Atikokan Hydro Inc.

Distribution System Plan

2025 - 2029

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5.0 About this Document

Atikokan Hydro Inc. has prepared this Distribution System Plan in accordance with the Ontario Energy Board's Chapter 5 Distribution System Plan Filing Requirements and as such has been created as part of Atikokan Hydro Inc. 2025 Cost of Service Rate Application; EB-2024-0008. The plan documents Atikokan's practices and processes to asset management. A detailed capital expenditure plan has been created in support of Atikokan's asset management.

The Distribution System Plan includes historical data (2017-2023); 2024, the bridge year, with forecast years 2024-2029 with 2025 being the test year.

5.1 General & Administrative Matters

5.1.1 Purpose of Filing a Distribution System Plan

The purpose of this Distribution System Plan is to present good distributor planning and provide evidence for capital-related expenditures required to maintain supplying electrical services to Atikokan Hydro customers. In adherence to the Filing Requirements, good planning must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes established by the board;

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

The Distribution System Plan must support the Cost of Service Rate Application; Atikokan confirms both have been prepared in support of one another.

Atikokan has followed the best practices of the electricity distribution industry while operating, including OEB's Distribution System Code (DSC) which sets out good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with best practices, Atikokan has diligently maintained its equipment in safe and reliable working order.

5.1.2 Investment Categories

For purpose of the Distribution System Plan, Atikokan's investment categories and activities have been grouped into one of the four OEB defined investment categories below, based on the trigger driver of the expenditure:

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Per filing requirements, a project involving two or more drivers associated with different categories should be placed into the category corresponding to the trigger driver. The following table shows the investment categories and example project/program drivers.

Figure 1: Investment Categories & Example Drivers and Projects

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

5.1.3 Timing of Filing

This distribution system plan covers the historical period of 2017 to 2023, 2024 the bridge year and 2025 to 2029 forecast years. This is Atikokan Hydro's second DSP but first DSP since the OEB's revised 2021 filing requirements for small utilities and Very Small Utilities Working Group (VSUWG) report. This Distribution System Plan is filed in conjunction with Atikokan's Cost of Service Rate Application for rates effective May 1, 2025.

5.2 Distribution System Plan

Atikokan Hydro Inc. has prepared this Distribution System Plan in accordance with the Ontario Energy Board's Chapter 5A Distribution System Plan Filing Requirements for Small Utilities with both a historical and forecast period. This DSP is named and numbered consistently with the OEB's DSP Filing Requirements.

Atikokan Hydro has not filed a DSP within the past five years, thereby the historical period is from 2017 through 2024, the bridge year. The forecast period of the plan is for the test year 2025 through 2029.

5.2.1 Distribution System Plan Overview

This section provides a high overview of the information filed in this plan.

The DSP demonstrates how Atikokan Hydro plans to develop, manage and maintain its distribution system and supporting assets to provide a secure, safe, reliable, and cost-effective service to its customers. The DSP identifies the major initiatives and projects to be undertaken over the DSP planning period.

Atikokan Hydro's 2025 DSP Plan includes:

- A forecast of capital investments for the period of 2025 through 2029.
- A review of the utility's historical performance

Atikokan Hydro's forecast period did not assume any growth in load forecasting based on the historical data of declining customer count. Because there are no drivers for expansion or growth, system access is not a driver of capital expenditures because of growth in the DS Plan period. System Access is however a driver of the DSP period as will be portrayed in this plan. Atikokan Hydro is planning and working together in conjunction with its upstream transmitter to have Atikokan's point of supply changed to inside the town limits, connecting to Mackenzie Transformer Station as its point of supply as opposed to the existing Moose Lake Transformer Station located outside the inner town limits. This system configuration change will strengthen and improve reliability and achieve long-term savings. The change will result in less kilometers of line to maintain by eliminating approximately 15km of Atikokan's 23km of its sub transmission lines. This has always been a vision of Atikokan Hydro but historically the up front capital cost has been cost prohibitive.

This DSP plan meets Atikokan's objectives and commitments.
Atikokan Hydro is committed

- To efficiently deliver a reliable supply of electricity to our customers at competitive distribution rates in the Town of Atikokan; lowest OM&A cost per customer possible in recognizing Atikokan's high OM&A expenses per customer.
- Provide a safe and rewarding work environment for our employes
- Assure that future supply is available to meet Atikokan's changing needs and future of electrification
- Be a good corporate citizen within the Town of Atikokan
- Foster the Town's strategic plan by supporting economic development, infrastructure, and municipal effectiveness and efficiency
- Maintaining adequate cash balances, maintaining the utilities financial health and minimizing financial risk
- Maintaining debt to equity ratio no greater than the OEB deemed level
- Annual investments in distribution assets exceed annual depreciation
- Appropriately allocate investments between distribution and non distribution system expenditures

Corporate Values
In pursuit of our goals, Atikokan Hydro holds certain core values in the operation of the utility and as it relates to its customers, staff and shareholder.
Atikokan Hydro values its employees, customers, partners, and our community. We provide our employees with a safe, healthy environment with fair remuneration and opportunities for learning. We value our customers and work hard to win their trust and support. We strive for excellence and continuous improvement in all aspects of our business. At all times we will act with integrity and respect. We value the long-term health and sustainability of Atikokan Hydro and work to create value for our shareholder by focusing on core business strengths and pursing appropriate business opportunities.

5.2.2 Coordinated Planning with Third Parties

This DSP has been prepared through a coordinated planning process with the following stakeholders

- Local municipality; the Town of Atikokan
- Telecommunication Companies
- Hydro One
- Independent Electricity System Operation (IESO)
- Customers

Municipality

Atikokan Hydro receives notice from the local municipality, the Town of Atikokan, of any proposed local zoning amendments and can comment should the amendments affect the utility.

In addition, beyond the Town of Atikokan being the shareholder, Atikokan Hydro and the municipality have a good working relationship and the CEO of Atikokan Hydro, and the municipality town officials communicate and meet as necessary to share information on local initiatives or needs. Either party initiates the communications from time to time.

Telecommunication Entities

Atikokan has Bell, Shaw and Tbaytel as telecommunications entities that operate in its service territory.

Atikokan has no knowledge of projects in Atikokan's service area relating to "supporting Broadband and Infrastructure Expansion Act, 2021". Based on this, Atikokan has not included any capital investment expenditures for "Broadband Expansion" telecommunication entities and has no specific requests from the local telecommunications entities.

Atikokan Hydro corresponds regularly with Telecommunication third parties due to the joint use attachment agreements in place with the telecommunication entities. Secondly, with infrastructure replacements, Atikokan Hydro notifies the telecommunication company attached to the poles that are going to be replaced arranging for the attacher attached to Atikokan owned poles. Atikokan Hydro consults with pole owners Atikokan is attached to when deficiencies are identified to arrange deficiency repairs. With that said, Atikokan is in frequent communication with telecommunication entities. Regular ongoing make work projects for new telecommunication attachments or transfer requests will be apart of the DSP period but will not materially affect the application. For this reason, no additional allocation of funds are required in the DSP period.

Hydro One

Atikokan has an excellent working relationship with Hydro One. Atikokan has access to an Account Executive at Hydro One for any questions or concerns. The account executive manages the relationship with Atikokan Hydro. Generally, Hydro One's Account Executive and Atikokan's CEO discuss at least once a year to discuss any concerns and inform either party of any future events that may affect either party. The meeting or consultation can be initiated by either party.

Capital investment expenditures included in this plan period are driven by consultations between Hydro One and Atikokan Hydro. Atikokan Hydro has forecasted to receive contributed contributions from Hydro One. Hydro One proposed and was approved by IESO a new double-circuit 230 kilovolt (kV) transmission line between the Lakehead Transformer Station in the Municipality of Shuniah and the Mackenzie Transformer Station (TS) in the Town of Atikokan; the Waasigan Transmission Line Project. This requires Hydro One to upgrade the Hydro One owned Mackenzie TS within the boundaries of the Town of Atikokan to facilitate a new 115kV/44kV load connection on the area transmission connected customers.

The new 115kV/44kV facility will allow Hydro One to supply the customer (Atikokan Hydro) through Mackenzie TS instead of Moose Lake TS, which will improve the overall reliability to Atikokan Hydro end-user customers with use of shorter rural feeder lines.

The existing load of Atikokan Hydro that is currently connected to Moose Lake TS, which will be transferred over once the new 44kV facility is in-service. The in service is proposed to be quarter 4 of 2025 but is contingent on project stage schedules. As of this application the in service is on schedule. In consultation with Hydro One, the in service should occur as projected.

In both the consultations during the regional planning and with Hydro One, Atikokan has known the transformers at Hydro One's owned Moose Lake TS are end of life. As the part of the overall plan and in discussion with Ontario Power Generation, Moose Lake TS load serving facilities will reduce from two transformers to one with one feeder position to maintain backup AC station service supply to Atikokan generating station. With the move of Atikokan Hydro's load to the

Mackenzie TS, Hydro One can invest in one smaller size transformer for Moose Lake; investing the savings of replacing both transformers into the upgrades required at the Mackenzie TS and by supporting Atikokan Hydro financial with capital contributions as a result of the distribution system changes and work required of Atikokan to make this configuration change. Atikokan Hydro is in support of Hydro One's plans. Long before these plans were evolving, Atikokan Hydro has visioned a supply point closer to Town. See Appendix F for an example of one of many correspondences with Hydro One where Atikokan was trying to establish movement. Atikokan Hydro does have a settlement agreement in place with Hydro One and Ontario Power Generation for a few customers in the area. Supporting and continuing to provide these customers with power requires the continued investment into the Moose Lake TS and is supported by the smaller sized new transformer and Ontario Power Generation's contract extension.

Customers

Atikokan Hydro has an office accessible to the public 5 days a week. This gives customers an opportunity to make their billing inquiries, pay their hydro bill, setup payment arrangements, setup an account, request disconnection or reconnection of hydro, request a service order for trees in their house service line and any other inquiries in person. Alternatively, customers can phone, fax, complete a web form or email for assistance.

Customers from time-to-time request changes to services including but not limited to underground service, service modifications, or line clearance letters when constructing a building such as a garage. Atikokan Hydro strives to respond to the customer in a timely manner meeting their needs and maintaining public safety and reliability. Atikokan will continue these good utility practices into the DSP forecast period. This follows the Ontario Distribution Sector Review Panel of Putting Consumers First.

IESO & Regional Planning

Atikokan Hydro did not initiate the consultations but participated in the Northwest Regions regional planning meetings facilitated by the IESO. The meetings involved IESO, Hydro One and LDCs assigned to the Northwest regional group. The Integrated Regional Resource Plan was released January 2023. Atikokan's primary input into the report was load forecast, this assists Hydro One with its regional planning.

Relevant material documents concerning regional planning can be found on the IESO's website. The most recent, January 2023, Integrated Regional Resource Plan for the Northwest Region will be included in the Appendix D of this document. There are no identified needs in the report that affect or result in distribution investments for Atikokan.

Atikokan is not forecasting or planning any changes to load nor renewable generation connections. With no material changes, Atikokan did not seek comment on Atikokan's DSP. For reference, Atikokan did however include both its REG investment plan from 2016 filed in conjunction with EB-2016-0056, 2017 Cost of Service Application, and the IESO Letter of comment in Appendix E.

5.2.3 Performance Measurement for Continuous Improvement

Distribution System Plan

Atikokan Hydro strives for continuous improvement and is motivated by internal and external influences. Section 7 of the Distribution System Code sets out the minimum service quality requirements that a distributor must meet in carrying out its licence to distribution electricity. As per the Ontario Energy Board Reporting and Record Keeping Requirements, Atikokan submits its service quality data information to the regulator on an annual basis.

Atikokan Hydro is continually working to improve performance and is motivated by the OEB's distributor benchmarks and Service Quality Requirements of the Distribution System Code but also driven by the paybacks to Atikokan Hydro's local ratepayers (consumers) as a result of improved performance. The OEB Scorecard is modelled to monitor performance and as such Atikokan utilizes it as a benchmark. See the following page for Atikokan Hydro's 2022 Scorecard as published by the OEB. The 2023 Scorecard was not finalized at the time of preparing this DS Plan.

Figure 2: Atikokan Hydro 2022 Scorecard

Scorecard - Atikokan Hydro Inc.

7/25/2023

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time								90.00%	
		Telephone Calls Answered On Time		100.00%	100.00%	100.00%	100.00%	100.00%		65.00%	
	Customer Satisfaction	First Contact Resolution		100%	100%	100%	100%	100%			
		Billing Accuracy		99.98%	99.17%	100.00%	99.98%	99.99%		98.00%	
		Customer Satisfaction Survey Results		100%	100%	100%	100%	100%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		85.00%	83.00%	83.00%	82.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.17	0.42	1.07	2.38	4.35			1.56
		Average Number of Times that Power to a Customer is Interrupted [2]		0.60	0.19	0.71	0.66	1.91			0.91
	Asset Management	Distribution System Plan Implementation Progress		On Target	On target	On Target	On Target	On Target			
	Cost Control	Efficiency Assessment		4	3	3	3	3			
		Total Cost per Customer [3]		$1,024	$1,035	$1,028	$1,024	$1,098			
		Total Cost per Km of Line [3]		$18,212	$18,329	$18,173	$18,024	$19,325			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time [4]									
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.37	1.35	1.41	1.73	2.48			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.19	0.17	0.12	0.08	0.04			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.78%	8.78%	8.78%	8.78%	8.78%			
			Achieved	11.21%	7.62%	7.29%	10.92%	7.22%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

Atikokan Hydro strives to meet or exceed OEB standards. Atikokan Hydro's decisions and efforts are driven by the following categories:

- Customer Oriented Performance [Customer Focus]
- Cost Efficiency and Effectiveness
- Asset/and or System Operations Performance

- **Customer Oriented Performance [Customer Focus]**

Customer Focus measures have two main performance categories on the Scorecard: Service Quality and Customer Satisfaction. These specific scorecard measures that monitor performance-based decisions with 'customer focus' in mind are as follows:

SERVICE QUALITY

New Residential/Small Businesses Connected on Time

Utility's must connect new services for customers within five 5 working days once all conditions of service are met 90 % of the time. Atikokan Hydro takes pride in its ability to honour customer requests for connections. Due to the small size of the LDC, office staff directly engage with the outside crew and are aware of their schedules and abilities to complete work order requests such as new connections. Atikokan Hydro does not have a lot of new connection requests but performs the same service quality for all connection requests including disconnect/reconnects for electrical upgrades or seasonal reconnections. This practice is one example of Atikokan Hydro's customer focus.

Scheduled Appointments Met on Time

For 2022, Atikokan Hydro had no appointments scheduled; thereby, for 2022 no measure was reported. The 2023 scorecard data reports the same. However, historically Atikokan Hydro meets 100% of its scheduled appointments on time, this exceeds the industry target of 90%. Atikokan Hydro strongly believes that our customers' time is very important and should be respected by meeting all scheduled appointments on time.

Telephone Calls Answered on Time

The Ontario Energy Boards target for answering telephone calls on time is 65%; however, Atikokan Hydro exceeds this with answering 100% of calls on time and has historically been consistent. Answering the call on time is defined as being answered within 30 seconds of receiving the call directly or having the call transferred to them 65% of the time. These statistics are manually logged. Atikokan Hydro has two incoming telephone lines and typically three staff in the office to ensure incoming calls are answered in a targeted manner. Again, this demonstrates Atikokan Hydro's focus on customers and excelling in service quality.

CUSTOMER SATISFACTION

First Contact Resolution

This is a measure of a distributor's effectiveness at satisfactory addressing customer's complaints. The OEB has permitted distributors discretion on how this measure is reported. Based on the 2022 Scorecard Atikokan Hydro resolves 100% of customer contact first time and does not require referral to management for resolution. The first contact resolution measure has a 99.80% five-year average for the most current five year historical period of 2019 through 2023.

Billing Accuracy

OEB industry standard is to have 98% billing accuracy; Atikokan Hydro reported a 99.99% billing accuracy for 2022. 2023 billing accuracy on the 2023 scorecard when publicized will show a 100% accuracy. Atikokan Hydro utilizes a report in its billing system to assist in tracking billing accuracy for the year, but this measure also requires coordinated manual tracking to determine the number of accurate bills issued as a percentage of total bills issued. Atikokan's five-year billing accuracy performance has an average 99.82% accuracy for the 2019 through 2023 historical period.

Customer Satisfaction Survey Results

Atikokan Hydro has had a portion of the bill dedicated to customer ability to express their satisfaction or dissatisfaction with Atikokan Hydro or make comments. Atikokan Hydro has not had customers respond to this feature and for this reason has interpreted this as favorable. Atikokan Hydro ran a customer satisfaction survey fall of 2023. Overall, of the customers that participated, results showed that the majority of respondents are 'very satisfied' with the services provided by Atikokan Hydro. Atikokan was pleased with the results. One hundred and nine surveys were returned. This represents less than ten percent of residential customers. Atikokan's summarized survey results are included in Appendix C.

- **Cost Efficiency and Effectiveness**

The performance categories for Operational Effectiveness from the OEB Scorecard include the following: Safety, System Reliability, Asset Management and Cost Control. Each of these categories have specific measures and will be discussed in greater detail.

SAFETY

Level of Public awareness

Level of Public Awareness measure requires distributors to execute a biannual survey every two years to measure the level of awareness of key electrical safety precautions among public within the electricity distributors service territory. Atikokan Hydro conducted the survey, using UtilityPulse. The latest survey completed March of 2024 indicated an Index Score of 87% reflecting many have good knowledge or have received some information pertaining to electrical safety including contact to overhead wires as an example. This index will be reported on Atikokan's 2023 scorecard once finalized. This index is an improvement from the previous 82% reported on the 2022 scorecard from the 2022 bi-annual survey.

Level of Compliance with Ontario Regulation 22/04

Like other Ontario distributors, Atikokan Hydro's designs, construction, inspection and maintenance practices are audited on a yearly basis as required by Ontario Regulation 22/04.
The scope of the audit is to review the processes, guidelines and standards used in designs, constructions, installations, use, maintenance and repairs, extension, connections and disconnections of electrical equipment forming the distribution system as to avoid or reduce the possibility of electrical hazards.

Section 4 of the regulation sets the safety standards and includes the statement: "All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected, and disconnected to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."

Ontario 22/04 regulation audit findings can include compliance, needs improvement and not in compliance. Atikokan's target is to be compliant. Atikokan Hydro has been compliant for all historical periods of this Distribution System Plan.

Additionally, to ensure compliance with Ontario Regulation 22/04, the Electrical Safety Authority performs Due Diligence Inspections (DDIs) of LDCs. Atikokan believes this measure to be a good measure of performance with respect to both public and employee safety. The DDIs focus on ensuring that construction in the field is in accordance with a plan, work instruction and/or standard design such that no undue hazards exist to the public of LDC personnel. Any needs improvements from a DDI are implemented as soon as possible.

Serious Electrical Incident Index

The Serious Electrical Incident Index measures the number and rate of serious electrical incidents involving the public and occurring on the distribution system. Atikokan Hydro believes safety of both staff and the public to be of the highest importance. Atikokan Hydro is pleased to report zero serious electrical incidents in the historical period covered by the DSP. The table will also be consistent with the data provided in the finalized 2023 scorecard.

Figure 3: Serious Electrical Incident Index

Results					**Target**
Year	Number of Incidents	km of Line	Rate Default Value	Serious Incident Index	Serious Incident Index
2023	0	92	10	0.000	0.000
2022	0	92	10	0.000	0.000
2021	0	92	10	0.000	0.000
2020	0	92	10	0.000	0.000
2019	0	92	10	0.000	0.000
2018	0	92	10	0.000	0.000
2017	0	92	10	0.000	0.000
2016	0	92	10	0.000	0.000
2015	0	92	10	0.000	0.000
2014	0	92	10	0.000	0.000
2013	0	92	10	0.000	0.000
2012	0	92	10	0.000	0.000
2011	0	92	10	0.000	0.000
2010	0	92	10	0.000	0.000

SYSTEM RELIABILITY

One of the questions asked in Atikokan Hydro's Customer Satisfaction Survey was "How satisfied are you with the reliability of the electrical service from Atikokan Hydro, based on the number of outages you have experienced?"

Overall respondents were very satisfied or satisfied:
-76% of respondents very satisfied
-21% of respondents were satisfied

In addition to customer satisfaction with reliability, Atikokan Hydro uses the industry standard system reliability measures SAIDI, SIFI for assessing performance and reliability. The indices measure both the

- Average Number of Hours that Power to a Customer is Interrupted and
- Average Number of Times that Power to a Customer is Interrupted

The industry standard system reliability measures are explained in greater detail in the next section: Service Quality and Reliability.

Due to the configuration of Atikokan Hydro's distribution system, it provides opportunity for enhanced reliability with the ability to complete switching and keep parts of town with power from other operable sub stations and feeders reducing the length of the outage. Generally, if the outage is town wide it is a result of loss of supply; outages on Atikokan's feeders historically affect only parts of town.

While the Distribution System Code requires inspections of distribution assets once every 3 years, Atikokan Hydro inspects its feeders annually as part of its maintenance activities.

ASSET MANAGEMENT

Atikokan completed its first Distribution System Plan in its previously filed Cost of Service Application for rates effective May 1, 2017. For scorecard reporting purposes Atikokan indicated it was on target.

COST CONTROL

Atikokan takes initiatives and measures to control costs where applicable. These efforts range from recycling paper to purchasing supplies on a need be basis, requesting quotes prior to purchasing, choosing the most cost-effective choice for the required quality of service or goods. All staff are mindful of the impacts to rates with expenditures, working together to complete tasks in house as opposed to incurring third party costs when Atikokan has the expertise and ability to complete in house. The DSP being one example, whereby it is completed in house.

Total Cost per Customer / Total Cost per KM of Line

Compared to other industry LDC's Atikokan does have one of the higher cost per customer costs. Atikokan Hydro is conscious of this and tries to make decisions where possible to minimize the impacts to overall rates.

In review of the OEB 2022 Yearbook of Electricity Distributors. Atikokan Hydro has the fourth highest OM&A Cost per Customer. There were 54 LDCs reported in 2022. For discussion purposes Atikokan sorted the LDCs in the OEB 2022 Yearbook and has included the 25 highest LDCs OM&A per Customer below.

Figure 4: OEB 2022 Yearbook Data[1]

LDC	TOTAL CUSTOMERS	TOTAL SERVICE AREA (sq km)	Total km of Line	OM&A per customer ($)	# of Customers per square km of Service Area	# of Customers per km of Line
Algoma Power Inc.	12,332	14,200	2,108	2,479	0.87	5.85
Toronto Hydro-Electric System Limited	790,518	630	29,158	1,312	1,254.79	27.11
Hydro One Networks Inc.	1,440,430	961,143	124,741	1,172	1.50	11.55
Atikokan Hydro Inc.	1,619	380	92	1,098	4.26	17.60
Canadian Niagara Power Inc.	30,434	357	1,535	968	85.25	19.83
Innpower Corporation	20,513	292	1,464	961	70.25	14.01
Halton Hills Hydro Inc.	22,908	281	1,701	874	81.52	13.47
Wellington North Power Inc.	4,053	14	221	863	289.50	18.34
Chapleau Public Utilities Corporation	1,224	14	54	862	87.43	22.67
Sioux Lookout Hydro Inc.	2,915	539	714	836	5.41	4.08
Niagara Peninsula Energy Inc.	58,226	827	4,578	812	70.41	12.72
Hydro Ottawa Limited	358,901	1,116	6,226	811	321.60	57.65
Niagara-on-the-Lake Hydro Inc.	9,816	133	328	804	73.80	29.93
Lakeland Power Distribution Ltd.	14,351	147	385	795	97.63	37.28
Bluewater Power Distribution Corporation	37,321	208	1,191	779	179.43	31.34
North Bay Hydro Distribution Limited	27,678	439	671	777	63.05	41.25
Oakville Hydro Electricity Distribution Inc.	75,885	139	2,021	775	545.94	37.55
Northern Ontario Wires Inc.	5,941	28	370	769	212.18	16.06
Synergy North Corporation	57,088	441	1,270	755	129.45	44.95
Alectra Utilities Corporation	1,076,538	1,924	50,795	753	559.53	21.19
Milton Hydro Distribution Inc.	42,634	368	2,844	738	115.85	14.99
Fort Frances Power Corporation	3,744	32	81	737	117.00	81.00
Burlington Hydro Inc.	68,879	188	1,521	731	366.38	45.29
PUC Distribution Inc.	33,938	342	740	725	99.23	45.86
Greater Sudbury Hydro Inc.	47,962	410	2,547	721	116.98	18.83

1 Partial yearbook data. Only 25 LDCs selected for reference of comparators

Atikokan Hydro has never been delighted by its cost per customer and one may argue this means Atikokan Hydro is one of the least cost efficient and effective; however, in review of the yearbook it is evident each LDC has its own contributors to costs and uniqueness. The yearbook data records both Total service area and KM. Reviewing these indicators it substantiates a few reasons why Atikokan believes it has a higher OM&A compared to others. Atikokan's customers are much more spaced compared to other distributors especially those located in southern Ontario. In the above table, Atikokan has the second lowest customer count; Chapleau Hydro having the least. Chapleau did however, enter into a partnership with Hydro One earlier this year for Hydro One to acquire the utility; therefore, not a good comparator and leaves Atikokan being the smallest LDC based on customer count in this data set. Additionally, Atikokan only has a few apartment buildings. In looking at the 25 LDCs in the above table you can see Atikokan is one of the LDCs with fewer customers per square km of service area and fewer customers per km of Line. Atikokan historically has a declining customer count negatively impacting rates. Atikokan's 2017 Board Approved Customer count/connection of 2259 whereby the 2023 Actual count/connection was 2243 and the 2025 Forecast year is forecasting 2235, another drop in customer count.

Atikokan Hydro monitors its spending throughout the year and reports to the board of director's quarterly with reports detailing activities that are over or under the year's budget in efforts to adhere to the set fiscal year's budget. Atikokan has a very conscious staff compliment in bill impacts.

The lack of economic growth has an adverse impact on the cost per customer. Atikokan Hydro has one of the highest monthly service charges in the province and receives the distribution rate protection subsidy for this reason.

Below is Atikokan's OM&A compared to other very small utilities with less than 5,000 customers.

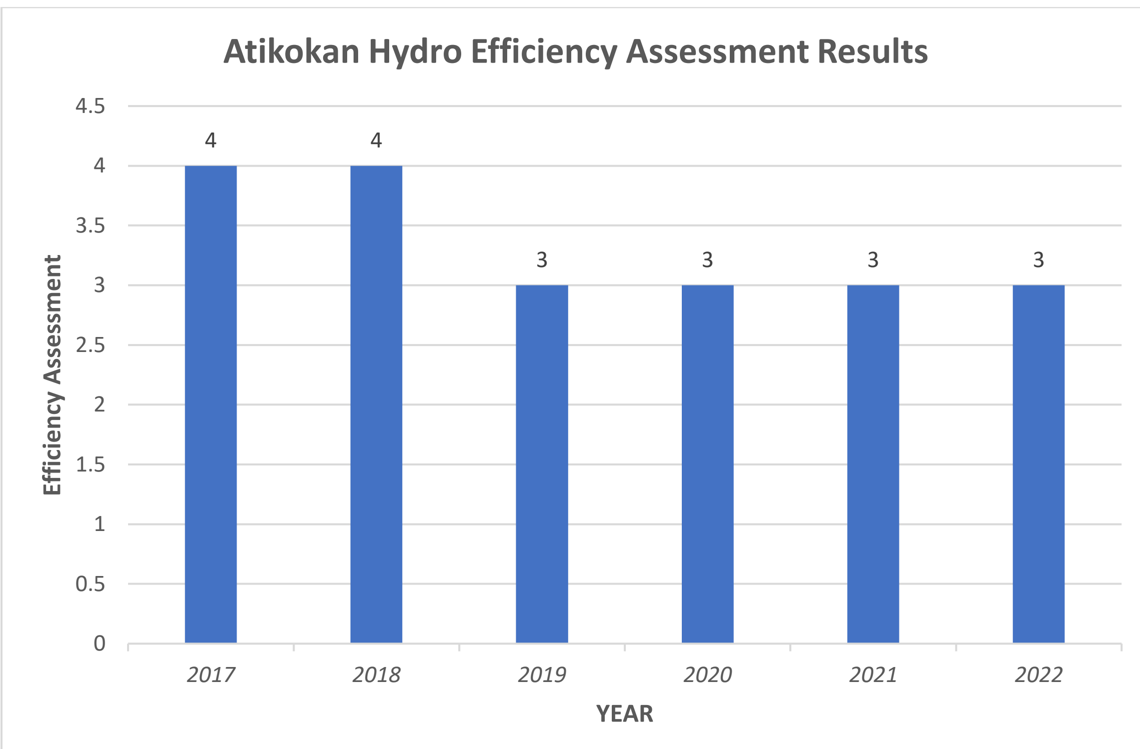
Figure 5: Very Small Utilities 2022 Yearbook Data

LDC	TOTAL CUSTOMERS	TOTAL SERVICE AREA (sq km)	Total km of Line	OM & A per customer ($)	# of Customers per square km of Service Area	# of Customers per km of Line
Atikokan Hydro Inc.	1,619.00	380.00	92.00	1,098.00	4.26	17.60
Wellington North Power Inc.	4,053.00	14.00	221.00	863.00	289.50	18.34
Chapleau Public Utilities Corporation	1,224.00	14.00	54.00	862.00	87.43	22.67
Sioux Lookout Hydro Inc.	2,915.00	539.00	714.00	836.00	5.41	4.08
Fort Frances Power Corporation	3,744.00	32.00	81.00	737.00	117.00	81.00
Hydro 2000 Inc.	1,268.00	9.00	21.00	664.00	140.89	60.38
Renfrew Hydro Inc.	4,384.00	13.00	81.00	640.00	337.23	54.12
Hearst Power Distribution Company Limited	2,720.00	93.00	97.00	599.00	29.25	28.04
Cooperative Hydro Embrun Inc.	2,575.00	5.00	38.00	482.00	515.00	67.76

Efficiency Assessment

The total cost and efficiency ranking (efficiency assessment) was developed by Pacific Energy Group (PEG), an independent third-party consultant of the OEB. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. For the past 5 historical years based on the scorecard data (2018 through 2022) Atikokan Hydro was placed in Group 3 for the most four current years. The 2023 scorecard will report Atikokan maintained its consistency to the prior historical years with its efficiency assessment remaining in the same group. A Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered “average efficiency” -- in other words Atikokan Hydro’s costs are within the average cost range for distributors in the Province of Ontario.

Figure 6: Historical Efficiency Assessments



Atikokan Hydro is continually striving to become more efficient and for greater accuracy of budgeting and reporting; a group 3 efficiency assessment is the utility’s target at minimal.

Bill Impact

Whereby Bill Impact is not a Scorecard measure, it is a measure utilized by both the utility and the Ontario Energy Board in both the proposal and approval of rate design. Atikokan ranks poorly in terms of customer rates as discussed in the previous section. Atikokan attributes the higher service charge compared to other neighboring LDC's to a small customer base, large service area for the customer size and reliability of the two sub transmission feeders contributing to higher OM&A costs per customer. Atikokan does, however, make every reasonable effort to minimize bill impacts and follow the Board's 10% threshold for bill impacts.

- **Public Policy Responsiveness Measures**

These measures are categorized into Conservation & Demand Management and Connection of Renewable Generation on the OEB Scorecard. Atikokan's initiatives in regard to these public policy responsiveness measures are described below.

Conservation and Demand Management

Per Ministry direction and OEB revocation of the CDM provisions in LDCs licenses; whereby, LDCs are to discontinue the Conservation First Framework, Atikokan Hydro did not offer various Conservation & Demand Management (CDM) programs during 2022 nor 2023 and as such there are no measures to report.

Connection of Renewable Generation

In terms of Connection of Renewable Generation, as of July 1, 2024 Atikokan Hydro has 13 micro FIT generators and no FIT generation. Atikokan Hydro's upstream transmitter has constraints and no area availability. Atikokan Hydro believes its existing configuration leaves capcaity limited to micro FIT generators. Given constraints and the history of the previous connections and interest, Atikokan does not find it prudent to make investments or apply for rates in the next 5 years. In doing so it would have a negative impact on rates and reliability for Atikokan hydro considering load is not forecasted to grow. Again, thinking of customer preference and focus this decision supports decision making based on customer impacts.

- Financial Performances

Financial performance is categorized by financial ratios, measuring financial viability and sustainability.

For Atikokan, review of historical financial ratios demonstrates financial performance was healthy and continues to have a trend of being strong.

Where Atikokan Hydro has had history of poor financial performance prior to its 2017 last Cost of Service, it became imperative that Atikokan Hydro re-align the companies financial performance to ensure financial viability of the company and sustainability while continuing to provide a safe and reliable supply of electricity and meeting reglatory obligations. It is of upmost importance Atikokan Hydro continue to make financial and rate impact decisions that achieve industry standards and minimize customer rate impacts to continue to be Atikokan's local distribution company. Financial ratios are part of Atikokan Hydro's quarterly reports to the Atikokan Hydro Board as a tool to measure and ensure the utility's financial health and performance are meeting expected targets.

- Liquidity: Current Ratio (Current Assets/Current Liabilities)

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

Atikokan Hydro's Current Ratio was 2.48 for year ending December 31, 2022 which is higher than the prior years that have ranged between 1.37 and 1.73. The higher current ratio is a reflection of Atikokan Hydro paying down its debt controlling its expenditures. 2023 reported a similar current ratio of 2.54. Debt is used to purchase material capital expenditures, as a means to smooth out the impacts to both the customers and the utility.

- Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt and 40% equity or a ratio of 1.5 (60/40) for rate setting purposes. A high debt to equity ratio indicates a distributor may have difficulty generating cash flows to make its debt payments. Atikokan is mindful of its debt. Atikokan does intend to borrow in the forecast DSP period but has cash flow to do so with its existing debts scheduled to be fully repaid in the 2025 test year.

- Profitability: Regulatory Return on Equity

Atikokan Hydro's current distribution rates were approved by the Ontario Energy Board and include an expected (deemed) Regulatory Return on Equity of 8.78%. The deemed Return on Equity was approved in Atikokan Hydro's last cost of service rate application for 2017 rates in decision EB- 2016-0056. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

Atikokan Hydro's actual achieved Return on Equity for 2022 was 7.22%; thereby, under but within the allowable 3% dead band. For 2023, Atikokan was an over earner but looking at the historical years on the 2022 scorecard, this is an anomaly. Deferred expenses, expired collective agreement, high interest rate and increased cash flow from deferred expenses and paying down debt with lessened debt levels contributed to over earnings. The cost of service application in conjunction with the DSP will address any misalignment in Atikokan's revenue requirement and tariffs if applicable.

Service Quality and Reliability

The standard reliability indices (SAIDA, and SAIFI) reflect performance of the distribution system. The indices measure past system renewal expenditures and drive future planned maintenance and capital expenditure plans. The indices along with annual asset inspections set priorities to meet service quality and reliability.

Atikokan Hydro's SAIDI, CAIDI and SAIFI statistics over the past 6 years are summarized in the table and graphs below. These industry standard distribution system reliability measures are used for assessing performance of Atikokan's electrical distribution system.

SAIDI: System Average Incident Duration Index (Hours) is defined as the length of outage customers experience in a year on average and it is expressed as hours per customer per year. Formula is as below:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interuptions}}{\text{Total Customers Served}}$$

SAIFI: System Average Interruption Frequency Index is defined as the average number of interruptions each customer experience and it is expressed as number of interruptions per year per customer. Formula is as below:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

Atikokan completed Appendix 2-G of the Chapter 2 Appendices and a live excel model has been filed separately. Atikokan has met or exceeded the service quality reliability indicators. The distributor reliability targets will be discussed in the next section. The following tables (Service Reliability and Service Quality) below have been copied from Appendix 2-G.

Figure 7: Historical Reliability Index's

Appendix 2-G
Service Reliability and Quality Indicators
Service Reliability

Index	Excluding Loss of Supply and Major Event Days				
	2019	2020	2021	2022	2023
SAIDI	0.42	1.07	2.38	4.35	0.12
SAIFI	0.19	0.71	0.66	1.91	0.28

5 Year Historical Average		
SAIDI		1.669
SAIFI		0.748

Including Major Event Days, Excluding Loss of Supply				
2019	2020	2021	2022	2023
0.42	1.07	2.38	4.34	0.28
0.19	0.71	0.66	1.91	0.12

5 Year Historical Average		
SAIDI		1.701
SAIFI		0.716

Including Loss of Supply, Excluding Major Event Days				
2019	**2020**	**2021**	**2022**	**2023**
0.62	1.08	2.38	4.35	5.29
1.20	0.71	0.66	1.91	1.12

5 Year Historical Average		
SAIDI		2.744
SAIFI		1.120

Including Loss of Supply and Major Event Days				
2019	**2020**	**2021**	**2022**	**2023**
0.62	1.08	2.38	4.34	5.29
1.20	0.71	0.66	1.91	1.12

5 Year Historical Average		
SAIDI		2.743
SAIFI		1.118

Figure 8: Historical Service Quality Results

Service Quality

Indicator	OEB Minimum Standard	2019	2020	2021	2022	2023
Low Voltage Connections	90.0%	100.00%	100.00%	100.00%	100.00%	100.00%
High Voltage Connections	90.0%					
Telephone Accessibility	65.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Met	90.0%					100.00%
Written Response to Enquires	80.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Emergency Urban Response	80.0%			100.00%		100.00%
Emergency Rural Response	80.0%	100.00%	100.00%			
Telephone Call Abandon Rate	10.0%					
Appointment Scheduling	90.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Rescheduling a Missed Appointment	100.0%					
Reconnection Performance Standard	85.0%	100.00%			100.00%	100.00%

Atikokan confirms the above Service Quality and Service Reliability indicators are consistent with the scorecard.

The following table provides a breakdown of outage counts by cause code for the give year period from 2019 to 2023 with the most frequent outage cause at the top.

Figure 9: Outage Causes

Most Frequent Outage Cause							
Code Cause of Fault	2019	2020	2021	2022	2023	Total	% Cause
(1) Scheduled	2	2	7	3	12	26	24.07%
(6) Weather	2	4	7	7	2	22	20.37%
(5) Defective Equipme	7	4	2	1	1	15	13.89%
(3) Tree Contact	6	1	3	2	0	12	11.11%
(8) Human Element	3	1	4	1	1	10	9.26%
(4) Lightning	2	1	3	1	3	10	9.26%
(9)Unknown	1	2	4	1	0	8	7.41%
(0) Supply Loss	2	1	0	0	1	4	3.70%
(2) Foreign Interface	0	0	0	0	1	1	0.93%
(7) Environment Code	0	0	0	0	0	0	0.00%
Total	25	16	30	16	21	108	100.00%

Atikokan has had no major events since the last Cost of Service filing; EB-2016-0056.

The table below shows the number of customer interruptions that occurred as a result of the cause of interruption.

Figure 10: Historical Customer Interruptions

Number of Customer Interruptions by Cause Code and Year					
Code	**2019**	**2020**	**2021**	**2022**	**2023**
(0) Unknown/Other	0	1	3	0	0
(1) Scheduled Outage	9	117	128	144	183.5
(2) Loss of Supply	1652	2	0	0	1625
(3) Tree Contact	87	348	8	672	0
(4) Lightning	32	1	48	548	3
(5) Defective Equipment	161	4	10	12	4
(6) Adverse Weather	2	701	623	1698	2
(7) Adverse Environment	0	0	0	0	0
(8) Human Element	12	1	2	5	1
(9) Foreign Interface	0	0	0	7	0
Total	1955	1175	822	3086	1818.5

The below table portrays the number of customer hours of interruption that occurred as a result of the cause of interruption.

Figure 11:Historical Customer Outage Hours

Number of Customer Hours of Interruptions by Cause Code and Year					
Code	**2019**	**2020**	**2021**	**2022**	**2023**
(0) Unknown/Other	0	0.5	13.5	0	0
(1) Scheduled Outage	36	357	435.5	307.5	382
(2) Loss of Supply	378	3	0	0	8125
(3) Tree Contact	111.75	522	33	671.67	0
(4) Lightning	31.5	4	48	228	184.5
(5) Defective Equipment	255.82	2	15	12	4
(6) Adverse Weather	2	879	3332	5667	18
(7) Adverse Environment	0	0	0	0	0
(8) Human Element	8	1	6.5	5	21
(9) Foreign Interface	0	0	0	46	0
Total	823.07	1768.5	3883.5	6937.17	8734.5

Distributor Specific Reliability Targets

Over the 5-year historical period, Atikokan did not meet System Reliability targets with the exception of 2020. However, the table titled Most Frequent Outage Cause shows 'scheduled' outages is the main driver in outages.

Although scheduled outages, do impact the customer and are therefore included in the indexes, however, it should be noted these planned outages are rarely town wide and typically affect only a few residential streets at a time. Scheduled outages generally affect approximately 20 customers at a time and an average outage duration of 4 hours. Planned outages are required for the safety of both employees and the general public. Transferring of services from old poles to new poles or relocating and or replacing a transformer are examples of performing scheduled outages. Where planned outages cannot always be avoided Atikokan Hydro tries its best to accommodate the customers affected by the outage as best as possible. If several businesses are affected, Atikokan Hydro has been known to coordinate the shutdown (planned outage) at a mutually agreeable time for the utility and the customers affected.

In the forecast DSP period Atikokan will continue the following practices in efforts to identify and mitigate potential problems impacting both service quality and reliability:

- Testing and inspecting of poles
- Proactive and aggressive vegetation management
- Ongoing inspection and maintenance of assets to identify and mitigate potential problems

As included in this DSP, Atikokan is working to change its point of supply in the upcoming forecast years; this change will strengthen Atikokan's reliability and risk of outages as a result of this change.

This will also improve response times from Hydro One for interruptions as a result of loss of supply where Hydro One crews need to physically visit their transformer station to identify and repair the causes. At minimal this will reduce outages in these circumstances by an hour due to the differences and easier access of geographical locations of Hydro Ones Moose Lake TS versus the Mackenzie TS.

In addition, Atikokan has a few outages a year on sections of its sub transmission lines as a result of trees; these particular sections that have been problematic will no longer be part of the distribution system in the near future. Atikokan strives to keep a well maintained right of way proactively addressing these concerns, but the height and quantity of many of the trees in the area make it difficult to maintain and avoid all outages that have occurred to date.

5.3 Asset Management Process

This section details Atikokan Hydro's process and approach to optimizing capital and operating and maintenance expenditures on its distribution system and general plant.

5.3.1 Planning Process

Process

The asset management process starts with identifying asset conditions through an asset condition assessment process utilizing asset inspections and outage reports. This helps identity the requirements of the upcoming capital and maintenance budgets to ensure safety and reliability of power supply is maintained. In addressing asset conditions and distribution system needs, a balance must be maintained ensuring a safe and reliable supply of electricity to its ratepayers while maintaining the financial health of the LDC including positive cash flows and manageable debt to equity ratios. Customer bill impacts and preferences are also considered when planning expenditures and the timeline of the expenditures.

Atikokan Hydro Inc.'s needs for planned expenditures starts with identifying the needs through powerline inspections completed annually in house by a competent and knowledgeable line crew. Inspections identify condition ratings using a number rated scale 1 through 5; 1 requiring immediate attention.

Rating	Condition	Comments
1	Immediate Attention	Hazardous condition exists that requires immediate attention
2	Immediate Analysis	Requires immediate analysis to determine severity of condition
3	Priority Schedule	Requires prompt planned attention but no immediate hazard exists
4	Regularly Schedule	Requires planned attention but no immediate hazard exists
5	Regular Inspection Cycle	Potential deficiency exists, to be re-evaluated during next regular inspection cycle

Deficiencies noted during powerline inspections are documented on the powerline inspection report using the condition rating and are signed off by the inspector.

Figure 12: Inspection Report Template

Powerline Inspection Report Date:

Feeder Inspected			Inspected by:				Signature:				
					Item of Concern						
Location / Address	Pole	Xarm	Insulators	Primary	Secondary	Service	Transformer	Trees	Comments	Correction Date	

Priority

1. Immediate Attention - Hazardous condition exists that requires immediate attention
2. Immediate Analysis - Requires immediate analysis to determine severity of condition
3. Priority Schedule - Requires prompt planned attention but no immediate hazard exists.
4. Regularly Schedule - Requires planned attention but no immediate hazard exists
5. Regular Inspection Cycle - Potential deficiency exists, to be re-evaluated during next regular inspection cycle

Deficiencies from the inspection reports are prioritized and those with higher need of attention are completed first and or may require further monitoring dependent on the asset.

Pole testing drives a portion of Atikokan Hydro's annual capital budget. All of Atikokan Hydro's poles are wood with the exception of one fibreglass pole. The condition assessment inspections of the poles are identified assessing including but not limited to leaning, cracked or broken poles, indications of burning, woodpecker, insect or beaver damage and excessive surface wear. Pole hammer tests are completed to test the structural integrity of the pole. To maintain a reliable and safe distribution system, aging, identified deficiencies and defective assets such as poles should be removed and replaced before they fail.

Since Atikokan's last DSP, Atikokan has invested in a pole testing unit to be used when deemed necessary to determine the severity of the condition of the pole in addition to the physical inspection and hammer test. The pole testing unit takes inputs factoring in the load on the pole and the pole condition outputting a result assessing whether it passes or fails integrity standards.

Inspections also identify and prioritize maintenance related activities.

Substation inspections occur on a monthly basis utilizing a checklist that is dated and signed off by the individuals who performed the inspection. See Appendix A for an inspection template. Any findings that require follow up require the date of the correction to be marked on the checklist. The yard, tower structure and transformers are inspected identifying deficiencies that require follow up and are planned accordingly. Yard components including and not limited to the condition of the station fence and gates, vegetation growth, condition of signage and locks as examples. Tower structure is observing the cement foundation, any corrosion or rust, condition of insulators and arrestors, loose bolts and any noticeable weaknesses. In addition to the monthly station inspections, substation transformer oil is sampled on an annual basis as part of Atikokan's asset management of the transformers. This helps monitor the condition of the transformer oil and its life expectancy.

Atikokan Hydro's maintenance activities conform to the requirements of Ontario Regulation 22/04 Section 4 "Safety Standards", section 5 "When Safety Standards met" and to the Ontario Energy Board's Distribution System Code Appendix C "Minimum Inspection Requirements". In addition to complying with these Ontario Regulations, the maintenance activities and processes are the foundation and driver to maintenance and capital expenditures for the various distribution system assets.

