and demands are closer if not back to normal levels and Atikokan has some new load from new build construction underway (multi-residential building and renovation and expansion of a school). New load is not believed to significantly change the overall Atikokan load based on the knowledge the LDC has. 2023 is forecasted to have a 1% influx from the year prior for potentials of other construction underway assuming the remainder of buildings, facilities and commercial establishments maintain status quo. 2025 assumed to reach 6 mw and assumed to plateau at 6 mw with no evidence of other significant load impacts. 6 mw is achievable based on historical loads and knowledge of local economic developments. It can additionally be accommodated under the current transformer ratings.

B.6 Synergy North Forecast Methodology

1. Background Information

1.1. Historic Peak information

Load transfers are a regular occurrence in the operation of the system in Thunder Bay. Load is frequently moved from one station to another for routine maintenance or during abnormal conditions. Although some of the peaks coincide with load transfers, it can be expected that load transfers will occur in any given year. Kenora MTS is a radial feeder and does not have capabilities to perform any load transfers.

1.1.1. Birch TS

2016 through 2019 peaks for Birch TS all occurred under normal operating conditions. The 2020 peak occurred during a temporary load transfer of a section feeder 2M4 (normally PATS) fed by 17M2 from Birch TS for scheduled maintenance by Hydro One at PATS.

1.1.2. Fort William TS

2016 through 2018 and 2020 peaks for FWTS all occurred under normal operating conditions. The 2019 peak occurred during scheduled maintenance on Birch TS T3. FWTS feeder 10M3 was used to pick-up a section of 17M1 normally fed by Birch TS.

1.1.3. Port Arthur TS

The 2016 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M3 on PATS due to an issue at an LDC DS. The 2017 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M2 on PATS due to maintenance at BRTS. The 2018 peak occurred during normal operating conditions. The 2019 peak during a load transfer of 17M2 (normally BRTS) to 2M4 on PATS due to T3 maintenance at BRTS. The 2020 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M5 on PATS due to a protection update for the feeder at Birch.

1.1.4. Kenora MTS

All the peaks for the station occurred during normal operating conditions. Kenora MTS does not have capability to transfer load as it is on a radial feed.

1.2. Electrical Load in Study Area

100% Synergy North's load is within the study area for the Integrated Regional Resource Plan for the Northwest Region.

1.3. Market and Rate Segmentation of Load

Station	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Birch TS	14,617	2,078	5	16,700
Fort William TS	22,300	2,103	7	24,410
Port Arthur TS	8,879	735	3	9,617

Note: Rate segmentation only available by customer counts and not MW. No data available for Kenora MTS.

2. Methodology

- Hourly net load and generation data was gathered from 2010 to 2020.
  - Aggregate micro and small generation data were split among stations based on percentage of allocated capacity at the station in relation the total.
- CDM program data and generation were added to the net load data to determine gross peaks.
  - CDM program benefits were carried from year to year with a considered depreciation value of 5% per year.
  - No new CDM was added for the forecast period, although depreciated existing CDM was included in gross totals.
- Monthly peaks were plotted against the average monthly temperature to generate a 3rd order polynomial line of best fit for weather dependence at each station.

- The gross data was normalized for weather by subtracting the weather dependence per the 3rd order polynomial.
- Multi-linear regression was performed on the weather normalized monthly gross load data using economic factors selected based on R2 correlation values to provide a model based on predicted factors. These factors include grain prices index, Thunder Bay unemployment rate, metal prices index, Thunder Bay CPI and Canada unemployment rate.

- Weather was added back into the forecast using the 3rd order polynomials per station and the assumed average monthly temperatures over the past 10 years to create the monthly forecast models.
- Modest growth factors were then added to forecast model to account for future development.
  - 0.5% for Birch TS
  - 0.5% for Fort William TS
  - 0.5% for Port Arthur TS
  - 1.25% for Kenora MTS (higher for Kenora as more interest in development)
- The annual gross peak was then determined from the final model.
- Note that the numbers provided were based on gross load (including DG and CDM) and the actual station peak demand provided did not include most DG or CDM.

3. Drivers of Load Growth

The municipal growth plan for Thunder Bay was high level and did not go into enough specifics to speculate on future load. No specific large load projects have been applied for in Synergy North's service territory at this time and therefore no specific project is included in the forecast. We have had interest from potential customers about future projects (including a possible 4MW project in Kenora), but no formal agreements have been signed. We have decided to roll these projects into the modest growth factors applied.

4. Behind the Meter Generation

No new behind the meter generation projects are currently in progress. Therefore, none have been included in the forecast. There has been some interest from proponents, but no connection impact assessments are currently underway. We have experienced a significant drop in all embedded generation applications including micro sized projects with the end of the FIT program. Two existing CHP load displacement generation projects connected to BRTS at 2.0MW and 1.984MW (3.984MW total) have been added to the effective winter capacity sheet.

5. EV Adoption

Synergy North used the 2020 Annual Planning Outlook (APO) as a base to predict the average hourly MW increase for the province, then applied that value to Thunder Bay and Kenora based on population as a portion of the provincial population. As the loads for EV's were expected to occur during non-peak times mainly, the average hourly increase was determined to be appropriate and was added to the original peak load forecast to come up with the attached high electrification forecast.

B.7 Projects Included in IRRP Mining Sector Forecast

The lists below reflect known projects as of Q4 2021.

Existing Active Mines in the Northwest Region

Mine Name	Owner	Location	Peak Demand	End date	Information Source
Helmo Property Mines	Barrick Gold Cop	Marathon	Known	2029	MDNM, Generation Mining Data Online,
Musselwhite Mine	Newmont Goldcorp	Pickle Lake	Known	2030	Generation Mining Data Online
Rainy River Mine	New Gold	Fort Frances Nestor Falls	Known		
Red Lake Complex	Evolution Mining	Red Lake	Known	2033	Generation Mining Data Online, Company Web site
Lac Des Iles Palladium Mine	Impala Canada Limited	Thunderbay	Known	2030	Generation Mining Data Online
PureGold (Madsen) Gold Mine	Pure Gold Mining	Red Lake	Known	2031	Generation Mining Data Online
Sugar Zone Mine	Harte Gold	Marathon	Known	2033	Generation Mining Data Online, Company Web site

Future Mines and/or Mining Exploration in the Northwest Region

Project Name	Owner	Location	Peak Demand	i/s	o/s	Information Source
Greenstone Gold Mines Project	Orion Mine/Premier Gold Mines	Greenstone	Known	2021	2036	CVNW, OMED

Battle North (Bateman) Gold Project	Evolution Mining	Red Lake	Known	2021	2030	CVNW, OMED, Hydro One
Marathon PGM-CU Project	Generation Mining	Marathon	Known	2024	2040+	CVNW, OMED, Hydro One
Hammond Reef Gold Project	Agnico - Eagle	Atikokan	Known	2025	2036	CVNW, Hydro One
Springpole Gold Project	First Mining Finance	Cat Lake	Known	2025	2035	CVNW, OMED, Hydro One
Eagle's Nest	Noront	Ring of Fire	Known	2025	2035	CVNW, OMED
Black Bird	Noront	Ring of Fire	Known	2028	2037	CVNW
Goliath Gold Project	Treasure Metals	Dryden	Known	2024	2033	CVNW, OMED
PAK Lithium Project	Frontier Lithium	Red Lake	Known	2025	2040+	CVNW, OMED, Hydro One
Moss Lake Project	Wesdome Gold	Thunderbay	Known	2025	2034	CVNW
AMI Project	Ambershaw Metallics	Ignace	Known	2025	2040+	CVNW
Separation Rapids Project	Avalon Advanced Metals	Kenora	Known	2025	2040+	CVNW, OMED
Georgia Lake Project	Rock Tech Lithium	Thunderbay	Known	2026	2040+	CVNW
Cameron Gold Project	First Mining Finance	Nestor Falls	Known	2026	2040+	CVNW, OMED
Winston LK Project	CROPS	Marathon	Known	2026	2040+	CVNW, OMED, Hydro One
Thunder Bay North PGM Project	Clean Air Metals	Thunder Bay North	Known	2029	2040+	CVNW, OMED, Hydro One
Theirry Project	Cadillac Ventures	Pickle Lake	Known	?	?	OMED
Albany Project	Zen Graphene	Hearst	Known	?	?	CVNW, OMED
Eagle Island/St Joseph Project	Rockex Mining Corp	NoD	Known	?	?	CVNW
Griffith	Lithium Energy Products	NoD	Known	?	?	CVNW
Sturgeon Lake Project	Glencore/Odin/FQML	Ignace	?	?	?	Company's website
Dixie Project	Great Bear Resources	Red Lake	?	?	?	CVNW
Mt. Jamie North Gold Project	Stone Gold	Red Lake	?	?	?	Company's website

Sunday Lake Project	Transition Metals	Thunder Bay	?	?	?	CVNW
Rowan Mine Project	West Red Lake Gold	Red Lake	?	?	?	Company's website
Horseshoe Island Project	First mining Gold	Red Lake	?	?	?	Company's website
Kyle Lake (U2 Kimberlite) Project	Metalex Ventures	?	?	?	?	OMED

B.8 IRRP Mining Demand Forecast Scenarios

The IRRP mining sector demand forecast scenarios can be found in the accompanying Excel spreadsheet Table B.8.

