Feedback Form

Regional Electricity Planning in Sudbury/Algoma – July 16, 2026

Feedback Provided by:

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Email: [redacted]

Date: 31 July 2026

To promote transparency, feedback submitted will be posted on the Sudbury/Algoma engagement webpage unless otherwise requested by the sender.

Following the Sudbury/Algoma electricity planning engagement webinar held on July 16, 2026, the Independent Electricity System Operator (IESO) is seeking your feedback on the draft electricity demand forecast scenarios and the proposed engagement plan. A copy of the presentation and the recording of the session can be accessed from the engagement web page.

Please submit feedback to engagement@ieso.ca by July 31, 2026.

Topic	Feedback
What additional information, if any, should be incorporated in the proposed scenarios? How can the proposed scenarios best capture the range and uncertainty of growth potential while informing near-term infrastructure investments?	See ORA comments below.

Topic	Feedback
What areas of concern or interest about electricity should be considered as part of the planning process?	See ORA comments below.
What information is important to provide throughout the engagement?	See ORA comments below.
Does the proposed Engagement Plan provide sufficient scope and opportunities for input?	See ORA comments below.

Ontario Rivers Alliance (ORA) is a not-for-profit grassroots organization with a mission to protect, conserve, and restore Ontario rivers. ORA advocates for effective policy and legislation to ensure that development affecting Ontario rivers is environmentally and socially sustainable.

ORA thanks the IESO for publishing the draft forecast methodology document[1] and the summer[2] and winter[3] data tables ahead of the webinar. In January, ORA asked the IESO to share the forecast load drivers, baseline data and explicit assumptions. The IESO replied that detailed methodologies are *typically published with the final report*[4] but that publication is sometimes advanced *to enable more purposeful community and stakeholder participation and input.*[4] The IESO did exactly that here. That decision is what makes the detailed comments below possible, and ORA asks that it continue at every milestone.

What additional information, if any, should be incorporated in the proposed scenarios? How can the proposed scenarios best capture the range and uncertainty of growth potential while informing near-term infrastructure investments?

The reference forecast is presented to the public as a firm-load forecast, but it is not one. The webinar presentation describes the reference scenario as *firm loads (current and planned)*[5] and states that the *Reference forecast based on firm loads will drive near-term to medium-term expenditures.*[5] The methodology document tells a different story. Table 3, titled "*Large Proposed Connections (Speculative Loads)*[1]", lists eleven such connections at Martindale TS and five at Clarabelle TS in the reference case. Section 1.2.3 confirms that *projects can be categorized into committed and uncertain categories, with uncertain projects having reduced load values.*[1] Greater Sudbury Hydro described this component at the webinar as *the proposed large connection or speculative load forecast.*[6] Uncertain projects are therefore in the reference case, discounted rather than excluded.

Two different firmness tests are being applied within a single forecast. For transmission-connected wholesale consumers, section 2.2 of the methodology sets a clear line: potential facilities were included in the reference forecast *only if the project was committed as per Market Manual 1.4.*[1] For distribution-connected large connections, no committed test is applied at all. Instead, a two-thirds utilization factor, a coincidence factor and a ramping schedule are used to produce a risked load value.[1] ORA is not questioning the arithmetic. ORA is asking that one standard be applied, and that the label match the contents, because this is the forecast the IESO says will drive near-term spending under the Ontario Energy Board test that approved projects be *just and reasonable.*[5]

Removing the low scenario compounds the problem. The presentation states that *a Low forecast was considered but not developed due to the small number of needs identified in previous planning stages.*[5] ORA asked for a low or no-growth scenario in January. The purpose of a low case is not to generate needs. Its purpose is to test whether the needs generated by the reference case survive if growth does not materialize, and to size the ratepayer exposure if it does not. Dropping the low case removes the only downside test, while speculative load remains inside the case that drives spending. The uncertainty in this forecast is real and material: the gap between the reference and high scenarios reaches 96.8 MW in winter 2045 and 89.2 MW in summer 2045.[2,3]

ORA Recommendation 1: Develop and publish a low demand scenario alongside the reference and high scenarios, and report identified needs and estimated ratepayer costs under all three.