Atikokan Hydro does not follow a formal 'worst performing feeder' process, nor does Atikokan have a Supervisory Control and Data Acquisition [SCADA] system or breakers. Each outage is followed up with corrective action as necessary. If numerous outages or complaints occur, Atikokan Hydro investigates the fault using best utility practises to determine the cause of the worst performing feeder. Staff continually review system performance with standard indices, compare the performance with trouble reports and inspection reports, and use the information for recommendations on future expenditures.

Data

Inspection reports are documented inspections identifying asset condition deficiencies of concern requiring follow up action; both the risk of failure and consequences of failure is analyzed. It is important to understand the impacts and risks associated with leaving the asset at its existing condition and what acceptable length of time. Assessment considerations include but are not limited to:

- Safety (worker and public),
- Regulatory,
- Reliability,
- Environmental
- Useful Life and
- Financial considerations.

The condition rating and risk analysis must be further analyzed and prioritized, categorizing the items of concern as follows:

1. Immediate Action
2. Within the next budget year and
3. To be considered with major rebuilds

Once risk assessment is completed and prioritized, actions plans can be prepared outlining the timeline and priority of and measures to be taken to resolve the deficiency.

Asset register

During 2015, Atikokan adopted ARCGIS mapping system by ESRI Canada; this register stores the information and characteristics of Atikokan's poles including but not limited to location, age and asset condition. The data collected and logged where applicable includes the following attributes:

1. GPS coordinates
2. Facility ID which indicates the feeder and pole number
3. Owner
4. Height
5. Pole Use

6. Arrester
7. Grounds
8. Manufacture year
9. Framing Standard
10. Install date
11. Pole condition
12. Manufacturer
13. Pole Class
14. Phase
15. Switch on pole
16. Switch ID
17. Transformer on pole
18. Transformer ID
19. Treatment
20. Pictures

Atikokan will continue to update its assets registry as asset improvements occur. Record keeping and asset management will be a continuous evolving and improving process into this DSP period. Examples of the pole specific IDs are illustrated in pictures below. The first picture shows tag ID "F3 174" on the tag. F3 representing the feeder (3) the pole is on and 174 being the pole specific ID. The second pictures tag represents a joint use pole being Atikokan Hydro is attached to a telecommunications pole; example, Bell. Similarly to the other tag (JU5 003) described the '5 ' after JU represents the Atikokan Hydro feeder number and 003 being the specific pole ID. In the first picture another tag is identified, Example T42; this represents the transformer number affixed to the pole.

Figure 13: Pole tags

The tag references has asset management benefits but also helps track the assigned costs to the specific pole.

5.3.2 Overview of assets managed

This section identifies Atikokan Hydro Inc.'s assets managed as a distributor.

Description of Distribution Service Area

Atikokan Hydro's service area covers 380 sq. km servicing approximately 1600 customers. Atikokan's considered to be in an urban distribution service area, as listed in on OEB Yearbook. However, if looking at the definitions of both Urban and Rural; Atikokan technically fits more with the description of rural based on population per Km of line, but Atikokan adheres to the Distribution System Code requirements for 'urban'. Definitions for both rural and urban are as follows:

> "Rural": Generally will be defined on a circuit or sub-circuit basis by each distributor, as areas with a customer density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the distributor may choose to treat some parts of its distribution system as urban though it is "rural" according to this definition.
>
> "Urban": Each distributor will define "Urban", or more populated areas, on a circuit or sub-circuit basis, as areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

Atikokan is located off Highway 11, between Fort Frances and Thunder Bay. The outlying service territory around Atikokan is serviced by Hydro One Networks Inc transmission assets. Fort Frances Power Corp and Synergy North are neighbouring LDCs. Fort Frances is 150 km from Atikokan whereas Thunder Bay is 209 km.

Atikokan is neither a host nor embedded distributor. Atikokan has not previously had any transmission or high voltage assets previously deemed by the OEB as distribution assets.

Electricity is transmitted from Hydro One's Moose Lake TS to Atikokan's two 44KV sub transmission feeders named the 3m2 and the 3m3. The two circuits create a redundancy of supply to the town. The circuits are paralleled in that the open point can be variable. The two lines create greater reliability as an alternative electricity source in event one line is down. Switching is often done as a means to minimize the outage length to customers; transferring load to the other feed while outages are investigated and or faults are corrected. Switching has also been done in the past to avoid an outage where switching allows this for maintenance purposes. 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's system configuration territory is inside and outside of town limits [rural and urban] to the point of supply from upstream transmitter hydro one; that serves the Town of Atikokan. Approximately 23 KM being urban; the remainder rural. The 23 KM is comprised of the mentioned 3M2 and 3M3 sub-transmission 44 kV lines both basically comparable in length at approx. 11.5 KM.

The following map below illustrates an overview of the Atikokan Hydro distribution area and that it extends outside of the town limits up to transmitter Hydro One Networks Inc at it's Moose Lake Transformer Station. The lines in the map illustrate Atikokan Hydro's sub-transmission 44 kV feeders named the 3M2 and 3M3. Not portrayed in the illustration is the distribution feeders within the town limits. The two sub-transmission lines transmitting power to Town have posed to be challenging; the terrain is rough, and access to the structures is limited. Atikokan Hydro does not have the internal resources, often utilizing outside contractors to repair noted line inspection deficiencies on these lines increasing the costs to maintain.

Figure 14: Service Area

The following two pictures are photos taken portraying the rugged and rough terrain of the two 44 kV feeders with limited off-road access.

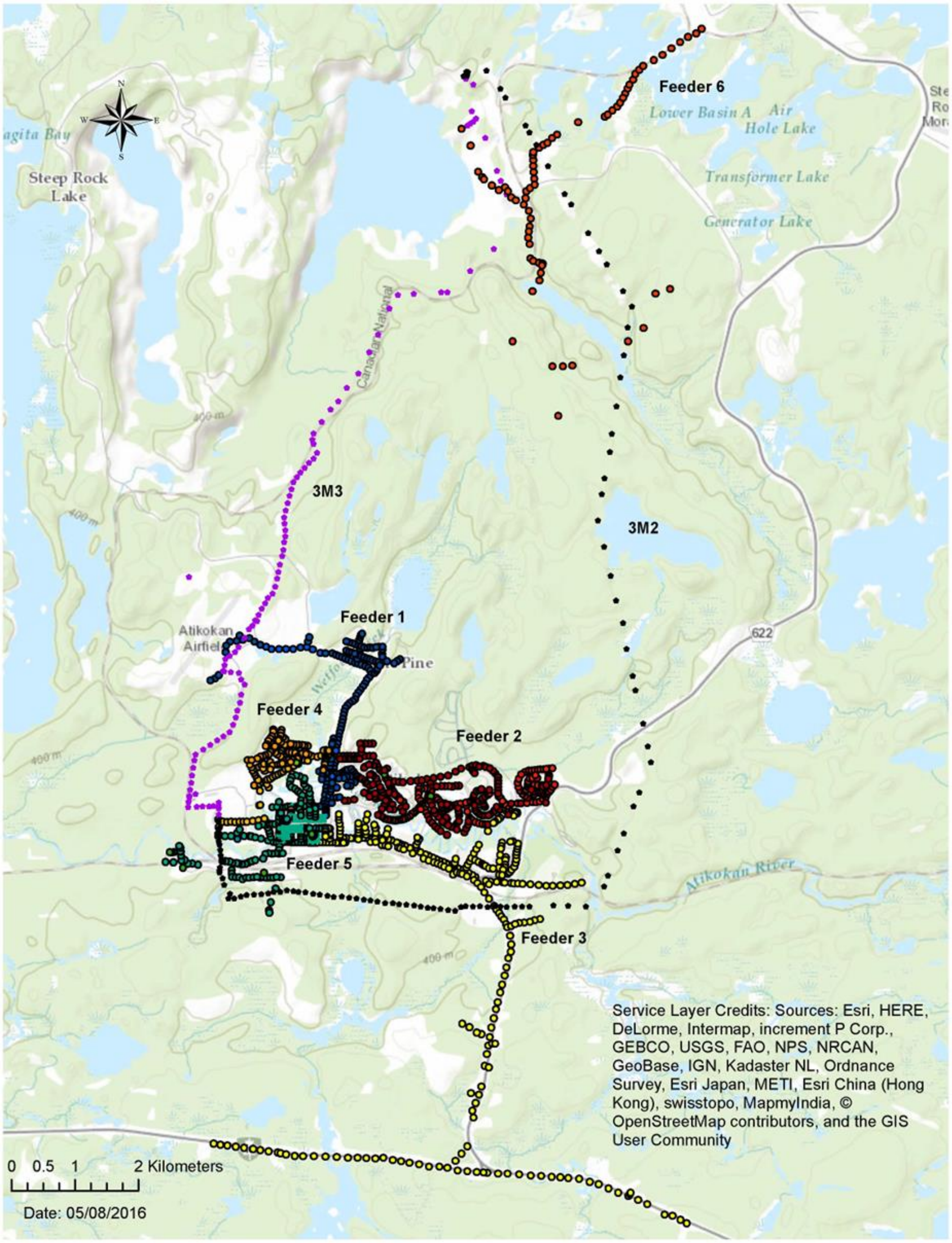
Figure 15:

Figure 16:

The majority of Atikokan Hydro's distribution system consists of overhead lines affixed to wood poles (90 Km). Atikokan only has 2 Km of underground.

Amongst these sub-transmission lines that are paralleled to Atikokan's supply point, Atikokan has had 6 distribution feeders of lines. The following map illustrates the poles and area of each feeder. Looking at the illustration, it is also apparent that feeders 1 through 5 are in more dense area of Atikokan (inside town limits) but feeder 6 and the feeder lines 3M2 and 3M3 extend outside of town.

Figure 17: Overview of Feeders



Note: some of feeder 6 has been removed with the decommissioning of Caland substation.

The following is a summary of Atikokan's principal characteristics.

Figure 18: Atikokan Hydro System Summary

2023		**Supporting Information**
Maximun Winter Monthly Peak *(with embedded generation)*	5,947 kW	Month of Peak Demand: February
Maximun Summer Monthly Peak *(with embedded generation)*	5605 kW	Month of Peak Demand: June
Service Area (sq. km)	380	
Kilometers of Line	92	
Total Customers (Metered)		Annual Usage (kWh)
Residential	1372	8,825,872.77
General Service <50 kW	230	4,501,424.13
General Service 50-4999 kW	16	16,062,198.30
Total Number of Metered Accounts	1618	
Total Unmetered Connections		Annual Usage (kWh)
Street Lighting	622	397,288.71
Total Number of Connections	622	
Annual Metered Consumption (kWh) (non-loss adjusted)		29,786,783.91
Annual Microfit Generation kWh	91,919 kWh	13 Microfit Customers
Number of Substations	3	
Wholesale Meter Points	4	
Poles	1331	
Primary Lines (km)		
Overhead	90	
Underground	2	
Transformers (units)	345	
44kV Switches Load Break	14	

5.3.2.a.i Weather Conditions

Referencing Wikipedia Atikokan climate is as follows:

> "Atikokan has a humid continental climate with four distant seasons. Winters are long, cold and snowy while summers are warm. Precipitation is higher during the summer months and lower during the winter months."

As a result of the long cold winters, Atikokan is a winter peaking LDC. Peak demand is driven by heating homes in the winters as opposed to the use of air conditioners in the summer. Winter and summer peaks often occur in January and July of the year.

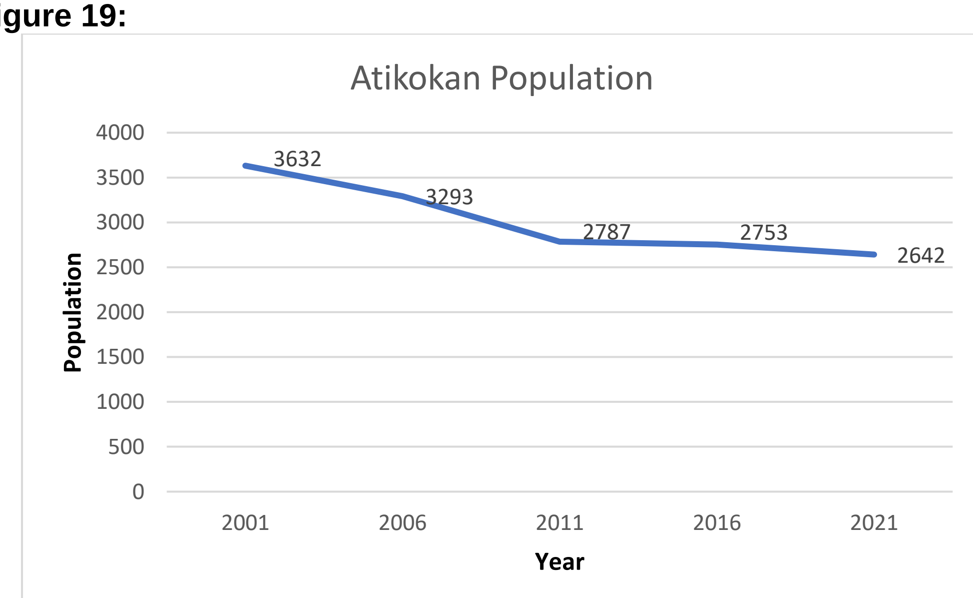
Atikokan has had historical record temperature low of -45.6 Celsius, record high of 37 Celsius; with historical averages of -24 celcius and 24 celcius for lows and highs.

Weather conditions can have an adverse effect on capital and maintenance plans if the temperatures are extreme cold, too much snow, too wet or dry.

5.3.2.a.ii Local Economic Conditions

Reviewing both population and Atikokan Hydro's historical customer count is evident Atikokan does not experience growth. Referencing Wikipedia for 2001, 2006, 2011, 2016 and 2021, the population is illustrated as follows:

Figure 19:



Over the twenty-year period, Atikokan's population has declined by nearly one thousand residents (990) or a drop of 27.3%. Similarly, as a result Atikokan's customer base as declined.

Atikokan's main employers are the Ontario Power Generating Plant located 20 km from Atikokan, the Atikokan General Hospital and the mills Biopower (located in town) and Resolute Forest Products located 30 km from Atikokan. OPG was converted to a biomass plant in 2014 and has pellets transported from Biopower, a manufacturer of pellets. Resolute became operational in 2014. Biopower has been operating since 2018; formerly it was owned and operated by another company. Atikokan thrives on the forest industry and has suffered ups and downs from the volatile impacts of the forestry industry. Overall, the economy of Atikokan is based on forestry, thermal generating station, government services, retail services, tourism and a mixture of small manufacturing businesses.

Summary of System Configuration

Atikokan has three distribution substations. The capacities are as below.

Atikokan Hydro Inc. Substations	
Substation	***Nameplate Capacity***
Hogan	*2 MW*
Hawthorne	*5 MW*
Mackenzie	*6 MW*

**Hawthorne as at 2024.*

Atikokan Hydro has three substations that contain 8 transformers. One of the stations, Hogan, has three single phase transformers with one spare. The Mackenzie substation has two three phase transformers whereas the Hawthorne has one three phase transformer. Two of the three substations have the capacity to hold the current town load. This is another measure of Atikokan's for redundancy and reliability of supply of power to its customers.

In Atikokan's former DSP period, Atikokan had a fourth substation named Caland in a sparsely populated area that delivered electricity at 4160 volts. Unlike the other three substations, Caland was located outside of the immediate town limits and was near Atikokan's upstream transmitter Hydro One's Moose Lake transformer station. This substation was decommissioned and dismantled late 2021. This was a result of Steep Rock Reclamation concerns. The Caland substation only served 5 customers at its most. With the decommissioning of the Caland substation Atikokan Hydro amended its preestablished settlement agreement between Hydro One and Ontario Power Generation to service the 3 remaining customers requiring power. Decommissioning of the Caland substation was imminent in Atikokan's previous Distribution Plan (2017-2021); however, at the time of filing not enough details were known to quantify and established a plan to be included in that DSP period. See Appendix G for an exert of from the DSP filed with EB-2016-0056 for context.

Each station and feeders are controlled by transformers, switchgear and load switches. Atikokan has no remote controlled reclosers for any of the stations or feeders.

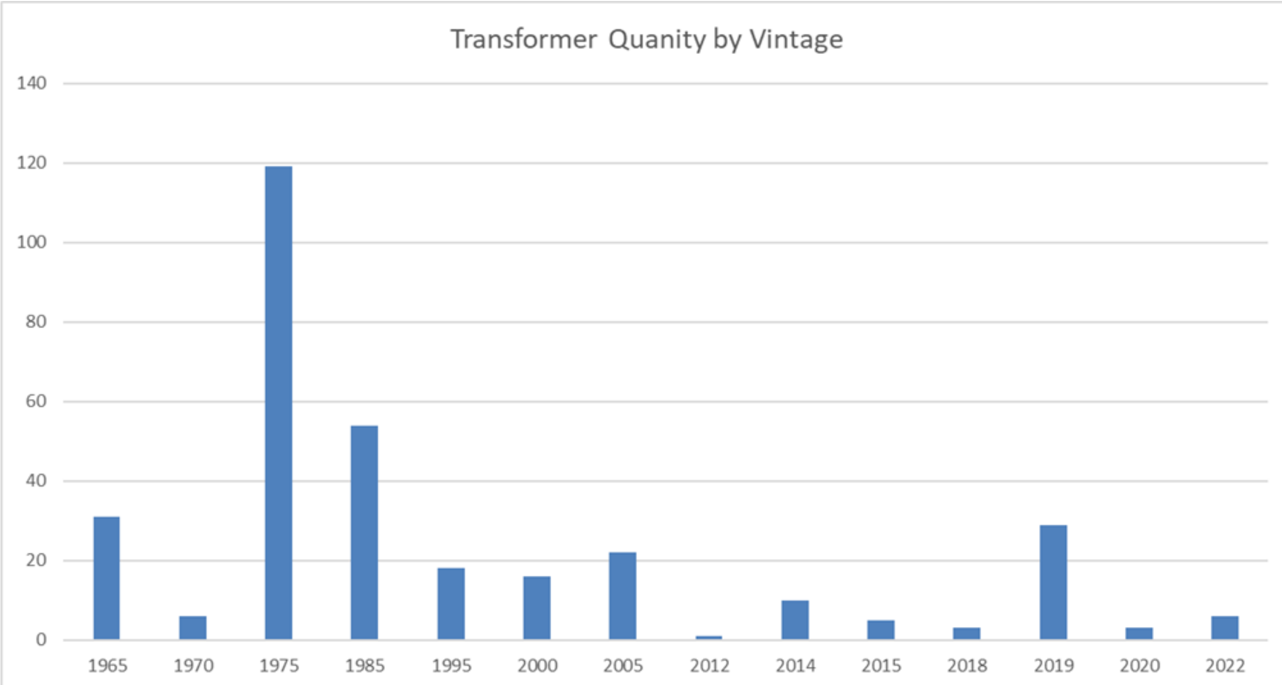
Transformers

Atikokan has 345 transformers mainly pole mounted including 7 trans-closure transformer vaults. Each trans-closure vault has 3 transformers. Excluding the spare transformers, 328 are in service. Size of transformers mainly range from 10 KVA to 100 KVA with most of the transformers ranging from 50 KVA to 100 KVA.

Given the age, condition and efforts to improve operational system performance Atikokan has budgeted a total of $80,000 over the period of the DS Plan to purchase new transformers. Some will address specific concerns identified through inspections and others for spares for emergency replacements. No individual year will exceed the materiality threshold of $50,000 for transformers nor will a single transformer exceed this amount.

The following table and graph shows the vintage and age of Atikokan transformers. This supports that 1) transformers are not replaced solely by age given nearly half are at or exceeding their deemed useful life. 2) It reasonable inspections are showing signs warranting continued investments are needed into replacement transformers.

Figure 20:


Transformer Quanity by Vintage
140
120
100
80
60
40
20
0
1965
1970
1975
1985
1995
2000
2005
2012
2014
2015
2018
2019
2020
2022

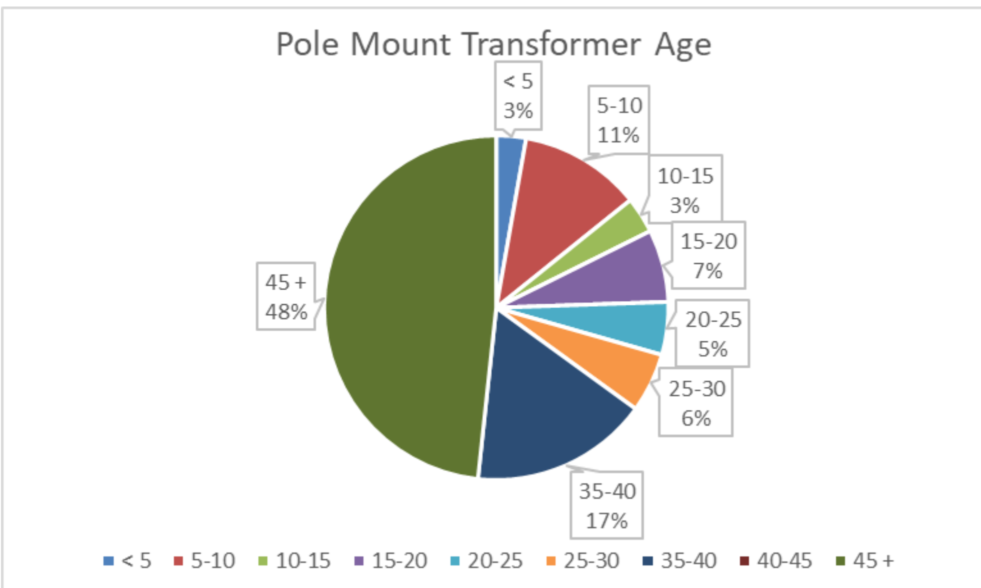

Pole Mount Transformer Age
< 5
3%
5-10
11%
10-15
3%
15-20
7%
20-25
5%
25-30
6%
35-40
17%
45 +
48%
< 5
5-10
10-15
15-20
20-25
25-30
35-40
40-45
45 +

Figure 21:

Pole mounted transformer.

Figure 22:

Some poles have a single transformer, whereas other poles like the image shows here have up to 3 transformers.

Figure 23:

Atikokan owned trans-closure transformer vault.

Figure 24:

Inside view of one of the transformers in trans-closure transformer vault. Trans-closure has 3 transformers.

Metering and Monitoring

Atikokan Hydro has approximately 1659 meters installed on customer premises and are billed actual energy consumption on a monthly basis. The smart meters vary by customer and include meters capable of measuring kWh consumption, kW demand and kVA as well as hourly interval data.

Atikokan Hydro uses Elster meters across its service territory and has contractual agreements with Thunder Bay Hydro Utilities (Synergy North) as the LDC's Metering Service Provider and a Savage Data Systems for Operational Data Store (ODS) which involves the validation, estimation and editing (VEE) of metered data. An agreement is in place with Elster Metering as an Advance Metering Infrastructure (AMI) Solution.

During 2019, 2020 and 2021, Atikokan sampled smart meters for accuracy in accordance with Measurement Canda requirements due to meters approaching a 10 year seal life. The sampling results were positive, with extended seal expiries of 8 years with respective seal expiries of 2027, 2028 and 2029. Metering capital will be a component of the DSP and will exceed the materiality threshold of $50,000 over the DS Plan period. Planned expenditures for meter replacement for failed smart meters will occur. Meters with seal expires will require to be re-sealed to extend their seal life or be replaced. A combined approach may be warranted. Atikokan believes it would be prudent to invest in reverification testing for seal expiry extensions as opposed to replacing the meters. However, if the smart meters do not pass testing, Atikokan will be required to replace all of its smart meters for 2027 through 2029 respectively significantly impacting the capital budget. Excluding installation costs, the costs alone for replacement of smart meters would be over $200,000.

As mentioned above and a successful process in the past, the plan is for seal extensions for both the residential and general service < 50 customers. General Service > 50 customers will forgo the reverification of meters for seal extension and outright replace the meters. This is on the basis Atikokan has 15 General Service > 50 customers. Following Measurement Canada guidelines all meters would need to be tested meaning the meters would need to be taken out of service and replaced with inventory meters for the time being as is. Atikokan does not have this many meters in inventory. For this reason, it is most beneficial and cost effective to replace General Service > 50 meters and have tested for reverification for spares.

Line crew have observed meters on premises facing the south and sun are the meters more likely to fail and require replacement. Dependent on continued failure rate of meters will determine the quantity of smart meter purchases for each year. Atikokan see's an average of 34 smart meters fail annually.

MicroFIT

MicroFIT interval metered data follows the same routine process as smart meters, with the exception that the data is not sent or stored in the MDMR.

Smart Meter Data Collectors

Atikokan Hydro has 4 smart meter data collectors that function to transmit smart meter data back to the central server; Master Application Server (MAS). In addition to these collectors in use, Atikokan has one spare data collector. These collectors are nearing their useful life but were recently upgraded.

Wholesale Metering

Atikokan Hydro has four wholesale meters; two main and two alternates used to measure Atikokan Hydro's electricity purchases from the grid. All four meters were recently replaced due to meter seal expiries; one in 2023 and the other three in 2024. All four seals are extended, one resealed until 2027 and the others 2032.

However, it should be noted these metering points will be de-registered and taken out of service during the DSP period. New wholesale metering will be installed at an alternative / new location as Atikokan's Wholesale metering. Further details, around the Wholesale Metering change is explained later in this plan. Atikokan Hydro has a service contract with Meter Service Provider Thunder Bay Hydro. Atikokan Hydro communicates with the wholesale meters via cellular data modems.

Poles, Towers & Fixtures

Atikokan Hydro nearly has a pole to residential customer ratio of 1:1. Atikokan's total pole count is 1331; (December 31, 2023 Residential customer count of 1372). Atikokan has all wood poles with the exception of one fibreglass pole installed in 2014. The 80 ft pole was installed by a third party contractor hired by Atikokan Hydro. This is the first and only fibreglass pole Atikokan Hydro has installed. The pole was placed on the 3M2 sub-transmission line.

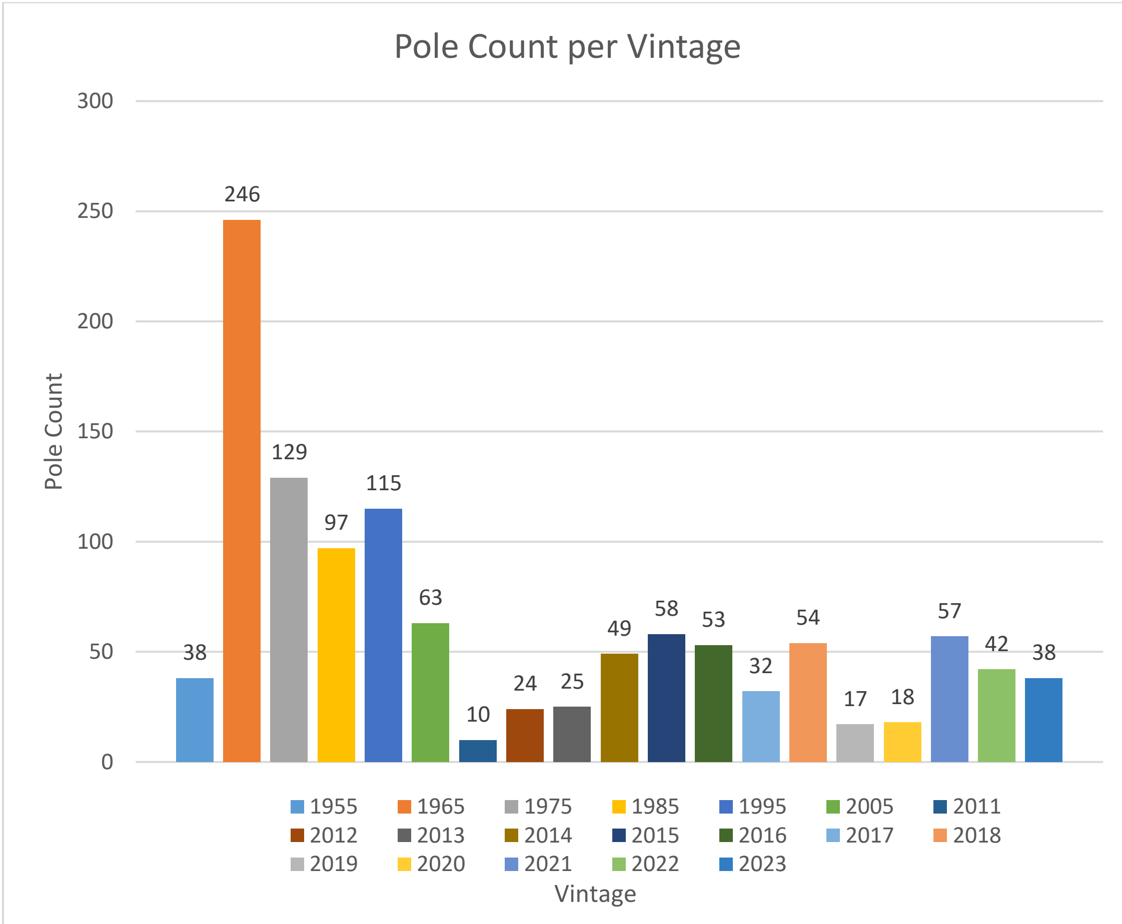
The poles are summarized by vintage in the following figure and illustrated charts.

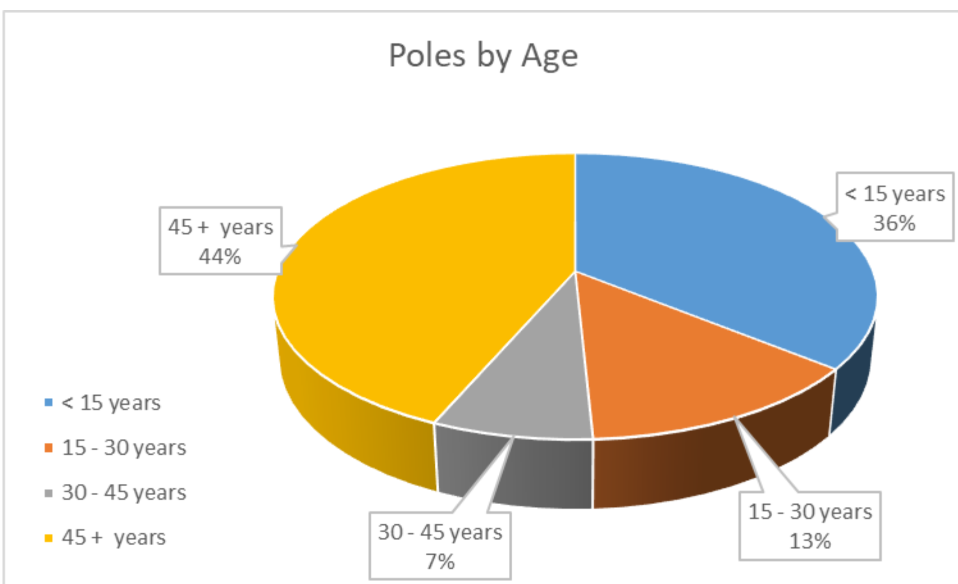
Figure 25:

Vintage	Pole Count
1955	204
1965	246
1975	129
1985	97
1995	115
2005	63
2011	10
2012	24
2013	25
2014	49
2015	58
2016	53
2017	32
2018	54
2019	17
2020	18
2021	57
2022	42
2023	38
Total	**1331**

The average number of pole replacements over the past ten years is 40 poles a year. The Atikokan Hydro board likes to see upward of 50 poles changed per year. Some poles will be less if there is greater focus on other distribution assets or vegetation manegement as a few variable factors that are driven from asset inspections.

Figure 26:


Pole Count per Vintage
Pole Count
300
250
200
150
100
50
0
246
129
97
115
63
10
24
25
49
58
53
32
54
17
18
57
42
38
38
1955
1965
1975
1985
1995
2005
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Vintage


Poles by Age
< 15 years
36%
15 - 30 years
13%
30 - 45 years
7%
45 + years
44%
< 15 years
15 - 30 years
30 - 45 years
45 + years

Poles range in height from 35 feet to 80 feet. The majority being between 35 to 45 foot poles. Atikokan has been replacing many of the 35 foot poles with 40 foot; this allows greater spacing, strength and compliance with 22/04.

Atikokan's pole count will be changing in this Distribution System period. Atikokan will be elimating approximately 15 km of the 23km of sub-transmission lines which will include 114 structures. Some of these strutures are single pole structure, others are two or three pole structures. Atikokan will however be adding approximately 2 km of sub-transmission. These changes are a result of changes to Atikokan's supply point and distribution system configuration as mentioned earlier in section 5.2.1; distribution system overview. This will be described further in material invetments.

The condition assesment rating of these poles supports why Atikokan must continue to heaviliy invest in poles, towers and fxitures for system renewal over the period of the distribution system plan for a total of $723,000 over the 5 year period. Each years total expenditure on poles, towers and fixtures will exceed the materialilty threshold of $50,000 but it should be noted historically Aitikokan's individual pole replacements have not exceeded the $50,000 threshold. Unless however, a contractor is hired to complete capital upgrades; typically these projects are larger in nature but one pole does not singley exceed the threshold .

Sourced from Atikokan's 2017 DSP " Between the 3M2 and 3M3; there are 214 structures; some of these single pole structures; others are two or three pole structures. In total the structures have 278 poles. As described throughout this plan, some of these structures need to be contracted out due to the challenge with limited access and rugged terrain of locations. Atikokan Hydro does not have the equipment to change out these structures. These poles range from 40 to 80 ft. About 30% of these structures require third party contractors to complete the work. On average, the structures cost $30,000 to hire a contractor for the capital upgrades; this is based on recent costing information."

The savings cannot be fully quantified but capital expenditures alone on the sub-transmission lines named 3m2 and 3m3 requiring hiring of third party's is over $750,000 for the past ten years. These lines have been vital in that they supply the town, reliability must be maintained. Due to the higher costs to change out these structures, Atikokan Hydro has historically tried to proactively plan to change a few structures a year based on condition assessments. Along with not jeopardizing reliability and safety, it is efficient and wiser to replace the structures on a proactive basis as opposed to on an emergency basis when the structures have failed or fallen where Atikokan Hydro does not have the internal resources to repair many of the structures. It should also be noted that Atikokan has monitored these lines more frequently in the past few years with efforts to try to strike the balance between keeping reliability but not investing in sections of lines that will be foregone with changes pending in this upcoming DSP period.

A picture of Atikokan's only fibreglass pole follows: This pole is on the 3M2 sub transmission feeder line and as the picture illustrates these feeders are most accessible by four-wheeler, snow machine or off-road equipment that Atikokan Hydro does not own. (Atikokan Hydro only owns four wheelers and snow machines).

Figure 27:

General Plant

General Plant does not fall into the categories of system access, system renewal or system service but are needed for day to day operations. General Plant investments include:

- Buildings (Office and Yard),
- Transportation Equipment (fleet),
- Tools,
- Computer software and
- Computer hardware.

Transportation Equipment

Rolling Stock and equipment are key to maintaining the electrical system. All existing rolling stock and equipment are fully utilized and have a purpose. The table below shows the list of the main pieces of vehicle and equipment's Atikokan currently has. The useful life of this asset class is 10- or 15-years dependant on the piece of truck / equipment.

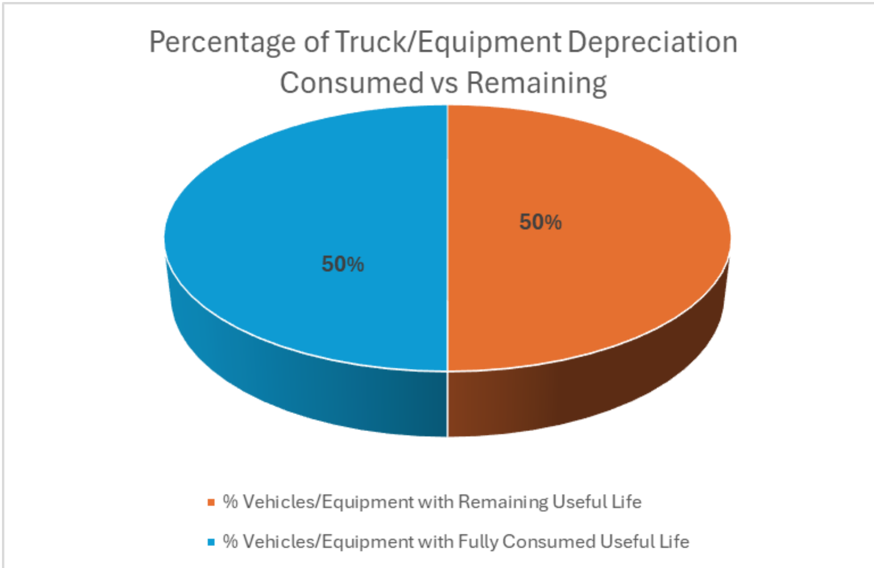
Figure 28: List of Rolling Stock (Trucks/Equipment)

	Vehicle/Equipment	Useful Life (Years)	Remaining Useful Life (Percentages)	Used Useful Life (Percentages)
1	2022 Skidoo Tundra LT 600 (9100)	10	70%	30%
2	2023 Skidoo Tundra LT 600 (9101)	10	20%	80%
3	ATV (Kodiak) - 9088	10	0%	100%
4	ATV (Kodiak) - 9089	10	0%	100%
5	SERVICE TRUCK - 9098	10	50%	50%
6	SERVICE TRUCK - 9099	10	50%	50%
7	BUCKET TRUCK - 9097	15	60%	40%
8	DOUBLE BUCKET BOOM TRUCK - 9095	15	6%	94%
9	UTILITY TRAILER - 9096	10	0%	100%
10	BRUSH CHIPPER - 9084	10	0%	100%
11	SKIDOO TRAILER	5	0%	100%
12	ATV TRAILER	10	0%	100%
13	POLE TRAILER 2 AXELS	10	0%	100%
14	UTILITY TRAILER 5 x 8 - 9102	10	100	0

Note, most of the equipment have numbers associated to them; this is key to asset management and allocating time and costs to projects and expenses to specific vehicles and equipment in instances of repairs and insurance costs.

During various jobs, Atikokan rents equipment such as backhoes on a need be basis. At other times because Atikokan Hydro does not have the required equipment Atikokan contracts out the capital projects. For example, capital work in the rugged limited accessibility areas outside of town often requires a third party contracted to complete the work due to the limited accessibility and terrain of the pole locations. It is pertinent Atikokan Hydro at the bare minimal maintain and replace as needed the existing rolling stock and equipment. In addition, the overall condition of the vehicles must be maintained and in good working condition as Atikokan does not have redundant units to use as alternatives. As noted in the following Pie Graph Chart, 50% of Atikokan’s fleet has exceeded its useful life. Note that Atikokan also considers each fleets asset condition prior to replacing. Since the last DSP, Atikokan replaced its two snow machines. The snowmachines were beyond their useful life and requiring more frequent repairs. Parts were becoming obsolete and becoming difficult to find parts to repair the snowmachines. Atikokan’s two four wheelers are in the same situation. To mitigate and control costs, Atikokan replaces one unit at a time and not both at once. An aspect of the Distribution System Plan will be non-distribution asset expenditures, replacing necessary aging and worn fleet including four wheelers, replacing the double bucket truck and purchasing a new fleet addition of a backyard machine to address operational efficiencies. Atikokan Hydro will strive to achieve the lowest costs while achieving the required rolling stock specifications and requirements. Atikokan Hydro entertains both new and used where applicable; however, for this DS Plan it has been determined purchasing ‘new’ would be the best business decision.

Figure 29:



Trucks are used in day-to-day utility work where the other equipment such as the pole trailer and equipment trailer are used to transport equipment or material to site locations. The crew perform monthly truck inspections and complete maintenance and repairs when capable. Other maintenance and repairs are completed by the local garage. An out of town third party completes the annual di-electric testing of the fleet vehicles and big equipment have annual inspections and services completed out of town. Appendix B is a copy of the monthly truck inspection form used by in-house line crew.

Reinvestment needs for vehicles and equipment has a material impact on Atikokan Hydro's DSP. Based on historical and replacement costs, Atikokan's planned capital for these expenditures is believed to be $1,040,000 for the period of this DS Plan. Atikokan will borrow where necessary which will reduce the yearly revenue requirement to fulfill these purchases having a lessened impact on customer rates. Replacement of fleet vehicle and equipment is based on consideration of usage, age, condition and on-going maintenance costs.

Given the geographical location of Atikokan and the nature of the business, bucket trucks are not available for rent locally nor effective to rent or borrow from another utility or contractor in the industry for day-to-day operations. Equipment must be maintained in reliable working order to be ready to meet both maintenance and outage demands that cannot be predicted.

While Atikokan will be eliminating unfavorable terrain and limited access portions of its feeders in the upcoming DSP period, Atikokan will still have portions of its feeders with the challenging terrain requiring snowmachines and four wheelers for access and contractor assistance in some cases. The following picture is a section of the sub transmission line Atikokan will still have in service.

Figure 30:

Tools

Tool purchases vary from year to year and are generally based on staff identifying tools and safety equipment needs to support day to day operational activities. Some needs identified are new tool needs for operational efficiency, safety or identified as replacing old tools or safety equipment that become defective. A capital tool allowance is allocated for each year to purchase tools such as chain saws, drills, etc that are over a purchase price of $500. This allowance will be continued throughout the period of this plan; however, the combined total of tool purchases over the period is less than the materiality threshold ($50,000). The past seven-year annual tool expenditure is an average of $5,501.

Buildings

Atikokan Hydro has its main office with a basement for storage of some small tools and inventory and a yard location where the rolling stock and equipment is stored in garages. The yard stores most of the inventory of line material. The office, open 5 days a week accepts bill payments and customer inquiries. Billing and accounting are completed in-house. The office building has had some basement water concerns, but no major repairs have been completed. Investment priorities are generally spent on maintaining reliability of supplying electricity compared to general plant expenditures like buildings if they are not in failed state. The office could further use some upgrades in terms of windows and doors but these expenses have not been prioritized as they are in working order. Similarly, the floor in the office is in working order but difficult to maintain in keeping it waxed to avoid salt from outdoor traffic wearing and deteriorating the floors condition. For emergency preparedness, it's been discussed whether the office requires a backup generator in event power is lost. Atikokan has allocated dollars to building and yard expenditures, but it does not exceed the materiality threshold; this DSP period may require Atikokan to invest into the building as prioritized.

Office Equipment

Atikokan owns various office equipment for daily administrative use. This includes printers, fax machine, photocopier, shredder, and postage machine and envelope stuffer. The office equipment is beyond its useful life and has needed some small repairs. The practice is to run the office equipment to failure prior to replacing. Small repairs are made when necessary if beneficial. It is believed in the 5 year period capital dollars will need to be allocated to a bill stuffer used for stuffing bills mailed and other existing pieces of office equipment. These items will be run to failure before replaced. Atikokan has contemplated outsourcing the printing of the bills but it is most cost effective to keep this task in-house and plans to continue this practice in this DSP period. The combined total of Office Equipment over the period is less than the materiality threshold ($50,000).

Computer Hardware / Software

Computer equipment has an assumed useful life of 5 years whereas software has a useful life of 2 years. The main office has a total of eight computers; including physical workstations and a few laptops. Some of the hardware and software will be maintained over the period of the distribution system plan and some workstations will need to be replaced based on performance. Workstations are generally in service beyond their deemed useful life. Workstations planned to be replaced as showing signs of age, running slow. Purchases will not exceed the materiality threshold; $19,100 has been allotted.

Server

IT system upgrades and replacements are part of the annual capital planning process. During the bridge year (2024), Atikokan replaced its 5-year-old year physical server with a new physical server. The server was not replaced solely because of being at the end of its system life but due to signs of intermittent failures. While the server had remaining extended support on the operating system it was end of life as of 2024. Further investments were made in efforts to have a more robust backup solution as part of Atikokan's Disaster Recovery Plan and measures for cyber security readiness.

5.3.3 Asset Lifecycle Optimization Policies and Practices

Atikokan does not have a formal 'lifecycle optimization policy' but has practices in place to optimize assets with strategies of both planned and reactive replacement practices.

It is possible to run assets to failure as opposed planned replacements, but it is not prudent for all assets nor is it efficient to return to individual locations multiple times to replace each individual asset. This requires a combined planned and reactive strategy.

In optimizing assets, the useful life (age) of an asset may be fulfilled but the asset is not outright replaced because the expected life has been met or exceeded. Factors must be considered including public safety, worker safety, accessibility, asset condition, risk and impact of running to failure.

If deemed appropriate given consideration of safety, asset condition, no signs of imminent hazards, asset conditions are documented and reassessed in future inspections and replacement plans leaving the asset in service. In some asset cases, refurbishments and maintenance can be performed extending the life of the asset if a trade-off of spending and replacing with new.
The utility has established routine maintenance and operational tasks in efforts to monitor and sustain assets to the end of their life or beyond.

Atikokan's in compliance with Sections 4 and 5 of Regulation 22/04, the Distribution System Code Appendix C and ESA Guidelines, adhering to inspection and maintenance protocol on all distribution and non distribution assets. Atikokan follows the recommended guidelines for 'rural' population density treatment as it sets greater expectation and frequency of inspections, resulting in a clearer updated knowledge of the distribution system condition and as such more proactive measures are in place.

All line patrols and inspections are documented. The inspection data is used to support and plan maintenance activities and capital expenditures. Inspections are audited annually within the Ontario Regulation 22/04 audit.

Atikokan optimizes asset lifecycle by performing inspections to monitor the health of distribution system assets, performing preventative and corrective maintenance where necessary and determined to be financially prudent and by proactively replacing critical assets at or near their end of life with hazardous assessment conditions.

In prioritizing asset replacements, the replacement must be completed at a pace that is sustainable and affordable for both the utility and the customers impacted. Replacement is the most viable option for most of Atikokan's distribution assets. Non-distribution assets categorized as general plant can generally be refurbished as opposed to outright asset replacement. These refurbishments can be completed at a reasonable dollar value extending the life of the asset and comparatively outweighing the costs of outright replacement. The impacts and risks of these expenditures are weighed in decision making. As much as possible, refurbishment is completed in house to control costs. Atikokan Hydro has talented staff and crew and pool resources together where and when needed.

A budget is forecasted based on inspection results and projected costs are determined. The upcoming capital projects are approved by Atikokan Hydro's Board of Directors. The budget is approved based on an optimal level of affordability but meeting regulatory requirements such as 22/04 compliance.