B.9 Conservation and Demand Management Assumptions

Energy efficiency measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the Northwest IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2020 Annual Planning Outlook including the 2021 – 2024 CDM Framework. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from the provincial level to the Northwest IESO transmission zone and then allocated to the Northwest region. This appendix describes the process and methodology used to estimate energy efficiency savings for the Northwest region and provides more detail on how the savings for the two categories were developed.

B.9.1. Estimated Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Northwest zone and compared with the gross peak demand forecast for each zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region, as further described below.

Consistent with the gross demand forecast, 2020 was used as the base year. New peak demand savings from codes and standards were estimated from 2021 to 2040. The residential annual peak reduction percentages for each year were applied to the forecast residential peak demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2040, the residential sector in the region is expected to see about 6.6% peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 0.8% peak-demand savings through codes and standards by 2040. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. It is assumed that there are no savings from codes and standards associated with the industrial sector.

B.9.2. Estimated Savings from Energy Efficiency Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and planned CDM programs were analyzed, which include the 2021 – 2024 CDM Framework, the existing federal programs, and the forecasted long term energy efficiency programs. A top down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province, to the Northwest zone, and finally to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages from program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Northwest zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2030, the residential sector in the region is expected to see about 0.2% peak demand savings through programs, while commercial sector and industrial sector will see about 1.6% and 1.9% peak reduction respectively.

B.9.3. Total Energy Efficiency Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated for each sector, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

The IRRP CDM forecast for each station can be found in the accompanying Excel spreadsheet Table B.9.3.

B.10 Installed Distributed Generation and Contribution Factor Assumptions

The distributed generation contribution factor assumptions station can be found in the accompanying Excel spreadsheet Table B.10.1. The distributed generation output assumptions for each station can be found in Table B.10.2.

B.11 Final Peak Forecast by Station

The final peak station-level demand forecast can be found in the accompanying Excel spreadsheet Table B.11.

Appendix C – Northwest IRRP Technical Study

C.1 Description of Study Area

The Northwest region bounded by Marathon TS to the east and the Minnesota and Manitoba interties to the west. The 230 kV system is comprised of the following lines and stations: WxM lines from Wawa TS to Marathon TS, the MxL lines from Marathon TS to Lakehead TS, the AxL lines from Lakehead TS to Mackenzie TS, and Mackenzie TS-Dryden TS-Kenora TS-Fort Frances TS loop formed by the D26A/K23D/K24F/F25A lines. A new 230 kV circuit, W54W, was recently added between Dinorwic Junction (near Dryden TS on D26A) and Wataynikaneyap TS near Pickle Lake. Interconnections to Minnesota and Manitoba are provided via F3M from Fort Frances TS and K21W/K22W from Kenora TS, respectively. The Northwest region also includes 230/115 kV autotransformers each of the 230 kV stations listed above and the respective 115 kV subsystems supplied from these autotransformers. A single line diagram of this region is shown in **Error! Reference source not found.** below.

C.2.1 Load Forecast

The initial need identification study used net winter extreme weather forecast snapshots in 2023, 2027, 2032, and 2040 (end of planning horizon). The station level forecast is provided in Appendix B.7 and B.11 above. The 2027 snapshot has the highest overall regional peak load because the mining sector forecast peaks in 2027 and declines thereafter.

A power factor of 0.90 was assumed unless there was specific information indicating that a higher power factor assumption was appropriate. An 0.95 power factor was assumed for Crilly DS loads (consistent with historical and expected future load characteristics) for the purpose of determining the station capacity need date. An 0.9 power factor was assumed for all other stations.

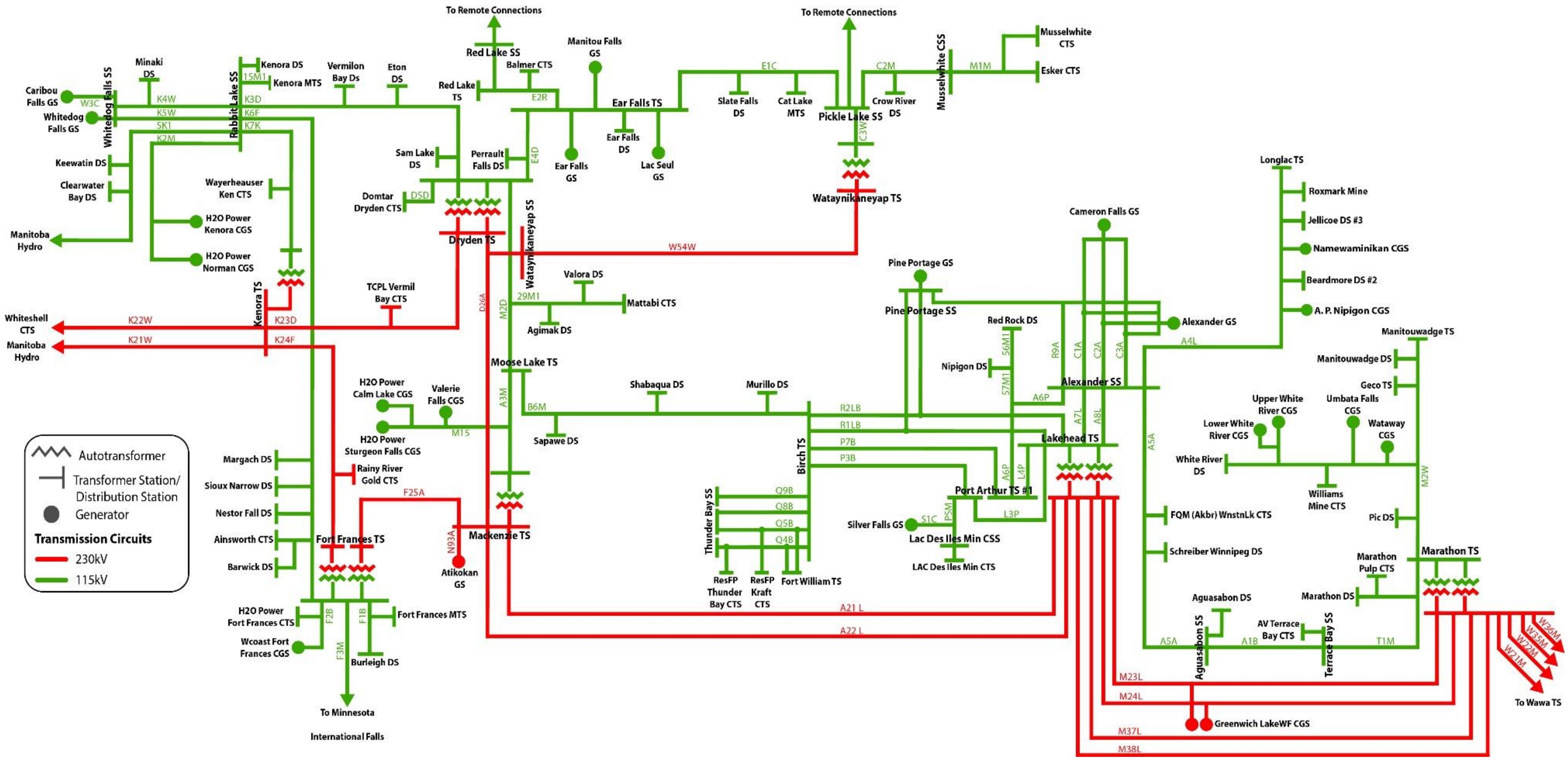


Figure 3 | Single Line Diagram of the Northwest Region

C.2.2 Local Generation Assumptions

Dependable 98th percentile and 85th percentile hydro generation output is tabulated in Table 1. All-in-service base cases used 98th percentile dependable hydro (consistent with ORTAC criteria) while outage condition base cases used 85th percentile hydro (consistent with historical best practices). Note that numbers in Table 1 are non-coincident (i.e. each facility at their individual 98th/85th percentile output). Coincident dependable hydro for any given subsystem (i.e. several facilities' combined 98th/85th percentile output) will usually be higher than the sum of the non-coincident output at each facility within the subsystem.