ORA Recommendation 2: Disclose the composition of the reference forecast, specifically: (a) apply a single, stated test of firmness to both distribution-connected and transmission-connected loads; (b) publish the megawatts contributed by committed and by uncertain projects separately; (c) publish the share of forecast growth attributable to transmission-connected wholesale consumers, as requested at the webinar and taken away for follow-up; and (d) either move uncertain loads to the high scenario or describe the reference scenario accurately.

On point (c), ORA has calculated the figure from the published data tables and offers it for confirmation. Between 2026 and 2045, transmission-connected wholesale demand accounts for roughly 28 percent of winter reference growth and 39 percent of summer reference growth. Distribution-connected demand accounts for the remaining 61 to 75 percent across seasons and scenarios.[2,3] This matters for what gets built, and it is addressed further below.

The forecast does not appear to incorporate Indigenous community data, although it was specifically requested and the IESO agreed it was essential. In January, M'Chigeeng First Nation asked the IESO to account for both Indigenous and non-Indigenous populations on Manitoulin Island, for Indigenous community energy plans, existing gaps and future projects, and for the potential electrification of natural gas. Whitefish River First Nation asked for Indigenous-led, community-level information including new housing, heating electrification, community facilities and future economic development areas *that may not appear in current forecasts.*[4] Brunswick House First Nation asked that community growth, new infrastructure, housing, forest harvesting operations and new technology be considered.[4] The IESO agreed, replying that given the number of Indigenous communities in the region *it is essential that community-level forecasts, policies, and plans are integrated early into the LDC demand forecasts.*[4]

The published methodology does not show that happening. The nineteen-page forecast methodology document does not contain the words Indigenous or First Nation.[1] The inputs it names are the City of Greater Sudbury Official Plan, the Greater Sudbury Community Energy and Emissions Plan, Hemson population projections, the Housing Accelerator Fund, Ontario Energy Board consumption data, and provincial gross domestic product and housing statistics.[1]

Hydro One Distribution serves the rural and island areas of this region, and therefore most of its First Nation communities. Its method was to apply a growth rate derived from provincial economic indicators to historical station peaks.[1] A provincial growth rate cannot see a First Nation housing plan, a new community facility, or a community energy plan. Sixteen First Nations and Indigenous communities are listed as interested parties in this engagement. They appear in the territory acknowledgement and in the appendix, but not in the forecast inputs. ORA also notes that the IESO's January response directed communities to contact their local distribution company themselves to have their growth plans reflected.[4] Where the IESO has accepted that an input is essential, the obligation to obtain it should rest with the Technical Working Group, not with the communities.

ORA Recommendation 3: Require the Technical Working Group to seek Indigenous community-level forecast inputs directly, including community energy plans, housing and infrastructure plans, planned community facilities and heating electrification, rather than directing communities to approach the local distribution company; and disclose in the final methodology which Indigenous communities were approached, what was received, and how it was reflected in the demand forecast.

The forecast also applies two very different standards of rigour inside one region, and Manitoulin Island is on the wrong side of the line. Greater Sudbury Hydro, which serves only Clarabelle TS and Martindale TS, produced a comprehensive, bottom-up forecast: household projections drawn from the City of Greater Sudbury Official Plan, electric vehicle modelling, building electrification by housing archetype, customer segmentation by class, and a named list of proposed large connections. That work occupies ten pages of the methodology document. Hydro One Distribution, which serves every other part of this region, including Manitoulin Island, Elliot Lake, Espanola, Blind River, the North Shore, West Nipissing and the great majority of the region's First Nation communities, occupies one page.[1] Its method was to apply to historical station peaks a growth rate derived from the Ontario gross domestic product growth rate, provincial housing statistics, *the intensification of urban developments (i.e., MW/sq. ft)*[1] and electrification trends.