Maintenance planning criteria and assumptions

Atikokan's routine monthly and annual maintenance programs are consistent with good utility practices and the Distribution System Code are the foundation for asset optimization and developing system renewal investments or routine system Operations and Maintenance functions. This includes but is not limited to practices like painting transformers to extend the life as opposed to outright replacement. Budgets for these functions are developed utilizing historical costs for repair as well as labour hours required to perform inspections. Budget envelopes may be adjusted annually based on the results of the inspection process.

Transformer Inspection and Maintenance

Atikokan previously tested all its distribution transformers for PCB Contamination. Contaminated transformers were disposed of using Ministry of Environment guidelines. This includes using a third party for disposal of transformers no longer in service. Atikokan will continue to test transformers and handle according to the appropriate guidelines. The inspection process checks for leaks and general tank condition; condition of the bushings; and oil discolouration which indicates flashover. Maintenance includes painting where conditions warrant painting will suffice otherwise the unit is replaced if leaking. Atikokan typically runs transformers to failure or alternatively replaces transformers in poorly accessible areas (located at the back of property's) if poles with pole mounted transformers are being replaced. This is considered an operational efficiency. For greater access and efficiency, Atikokan tries to bring transformers to the roadside where possible during upgrades.

Substation Inspection and Maintenance

Atikokan Hydro owns and maintains 3 substations within its service territory. Monthly, each substation is visually inspected by Atikokan Hydro line personnel. Monthly inspections are documented. Visual inspections look for signs of oil leakage, corrosion, rust, or damage to equipment, condition of fence, vegetation growth, condition of signage, locks, etc. Feeder amperage is read and documented. Standard oil testing is completed annually to monitor the condition of the substation transformer oil. Defects and findings during inspections are documented and corrected immediately or scheduled for corrective action depending on the complexity and risk of the repair. The testing of substation transformer oil annually is one example of asset optimization; the oil samples monitor the condition and performance of the oil.

Further a past practice has also including filtering the oil as recommended by a third party from the oil samples to sustain the life of the oil and transformer.

Vault Transformer Inspection and Maintenance

The inspection of these units coincides with the requirements in the Distribution System Code in that they are to be inspected every three years; Atikokan inspects biannually including cable testing performed by a third party to monitor the condition of the cables. The condition assessment allows cables to continue to be in service and not replaced primarily due to age. Atikokan also performs infrared scanning biannually. Due to the nature of the installation and costs of removing and replacing these units upon failure, consideration is given to converting these installations to pole mounted infrastructure when applicable. Where defects to customer owned infrastructure is identified, Atikokan Hydro notifies the customer as to the nature of the defect and seeks a timeline for corrective action.

Distribution Pole Inspection and Testing

The inspection of these assets coincides with the requirements set forth in the DSC in that they are to be inspected on a three year cycle. Atikokan conducts a visual inspection of all the poles it owns within its service territory. The inspection considers overall pole condition and condition of pole attachments. Poles that have been identified, through visual inspection, as being in poor condition are further inspected in detail. Through non-destructive testing (hammer testing) or the use of Atikokan's pole tester; inspectors ascertain the extent to which the asset has deteriorated. Poles identified as being a hazard or in imminent risk of failure are replaced immediately; other poles are prioritized based on their health as part of the asset management and capital planning process.

Atikokan completes system patrols on a yearly basis. The patrol includes visual inspection for the poles looking for visible signs of damage or a leaning pole. In addition to visual inspection, Atikokan has a pole testing unit as discussed earlier in this plan in section 5.3.1 as part of Atikokan's planning process.

Overhead Switch Inspection and Maintenance

The inspection of these assets coincides with the requirements set forth in the DSC in that they are to be inspected on a three-year cycle. Atikokan exceeds this and inspects annually. The intention is to ensure that every switch is at least visually inspected. Visual inspection of the in-line, air-break, load-break, and recloser population is captured under this initiative. Switch maintenance activities are conducted in parallel with switch inspection activities. Where the inspection determines that maintenance of the switch is required, the line crew may conduct the maintenance immediately and note this on the inspection form. Where the crew is unable to immediately perform the maintenance, a deficiency is noted on the inspection form for follow up corrective action. The completed detailed inspection form is submitted for prioritization based on available resources and details of the annual inspection are then logged.

Meters

All maintenance activities related to meters follow requirements of Measurement Canada.

Tree Trimming Maintenance and Inspection

Atikokan performs an aggressive vegetation control management in a reactive and proactive manner through its service area. Atikokan receives many third party requests annually to manage vegetation that has been identified as posing a potential threat to Atikokan's overhead infrastructure and services on customer premises. These are generally safety concerns and are remediated in both a reactive or proactive nature depending on the request. Part of Atikokan's annual powerline inspections include identify areas requiring vegetation management, tree trimming, removal or pesticide spraying. Atikokan also proactively manages vegetation in areas of planned capital investment prior to executing work in these areas. Atikokan is licenced to use pesticides as part of its vegetation control but also utilizes a third party to complete some of the spraying in areas on the 3M2 and 3M3 feeders where accessibility is limited. From experience, Atikokan finds trimming trees will have the tree growth back within 2 to 3 years; for efficiency Atikokan is aggressive and prefers to cut and remove the trees when possible.

Atikokan strives to remove debris and return the site to the as found condition unless a customer has consented Atikokan Hydro to leave the debris for customer clean up. Atikokan will leave the debris in a condition that is manageable for the customer. In some of Atikokan's right of way that are not residential areas, Atikokan will leave the debris where possible, leaving the debris helps stunt new growth.

Reactive Maintenance

Reactive maintenance occurs in many forms, at many different times and across all asset categories. It can occur during regular business hours or after hours. These events can include responding to trouble calls, repairing unexpected deficiencies and equipment failures; failures which cannot be accounted for and corrected through by any other means.

Risk is defined as the product of criticality and probability of failure. The assessment of risk begins with the inspection and patrolling of assets observing and identifying deficiencies.

Upon maintenance inspection reports identifying asset condition deficiencies of concern requiring follow up action; both the risk of failure and consequences of failure is analyzed. In order to do so, it is important to understand the impacts and risks associated with leaving the asset at its existing condition and what acceptable length of time. Assessment considerations include but are not limited to:

- Safety (worker and public),
- Regulatory requirement,
- Reliability impact
    - Outages causes and frequency
    - Restoration capability
    - Power quality,
- Environmental
- Useful Life and
- Financial considerations.

The condition rating and risk analysis must be further analyzed and prioritized, categorizing the items of concern as follows:

4. Immediate Action
5. Within the next budget year and
6. To be considered with major rebuilds

Once risk assessment is completed and prioritized, actions plans can be prepared outlining the timeline and priority of and measures to be taken to resolve the deficiency.

Risk mitigation may not be an acceptable option based on the risk assessment and due diligence of being compliant with the Distribution System Code. Finding a commonality for delivery of safe and reliable service at a pace that keeps the financial health of the utility and rate impacts on customers acceptable is not an easy task but the utility must strive to measure its performance and reactions for continuous improvement.

5.3.4 CDM Activities to Address System Needs

Atikokan has no distributor costs to accommodate, and connection renewable generation facilities included in this Distribution System Plan.

5.3.5 Rate-Funded Activities to Defer Distribution Infrastructure

The OEB's Conservation and Demand Management (CDM) guidelines require distributors to make reasonable efforts to incorporate CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure.

Atikokan Hydro is not aware of any Conservation and Demand Management (CDM) initiatives that would impact its planning for the period of 2025 through 2029. There are no capacity constraints anticipated on the distribution system requiring investment into capacity upgrades; therefore, at this time CDM activities have not been considered as an approach to meeting system needs to avoid or defer spending on infrastructure. Nor does Atikokan have any pending or outstanding application for CDM funding to defer infrastructure.

5.4 Capital Expenditure Plan

In accordance with the filing requirements, in this section Atikokan provides a snapshot of its capital expenditures with five years historical and five forecast years. Atikokan historically has not categorized its capital expenditures into the four OEB investment categories [system access, system renewal, system service and general plant] but for purposes of this application used best efforts to categorize historical expenditures. Atikokan relied on the Board definitions and examples in doing so.

The four capital investment categories are defined earlier in this document in section 5.1.2 Investment Categories.

5.4.1 Capital Expenditure Summary

Per the filing requirements Atikokan completed both the Chapter 2 appendices 2-AA Capital Projects and 2-AB Capital Expenditure Summary Table for the historical and forecast years. These appendices are included below but the excel format can be viewed in Atikokan's separately filed Chapter 2 Appendices:

Atikokan_2025 COS_Filing_Requirements_Chapter_2_Appendices_1_20241030

Figure 31:

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026	2027	2028	2029
Reporting Basis													
System Access													
Meters	5,653	21,062	15,119	29,821	465	0	40,802	18,414	165,274	15,174	40,000	24,000	12,000
Fixtures - Poles & Towers									50,000				
3M2 Line Poles & Fixtures									150,000				
System Access Gross Expenditures	5,653	21,062	15,119	29,821	465	0	40,802	18,414	365,274	15,174	40,000	24,000	12,000
System Access Capital Contributions													
Sub-Total	5,653	21,062	15,119	29,821	465	0	40,802	18,414	365,274	15,174	40,000	24,000	12,000
System Renewal													
Poles, Towers & Fixtures Feeder 1	17,548	14,062			5,982	27,441	32,291	25,750	20,000	33,400	24,400	24,400	24,400
Poles, Towers & Fixtures Feeder 2	19,201	30,841	12,723	22,335	17,744	45,193	29,495	35,750	15,000	33,400	24,400	24,400	24,400
Poles, Towers & Fixtures Feeder 3	17,047	52,328	24,923	11,996	6,565	4,724	33,054	5,000	15,000	33,400	24,400	24,400	24,400
Poles, Towers & Fixtures Feeder 4	7,636	2,646	3,685	6,368		4,021	30,004	5,000	15,000	33,400	24,400	24,400	24,400
Poles, Towers & Fixtures Feeder 5	7,681	7,091	26,798	8,566	92,670	60,374	24,233	10,000	10,000	33,400	24,400	24,400	24,400
Poles, Towers & Fixtures Feeder 6		5,529		20,432									
3M2 Line Poles & Fixtures	22,642	21,519			7,432					30,000	20,000	20,000	20,000
3M3 Line Poles & Fixtures	48,836	28,246	20,492	6,399						30,000	20,000	20,000	20,000
Poles, Towers & Fixtures - Contracted	127,978	221,376			62,192			75,000	45,000				
									25,000				
Line Transformers		16,800	74,692	7,731		14,550		93,945	40,000				
System Renewal Gross Expenditures	268,568	400,439	163,312	83,828	192,585	156,304	149,077	250,445	185,000	227,000	162,000	162,000	162,000
System Renewal Capital Contributions													
Sub-Total	268,568	400,439	163,312	83,828	192,585	156,304	149,077	250,445	185,000	227,000	162,000	162,000	162,000
System Service													
Distribution Station Equipment								500,000					
System Service Gross Expenditures	0	0	0	0	0	0	0	500,000	0	0	0	0	0
System Service Capital Contributions													
Sub-Total	0	0	0	0	0	0	0	500,000	0	0	0	0	0
General Plant													
Computer Software						6,500							
Computer Hardware	1,997		18,668	2,649				5,107	5,000	5,000	2,000	2,000	5,100
Transportation Equipment		291,743	102,114	15,850	12,498	13,139		6,218	365,000	15,000	600,000		60,000
Tools	4,662	2,122		5,035	5,879	17,562	1,797	3,320	4,000	4,000	4,000	4,000	4,000
Office Furniture & Equipment	500	984		9,348				10,000	10,000	10,000	10,000	10,000	10,000
Buildings & Fxitures						33,697						25,000	
General Plant Gross Expenditures	7,158	294,850	120,782	32,882	18,377	70,898	1,797	24,645	384,000	34,000	616,000	41,000	79,100
General Plant Capital Contributions													
Sub-Total	7,158	294,850	120,782	32,882	18,377	70,898	1,797	24,645	384,000	34,000	616,000	41,000	79,100
Miscellaneous													
Total	**281,379**	**716,351**	**299,213**	**146,531**	**211,428**	**227,202**	**191,676**	**793,504**	**934,274**	**276,174**	**818,000**	**227,000**	**253,100**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***													
Total	**281,379**	**716,351**	**299,213**	**146,531**	**211,428**	**227,202**	**191,676**	**793,504**	**934,274**	**276,174**	**818,000**	**227,000**	**253,100**

Figure 32:

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

CATEGORY	**Historical Period** (previous plan[1] & actual)														
	2017			2018			2019			2020			2021		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%
System Access	10,000	5,653	-43.5%	40,000	21,062	-47.3%	50,000	15,119	-69.8%	15,000	29,821	98.8%	10,000	465	-95.3%
System Renewal	261,740	268,568	2.6%	92,000	400,439	335.3%	114,000	163,874	43.7%	167,000	79,844	-52.2%	182,000	192,585	5.8%
System Service	-		--			--			--			--			--
General Plant	304,000	7,158	-97.6%	73,000	294,850	303.9%	37,000	120,782	226.4%	28,000	32,882	17.4%	18,000	18,377	2.1%
TOTAL EXPENDITURE	575,740	281,379	-51.1%	205,000	716,351	249.4%	201,000	299,775	49.1%	210,000	142,547	-32.1%	210,000	211,428	0.7%
Capital Contributions		- 20,123	--		- 70,300	--		- 17,993	--		- 34,970	--		- 92,867	--
NET CAPITAL EXPENDITURES			--			--			--			--			--
System O&M	$ 498	$ 544	9.3%	$ 498	$ 506	1.7%	$ 504	$ 495	-1.7%	$ 492	$ 517	5.0%	$ 492	$ 507	3.0%

Figure 33:

Appendix 2 – AB continued

CATEGORY	Historical Period (previous plan[1] & actual)								
	2022			2023			2024		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	10,000		-100.0%	57,785	40,802	-29.4%	18,414	6,229	-66.2%
System Renewal	138,031	156,304	13.2%	162,776	149,077	-8.4%	250,445	133,107	-46.9%
System Service			--			--	500,000	391,005	-21.8%
General Plant	86,900	70,898	-18.4%	5,500	1,797	-67.3%	24,645	14,644	-40.6%
TOTAL EXPENDITURE	234,931	227,202	-3.3%	226,061	191,676	-15.2%	793,504	544,985	-31.3%
Capital Contributions		- 91,282	--		- 17,987	--	- 350,000	- 350,000	0.0%
NET CAPITAL EXPENDITURES			--			--			--
System O&M	$ 490	$ 541	10.5%	$ 606	$ 530	-12.5%	$ 595	$ 382	-35.8%

[2] Actual 2024 includes 8 months of actual data; 2024 bridge year

Figure 34:

Appendix 2 – AB continued

CATEGORY	Forecast Period (planned)				
	2025	2026	2027	2028	2029
	$ '000				
System Access	165,274	15,274	4,000	24,000	12,000
System Renewal	185,000	227,000	162,000	162,000	162,000
System Service	200,000				
General Plant	384,000	34,000	616,000	41,000	79,100
TOTAL EXPENDITURE	934,274	276,274	782,000	227,000	253,100
Capital Contributions	- 300,000				
NET CAPITAL EXPENDITURES					
System O&M	$ 619	$ 641	$ 664	$ 688	$ 713

Atikokan has no known developments or forecasted customer or load growth and consequently there is no growth driver for capital investments. Primarily, capital investments are driven by asset renewal historically and in this forecast period. Atikokan's existing system configuration has served the load adequately. This DSP period in the forecast does have a System Service driver but for other reasons than load growth. The current capital expenditures over the forecast period of 2025 through 2029 are shown below.

Figure 35: DSP Forecast Period

	Forecast Period (Planned)					
CATEGORY	2025 $	2026 $	2027 $	2028 $	2029 $	Total
System Access	165,274	15,274	40,000	24,000	12,000	256,548
System Renewal	185,000	227,000	162,000	162,000	162,000	898,000
System Service	200,000	-	-	-	-	200,000
General Plant	384,000	34,000	616,000	41,000	79,100	1,154,100
Total	**934,274**	**276,274**	**818,000**	**227,000**	**253,100**	**2,508,648**
Capital Contibutions	(300,000)	-	-	-	-	(300,000)
Net Capital Expenditures	634,274	276,274	818,000	227,000	253,100	2,208,648
SYSTEM O&M	618,539	640,806	663,875	687,775	712,535	3,323,531

Atikokan considers most of the capital budget non-discretionary and as such to satisfy regulatory requirements, environment or health and safety risks and conditions of service, thereby, the proposed investments fall into the definition of non-discretionary. These programs are for refurbishment and replacement of assets that have failed or at high risk or failure or performance and functional obsolescence. Atikokan's asset management data and asset conditioning through recent inspections support these investment proposals.

System Access activities are not historically triggered from customer or load growth for Atikokan but mandated service obligations such as the expiry of smart meter seals. It is extending the smart meter seal expiry and replacing smart meters that are driving capital expenditures in this OEB category as well as new wholesale metering for compliance. The actual investment spent on meters will be dependent on the success of seal expiries passing the sampling process; however, $106,548 has been allotted to meters for replacement of failed meters and the new meters for sampling. Atikokan's capital investment budget will need to be reevaluated in the event samples fail and seals cannot be extended. This would be a significant material cost burden to the utility and Atikokan's rate base. This expenditure is non-discretionary. $150,000 has been allotted towards wholesale metering.

System Renewal activities are generally non-discretionary and include items such as pole replacement, transformer replacement and distribution equipment. These are triggered by inspections, asset condition assessments and compliance with 22/04. In total the projects will exceed the materiality threshold, but generally individual planned projects are not material. Atikokan exercises individual worst conditioned pole replacement and not by feeder. It should be noted addressing System Renewal Category meets System Service in delivering safety, reliability and power quality. Renewal identifies system weaknesses but in turn improves the performance of the distribution system or otherwise categorized as system service. $898,000 has been assigned to system renewal over the DSP period; averaging $179,600 annually.

System Service expenditures meet the operational objective of safety, reliability, power quality and system efficiency. Historically, Atikokan categorizes expenditures into system renewal as it is deemed to be the primary trigger driver although these expenditures could be categorized as system service since failure risk affects operational performance. Making such categorization assumptions is in accordance with the Filing Requirements. However, for this forecast period $200,000 has been assigned to the OEB category of system service. This is for two gang operated switches outside of the Hydro One owned Transformer station and new feeders out of the station. The switches are a safety mechanism where Atikokan can isolate the feeders if required.

General plant expenditures at times, may be discretionary such as tools. If continuing to work without a new acquired tool or repairing the existing tool does not pose imminent high-risk concerns, management makes cuts in budget items such as tools to meet budget shortfalls for items that have greater priority. Often priority for this category is low compared to the other asset expenditure categories but can become necessary for daily operations. Often this category will run until failure if running the asset to failure will not be detrimental to operations. The primary driver in this category for the DS Plan is retirement of a fleet plus a new addition to the fleet complement; $50,000. Due to the nature of the fleet, these general plan expenditures cannot run until failure. General Plant expenditures often are lumpy in nature; like the forecast period whereby 2025 is considerably higher than the other consistent years driven by fleet expenditures proposed. Other general plant expenditures in the plan include, computer hardware, tools, office furniture and equipment and building expenditures for a cumulative total of $114,100. None of the planned expenditures or categories will be in excess of $50,000.

5.4.2 Justifying Capital Expenditures

Atikokan has regulatory obligations and responsibilities to the Ontario Energy Board and the Electrical Safety Authority. Atikokan Hydro must comply with Ontario Regulation 22/04 Electrical Distribution Safey and is subject to annual Audits and Declaration of Compliance. In addition, the utility not only has obligations and responsibilities but has a commitment to providing it's customers safe, reliable supply of power.

Planning criteria and assumptions used in determining the capital plan include but are not limited to the following inputs:

- change or forecast in growth, if any
- change or forecast in load, if any
- coordination with customers' needs
- coordination with third parties
- asset conditions
- environmental impacts
- reliability / safety, ESA Standards
- regulatory requirements
- impact of CDM and REG
- historical trends
- adequate level of investment, exceed amortization
- financial position and rate impacts

Using historical trends and adjusting for current and future needs, Atikokan developed its capital expenditure plan in efforts to meet and satisfy all stakeholders.

Historically both customer needs and third parties' requests can be addressed in the short term as the request generally is not complex in nature and can be coordinated with existing business.

In supporting and justifying Atikokan's forecast period spend and plan; this next section compares Atikokan's historical capital expenditures previously planned versus the actual expenditures.

Figure 36: Historical Plan Period

CATEGORY	2017 Plan $	2018 Plan $	2019 Plan $	2020 Plan $	2021 Plan $
System Access	10,000	40,000	50,000	15,000	10,000
System Renewal	261,740	92,000	114,000	167,000	182,000
System Service	-	-	-	-	-
General Plant	364,000	73,000	37,000	28,000	18,000
Total	635,740	205,000	201,000	210,000	210,000

Yearly variances between planned and actuals by investment category will be analyzed in this section.

Figure 37: 2017 Planned vs. 2017 Capital Expenditure Actuals

CATEGORY	2017 Planned	2017 Actual	Variance
System Access	10,000	5,653	(4,348)
System Renewal	261,740	268,568	6,828
System Service	-		-
General Plant	304,000	7,158	(296,842)
Total	575,740	281,379	(294,361)

<u>System Access</u>

System Access for 2017 was $4,348 less than the board approved plan amount; this variance is less than the materiality threshold.

<u>System Renewal</u>

System Renewal for 2017 was $6,828 greater than the board approved planned amount; this variance is less than the materiality threshold.

System Service

Atikokan had no change to System Service.

General Plant

The actual 2017 general plant spend amount was $296,842 less than the board approved planned amount. In Atikokan's 2017 COS, a capital expenditure of $300,000 for a digger derrick as a replacement was approved. The consignment of the purchase did not occur until early 2018.

Figure 38: 2018 Planned vs. 2018 Capital Expenditure Actuals

CATEGORY	2018 Planned	2018 Actual	Variance
System Access	40,000	21,062	(18,938)
System Renewal	92,000	400,578	308,578
System Service			-
General Plant	73,000	294,850	221,850
Total	205,000	716,490	511,490

System Access

Actual System Access expenditures were less than the planned amount by $18,938. Less smart meters were purchased.

System Renewal

2018 System Renewal capital exceeded the planned spend amount by $308,578. The main driver was $221,376 spent on outsourcing line work to a contractor on Atikokan Hydro's sub transmission 44Kv lines. Powerline inspections with condition assessment indicated high priority to have capital completed. Atikokan was aware of work needed going into its 2017 COS but this was cut from the final settlement. $21,000 was also spent on a new switch in 2018. This was not originally planned. A switch pole was compromised from a grass fire.

System Service

In 2018, Atikokan had no change to System Service.

General Plant

2018 had a planned general plant expenditure of $73,000 with actual expenditure total of $294,850; $211,850 over the planned amount. This was mainly a result of the Digger Derrick truck purchase approved for 2017 but was deferred into 2018 because it was not ready for consignment until early 2018. The digger derrick cost $291,743.32. The original 2018 plan budgeted $60,000 for replacement of a service truck but that was deferred.

Figure 39: 2019 Planned vs. 2019 Capital Expenditure Actuals

CATEGORY	2019 Planned	2019 Actual	Variance
System Access	50,000	15,119	(34,881)
System Renewal	114,000	163,874	49,874
System Service			-
General Plant	37,000	120,782	83,782
Total	201,000	299,775	98,775

<u>System Access</u>

In 2019, System Access expenditures decreased by $34,881; this variance is immaterial.

<u>System Renewal</u>

System Renewal in 2019 increased by $49,874. This is mainly a result of transformers purchases received in 2019; this was a result of inspection priorities and planned projects. The transformer needs were greater than originally forecasted.

<u>System Service</u>

In 2019, Atikokan had no change to System Service.

<u>General Plant</u>

2019 General Plant expenditures exceeded the planned amount by $83,782. This was driven by the purchasing of two service trucks during 2019 that replaced old fleet. Both purchases were deferred in budgets; one being cut from 2017 and the other deferred from being included in 2018 from the 2017-2021 DSP. The trucks were purchased a few months apart. Both replaced trucks were in conditions whereby the frames were rusted and not advisable to pass safeties. The purchases were no longer discretionary, and the purchases could not be phased over fiscal years.

Figure 40: 2020 Planned vs. 2020 Capital Expenditure Actuals

CATEGORY	2020 Planned	2020 Actual	Variance
System Access	15,000	29,821	14,821
System Renewal	167,000	79,844	(87,156)
System Service			-
General Plant	28,000	34,337	6,337
Total	210,000	144,002	(65,998)

System Access

The planned expenditures in 2020 for System Access were $14,821 greater than the planned amount and attributed to smart meter purchases. Smart meter purchases were apart of the DSP period.

System Renewal

2020 System Renewal capital expenditures were $87,156 less than the planned amount. This is a result of COVID. This was the first year of COVID with many uncertainties with the new virus. Atikokan Hydro, while an essential service did take precautions with social distancing, separated work crews keeping personnel safe but less productivity occurred. The focus was on prioritised pole replacement jobs.

System Service

In 2020, Atikokan had no change to System Service.

General Plant

In 2020, General Plant was $6,337 more than the planned $28,000 for the year. This is less than the materiality threshold.

Figure 41: 2021 Planned vs. 2021 Capital Expenditure Actuals

CATEGORY	2021 Planned	2021 Actual	Variance
System Access	10,000	465	(9,535)
System Renewal	182,000	192,585	10,585
System Service			-
General Plant	18,000	18,377	377
Total	210,000	211,428	1,428

<u>System Access</u>

The planned expenditures in 2021 for System Access were $9,535 less than the planned amount but not considered material.

<u>System Renewal</u>

2021 System Renewal capital expenditures was $10,585 more than the planned amount.

<u>System Service</u>

In 2021, Atikokan had no change to System Service.

<u>General Plant</u>

In 2021, General Plant was $337 more than the plan, nearly breakeven.

This ends the historical period of Atikokan's former DSP Plan; 2017-2021 filed with Atikokan's 2017 Cost of Service Distribution System Plan. Per the filing requirements, in absence of a previously filed plan, applicants should include the planned budget in each subsequent historical year up to and including the bridge year. The next few tables labelled planned are Atikokan's planned annual budget amounts versus the actuals. Material variances by category will be explained.

Figure 42: 2022 Planned vs. 2022 Capital Expenditure Actuals

CATEGORY	2022 Planned	2022 Actual	Variance
System Access	10,000	-	(10,000)
System Renewal	138,031	156,304	18,273
System Service			-
General Plant	86,900	70,898	(16,002)
Total	234,931	227,202	(7,729)

System Access

The actual expenditures in 2022 for System Access was $10,000 less than the planned amount and while not material, Atikokan offers an explanation that the planned meter purchases in 2022 were not received until 2023 due to supply chain delays.

System Renewal

2022 System Renewal capital expenditures was $18,273 more than the planned amount.

System Service

In 2022, Atikokan had no change to System Service.

General Plant

In 2022, General Plant was $16,002 less than the plan.

Figure 43: 2023 Planned vs. 2023 Capital Expenditure Actuals

CATEGORY	2023 Planned	2023 Actual	Variance
System Access	57,785	40,802	(16,983)
System Renewal	162,776	149,077	(13,699)
System Service			-
General Plant	5,500	1,797	(3,703)
Total	226,061	191,676	(34,385)

System Access

The planned expenditures in 2023 for System Access were $16,983 less than the planned amount. this is in part one of the planned meter projects came under budget but also was reevaluated to be a non-capital expense.

System Renewal

2023 System Renewal capital expenditures was $13,699 less than the planned amount.

System Service

In 2023, Atikokan had no change to System Service.

General Plant

In 2023, General Plant was $3,703 les than the plan.

Figure 44: 2024 Planned vs. 2024 Capital Expenditure Actuals

CATEGORY	2024 Planned	2024 Actual[1]	Variance
System Access	18,414	6,229	(12,185)
System Renewal	250,445	133,107	(117,338)
System Service	500,000	391,005	(108,995)
General Plant	24,645	14,644	(10,001)
Total	793,504	544,985	(248,519)

[1]The following 2024 bridge year compares Atikokan's planned capital expenditures per category versus the year to date actuals for the first 8 months of the year; no further data is available for the bridge year given the timing of the application.

Due to the planned 2024 expenditures being 12 months of plans and the actuals only reflecting 8 months of project competition there are material differences. Based on the continued plans and provided no material delays, the actual expenditures should not have material differences in excess of $50,000; the materiality threshold after the year is complete.

The following table compares the previously filed DSP period to the current Forecast DSP period.

This DSP period in comparison to the prior period, shows Atikokan does have more projects of material value and scope planned. These projects will be discussed in further detail in the following sections thereafter.

Figure 45: Prior DSP Versus Current DSP

CATEGORY	2017-2021 Planned DSP	2025-2029 Planned DSP	Variance
System Access	125,000	256,548	131,548
System Renewal	816,740	898,000	81,260
System Service	-	200,000	200,000
General Plant	460,000	1,154,100	694,100
Total	1,401,740	2,508,648	1,106,908
Capital Contributions		(300,000)	(300,000)
Net Capital	1,401,740	2,208,648	806,908

The next table show a summary of the forecast period by category and year of the plan.

Figure 46: Forecast DSP by Category

	Forecast Period (Planned)				
CATEGORY	2025 $	2026 $	2027 $	2028 $	2029 $
System Access	165,274	15,274	40,000	24,000	12,000
System Renewal	185,000	227,000	162,000	162,000	162,000
System Service	200,000	-	-	-	-
General Plant	384,000	34,000	616,000	41,000	79,100
Total	**934,274**	**276,274**	**818,000**	**227,000**	**253,100**
Capital Contibutions	(300,000)	-	-	-	-
Net Capital Expenditures	634,274	276,274	818,000	227,000	253,100
SYSTEM O&M	618,539	640,806	663,875	687,775	712,535

Per filing requirements, Atikokan compares the year over year planned expenditures by category, describing variances that meet or exceed the materiality threshold of $50,000.

Figure 47: 2025 Forecast vs.2026 Forecast Capital Expenditure

CATEGORY	2025 Plan	2026 Plan	Variance
System Access	165,274	15,274	(150,000)
System Renewal	185,000	227,000	42,000
System Service	200,000	-	(200,000)
General Plant	384,000	34,000	(350,000)
Total	934,274	276,274	(658,000)
Total CAPEX less Capital Contributions	634,274	276,274	358,000

<u>System Access</u>

Atikokan plans to spend $150,000 less in System Access for 2026. 2026 dollars are for smart meter purchases for reserves to replace failing meters; 2025 included meter purchases but also included a material amount for new wholesale metering and not an on-going expenditure.

<u>System Renewal</u>

In 2026, Atikokan plans to spend $42,000 more in System Renewal than 2025; this variance is less than the materiality threshold but mainly attributed to Atikokan will be working on other OEB Category projects during 2025 that will not occur during 2026, leaving more resources (time and allotted budget) to system renewal for 2026.

<u>System Service</u>

In 2026, Atikokan has no plans of spending on system service, being $200,000 less than the prior year of 2025 spending $200,000. 2025 system service capital expenditures are for building a pole line to connect Atikokan Hydro's pre-existing feeders to Hydro Ones Mackenzie Transformer Station and purchasing and installing switches on these lines for isolation.

<u>General Plant</u>

In 2026, Atikokan plans to spend $350,000 less in General Plant; this is a result of the prior year purchasing a backyard track machine to meet operational fleet needs to maintain the distribution system and replacing one four-wheeler.

Figure 48: 2026 Forecast vs.2027 Forecast Capital Expenditure

CATEGORY	2026 Plan	2027 Plan	Variance
System Access	15,274	40,000	24,726
System Renewal	227,000	162,000	(65,000)
System Service	-	-	-
General Plant	34,000	616,000	582,000
Total	276,274	818,000	541,726

<u>System Access</u>

Atikokan plans to spend $24,726 more in System Access for 2027 compared to 2026; this is less than the materiality value, no further discussion required.

<u>System Renewal</u>

Atikokan plans to spend $65,000 less in System Renewal for 2027 compared to 2026. See 2025 forecast versus 2026 forecast for explanation.

<u>System Service</u>

In 2027, Atikokan Plans to have no change to System Service.

<u>General Plant</u>

2027 is planned to have $582,000 more capital expenditures in General Plant; this to purchase a new double bucket truck. $600,000 of the 2027 planned General Plant of $616,000 is for the double bucket truck but the incremental spend from the prior year in the general plant category is $582,000.

Figure 49: 2027 Forecast vs.2028 Forecast Capital Expenditure

CATEGORY	2027 Plan	2028 Plan	Variance
System Access	40,000	24,000	(16,000)
System Renewal	162,000	162,000	-
System Service	-	-	-
General Plant	616,000	41,000	(575,000)
Total	818,000	227,000	(591,000)

<u>System Access</u>

In 2028, $16,000 less in System Access is planned. This difference is immaterial.

System Renewal

In 2028, no discussion required, no change and variance in system renewal capital forecasted.

System Service

In 2028, Atikokan Plans to have no change to System Service.

General Plant

General Plant is planned to decrease by $575,000; see 2026 versus 2027 forecast above for explanation.

Figure 50: 2028 Forecast vs.2029 Forecast Capital Expenditure

CATEGORY	2028 Plan	2029 Plan	Variance
System Access	24,000	12,000	(12,000)
System Renewal	162,000	162,000	-
System Service	-	-	-
General Plant	41,000	79,100	38,100
Total	227,000	253,100	26,100

System Access

In 2029, $12,000 less in System Access is planned. This difference is immaterial requiring no further discussion.

System Renewal

In 2028, no discussion required, no change and variance in system renewal capital forecasted.

System Service

Atikokan Plans to have no change to System Service in 2029.

General Plant

General Plant is planned to increase by $38,100 in 2029; this does not meet the materiality threshold; however, Atikokan does plan that the service trucks will need to be replaced one by one, starting with the replacement of one unit in 2029, making this year lumpier.

System O&M Costs

Atikokan does not forecast to see material reductions nor increases in System Operations and Maintenance (O&M) over the forecast period. At this time Atikokan cannot quantify the savings but would note the favorable benefits and indirect realized savings from eliminating approximately 15km of sub transmission lines and changing its point of supply from Moose Lake TS to Mackenzie TS. Gains in efficiencies and use of time, fuel savings and reduced wear and tear on equipment/fleet will be gained in eliminating the travel time and wear from town to Moose Lake TS and along those 15 km of line. Time spent on inspecting and maintaining those lines including utilizing third party contractors for spraying ROW can be better spent and invested into other assets and areas.

Atikokan will continue to require equipment such as four wheelers and snow machines. Atikokan will continue to have at least 8 km of sub-transmission lines.

Acquiring a backyard machine will be a fleet complement addition and will add to O&M with another unit to be insured and maintenance expenses but will be worth the added expense with realized savings and gains from operational efficiencies.

Replacement of distribution assets generally results in assets being replaced with similar ones and therefore there would be little or no changes to O&M in the regard that inspections need to be completed as per the Distribution System Code and for reliability and mitigating unplanned outages as a result of asset failures. New infrastructure for example should lessen the chance of unexpected call outs due to equipment failure; however, this historically has not been material.

Transportation Equipment (Fleet) replacement will result in reduced OM&A for new units; however, this will be offset by increasing O&M of the other equipment as they get older.

Historically, Atikokan has not seen a significant nor material download pressure on O&M as a result of capital plans as cost savings are generally offset by other increases expenditures; for this reason, Atikokan does not anticipate download pressure of O&M. Atikokan's forecasted Operations and Maintenance (O&M) increases during the DS Plan are predicted to be 3.60% per year. This is consistent with the OEB inflation rate when increases are not known nor can be confirmed.

5.4.2.1 Material Investments

Per the filing requirements, projects that meet the materiality threshold of $50,000 will be described below.

While the total capital expenditures by category exceed the materiality threshold, Atikokan does not have that many projects that meet or exceed the threshold.

Figure 51: DSP Forecast Period

	Forecast Period (Planned)				
CATEGORY	2025 $	2026 $	2027 $	2028 $	2029 $
System Access	165,274	15,274	40,000	24,000	12,000
System Renewal	185,000	227,000	162,000	162,000	162,000
System Service	200,000	-	-	-	-
General Plant	384,000	34,000	616,000	41,000	79,100
Total	**934,274**	**276,274**	**818,000**	**227,000**	**253,100**
Capital Contibutions	(300,000)	-	-	-	-
Net Capital Expenditures	634,274	276,274	818,000	227,000	253,100
SYSTEM O&M	618,539	640,806	663,875	687,775	712,535

System Access

- New Wholesale Metering [2025]
- Gang Operated Switches (x2) [2025]
- Pole Line Construction [2025]

The above three ‘projects’ will be addressed with project change upstream transmitter connection point. The expenditures while broken down are part of the scope of the project of Atikokan Hydro changing its connection point to its upstream transmitter. The end goal has many components of the meeting the final outcome.

System Renewal

System renewal expenditures historically primarily driven by pole replacements and transformer purchases. Pole replacements historically do not exceed the materiality threshold unless a contractor is hired. Atikokan does however, historically and plans to spend over $50,000 annually on combined pole and fixture replacements in the upcoming DSP period. Likewise, no single distribution transformer historically purchased exceeds the materiality threshold nor will future purchases exceed the threshold on an individual basis.

Pole replacements occur annually based on the age and overall condition of the asset assessment based on line inspections. Individually in-house replaced poles are less than the materiality threshold but the sum of the annual poles replacement are historically greater than the materiality threshold. This will also be the case for the forecast period. Atikokan prioritizes replacements based on asset condition and inspections.

Atikokan Hydro will be contracting out various pole replacement projects for poles that are off-road accessible; the exact amount cannot be fully quantified at this time given the competitive bid process that occurs with these capital expenditures.

For the forecast period of 2026 through 2029 Atikokan did include $162,000 annually towards System Renewal for pole replacements. Atikokan used a 3-year average for the historical years 2021 through 2023 in determining a budgeted amount to forecast; this seemed to be a reasonable and justifiable approach. In the 3-year period an average of 45 poles were replaced. The number of poles is dependent on inspections but dependent on the complexity of the pole being replaced; secondary versus primary, number of attachments, transformer pole, etc. Trade offs must also occur between other work identified with needs from inspections.

<u>System Service</u>

General Plant

- Backyard Track Machine $350,000 [2025]
- New replacement double bucket truck $600,000 [2027]

<u>General Plant</u>

- New replacement service truck $60,000 [2029]

PROJECT: CHANGE UPSTREAM TRANSMITTER CONNECTION POINT (POINT OF SUPPLY)

A. GENERAL INFORMATION

Investment Category: System Access

Capital Investment: $347,242

Capital Contributions: $ 300,000 [2025]

Atikokan Hydro is anticipating and forecasted to receive capital contributions for this project for $600,000 to $750,000; $350,000 to be received in the 2024 bridge year, $300,000 to be received late of the test year 2025 or beginning of 2026. For purposes of the application, Atikokan has forecasted for the contributions to be received in 2025 and $300k and not the max of $400k based on the current data available at the time.

Start: 2024

In Service: November 2025 [projected]

Project Summary: Change Atikokan Hydro's connection point to its upstream transmitter Hydro One from the Hydro One owned Moose Lake Transformer Station to the Hydro One owned Mackenzie Transformer Station. This project is changing Atikokan's connection, point of power supply from Hydro One.

<u>Project Scope</u>

- This project has many components required as a result.
    - New pole line construction – to connect Atikokan's existing pole line to the Mackenzie TS. Atikokan will have two lines coming from the station to maintain the similar configuration Atikokan has had to date from the Moose Lake transformer Station, allowing redundancies, and maintaining the service quality Atikokan customers are accustomed to. [2025]
    - Install two gang operated switches outside Hydro Ones Mackenzie Station on Atikokan Hydro owned feeders.
    - New Wholesale metering

- Install new wholesale metering for Atikokan's supply from Mackenzie TS [2025]
- Take former wholesale meter (Moose Lake) out of service

Other components of the project scope that will and have occurred during the 2024 bridge year and will occur in future years of the DSP that cannot be quantified at this time but are mentioned for context:

- Upgrade Hawthorne substation
    - Install new transformer with increased capacity with capability to carry town load. Allows redundancy and keeps Atikokan's operational objectives of customer reliability. This configuration will have two of Atikokan's substations capable to hold the town load in the event one is out of commission or dependent on where the line fault is. [2024]
    - Install new station ground grid [2024]
    - Install new primary, secondary fuses, primary fuse mounting and fuses; appropriate sizing standards for station transformer rating. [2024]
- Decommission sections of sub transmission lines 3m2 and 3m3 no longer necessary due to new point of supply and system configurations; approximately 15 km. No current set timelines; will need to be planned in phases over a short to long term period. At this time without actual plans, the costs cannot be quantified and for this reason has not explicitly been included in the DSP but worth mentioning as planning and resources will be needed towards these future idle lines. Consideration will also need to be given to Atikokan's existing Land Use Permit for this area of lines; permit expiry December 31, 2032.

<u>Risk Identified & Mitigation</u>

This will achieve greater reliability and efficiency's for the utility and its rate payers. Mitigation of tree caused outages. Mitigate the length of loss of supply outages waiting on Hydro One personnel to be dispatched to their Transformer Station. The Mackenzie TS location is in a far more optimal location to access. See the picture on the following page portraying the geographical differences and distance Moose Lake TS is compared to in town corridor of Atikokan.

Comparative Information:

New project of this scope, no comparator. Received some quotes.

REG Investment

Additionally, this project will address Atikokan's upstream distributor, Hydro One's, current station unequal transformer sizes at Moose Lake TS and 'no area availability' further preventing renewable generation connection and other new loads in the near or foreseeable future. Moose Lake TS has two transformers, one 15 MW and a 8MW for a combined total of 23 MW. The Mackenzie TS is being upgraded and built to have two transformers both of equal sizing of 25 MW each for a combined 50 MW. Any prospective REG investments will still need to be analyzed but the new connection and transformer size should open up greater opportunities for consideration that cannot be considered at this time due to the current Moose Lake TS upstream constraints.

B. EVALAUTION CRITERIA AND INFORMATION REQUIREMENTS

Efficiency, Customer Value, Reliability

Project Drivers

Coordinated planning with third party, system access.

Investment Priority

Impacted reliability targets; lowering SAIDI and SAIFI results. Changing and increasing inclement weather patterns. Contributed capital, reducing financial impact to customer.

Project Alternatives

1) Do nothing, keep the current system configuration and point of supply from Moose Lake TS.
2) Make the configuration change, changing point of supply from upstream transmitter.
   For context Atikokan has had discussions with Hydro One various times over the years to have Atikokan's connection point at Mackenzie TS due to the barrier of operating the sub transmission lines and geographical location of the Moose Lake TS but it has been cost prohibitive; therefore, Atikokan had kept the system as is because the cost would be born entirely to the Atikokan rate payers as this would have been a customer request and driven

by the Hydro One customer, Atikokan Hydro. Per the distribution and transmission code, the customer pays when the driver for the change and need. There may not be the same opportunity and business case in the future. Hydro One is upgrading and making changes to the Mackenzie TS to accommodate the Waasignan line, directive from the IESO, while both the Waasignan Project and Atikokan Hydro's feeders tapping from the Mackenzie TS are two separate projects if Atikokan projects did not occur simultaneously, the likelihood may not exist and the cost would be considerably more especially if Waasignan project assets needed to be moved to accommodate clearance between feeders.

In Atikokan's 2023 Customer Satisfaction survey, Atikokan specifically asked if survey respondents agreed with the project. 88% agreed, 1% different and 11% of respondents didn't know.

Safety

Indirect safety benefits due to increased reliability and reduced risk of outages.

Cyber Security & Privacy

Not applicable

Co-ordination, Interoperability

Not applicable

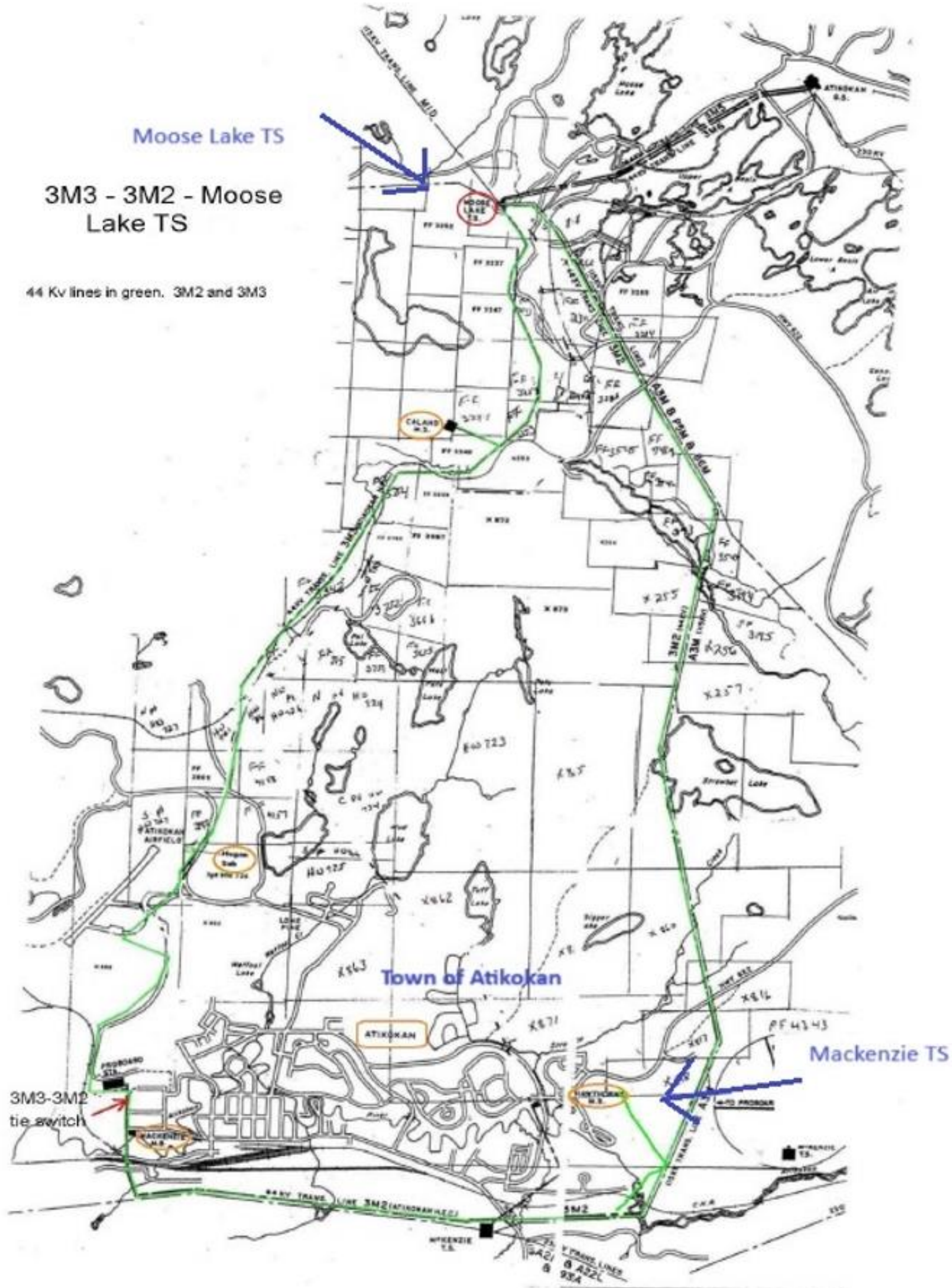
Economic Development:

Short term economic benefits to the local community with the construction that is occurring to the Hydro One owned Mackenzie TS for upgrades because of the increased construction workers and contractors in town contributing to businesses lively hoods.