Table 1 | Dependable Hydro Assumptions (Non-Concident) in the Northwest Region

Hydro Facility	Winter 98th (MW)	Winter 85th (MW)	Summer 98th (MW)	Summer 85th (MW)
ABKENORA	8.6	9.5	0.4	4.7
AGUASABON	11.0	29.7	0.0	11.3
ALEXANDER	39.0	41.6	24.6	26.7
CALMLAKE	6.9	8.1	3.3	5.9
CAMERONFALLS	47.0	53.1	27.4	32.8
CARIBOUFALLS	43.4	66.6	7.8	29.0
EARFALLS	16.9	21.5	4.9	10.9
FORTFRANCS	3.3	4.7	4.0	4.1
KAKABEKA	9.0	14.6	1.7	5.4
LOWERWHITE	3.5	4.4	2.2	2.5
MANITOUFALLS	43.0	50.7	7.3	22.9
MANITOUWATS	0.2	0.5	0.0	0.1
NAMEWAM	2.3	2.7	0.0	0.4
PINEPORTAGE	45.6	74.3	14.5	39.5
SILVERFALLS	30.6	32.9	0.0	0.0
STURGEONFALL	4.9	6.6	2.2	4.3
UMBATAFALLS	5.0	8.6	1.8	4.2
UPPERWHITE	3.1	3.1	1.9	3.4
VALRIEFALLS	2.9	4.5	0.4	1.6
WAWATAY	1.2	2.5	0.2	1.1
WHITEDOG	22.5	38.6	6.3	27.6
Total Non-Coincident	348.3	478.8	111.1	238.3
Total Coincident	481.3	512.0	268.8	317.4

Table 2 below shows the non-hydro transmission-connected generation. Atikokan GS and Nipigon GS were assumed to be out-of-service since their current contract term date ends in the near term. Greenwich Lake Wind Farm was also assumed to be out-of-service for simplicity but this generator does not materially impact the IRRP study since it is connected along the MxL East-West Tie (EWT) lines. While Greenwich Lake Wind Farm does impact the overall flow along the EWT, the EWT transfer capability was not in scope for the IRRP and the wind farm does not impact any of the local subsystems' load meeting capability.

Table 2 | Non-Hydro Transmission-Connected Generation in the Northwest Region

Facility Name	Contract Capacity	Term Start Date	Term End Date
Atikokan GS	205 MW	2014	2024
Nipigon GS	16 MW	2018	2022
Greenwich Lake Wind Farm	99 MW	2011	2031

Note that the tables above do not include distribution-connected generation nor generation at transmission-connect customer stations. Distribution-connected generation are accounted for directly in the demand forecast. There is no contractual mechanism to rely on generation at transmission-connected customer stations for capacity during peak demand conditions.

---- End of Section ---

C.3 System Topology

C.3.1 Monitored Circuits and Stations

Table 3 lists the monitored transformers station in the Northwest Region.

Table 3 | Monitored Stations in the Northwest Region

Station Names	
Agimak DS	Margach DS
Ainsworth CTS (Voyageur CTS)	Minaki DS
Balmer CTS	Moose Lake TS
Barwick TS	Murillo DS
Beardmore DS #2	Musselwhite CTS
Birch TS	Musselwhite CTS
Bowater Thunder Bay CTS	Nestor Falls DS
Burleigh DS	Nipigon DS
Cat Lake MTS	Perrault Falls DS
Clearwater Bay DS	Pic DS
Crow River DS	Port Arthur TS #1
Dryden TS	Rainy River CTS (Rainy River Gold CTS)
Ear Falls TS	Red Lake TS
Esker CTS	Red Rock DS
Eton DS	Sam Lake DS
Fort Frances MTS	Sapawe DS
Fort Frances TS	Schreiber Winnipeg DS
Fort William TS	Shabaqua DS
Geco Mines Xstrata CTS	Sioux Narrows DS
Jellicoe DS #3	Slate Falls DS
Keewatin DS	TCPL Vermillion Bay CTS
Kenora MTS	Teck Corona CTS (Williams Mine CTS)
Kenora TS	Terrace Bay CTS
Lac des Iles Mine CTS	Valora DS
Lakehead TS	Vermilion Bay DS
Longlac TS	Wataynikaneyap TS
Mackenzie TS	Wayerheauser Dryden CTS
Manitouwadge DS #1	Wayerheauser Ken CTS
Manitouwadge TS	White River DS
Marathon DS	Winston Lake CTS
Marathon TS	Xstrata Mattibi Mine CTS

Table 4 lists the monitored circuits in the Northwest Region. Note that the summer ratings have in Table 4 have not been updated to reflect the latest 35 degree ratings which were introduced during the IRRP. Since the IRRP technical studies were already underway, the initiate needs identification studies were not repeated with the new ratings but, where thermal constraints were identified, the new 35 degree ratings were used to determine the load meeting capability.

Table 4 | Monitored Circuits and Ratings

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
A1B	1	Aguasabon SS	AV Terrace Bay JCT	680	680	680	570	570	570
A1B	2	AV Terrace Bay JCT	Terrace Bay SS	720	870	1020	620	790	960
A1B	3	AV Terrace Bay JCT	AV Terrace Bay CTS	720	870	1020	620	790	960
A21L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A21L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A22L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A22L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A23P	1	Algoma TS	Mississagi TS	1020	1230	1510	880	1120	1430
A24P	1	Algoma TS	Mississagi TS	1020	1230	1510	880	1120	1430
A4L	1	Alexander SS	A4L STR 217 JCT	390	390	390	310	310	310
A4L	2	Beardmore JCT	Namewaminikan JCT	330	330	330	260	260	260
A4L	6	Jellicoe DS #3 JCT	Longlac TS	330	330	330	260	260	260
A4L	7	Beardmore JCT	Beardmore DS #2	430	510	570	370	470	530
A4L	10	A.P. Nipigon JCT	Beardmore JCT	390	390	390	310	310	310
A4L	11	A.P. Nipigon JCT	A.P. Nipigon CGS	580	600	610	500	530	530
A4L	12	Jellicoe DS #3 JCT	Jellicoe DS #3	330	330	330	260	260	260
A4L	13	Namewaminikan JCT	Jellicoe DS #3 JCT	330	330	330	260	260	260
A4L	14	Namewaminikan JCT	Namewaminikan CGS	580	690	710	500	630	660
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	390	390	390	310	310	310
A5A	1	Alexander SS	Minnova JCT	580	580	580	430	430	430
A5A	1	Alexander SS	Minnova JCT	580	580	580	430	430	430
A5A	2	Minnova JCT	Schreiber JCT	580	580	580	430	430	430
A5A	3	Schreiber JCT	Aguasabon SS	580	580	580	430	430	430
A5A	4	Schreiber JCT	Schreiber Winnipg DS	330	330	330	260	260	260
A5A	6	Minnova JCT	Minnova JCT	430	430	430	340	340	340
A6P	1	Alexander SS	Reserve JCT	640	680	680	520	520	520
A6P	2	Reserve JCT	Port Arthur TS #1	630	630	630	540	540	540
A7L	1	Alexander SS	Reserve JCT	430	430	440	340	340	340
A7L	2	Reserve JCT	Lakehead TS	430	430	430	340	340	340
A8L	1	Alexander SS	Lakehead TS	540	540	540	420	420	420
B15	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
B15	2	Abitibi JCT	James Street JCT	1000	1090	1140	850	970	1030
B15	3	James Street JCT	St.Paul JCT	1000	1090	1140	850	970	1030

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
B15	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
B15	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
B15	6	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1430	850	1100	1350
B15	7	St.Paul JCT	ResFP Kraft CTS	720	870	940	620	790	870
B15	8	Walsh Street JCT	Fort William TS	1000	1090	1140	850	960	1020
B3E	1	Blind River TS	Elliot Lake JCT	580	700	720	500	640	670
B3E	2	Elliot Lake JCT	Elliot Lake TS	580	700	720	500	640	670
B5	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
B5	2	Abitibi JCT	James Street JCT	1000	1200	1490	850	1100	1410
B5	3	James Street JCT	St.Paul JCT	1000	1200	1490	850	1100	1410
B5	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
B5	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
B5	6	Abitibi JCT	Erco JCT	720	870	950	620	790	880
B5	7	Erco JCT	Q5B STR A6 JCT	720	870	950	620	790	880
B5	8	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1490	850	1100	1410
B5	9	St.Paul JCT	ResFP Kraft CTS	720	810	840	620	720	760
B5	10	Walsh Street JCT	Fort William TS	1000	1000	1000	850	850	850
B6M	1	Birch TS	Murillo JCT	590	590	590	440	440	450
B6M	2	Stanley JCT	Shabaqua JCT	580	580	580	430	430	430
B6M	3	Shabaqua JCT	Shebandowan JCT	610	610	610	470	470	470
B6M	4	Shebandowan JCT	Kashabowie JCT	600	600	600	460	460	460
B6M	5	Kashabowie JCT	Sapawe JCT	580	580	580	430	430	430
B6M	6	Caland Ore JCT	Moose Lake TS	720	820	850	620	740	770
B6M	7	Shabaqua JCT	Shabaqua DS	430	510	570	370	470	530
B6M	12	Murillo JCT	Stanley JCT	580	580	580	430	430	430
B6M	15	Sapawe JCT	Caland Ore JCT	720	820	850	620	740	770
B6M	16	Sapawe JCT	Sapawe DS	580	690	790	500	630	740
B6M	17	Murillo JCT	Murillo DS	330	330	330	260	260	260
B9	1	Thunder Bay SS	Birch TS	1270	1530	1730	1090	1390	1600
C1A	1	Cameron Falls GS	Alexander SS	720	870	920	620	790	840
C1A	2	Alexander SS	Alexander GS	720	870	920	620	790	840
C1A	3	Alexander SS	Alexander SS	540	540	540	420	420	420
C2M	1	Pickle Lake SS	C2M T#NB1 JCT	480	480	480	380	380	380
C2M	2	C2M T#NB1 JCT	Placer JCT	430	430	430	340	340	340
C2M	3	Placer JCT	Placer JCT	280	280	280	230	230	230
C2M	4	Placer JCT	Crow River DS	280	280	280	230	230	230
C2M	5	C2M T#NB1 JCT	Musselwhite CSS	430	430	430	340	340	340
C2M	6	Placer JCT	Crow River DS	280	280	280	230	230	230
C3A	1	Cameron Falls GS	Alexander SS	720	870	920	620	790	840
C3A	2	Alexander SS	Alexander GS	720	870	920	620	790	840
C3A	3	Alexander SS	Alexander SS	720	870	920	620	790	840
C3W	1	Pickle Lake CTS	Pickle Lake SS	730	730	730	550	550	550