Manitoulin TS is the third largest station in this region by winter demand, at 39.0 MW in 2026, behind only Martindale and Clarabelle.[3] It has an identified station capacity need and an identified voltage issue.[4] It is nonetheless forecast by applying a provincial economic indicator to a historical peak. An urban intensification metric expressed in megawatts per square foot has no meaningful application to Manitoulin, which has a length of 100 miles (160 km) and an area of 1,068 square miles (2,766 square km), and is served by small municipalities and First Nations rather than by urban density.[7]

Manitoulin Island is not part of the City of Greater Sudbury, and it is not a suburb of it. It should not be forecast as a residual of provincial averages. The methodology states that local information was used *where possible*[1] to augment these values, but nothing published shows what local information was obtained for Manitoulin, or from whom.

ORA Recommendation 4: Produce a bottom-up demand forecast for Manitoulin TS and the other Hydro One Distribution supplied stations in this region, built from local municipal and First Nation growth information rather than from a provincial economic growth rate applied to historical station peaks, and publish that methodology at the level of detail already provided for Greater Sudbury Hydro.

The forecast assumes existing distributed generation disappears. Effective distributed generation contribution to coincident peak falls from 19.8 MW to 12.3 MW in winter and from 20.2 MW to 9.6 MW in summer over the forecast period. At Manitoulin TS the contribution falls from 1.7 MW to zero by 2032, and at Northshore DS from 3.2 MW to zero by 2034.[2],[3] No explanation is given. If these declines reflect contract expiries rather than physical retirement, then the forecast is building a need out of a procurement decision that has not yet been made. Retaining an existing resource is almost always cheaper for ratepayers than building infrastructure to replace it.

ORA Recommendation 5: Publish the contract expiry dates and resource types behind the declining distributed generation contribution, and run a sensitivity in which existing distributed generation is retained, before any need arising from its loss is carried into the options stage.

Climate change is absent from the forecast methodology. The nineteen-page methodology document normalizes historical demand to median weather for a 2025 base year, meaning *the most likely, or 50th percentile, weather conditions*[1], and then applies an extreme weather adjustment. Nothing in the document projects a changing climate. Ontario's own assessment finds that *the highest risks across all sub-categories were found to be for electrical power generation infrastructure*[8] and that those risks are high now and remain high for all future time periods. This has a concrete consequence here. Sudbury/Algoma is a winter-peaking region, at 661.9 MW winter against 628.4 MW summer in 2026, and building electrification pushes winter harder still, at 31 percent growth in winter against 24 percent in summer.[2],[3] Under warming, winter peaks moderate and summer peaks intensify. The timing of that crossover determines what is built and when. A twenty-year forecast running to 2045 cannot be anchored to 2025 weather distributions and still get that timing right.

The federal science says the same thing and adds to it. Canada's Changing Climate Report finds that warming in Canada is about twice the global rate, that national precipitation increased by roughly 20 percent between 1948 and 2012, and that annual and winter precipitation is projected to increase everywhere in Canada, with the largest percentage increases in the north.[9] For Sudbury/Algoma that means warmer winters, wetter and flashier winter and spring conditions, and hotter summers. Each of those moves peak demand, shifts the seasonal balance between the winter and summer peaks, and stresses the physical infrastructure this IRRP is being written to plan. None of it appears in the forecast methodology. ORA has now asked for this in two consecutive rounds of this engagement and asks that the answer this time be a number rather than an assurance.

ORA Recommendation 6: Run the demand forecast against forward-looking, climate-adjusted weather conditions drawn from the Ontario Provincial Climate Change Impact Assessment rather than 2025 historical medians and disclose how the extreme weather adjustment was derived and whether it is trended over the forecast period. Publish the resulting sensitivity, so that communities can see how much of this forecast rests on the assumption that future weather will resemble past weather.

The energy efficiency assumption may understate what has already been funded. Forecast regional savings from codes, standards and demand-side management reach only 31.0 MW by 2045 against 870.9 MW of winter demand, and 39.6 MW against 779.2 MW in summer, or roughly 4 to 5 percent.[2],[3] Those savings are allocated top down, from the province to the Northeast zone to individual stations, rather than built up from local achievable potential. The methodology states that savings beyond 2027 rest on *the assumed continuation of provincial programs beyond 2027 at savings levels* *consistent with the current framework adjusted for gross demand growth.*[1] Meanwhile the same webinar promoted the expansion of Save on Energy from $1 billion over four years to $10.9 billion over twelve years.[5],[10] If the larger commitment is not reflected in these numbers, the forecast overstates the need, and the IRRP will recommend infrastructure that energy efficiency has already been funded to avoid.