Environmental Benefits

Not applicable

Figure 52:


Moose Lake TS
3M3 - 3M2 - Moose Lake TS
44 Kv lines in green. 3M2 and 3M3
Town of Atikokan
ATIKOKAN
Mackenzie TS
3M3-3M2 tie switch

PROJECT: REPLACE DOUBLE BUCKET TRUCK

A. GENERAL INFORMATION

Investment Category: General Plant

Capital Investment: $600,000

Capital Contributions: $0

Start: 2024/2025 (Research/quotes/selection)

In Service: 2027* *Preliminary research indicates nearly 3-year lead time

Project Summary: Replace and retire 2009 Double Bucket Truck.

Atikokan is planning to replace its existing double truck that is a 2009 vintage meaning the truck is at the end of its deemed useful life. To support its age, the truck is starting to have more maintenance expenditures and showing signs of wear with the body of the truck rusting. This poses safety and reliability concerns.

For good distributor planning Atikokan has been researching the estimate and lead times required to replace the unit. Trucks Atikokan will obtain quotes for comparison adhering to its purchasing policy, but preliminary information indicates a double truck to meet Atikokan's needs will not be available until 2027 and would cost upward of $600,000 to replace. During Atikokan's next annual inspection, Atikokan will seek advice from a mechanic on the expected longevity of the truck.

Risk Identified & Mitigation

Disruption to operations/response times, increased operations and maintenance costs. Replacing the truck mitigates risk of truck failing inspection or not starting and does not add duration to outages and added O&M costs. Geographical location of Atikokan is a detriment in that there are no like equipment locally for alternatives and backups. Heavy duty equipment mechanics are locally in town but not experts with utility fleet.

Comparative Information

Historical heavy duty truck purchases plus in-house knowledge and experience the cost of material, goods and services has significantly increased since last COS and last double bucket purchase.

REG Investment

Not directly applicable, however, the truck could be used in future REG investment connections.

B. EVALAUTION CRITERIA AND INFORMATION REQUIREMENTS

Efficiency, Customer Value, Reliability

Investment Priority

Project will become imminent priority if not replaced; the truck may not pass safety/inspection and increasing incurring O&M costs to keep operating in good condition. Need to be proactive in replacing the existing double bucket truck before it fails because there is significant lead time on replacing; upward of 3 years for some models and brands.

Given the nature of the fleet used in this industry and the geographical location to the nearest utility, borrowing and renting is impractical, inefficient and not an option; prioritizing the planned replacement of the truck. Good working order fleet is needed to support the line crew in providing the customers with the service they value and expect.

Project Options / Alternatives Considered

1) Do Nothing - continue to use and repair as needed required maintenance and downtime will likely increase thus resulting in lost productively by line crew and increased operational costs. Risk the truck may not pass safety at one point due to rusting of truck body.

2) Purchase Used - It puts risk on dependability and no warranty. No knowledge of wear and use by previous owner(s).

3) Borrow/Rent – Nearest utility or contractor with bucket trucks are minimal two hours away. Not practical, efficient or reliable for needs during power outages. This would mean lengthier outages IF even availability of truck. Not a good utility practice to borrow on an as needed basis especially for unplanned outages requiring the use of the truck. Renting on a long-term basis would not be the most economical decision.

4) Purchase New – 9095, the double bucket truck to be replaced was originally purchased new and has been a good business decision. Warranty is included with new purchases. With purchasing new you are aware of what you’re getting and should last the expected life of the truck plus some if well maintained. Achieves efficiencies and reliability.

Project Priority

This project will become an imminent priority sooner than later if not replaced; the truck may not pass safety/inspection or may become an undue hazard. Given the procurement supply chain challenges, increasing lead times, Atikokan will need to make a final purchase decision in the short term to ensure a replacement is planned and secured. Purchasing in 2027 addresses the lead times of a new truck but also allows the sustainment of loans payment requirements. Current lead times are projecting two to three years upon order. O&M spent on truck annually increasing.

Safety

Replacement ensures crew are driving safe, reliable equipment to perform work in compliance with safety regulations.

Cyber Security & Privacy

Not applicable

Co-ordination, Interoperability

Not applicable

Economic Development

Not applicable

Environmental Benefits

Newer vehicles have lower emissions.

PROJECT: FLEET ADDITION, PURCHASE BACKYARD TRACK MACHINE

A. GENERAL INFORMATION

Investment Category: General Plant

Capital Investment: $ 350,000

Capital Contributions: $ 0

Start: 2025

In Service: 2025, April

Project Summary: Purchase a backyard track machine

Risk Identified & Mitigation

Support setting poles in limited access areas in backyards where we have had to utilize third parties for assistance in the past for a fee. The machine would potentially leave less sink holes in customers yards and allow better access to cut trees. Should gain access to some off-road poles due to the machine's tracks. Access we currently do not have with fleet.

Comparative Information:

New project of this scope, no comparator.

REG Investment

Not directly applicable, however, the truck could be used in future REG investment connections.

B. EVALAUTION CRITERIA AND INFORMATION REQUIREMENTS

Efficiency, Customer Value, Reliability

Investment Priority

General plant expenditure, not direct system renewal that often has greater priority; however, this fleet gains priority in that it would contribute to gained efficiencies with setting poles in the back of properties with limited access, efficiencies in vegetation management. All of which contribute to increased reliability. If machine allows less restoration work to customer's lawns with utility infrastructure this is another gain and added value to both the utility and the customer.

Project Alternatives

1) Do nothing, no fleet addition, status quo fleet compliment
2) Rent equipment as needed
3) Lease backyard track machine
4) Purchase backyard track machine

Safety

Safer and more efficient access for tree clearing in backyards and setting poles with limited access.

Cyber Security & Privacy

Not applicable

Co-ordination, Interoperability

Not applicable

Economic Development:

Not applicable

Environmental Benefits

Not applicable

Appendix A: Substation Inspection Reports

Atikokan Hydro Inc.- Monthly McKenzie MS Substation Inspection

	Acceptable	Problem/ Condition Description	Date of Correction
Yard:			
Condition of Driveway & Yard			
Condition of Station Fence & Gates			
Condition Of Signage			
Condition Of Locks			
Condition of Fence Grounds			
Vegetation Growth			
Tower Structure:			
Cement Foundation			
Corrosion/Rust			
Loose Bolts			
Phase Markers			
Structure Condition			
Condition of Insulators/Arrestors			
Transformer;			
Phase/ Feeder - Feeder 4			
Leaking Oil			
Paint Condition			
Rust / Corrosion			
Damage			
Condition of Brushings			
Feeder Amperage	Red Phase	Blue Phase / White Phase	

	Acceptable	Problem/Condition Description	Date of Correction
Transformer;			
Phase/ Feeder - Feeder 5			
Leaking Oil			
Paint Condition			
Rust / Corrosion			
Damage			
Condition of Brushings			
Feeder Amperage	Red Phase	Blue Phase / White Phase	

Notes/Comments:

Date Inspected:

Inspected by:

Signature:

Appendix B: Monthly Truck Inspection

MONTHLY TRUCK INSPECTION REPORT

DATE: **TRUCK#:** **ODOMETER READING:**

ENGINE

FLUID LEVELS	OK	COMMENTS
RADIATOR COOLANT		
ENGINE OIL		
BRAKE FLUID		
POWER STEERING FLUID		
WINDOW WASH FLUID		

BODY/CHASSIS

EXHAUST SYSTEM	OK	COMMENTS
LEAKS		
MOUNTING/ HANGERS		
MUFFLER		
TAIL PIPE		

TIRES/WHEELS	OK	COMMENTS
INFLATION		
STUDS		
NUTS		
RIMS		
TREAD		

SUSPENION	OK	COMMENTS
SPRINGS		
SHACKLES		
U-BOLTS		
FRONT END		

LIGHTS	OK	COMMENTS
SIGNALS		
FOUR WAYS		
HEADLIGHTS		
CLEARANCE LIGHTS		
BACKUP LIGHTS		
AMBER FLASHING LIGHT		

CONTINUED MONTHLY TRUCK INSPECTION

GLASS/MIRRORS	**OK**	**COMMENTS**
WINDSHIELD		
WIPERS		
SIDE WINDOWS		
REAR WINDOW		
DRIVERS MIRROR		
PASSENGER MIRROR		
REAR VEIW MIRROR		

TOWING ACCESSORIES	**OK**	**COMMENTS**
BALL/ PINTLE HITCH		
ELECTRICAL PLUG SOCKET		
SAFETYCHAIN ATTACHMENTS		

SAFETY EQUIPMENT	**OK**	**COMMENTS**
HORN		
FIRE EXTINGUISHER		
TRAFFIC CONES		
TRIANGLES/FLARES		
WHEEL CHALKS		
FIRST AID KIT		
REVERSING INDICATOR		
BOOM CLEANED		

BRAKES	**OK**	**COMMENTS**
AIR BRAKES		
PARK BRAKES		
HYDRAULIC BRAKES		
ELECTRIC BRAKES		

CAB INTERIOR	**OK**	**COMMENTS**
GUAGES		
DASH LIGHTS		
INTERIOR LIGHTS		
TWO RADIO		
SEAT BELTS		
HEAT/AIR CONDITIONER		
FLASH LIGHT		
FLOOD LIGHT		
CLEAN/ORGANIZED		

INSPECTED BY: Signature:

Appendix C: Atikokan Hydro 2023 Customer Satisfaction Survey Results

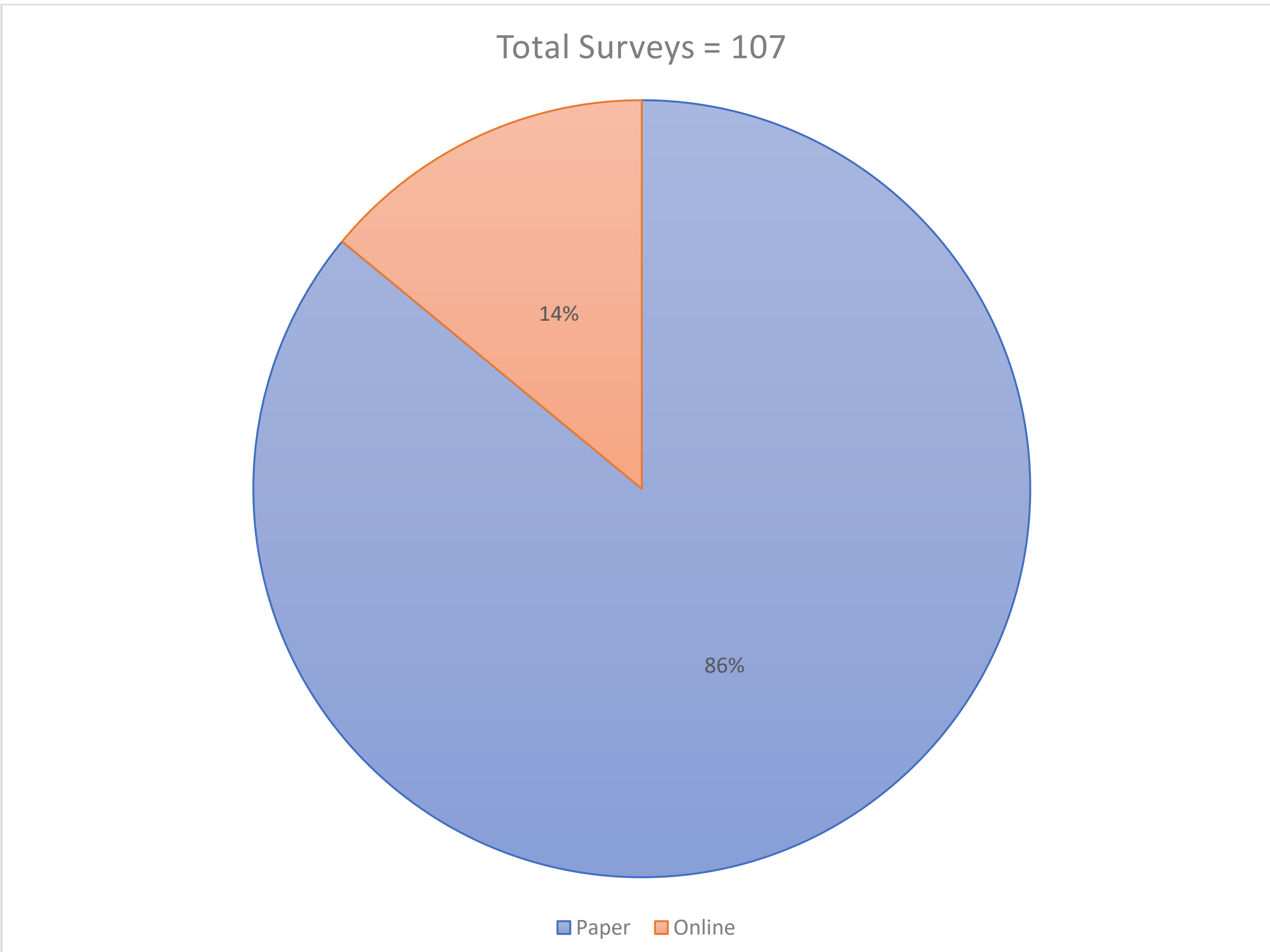
2023

Atikokan Hydro Inc.

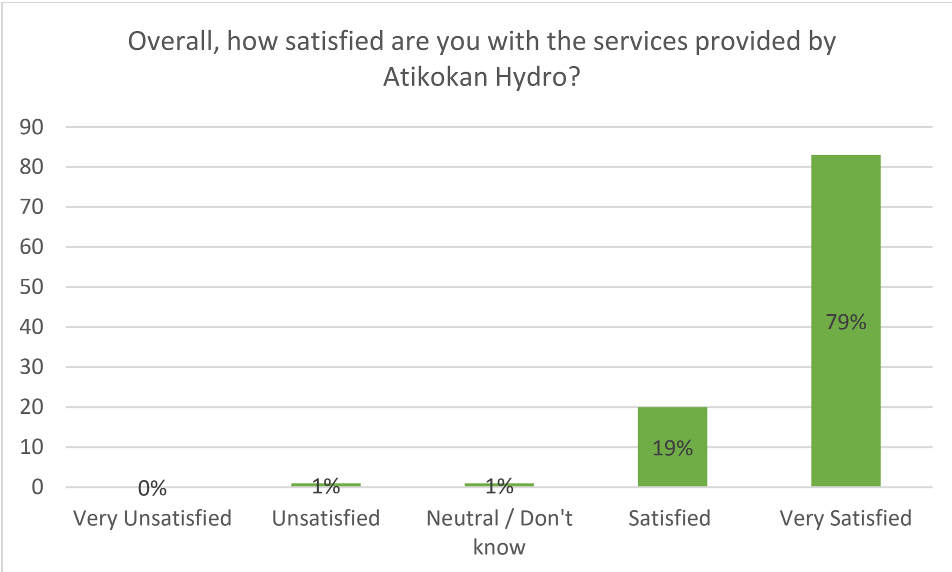
CUSTOMER SATISFACTORY SURVEY RESULTS

2023 Customer Satisfaction Survey

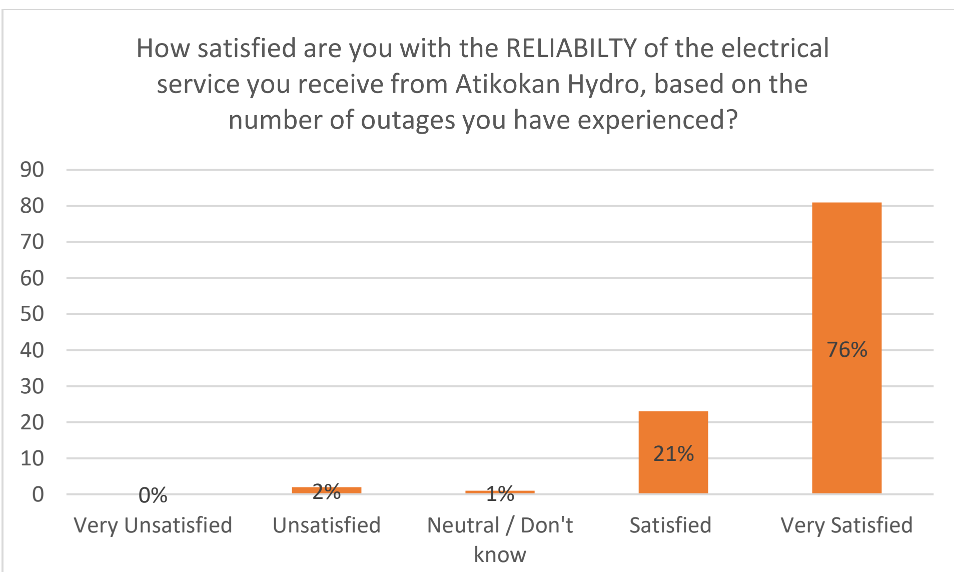
Customer Satisfaction survey ran September 5th through October 6th, 2023. The survey was a hybrid approach with the option to complete the survey online or through a paper-based survey. The paper survey was distributed as an insert in the Atikokan Progress's September 6th paper. Most responses were received via paper and were returned directly to the office. A few were returned in the mail.



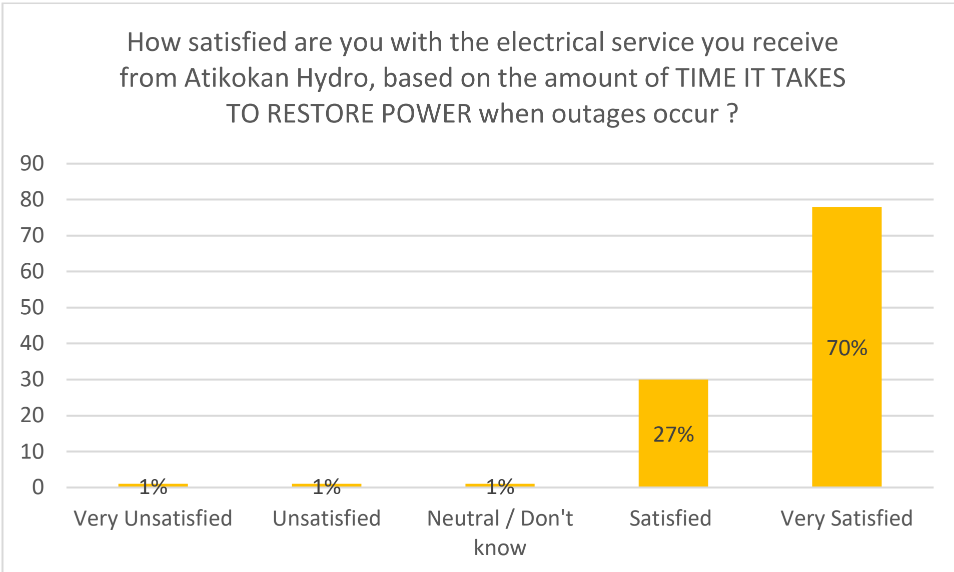
1. Overall, how satisfied are you with the services provided by Atikokan Hydro?



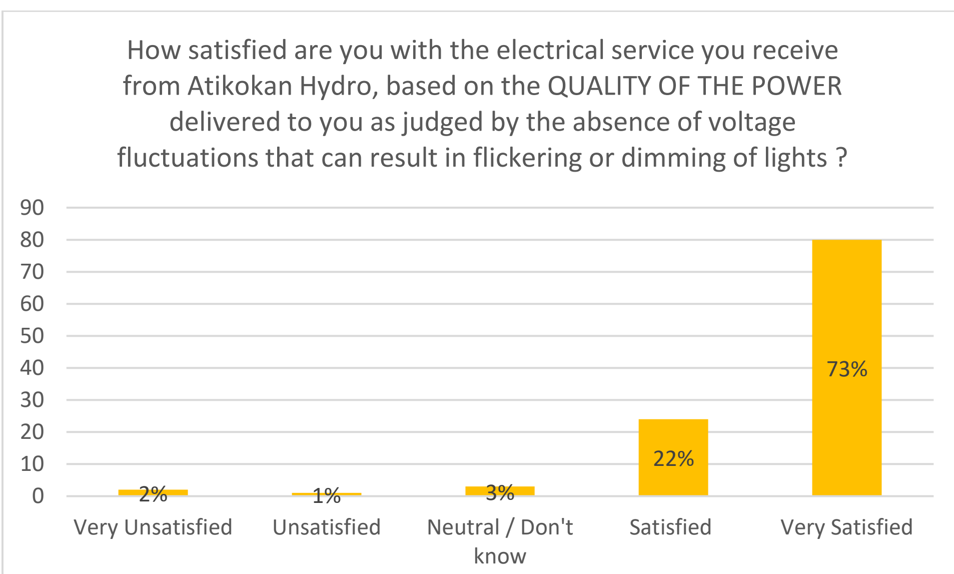
2. How satisfied are you with the RELIABILTY of the electrical service you receive from Atikokan Hydro, based on the number of outages you have experienced?



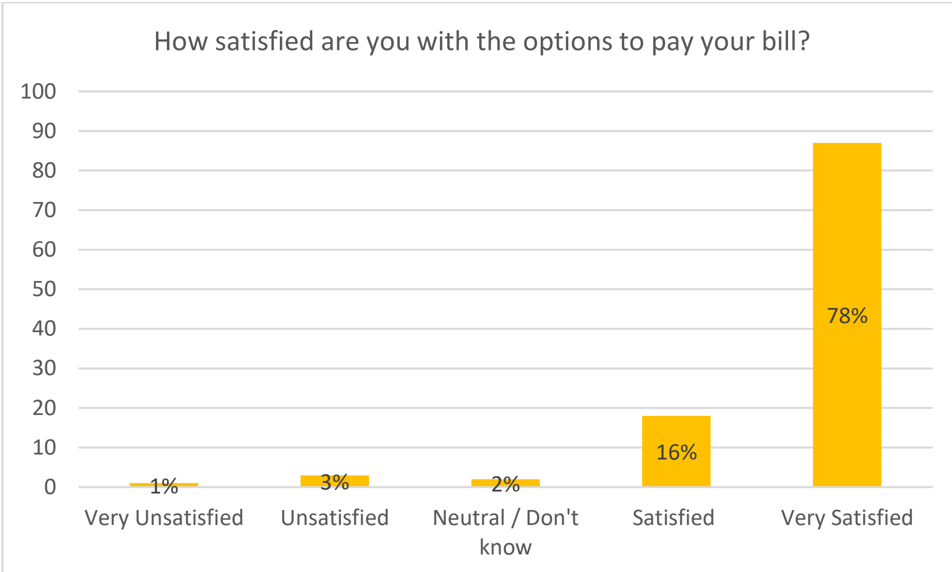
3. How satisfied are you with the electrical service you receive from Atikokan Hydro, based on the amount of TIME IT TAKES TO RESTORE POWER when outages occur?



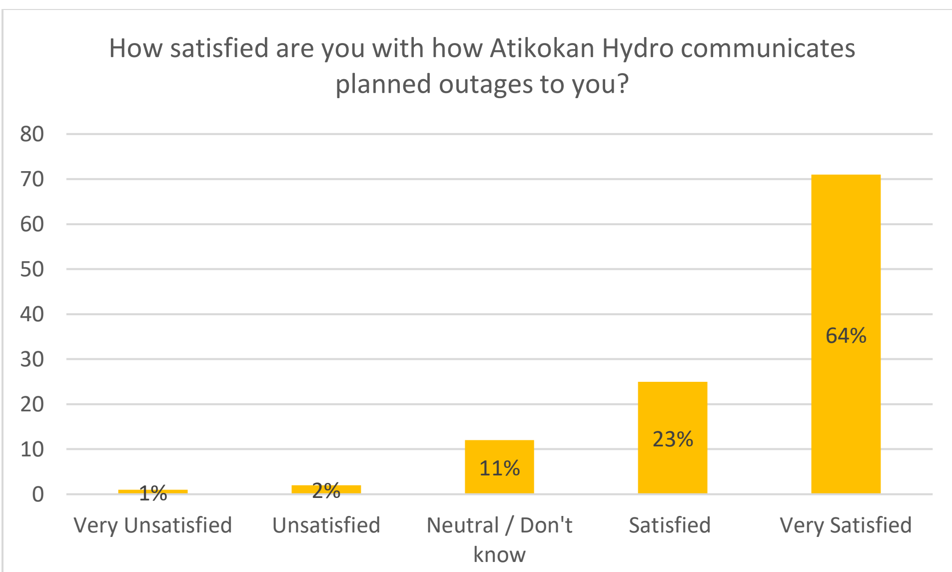
4. How satisfied are you with the electrical service you receive from Atikokan Hydro, based on the QUALITY OF THE POWER delivered to you as judged by the absence of voltage fluctuations that can result in flickering or dimming of lights?



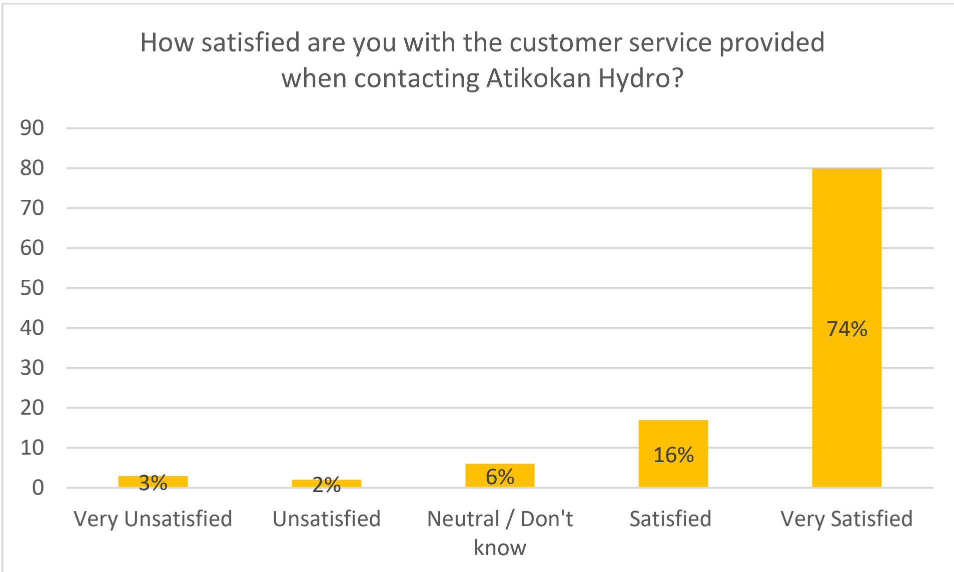
5. How satisfied are you with the options to pay your bill?



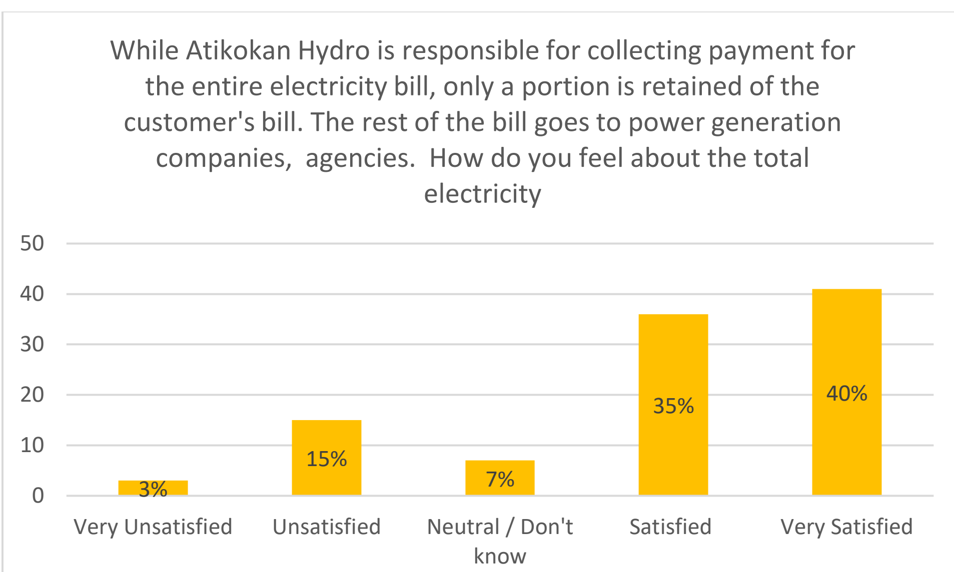
6. How satisfied are you with how Atikokan Hydro communicates planned outages to you?



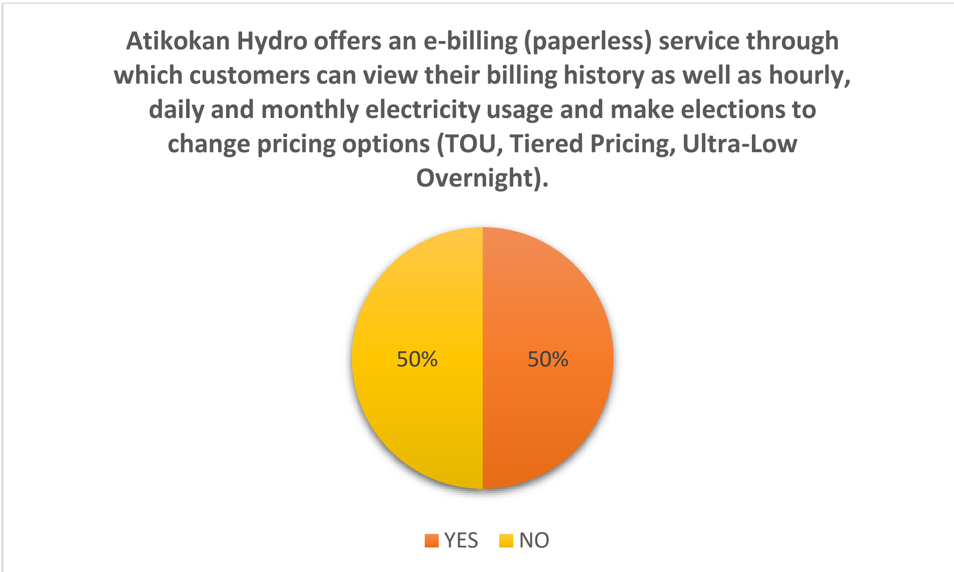
7. How satisfied are you with the customer service provided when contacting Atikokan Hydro?



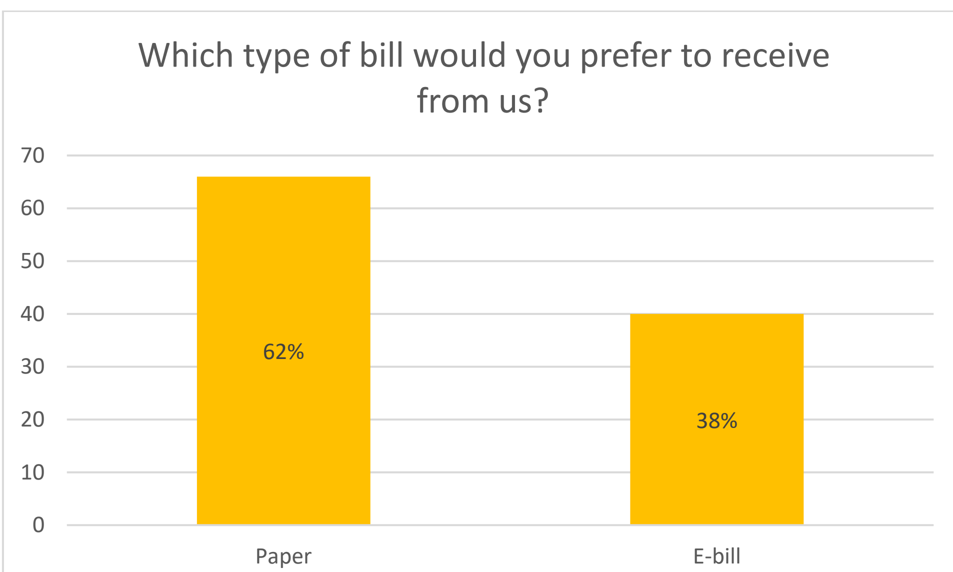
8. While Atikokan Hydro is responsible for collecting payment for the entire electricity bill, only a portion is retained of the customer's bill. The rest of the bill goes to power generation companies, agencies. How do you feel about the total electricity bill you pay for and your hydro services provided?



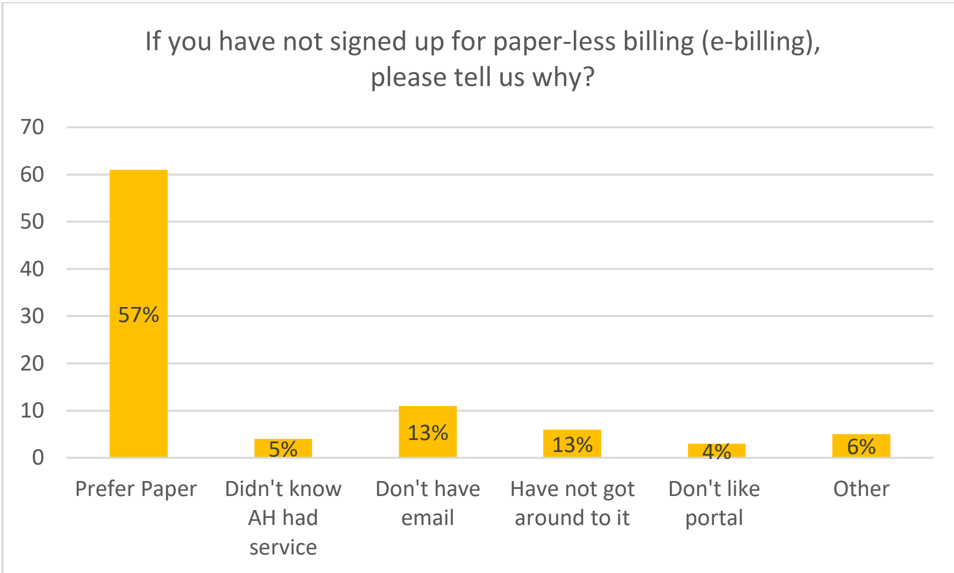
9. Atikokan Hydro offers an e-billing (paperless) service through which customers can view their billing history as well as hourly, daily and monthly electricity usage and make elections to change pricing options (TOU, Tiered Pricing, Ultra-Low Overnight). Is this of value to you?



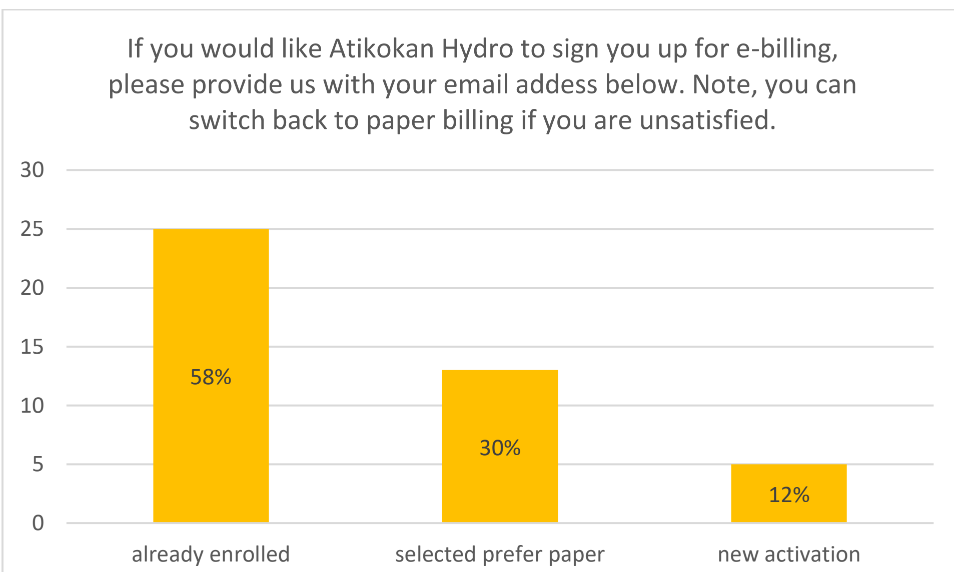
10. Which type of bill would you prefer to receive from us?



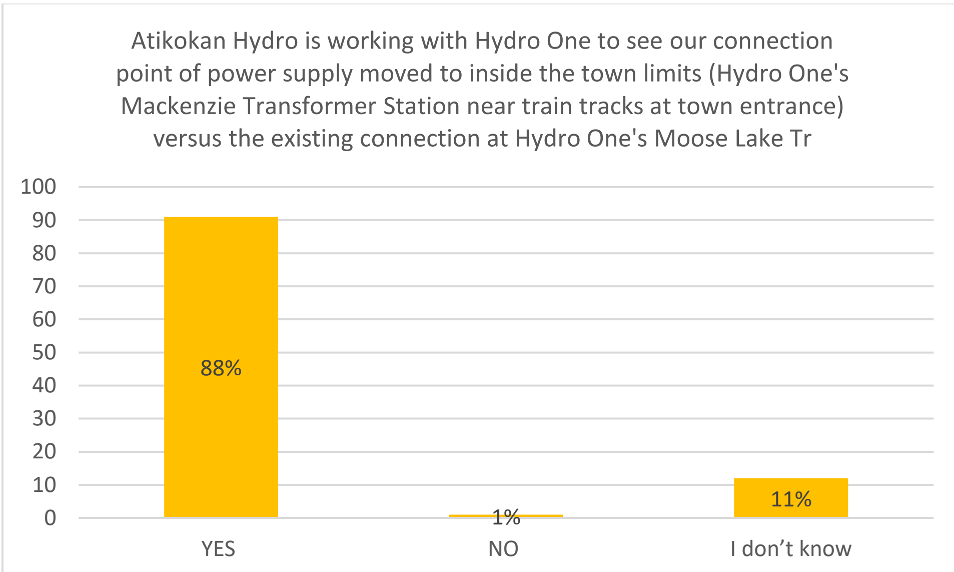
11. If you have not signed up for paper-less billing (e-billing), please tell us why?



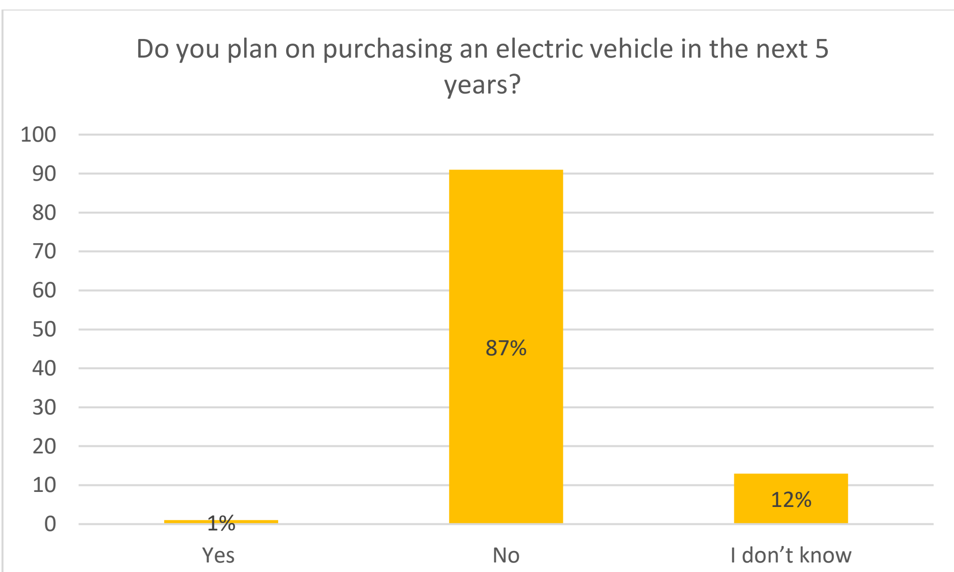
12. If you would like Atikokan Hydro to sign you up for e-billing, please provide us with your email address below. Note, you can switch back to paper billing if you are unsatisfied.



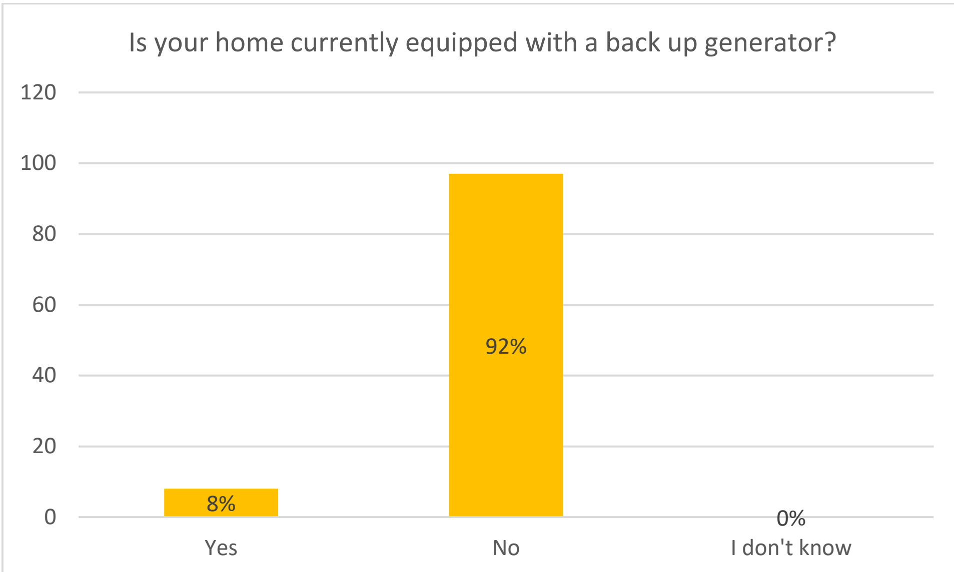
13. Atikokan Hydro is working with Hydro One to see our connection point of power supply moved to inside the town limits (Hydro One's Mackenzie Transformer Station near train tracks at town entrance) versus the existing connection at Hydro One's Moose Lake Transformer Station (out near Atikokan's Generation Station, OPG). This will enable a more accessible connection point with improved reliability. Do you agree with this project?



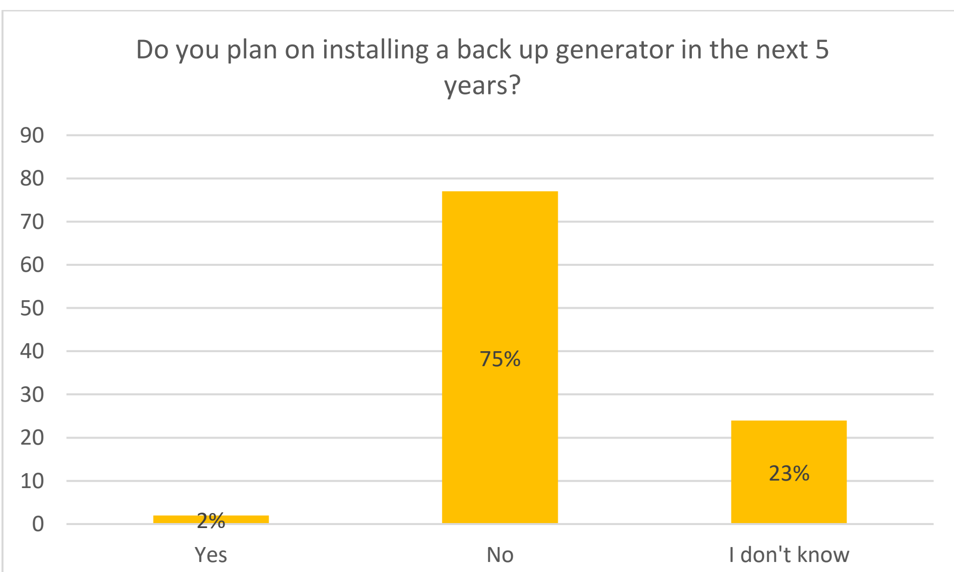
14. Do you plan on purchasing an electric vehicle in the next 5 years?



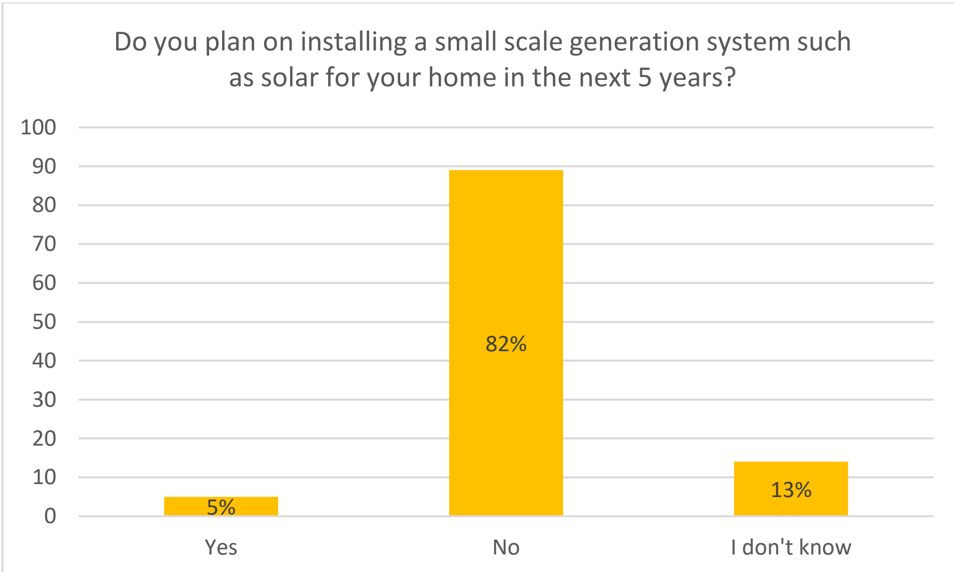
15. Is your home currently equipped with a back up generator?