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	**LTE**	**STE**	**Cont**	**LTE**	**STE**
D26A	1	Dryden TS	Mackenzie TS	1020	1020	1020	880	880	880
D26A	1	Dryden TS	Dinorwic JCT	1020	1020	1020	880	880	880
D26A	2	Dinorwic JCT	Mackenzie TS	1020	1020	1020	880	880	880
D26A	4	Dinorwic JCT	Dinorwic JCT	1020	1020	1020	880	880	880
D5D	1	Dryden TS	Dryden JCT B	720	870	1020	620	790	960
D5D	2	Dryden JCT B	Domtar Dryden CTS	670	670	670	550	550	550
D5D	3	Dryden JCT B	Dryden JCT B	670	670	670	550	550	550
E1C	1	Ear Falls TS	Selco JCT	280	280	280	230	230	230
E1C	2	Selco JCT	Slate Falls JCT	280	280	280	230	230	230
E1C	3	Etruscan JCT	Placer JCT	280	280	280	230	230	230
E1C	3	Etruscan JCT	E1C T#NA1 JCT	280	280	280	230	230	230
E1C	5	Etruscan JCT	Etruscan Entrprs CTS	280	280	280	230	230	230
E1C	8	Golden Patricia JCT	Etruscan JCT	280	280	280	230	230	230
E1C	8	Golden Patricia JCT	Etruscan JCT	280	280	280	230	230	230
E1C	11	Slate Falls JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	11	Slate Falls JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	12	Slate Falls JCT	Slate Falls DS	280	280	280	230	230	230
E1C	13	Placer JCT	Crow River DS	280	280	280	230	230	230
E1C	14	Placer JCT	Placer JCT	280	280	280	230	230	230
E1C	15	Placer JCT	Crow River DS	280	280	280	230	230	230
E1C	16	Placer JCT	Musselwhite CSS	430	430	430	340	340	340
E1C	17	Golden Patricia JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	18	E1C T#NA1 JCT	Placer JCT	280	280	280	230	230	230
E1C	19	E1C T#NA1 JCT	Pickle Lake SS	480	480	480	380	380	380
E2R	1	Ear Falls TS	Pakwash JCT	540	540	540	420	420	420
E2R	2	Pakwash JCT	Balmer JCT	540	540	540	420	420	420
E2R	4	Balmer JCT	Red Lake TS	540	540	540	420	420	420
E2R	4	Balmer JCT	Red Lake JCT	540	540	540	420	420	420
E2R	6	Red Lake JCT	Red Lake TS	540	540	540	420	420	420
E2R	7	Red Lake JCT	Red Lake CSS	540	540	540	420	420	420
E4D	1	Ear Falls TS	Scout Lake JCT	610	610	610	470	470	470
E4D	2	Scout Lake JCT	Dryden TS	610	610	610	470	470	470
E4D	3	Scout Lake JCT	Perrault Falls DS	280	280	280	230	230	230
F1B	1	Fort Frances TS	Fort Frances JCT	550	550	550	460	460	460
F1B	2	Burleigh JCT	Burleigh DS	1000	1200	1490	850	1100	1410
F1B	3	Fort Frances TS	Fort Frances MTS	430	430	430	340	340	340
F1B	4	Fort Frances JCT	Burleigh JCT	550	550	550	460	460	460
F1B	5	Burleigh JCT	Hwy #11 JCT	600	600	600	280	280	280
F25A	1	Fort Frances TS	Mackenzie TS	1020	1020	1020	880	880	880
F2B	1	Fort Frances TS	H2O Pwr FtFrnces CGS	720	830	860	620	740	780
F3M	1	Fort Frances TS	H2O Pwr FtFrnces CGS	920	920	920	750	750	750
F3M	2	H2O Pwr FtFrnces CGS	Int'l Bdy Minn JCT	850	920	920	730	750	750

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
K21W	1	Kenora TS	IPB Manitoba 230 JCT	1020	1020	1020	880	880	880
K22W	1	Kenora TS	IPB Manitoba 230 JCT	1020	1020	1020	880	880	880
K23D	1	Kenora TS	TCPL Vermill Bay JCT	1020	1020	1020	880	880	880
K23D	2	TCPL Vermill Bay JCT	Dryden TS	1020	1020	1020	880	880	880
K23D	3	TCPL Vermill Bay JCT	TCPL Vermill Bay CTS	1020	1020	1020	880	880	880
K24F	1	Kenora TS	Rainy River Gold JCT	1020	1170	1250	880	1060	1140
K24F	2	Rainy River Gold JCT	Fort Frances TS	1020	1170	1250	880	1060	1140
K24F	3	Rainy River Gold JCT	Rainy River Gold CSS	1020	1170	1250	880	1060	1140
K2M	1	Rabbit Lake SS	Norman JCT	710	710	710	600	600	610
K3D	1	Rabbit Lake SS	K3D-10 SW JCT	610	610	610	470	470	470
K3D	2	K3D-10 SW JCT	Vermilion Bay JCT	610	610	610	470	470	470
K3D	3	Vermilion Bay JCT	Eton JCT	610	610	610	470	470	470
K3D	4	Vermilion Bay JCT	Vermilion Bay DS	430	510	570	370	470	530
K3D	5	Dryden TS	Sam Lake DS	540	540	540	420	420	420
K3D	6	Eton JCT	Dryden TS	610	610	610	470	470	470
K3D	7	Eton JCT	Eton DS	430	510	570	370	470	530
K4W	1	Rabbit Lake SS	Minaki JCT	580	580	580	430	430	430
K4W	2	Minaki JCT	Whitedog Falls SS	720	790	810	620	700	720
K4W	3	Minaki JCT	Minaki DS	580	580	580	430	430	430
K4W	4	Minaki JCT	Minaki DS	580	580	580	430	430	430
K5W	1	Rabbit Lake SS	Minaki JCT	580	580	580	430	430	430
K5W	3	Minaki JCT	Whitedog Falls SS	720	720	720	610	610	610
K6F	1	Rabbit Lake SS	Margach JCT	650	650	650	530	530	530
K6F	2	Margach JCT	Sioux Narrows JCT	580	580	580	430	430	430
K6F	3	K6F-10 SW JCT	Nestor Falls JCT	610	610	610	470	470	470
K6F	4	Nestor Falls JCT	Ainsworth JCT	610	610	610	470	470	470
K6F	5	Sioux Narrows JCT	Sioux Narrows DS	720	870	1020	620	790	960
K6F	6	Nestor Falls JCT	Nestor Falls DS	370	440	490	320	400	460
K6F	7	Sioux Narrows JCT	K6F-10 SW JCT	650	650	650	530	530	530
K6F	8	Ainsworth JCT	Fort Frances JCT	610	610	610	470	470	470
K6F	10	Margach JCT	Margach DS	370	440	490	320	400	460
K6F	11	Margach JCT	Margach DS	370	440	490	320	400	460
K6F	12	Ainsworth JCT	Barwick JCT	430	450	450	370	390	400
K6F	13	Fort Frances JCT	Fort Frances TS	610	610	610	470	470	470
K6F	14	Fort Frances JCT	Fort Frances JCT	610	610	610	470	470	470
K6F	15	Barwick JCT	Ainsworth Str #4 JCT	430	450	450	370	390	400
K6F	16	Barwick JCT	Barwick TS	1000	1200	1490	850	1100	1410
K6F	17	Barwick JCT	Barwick TS	1000	1200	1490	850	1100	1410
K7K	1	Kenora TS	Kenora TS	720	870	1020	620	790	960
K7K	2	Kenora TS	Rabbit Lake SS	720	870	970	620	790	910
K7K	3	Kenora TS	Weyerhaeuser Ken CTS	360	360	360	280	280	280
L3P	1	Lakehead TS	Port Arthur TS #1	840	1000	1200	720	920	1130