ORA Recommendation 7: Confirm whether the demand-side management assumptions carry the full 2025 to 2036 Electricity Demand Side Management Framework, and commission a bottom-up local achievable potential study for the stations where needs are identified, to be published with the needs rather than after options have been screened.

Finally, a small data point. In Table 9 of both data tables, several historical power factor values are recorded as negative one, including at Sowerby DS, Verner DS and Wharncliffe DS, and Sowerby DS shows a 2021 winter value of 4.6 MW against roughly 2.0 MW in every subsequent year.[2],[3] These are likely sign conventions or metering artifacts, but they feed the planning forecast. ORA asks that they be corrected or explained in the final dataset.

What areas of concern or interest about electricity should be considered as part of the planning process?

The shape of the growth points to non-wires solutions. The presentation states that transmission-connected demand is *driven by mining, forestry products.*[5] That describes the existing base, not the growth. As set out above, 61 to 75 percent of forecast growth is distribution-connected: households, electric vehicles, heat pumps, and mid-sized commercial and industrial connections in Greater Sudbury and the surrounding communities.[2],[3] Growth of that shape is precisely what energy efficiency, demand response, distributed energy resources, storage and targeted distribution reinforcement are designed to serve. It is not, on its face, a case for major new transmission.

ORA asked in January that non-wires options be treated as primary solutions rather than as alternatives considered after the fact, and the forecast now published supports that request on the IESO's own numbers.

ORA Recommendation 8: Evaluate non-wires options against the distribution-connected growth profile the forecast actually shows and present the non-wires potential assessment at the same milestone as the identified needs, rather than one milestone later, so that options are not shaped by wires before non-wires have been quantified.

The contribution factors deserve scrutiny, because they decide what can compete. Table 1 of the data tables assigns solar a contribution factor of zero percent in winter and 23 percent in summer, and wind 26 percent in winter and 12 percent in summer.[2],[3] No derivation is published. A resource carrying a zero contribution factor cannot compete at the options stage regardless of its cost, and neither factor appears to account for pairing with storage. The IESO's own Hybrid Resource Equivalency Assessment found that wind, solar and battery storage can provide firm, dispatchable capacity competitive with conventional resources.[11] The same table is also instructive on hydroelectricity, which is assigned 82 percent in winter and 64 percent in summer, below thermal at 94 percent and materially lower in the summer season.[2],[3] That is the IESO's own arithmetic confirming what ORA has argued for years: hydroelectric output is energy limited and seasonally degraded, and it declines further under drought.

ORA Recommendation 9: Publish the derivation and vintage of the distributed generation contribution factors, update the wind and solar factors using current Ontario performance data, and assess renewable resources paired with storage on the firm-capacity basis established by the IESO's own Hybrid Resource Equivalency Assessment.

Manitoulin Island should be treated as a distinct planning area, and it is the natural test case for a non-wires solution. M'Chigeeng First Nation, Whitefish River First Nation, the Manitoulin Planning Board and the Municipality of Central Manitoulin all raised Manitoulin's particular circumstances in January, and ORA supports them.[4] The island has limited transmission redundancy, an identified station capacity need, modest forecast growth from 39.0 MW to 50.5 MW in winter, and an existing voltage issue.[3],[4]

ORA asks the IESO to reconsider how that voltage issue is characterized. The IESO's January response states that low-voltage violations at Manitoulin TS *occur during peak demand when the McLean Mountain wind farm is offline, dropping below the Ontario Resource and Transmission Assessment Criteria (ORTAC) minimum voltage of 113 kV.*[4] Read plainly, that is not a wind problem. It is an unaddressed reactive power and voltage support problem, and it confirms that a 60 MW wind facility owned 50 percent by Northland Power and developed in partnership with the United Chiefs and Councils of Mnidoo Mnising is already carrying reliability value on the island.[12] Voltage support is routinely and cheaply supplied by capacitor banks, static or dynamic reactive devices, or by dynamic reactive support from existing inverters during low-wind hours. The IESO took exactly this route at Chapleau in the East Lake Superior plan, meeting the need with a low-cost capacitor and demand-side management rather than new supply.