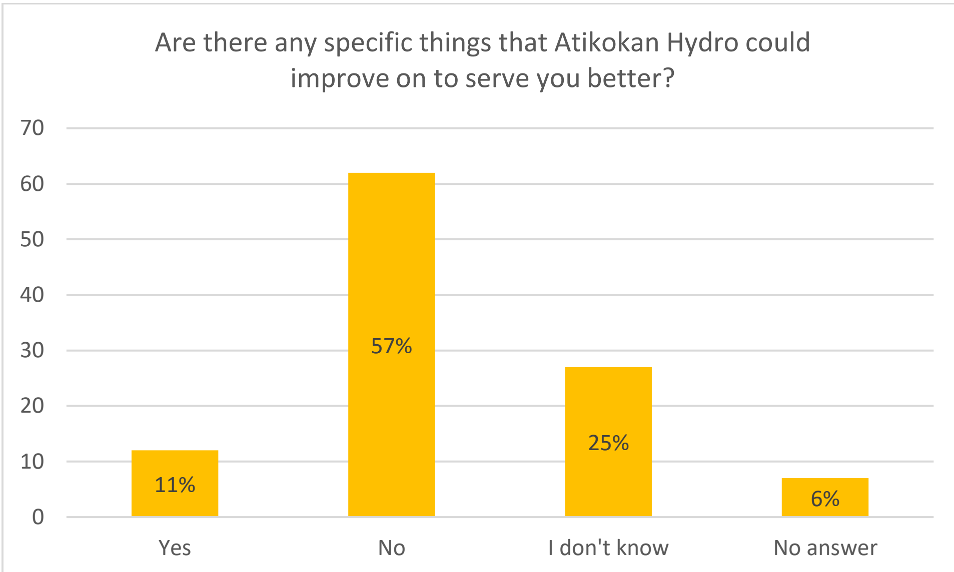
16. Do you plan on installing a back up generator in the next 5 years?

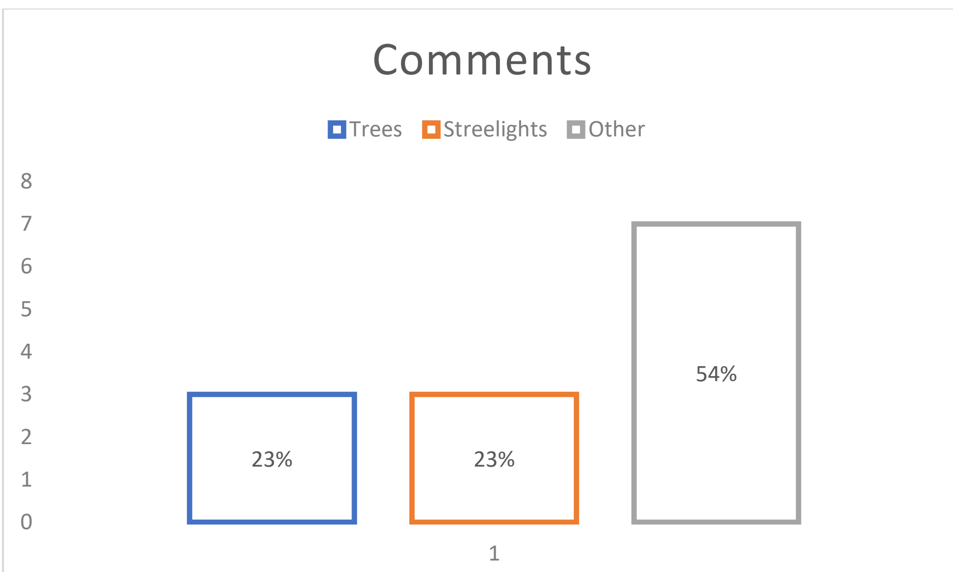


17. Do you plan on installing a small-scale generation system such as solar for your home in the next 5 years?



18. Are there any specific things that Atikokan Hydro could improve on to serve you better?





Below are the generalized comments received broken down by category that Atikokan Hydro when asked how Atikokan Hydro can improve to serve [customers] better.

Trees

-Cute trees on hydro lines

-Trim tree branches around streetlights

-Woodchipper for trees trimmed and removed

Streetlights

Fix streetlights more promptly

Other

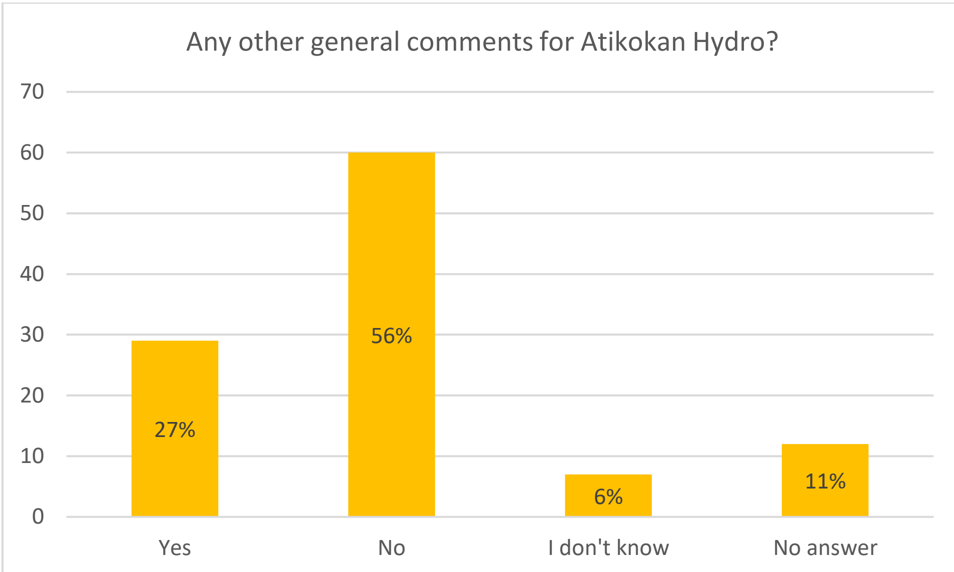
-Cost

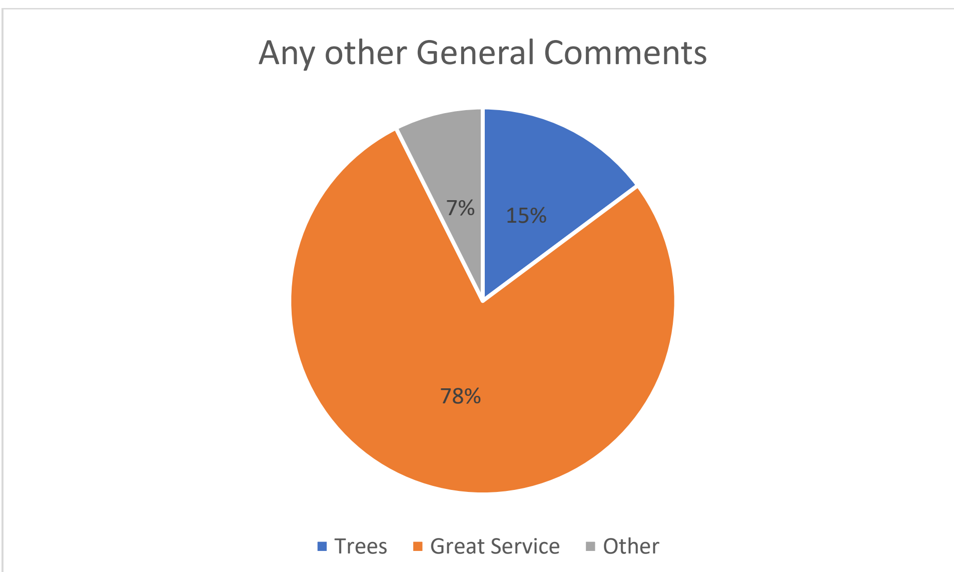
-Are you able to get reduced rates or provided help in purchasing generlink mounted transfer switch?

-Smart meter concerns with running on Eastern Standard Time and accuracy.

-Response time to customer requested work orders

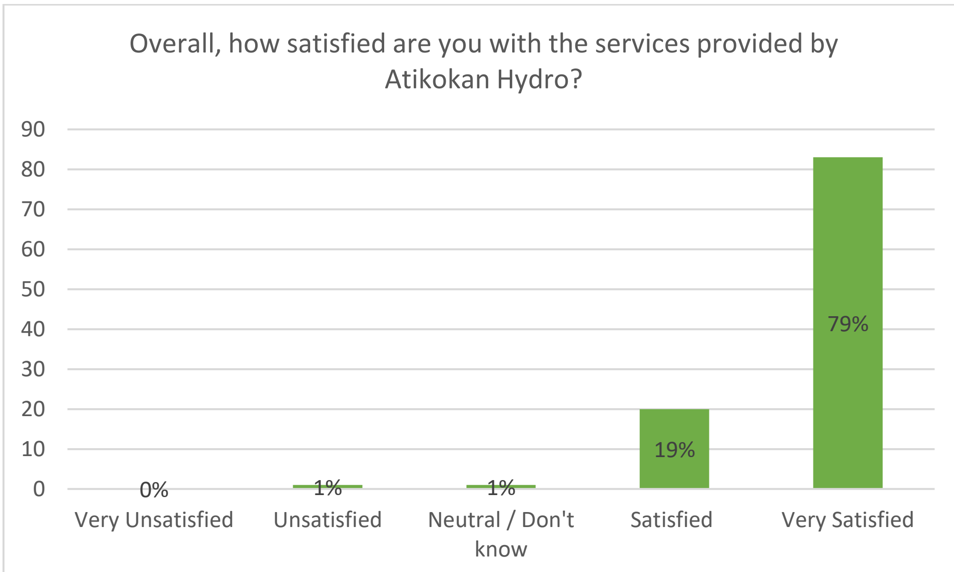
19. Any other general comments for Atikokan Hydro?

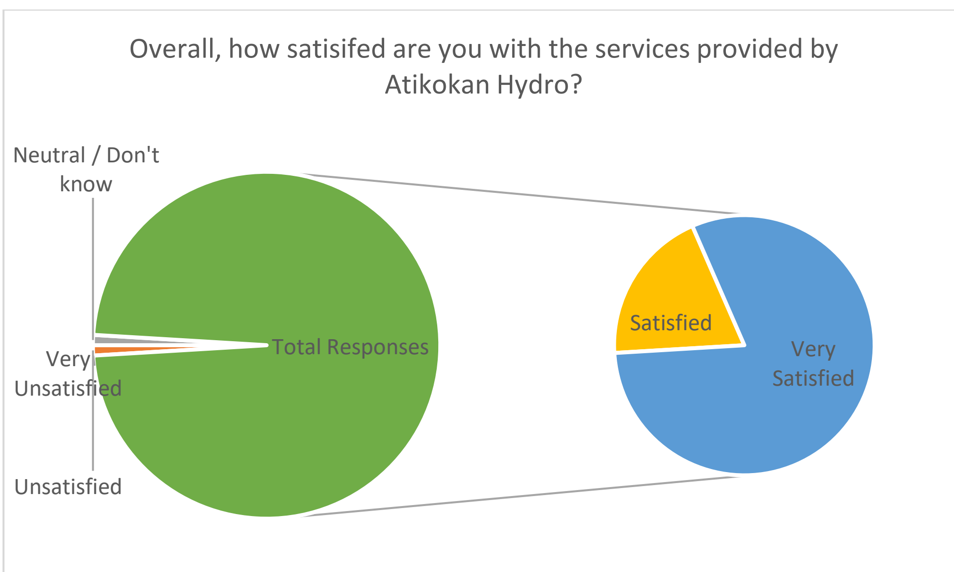




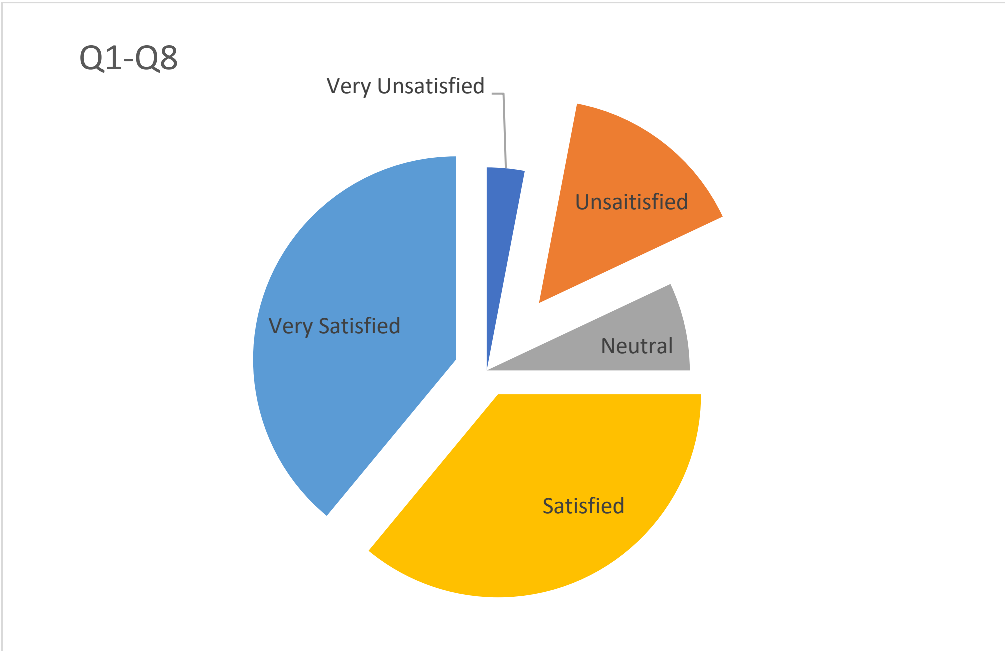
Overall Findings

Satisfaction with the services provided by Atikokan Hydro?





Overall satisfaction: services, reliability, power restoration and quality of power delivered.



<u>Other survey observations</u>

Majority of survey participants

- are not likely to purchase an EV in the next five years.
- do not have a backup generator nor plan to have on in the next five years.
- Do not plan to install small scale generation.
- prefer paper-based bills; over half of respondents.

- Support Atikokan Hydro's connection point of power supply moved to inside the town limits (Hydro One's Mackenzie Transformer Station) versus the existing connection at Hydro One's Moose Lake Transformer Station.

Appendix D: Integrated Regional Resource Plan January 2023 (Northwest Region)

Integrated Regional Resource Plan

Northwest Region
January 2023

Connecting Today.
Powering Tomorrow.

Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this document are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this document, as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed herein. The IESO undertakes no obligation to revise or update any information contained in this document as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

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List of Acronyms

Acronym	Definition
APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station
ULTC	Under-Load Tap Changer

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Northwest region which included the following members:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

Synergy North

The Working Group assessed the reliability of electricity supply to customers in the Northwest Region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options while maintaining flexibility to accommodate changes in key conditions over time.

The Northwest Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The Northwest Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Northwest region over the next 20 years from 2021 to 2040. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay. A geographic map of the Northwest region is shown in Figure 1-1. Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. A single line diagram of the electrical infrastructure in the region is shown in Figure 1-2.

Northwest regional electricity demand is winter peaking and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. Local generation in the region is predominantly hydroelectric and biomass-fueled.

The region's electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO.[1] The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[1] The Needs Assessment can found on Hydro One's Northwest Ontario regional planning website and the Scoping Assessment Outcome Report can be found on the IESO's Northwest regional planning engagement website.

- Demand forecast scenarios, distributed generation assumptions, and conservation and demand management are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An update on the Supply to the Ring of Fire study is provided in Section 8
- A summary of engagement to date and the next steps are provided in Section 9; and
- The conclusion is provided in Section 10

Figure 1-1 | Geographic Map of the Northwest Region

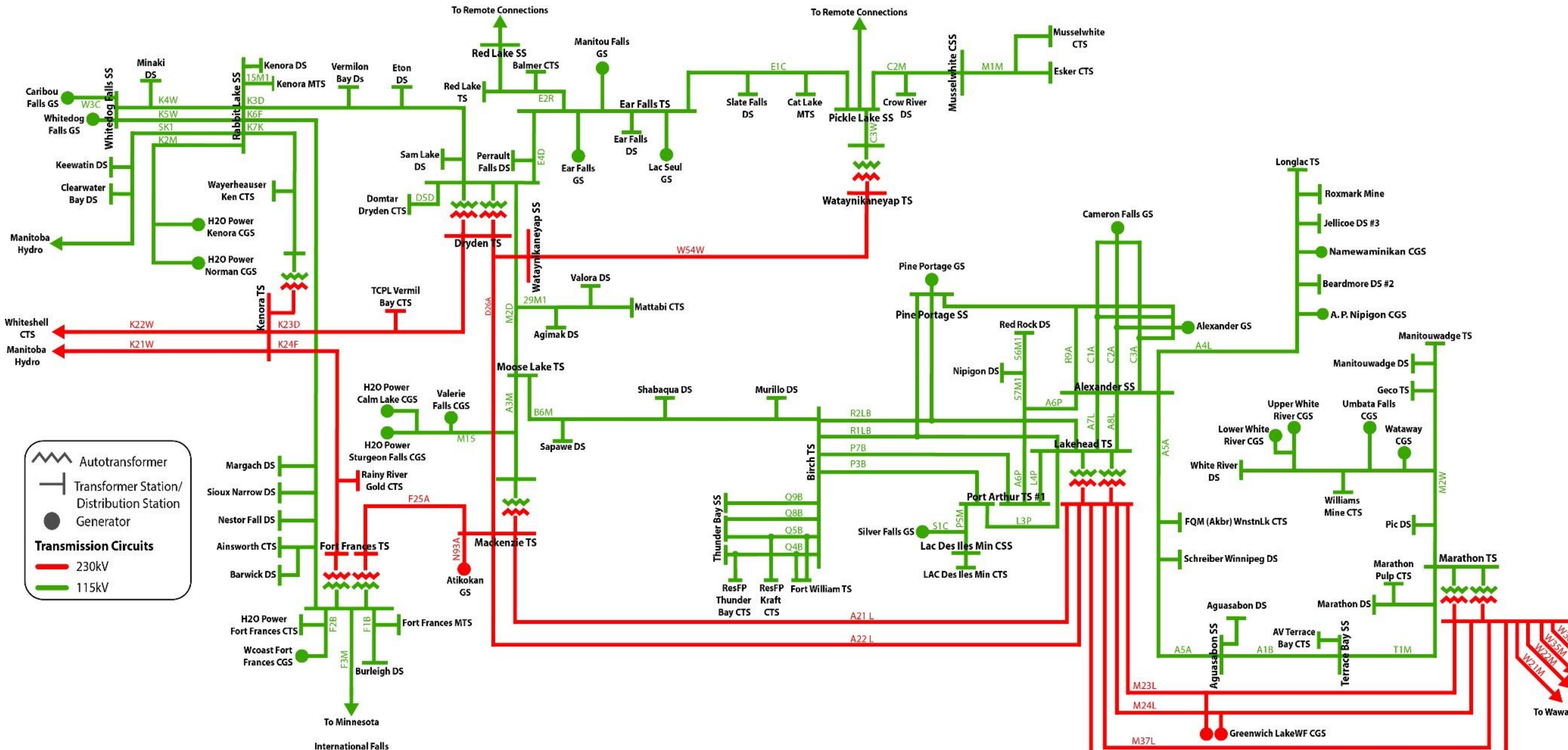

Figure 1-2 | Electricity Infrastructure in the Northwest Ontario Region

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Northwest region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through the application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic and feasible), and feedback from stakeholders.

There are several recent or ongoing transmission reinforcement projects in the Northwest region including the:

- East-West Tie Reinforcement (new double circuit 230 kV line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS),
- Waasigan Transmission Line Project (Phase 1 being a new double circuit 230 kV line from Lakehead TS to Mackenzie TS and Phase 2 being a new single circuit 230 kV line from Mackenzie TS to Dryden TS), and
- Wataynikaneyap Transmission Project (new single circuit 230 kV line from Dinorwic Junction near Dryden to Wataynikaneyap TS near Pickle Lake as well as 115 kV remote connection circuits north of Pickle Lake and Red Lake).

Taken together, these projects reinforce many of the 230 kV transmission paths in the region. With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. There are no new transmission projects recommended as a result of this Northwest planning initiative.

Northwest electricity demand growth is driven by the mining sector which tends to add large incremental blocks of load, often with short lead times. Therefore, this IRRP also studied several high growth sensitivities beyond forecast demand levels to test the robustness of the plan.

The plan below is organized into two sections: near-/medium-term recommendations and ongoing monitoring. Near-/medium-term recommendations include actions or further studies to be undertaken by Working Group member(s) by a specified date. These recommendations address needs with a high level of forecast certainty and requires firm commitments in this cycle of regional planning. Ongoing monitoring activities address long-term needs or potential needs flagged in high growth sensitivities that may emerge but are not yet certain based on the latest electricity demand forecast. This approach ensures that the IRRP provides clear guidance on investments needed in the near future while remaining flexible to consider new information such as electrification, energy efficiency, and industrial/mining development plans.

2.1 Near-/Medium-Term Recommendations

The near- and medium-term recommendations are summarized in Table 2-1 and further discussed below.

Table 2-1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Required By
Kenora MTS Station Capacity	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning	Synergy North; IESO	2029
Crilly DS Station Capacity	NWAs not suitable; Hydro One Distribution will refine options for refurbishment or a new station in local planning	Hydro One Distribution	2027
Margach DS Station Capacity	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer	Hydro One Distribution	2023
Fort Frances MTS Customer Reliability	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Fort Frances Power and Hydro One Transmission will refine configuration in local planning	Fort Frances Power; Hydro One Transmission	As Soon as Practical
E1C Operation and High Voltage	With the new W54W circuit in-service, part of the Wataynikaneyap Transmission Project, E1C will be operated "normally open" and additional reactors will be installed at/near Pickle Lake SS to manage high voltages; Hydro One and IESO will collaborate in the Regional Infrastructure Plan to refine location of open point and reactor sizing	IESO Hydro One Transmission	As Soon as Practical

Note that all costs discussed below are planning-level estimates (-50% to +100%) provided for the purpose of comparing options. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

2.1.1 Kenora MTS Station Capacity

Kenora MTS is expected to reach capacity in 2029. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits.[2] The wires options and distribution benefits are further discussed in Section 7.1.4.1. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station.[2] Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[3] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[4] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

2.1.2 Crilly DS Station Capacity

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to

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[2] The methodology for calculating cost estimates is set out in Section 7.1.1

[3] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[4] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to the existing reliance on backup generation. Distributed energy resources cannot remove the reliance on backup power and provide reliability comparable with other standard supply arrangements. Furthermore, the pool of customers served at Crilly DS is too small to target demand-modifying solutions such as energy efficiency and demand response. The IRRP recommends that Hydro One Distribution conducts local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost. Options considered thus far include:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),
- Rebuild Crilly DS at a different location as a 115/25 kV HVDS,
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS, or
- Replace Crilly DS with a 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

Wires options for Crilly DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.2. Hydro One Distribution should monitor load growth to determine when a firm commitment to refurbish/rebuild Crilly DS is required.

2.1.3 Margach Station Capacity

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS. Margach DS is approximately 10 km east of Kenora. Non-wires alternatives are not capable of addressing this large near-term step increase in demand.

The IRRP recommends that Hydro One distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service but no recommendation beyond the fan monitoring is required today. Wires options for Margach DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.3.

2.1.4 Fort Frances MTS Customer Reliability

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS. The two stations are located immediately across the street from each other. Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during certain transmission outages. Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. While the station equipment has not yet reached end-of-life, most equipment has reached or exceeded its typical useful life (as defined in the OEB's Asset Depreciation Study[5]) and will need to be replaced gradually over the next 10-15 years. While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power which could quickly use up the remaining station capacity. Furthermore, 115 kV breakers at Fort Frances TS are also approaching end of life around 2027 which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS. Customer reliability, sustainment, and potential capacity needs are further discussed in Sections 6.2.2 and 0.

Fort Frances Power is developing a roadmap for Fort Frances MTS considering the replacement of aging assets, demand growth, and reliability improvements by reconfiguring supply from Fort Frances TS. Considering these needs simultaneously will ensure the most optimal and cost-effective outcome. Hydro One has proposed several Fort Frances TS reconfigurations that would incrementally improve customer reliability for Fort Frances TS and are further discussed in Section 7.2. The IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and refine a configuration in local planning.

2.1.5 E1C Operation and High Voltage

With the new 230 kV Wataynikaneyap circuit W54W in-service, operating circuit E1C closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W. The IRRP confirms that E1C should be operated normally open. This configuration is consistent with the 2015 North of Dryden IRRP.

With E1C operated normally open, high voltage arises due to line charging. Studies show that opening E1C closer to the Ear Falls TS end minimizes high voltage issues. Additionally, the IRRP recommends an additional reactor (approximately 10 MVar) at or near Pickle Lake SS.

E1C closed loop transfer limitations and E1C normally open high voltage issues are further discussed in Section 6.2.3. The IESO and Hydro One Transmission will collaborate in the Regional Infrastructure Plan to refine the location of the open point on E1C and the sizing of the reactor, considering asset conditions and costs.

[5] The OEB's Asset Depreciation Study can be found on the Ontario Energy Board's website.

2.2 Ongoing Monitoring

In addition to the needs addressed in the near- and medium-term plan above, there are several long-term or potential needs that may emerge over the forecast horizon. These needs will be monitored by the Working Group to determine when future planning studies should be triggered.

2.2.1 Station Capacity Needs Emerging in the Long-term

White Dog DS and Marathon DS are expected to reach capacity in 2032 and 2038 respectively. In both cases, current demand already exceeds 85% of the station capacity but forecast growth is modest over the forecast horizon. As with many stations across the Northwest, growth can materialize quickly if industrial development intensifies. Therefore, White Dog DS and Marathon DS should be monitored, and further planning activities should be triggered at least five years before anticipated capacity needs to enable consideration of non-wires alternatives. White Dog DS and Marathon DS station capacity needs are further discussed in Section 6.2.1.4 and 6.2.1.5.

2.2.2 Potential Growth in the Red Lake Area

The Red Lake area has significant mining activity and electricity demand is forecast to grow from 58 MW today to 70 MW by 2028. The W54W circuit recently completed as part of the Wataynikaneyap Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake.

No capacity needs are anticipated based on the current demand forecast which was finalized by the end of 2021. However, the Working Group is aware of additional potential mining projects that are not captured in the current reference scenario demand forecast.[6] The timing and amount of load associated with these mines are not yet certain but, considering the typical size of new mining projects, remaining capacity in the Red Lake area can quickly be exhausted. Section 6.3.1 identifies the load meeting capability for the Red Lake area as well as constraints on the supply to Ear Falls and Dryden. Depending on the demand that materializes, bulk system enhancements beyond the scope of this IRRP (e.g., Waasigan Transmission Line Project Phase 2) may also be required.

The Working Group will monitor growth in the Red Lake area to determine when future planning activities should be triggered. The IESO will also continue to update the mining demand forecast, including mines in the Red Lake area, to inform ongoing bulk planning activities.

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[6] As described in Section 5.4, for the purpose of this IRRP, the mining sector demand forecast was finalized by the end of 2021. The Working Group is aware of additional future mining projects that were either brought to the awareness of the Working Group after 2021 or were not yet certain enough for inclusion in the demand forecast. The IESO is updating the mining sector demand forecast by end of Q1 2023 and will provide updates to the Working Group to inform the Regional Infrastructure Plan.

2.2.3 Potential Growth in the Fort Frances Area

Several large industrial customers have expressed interest in connecting in the Fort Frances area; these customers' potential loads are not included in the current demand forecast. While the incremental electricity demand associated with these customers (approximately totalling 100 MW) may be significant, no firm commitments have been made.

No supply capacity needs are anticipated based on the current demand forecast. Section 6.3.2 identifies the load meeting capability of the Fort Frances area. The Working Group will monitor growth in the Fort Frances area to determine when future planning activities should be triggered.

2.3 Coordination with ongoing Bulk Planning and Project Implementation Activities

In April 2022, as part of the IESO's obligation to recommend the specific scope and timing of the Waasigan Transmission Line Project, the IESO recommended a staged approach for construction with Phase 1 (a new line from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the region, update the mining sector demand forecast and provide an update on the need for Phase 2 (a new line from Atikokan to Dryden) by Q2 2023.

The IESO is also conducting a Northern Ontario Voltage Study to identify reactive compensation needs across northern Ontario. There are several recently implemented or planned major transmission reinforcement projects in the north including the East-West Tie Reinforcement, Waasigan Transmission Line Project, Wataynikaneyap Transmission Project, and Northeast Bulk Plan recommendations.[7] These projects will impact the voltage characteristics across the northern bulk transmission system, including the Northwest region. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

The Waasigan Transmission Line Project and Northern Ontario Voltage Study are further described in Section 4.2. The IESO will continue to update the Working Group regarding ongoing bulk planning and project implementation developments for consideration in the Regional Infrastructure Plan.

In addition to the plans above, the IESO is carrying out a Supply to the Ring of Fire study in parallel with this IRRP. The preliminary findings are discussed in Section 8. The Supply to the Ring of Fire Study will continue in 2023 and the IESO will update the working group on findings for consideration in future regional planning activities.

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[7] The Need for Northeast Bulk System Reinforcements report can found on the Northeast Bulk Planning webpage.

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 defined planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An Integrated Regional Resource Plan (IRRP), led by the IESO, proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

Regional planning is not the only type of electricity planning in Ontario. Other planning activities include bulk system planning, carried out by the IESO, and distribution system planning, carried out by LDCs. There are inherent overlaps in these three levels of electricity infrastructure planning.

The IESO completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. The IESO's Regional Planning Process Review report is posted on the IESO's website. Implementation of Regional Planning Process Review recommendations by the IESO, Ontario Energy Board, and its Regional Planning Process Advisory Board are ongoing.

3.2 The Northwest Region and IRRP Development

The process to develop the Northwest IRRP was initiated in January 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and Scoping Assessment Outcome Report in January 2021 by the IESO. As per the 18-month timeline, triggered by the publication of the Scoping Assessment Outcome Report, the original publication date for the Northwest IRRP was scheduled for July 13, 2022.

In April 2022, the IESO wrote to the Ontario Energy Board (OEB) to provide notice that the IESO required an additional six months to complete the IRRP. The IRRP's original scope was expanded to include additional key developments in the Northwest region. The expanded scope enabled more extensive stakeholder engagement, consideration of additional growth sensitivities, and better alignment with ongoing bulk studies across the Northwest and Northeast regions. Based on the IESO's estimate of the additional time required to incorporate the expanded scope, the new expected posting date for the Northwest IRRP was extended to January 13, 2023.

4. Background and Study Scope

This is the second cycle of regional planning for the Northwest region. In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (published January 2015)

A summary of each of the above IRRPs can be found in the 2021 Scoping Assessment Outcome Report[8]. The Scoping Assessment for this planning cycle recommended a single IRRP covering the entire Northwest region. This report presents an integrated regional electricity plan for the next 20-year period from 2021-2040.

Note that two new transmission system projects, the East-West Tie ("EWT") reinforcement and the Wataynikaneyap Transmission Project ("Watay Project") came into service during the current IRRP study. They were both assumed to be in-service for the purpose of this IRRP's technical assessments. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The new EWT circuits were placed in service in March 2022. The Watay Project includes a new 230 kV circuit, W54W, between Watay 230/115 kV TS and Dinorwic Junction on circuit D26A, which runs between Dryden TS and Mackenzie TS. W54W was placed in service in August 2022. The Watay Project includes the connection of ten remote First Nation communities north of Pickle Lake (electrically supplied by Pickle Lake SS) and an additional seven remote First Nation communities north of Red Lake (electrically supplied by Red Lake SS). As of Q4 2022, work is still underway to connect Pickle Lake and Red Lake remote communities, but they were assumed to be in service for the purpose of this IRRP's technical assessments.

4.1 Study Scope

This IRRP identifies electricity needs in the Northwest Region and develops and recommends options to meet these needs. A list of transmission facilities included in the scope of this study can be found in Appendix C. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation, and demand management (CDM), distributed generation (DG), transmission and distribution system

[8] The 2021 Scoping Assessment Outcome Report can be downloaded from the Northwest Regional Planning engagement webpage.

capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The Northwest IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NERC, and NPCC criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
- Confirming identified end-of-life asset replacement needs and timing with LDCs and transmitters;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including conservation and demand management;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

For the Northwest IRRP, areas of interest with high growth potential beyond forecast demand levels were identified through stakeholder engagement. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.1.1 Scope of Regional Planning Regarding New Connections

The purpose of the IRRP is to identify and address reliability needs that require coordination between transmitters, distribution companies, and the IESO. In the Northwest region, growth is driven in large part by industrial customers, predominantly in the mining sector. A subset of these customers are not currently connected to the electricity grid but are pursuing grid connection in the near term. The IRRP used the best available information to accurately simulate the connection arrangement of future customers and projects. However, IRRP technical studies were focused on evaluating the overall adequacy of regional infrastructure to supply forecast demand rather than the capability to supply any specific new project. The IRRP did not study the local connection requirements of any individual project unless there was an opportunity to align with broader regional needs.[9]

4.2 Parallel Bulk Planning Activities

The Waasigan Transmission Line Project and the Northern Ontario Voltage study are proceeding in parallel with this IRRP and the upcoming Regional Infrastructure Plan. Findings and recommendations from these bulk planning activities will inform ongoing regional planning activities.

4.2.1 Waasigan Transmission Line Project

The Waasigan Transmission Line Project ("Waasigan Project"), formally the Northwest Bulk Line, was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project to:

- Increase electricity supply to the region west of Thunder Bay;
- Provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- Enhance the potential for development and connection of renewable energy facilities.

The LTEPs divided the Waasigan Project into three phases:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council, also in 2013, that amended Hydro One's license to develop and seek approval for the Waasigan Project according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs.

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[9] Potential customers seeking connection should note that participation in the IRRP does not replace connection processes, namely Customer Impact Assessments (CIA) or System Impact Assessments (SIA). Furthermore, the absence of regional reliability needs identified through the IRRP in a particular area does not guarantee that connection requests in that area will be approved in a CIA or SIA.

In 2022, the IESO updated the demand forecast for the region west of Thunder Bay with information from the IRRP demand forecast and feedback from stakeholders. The mining sector demand forecast drove the majority of the demand growth and is further discussed in Section 5.4. The updated demand forecast showed a need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027, but not thereafter as some existing mining projects reach end of life. Therefore, the IESO recommended a staged approached for construction where Hydro One would construct the Project to meet near-term system capacity needs, with Phase 1 being placed in service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the Region and provide an update in Q2 2023 on the expected need date for Phase 2. This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks.

The IESO recognizes that a firm need for Phase 2 could materialize quickly given the potential for additional growth in the region. The IESO is currently in the process of updating the mining demand forecast to reflect additional information received over the past year since the last forecast iteration and to better capture future growth driven by electrification trends and government policy. The forecast update is expected to be completed in Q1 2023.

4.2.2 Northern Ontario Voltage Study

The IESO is conducting a Northern Ontario Voltage Study to identify reactive compensation needs across the bulk system in northern Ontario. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

4.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. The decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as they are the direct beneficiaries, or with the provincial and federal governments, to advance broader policy objectives.

Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with this IRRP to help inform government policy and potential customers seeking connection. This study outlines opportunities for alignment, updated high-level transmission supply cost estimates, updated avoided diesel system costs from connecting remote communities, and greenhouse gas reductions as a result of supplying remote communities and potential mines from the electricity grid instead of local generation. The preliminary findings are discussed in Section 8.

The study scope and timing of this ongoing study will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

5. Electricity Demand Forecast

This section describes the development of the demand forecast for the Northwest Region that underpins this IRRP. The 20-year forecast has three components:

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the Northwest and is based on information submitted by local distribution companies.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This is typically comprised of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.
- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement individual project proponents. Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

Each forecast component is described in detail below. Note that the forecasts in this section refer to the non-coincident peak demand forecast (i.e., the sum of each station's individual peak demand). Coincident forecasts (i.e., contribution of each station to the overall peak demand hour) for the subsystem in question are used for the purpose of identifying need dates and options analysis in Section 6 and 7. Coincident forecasts are found by applying a coincidence factor based on the contribution of each station to the subsystem's coincident peak over the past five years.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Northwest IRRP forecast was created prior to October 2022, the Ontario Energy Board has also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.[10]

[10] The Load Forecast Guideline can be found on the Ontario Energy Board's website.

5.1 Historical Demand

Figure 5-1 shows the net and gross historical demand over the last five years in the Northwest region. Distribution-connected customer historically make up approximately 55% of peak demand with the remainder made up of transmission-connected customers. Growth has been steady over the last five years, with an average annual demand growth rate of 1.1% and Northwest demand hovering just over 800 MW from 2018 through 2020. Northwestern Ontario is winter peaking, with the peak demand hour for each year typically occurring on winter evenings between 7 p.m. And 11 p.m.

Existing distributed generation resources historically contributed approximately 10-15 MW during peak demand conditions. This contribution was added back into the net demand forecast to arrive at the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast unless station-level adjustments were necessary to account for anomalous demand conditions on a case-by-case basis.

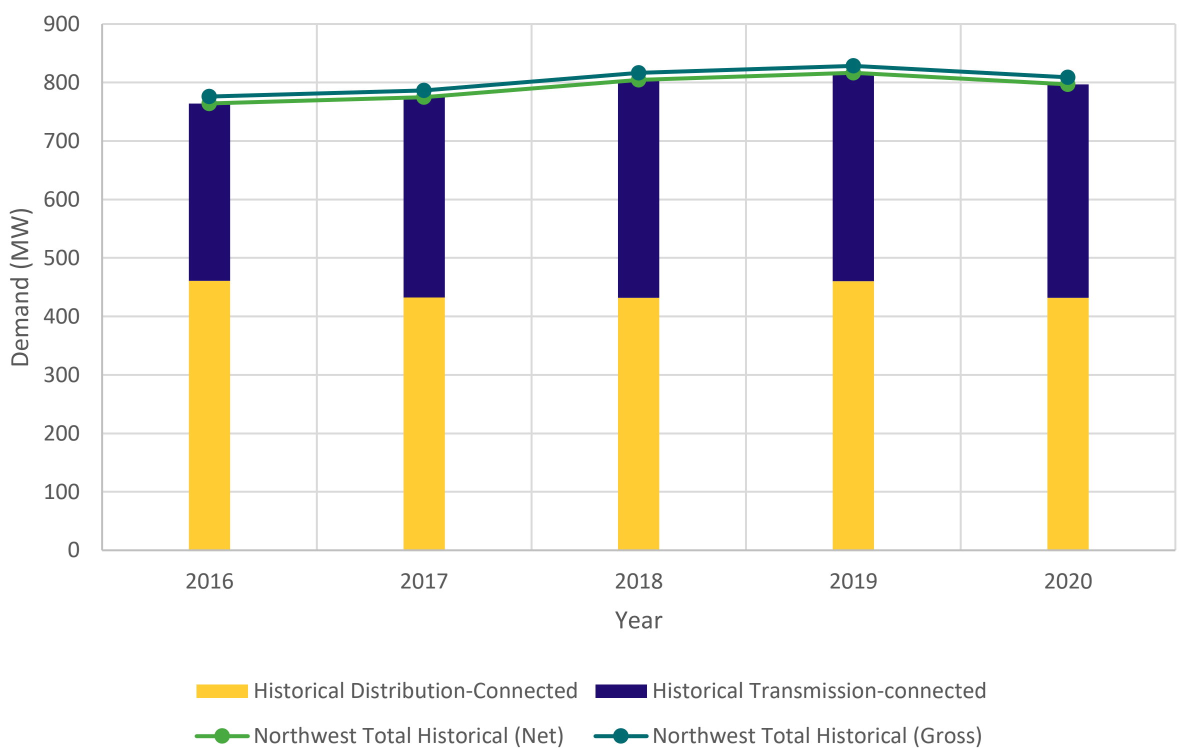

Figure 5-1 | 2016-2020 Historical Demand

5.2 Distribution-connected Forecast

The distribution-connected forecast component starts with a gross station-level demand forecast developed by local distribution companies for their service territory. The gross forecast was then modified to reflect the peak demand impacts of provincial conservation targets and distributed generation contracted through previous provincial programs such as FIT and microFIT[11] and adjusted to reflect extreme weather conditions to produce a reference scenario net forecast for planning assessments. Additional details related to the development of the distribution-connected demand forecast are provided in the sections below and in Appendix B.

5.2.1 Gross Local Distribution Company Forecast

Each participating local distribution company in the Northwest region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications within their service territories.

Note that the regional planning process relies on distributors to consider municipal and regional official plans and translate development plans into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve. More details on each distributor's demand forecast assumptions can be found in Appendix B.2 to B.6. Distributors are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future distributed generation or new conservation measures which are accounted for by the IESO, as discussed in Section 5.2.2 and 5.2.3 below.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

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[11] More information about the Feed-in Tariff can be found on the IESO's website.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

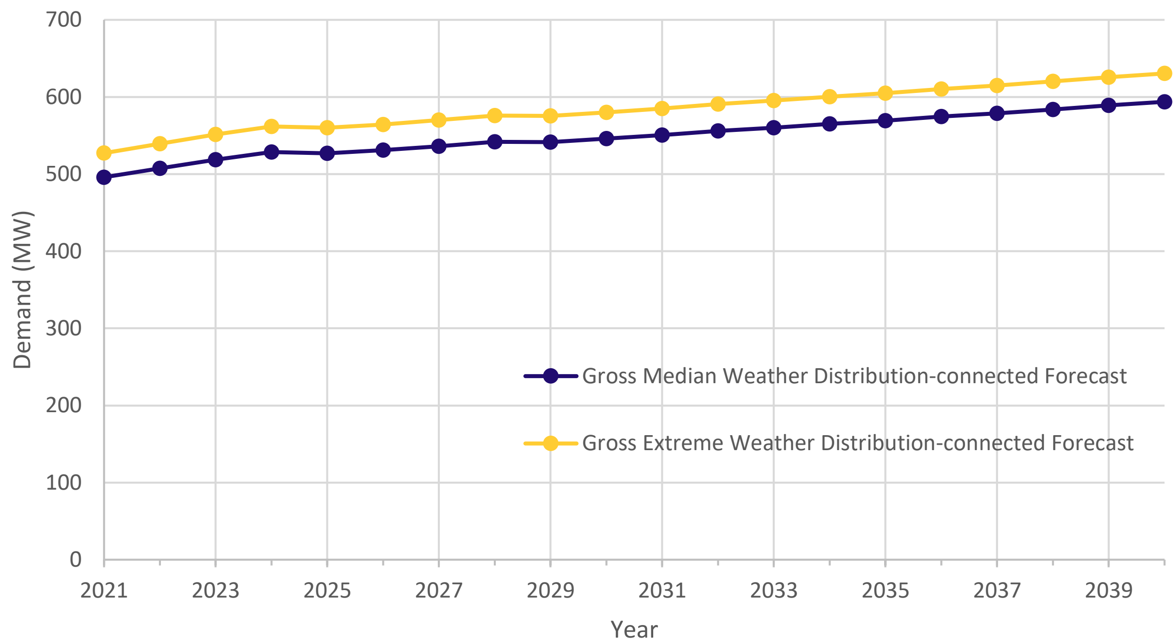


Figure 5-2 | Total Gross Median Weather Distribution-connected Forecast

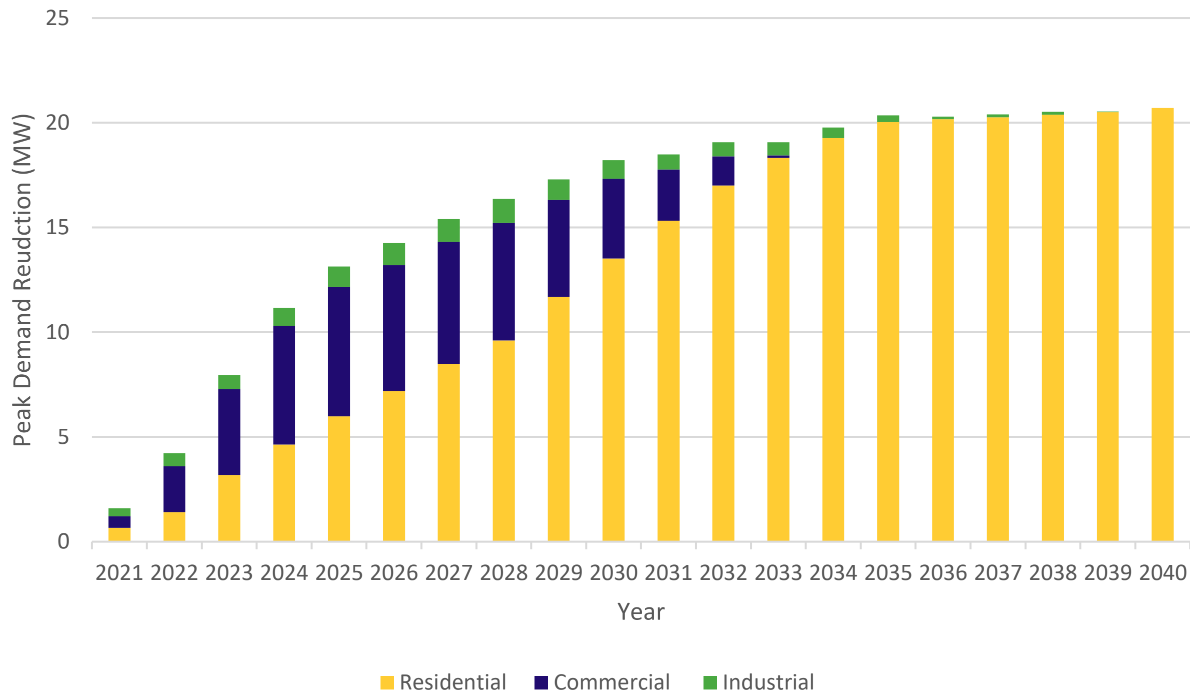
5.2.2 Contribution of Conservation to the Forecast

CDM is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers, i.e., residential, commercial, and industrial consumers.

The estimates of demand reduction due to new program-related activities account for Ontario programs, federal programs that result in electricity savings in Ontario, and forecast future energy efficiency programs. The 2021 – 2024 CDM Framework is the central piece in which the IESO delivers programs on a province-wide basis to enable Ontario's electricity consumers to improve the energy efficiency of their homes, businesses, institutions, and industrial facilities.

Figure 5-3 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for residential, commercial, and industrial market segments. Additional details on the conservation forecast methodology are provided in Appendix B.9.