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
L4P	1	Lakehead TS	Port Arthur TS #1	720	870	1020	620	790	960
M1S	1	Moose Lake TS	Valerie Falls JCT	450	450	450	320	320	320
M1S	2	Mill Creek JCT	H2O Pwr SturgFls CGS	540	540	540	450	450	460
M1S	4	Mill Creek JCT	H2O Pwr Calm Lk CGS	340	340	340	280	280	280
M1S	6	Valerie Falls JCT	Mill Creek JCT	450	450	450	320	320	320
M23L	1	Marathon TS	Greenwich WF CGS JCT	1020	1070	1100	880	940	970
M23L	1	Marathon TS	Greenwich WF CGS JCT	1020	1070	1100	880	940	970
M23L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M23L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M23L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	1020	1030	1040	880	890	900
M24L	1	Marathon TS	Greenwich WF CGS JCT	1020	1140	1210	880	1020	1090
M24L	1	Marathon TS	Greenwich WF CGS JCT	1020	1140	1210	880	1020	1090
M24L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M24L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M24L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	1020	1030	1040	880	890	900
M2D	1	Ignace JCT	Dryden TS	540	540	540	420	420	420
M2D	1	Ignace JCT	Dryden TS	540	540	540	420	420	420
M2D	2	Moose Lake TS	Ignace JCT	670	670	670	550	550	550
M2D	4	Dryden TS	Dryden TS	670	670	670	550	550	550
M2D	5	Dryden TS	Dryden JCT B	670	670	670	550	550	550
M2W	1	Marathon TS	Pic JCT	720	870	1020	620	790	960
M2W	1	Marathon TS	Pic JCT	720	870	1020	620	790	960
M2W	2	Pic JCT	Manitouwadge JCT	430	450	460	350	350	350
M2W	4	Manitouwadge JCT	Willroy JCT	580	690	790	500	630	740
M2W	6	Manitouwadge JCT	Manitouwadge JCT B	580	690	720	500	630	660
M2W	8	Marathon TS	Black River JCT	430	510	570	370	470	530
M2W	8	Marathon TS	Black River JCT	430	510	570	370	470	530
M2W	9	Williams Mine JCT	Hemlo Mine JCT	330	330	330	230	230	240
M2W	10	Hemlo Mine JCT	Animki JCT	430	510	570	370	470	530
M2W	10	Hemlo Mine JCT	Animki JCT	430	510	570	370	470	530
M2W	15	Marathon TS	Pic DS	370	440	490	320	400	460
M2W	16	Black River JCT	Umbata Falls JCT	430	510	570	370	470	530
M2W	16	Black River JCT	Umbata Falls JCT	430	510	570	370	470	530
M2W	22	Manitouwadge JCT B	Manitouwadge DS #1	370	440	470	320	400	440
M2W	25	Umbata Falls JCT	Williams Mine JCT	330	330	330	230	230	240
M2W	25	Umbata Falls JCT	Williams Mine JCT	330	330	330	230	230	240
M2W	26	Manitouwadge JCT B	Manitouwadge TS	580	690	790	500	630	740
M2W	27	Animki JCT	White River DS	430	510	570	370	470	530
M2W	27	Animki JCT	White River DS	430	510	570	370	470	530
M37L	1	Lakehead TS	M37L_M38L T#A001 JCT	1300	1580	1780	1120	1440	1650
M37L	3	M37L_M38L T#C279 JCT	Marathon TS	1300	1580	1780	1120	1440	1650
M38L	1	Lakehead TS	M37L_M38L T#A001 JCT	1300	1580	1780	1120	1440	1650

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
M38L	3	M37L_M38L T#C279 JCT	Marathon TS	1300	1580	1780	1120	1440	1650
N93A	1	Atikokan TGS	Marmion Lake JCT	1020	1230	1510	880	1120	1430
N93A	2	Marmion Lake JCT	Mackenzie TS	1300	1580	2030	1120	1440	1920
P1P	1	Port Arthur TS #1	Port Arthur JCT	430	510	570	370	470	530
P1T	1	Port Arthur TS #1	TBPI Thunder Bay JCT	580	690	710	500	630	660
P1T	2	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	430	510	570	370	470	530
P1T	3	TBPI Thunder Bay JCT	TBPI Thunder Bay JCT	580	690	710	500	630	660
P1T	4	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	430	510	570	370	470	530
P21G	1	Mississagi TS	P21G POLE 261 JCT	1020	1230	1510	880	1120	1430
P21G	2	P21G POLE 261 JCT	Third Line TS	1128	0	1200	963	0	1068
P22G	1	Mississagi TS	Echo River TS	1128	0	1200	963	0	1068
P22G	2	Echo River TS	Third Line TS	1128	0	1200	963	0	1068
P25W	1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P25W	2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P25W	3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P26W	1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P26W	2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P26W	3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P3B	1	Port Arthur TS #1	Birch TS	720	830	860	620	740	780
P5M	1	Port Arthur TS #1	Conmee JCT	580	610	620	500	530	540
P5M	4	P5M STR 603 JCT	P5M STR 608 JCT	580	580	580	430	430	430
P5M	6	P5M STR 621 JCT	P5M STR 626 JCT	580	580	580	430	430	430
P7B	1	Port Arthur TS #1	P7B STR 320 JCT	840	920	960	720	830	860
P7B	2	P7B STR 320 JCT	Birch TS	720	870	940	620	790	870
Q4B	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
Q4B	2	Abitibi JCT	James Street JCT	1000	1090	1140	850	970	1030
Q4B	3	James Street JCT	St.Paul JCT	1000	1090	1140	850	970	1030
Q4B	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
Q4B	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
Q4B	6	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1430	850	1100	1350
Q4B	7	St.Paul JCT	ResFP Kraft CTS	720	870	940	620	790	870
Q4B	8	Walsh Street JCT	Fort William TS	1000	1090	1140	850	960	1020
Q5B	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
Q5B	2	Abitibi JCT	James Street JCT	1000	1200	1490	850	1100	1410
Q5B	3	James Street JCT	St.Paul JCT	1000	1200	1490	850	1100	1410
Q5B	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
Q5B	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
Q5B	6	Abitibi JCT	Erco JCT	720	870	950	620	790	880
Q5B	7	Erco JCT	Q5B STR A6 JCT	720	870	950	620	790	880
Q5B	8	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1490	850	1100	1410
Q5B	9	St.Paul JCT	ResFP Kraft CTS	720	810	840	620	720	760
Q5B	10	Walsh Street JCT	Fort William TS	1000	1000	1000	850	850	850

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
R1LB	1	Pine Portage SS	Lakehead TS	410	410	410	330	330	330
R1LB	2	Lakehead TS	Birch TS	720	860	910	620	790	840
R2LB	1	Pine Portage SS	Lakehead TS	540	540	540	420	420	420
R2LB	2	Lakehead TS	Birch TS	720	870	920	620	790	840
R9A	1	Pine Portage SS	Alexander SS	540	540	540	420	420	420
R9A	2	Alexander SS	Alexander GS	430	430	430	340	340	340
R9A	3	Alexander SS	Alexander SS	540	540	540	420	420	420
S1C	1	Conmee JCT	Lac Des Iles JCT	560	560	560	400	400	400
S1C	2	Lac Des Iles JCT	Silver Falls GS	560	560	560	400	400	400
S1C	6	Lac Des Iles JCT	Lac Des Iles Min CSS	430	450	450	370	390	400
T1M	1	Terrace Bay SS	Angler Switch JCT	600	600	600	460	460	460
T1M	2	Angler Switch JCT	Pic JCT	600	600	600	460	460	460
T1M	3	Pic JCT	Marathon TS	720	870	1020	620	790	960
T1M	3	Pic JCT	Marathon TS	720	870	1020	620	790	960
T1M	4	Pic JCT	Marathon DS JCT	430	490	490	370	440	450
T1M	5	Marathon DS JCT	Marathon DS	430	490	490	370	440	450
W21M	1	Wawa TS	Marathon TS	1020	1020	1020	880	880	880
W21M	1	Wawa TS	Marathon TS	1020	1020	1020	880	880	880
W22M	1	Wawa TS	Marathon TS	1020	1140	1200	880	1020	1080
W22M	1	Wawa TS	Marathon TS	1020	1140	1200	880	1020	1080
W35M	1	Marathon TS	W35M_W36M T#D001 JCT	1300	1580	1780	1120	1440	1650
W35M	4	W35M T#F235 JCT	Wawa TS	1300	1580	1780	1120	1440	1650
W36M	1	Marathon TS	W35M_W36M T#D001 JCT	1300	1580	1780	1120	1440	1650
W36M	4	W36M T#F233 JCT	Wawa TS	1300	1580	1780	1120	1440	1650
W3C	1	Whitedog Falls SS	Caribou Falls GS	670	670	670	550	550	550

C.3.2 Special Protection Systems

Table 6 below shows the available special protection systems in the study region.