ORA asks the IESO to take note of an important fact about this island. The First Nations of Manitoulin are already generating power for Ontario. The United Chiefs and Councils of Mnidoo Mnising are partners in a 60 MW wind facility that has supplied the provincial grid since 2014 under a twenty-year power purchase agreement with the IESO,[12] and the IESO's own evidence shows that the island's voltage performance depends on it.[4] These communities accepted the land use, the risk and the long-term commitment that Ontario asked of them. What they have received in return, in this forecast, is a local generation contribution written down to zero by 2032, a demand projection derived from provincial averages rather than from their own plans and situation, and an identified voltage need that remains unresolved.[3]

That balance should be corrected in this plan. The First Nations and municipalities of Manitoulin Island are entitled to an electricity system stable enough to support their housing, their community facilities and their economic development, and to a planning process that treats their own growth information as a primary input rather than an afterthought. Communities that have delivered generation for the province should not be left waiting for the reliability and the capacity they need in return. Most of what is required here sits within the IESO's mandate for reliability and ratepayer protection. Where any part of it does not, ORA asks the IESO to convey that message to the Minister of Energy and Mines.

ORA Recommendation 10: Identify and report Manitoulin Island needs separately, and evaluate reactive power and voltage support options, including capacitor banks, static and dynamic reactive devices, and dynamic reactive support from existing generation during low-wind hours, before any wires option is screened in for the Manitoulin voltage need. Report Manitoulin Island in a dedicated section of the IRRP and examine Indigenous equity participation opportunities in both wire and non-wire solutions on the island, as Whitefish River First Nation requested.

Reliability and resiliency are not currently forecast inputs, and they should be. At the webinar, Energy Corridor First Nations asked why service quality and reliability did not appear among the local planning drivers and noted that in Greater Sudbury's Ontario Energy Board scorecard a substantial share of distribution outage time is attributable to loss of supply, which originates on the transmission system.[6] The IESO deferred the question to the next phase.

ORA supports Energy Corridor First Nations on this point, and made the same request in January, asking that outage frequency and duration be examined as climate-resilience indicators. Communities experiencing repeated loss-of-supply outages are being asked to accept that this is not a planning input.

ORA Recommendation 11: Incorporate reliability and resiliency data, including outage frequency, duration and loss-of-supply causation, as explicit inputs to the needs assessment, and present that data alongside the identified needs at the second engagement webinar.

Committed bulk projects must be netted out before regional needs are declared. The presentation identifies three bulk initiatives already scheduled to affect this region: the Northeast Bulk Plan, comprising three new transmission lines with planned completion in 2029 to 2030; reactive power devices from the Northern Ontario Voltage study, in service from 2025 to 2029; and a new transmission line under the Northern Ontario Bulk Plan.[5] Hydro One's proposed North Shore Link, a new double-circuit 230 kV line terminating at Mississagi TS, also lands inside this region. If the incremental regional need is not calculated after these projects are in service, ratepayers will be asked to fund the same capability twice.

ORA Recommendation 12: Publish the assumed in-service dates and capability contributions of the Northeast Bulk Plan, the Northern Ontario Voltage study devices, the Northern Ontario Bulk Plan and the North Shore Link and calculate regional needs on an incremental basis after those projects are in service.

What information is important to provide throughout the engagement?