5.2.3 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, distributed generation in the Northwest region is also forecast to offset some peak demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed distributed generation capacity by fuel type and contribution factor assumptions can be found in Appendix B.10.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted distributed generation in the region (similar to the adjustment between net and gross historical demand described in Section 5.1 except with forward looking contracted distributed generation rather than existing distributed generation). Figure 5.5 shows the impact of distributed generation reducing the demand forecast. In the long term, the contribution of distributed generation is expected to diminish as these contracts expire. Note that any facilities without a contract with the IESO are not included in the distributed generation peak demand reduction forecast.

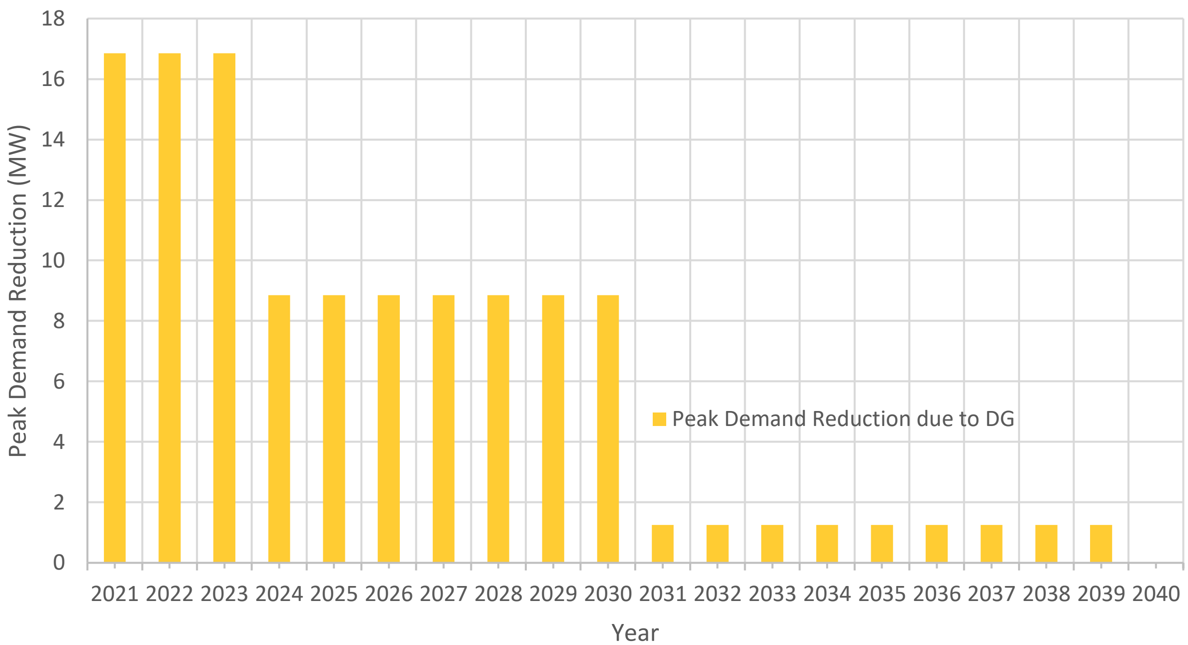


Figure 5-4 | Peak Demand Reduction to Demand Forecast due to Contracted Distributed Generation

5.3 Existing Transmission-connected Forecast

The Northwest region has fifteen customer transformer stations (CTS) that directly serve customers connected to the high-voltage transmission system. The IRRP relies on information from these customers to inform the transmission-connected forecast either directly through their account representative or through comments submitted through the IRRP engagement events. If, for a given station, no information about future demand changes is available, the default assumption is that demand at that station will remain the same as the average historical peak demand over the last five years. Figure 5-5 shows the total non-coincident transmission-connected customer demand forecast. The transmission-connected forecast is generally flat except for a few project expansions/retirements resulting in growth in 2026 and subsequent decline in 2028. Note that, unlike the distribution-connected forecast component, the transmission-connected component is not adjusted for extreme weather because industrial demand does not typically fluctuate with weather. Furthermore, while some customers have behind-the-meter generation facilities, they are not reflected in the forecast unless they are contracted with the IESO.

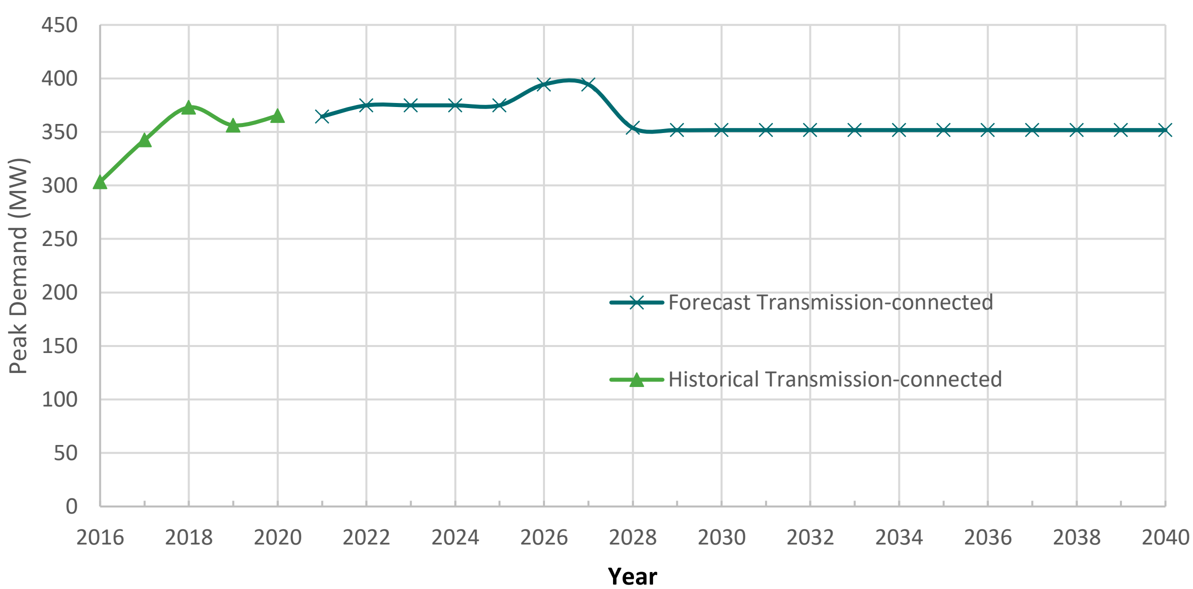


Figure 5-5 | Total Transmission-connected Demand Forecast

5.4 Mining Sector Forecast

In addition to the distribution- and transmission-connected forecasts, expansion of existing mines and new mining projects connecting to the grid are expected to make up the majority of the overall electricity demand growth in the Northwest region. As of Q4 2021, the IESO was aware of more than 20 potential future mining projects in the Northwest region at various stages of planning and development that had known electricity demand forecasts and projected in-service dates. The IESO is also aware of at least ~7-10 projects that are under consideration but have not yet progressed far enough to have an in-service date or electrical demand forecast. Note that information about future mining projects changes frequently. The IESO solicited public feedback on the mining demand forecast and associated list of known mining projects in May 2021. For this IRRP, the mining forecast was considered finalized by the end of 2021 to allow sufficient time for technical assessments that depended on forecast inputs. The mining projects incorporated in the IRRP mining forecast are listed in Appendix B.7.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

Table 5-1 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus the full undiscounted demand forecast from projects classified as "most likely" and "likely" - Aligned with 2021 Annual Planning Outlook[12] reference scenario
High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand o "Less likely" project forecasts discounted to 50% of their full project demand o "Least likely" project forecasts discounted to 20% of their full project demand - Aligned with 2021 Annual Planning Outlook high scenario

[12] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 5-1 above.

Figure 5-6 shows the low, reference, and high mining demand forecast scenarios. The total aggregate undiscounted (i.e., without consideration of likelihood factors) forecast demand from all known projects is also shown in a dashed line. Note that the total aggregate undiscounted forecast demand is not a realistic growth scenario since it is highly unlikely for all proposed mining projects to materialized. The undiscounted forecast is provided for transparency to illustrate the scale of potential demand growth considered in the low, reference, and high scenarios.

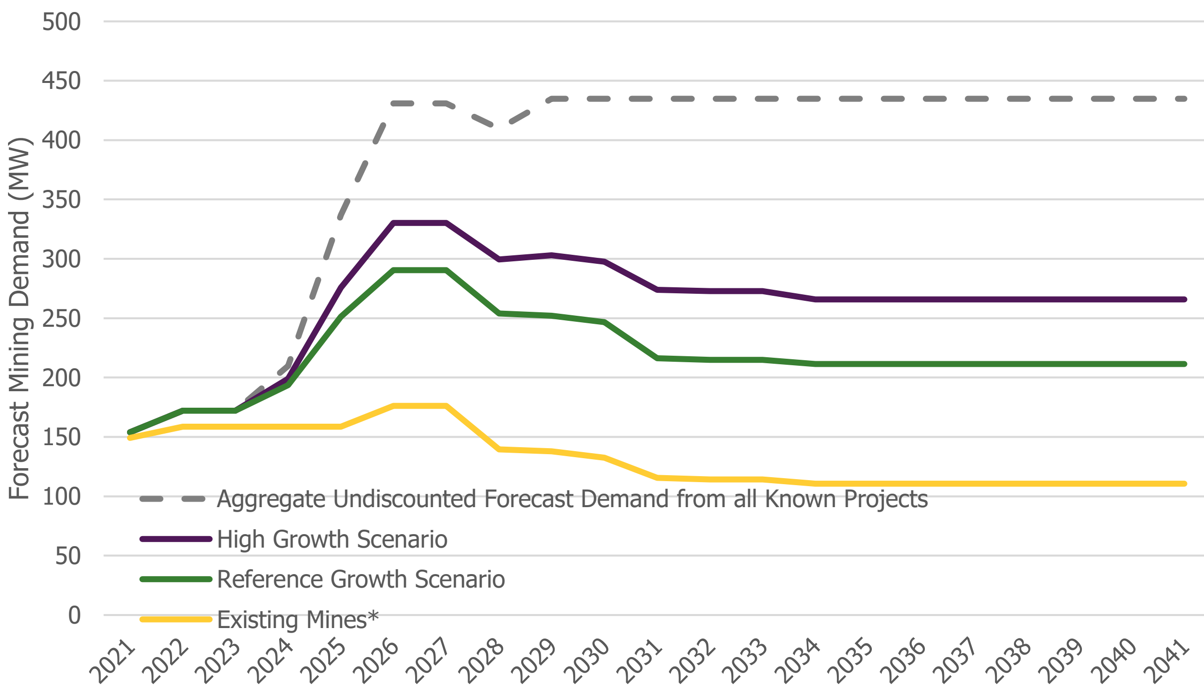


Figure 5-6 | Mining Demand Forecast

The mining sector already accounts for approximately 150 MW of demand today and is projected to grow to 290 MW by 2027 under the reference scenario. The low and high scenarios grow to 175 MW and 330 MW by 2027, respectively. Note that the IRRP does not provide disaggregated project-level forecast to preserve confidentiality.

Generally speaking, the existing mines (low) scenario informs local reliability needs that must be addressed even if no new mines materialize. The reference scenario informs the identification of needs that will likely arise and options to address those needs if/when mines materialize. Finally, the high scenario explores possible additional needs to test the robustness of the IRRP.

Note that in all scenarios, the mining forecast peaks in 2027 before declining for the remainder of the forecast horizon. This is a result of developing a project-based demand forecast as opposed to a top-line forecast for the mining sector as a whole. Information about existing and near-term projects are more readily available than information about long-term projects. Most known near- and mid-term new mining projects plan to come in-service by 2027. After 2027, demand begins to taper off as both existing and new mines reach the end of their planned operating life. The forecast scenarios do account for project extensions beyond their initial operating life but high uncertainty surrounding these extensions has meant that they were assigned low likelihood factors. In sum, the forecast performs well for predicting near- and medium-term mining growth but has less visibility of longer-term trends. Despite this shortcoming, a project-based demand forecast is more useful than a top-line forecast for the purpose of infrastructure planning. The project-based forecast provides relatively detailed information in the near- to mid-term when planning decisions must be made and provides critical geographic granularity necessary for transmission system studies.

5.5 Total Northwest Demand Forecast Scenarios

The total non-coincident Northwest demand forecast is shown in Figure 5-7 below. Note that when the mining forecast component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting. The reference scenario Northwest demand grows to 1060 MW by 2027. The low and high scenarios growing to 945 MW and 1100 MW by 2027, respectively. Note that the discontinuity between historical and forecast demand from 2020 to 2021 is partly due to the extreme weather correction applied to the distribution-connected forecast.

The IRRP reference forecast is approximately 20% higher than the Annual Planning Outlook forecast for the Northwest zone. This difference is in part due to the non-coincidence of the IRRP's station-level forecast; the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest. The sum of regional planning forecasts is also generally higher than their bulk planning counterparts since regional forecasts capture potential growth at a greater granularity not all of which may materialize when aggregated at a larger geographic scale.

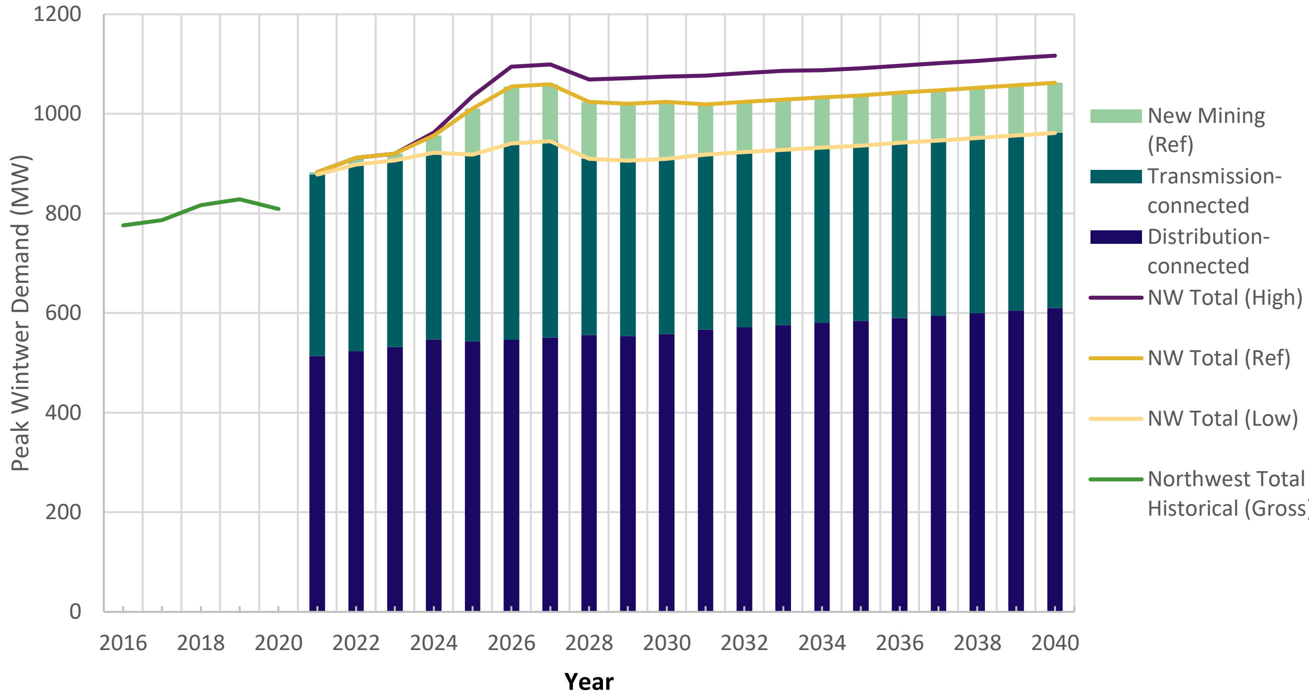


Figure 5-7 | Total Northwest Demand Forecast

5.6 Demand Profiling – Kenora MTS

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for stations or groups of stations with identified needs can be developed to characterize their needs with finer granularity. This is typically undertaken to inform an analysis of potential non-wires alternatives.

For this IRRP, hourly demand profiles were developed for Kenora MTS where a firm station capacity need was identified for which non-wires alternatives are promising. The Kenora MTS hourly demand profiles can be found in Appendix D.2. There were no other needs identified in this IRRP which could be addressed by non-wires alternatives.

Hourly demand profiles are created by first training a multiple linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles. The profiles are then ranked based on their median energy values. The median profile is scaled to match the peak demand forecast in each year and used to size and simulate non-wires alternatives as described in Section 7.1. A more fulsome description of the demand profiling methodology can be found in Appendix D.1.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. Taking into account committed transmission projects identified through bulk planning processes (i.e., the East West Tie expansion and the Waasigan transmission line), the Northwest region is generally adequate to support forecast electricity demand growth. The needs identified in the IRRP deal with localized supply to various pockets of demand in the Northwest as well as high-growth scenarios in areas identified as having strong future development potential.

This section is organized as follows:

- Section 6.1 summarizes the methodology for identifying needs,
- Section 6.2 describes firm station capacity and local operational needs (i.e., needs that would materialize under the reference forecast scenario), and
- Section 6.3 describes potential needs that may arise if higher than forecast growth materializes in select subsystems in the region.

Section 6.2.3 (E1C Operation and High Voltage Need), in addition to specifying the needs identified, will also discuss the recommended solutions since there are no "alternatives" that would normally be discussed in Section 7.

Note that bulk system needs are not in scope for the IRRP, which is focused on local reliability and ensuring that local/regional infrastructure can serve forecast demand. Nonetheless, this IRRP report flags any potential interactions between regional and bulk system needs.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity needs which generally fall into the following categories:

- **Station Capacity Needs** arise when the demand forecast exceeds the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service.[13] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low-voltage bus, or high voltage circuits) is undersized relative to the transformer rating.

- **Supply Capacity Needs** describe the electricity system's ability to provide continuous supply to a local area at peak demand. This is limited by the Load Meeting Capability (LMC) of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements (e.g., a transmission line, group of lines, or autotransformer) when subjected to contingencies and criteria prescribed by ORTAC and NERC/NPCC standards. LMC studies are conducted using power system simulation analysis. For the high growth sensitivities in Section 6.3, the LMCs for the subsystems in question are higher than the total forecast demand (both reference and high scenarios). Nonetheless, as these areas have been identified to have future development potential, the IRRP explores the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. Details regarding the power flow simulations, including the system topology and credible contingencies studied, can be found in Appendix C.

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. Note that IRRPs do not typically study and make recommendations for all end-of-life needs[14] where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process. Instead, the IRRP focuses on a subset of end-of-life needs where there are interactions with other regional needs and where there may be opportunities to reconfigure or right-size assets. Therefore, in the sections below, end-of-life needs are described in conjunction with other needs where relevant.

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[13] Some stations in the Northwest only have a single transformer in which case the transformer's LTR is the limiting element.

[14] A list of transmission assets reaching end-of-life can be found in the Needs Assessment.

- **Load Security and Restoration Needs** describe the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

6.2 Needs Identified

Table 6-1 summarizes the firm needs identified in this IRRP and are further discussed in the sections below. Note that the White Dog DS and Marathon DS station capacity needs occur in the long-term and are not further discussed in Section 7 since no firm recommendations are needed at this time.

Table 6-1 | Summary of Needs

Need	Need Description	Need Date
Fort Frances MTS Customer Reliability	Frequent loss of supply due to transmission outages; end-of-life assets at both Fort Frances TS and Fort Frances MTS	Today
E1C Operation	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	Today
Margach DS	Station step-down transformer capacity	2023
Crilly DS	Station step-down transformer capacity	2027
Kenora MTS	Station step-down transformer capacity	2029
White Dog DS	Station step-down transformer capacity	2032
Marathon DS	Station step-down transformer capacity	2038

6.2.1 Station Capacity Needs

6.2.1.1 Margach DS

Margach DS is approximately 10 km east of Kenora. Margach DS has an LTR of 10.4 MW and historical demand has been stable at just under 10 MW. As shown in Figure 6-1, Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS.

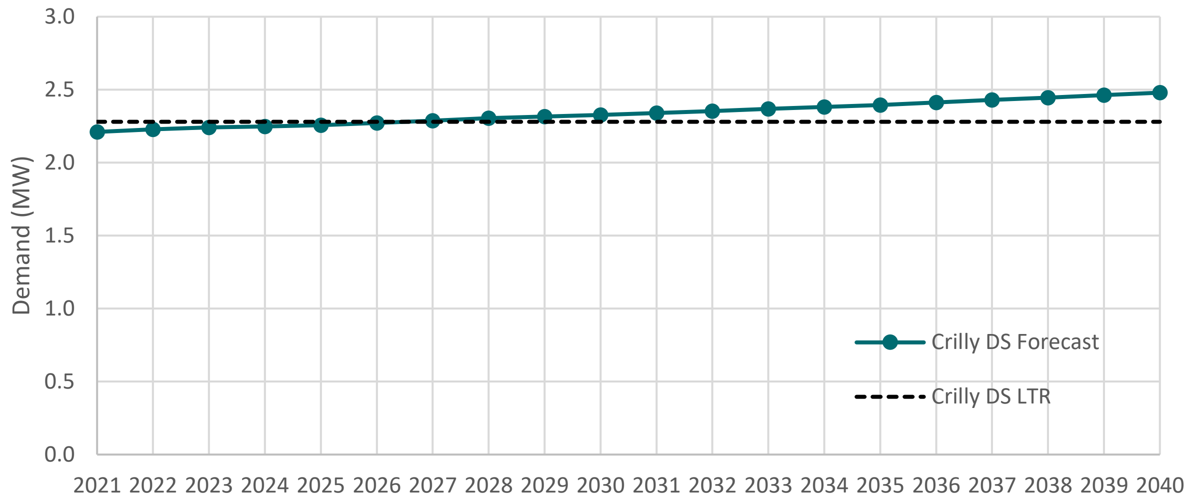

Figure 6-1 | Margach DS Forecast

6.2.1.2 Crilly DS

Crilly DS is a small (~2.2 MW LTR) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Crilly DS is expected to reach capacity in 2027 due to incremental growth in the community as shown in Figure 6-2.

6.2.1.3 Kenora MTS

Kenora MTS serves the City of Kenora and has a LTR of 23.4 MW. Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest.

Figure 6-2 | Crilly DS Forecast

Kenora MTS is expected to reach capacity in 2029 as shown in Figure 6-3.

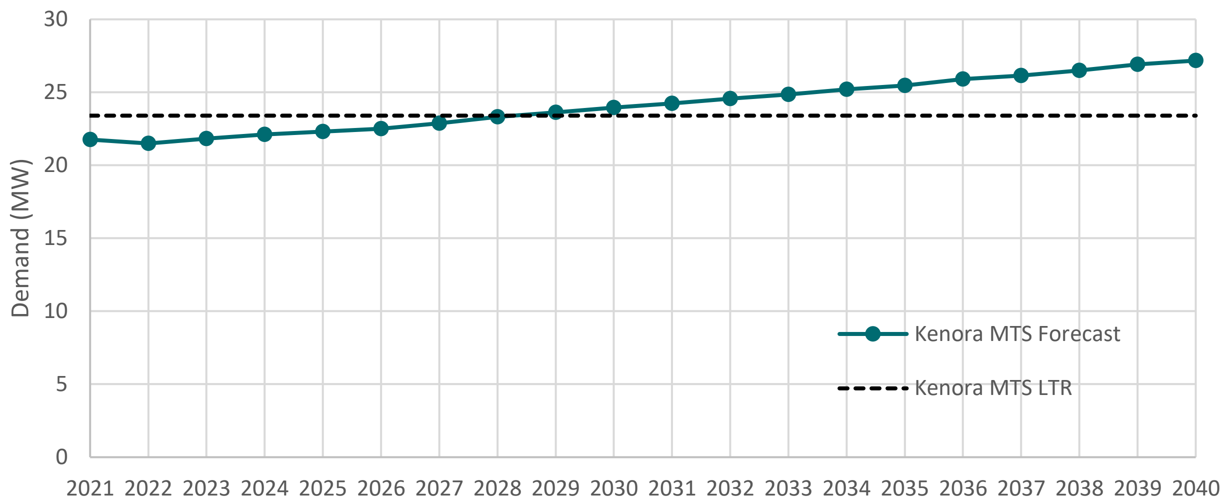

Figure 6-3 | Kenora MTS Forecast

6.2.1.4 White Dog DS

White Dog DS is located approximately 50 km northwest of Kenora and has a LTR of 2.9 MW. White Dog DS demand is expected to grow relatively quickly at an average rate of 1.3% annually due to growth in the community. White Dog DS is expected to reach capacity in 2032 as shown in Figure 6-4.

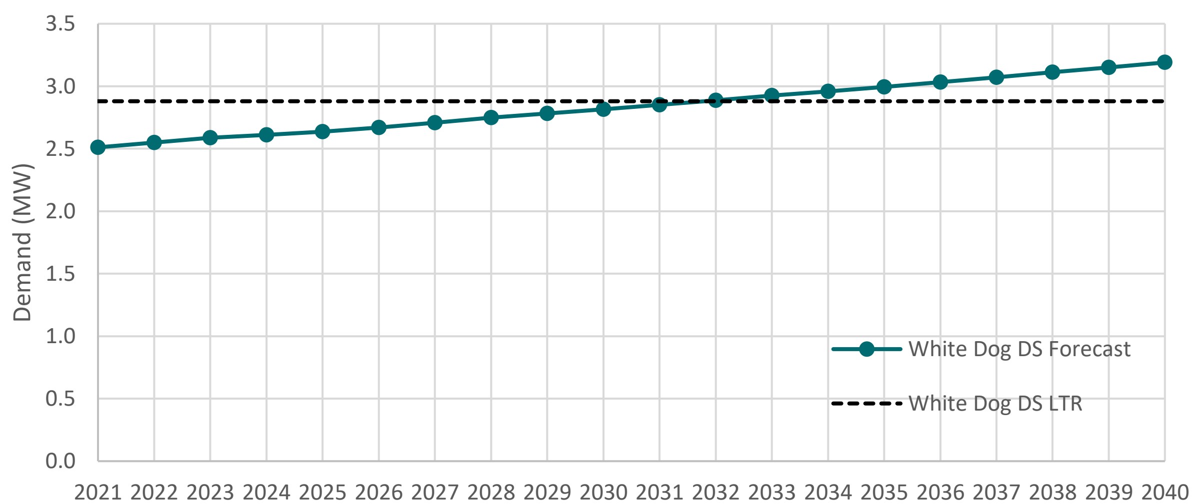

Figure 6-4 | White Dog DS Forecast

6.2.1.5 Marathon DS

Marathon DS serves the Town of Marathon and has a LTR of 10.4 MW. Growth is expected to be moderate and stable at an average annual growth rate of 0.9%. Marathon DS is expected to reach capacity in 2038 as shown in Figure 6-5.

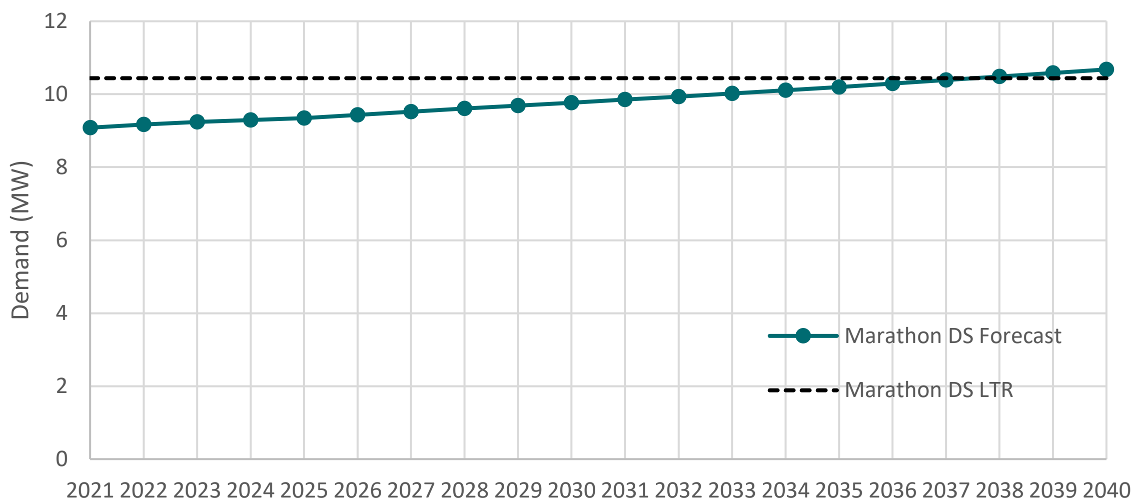

Figure 6-5 | Marathon DS Forecast

6.2.2 Fort Frances Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies the Town of Fort Frances, is supplied via a single circuit 115 kV line, F1B, from the nearby Fort Frances TS. The two stations are located across the street from each other as shown in Figure 6-6. Fort Frances MTS experiences outages semi-annually to accommodate planned maintenance outages on F1B. Despite there being two step-down transformers at Fort Frances MTS, the single circuit supply configuration results in community-wide power outages since there is no redundant supply path to the station.

Historically, outage durations ranges from 4 to 8 hours and impact critical loads such as the regional hospital and local health clinics. Customers have raised concerns with interruptions to surgery schedules and vaccine spoilage due to the loss of refrigeration. Power outages also disrupt other commercial and residential customers. Customer surveys conducted by Fort Frances Power suggest that customers can tolerate short outages but are increasing sensitive to prolonged outages. Of the 10 causes of distribution system customer interruptions tracked by the Ontario Energy Board, loss of transmission supply accounts for 90% of Fort Frances Power’s customer interruptions over the last 10 years.

Note that this customer reliability issue does not violate ORTAC load security and restoration criteria due to the relatively low total demand served at Fort Frances MTS. Fort Frances MTS serves approximately 16 MW of load today and is expected to grow to 18 MW by the end of the forecast horizon.[15] Load security criteria limits the total amount of demand interrupted with any single element out of service to 150 MW. For loads under 150 MW, load restoration criteria only require that service is restored within 8 hours. Despite compliance with ORTAC criteria, the Fort Frances MTS supply configuration is still highly disruptive for customers and could potentially be improved with relatively low-cost solutions given the proximity to Fort Frances TS.

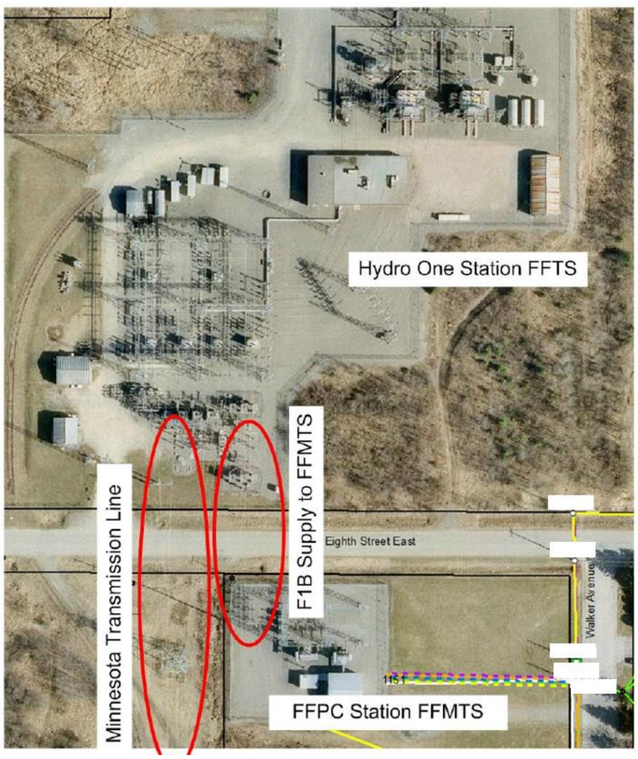

Figure 6-6 | Overhead view of Fort Frances TS (labeled as FFTS) and Fort Frances MTS (labeled as FFMTS)

[15] While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power that could quickly use up the remaining station capacity if they commit. This is further discussed in Section 6.3.2.

Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. The OEB's Asset Depreciation Study defines minimum, typical, and maximum useful life for a variety of electricity system assets. Apart from the main station breaker, which was replaced in 2019, all equipment at Fort Frances MTS is between its typical and maximum useful life. Furthermore, Fort Frances TS 115 kV breakers are also approaching end of life around 2027, which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS.

6.2.3 E1C Operations and High Voltage Need

This section discusses the E1C operations with the new 230 kV Wataynikaneyap circuit, W54W, in service. W54W was first energized in Aug 2022. However, C3W, a short 30 m circuit between Wataynikaneyap TS and Pickle Lake SS, is still operated normally open. Therefore, W54W is not yet connected to the existing 115 kV circuits from Ear Falls TS to Pickle Lake SS and Musselwhite CSS (E1C, C2M, and M1M). C3W will be operated closed in the near future so that W54W can help support demand growth on C2M. This is consistent with the IESO's original recommended scope for the Wataynikaneyap Transmission Project in 2016.[16] For the purposes of this IRRP report, W54W being "in-service," refers to the final state with C3W closed. A single-line diagram of the area is shown in Figure 6-7.

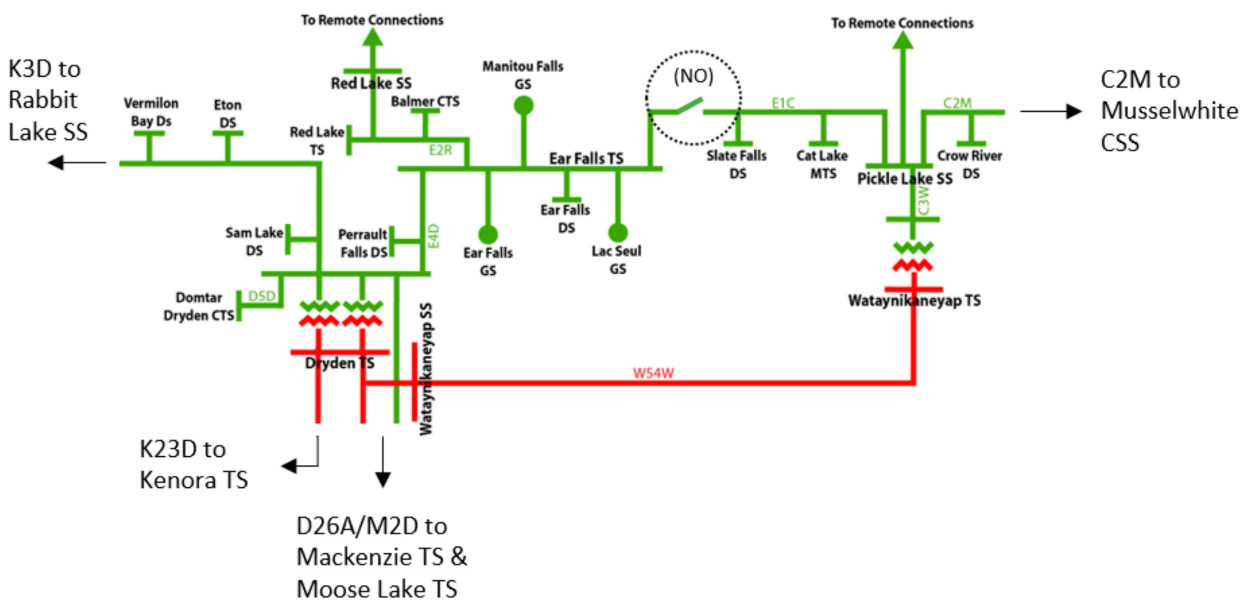

Figure 6-7 | Simplified Single Line Diagram of the Dryden and Pickle Lake Areas with Potential Normally Open Point

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16 The IESO's 2016 Recommended Scope of the new Line to Pickle Lake and Support Scope for the Remotes Connection Project is available on the Ontario Energy Board's priority transmission projects webpage.

With W54W in-service and connected to E1C via C3W, operating circuit E1C normally closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W as documented in the 2016 W54W System Impact Assessment (SIA) report.[17] When operating with the E4D-E1C-W54W loop closed, loads in the Ear Falls area will remain connected through E1C via the 230 kV path following the loss of E4D. Post-contingency voltage collapse limits the E4D+W54W flow to 57 MW which is insufficient for supplying existing demand in the Ear Falls, Red Lake, and Pickle Lake areas. The SIA notes that E1C must be opened pre-contingency as a mitigating control action when flow exceeds 57 MW and that this could occur multiple times per day at existing demand levels.

Furthermore, the SIA found that with the E4D-E1C-W54W loop closed, the Manitou Falls and Ear Falls hydro generators would remain connected to the grid following the loss of E4D, which causes transient instability when the post-contingency flow on the E1C exceeds 30 MW. To ensure that transient stability of the generators is maintained, pre-contingency generation levels would need to be reduced such that post-contingency flow on E1C does not exceed 30 MW. This reduction of transfer capability on E1C not only violates ORTAC Section 4.1, which limits reduction in transfer capability that results from a new connection, but would bottle hydro-electric generation that is otherwise available to provide capacity to the Northwest system. Therefore, the SIA recommended that the E4D-E1C-W54W loop should be opened pre-contingency to prevent pre-contingency generation reductions.

Due to these documented issues, this IRRP reaffirms that E1C should be operated normally open once W54W is in-service with C3W closed. This configuration resolves the violations described above and the resulting system is adequate to serve forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. This configuration is consistent with the recommended scope for W54W (which was referred to as the "Line to Pickle Lake") in the 2015 North of Dryden IRRP. Note that operating E1C normally open enables W54W to relieve E4D which allows W54W to serve the dual purposes of improving the load meeting capability of both the Pickle Lake and Ear Falls/Red Lake areas. This was an important consideration that contributed to the recommendation for W54W.

However, with E1C operated normally open, another problem emerges. High voltage violations (voltages exceeding 127 kV) occur post-contingency under light load conditions. High voltages occur on the line end open of E1C and either Pickle Lake SS or Ear Falls TS depending on where the open point on E1C is located. High voltage violations are less severe when opening E1C near Ear Falls TS compared to near Pickle Lake SS. When E1C is open near Ear Falls TS, the most critical contingency is the loss of one of the existing 20 MVar reactors at Wataynikaneyap TS. The high voltage violations can be addressed by installing an additional 10 MVar reactor at or near Pickle Lake SS. The post-contingency voltages at nearby stations with and without this

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[17] The 2016 W54W System Impact Assessment report is available on the IESO's Application Status webpage by searching for SIA ID 2016-567.

additional 10 MVar reactor are shown in Table 6-2. The post-contingency voltages exceed 127 kV at the E1C open line end and Pickle Lake SS for the loss of the existing 20 MVar reactor at Wataynikaneyap TS. Post-contingency voltages are maintained below 127 kV with the additional 10 MVar reactor.

Table 6-2 | Post-contingency Voltages with and without Additional 10 MVar Reactor at Pickle Lake SS with E1C Normally Open at Ear Falls TS

Bus/ Station Name	Post-contingency voltage (kV)	Post-contingency voltage (kV) with additional 10 MVar Reactor at Pickle Lake SS
E1C LEO	**130.7**	123.3
Pickle Lake 115	**127.7**	120.6
Watay 115	126	120.1
Watay SS 230	238	235.5
Dinorwic 230	237.8	235.6
Mackenzie 230	244.8	244
Musselwhite 115	120	115.1

The IRRP recommends that the IESO and Hydro One collaborate in the Regional Infrastructure Plan refine the location of the E1C open point and associated reactive compensation devices required. The E1C open point can be fine-tuned to minimize high voltages. The open point on E1C should consider the location and condition of existing switches as well as their accessibility for restoration purposes should E1C be needed to partially restore loads following a W54W or D26A contingency.

Furthermore, the Regional Infrastructure Plan should consider the installation of a voltage-based automatic switching scheme for the reactors at Pickle Lake SS, Wataynikaneyap TS, and Dinorwic Jct similar to existing switching schemes at other stations across the Northwest region. Voltage-based automatic switching would improve the transmission system's operational flexibility, help manage high voltage conditions currently experienced across the Northwest and help reduce post-contingency high voltages to the acceptable continuous maximum voltage within 30 minutes. Potential interactions with the existing Northwest reactor switching scheme should be considered as this scheme is developed.

6.3 Potential Needs and High Sensitivities

No firm regional supply capacity needs were identified in the Northwest in either the reference or high forecast scenarios. However, most of the growth in the Northwest is driven by large mining and industrial development which can add large, incremental blocks of demand with minimal lead time that can quickly use up remaining supply capacity. Through engagement with development proponents and stakeholders, the Working Group identified two areas in the Northwest, the Dryden/Ear Falls/Red Lake area and the Fort Frances area, where there is particularly strong development interest and where the existing transmission system, although adequate for current forecast scenarios, may become constrained if all known proposed projects materialize.

For these two areas, the IRRP studied high growth sensitivities to quantify the load meeting capability and identify the limiting phenomena on the existing system. This was accomplished by adding hypothetical loads at existing stations/busses to simulate new developments and increasing the hypothetical load until a planning standards violation was observed.

As discussed in Section 4.1, the IRRP did not study local connection requirements of any individual project. The purpose of the high growth sensitivity studies is to quantify system limitations so that growth can be more effectively monitored between regional planning cycles and future planning activities can be initiated in a timely manner if growth materializes. Regardless of the availability of regional supply capacity identified in the IRRP, customers seeking connection may be subject to additional requirements and limitations specified in Customer Impact Assessments (CIA) or System Impact Assessments (SIA).

6.3.1 Dryden/Ear Falls/Red Lake Load Meeting Capability

The Dryden/Ear Falls/Red Lake area hosts significant mining activity today. It includes the 115 kV system supplied from the Dryden TS autotransformers, circuit K3D from Rabbit Lake SS, and M2D from Moose Lake TS. The recently completed 230 kV Wataynikaneyap Transmission Project line W54W will help relieve constraints on the 115 kV circuit E4D, once the recommendations in section 6.2.3 are implemented, and no incremental capacity needs are anticipated in this area based on the current demand forecast.[18]

The area's load meeting capability (LMC) is a function of three nested local constraints as shown in Figure 6-8:

(1) Supply to the Red Lake subsystem including: Red Lake TS, Balmer CTS, and Red Lake remote communities

[18] Consistent with the recommendation in Section 2.1.5 (E1C Operation and High Voltage) and the needs discussed in Section 6.2.3, the IRRP technical studies assumes that E1C will be operated normally open at Ear Falls TS.

(2) Supply to the Ear Falls subsystem including: Ear Falls DS, Perrault Falls DS, and the Red Lake subsystem described above

(3) Supply to the Dryden subsystem including: Sam Lake DS, Eton Ds, Vermilion Bay DS, Domtar Dryden CTS, and the Ear Falls subsystem described above

An implication of this "nesting" is that, depending on where new loads connect, they could contribute to one or more subsystem needs. For example, a load connecting close to Dryden would contribute to needs in the Dryden subsystem only, whereas a load connecting at Red Lake would contribute to potential needs in all three subsystems.

The supply capacity in these subsystems may be further constrained by bulk system limitations on the 230 kV supply to the area West of Thunder Bay. Bulk system limitations are outside the scope of regional planning and will be addressed by the Waasigan Transmission Line Project.

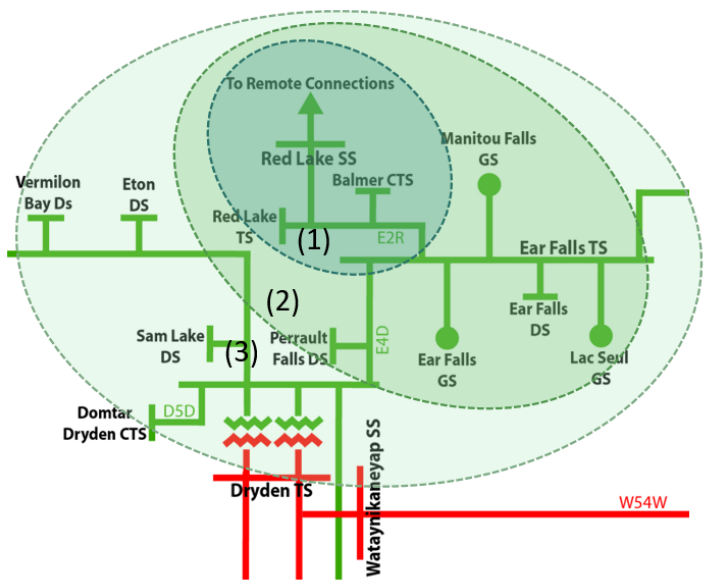

Figure 6-8 | Dryden/Ear Falls/Red Lake Nested Subsystems

Depending on which subsystem was being tested, the load meeting capabilities were derived by adding new hypothetical loads at Red Lake TS, Ear Falls TS, or the 115 kV bus at Dryden TS until a limiting phenomenon was encountered. The load meeting capabilities and the most limiting phenomenon or season for each subsystem is summarized in Table 6-3 and further described below. Note that, since the Northwest region is winter peaking, the IRRP forecast was developed for winter peak demand. However, since the Ear Falls and Red Lake subsystems can be thermally constrained, a summer peak forecast was also developed using the historical ratio between each station's summer and winter peaks.

Table 6-3 | Summary of Dryden/Ear Falls/Red Lake Load Meeting Capabilities

Subsystem	Load Meeting Capability	2032 Reference Peak Demand Forecast	2040 Reference Peak Demand Forecast
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	90 MW (summer thermal limitation)	67 MW summer peak	74 MW summer peak
3. Dryden	160 MW [19](summer/winter voltage decline)	129 MW winter peak	140 MW winter peak

6.3.1.1 Red Lake Subsystem

The Red Lake subsystem load meeting capability is limited in the summer by pre-contingency thermal overload of circuit E2R. The E2R continuous summer rating is 421 A which translates to a load meeting capability of approximately 74 MW.

The winter load meeting capability is higher than the summer capability. The winter load meeting capability is limited to 93 MW due to E2R pre-contingency thermal and voltage limitations. The winter E2R continuous winter rating is 528 A which translates to a load meeting capability of approximately 93 MW. 93 MW of load also causes pre-contingency voltage decline at Red Lake TS (i.e., voltages are under 113 kV). Note that the pre-contingency voltage limitation can be mitigated by installing appropriately sized voltage devices at the connection point of any new load. All load meeting capabilities described for the Red Lake and Dryden subsystems below assume that any new load will be accompanied by voltage devices to maintain adequate voltage performance at the point of connection.

Figure 6-9 below shows the Red Lake subsystem summer and winter peak demand forecast and associated load meeting capabilities.

The summer thermal limitation on E2R could be addressed by upgrading to higher rated conductors. There are several conductor options available with summer continuous ratings ranging from 590 A to 740 A.