Table 5 | Relevant Special Protection Systems

Facility	Description
NW-SPS	The Northwest SPS is used to prevent instability in the West system, prevent low and high voltage in Wawa area, and prevent high voltages in Algoma Area. Following the loss of East-West 230kV tie between Wawa and Mississagi, Algoma and Mississagi, Algoma and Sudbury with flows west, it rejects load in Lakehead area, Great Lakes Power and/or Algoma and/or trip capacitor at Algoma.
NW-SPS2	Northwest SPS 2 has the capability of cross-tripping multiple 115 kV circuits. The scheme initiates cross-tripping based on single or double circuit contingencies on the 230 kV lines.

---- End of Section ---

C.4 Credible Planning Events and Criteria

C.4.1 Studied Contingencies

Table 7 below shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the amount of load rejection/curtailment allowed as per ORTAC.

Table 6 | Types of Contingencies Assessed

Pre-contingency	Contingency[2]	Type	Mapping to TPL/Directory 1 Event	Rating[3]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by-configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total
All Transmission Elements in-service, local generation out-of-service, followed by system adjustments (Satisfy ORTAC 2.6 Re: local generation outage)	None	N-0	N/A	Continuous	None
	Single	N-1	P3	LTE	150 MW by-configuration; >0 MW lost by curtailment[4]; Total 150 MW
	Double	N-2	N/A	STE, reduced to LTE	>150 MW lost by curtailment[3] ; 600 MW Total
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment; Total 600 MW

[2] Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection; the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

[3] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
STE: Short-term emergency rating. 15-min rating for circuits and transformers.

[4] Only to account for the magnitude of the generation outages

The tables below show the single, common tower, and breaker failure contingencies. Note that:

- Breaker failures and transformer failures that result in the same post-contingency state as the N-1 already documented are omitted.
- The outage events used for the N-1-1 studies are very similar to the N-1 contingencies documented in Table 8 but may be slightly different in some cases to reflect the fact that outages are the removal of a single element rather than all elements in a single zone of protection.

Table 7 | Studied N-1 Contingencies

			Contingencies			
15M1	C2A	Fort Frances T1	Lac Des Iles Mine T5	Murillo T3	Sachigo TS T1	W2
29M1	C2M	Fort Frances T2	Lakehead R1	Muskrat TS T1	Sachigo TS T2	W21M
56M1	C3A	Fort William EG	Lakehead SC11	Muskrat TS T2	Sam Lake T1	W22M
57M1	C3W	Fort William T5	Lakehead SC21	Mussel White T1	Sam Lake T2	W35M
A1B	Calm Lake T1	Fort William T6	Lakehead T7	Mussel White T2	Sandy Lake T1	W36M
A21L	Cameron Falls T1	Geco T1	Lakehead T8	N93A	Sandy Lake T2	W3C
A22L	Cameron Falls T2	Greenwich T1	Long Rapids Gen	Namewamns s T1	Sapawe T1	W54W
A23L	Cameron Falls T3	Greenwich T2	Longlac T2	Nestor Falls T1	Sapawe T2	W8C
A24L	Caribou Falls T1	Jellico T1	Longlac T3	Nipigon 24T1	Schreiber T1	WCD
A3M	Cat Lake T1	K21W	Lowerwhite T1	Nipigon GS T1	Shabaqua T1	WCJ
A4L	Clearwater Bay T1	K22W	M1S	Norman 20T1	Silver Falls T1	WDE
A5A	Crow River T1	K23D	M23L	North Caribou Lake T1	Sioux Narrows T1	WEF
A6P	Crow River T2	K24F	M24L	North Caribou Lake T2	Sioux Narrows T2	WEG
A7L	D26A	K2M	M2D	P1T	Slate Falls T1	WJK
A8L	D5D	K3D	M2W	P3B	South Bay T1	WKM
Agimak T1	Deer Lake TS T1	K4W	M37L	P5M	Spirit Lake T1	WPQ
Agimak T2	Deer Lake TS T2	K5W	M38L	P7B	Spirit Lake T2	WQR
Aguasabo n T1	Dryden Gen EG	K6F	M3E	Perrault Falls T1	Sturgeon Falls T1	WRS

Contingencies

Ainsworth T1	Dryden T22	K7K	Mackenzie T3	Pic T1	T1M	WRT
Alexander T1	Dryden T23	Kakabeka G1	Manitou Falls T1	Pic T2	Tbaybowater T04	WTU
Alexander T2	Dryden T4	Kakabeka G2	Manitou Falls T2	Pikangi TS T1	Tbaybowater T1	WTZ
Alexander T3	Dryden T5	Kakabeka G3	Manitouwa DS T1	Pikangi TS T2	Tbaybowater T2	WVY
Alexander T4	E1C	Kakabeka G4	Manitouwa T1	Pine Portage T1	Tbaybowater T3	WZV
Atikokan T1	E2R	Keewatin T1	Marathon DS 2735T1	Pine Portage T2	Tbaybowater T6	WZW
B6M	E4D	Keeway TS T1	Marathon R11	Poplar Lake T1	Tbaybowater TA	Wapekeka TS T1
BOWATR T26903	Ear Falls T1	Keeway TS T2	Marathon R12	Poplar Lake T2	Tbaybowater TB	Wapekeka TS T2
Balmer T1	Ear Falls T2	Kenora Abitibi AT1	Marathon R3	Port Arthur T1	Tbaybowater TC	Watay TS T1
Balmer T2	Ear Falls T5	Kenora DS T1	Marathon R4	Port Arthur T2	Tbaybowater TD	Wawakape TS T1
Barwick T1	Esker T1	Kenora DS T2	Marathon SC21	Q4B	Tbaybowater TJ	Wawakape TS T2
Barwick T2	Esker T2	Kenora MS T1	Marathon SC29	Q5B	Tbaybowater TK	Wawakape TS T3
Beardmore T1	Eton T1	Kenora MS T2	Marathon T11	Q8B	Tcplvermil T1	Wawatay T1
Beardmore T2	Eton T2	Kenora MS T4	Marathon T12	Q9B	Thunderbay LT2	Weyerhaeuser Dryden T1
Bearskin TS T1	F1B	Kenora TS T1	Margach T1	R1LB	Thunderbay LT3	Weyerhaeuser Dryden T2
Bearskin TS T2	F25A	Kimberclark T3	Margach T2	R2LB	Thunderbay T2	Weyerhaeuser Dryden T3
Birch SC11	F2B	Kimberclark T4	Mattabi T1	R9A	Thunderbay T3	Weyerhauser T1
Birch T2	F3M	Kingfisher TS T1	Mattabi T2	Rainy River T1	Twin Falls Gen	White River T1
Birch T3	Fort Frances MS T1	L3P	Minaki T1	Rainy River T2	UB3B	White River T2
Birch T4	Fort Frances MS T2	L4P	Minaki T2	Red Lake T3	Umbata Falls MPT1	Whitedog Falls T1
Bowater 2690	Fort Frances R2	Lac Des Iles Mine 1209T1	Moose Lake T2	Red Lake T4	Upperwhite T1	Williams Mine T1
Bowater T1	Fort Frances SC1	Lac Des Iles Mine 310TRF001	Moose Lake T3	Redrock DS T1	Valora T1	Williams Mine T2
Burleigh T1	Fort Frances SC2	Lac Des Iles Mine 310TRF002	Murillo T1	S1C	Valrie Falls T1	Winston T1
C1A	Fort Frances SC3	Lac Des Iles Mine T4	Murillo T2	SK1	Vermillion Bay DS T1	