The early release of the methodology and data tables set a good precedent, and the most useful thing the IESO can do is extend it to the assumptions that actually generate the needs. Table 1 of the Engagement Plan lists the information the IESO will make available and whether there is an opportunity for input.[13] Several of the most consequential items are marked no. Planning Assessment Criteria, Historical Demand, Transmission System Assumptions, Resource Assumptions and System Needs are all closed to input. Resource Assumptions are described as including *operational assumptions such as hydroelectric output, capacity factor assumptions, power factor assumed in the analysis*[13], and are published only with the final IRRP report, which is to say after the plan is finished. The public is therefore invited to comment on the demand forecast and on the options, but not on the technical criteria and resource assumptions that convert one into the other.

ORA Recommendation 13: Reclassify the Planning Assessment Criteria and the Resource Assumptions as open to input and publish both at the second engagement webinar together with the identified needs and the studies that produced them, so that feedback can address the assumptions rather than only the conclusions.

Does the proposed Engagement Plan provide sufficient scope and opportunities for input?

In structure, yes. Three webinars aligned to forecast, needs and options, supported by targeted one-on-one discussions and published responses to feedback, is a sound design, and the commitment to engage Indigenous communities in the ways they determine to be most effective is welcome. Three practical fixes would make it work as intended.

First, honour the stated comment period. The Engagement Plan says comments will be accepted *typically over a three-week period*[13] following each engagement session. For this milestone, the webinar was held on July 16 and comments are due July 31, which is fifteen calendar days and eleven business days, over a summer period when municipal councils and First Nation councils frequently do not sit. Small municipalities, Indigenous communities and volunteer organizations cannot review a forty-one-slide presentation, a nineteen-page methodology document and two twenty-year datasets in that window.

Second, correct the engagement schedule. The proposed schedule table lists one-on-one discussions in Q2 2025, the engagement launch in Q3 2025 and Public Webinar #1 in Q3 2025, then moves to Q3 and Q4 2026.[13] Public Webinar #1 was held on July 16, 2026. A published engagement plan is the accountability document for this process, and its dates should be right.

Third, close the loop visibly. ORA and other participants have asked across several rounds that feedback influence outcomes rather than simply be acknowledged. The IESO's responses to date have been thorough and courteous, and in the case of early methodology publication the IESO acted on what it heard. That should be made visible.

ORA Recommendation 14: Amend the Engagement Plan to: (a) provide the full three-week comment period after each engagement session, with extensions available on request to Indigenous communities and municipalities; (b) correct the 2025 dates in the proposed engagement schedule to 2026; and (c) publish, with each response to feedback, a short statement identifying which submissions changed the plan and how.

ORA General Feedback:

ORA thanks the IESO for a clear and direct answer on hydroelectricity. In its January response the IESO stated that *hydroelectricity is not included in the evaluation of wire and non-wire options*[4] and, in a second passage, that *as part of this evaluation, magnetic generators and hydroelectricity are not considered.*[4] ORA welcomes that position and the clarity with which it was given. Because this IRRP will be developed over more than a year and will undergo an options analysis in 2027, ORA asks that the position be recorded in the plan itself rather than resting solely in a response-to-feedback document.

ORA Recommendation 15: State in the Sudbury/Algoma IRRP report, in the section describing option screening, that hydroelectricity is not included in the evaluation as wire or non-wire options, so that the record is unambiguous for this planning cycle and the next.

ORA places the reason on the record briefly, without asking the IESO to act outside its mandate. Hydroelectric generation is not fuel-free. Its fuel is freshwater, and that fuel is becoming less reliable. Ontario's own climate impact assessment identifies electrical power generation infrastructure as the highest-risk infrastructure category, now and for all future periods, and specifically notes that low water flows during drought reduce hydroelectric output.[8]

Reservoirs are also not emissions-free. A global synthesis published in BioScience estimated reservoir water surfaces emit approximately 0.8 gigatonnes of carbon dioxide equivalent each year, with a range of 0.5 to 1.2.[14] Describing hydroelectricity as non-emitting misleads the communities and Indigenous Nations who are asked to host it. The IESO's contribution factors of 82 percent in winter and 64 percent in summer already reflect the operational half of this reality.