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[19] This LMC is significant higher than the existing Dryden Area Inflow (DAI) limit in existing System Control Orders documentation. This difference is mainly due to topology changes (i.e. new W54W). The IRRP sensitivity study also assumes that new loads will connect with appropriate voltage control devices installed at the point of connection which alleviates previously documented low voltage issues.

Upgrading to 740 A conductors would result in a summer load meeting capability of approximately 130 MW. Note that upgrading to higher rated conductors would also necessitate replacing existing structures to increase their height so that the conductors can be operated at a higher temperature. Furthermore, Red Lake TS would need an alternative supply while work on E2R is carried out. Upgrading E2R would cost approximately $23M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[20] The cost difference between different conductor choices is relatively insignificant. Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

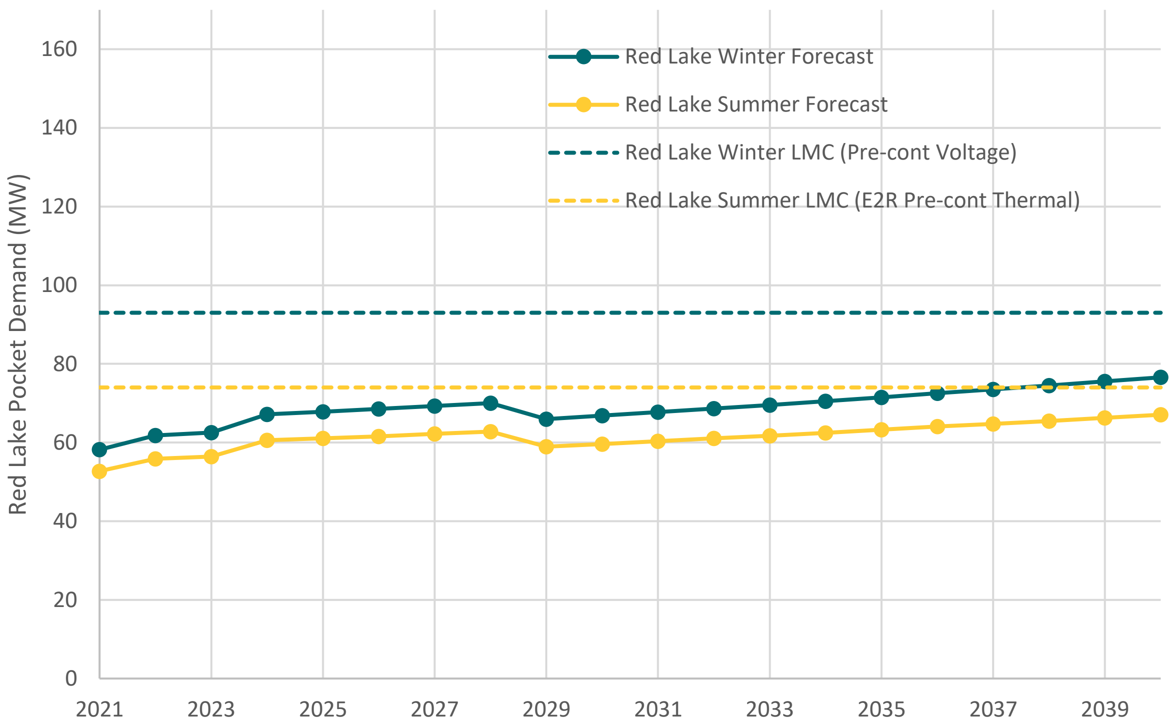

Figure 6-9 | Red Lake Subsystem Load Meeting Capabilities and Demand Forecast

E2R is approximately 75 years old. Hydro One anticipates that the average expected service life for the conductors is 90 years. The wood pole structures have a shorter expected service life at approximately 50 years. The end-of-life date for E2R will be based on actual asset conditions and no date has been determined for E2R as of 2022. If growth materializes, future planning

[20] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

studies should consider the cost of advancing E2R refurbishment as compared to alternatives such as local generation.

6.3.1.2 Ear Falls Subsystem

The Ear Falls subsystem load meeting capability is limited in the summer by E4D pre-contingency thermal overload. The E4D continuous summer rating is 410 A, which translates to approximately 72 MW. There is also a combined 18 MW of summer 98th percentile dependable hydro generation output from Ear Falls GS, Manitou Falls GS, and Lac Seul GS. Together the thermal capability and hydro generation results in a load meeting capability of approximately 90 MW.

Note that the winter load meeting capability is not expected to be limiting since it is significantly higher than the summer capability due to both the higher winter thermal rating of the circuit as well as higher dependable hydro generation output (approximately 64 MW of 98th percentile dependable hydro generation output).

Figure 6-10 below shows the Ear Falls subsystem summer demand forecast and load meeting capability.

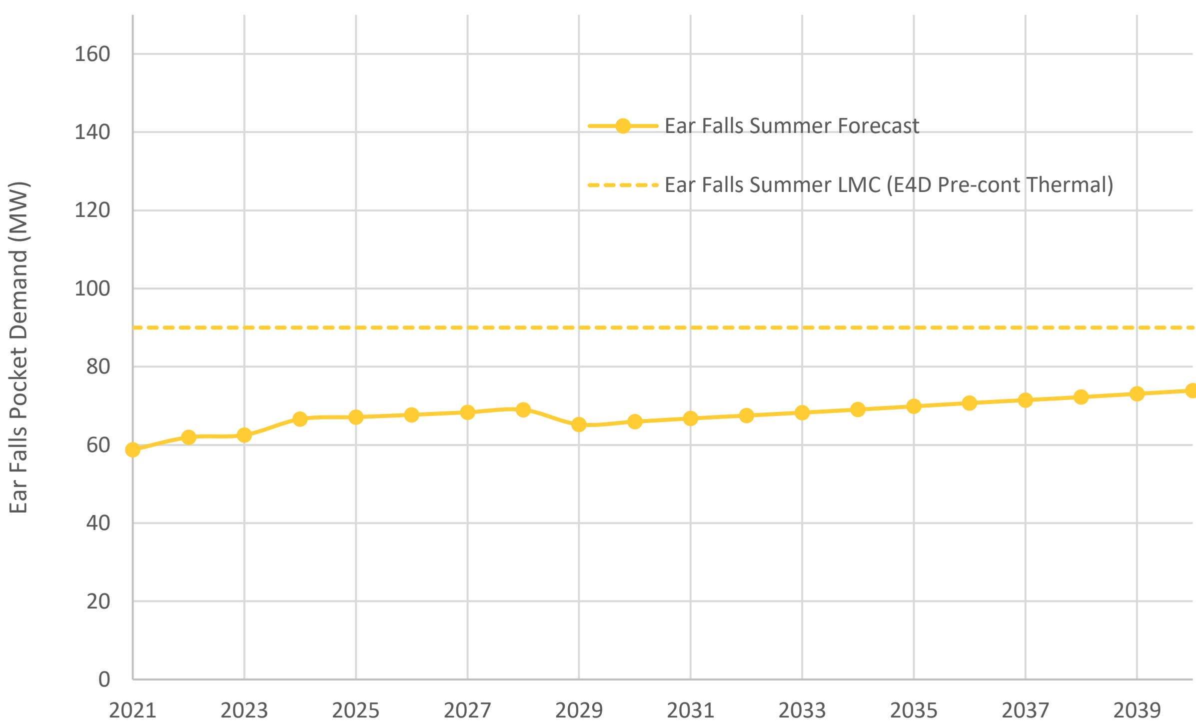

Figure 6-10 | Ear Falls Subsystem Load Meeting Capability and Demand Forecast

The summer load meeting capability for the Ear Falls subsystem can be increased to 130 MW by upgrading E4D with higher rated conductors (740 A summer continuous rating similar to conductors contemplated for E2R in the previous section). Upgrading E4D would cost approximately $35M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[21] Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. E4D is approximately the same age as E2R; future planning studies should also consider the cost of advancing E4D refurbishment as compared to alternatives such as local generation.

6.3.1.3 Dryden Subsystem

The Dryden subsystem load meeting capability is limited to 160 MW in both the summer and winter due to post-contingency voltage decline following the loss of D26A. When total demand in the Dryden subsystem exceeds 160 MW, the voltage decline at Dryden TS will exceed criteria (10% decline) as shown in Table 6-4. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

Table 6-4 | Post-Contingency (D26A N-1) Voltage Change (160 MW Dryden Subsystem Total Demand)

Station	Pre-Cont Voltage	Post-Cont (Pre-ULTC) Voltage	Post-Cont (Post-ULTC) Voltage
Mackenzie TS	247 kV	242 kV	239 kV
Dryden TS	237 kV	216 kV	214 kV (10% decline)
Kenora TS	243 kV	229 kV	230 kV
Fort Frances TS	244 kV	229 kV	231 kV

Dryden TS post-contingency voltage decline will no longer be limiting once Phase 2 of the Waasigan Transmission Line Project is built since it will provide a redundant path from Mackenzie TS to Dryden TS parallel to D26A. Without Phase 2, the post-contingency voltage decline could be addressed by a dynamic voltage device at Dryden TS, but this was not further studied since the device requirements would depend on the connection arrangement and characteristics of future loads.

[21] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

Note that the D26A + K23D N-1-1 contingency results in more severe voltage decline but could be addressed by a load rejection scheme since special protection systems are permitted by ORTAC for outage conditions.

Figure 6-11 shows the Dryden subsystem summer and winter peak demand forecast and associated load meeting capabilities.

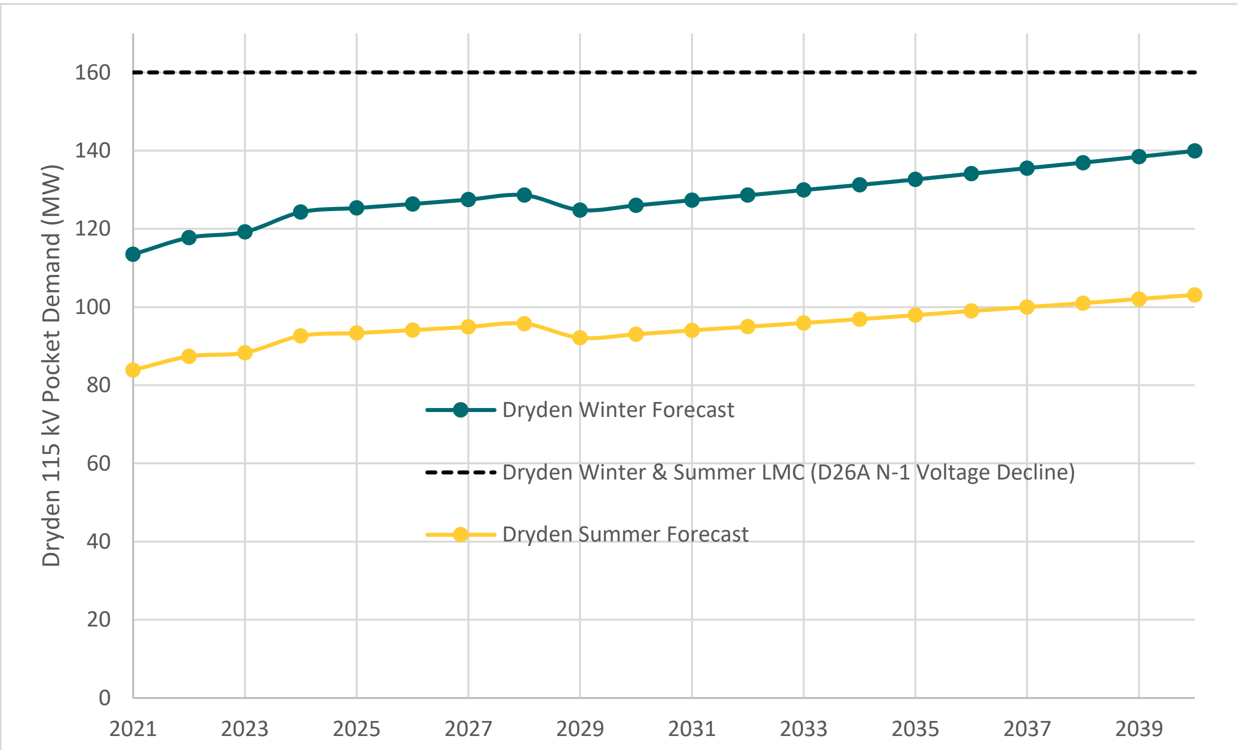

Figure 6-11 | Dryden Subsystem Load Meeting Capabilities and Demand Forecast

6.3.2 Fort Frances Load Meeting Capability

The Fort Frances area includes the 115 kV system supplied from the Fort Frances TS autotransformers and circuit K6F from Rabbit Lake SS as shown in Figure 6-13. For this high-growth sensitivity study, the Fort Frances area includes Fort Frances MTS, Burleigh DS, and a new hypothetical load connected directly to the 115 kV bus at Fort Frances TS. The stations connected to K6F do not materially impact the load meeting capability of the Fort Frances area.

Forecast demand in the Fort Frances area is relatively modest and is expected to grow from 21 MW today to 23 MW in 2040. However, the Working Group is aware of multiple inquiries from potential large new customers seeking connection in the Fort Frances area. Their combined load exceeds 100 MW but there is a high degree of uncertainty in whether their developments will proceed and where they may choose to connect to the grid. Some potential customers are also considering connection points in other parts of the province.

The Fort Frances load meeting capability is limited to 82 MW inclusive of approximately 3 MW of 98th percentile winter dependable hydro generation output from Fort Frances GS. This load meeting capability is the maximum total amount of load that can be served at Fort Frances MTS, Burleigh DS, and a new hypothetical load directly served on the Fort Frances TS 115 kV bus. It does not include load served on K6F. To achieve this load meeting capability, two new 25 MVar capacitor banks are assumed to be installed on the Fort Frances TS 115 kV bus to manage pre-contingency voltages. The load meeting capability is limited by post-contingency voltage decline on the Fort Frances TS 115 kV bus following the loss of F25A as shown in Table 6-5. The F25A contingency has a significant impact on 115 kV bus voltages because it removes one of the Fort Frances TS transformers (and the existing capacitor bank on its tertiary winding) by configuration. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

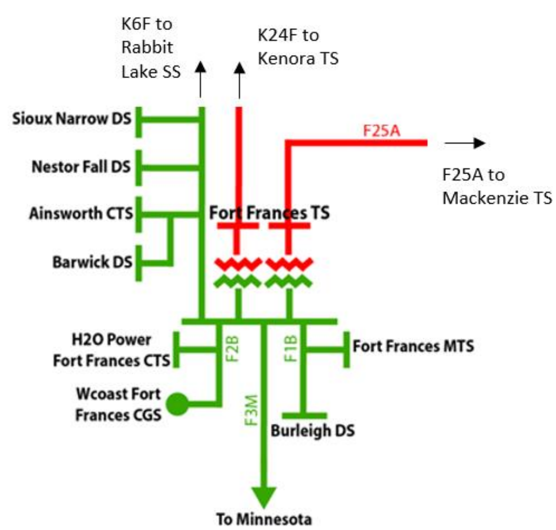

Figure 6-12 | Fort Frances Subsystem

Figure 6-13 below shows the Fort Frances subsystem winter peak demand forecast and associated load meeting capability.

Table 6-5 | Post-Contingency (F25A N-1) Voltage Change (82 MW Fort Frances Subsystem Total Demand)

Station/Bus	Pre-Cont Voltage	Post-Cont Pre-ULTC Voltage	Post-Cont Post-ULTC Voltage
Fort Frances TS (230 kV)	240 kV	234 kV	228 kV
Fort Frances TS (115 kV)	123 kV	110 kV (10% decline)	116 kV

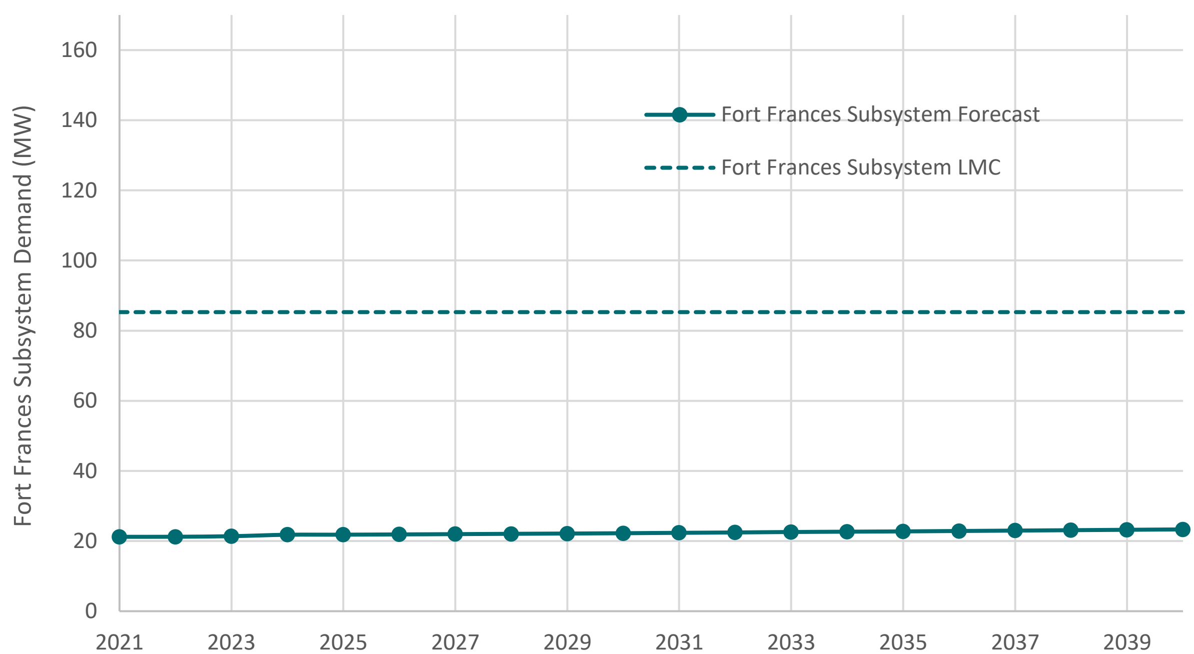

Figure 6-13 | Fort Frances Subsystem Load Meeting Capability and Demand Forecast

7. Options Considered and Recommendations

This section describes the options considered and recommendations to address the near- to medium-term needs identified in section 6. This section is organized as follows:

Section 7.1 describes the options considered for the Margach DS, Crilly DS, and Kenora MTS station capacity needs. This includes a discussion of how each station capacity need was screened for non-wires alternative suitability and, where there were promising non-wires opportunities, the options considered and financial analysis.

Section 7.2 explores configuration options to improve customer reliability at Fort Frances TS. These options will inform the Regional Infrastructure Plan where a final configuration will be chosen.

Note that the recommendation for the E1C operations and high voltage need can be found in Section 6.2.3 and will not be further discussed in this section.

7.1 Options and Recommendations for Station Capacity Needs

7.1.1 Methodology and Options Considered

There are two approaches for addressing station capacity needs:

- Build new infrastructure to increase station capacity. This is commonly referred to as a "wires" option and typically entails upsizing the existing station (e.g., replacing transformers with higher rated transformers or adding additional transformers) or building a new station to supply incremental demand growth. Wires options may also include modifications to or the addition of other power system equipment such as voltage regulation devices, switches, or breakers.

- Install or implement measures to reduce net peak demand to maintain loading within existing station capacity. This is commonly referred to as a "non-wires" alternative and can include options like energy storage, local distributed generation, demand response, conservation and demand management, or any combination of the above. Note that centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast, as discussed in Section 5.2.2. Additional conservation and demand management can be considered as a non-wires alternative.

While wires options typically provide a step-change increase in capacity and are available in all hours, non-wires alternatives are more targeted and must account for the frequency and duration of the capacity need in addition to its magnitude. Therefore, identifying suitable technology types, sizing options, and simulating their discounted cash flows are significantly more complex for non-wires alternatives than wires options.

Non-wires alternatives are not suitable for all station capacity needs and there are often qualitative factors that rule out the use of non-wires alternatives. Before carrying out options analysis, a screening process is first applied to determine the suitability of non-wires alternatives for each need that considers the characteristics of the demand growth, the technical feasibility of non-wires alternatives to address the limiting phenomena, and any additional factors that would complicate or facilitate the implementation of non-wires alternatives. For stations where non-wires alternatives are suitable, the IRRP carries out options analysis as described below.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Note that the error margin in cost estimates is significant at the planning stage (-50% to +100%); they are only intended to enable comparison between options during the IRRP. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. Wires option costs can be reviewed in the Regional Infrastructure Plan before implementation work begins and the Working Group will revisit recommendations if cost estimates differ significantly. Actual non-wires alternative costs can also vary significantly from the benchmark estimates used in the IRRP depending on local market constraints at the time of implementation. The entity responsible for implementing the non-wires alternative (for station capacity needs, this will typically be the local distribution company) will only implement the alternative if it remains cost effective. Subsequent regional planning activities will be triggered if future costs differ significantly from those in the current IRRP.

For non-wires options, upfront capital and operating costs are compiled to calculate the levelized unit energy cost ($/MW-year). Similarly, an annual revenue requirement ($/year) is compiled for wires options. For each option, a discounted cash flow model is created which includes the levelized unit energy cost or annual revenue requirement as well as bulk system energy and capacity costs where applicable. Note that, in order to enable an apples-to-apples comparison, the discounted cash flow for the non-wires options includes a credit for the bulk system capacity value it provides. The discounted cash flow model for all options is compiled over the lifespan of the longest option considered (typically 70 years for wires options). The net present value (in 2021 CAD dollars) of these cash flows are the primary basis through which options are compared.

A list of the assumptions made in the economic analysis can be found in Appendix E.

7.1.2 Options and Recommendation for Crilly DS

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (LTR of ~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power whenever Sturgeon Falls is on outage. Furthermore, the existing station equipment will reach end-of-life over the next ~10 years and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to three factors. First, non-wires alternatives will not be able to eliminate nor reduce existing reliance on backup generation. Load modifying non-wires alternatives (e.g., energy efficiency measures or demand response) could potentially reduce peak demand and overall energy consumption but, when transmission supply is interrupted due to Sturgeon Falls outages, they cannot replace the need for backup generation. Similarly, distributed energy resources can reduce peak demand below the station LTR but, during outages, the distribution system served by Crilly DS must still rely on backup diesel generation. Frequent reliance on backup diesel generation results in poor reliability and is technically challenging due to difficulties in staying connected and maintaining power quality when supplying loads on a long single-phase distribution line. The long-term solution for Crilly DS station capacity should ideally provide reliability on par with other single circuit supply stations (where regular supply interruptions are not required for generator maintenance outages).

Second, structures and equipment at Crilly DS are approaching end-of-life in the near future. While the specific end-of-life dates vary based on asset conditions, existing structures and equipment are expected to require refurbishment/replacement over the next 10 years. Even if non-wires alternatives can address overloads due to incremental growth above the current station capacity, the station must still be rebuilt/refurbished at end-of-life.

Third, Crilly DS serves a small pool of customers (approximately 500 homes and businesses) in a remote location. This customer pool is too small to cost-effectively target energy efficiency or demand response measures since the overhead costs will likely be prohibitive compared to the potential savings in deferred or upsized infrastructure. Furthermore, while voluntary energy efficiency and demand response programs can produce predictable results when applied over large populations, the demand savings when targeted to a small group of customers is unreliable.

Since non-wires alternatives are not suitable for Crilly DS, Hydro One Distribution is considering the follow wires options:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),

- Rebuild Crilly DS at a different location as a 115/25 kV HVDS (close to the existing station/supply point),
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS (connected to F25A closer to the community served by Crilly DS), or
- Replace Crilly DS with 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

The cost of these wires options ranges from $7.5-15M (including line work required for connection) and will address both the station capacity and end-of-life needs. Refurbishing Crilly DS at its current location is likely the least costly option but is undesirable due to the continued reliance on backup power. Furthermore, the incremental capacity that can be accommodated at the existing location may be limited due to the space constraints. Rebuilding Crilly DS as a full HVDS (either at 115 kV or 230 kV) would offer the best reliability and performance but also at the greatest cost. Replacing Crilly DS with a padmount transformer may be a more cost-effective option but there are still technical hurdles to be further investigated such as the ability for 115 kV protections to be accommodated within a padmount configuration.

Since non-wires alternatives are not suitable and there are no upstream supply capacity needs that require further regional coordination, the IRRP recommends that Hydro One Distribution conduct local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost.

7.1.3 Options and Recommendation for Margach DS

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied from a nearby CTS. Margach DS is approximately 10 km east of Kenora.

Non-wires alternatives are not suitable for addressing the Margach DS station capacity need due to the timing and magnitude of the demand increase. Resupplying the large industrial customer causes the forecast demand at Margach DS to jump by 40% from 2022 to 2023. Energy efficiency measures are typically only feasible if the demand exceeding station capacity is a small percentage of the total demand in each year. Similarly, historical zonal demand response auction data indicates that demand response is only feasible to reduce peak demand levels by single digit percentages. While distributed generation can technically be sized to accommodate any demand growth (within station short circuit and thermal limitations) this would functionally be the same as the new customer self-generating rather than seeking grid supply and is unlikely to be cost effective. The near-term timing of the demand growth is also problematic for implementing non-wires alternatives since many of the technical and regulatory barriers for implementing non-wires alternatives are still being tested.

The IRRP recommends that Hydro One Distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. Installing fan monitoring is an inexpensive method to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers. The cost of installing fan monitoring is in the range of $1-1.5M compared to the cost of adding a new transformer which would be greater than $3M. Fan monitoring will increase the station capacity from approximately 10 MW today to 16 MW.

If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service, but no recommendation beyond the fan monitoring is required based on the current forecast.

7.1.4 Options and Recommendations for Kenora MTS

Kenora MTS serves the City of Kenora and is expected to reach capacity in 2029 with a moderate annual growth rate of 1.25%. The station has an LTR of 23.4 MW and demand will exceed the LTR by approximately 4 MW by the end of the forecast horizon (2040).

Non-wires alternatives are promising for addressing the Kenora MTS station capacity need. The magnitude of the need relative to the total demand is moderate which makes targeting load modifying non-wires alternatives like energy efficiency and demand response feasible. The timing of the need is in the mid-term, so the forecast confidence is reasonably high while still having adequate lead time to demonstrate the efficacy of relatively untested non-wires alternatives and navigate technical and regulatory barriers. The timing of the need also means that lessons learned from the IESO's York Region Non-Wires Alternative Demonstration Project can be leveraged for implementing non-wires alternatives for Kenora MTS.

The following subsections discuss the wires options for Kenora MTS, non-wires alternatives, and recommendations.

7.1.4.1 Wires Options

There are two high-level wires options:

- Expand Kenora MTS with an additional transformer and associated protections, control, and structures at a cost of approximately $5M. This can be accommodated on existing land owned by the distributor, Synergy North, within the station. This option assumes that feeder loads can be rebalanced and servicing these loads on existing distribution system infrastructure is possible.
- Construct a new substation located across the city from the existing station at a cost of approximately $30M. The new station would be supplied from Rabbit Lake SS.

The existing Kenora MTS station is located on the northern edge of the city. The proposed new substation would be located on the far west side of the city and, in addition to addressing station capacity needs, would provide substantial distribution system benefits by reducing the length of feeders required to reach customers and improving voltage and frequency regulation. The long feeders to the western parts of the system currently experience voltage and frequency issues especially during outages requiring parts of the distribution system to be resupplied from alternate feeders. Synergy North is also aware of significant development interest along the western outskirts of the city, but no formal agreements have been finalized. A new station would provide a supply point close to these customers and improve distribution system performance.

A new station would also provide a redundant transmission supply point that is connected to a different bus/breaker at Rabbit Lake SS than the existing station. If a new station is built, the distribution system could be designed with tie points and reclosers to enhance the overall reliability across Kenora.

The distribution system benefits above have only been qualitatively described in the IRRP. As discussed in the following subsections, the cost effectiveness of the non-wires alternatives may hinge on whether they can provide similar distribution system benefits as a new station. Future analysis by Synergy North should further quantify the value of these benefits.

7.1.4.2 Non-wires Alternatives

Three non-wires alternatives for Kenora MTS were identified and sized according to the characteristics of the hourly demand profile described in Section 5.6:

- A 4 MW gas generation facility (aero engine). The cost estimate for gas generation is based on the IESO's internal benchmark cost reports. To estimate its contribution to provincial system adequacy, its effective capacity was assumed to be 93% of its installed capacity, which is the lesser of its unforced capacity and the zonal capacity maximums reported in the 2021 IESO Annual Planning Outlook.[22]

- A 6-hour 4 MW (24 MWh) battery. The cost estimate for battery storage is based on data from the National Renewable Energy Laboratory. Note that local generation (e.g., wind or solar) was not required to complement the battery due to the relatively low energy requirement (i.e., the battery can be recharged from existing grid power when it is not needed).

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[22] The 2021 Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

- A combination of energy efficiency measures and demand response. The availability and cost of incremental energy efficiency measures (i.e., in addition to the conservation and demand management programs already included in the demand forecast) are based on the IESO's 2019 Conservation Achievable Potential Study[23]. The 2019 Achievable Potential Study and incremental energy efficiency savings for Kenora MTS are further described in Appendix E. Demand response costs are estimated from average capacity auction values from 2018-2021 for the Northwest zone.

The net present value (NPV) of each wires and non-wires alternative's cost is shown in Table 7-1. The NPV includes the levelized unit energy cost as well as bulk system energy and capacity costs and benefits associated with each option over a 45-year asset life (which is typical for station equipment).

Table 7-1 | Kenora MTS Wires and Non-wires Alternative Costs

Option	Cost NPV ($2021 Real)
Expand Kenora MTS	$4 M
New Station	$25 M
4 MW Gas Generation	$22 M[24]
24 MWh Battery Storage	$10 M[24]
Combination of Energy Efficiency and Demand Response	$1-9 M[25]

7.1.4.3 Recommendation

The cost of the non-wires alternatives generally falls between the cost of expanding the existing station and a new station (which also improves reliability and performance on the distribution system). Therefore, the decision to pursue non-wires alternatives versus traditional wires options rests on distribution system benefits that can be realized by each option. For example, battery storage can be sited on the distribution system such that it improves voltage regulation along lengthy feeders. If the value of the distribution system benefits is greater than the cost difference between the battery and station expansion, the battery may be the most cost-effective solution for ratepayers overall.

[23] The 2019 Conservation Achievable Potential Study can be found on the IESO's website.

[24] Assumes full (unforced capacity) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.

[25] Cost ranges from $1-9 M depending on whether the energy efficiency measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

The technologies, regulatory framework, and protocols required to implement dispatchable non-wires alternatives (e.g., batteries, gas generation, or demand response) for the purpose of meeting local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[26] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Region Pilot and further refine the procurement and operation of non-wires alternatives for Kenora MTS.

Since there are no upstream constraints on the transmission system requiring further regional coordination, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement non-wires alternatives if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[27] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines[28] to leverage distribution rates for non-wires alternatives.

7.2 Options for Improving Customer Reliability at Fort Frances TS

As discussed in Section 2.1.4, the IRRP will not make a specific recommendation for improving customer reliability since Fort Frances Power's roadmap for Fort Frances MTS is still under development. However, this section will document the options considered during the IRRP process and the IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and select a preferred option in local planning.

The Fort Frances TS 115 kV station layout and connection to Fort Frances MTS is shown in Figure 7-1. The 115 kV side of Fort Frances TS is comprised of a 6-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B, and F1B. Fort Frances MTS is currently connected to the L1-bus (which connects to F1B) and is physically located immediately adjacent to Fort Frances TS. Transmission outages to F1B and the L1 bus have accounted for 90% of Fort Frances Power's customer interruptions over the last 10 years. Therefore, Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

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[26] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[27] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

[28] More information about the Conservation and Demand Management Guidelines is available on the OEB's website (link).

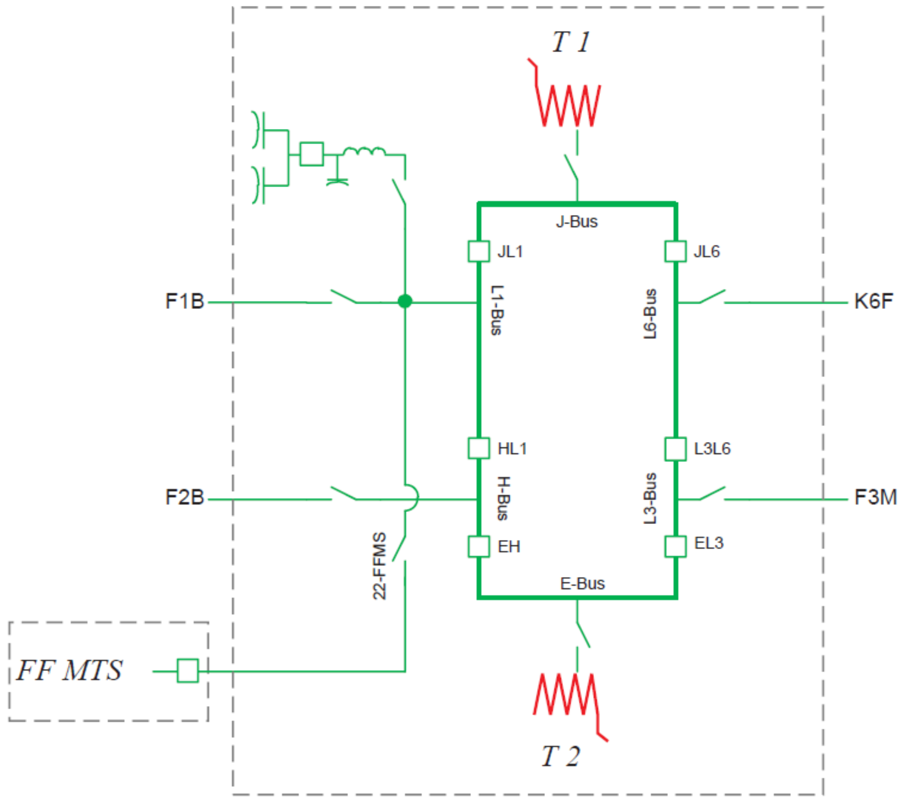

Figure 7-1 | Fort Frances TS 115 kV Single Line Diagram

The following options, in order of increasing complexity and cost, were contemplated:

- Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.

- Install a new 115 kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit.

- Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

8. Supply to the Ring of Fire

The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals.[29] There is strong interest in developing mining activities in this area, however as it is located far from established infrastructure, it is currently without all-season road access or grid power supply. Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning for Northwest Ontario. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with the ongoing Northwest IRRP. This report provides an update on preliminary findings as of Q4 2022 including:

- Transmission supply options and high-level cost estimates;
- Key opportunities for alignment that should be considered in the decision to pursue transmission supply to the Ring of Fire as well as its routing and connection point;
- Avoided diesel system costs from connecting remote communities to the grid via a transmission line to the Ring of Fire; and
- Greenhouse gas reductions associated with connecting remote communities and Ring of Fire mines to the grid, as opposed to self generation.

Note that the decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as the direct beneficiaries of such a project, and with the provincial and federal governments to advance broader policy objectives. The purpose of the renewed Supply to the Ring of Fire study is to help inform government policy and potential customers seeking connection.

8.1 Background

A map of the Ring of Fire area and nearby features of interest are shown in Figure 8-1. Interest in developing the Ring of Fire has varied over the years and there is a high degree of uncertainty in the eventual mining sector electrical demand that may materialize. However, with the current focus on developing critical minerals to support decarbonisation, interest in developing the Ring of Fire area is growing.

[29] Ontario's critical mineral list can be found in the 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

In addition to potential mining loads, there are five off-grid Matawa First Nation communities in the vicinity of the Ring of Fire. These communities rely on diesel generation systems that are expensive to operate, produce environmental pollutants, and may constrain the communities' growth. Enabling grid supply for these communities is an important factor contributing to the overall rationale for transmission supply to the Ring of Fire. The transmission supply routing and connection point to the existing electricity system should also consider the significant potential for hydro generation in the area which may be able to connect to the grid via the transmission line to the Ring of Fire.

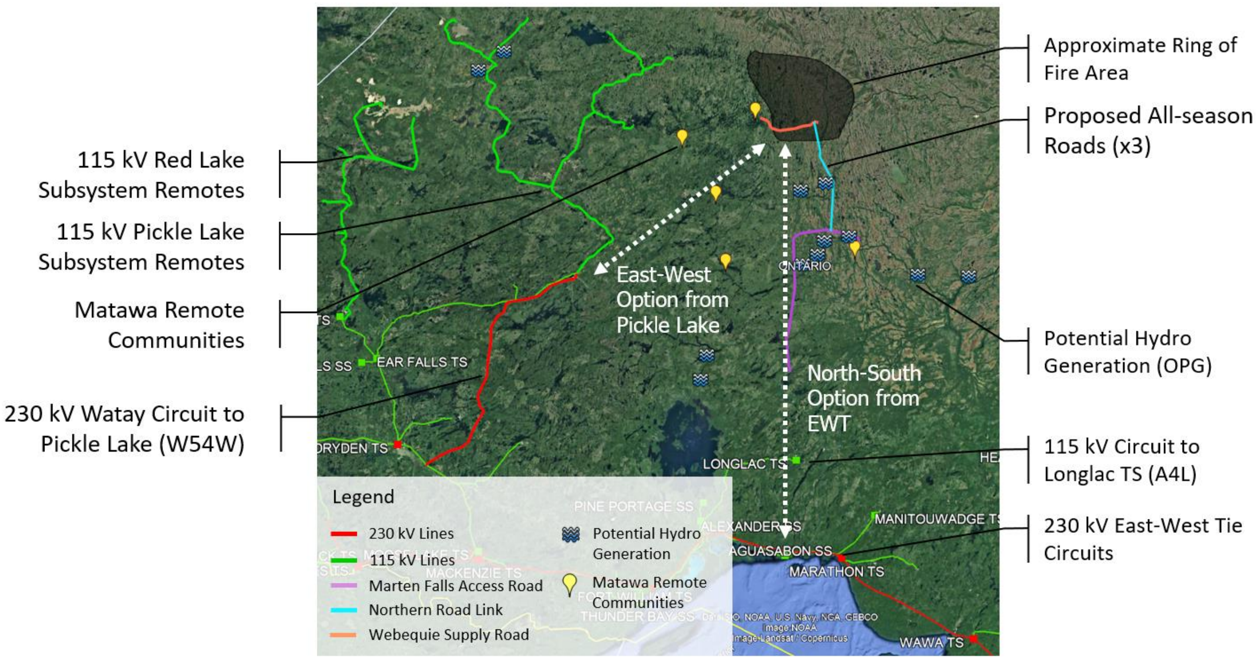

Figure 8-1 | Ring of Fire and Surrounding Area Map

Transmission supply to the Ring of Fire was contemplated in the 2015 North of Dryden IRRP and the 2016 Greenstone-Marathon IRRP. The North of Dryden IRRP outlined potential transmission supply options with the goal of connecting remote communities as well as serving mining electricity demand at the Ring of Fire if it were to materialize. This plan contemplated reinforcing the existing transmission system from the Dryden area to Pickle Lake and building a new transmission line from Pickle Lake to the Ring of Fire. The North of Dryden IRRP, in conjunction with the 2014 Remote Connection Plan, culminated in the indigenous-led Wataynikaneyap Transmission Project.

The Wataynikaneyap Transmission Project includes a new 230 kV line from Dinorwic Junction (near Dryden) to Pickle Lake as well as 115 kV transmission lines extending north of Pickle Lake and Red Lake to connect remote communities. The Matawa area remote communities chose not to participate in the Wataynikaneyap Transmission Project and no transmission lines were built from Pickle Lake to the Matawa communities or the Ring of Fire. This transmission supply option to the Ring of Fire is referred to as the East-West option in Figure 8-1.

The Greenstone-Marathon IRRP extended this analysis to consider potential cost optimization opportunities between new customers in the Greenstone area and remote communities/mines at the Ring of Fire. This entailed a North-South transmission supply option extending from the existing East-West Tie circuits northwards through Greenstone (which is electrically supplied from Longlac TS) and onwards to the Ring of Fire. The largest new customer in the Greenstone area at the time choose to self-generate instead of pursuing transmission supply and the North-South transmission supply option did not proceed.

To date, there have been no firm commitments from customers seeking transmission connection in the Ring of Fire area.

8.2 Policy Drivers and Demand Forecast

Enabling development in the Ring of Fire area is an important policy objective for the provincial government. Ontario's Critical Mining Strategy[30] identifies the Ring of Fire as a "priority project" and a "transformative opportunity for unlocking multi-generational development of critical minerals." The strategy also highlights the importance of Ontario's relatively clean electricity system for enabling development of lower-emissions mining compared to other jurisdictions.

The province has also expressed support for a "Corridor to Prosperity" comprised of three proposed all-season roads led by First Nations partners that connects to the existing highway system and extends northwards towards the Ring of Fire. These proposed roads include the Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link. The proposed roads are at various stages in their provincial and federal Environmental and Impact Assessments. Taken together, they would provide a continuous all-season transportation corridor to the Ring of Fire that would be necessary to facilitate mining development. Ontario has committed $1 billion to support these road infrastructure projects on the basis that federal contributions will match provincial commitments.

There is a high degree of uncertainty in terms of both the magnitude and timing of mining electricity demand at the Ring of Fire. The IESO's latest mining demand forecast includes approximately 30 MW of electricity demand associated with two proposed mining projects. The 2015/6 IRRP forecasts included up to 70 MW of demand at the Ring of Fire but some proponents have since walked away from their development plans. If transmission and

[30] The 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

transportation infrastructure were developed, mining demand would almost certainly be much higher than currently forecast. As of January 2022, there are approximately 26,000 active mining claims held by 15 companies in the Ring of Fire. The IESO will continue monitoring development plans and intends to update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios.

The five Matawa area remote communities have a total demand of approximately 4 MW today and are forecast to grow at 4% per year.[31] This forecast was last updated in 2019 and will be updated as new information becomes available.

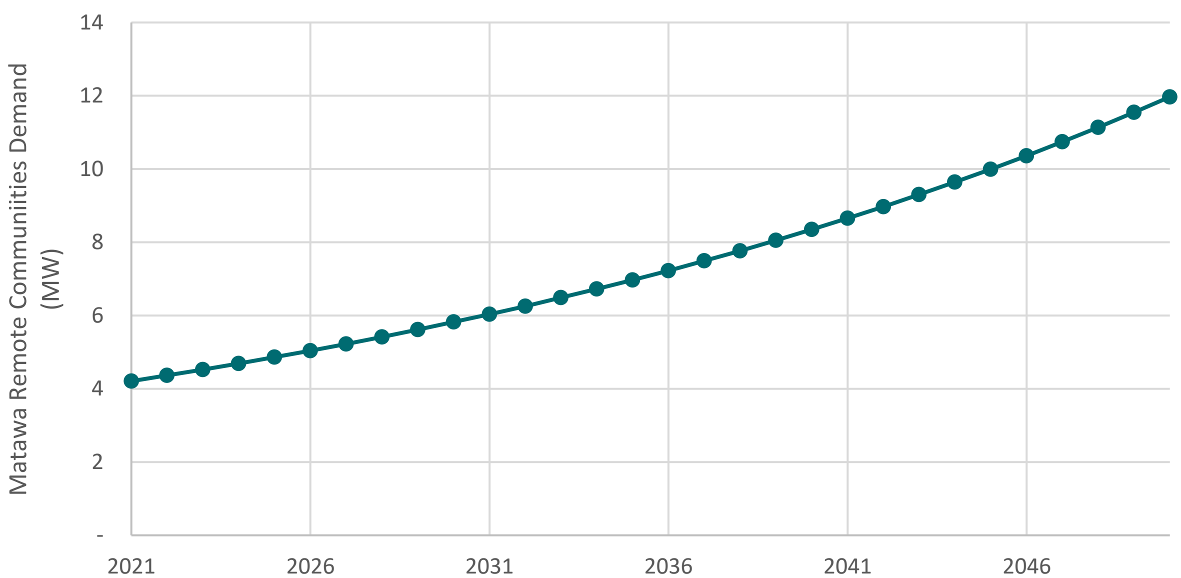

Figure 8-2 | Matawa Remote Communities Demand Forecast

[31] The forecast 4% growth rate reflects potential demand growth if the remote communities are grid connected and no longer constrained by diesel supply capacity.

8.3 Transmission Supply Options and Cost Estimates

As discussed in Section 8.1, at a high level, there are two transmission supply options to the Ring of Fire that could be pursued: a North-South option connecting to the East-West Tie circuits between Marathon and Thunder bay and an East-West option connecting to the new Wataynikaneyap TS near Pickle Lake. The conceptual electrical elements of each option are listed in Table 8-1. Note that at this stage, no detailed engineering design or routing work has been performed. The transmission options are presented here for discussion purposes and to facilitate high-level cost estimation (-50% to +100%).

The North-South option is estimated to cost between $860M and $1.08B while the East-West option is estimated to cost between $600M and $780M ($2022 real, overnight capital cost). The cost ranges reflect uncertainty in the final station configurations as well as in the per unit (km) cost of transmission lines which can vary depending on the technology type and geography. These cost estimates are not inclusive of step-down transformer stations at the loads themselves nor reactive compensation devices which will depend on the magnitude of the demand. Note that material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

Table 8-1 | Ring of Fire Transmission Option Conceptual Elements

Transmission Supply Option	Element #	Description	Length (km)	Cost ($2022 real)
North-South	1	230 kV single circuit line from East-West Tie circuits to Longlac	120	$170-215M
	2	New stations at East-West Tie connection point[32] and Longlac (to enable connection to A4L);	N/A	$115-125M
	3	230 kV single circuit line from Longlac to McFaulds Lake; roughly parallel to proposed roads	410	$575-740M
East-West	1	230 kV single circuit line from Wataynikaneyap TS near Pickle Lake to McFaulds Lake; roughly along route envisioned in the 2014 Remote Connection Plan	370	$580-745M
	2	Wataynikaneyap TS modifications	N/A	$20-30M

[32] Connecting the Ring of Fire line directly to East-West Tie lines between Lakehead TS and Marathon TS minimizes costs since it is the closest 230 kV supply point to the Ring of Fire. However, connecting to only one (or any subset) of the four parallel East-West Tie lines will unbalance flows between Marathon TS and Lakehead TS and may decrease the overall transfer capability of the East-West Tie. Future studies should weigh the costs and benefits of connecting to either Lakehead TS or Marathon TS versus a new junction and/or switching station on the East-West Tie.