Table 8 | Studied N-2 Contingencies

Contingencies						
A21L+A22L	M2W+M38L	Alexander GS G3T4	Dryden HL26	Lakehead New L4	Marathon L21L23	Rabbit Lake DL2
A23L+A24L	M2W+T1M	Alexander GS G4G5	Dryden JL23	Lakehead PL22	Marathon L22L24	Rabbit Lake DL6
A4L+A5A	M2W+W21M	Alexander GS G4T4	Dryden JL26	Lakehead PL24	Marathon PL1	Rabbit Lake HL3
A7L+R1LB	M2W+W22M	Alexander GS G5T1	Ear Falls L1L4	Lakehead PL37	Marathon PL2	Rabbit Lake HL6
A8L+R2LB	M2W+W35M	Alexander HL6	Ear Falls L3L4	Lakehead W1L37	Marathon W1L36	Rabbit Lake HL7
B6M+P5M	M2W+W36M	Alexander HL7	Ear Falls W1L1	Lakehead W1L38	Marathon W1L38	Rabbit Lake L2L4
C1A+C2A	M37L+M38L	Alexander HL8	Ear Falls W1L3	Lakehead W2L21	Marathon W2L35	Rabbit Lake L2L7
C2A+C3A	M37L+T1M	Alexander KL2	Ebane CB3	Lakehead W2L24	Marathon W2L37	Rabbit Lake L3L4
C3A+R9A	M38L+T1M	Alexander KL4	Fort Frances AK1	Mackenzie HL21	Moose Lake L1L2	Terrace Bay T1M
D26A+F25A	P3B+R1LB	Alexander KL9	Fort Frances AK2	Mackenzie HL93	Moose Lake L1L3	Thunder Bay 30Q5B
F1B+F25A	P7B+R2LB	Alexander L2L7	Fort Frances EH	Mackenzie L21L25	Moose Lake L3L6	Thunder Bay 30Q8B
K21W+K22W	Q4B+Q5B	Alexander L4L5	Fort Frances EL3	Mackenzie L22L93	Moose Lake TL2	Wawa AL21
K24F+K6F	Q8B+Q9B	Alexander L5L6	Fort Frances HL1	Mackenzie New L2	Moose Lake TL6	Wawa AL22
K2M+SK1	R1LB+R2LB	Alexander L8L9	Fort Frances JL1	Mackenzie New L3	Musselwhite 1210M1M	Wawa AL36
K4W+K5W	W21M+W22M	Birch AL1	Fort Frances JL6	Mackenzie New M2	Pine Portage L1L2	Wawa DL1
L3P+L4P	W21M+W35M	Birch AL4	Fort Frances L3L6	Mackenzie PL22	Pine Portage T1L2	Wawa DL2
L3P+P7B	W21M+W36M	Birch AL5	Kenora L21L23	Mackenzie PL25	Pine Portage T1L9	Wawa HL35
M23L+M24L	W22M+W35M	Birch AL8	Kenora L21L24	Marathon AL22	Pine Portage T2L1	Wawa L21L26
M23L+M2W	W22M+W36M	Birch KL2	Kenora L22L23	Marathon AL23	Pine Portage T2L9	Wawa L22L23
M23L+M37L	W35M+W36M	Birch KL4	Kenora PL22	Marathon AL36	Port Arthur 2A6P	Wawa L35L36
M23L+M38L	Aguasabon T1L1	Birch KL6	Kenora PL24	Marathon AL37	Port Arthur 2L3P	Whitedog F L3L4
M23L+T1M	Aguasabon T1L5	Birch KTL3	Lakehead HL21	Marathon HL21	Port Arthur 2L4P	Whitedog F L3L5
M24L+M2W	Alexander GS G1T1	Birch L2L8	Lakehead HL23	Marathon HL24	Port Arthur 2P1P	Whitedog F T1L4
M24L+M37L	Alexander GS G1T2	Birch L5L6	Lakehead HL38	Marathon HL35	Port Arthur 2P1T	Whitedog F T1L5

M24L+M38L	Alexander GS G2T2	Birch TL3L1	Lakehead L22L23	Marathon HL38	Port Arthur 2P3B
M24L+T1M	Alexander GS G2T3	Bowater 2660	Lakehead New L1	Marathon KL1	Port Arthur 2P5M
M2W+M37L	Alexander GS G3T3	Dryden HL23	Lakehead New L3	Marathon KL2	Port Arthur 2P7B

C.4.2 Planning Criteria

The study will use the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),
- Northeast Power Coordinating Council ("NPCC") Directory 1 "Design and Operate of the Bulk Power System" (where appropriate), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

---- End of Section ---

C.5 Study Result Findings

With recent and ongoing transmission reinforcement projects (East-West Tie Reinforcement, Waasigan Transmission Line Project Phase 1, and the Wataynikaneyap Transmission Project) in-service, the Northwest region will be generally adequate to support forecast growth.

Technical studies did not identify any firm supply capacity needs. Nonetheless, high growth sensitivities were studied for the Red Lake/Ear Falls/Dryden and Fort Frances subsystems. IRRP studies explored the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. The limiting phenomena for these subsystems are fully described in the IRRP report body.

Appendix D – Kenora MTS Demand Profiling

D.1 General Methodology

An hourly demand forecast consists of a series of year-long hourly profiles (“8760 profile”, based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are developed to help determine which non-wires options may be best suited to meet regional needs.

For the Niagara IRRP, hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years’ worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station’s hourly load profile. The following predictor variables were used:

- Calendar factors (such as holidays and days of the week);
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled);
- Demographic factors (population data[5]); and
- Economic factors (employment data[6]).

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future While values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 31 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 465 possible hourly load forecasts for each future year being forecast. For example: 31 years of historical weather data × 15 weather sequence shifts = 465 weather scenarios for each year being forecast. June 2nd 2025 was forecast assuming the historical weather from every May 26th to June 9th period that occurred between 1991 and 2021.

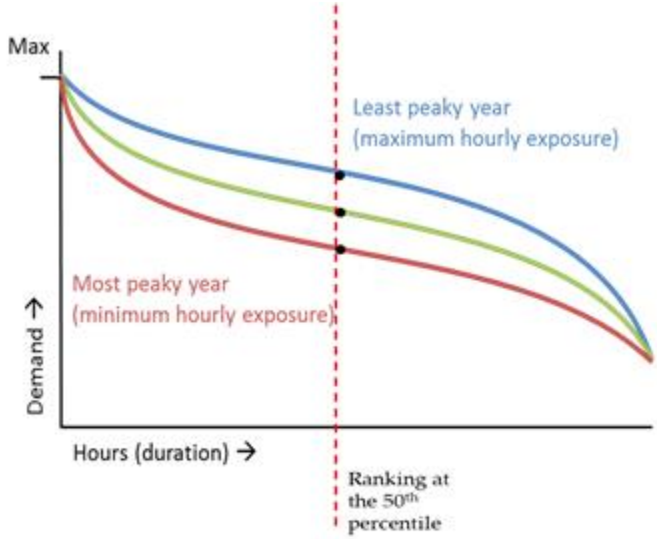
Subsequently, the list of 150 forecasts were ranked in ascending order based on their median energy values. Load duration curves which illustrate this ranking can be seen in Figure 4**Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy**

---

[5] Sourced from the Ministry of Finance and Statistics Canada
[6] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

.

Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy



The forecast in the 3rd percentile was considered the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve). For the Northwest IRRP, the median profiles were scaled to their respective maximums from the peak demand forecast.

D.2 Kenora MTS Demand and Energy-not-Served Profiles

The Kenora MTS hourly demand forecast can be found in the accompanying Excel spreadsheet Table D.2.

Appendix E – Energy Efficiency

Energy efficiency is a low cost resource that offers significant benefits to individuals, businesses and the electricity system as a whole. Targeting energy efficiency in areas of the province with regional and local needs can help offset investments in new power plants and transmission lines, defer this spending to a later date and/or can compliment these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting energy efficiency in a local area, data and assumptions can be leveraged from provincial energy efficiency potential forecasts. In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)[7]. The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. This achievable potential modeling is used to inform:

- future energy efficiency policy and/or frameworks;
- program design and implementation; and
- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.

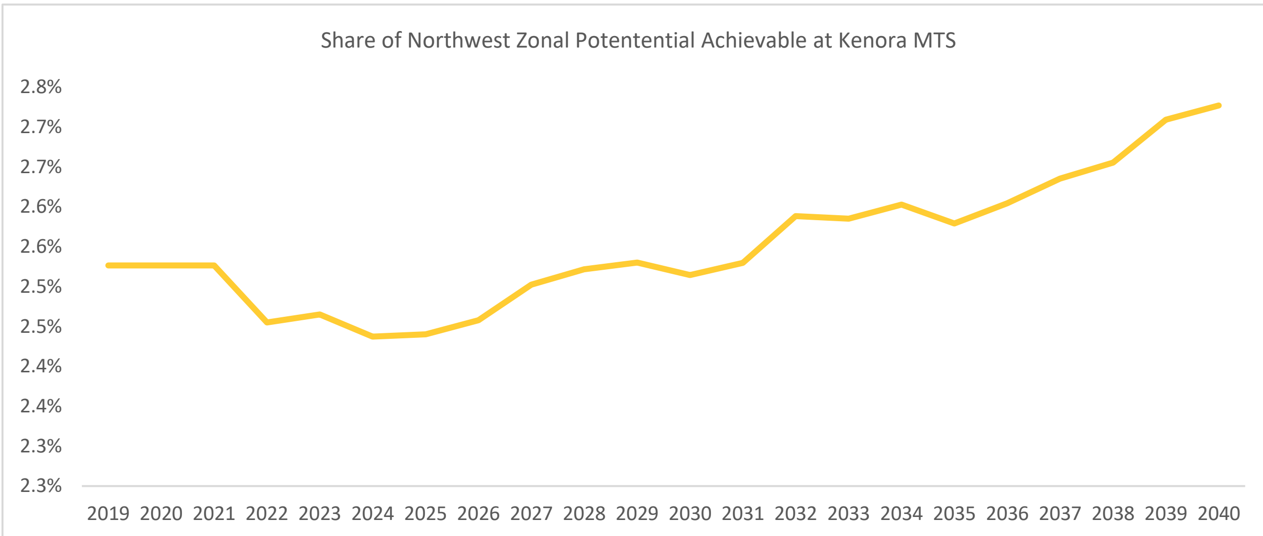
1. The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all CDM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures. Under this scenario, the study shows that CDM measures have the potential to reduce summer electricity peak demand by up to 3,000 MW in the province over the 20-year forecast period and can produce up to 24 TWh of energy savings over the same period.