In Closing:

ORA's requests in this submission are all within the IESO's mandate of reliability and ratepayer protection. Nothing here asks the IESO to conduct an environmental assessment or to regulate emissions. What ORA asks is that the forecast be labelled accurately, that the downside be tested as rigorously as the upside, that resources already funded and already built be counted before new infrastructure is proposed, and that the assumptions which turn a forecast into a construction program be open to the communities that will pay for it.

Sudbury/Algoma is being planned at a moment when the cheapest capacity available is the capacity that does not have to be built. The forecast the IESO has published shows growth that is overwhelmingly local, distributed and gradual. Planned and well supported, this region can meet that growth with efficiency, distributed resources, storage and modest reinforcement, at lower cost to ratepayers and without new impacts to local rivers, wetlands and watersheds this region depends on.

ORA looks forward to the needs assessment in the fall, and thanks the Technical Working Group for its work to date.

Respectfully submitted,

Linda Heron
Chair, Ontario Rivers Alliance
[redacted]

Endnotes

1 *Independent Electricity System Operator. Sudbury Algoma Integrated Regional Resource Plan, DRAFT Forecast Methodology Document. July 16, 2026. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/SA-20260716-Forecasting-Methodology.pdf*

2 *Independent Electricity System Operator. Sudbury Algoma Area Integrated Regional Resource Plan Data Tables 2026, Summer (Draft). July 16, 2026. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/SA-20260716_Forecast-Data-Table-Summer-Draft.xlsx*

3 *Independent Electricity System Operator. Sudbury Algoma Area Integrated Regional Resource Plan Data Tables 2026, Winter (Draft). July 16, 2026. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/SA-20260716_Forecast-Data-Table-Winter-Draft.xlsx*

4 *Independent Electricity System Operator. Feedback Received and IESO Responses, Regional Electricity Planning in Sudbury/Algoma, Scoping Assessment Webinar December 18, 2025. January 23, 2026.*

https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/Sudbury-Algoma-20260112-Responses-to-Feedback.pdf

5 *Independent Electricity System Operator. Sudbury Algoma Area Regional Electricity Planning, Webinar #1: Demand Forecasts. July 16, 2026. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/SA-20260716-Demand-Forecast.pdf*

6 *Independent Electricity System Operator. Sudbury Algoma Public Webinar #1, recorded presentation. July 16, 2026. https://youtu.be/k_9jPsoPrPA*

7 *Encyclopaedia Britannica. Manitoulin Islands, Great Lakes, Ontario, Canada. https://www.britannica.com/place/Manitoulin-Islands*

8 *Ontario Ministry of the Environment, Conservation and Parks. Ontario Provincial Climate Change Impact Assessment. 2023. https://www.ontario.ca/page/ontario-provincial-climate-change-impact-assessment*

9 *Bush, E., and Lemmen, D.S. (eds.). Canada's Changing Climate Report. Government of Canada, Ottawa. 2019. https://changingclimate.ca/CCCR2019/*

10 *Independent Electricity System Operator. 2025-2036 Electricity Demand Side Management Framework. https://www.ieso.ca/Sector-Participants/Energy-Efficiency/2025-2036-Electricity-Demand-Side-Management-Framework*

11 *Independent Electricity System Operator. Hybrid Resource Equivalency Assessment. August 2025. https://ieso.ca/-/media/Files/IESO/Document-Library/Technical-papers/Hybrid-Resource-Equivalency-Assessment.pdf*

12 *Northland Power Inc. McLean's Mountain. https://northlandpower.com/sites/mcleans-mountain/*

13 *Independent Electricity System Operator. Regional Electricity Planning, Sudbury Algoma, Engagement Plan. June 11, 2026. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Sudbury-Algoma/SA-20260611-Engagement-Plan.pdf*

14 *Deemer, B.R., Harrison, J.A., Li, S., Beaulieu, J.J., DelSontro, T., Barros, N., Bezerra-Neto, J.F., Powers, S.M., dos Santos, M.A., and Vonk, J.A. Greenhouse Gas Emissions from Reservoir Water Surfaces: A New Global Synthesis. BioScience 66(11): 949-964. 2016. https://academic.oup.com/bioscience/article/66/11/949/2754271*