While the East-West option is less expensive than the North-South option, it would provide less incremental capacity to supply load and would also increase exposure to outages. The load meeting capability for a radial expansion of the transmission system like the Ring of Fire is typically constrained by thermal, voltage, and load security limits. The thermal rating of a 230 kV single circuit line is unlikely to be constraining; as an example, a single East-West Tie circuit has a continuous rating of approximately 320 MW in the summer and 390 MW in the winter. This far exceeds the current known mining and remote community demand forecast. Voltage limits can be managed by installing voltage regulation devices at the loads and can be sized according to the expected demand, however this would add incremental cost and operational complexity. Load security limits, however, may become the most limiting factor depending on future mining developments.

Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 7.1 load security criteria specifies the maximum amount of load that can be interrupted after certain contingencies. For the loss of a single element (i.e. single circuit supply to the Ring of Fire), no more than 150 MW may be interrupted. This limits the total load served on the North-South option to 150 MW. The East-West option is connected downstream of the new single circuit Wataynikaneyap line (W54W). The total load served by W54W is also limited to 150 MW including the all existing loads and their growth, new mining customers along W54W, and the Ring of Fire and Matawa communities. Existing load served on W54W totals approximately 45 MW today and is expected to grow to 80 MW by 2040. While the remaining room is sufficient for serving the currently forecast demand at the Ring of Fire (30 MW mining plus Matawa area communities), it leaves relatively little room to accommodate additional development. Furthermore, the IESO is aware of several additional mining projects potentially seeking connection along W54W. While these projects are not yet certain enough to be included in the IRRP reference forecast, they could significantly reduce the available capacity for growth at the Ring of Fire.

While not addressed by ORTAC criteria, another consideration is the level of exposure to outages. The East-West option would involve connecting the Ring of Fire and Matawa communities to a radial system that already spans several hundred kilometers of transmission lines (W54W and D26A). Each time any part of this system is faulted (e.g., in an electrical storm or fire), the whole system is removed from service until the fault can be addressed. By comparison, the North-South option can be connected to the East-West Tie (or nearby station) which are more robust and has redundant supply.

Due to the uncertainty in future mining developments, it is too early to rule out the East-West option at this time. However, the potential capacity constraints and customer reliability impacts related to the East-West option should be considered when selecting a preferred transmission option. The next section discusses opportunities for alignment and further considerations that may impact the preferred transmission option.

8.4 Opportunities for Alignment

A decision to pursue transmission supply to the Ring of Fire, and decisions on its preferred routing, should consider alignment with four opportunities in addition to supplying mining demand at the Ring of Fire:

- Supplying Matawa Remote Communities
- Enabling potential hydro generation
- Improving supply to Longlac
- Co-locating with transportation corridor

These opportunities for alignment are discussed in turn below.

8.4.1 Supplying Matawa Remote Communities

There are five Matawa indigenous remote communities in the vicinity of the Ring of Fire:

- Webequie
- Nibinamik
- Neskantaga
- Marten Falls
- Eabametoong

These communities were previously identified as economic for grid connection in the 2014 Remote Connection Plan but elected not to participate in the Wataynikaneyap Transmission Project. The 2014 Remote Connection Plan found that it was more cost-effective to supply the communities via a single circuit 115 kV transmission line (either from Pickle Lake or the East-West Tie circuits) than continued reliance on off-grid diesel generation systems. Transmission supply to the Ring of Fire could also enable connection of the Matawa remote communities. Both the North-South and East-West transmission options would serve this purpose. Updated potential avoided diesel generation system costs are discussed in Section 8.4.2.

Note that the decision to pursuing grid connection is up to the communities. The IESO will continue to engage with the Matawa communities to inform future studies. Furthermore, grid connection of remote communities does not preclude local energy projects such as the installation of distributed generation and storage. The IESO continues to support broad equitable participation in Ontario's energy sector through its Energy Support Programs including the Indigenous Energy Projects (IEP) Program[33] which provides funding support to First Nation and Metis communities to assess and develop energy projects and partnerships.

8.4.2 Enabling Hydro Generation

In Jan 2022, the Ontario government asked Ontario Power Generation to examine opportunities for new hydroelectric development in northern Ontario. New hydroelectric generation could address the growing long-term electricity needs forecast for the province, with the potential for economic benefits for local and Indigenous communities in the north. Ontario Power Generation has shared this work with the Ministry of Energy and the IESO so that it can be considered as part of the IESO's work towards developing an achievable pathway to zero emissions in the electricity sector. Development of transmission supply to the Ring of Fire should consider the connection of potential hydro generation in the area.

There is significant hydroelectric generation potential in the vicinity of the Ring of Fire. Due to the geographic distribution of these potential generation facilities, the North-South transmission option is better suited than the East-West option to connect these facilities on the way to the Ring of Fire. Furthermore, the North-South option connects to a more robust point in the bulk transmission system which may result in fewer deliverability constraints and lower overall losses. The Ring of Fire North-South transmission line is not necessarily the optimal connection point for potential hydro generation near the Ring of Fire. Other connection options, to Pinard TS for example, may reduce the overall bulk system reinforcements needed to deliver the hydro generation capacity to southern Ontario. However, connecting to the Ring of Fire transmission line could significantly reduce the length of connection lines required for these potential hydro generators and future studies should consider the synergies between Ring of Fire transmission supply and enabling the connection of potential hydro generation.

8.4.3 Improving Supply to Longlac

The existing radial 115 kV circuit, A4L, to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages. While no firm growth plans or new customer connection requests were received during this IRRP, there continues to be a high degree of interest for mining and industrial developments in the Greenstone and Geraldton areas supplied by A4L. There are also existing customers along A4L who have elected to self-generate rather than connect to the transmission system due to capacity constraints.

A4L refurbishment is underway and distance-to-fault relays have been installed which should decrease the frequency of outages and improve restoration times. However, these improvements do not increase the load meeting capability on A4L and, as with many other areas in the Northwest region, growth can materialize quickly.

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[33] For more information, please visit the Indigenous Energy Projects Program webpage.

The North-South transmission option passes directly by Longlac TS and could help increase capacity and provide a secondary supply path to further improve reliability. The North-South option conceptual elements in Table 8-1 includes a 230/115 kV transformer station at Longlac for this purpose. Note that the East-West option is not suitable for reinforcing Longlac.

8.4.4 Co-locating with Transportation Corridor

The proposed Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link will provide a continuous all-season transportation corridor to the Ring of Fire. While detailed routing has not yet been performed, the North-South transmission option is well aligned with the proposed roads. The line length determined for the North-South option in Table 8-1 assumes that the transmission corridor runs parallel to the proposed roads wherever possible but the potential cost savings associate with colocation has not been factored into the transmission cost estimate yet. This likely overestimates the cost of the North-South transmission option compared to the East-West option; future studies should conduct more detailed engineering design and routing analysis to better quantify the benefits of colocation.

Co-locating linear infrastructure is consistent with provincial policy as articulated in Section 1.6.8 of the 2020 Provincial Policy Statement[34] and may help reduce environmental impacts. The roads would also provide easier access to the transmission line which could simplify construction as well ongoing operation and maintenance. Note that there are no proposed all-season roads along the East-West option route.

8.5 Avoided Matawa Communities Diesel System Costs

The Matawa remote communities are currently supplied by remote on-site diesel generation which is costly to operate. Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions from fuel transport. The costs of supplying electricity from remote diesel generation systems versus the grid over the first 20 years of transmission connection are shown in Figure 8-3. The net present value of remote diesel generation costs is estimated to be $446M over this period, while serving the same load from the provincial grid is estimated to be roughly $35M.[35] These net present values are expressed in real dollars in the year when transmission connection is hypothetically brought in-service. For the purpose of this assessment, it was assumed that transmission connection occurs in 2030 given the typical 7-year lead time of new transmission projects.

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[34] The 2020 Provincial Policy Statement can be found on the Ontario government's Land Use Planning webpage.

[35] The cost of serving loads on the provincial grid is solely based on the system's marginal cost of energy. It does not include cost of transmission connection itself. Connecting remote communities is one of multiple potential benefits (other benefits include supplying mining loads and enabling hydro generation) that contribute towards a rationale for transmission supply. The cost of transmission supply should be compared against this full suite of benefits.

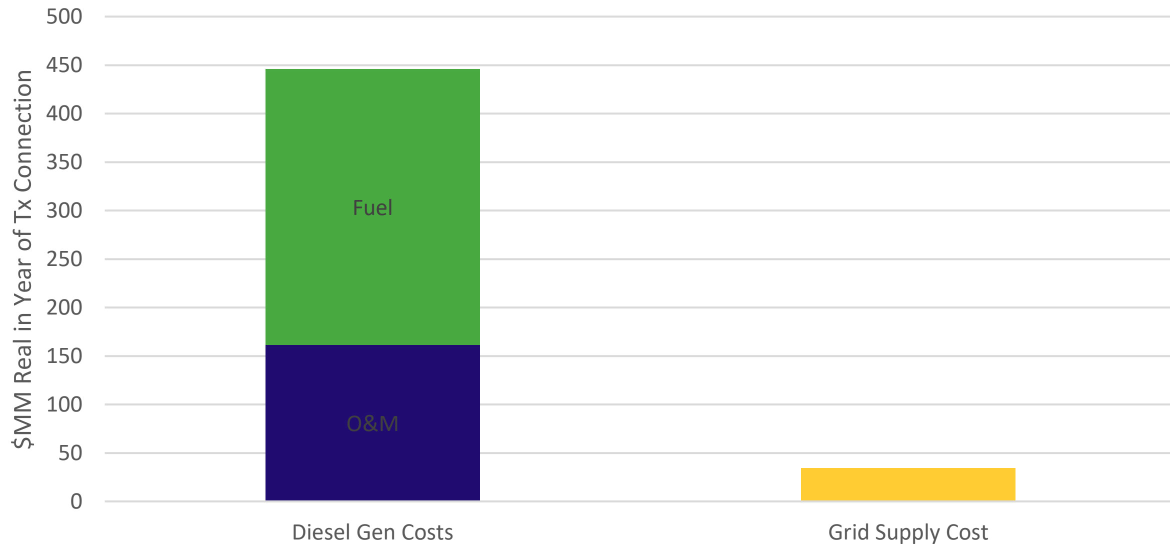

Figure 8-3 | NPV of Electricity Supply Costs from Diesel Generation versus the Provincial Grid for Matawa Remote Communities over the First 20 Years of Grid Connection

The cost of continuing to supply electricity to the remote Matawa communities by local diesel generation was estimated using the IESO's internal fuel forecast and aggregated cost data for remote communities served by Hydro One Remote Communities.[36] Generally speaking, economic and cost assumptions were consistent with the 2014 Remote Connection Plan adjusted for inflation. The cost of supplying electricity from local diesel generation is comprised of two components:

- Fuel costs including the cost for the fuel itself, winter road/air transportation, and the cost of carbon;
- Operating and maintenance costs estimated from historical revenue requirement and rate application regulatory submissions as a percentage of fuel costs.

[36] Not all Matawa communities are served by Hydro One Remote Communities. For communities served by Independent Power Authorities for which cost data was not directly available, system costs were estimated based the size of their load and Hydro One Remote Communities' system costs.

Of the $446M net present value, $284M is associated with fuel costs and $162M with operating and maintenance costs. Note that this cost estimate does not include the capital costs associated with expanding existing diesel systems to meet future capacity growth. This enables an apples-to-apples comparison with the cost of grid electricity which also did not include the incremental resource capacity cost of serving the newly connected remote communities. Furthermore, since the incremental capacity requirement is dependent on the year in which transmission connection occurs and the system needs/market conditions in the period following grid connection, capital costs associated with this capacity cannot be accurately calculated today. Future studies should refine the consideration of capacity costs when there is more certainty on when transmission supply will proceed.

The cost of serving Matawa remote communities should they be connected to the provincial electricity grid was based on the system marginal cost forecast in the 2021 Annual Planning Outlook.

8.6 Avoided Greenhouse Gas (GHG) Emissions

Avoided GHG emissions was estimated for the Matawa communities and the future mining load through the comparison of emissions on the electricity system (consistent with the 2021 Annual Planning Outlook emission rate per MWh) versus diesel generation for remote communities and natural gas generation for mining loads.[37]

The GHG reduction associated with connecting Matawa communities depends on the forecast demand levels and growth rate when transmission connection occurs. Consistent with the diesel system cost savings estimates in the previous section, transmission connection was assumed to occur in 2030. On average, over the first 20 years of transmission connection (i.e. 2030-2049), GHG reductions are expected to be approximately 27,000 tCO2e per year.

The GHG reduction associated with mining loads depends on the amount of demand that materializes. As discussed in Section 8.2, there is a high degree of uncertainty in terms of both the magnitude and timing of this demand. For illustrative purposes, if 30 MW of demand materializes (consistent with demand from known projects), GHG reductions would total 68,000 tCO2e per year. If 70 MW of demand materializes (consistent with demand from the 2015 IRRP forecasts), GHG reductions would total 160,000 tCO2e per year. The true avoided GHG emissions associated with connecting mining loads instead of on-site generation could be much higher given the large number of active mining claims in the Ring of Fire.

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[37] The natural gas generation was assumed to be a combined cycle gas turbine (CCGT) facility with a heat rate of 7.265 MW/MMbtu and a natural gas emission intensity of 53.157 kgCO2e/MMbtu. For diesel generation emissions, the Hydro One Remote Communities fleet average generator efficiency and a diesel emission intensity of 75.22 kgCO2e/MMbtu was assumed.

8.7 Next Steps

The sections above provide an overview of preliminary findings to date of the Supply to the Ring of Fire Study and highlights some areas of uncertainty that will require further investigation. The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope, timing, and engagement process will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

9. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for this Northwest IRRP.

9.1 Engagement Principles

The IESO's engagement principles[38] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

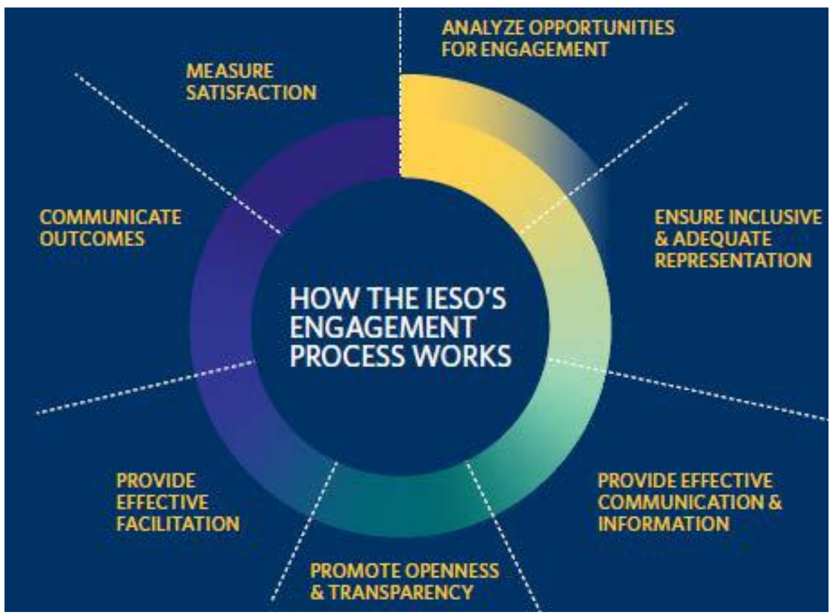

Figure 9-1 | IESO's Engagement Principles

38 https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

9.2 Creating an Engagement Approach for the Northwest

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage[39] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted discussions sessions;
- Face-to-face meetings; and
- One-on-one outreach with specific communities and stakeholders to ensure that their identified needs are considered (see Sections 9.4 and 9.5).

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[39] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the Northwest region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the Northwest Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to ensure that municipal energy planning, including the need to recognize climate change priorities, as well as economic development and industrial growth (including forestry and mining) were in scope of the development of the IRRP. In addition, reliability remained a paramount concern within this region. Along with a response to the feedback received, the final Scoping Assessment was posted on January 13, 2021, which identified the need for a coordinated regional planning approach across the Northwest region – particularly important since the previous planning cycle targeted regional plans within five identified sub-regions.

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input. Four public webinars were held at key stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on various components of the plan.

All these engagement sessions received strong participation with a cross-representation from stakeholders and community representatives. Feedback was received as a result each engagement meeting which was considered in each of the stages in the IRRP development.

The public webinars invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

In addition, three targeted discussions were held virtually to uncover specific feedback from communities and stakeholders on the following three topics:

1. Customer Reliability Concerns
2. Emerging Local Initiatives
3. Emerging Electricity Needs in the North of Dryden Area

Comments received during this engagement focused on the following major themes:

- Given the large geographic area for this planning region, consideration throughout the engagement should be given to targeted discussions to address local reliability and priorities. Education and support should be available to enable purposeful engagement for all interested parties
- Consideration in the demand forecast should be given to local developments, growth plans and climate change goals (i.e., electrification) – particularly in communities where capacity may be limited
- Non-wires alternatives should be considered to meet needs and, in particular, climate change priorities; existing resources in the region should be considered where contracts are due to expire
- Due consideration should be given to providing capacity for new commercial and industrial (mining and forestry) growth as well as electrification of existing industry
- Opportunities for future proponents to leverage existing partnerships or create new relationships among local and Indigenous communities to have due consideration of priorities and provide business prospects, where possible

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities as well as the members of the Northwest Regional Electricity Network.

Based on the discussions through the Northwest IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for development of the mining sector in this region and to look for alternative energy solutions to meet local needs, particularly as communities and industries shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's Northwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and planning initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Northwest IRRP engagement webpage.

9.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with targeted municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; reliability concerns; and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities located in or near the Northwest region to participate in webinars that were held on:

- December 8, 2020
- May 20, 2021
- September 27, 2021
- November 2, 18, 29, 2021
- April 25 and 26, 2022
- November 3, 2022

The First Nation communities that were invited to the webinars were:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Couchiching
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort William
- Grassy Narrows
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Lac des Mille Lacs
- Lac La Croix

- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Mitaanjigamiing
- Muskrat Dam Lake
- Naicatchewenin
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Nigigoonsiminikaaning
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake
- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Whitesand
- Wunnumin Lake

The Métis communities that were invited to the webinars were:

- MNO Atikokan Métis Council
- MNO Greenstone Métis Council
- MNO Kenora Métis Council
- MNO Northwest Métis Council (Dryden)
- MNO Sunset Country Métis Council (Fort Frances)
- MNO Superior North Shore Métis Council (Terrace Bay)
- MNO Thunder Bay Métis Council
- Red Sky Independent Métis Nation

9.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

There are no new transmission projects recommended as a result of this Northwest planning initiative.

10. Conclusion

The Northwest IRRP identifies electricity needs in the region over the 20-year period from 2021-2040, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

In the near term, the IRRP recommends new and/or upgraded stations to address station capacity needs at Crilly DS and Margach DS, further refinement of non-wires alternatives at Kenora MTS, reconfiguration of Fort Frances TS to improve customer reliability at Fort Frances MTS, and additional reactors at or near Pickle Lake SS to manage high voltages so that E1C can be operated normally open. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The IRRP recommends that the Working Group monitor growth, particularly in the Red Lake and Fort Frances areas. The IRRP studied high growth sensitivities to establish load meeting capabilities in these areas against which growth should be monitored to determine when future regional planning activities should be triggered. The IESO will update its mining sector demand forecast in early 2023 and provide updates to the Working Group. Electricity demand at White Dog DS and Marathon DS should also be monitored to confirm the timing of station capacity needs emerging in the 2030's. No firm recommendations are required for these potential long-term needs at this time.

The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope and timing will evolve with government policy direction and the IESO will share updates with the Working Group to inform upcoming regional planning activities.

The Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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Connecting Today.
Powering Tomorrow.

Appendix E: Atikokan Hydro Renewable Energy Generation Investment Plan 2016

ATIKOKAN HYDRO INC.

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July 15, 2016

Regulatory Affairs
Ontario Power Authority
120 Adelaide Street West
Toronto, ON M5H 1T1
Regulatory.Affairs@ieso.ca

To Whom it may concern,

Atikokan Hydro Inc. is pleased to share its renewable energy generation investment plans with the OPA as per OEB Distribution System Plan filing requirements. Atikokan requests the OPA provide comment on the plan.

OEB filing requirements indicate the OPA comment letter should include:

- The applications it has received from renewable generators through the FIT program for connection in the distributors service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan

Atikokan Hydro further respectfully asks the OPA to approve our plan within 30 days so it can be submitted to the OEB with our cost of service rate application. If any questions or additional information required, the undersigned may be contacted.

Sincerely

Jennifer Wiens

Jennifer Wiens
CEO/Sec/Tres
Atikokan Hydro Inc.

ATIKOKAN HYDRO INC

RENEWABLE ENERGY GENERATION INVESTMENTS PLAN

Table of Contents

Introduction

As per the Chapter 5 Consolidated Distribution System Plan Filing Requirements Atikokan Hydro is submitting its renewable energy generation investments plan for consideration and comment from the OPA.

Atikokan Hydro Inc. is a Northwest Ontario licensed electricity distributor (ED-2003-0001), supported by transmission assets within Northwestern Ontario ,that owns and operates electricity distribution systems that provides service to the Town of Atikokan; service area of approximately 380 km square. Electricity is delivered from Hydro One's Moose Lake Transformer Station (TS) to Atikokan Hydro's substations via two 44 kV circuits. Atikokan Hydro then distributes electricity at the appropriate voltage to residential and commercial customers. As of July 1, 2016 Atikokan Hydro had a total of 1646 residential and commercial customers combined and 625 streetlight connections. Less than one percent of Atikokan Hydro's customer base have renewable generation contracts. Of these contracts; these are all Micro FIT, none are under the FIT program.

Current assessment of the distribution system

Atikokan Hydro's point of supply is Moose Lake TS owned by transmitter Hydro One Networks Inc. Moose Lake TS is a standard vintage TS with a dual bus arrangement (B2 & B3) that can be tied together. The primary side is a 115 kV with a complex closed transition switching arrangement amongst four circuits. The four circuits are the A3M (Mackenzie TS to Moose Lake TS}, the M2D (Moose Lake TS to Dryden TS), the B6M (Moose Lake TS to Lakehead TS) and the M1S which serves as a collector for privately owned hydro electric generators including Valerie Falls, Calm Lake and Crilly.

Atikokan Hydro owns the 3M2 and 3M3 sub transmission feeders fed from the B2 and B3 bus respectively. These two lines operate at 44 kV and are connected directly to the Moose Lake TS. See the attached map, Appendix A, showing the two circuits. Moose Lake TS has two transformers which differ in size ratings; T2 transformer is 8 MWA while the T3 transformer is 15 MVA. The thermal capacity listed in Hydro One's List of Station Capacity supports this difference in size ratings. The following table was documented in Hydro Ones' listing.
(Retrieved from http://www.hydroone.com/Generators/Documents/HONI_LSC.PDF, pg. 16)

Table 1 Hydro One Station Capacity

Hydro One Station Capacity								
Station Name	**Bus Name**	**Feeder Name**	**Voltage (kV)**	**Minimum Load (MW)**	**Short Circuit Capacity (MVA)**	**Thermal Capacity (MW)**	**Upstream TS**	**Upstream TS Feeder**
Moose Lake TS	B2	M2, M5	44	0.8	1204.6	4.6		
Moose Lake TS	B3	M3, M6	44	1.1	1139.8	8.3		
Moose Lake TS	Total	M2, M3, M5, M6	44	1.8	N/A	5.7		

In preparation of Atikokan Hydro's GEA Plan, Atikokan referred to the IESO's document, LRP: Connection Availability and TAT Tables, dated June 4, 2015. (http://www.ieso.ca/Documents/generation-procurement/lrp/lrp-1-final/LRP-Connection-Availability-and-TAT-Tables.pdf, pg 7, 8, 13 and 35). The following was compiled for the Northwest area and specifically those closely tied to Atikokan Hydro.

Table 2: Connection Availability – Circuit

Connection Availability Table - Circuit				
Transmission Circuit	**Area**	**Area Availability (MW)**	**Circuit Availability (MW)**	**Name of Transmitter**
A3M	Northwest	**No Area Availability**		Hydro One Networks Inc.
B6M	Northwest	**No Area Availability**		Hydro One Networks Inc.
M1S	Northwest	**No Area Availability**		Hydro One Networks Inc.
M2D	Northwest	**No Area Availability**		Hydro One Networks Inc.

While not listed in Table 1; it should be noted the connection area availability for all Northwest stations, there is 'No Area Availability'. Additionally, data available in 2011 indicated area availability for FIT capacity as 100 MW. It is clear from both the present data and research, circumstances have changed and there is currently no room; the capacity has been awarded in previous contracts.

Table 3: Connection Availability – Station

Connection Availability Table - Station										
Station Name	**Bus Name**	**Thermal Availability (MW)**	**Short Circuit Availability (MVA)**	**Upstream Supply Circuit #1**	**Availability of Supply Circuit #1 (MW)**	**Upstream Supply Circuit #2**	**Availbility of Supply Circuit #2 (MW)**	**Area**	**Area Availbility (MW)**	**Station Owner**
Moose Lake TS	B2							Northwest	**No Area Availability**	Hydro One Networks Inc
Moose Lake TS	B3							Northwest	**No Area Availability**	Hydro One Networks Inc
Moose Lake TS	Total							Northwest	**No Area Availability**	Hydro One Networks Inc

In both the above Circuit and Station tables the area availability indicates 'no area availability' meaning ineligibility for Large Renewable Procurement (FIT). Therefore, in summation, the available capacity to connect generation to these feeders is not an option based on the most current published information.

Hydro One have indicated that Moose Lake TS is due for upgrades and refurbishment due to end of life of the assets. Both Hydro One and Regional planning indicates refurbishment to occur in 2019. This may be considered as one reason the area availability is marked as 'no area availability' and as such ineligible.

Description of Feeders

Atikokan Hydro as noted above has two feeds from Moose Lake TS. 3M3 feeder is fed from T3 (B3 bus) and 3M2 feeder fed from the T2 (B2 bus). As noted previously, the T3 transformer has the greatest physical capacity. Both 44 kV circuits (3M3 and 3M2) come into town and are paralleled such that the open point can be variable. Mostly the two lines are kept at open point in the middle but the two lines create greater reliability as an alternative electricity source in event one line is down or needed to take out of service for maintenance as an example. Although the T3 has greater capacity, neither bus' have the area availability for renewable generation connection as referenced in Table 2 on page 2.

Information on the planned development of the system to accommodate renewable generation connections

Atikokan Hydro does not have investments planned at this time to accommodate renewable generation connections. Atikokan Hydro is not aware of any FIT applications nor Micro FIT connection requests; for this reason it is not justifiable to allocate dollars to system developments for renewable generation connections.

Further Atikokan Hydro has no historical capital or OM&A expenditures related to renewable generation connections; therefore, no approved expenditures funded through current rates.

Atikokan Hydro will however cooperate and evaluate system capacity if potential interest arise.

Applications from renewable generators over 10 kW

Atikokan Hydro does not have any applications from renewable generators over 10 kW for connection and to Atikokan Hydro's knowledge the OPA/IESO has never had to approve or deny any applications for renewable generators over 10 kW for the FIT program.

Overall potential for developing renewable generation in the distributor's service area.

To Atikokan Hydro's knowledge there is no present interest in developing renewable generation under the FIT program nor micro FIT connections.

It should be noted with Atikokan's Hydro's configuration, a good utility practice would be accepting micro FIT'S only at this time. To have the potential and ability to connect FIT projects, significant investment would be required; negatively impacting customer's rates. The configuration of Atikokan's substations is discussed in further detail in the next section.

Constraints within for the distributors system related to the connection of renewable generation

Atikokan Hydro has four substations fed from the two 44 kV feeders. Three of the substations are located within the more densely populated area of Atikokan hydro's service area. These substations supply five feeders. These feeders are configured to allow load to be transferred from one feeder to the other without interrupting service to customers. This has an advantage of being able to match load to substation capacity as well as restoring power should a substation be interrupted. This is often termed a ring bus configuration that can accommodate closed transition switching.

The substations are protected by fuses and load break switches. If generation were to be added, regardless of the location, it would need to be sized to accommodate reverse flow in the smallest sub station. The smallest rated substation being Hogan at 2 megs or 2000 kilowatts. Upgrading substations would have a significant negative impact on rates for Atikokan Hydro customers considering load is not expected to grow significant in the next 5 years. In fact, Atikokan Hydro has historically been dropping in customer count.

Upstream constraints of a host distributor or transmitter that may affect the ability to accommodate renewable generation connection in the distributor's service area

Atikokan Hydro does not expect additional micro FIT projects in the near future assuming incentives and pricing remain the same. Atikokan Hydro's last connection was October of 2014; over a year and a half ago. The table below summarizes Atikokan Hydro's connections to date and suggests the greatest interest occurred in 2011 and 2012 and diminished thereafter. No recent applications have been submitted nor pending connections since the total existing 15 micro FIT contracts were issued. Therefore, Atikokan Hydro is not aware of any future new connections or generation impacts. Provided the future is consistent with the last few years minimal to no activity, Atikokan Hydro does not find it prudent to make investments or apply for rates to support investments to support renewable FIT installations in this filing period. Previous connections were at no costs to Atikokan Hydro; any applicable connection costs including the cost of the meter was incurred by the customer. Similarly, future generators will also be responsible for any applicable installation costs. Atikokan Hydro will continue to assist and work with any potential upcoming micro FIT generators and ensure connections are made in a timely manner. Atikokan Hydro has reason to believe based on existing configuration, future micro FIT generations can be accommodated but each connection will have to be evaluated due to substation capacity; ensuring reliability is maintained.

Table 4: Summary of Atikokan Hydro Generators

Summary of Atikokan Hydro Micro FIT Generations		
Year Connected	**Number of Connections**	**Total Nameplate Capacity (Kw)**
2010	2	6.29
2011	6	55.95
2012	3	28.38
2013	1	10
2014	1	9.8
2015	0	0
Total	**13**	**110.42**

Table 5 : Summary of Atikokan Hydro Connections

Summary of Atikokan Hydro Individual Connection Capacity

Connection	Nameplate Capacity (kW)
Micro FIT #1	4.20
Micro FIT #2	3.99
Micro FIT #3	6.84
Micro FIT #4	8.17
Micro FIT #5	9.40
Micro FIT #6	9.88
Micro FIT #7	9.88
Micro FIT #8	9.88
Micro FIT #9	9.89
Micro FIT #10	9.89
Micro FIT #11	8.60
Micro FIT #12	10.00
Micro FIT #13	9.80

Note: Above connections are listed in order of connections

Micro FIT Nameplate Capacity	Smallest connection	4.20	kW
	Largest connection	10.00	kW
	Average connection	8.49	kW
	Total connections	110.42	kW

In terms of total connections, it should be noted, Atikokan Hydro has 13 Micro FIT customers; however, there are actually 15 Micro FIT contracts awarded by the IESO. Two applicants were awarded contracts but added incremental installations with both IESO and Atikokan Hydro connection and contract approval. One applicant added both the original installation and incremental installation in the same year (2010); whereas, the other application completed the original installation in 2011 and added the incremental installation thereafter in 2012.

Downstream constraints that the distributor may cause for an embedded distributor

Atikokan Hydro does not have an embedded distributor but the constraints discussed previously would apply if this was applicable.

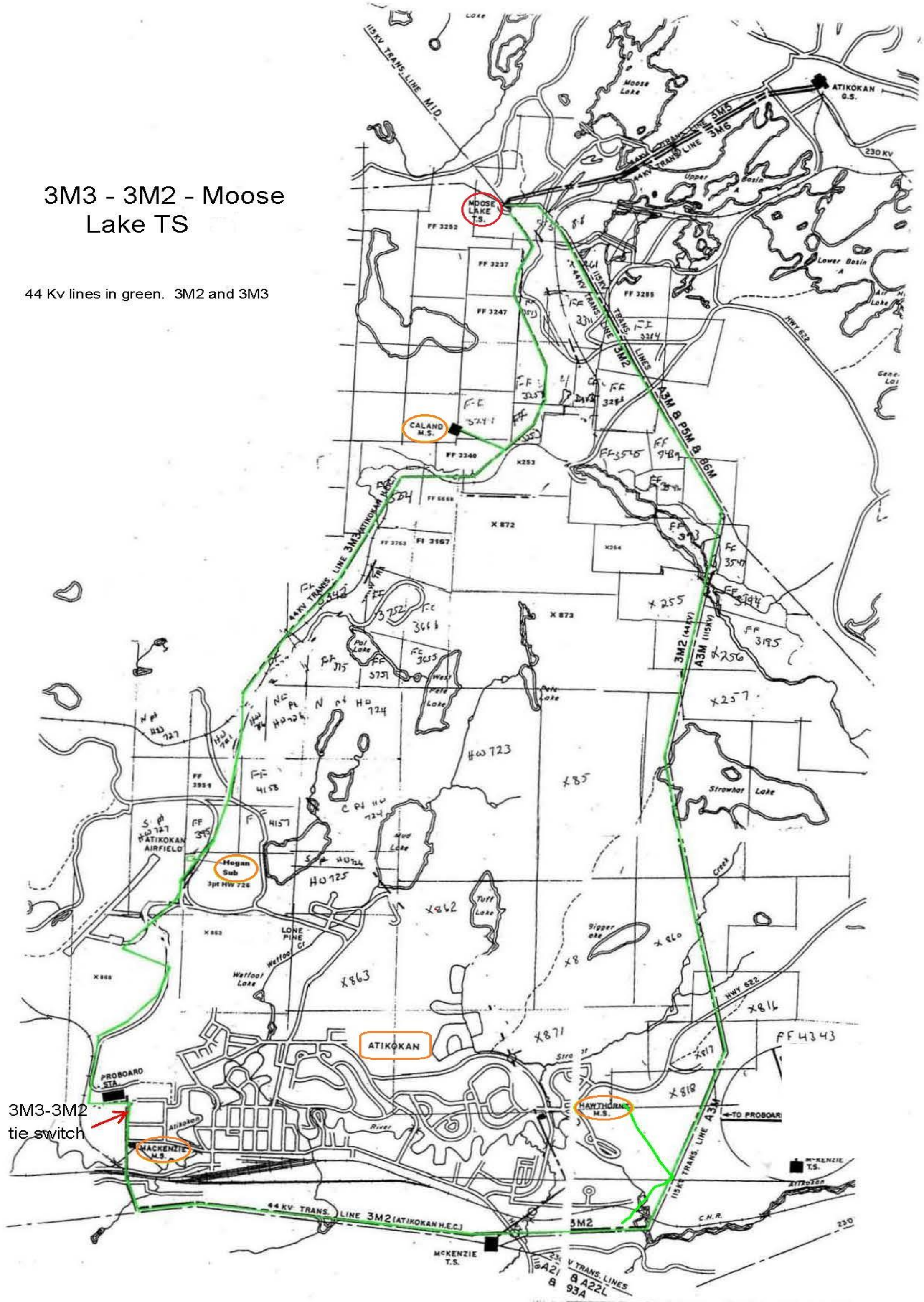
Any information received from the OPA regarding integrated planning for regions of the province or the province as a whole

Atikokan Hydro participates with the IESO in the Integrated Regional Resource Plan (IRRP) West of Thunder Bay with the other working group members. The IRRP is only in draft form at this time. However, there has been consideration to increase the capacity of the 230 kV circuit from Atikokan to the Dryden area and beyond. There are no other major considerations at this time. In the northwest, planning is driven by new or expanding large transmission connected industrial customers, unlike southern Ontario which is mostly driven by growth in the LDC customer base.

Conclusion

In closing, Atikokan Hydro will continue to be open to future interested generator applicants. Atikokan Hydro does however believe its existing configuration leaves capacity limited and Micro FIT generators would be the best utility practice without having a negative impact on reliability and customer rates. The upstream constraints at Moose Lake TS, including the unequal transformer sizes and the 'no area availability' will prevent any renewable generation connections in the near or foreseeable future. Atikokan Hydro will continue to monitor the capacity for the Northwest region, but given present time indicators, it would not be prudent for Atikokan Hydro to make investments or apply for rates to support renewable FIT installations for at least another 5 years.

Appendix A: 3M2 and 3M3 44 kV Lines



IESO Letter of Comment

Atikokan Hydro Inc.

Renewable Energy Generation Investment Plan

July 29, 2016

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Aitkokan Hydro Inc. – Distribution System Plan

On July 15, 2016, the IESO received Atikokan Hydro Inc.'s ("Atikokan Hydro") 5-year Renewable Energy Generation Investment Plan ("Plan"). The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

With respect to existing and proposed REG connections, Table 4 of the Plan illustrates that Atikokan Hydro has connected 15 microFIT projects totalling 110.42 kW of capacity. The Plan indicates that the last connection was in 2014 and there are no FIT projects connected, or FIT and microFIT applications awaiting connection (pp. 4 and 5). Atikokan Hydro also indicates that it does not expect additional renewable generation connections in the near future, and proposes no REG connection investments at this time.

According to the IESO's information as of June 30, 2016, the IESO has offered contracts to 15 microFIT projects totalling 105 kW of capacity. The REG connections information in Atikokan Hydro Inc.'s Plan is therefore substantially consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

Atikokan Hydro is one of the five local distribution companies in the West of Thunder Bay Sub-region, which is a sub-region of the Northwest Ontario Region identified through the Ontario Energy Board regional planning process. As member of the Technical Working Group for the West of Thunder Bay Sub-region, Atikokan Hydro has been involved in the development of the West of Thunder Bay Integrated Regional Resource Plan ("IRRP"), which was published on July 27, 2016[2].

The regional planning process for this region is now complete and will be undertaken again when the next 5-year planning cycle commences, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

The IESO appreciates the opportunity to comment on the Renewable Energy Generation Investment Plan provided by Atikokan Hydro Inc. as part of its Distribution System Plan.

[2] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/West-of-Thunder-Bay.aspx

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Appendix F: Atikokan Hydro Letter to HONI

ATIKOKAN HYDRO INC.

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Atikokan, Ontario P0T 1C0

Telephone (807)597-6600
Fax (807)597-6988
e-mail jen.wiens@athydro.com
Website: www.athydro.com

March 1, 2018

Hydro One Networks Inc.
[redacted], Account Executive
[redacted]

Dear John,

Please accept this letter as a formal request to Hydro One Networks Inc. (HONI) in follow up of some discussions that have recently taken place.

It is mutually agreed all LDCs including HONI itself, have challenges and face barriers and must make decisions with the rate payers in mind and abiding by license conditions regulated by our regulator, the OEB. Atikokan Hydro believes the location of Atikokan's connection point to Hydro One; the Moose Lake Transformer Station, a challenge and believes there would be financial and operational benefit to not only the local Atikokan community but to HONI if the Moose Lake TS was relocated to Mackenzie TS. The 23 km of sub-transmission line could be abandoned.

Back in 1994, Atikokan Hydro had an option to:
1. acquire 3m2 from Hydro One,
2. build a transformer station at Mackenzie Substation abandoning the 44 Kv bush lines or
3. bear specific facility charges and line losses.

At the time, option 1, purchasing the 3M2 line from Hydro One was the most feasible.

As discussions between HONI and Atikokan support; Atikokan Hydro has often reconsidered the option of abandoning the 44Kv bush line and how Atikokan Hydro could have an influence on relocating the Hydro One owned transformer station in town at the Mackenzie location. However, back in 1994 this option was unachievable due to the financial burden; over twenty years later and the same financial barriers remain. Atikokan cannot solely bear the costs associated with relocating the connection point, Moose Lake TS.

Justifying the location of the TS is difficult for Atikokan Hydro. 1) The utility does not have a customer base along these sub transmission lines into the town corridor. The map enclosed with this letter visually shows the distance between the location of the Moose Lake TS and town limits. The combined two sub-transmission lines into town comprise of 23km. Atikokan has only a few customers in the near vicinity of the Moose Lake TS. 2) HONI infrastructure exists at Atikokan town limits for other HONI connections. 3) Atikokan sub transmission lines are located along bush lines with limited accessibility of many pole structures 4) inevitable accessibility constraints and inundating of infrastructure due to flooding of SteepRock Mine Site.

Atikokan Hydro has approached HONI with requesting relocating the TS but HONI has indicated the costs would need to be recovered and paid by AHI as per direction of The Transmission System Code. For this reason, similar to back in 1994, Atikokan Hydro and is looking for options and as a result asks HONI to have consideration and make comment to the following below scenarios.

1. What would a HONI Service Contract look like, costs included, if HONI was to provide operating and service support for the 23 km of feeders?
2. What would be the overall impact of proposing to the OEB the sale of the 23km feeder from AHI to HONI? Atikokan recognizes it would require OEB approval, and HONI Management would need to be willing to pursue this transaction; however, AHI asks HONI to look at impacts and include any financial impact beyond just the sale of the line, such as difference in Settlements of future rates that AHI would pay either to IESO or, as embedded Distributer, to HONI Dx.
3. At what point would Atikokan Hydro's operational decisions as a result of the environmental issue rising water levels affect and impact HONI operations and considerations.

Atikokan Hydro asks HONI to work with Atikokan to determine a mutually agreed solution or plan to address the barriers before us. HONI alike, Atikokan Hydro is identified as one of utilities with the highest distribution charges in the province; thereby, as part of the Ontario Fair Hydro Plan Atikokan Hydro is included in the Distribution Rate Protection Program providing a cap on the amount that can be charged for base distribution charges to residential customers. AHI believes that relocation of connection may appear to alleviate operational/economical challenge to AHI, the focus point is the 23km of two (2) 44kV feeders from Moose Lake TS to Atikokan. This 23km is identified by AHI as the major contributor to impacting AHI's ability to reduce costs bore by AHI's rate payers. If a business case for relocating the Moose Lake TS is not plausible, what options do Atikokan Hydro have to address our concerns all while providing reliable power to our customers at an acceptable and affordable rate.

Thank you for your consideration. We look forward to your response.

Sincerely,

Jennifer Wiens
CEO/Sec/ Tres

cc: Atikokan Hydro Board of Directors
[redacted]

Appendix G: 2017-2021 DSP EB-2016-0056, pages 10 to 12

5.2.1 Distribution System Plan Overview

This section provides a high overview of the information filed in this plan.

(5.2.1a) Key Elements of the DS Plan

Key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives.

In review of Atikokan Hydro's historical capital investments, it is obvious several years Atikokan did not invest in distribution assets but heavily invested in non-distribution assets and also investment in capital did not exceed annual amortization. A few major non-distribution purchases were incurred and significant dollars were allocated to installing smart meters. For this reason, the key elements of the DS Plan are system renewal, to replace distribution assets that have exceeded their useful life but also general plant purchases for non-distribution assets will be required. As providing a safe and reliable electricity service, workers must have safe and reliable equipment to maintain the distribution system. The distribution system plan must be balanced to maintain a safe and reliable supply of electricity to its ratepayers but at a pace to keep the financial health of the LDC including positive cash follows and manageable debt to equity ratios.

Historically, significant dollars are not spent on system access as Atikokan does not experience growth in its customer base thereby modifications or expansions for customer connections is not required. It is strictly maintaining existing service connections. However, with smart meter seals expiring during the DS Plan period, investments will be made to this System Access. Additionally, where it cannot be quantified at this time, planning and resources will be needed towards system access in the near term for an environmental reason. Thus far at the time of this filing, only preliminary discussions have occurred around an environmental situation affecting future service reliability. No formal consultations have occurred to allocate specific investments and timelines. The planning and resources mentioned will be required for addressing Steep Rock Reclamation concerns. History of the Steep Rock Reclamation is described next providing greater explanation of the situation.

Steep Rock Reclamation can be identified as water management both during mine operations and after Mine Abandonment. *"The Steep Rock Iron Mines at Atikokan, Ontario operated from 1944 to 1979. The iron ore was location at the bottom of Steep Rock Lake and water management was a key factor in developing the mines. Open pit mining required a massive water diversion scheme, including the diversion of the Seine River, draining of Steep Rock Lake, and construction of various dams and other diversion structures. In order to abandon the mine, the Province of Ontario required a suitable abandonment and long-term water management plan, and assessment of the condition of various water control and diversion structures. Reclaiming of the Seine River to its original course was not possible and, consequently, the water control structures, primarily dams and tunnels, will be operating in perpetuity."*

"In 1985, the coal-fired Atikokan Electrical Generating Station, constructed by Ontario Power Generation…. Took over many of the dams and water control structures constructed from the mine as part of the water control system for the Atikokan Generation Station. Ontario Power Generation has assumed responsibility for pumping the water that collects upstream of the Fairweather Dam." [1] *[1Reference: Water management of the Steep Rock Iron Mines at Atikokan, Ontario during construction, operations and after mine abandonment, Sowa, Victor A.; Adamson, R. Bruce; Chow, Allan W. , 2001]*

Atikokan Hydro delivers electricity to Ontario Power Generation (OPG) running the pump to control the water levels. A substation located at the old Caland Ore Mine Site exists to supply OPGs s pump and a few other customers in the area but OPGs pump being the largest customer. The cost to maintain the substation and hydro lines for the few customers has had much debate over the years. The pumping of the water as water management has been vital to public safety, protecting existing developments and environmental protection as a result of dredge spoil material impounded during the mining operation. The Ministry of Natural Resources has been monitoring elevations and the rate at which the mines pits are filling up. Recent informal discussions with the Ministry of Natural Resources have indicated flooding will be unavoidable. Recent research has suggested within a 5 to 7 year timeframe Atikokan Hydro will see infrastructure and road access to its distribution substation [Caland] compromised. Because of the latest timelines, the MNR is now evaluating potential temporary solutions (if possible) and notifying affected parties. Since preliminary [informal] discussions Atikokan Hydro has requested the MNR confirm details in writing but at the time of this application has not heard any communications in writing. From a planning and regulatory perspective, Atikokan Hydro needs a letter to support its Distribution System Plan filing. As per the Distribution System Code and noted in the Transmission System

Code, Atikokan Hydro must notify the affected customers of the impacts and significant costs that will be incurred. Further Atikokan Hydro will be applying to the Ontario Energy Board with a rate application to recover these costs incurred upon greater evidence and a source of plan of action. Formerly, the Ministry of Natural Resources and Forestry indicates that the risk of flooding of the Moose Lake TS is not expected to occur until 2070. Comments were made to aid Regional planning in the end of life refurbishment of the Moose Lake TS; however, the timeframes and impacts on other infrastructure in the area was not clear. In light of the latest information, Atikokan Hydro is trying to gather the evidence and push for a sense of urgency with the MNR to provide responses in writing to evaluate the situation and possible solutions and how reliability of power supply can be maintained. Atikokan intends to stay abreast of this situation.