2. After scaling this level of forecasted maximum achievable savings potential to the local area, the committed savings that are expected to come from existing provincial and federal CDM programs as well as from codes and standards have been netted out and the remaining uncommitted achievable savings potential is presented below. This uncommitted potential provides an estimate of the amount of incremental CDM savings potential that is available to help address emerging local needs in the Northwest region.

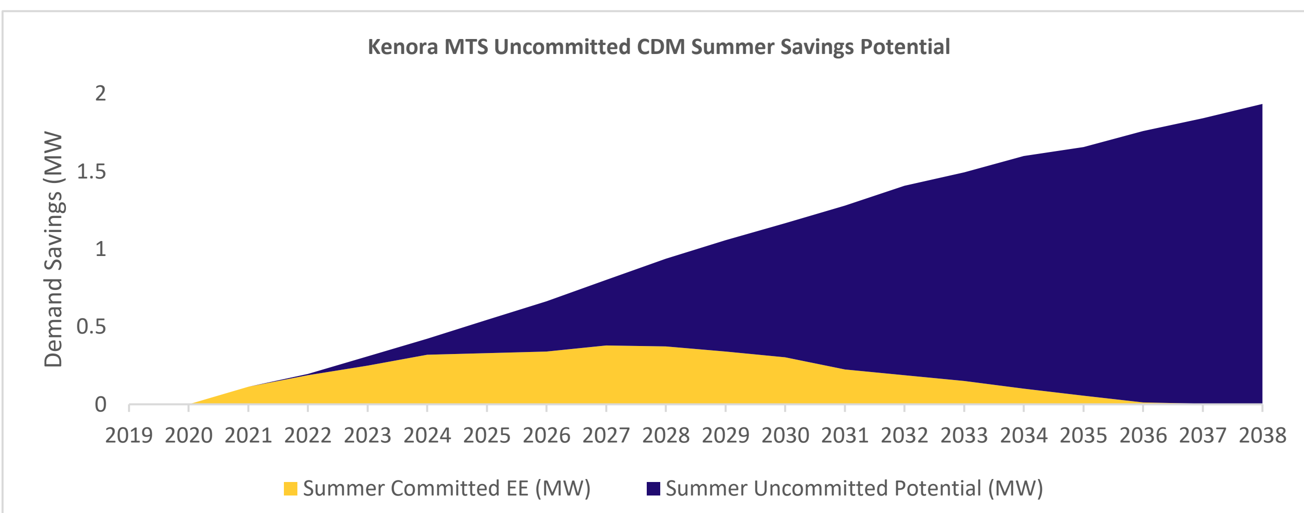
E.1 Incremental CDM for Kenora MTS

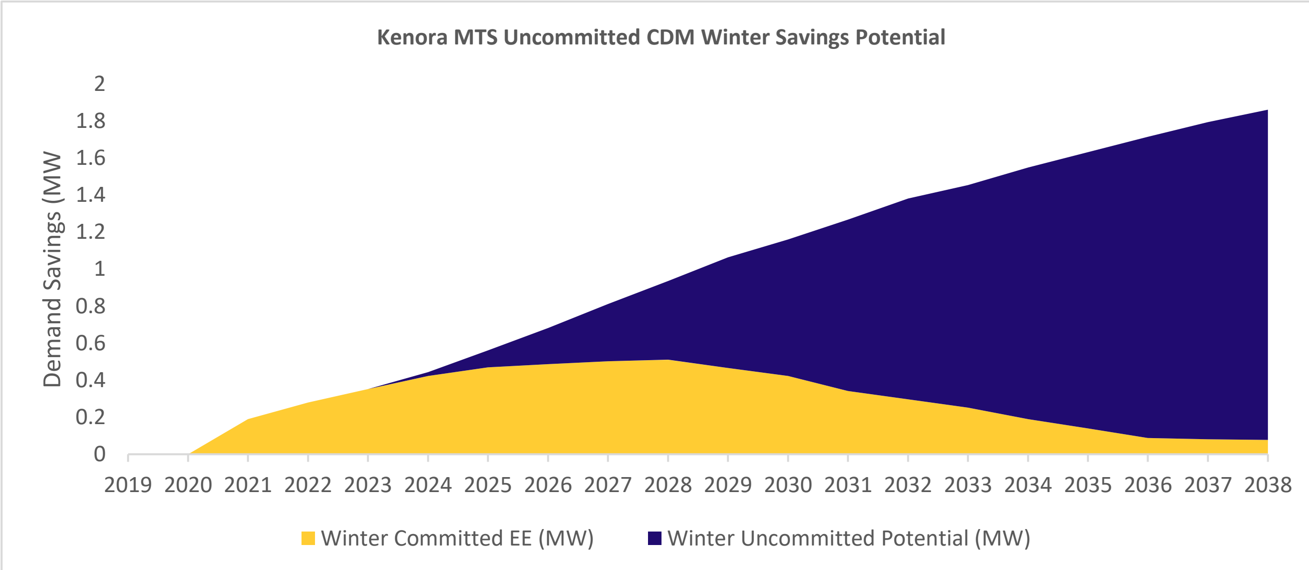
[7] More information about the 2019 Conservation Achievable Potential Study is available on the IESO website (link)

Comparing the regional planning forecast at the Kenora MTS to the zonal energy forecast used for the 2019 APS, it is estimated that approximately 2.5% of the savings potential modeled in the Northwest zone is achievable at the Kenora MTS on average over the forecast period. The rate of zonal savings that is expected to be achievable at the Kenora MTS in each year is illustrated in the graph below.



Applying these rates to Northwest zonal forecasted savings potential provides the maximum achievable savings potential that is expected to be achievable at Kenora MTS. In the near-term, a portion of these achievable savings opportunities are captured by the 2021-2024 CDM Framework programs. Overtime, new opportunities emerge with savings potential available across all sectors in this zone. The figures below illustrate the total committed savings potential that is expected to be achieved by existing programs as well as the uncommitted savings potential, which together add to the total forecasted maximum achievable potential for winter and summer.





Kenora MTS	**2026**	**2040**
Max Achievable CDM Potential Summer (MW)	0.66	1.9
Committed CDM Potential Summer (MW)	0.34	0
Uncommitted CDM Potential Summer (MW)	0.32	1.9
Max Achievable CDM Potential Winter (MW)	0.68	1.9
Committed CDM Potential Winter (MW)	0.49	0.1
Uncommitted CDM Potential Winter (MW)	0.20	1.8

At the Kenora MTS, is estimated that this 1.9 MW of summer savings potential and 1.8 MW of winter potential would cost $7 million dollars to deliver over the forecast period.

Appendix E – Economic Assumptions

The following is a list of the assumptions made in the economic analysis:

- The NPV of the cash flows is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.76 for the study period.
- Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO)
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the reciprocating engine generation and storage assets was assumed to be 30 years and 15 years respectively. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for generation and storage were assumed to be 3 years.
- The size of the resource option was determined by a deterministic capacity assessment.
- A reciprocating gas engine was identified as one of the lowest-cost gas generation resource alternatives for the Northwest region, based on escalating values from a previous study independently conducted for the IESO.[8]
- A battery energy storage system was identified as another low-cost resource alternative. Total battery storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The battery storage capacity and energy costs are based on the 2021 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).
- Sizing of the battery storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing resources to sufficiently charge to meet the hours of unserved energy.
- System capacity value was $144 k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new simple cycle gas turbine (SCGT) in Ontario.
- Production costs were determined based on energy requirements to serve the local reliability need, assuming the fixed and variable operating and maintenance costs for the resource (i.e., battery energy storage system or gas generation)
- Carbon pricing assumptions are based on the proposed Federal carbon price increase of a carbon price that escalates to $170/tCO2e by 2030. Thereafter, the $170/tCO2e assumption is held

---

[8] New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the lowest option of new generation.

constant in real dollars for the forecast period. The benchmark (tCO_2e/GWh) for new gas facilities is assumed to be eliminated by 2030.

- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.